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

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December 30, 2014

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

Re: Cost of Gas Adjustment (COG)
January 2015

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 (106th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (106th Revised Sheet No. 8), showing the January 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $1.5090 per dk for residential and firm general service customers and a decrease of $1.6016 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for January 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $1.5871 per dk since the last COG filing. There has been an increase in pipeline charges of $0.0781 per dk due to a change in pipeline rates. In addition, Great Plains' has moved the recovery of the LMS costs to the commodity portion of the COG filing instead of the demand portion. The net effect of these changes is a decrease of $1.5090 per dk for residential and firm general service customers since the last COG filing.

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

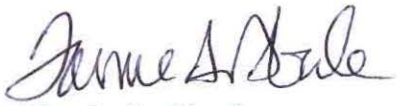
Attachment D shows the calculation of the balancing account since April 30, 2014.

Great Plains submitted a check for $650.00 on November 26, 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 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,



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

106th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 105th Revised Sheet No.1.1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/dk
Firm Gas Service - General	2	$3.50 per month	First 10 dk	$1.2869	$6.5971	$7.8840
			Over 10 dk	1.0646		7.6617
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$4.6072	$5.7578
			Next 2,600 dk	0.9021		5.5093
			Over 3,000 dk	0.7486		5.3558
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$4.6072	$5.8588
Transportation Service	5	$3.50 per month	First 400 dk	$1.1506		$1.1506
			Next 2,600 dk	0.9021		0.9021
			Over 3,000 dk	0.7486		0.7486

Date Filed: December 30, 2014

Effective Date: Service rendered on and after January 1, 2015

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

106th Revised Sheet No. 8

Canceling 105th 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	$0.0662	$5.1708	$0.0000	$5.2370	$5.1708	$0.0000	$5.1708
Accumulated Adj.	1.4690	0.0539	1.3462	2.8691	0.0684	0.9696	1.0380
Current Adj.	0.0781	(1.5871)	0.0000	(1.5090)	(1.6016)	0.0000	(1.6016)
Total Adj.	1.5471	(1.5332)	1.3462	1.3601	(1.5332)	0.9696	(0.5636)
Total Rate	$1.6133	$3.6376	$1.3462	$6.5971	$3.6376	$0.9696	$4.6072

Date Filed: December 30, 2014

Effective Date: Service rendered on and after January 1, 2015

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2015

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$4.3706	12	$419,578	$0.2978
FT-A - Zone 1-1	5,000		4.7507	5	118,768	0.0843
FT-A Seasonal	2,000		4.7507	5	47,507	0.0337
TFX Seasonal	2,000		15.1530	5	151,530	0.1075
TFX - Winter	13,000		15.1530	5	984,945	0.6990
TFX - Summer	13,000		5.6830	7	517,153	0.3670
BP Seasonal Contract	500		2/	3	33,750	0.0240
Total Demand Charges					$2,273,231	1.6133
Estimated Weighted Average Commodity Cost	1,409,081	1/	3.6376		5,125,673	3.6376
Gas Cost Reconciliation Adjustment						1.3462
Total Current Firm Gas Cost					$7,398,904	6.5971
Base Cost of Gas						5.2370
Accumulated Adjustment						$1.3601
Interruptible						
Estimated Weighted Average Commodity Cost						$3.6376
Gas Cost Reconciliation Adjustment						0.9696
Total Current Interruptible Gas Cost						4.6072
Base Cost of Gas						5.1708
Accumulated Adjustment						($0.5636)

1/ Three year normalized average Dk sales
2/ Contract terms are 500 dk/day at $0.75/dk for the period December 1, 2014 through February 28, 2015.

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2015

Rates Effective January 1, 2015	$/Dk	
FT-A - Zone 1-1 (Category 1)	$4.7507	Per Dk/Mo.
FT-A - Zone 1-1 (Category 3)	4.3706	Per Dk/Mo.
FT-A - Seasonal	4.7507	Per Dk/Mo.
TFX	15.1530	Per Dk/Mo.
TFX Seasonal	15.1530	Per Dk/Mo.
Estimated Weighted Average Commodity Cost:	3.6376	Per Dk

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

Base Rate Calculation

Firm		
Demand 2/	$0.0662	Per Dk
Commodity	5.1708	Per Dk
Total Firm Base Cost	$5.2370	Per Dk

Interruptible:		
Commodity	$5.1708	Per Dk

1/ The Firm Gas Base Cost is based on the FERC Gas Tariff, Third Revised Volume No. 1 of Midwestern Gas Transmission Company, effective July 1, 1981.

2/ Demand base rate calculation:

Demand Charge		0.81	Per MCF/Mo.
Convert mcf to dk	x	0.99	Therm Factor
		0.82	Per Dk/Mo.
Capacity	x	4,768	
Months	x	12	
		46,814.13	
Volumes	/	707,222	
		0.0662	Per Dk

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	$4.7507
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate 1/	$5.7394
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$3.3143
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	$4.5607
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$5.5494
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$3.1243
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	$4.3706
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$5.3593
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.9343
Zone 2-2 Minimum Rate	$0.0000

1/ Throughout Viking's Statement of Rates and Tariff, "Zone 1-2" shall mean Transportation Service for quantities received in Zone 1 and delivered in Zone 2 or received in Zone 2 and delivered in Zone 1 whether by transport, exchange, or Displacement.

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	$0.0116	0.00%
Zone 1-2	$0.0116	0.00%
Zone 2-2	$0.0116	0.00%
Minimum Rate	$0.0116	
IT and AOT		
Zone 1-1	$0.1678	0.00%
Zone 1-2	$0.2003	0.00%
Zone 2-2	$0.1206	0.00%
Minimum Rate	$0.0116	

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/ The Fuel and Loss Retention Percentages shall be applicable to all transportation rate schedules and includes the following Gas Lost and Unaccounted For Percentages: 0.00% for Zone 1-1, 0.00% for Zone 1-2, and 0.00% for Zone 2-2. Transportation entirely by Displacement will incur only the Gas Lost and Unaccounted For Percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.00		$1.00
LMS – Daily Overrun Rate	$0.2003		$0.2003
LMS – Load Management Cost Reconciliation Adjustment		$0.0116	

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	$0.2003	$0.0000
RPL Service:		
Daily Reservation Rate	$0.2003	$0.0000

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	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 $0.0005 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

	MARKET-TO-MARKET		FIELD-TO-FIELD	
RESERVATION RATES	Apr-Oct	Nov-Mar	Apr-Oct	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	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

	Reservation 1/		Commodity 6/		Out-of-Balance 6/	
GULF COAST	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
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 $0.0005 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)	1.39%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.09% 4/ 5/
FDD Storage Fuel	1.76%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0005
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, 2013.

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, ILD & 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 ILD		
Maximum Charge	11.7500	
Minimum Charge	0.5044	
Performance Obligation Charge	2.0000	
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 2015

The principal 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 decrease 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.

December temperatures returning to normal for much of the country, domestic production levels reaching record highs during the past month and the national storage level continuing to rebound from the large deficits after the last heating season, were the contributing factors to the decrease in first of the month index price of natural gas. The EIA reported storage levels nationwide as of December 19, 2014 were 4.9 percent below the five-year average and 4.8 percent above last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 18.

Independent Statistics & Analysis
U.S. Energy Information Administration

December 2014

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil spot prices fell by more than 15% in November, declining from $85/barrel (bbl) on November 3 to $72/bbl on November 28. Monthly average Brent crude oil prices have declined 29% from their 2014 high of $112/bbl in June to an average of $79/bbl in November, the lowest monthly average since September 2010. The November price decline reflects continued growth in U.S. tight oil production along with weakening outlooks for the global economy and oil demand growth. The Organization of the Petroleum Exporting Countries' (OPEC) decision in late November to maintain its current crude oil production target, despite lower oil prices, put additional downward pressure on price expectations.

- The current values of futures and options contracts suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for March 2015 delivery, traded during the five-day period ending December 4, averaged $67/bbl. Implied volatility averaged 32%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in March 2015 at $51/bbl and $89/bbl, respectively. Last year at this time, WTI for March 2014 delivery averaged $96/bbl and implied volatility averaged 19%. The corresponding lower and upper limits of the 95% confidence interval were $82/bbl and $112/bbl.

- Total U.S. crude oil production averaged an estimated 9.0 million barrels per day (bbl/d) in November. Projected total crude oil production averages 9.3 million bbl/d in 2015, a reduction of 0.1 million bbl/d from last month's STEO.

- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged $2.78/gallon (gal) on December 1, the lowest since October 4, 2010. U.S. regular gasoline retail prices are projected to continue declining for the remainder of the year, averaging $2.61/gal in December. EIA expects U.S. regular gasoline retail prices, which averaged $3.51/gal in 2013, to average $3.37/gal in 2014 and $2.60/gal in 2015. Forecast retail gasoline prices for 2015 are $0.35/gal lower than in last month's STEO.

- U.S. population-weighted heating degree days (HDD) were an estimated 18% higher than the previous 10-year average for November. Despite a cold start to the winter, lower fuel prices and the National Oceanic and Atmospheric Administration's (NOAA) projection of near-normal temperatures for the remainder of the winter are expected to help lessen

consumer expenditures on home heating compared with last winter. Lower crude oil prices are expected to help reduce household heating oil expenditures by 27% ($632) compared with last winter, with U.S. heating oil prices averaging 20% lower at $3.09/gal. Propane prices are expected to be 13% lower in the Northeast and 26% lower in the Midwest, resulting in households spending 20% and 34% less on propane in those regions, respectively.

- Natural gas working inventories on November 28 totaled 3.41 trillion cubic feet (Tcf), 0.23 Tcf (6%) below the level at the same time a year ago and 0.37 Tcf (10%) below the previous five-year average (2009-13). Despite the lower stocks at the start of this winter's heating season, EIA expects the Henry Hub natural gas spot price to average $3.98/million British thermal units (MMBtu) this winter compared with $4.53/MMBtu last winter, reflecting both lower expected heating demand and higher natural gas production this winter.

Global Petroleum and Other Liquids

At the conclusion of its meeting in late November, OPEC announced that it would maintain its current crude oil production target of 30 million bbl/d. EIA expects that global liquid fuels supply will continue to outpace consumption, resulting in an average stock build of 0.4 million bbl/d in 2015. Stock builds are expected to be concentrated in the first half of the year, averaging 0.7 million bbl/d during this period. EIA forecasts global liquid fuels supply to average 92.8 million bbl/d in 2015, 0.2 million bbl/d lower than in last month's STEO. The 2015 global demand forecast was also revised downward by 0.2 million bbl/d to an average of 92.3 million bbl/d, based on weaker global economic growth prospects for next year.

Consistent with OPEC's announcement, Saudi Arabia has indicated its intention to maintain its export market share rather than cut production to keep prices higher. In the past, Saudi Arabia often played the role of the swing producer, temporarily cutting its production to accommodate supply growth elsewhere or weaker global demand, or increasing its output level to make up for a supply shortfall. Saudi Arabia's production is still projected to decline in 2015 compared with this year, but by a smaller amount than previously expected. EIA projects that Saudi Arabia will cut production below its current level of 9.6 million bbl/d amid high non-OPEC supply growth, but maintain output above 9.0 million bbl/d through 2015.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.3 million bbl/d in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in 2014 and 0.9 million bbl/d in 2015. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2013, is projected to grow by 2.7% and 2.9% in 2014 and 2015, respectively. Compared with last month's forecast, global consumption was revised downward by 0.2 million bbl/d in 2015, based on a 0.3% reduction to forecast global oil-consumption-weighted real GDP growth. In the short term, the income elasticity of global demand is greater than the price elasticity of

global demand. Thus, the negative impact of lower forecast economic growth on demand outweighs the positive impact of lower oil prices.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) is projected to grow by 1.2 million bbl/d in 2014 and 0.9 million bbl/d in 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by an annual average of 0.36 million bbl/d in 2014 and 2015.

EIA expects a 0.2-million-bbl/d decline in OECD consumption in 2014. Japan and Europe are expected to account for much of the projected OECD consumption decline. EIA expects Japan's consumption, which fell by 0.16 million bbl/d in 2013, to decline by an additional 0.16 million bbl/d in 2014 and 0.14 million bbl/d in 2015. Japan is expected to use less fuel oil in the electricity sector as the country returns some nuclear power plants to service in 2015 and increases the use of natural gas and coal to generate electricity. EIA forecasts that OECD Europe's consumption, which fell by 0.15 million bbl/d in 2013, declines by an additional 0.12 million bbl/d in 2014 and 0.14 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to remain flat in 2014 and then increase by 0.14 million bbl/d in 2015.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.9 million bbl/d in 2014 and 0.8 million bbl/d in 2015, with the United States as the leading contributor. Non-OPEC supply is forecast to increase by 1.6 million bbl/d in 2014 and 1.0 million bbl/d in 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.05 million bbl/d in 2014 and decline by 0.09 million bbl/d in 2015, reflecting declines in Russia and Azerbaijan.

Unplanned supply disruptions among non-OPEC producers averaged slightly lower than 0.6 million bbl/d in November, virtually unchanged from the previous month. South Sudan, Syria, and Yemen accounted for more than 90% of total non-OPEC supply disruptions.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of almost 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, Iran, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.1 million bbl/d in 2014 and by 0.2 million bbl/d in 2015. Previously projected OPEC crude oil production declines were reduced based on a reassessment of Saudi Arabia's willingness to cut production.

The Iraqi government in Baghdad reached a deal on oil exports and revenue with the Kurdistan Regional Government (KRG) in early December 2014, which could facilitate increased production and exports from northern fields controlled by the KRG and by Baghdad. Notwithstanding this agreement, the threat of the Islamic State of Iraq and the Levant (ISIL) on northern production and exports still looms. As a result, Iraq is a major wildcard to the 2015 world oil production

forecast. EIA projects that Iraq's production will grow by 0.2 million bbl/d next year. Actual production growth has the potential to exceed this forecast if Baghdad and KRG follow through on the deal, and if ISIL does not substantially affect production.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.7 million bbl/d in November 2014, an increase of nearly 0.6 million bbl/d because of new production outages in Libya and continued outages in the Neutral Zone shared by Kuwait and Saudi Arabia. Intermittent supply outages in Libya will most likely persist as the country faces political instability and a deteriorated security environment. As a result, EIA does not expect Libya's oil production to recover to its pre-blockade level of 1.4 million bbl/d over the forecast period.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.1 million bbl/d in 2014 and 2.5 million bbl/d in 2015. The estimates do not include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.64 billion barrels at the end of 2014 and 2.71 billion barrels at the end of 2015.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged $79/bbl in November, down $8/bbl from the October average and the first month Brent crude oil prices have averaged below $80/bbl since September 2010. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices (EIA, *This Week in Petroleum*, November 13, 2014). On November 27, following OPEC's decision to leave its crude oil production target unchanged, Brent crude oil spot prices fell by more than 10%, and have since fallen to $68/bbl as of December 4, the lowest daily price since May 25, 2010.

EIA expects global oil inventories to continue to build over the next year, keeping downward pressure on oil prices. The forecast Brent crude oil price averages $68/bbl in 2015, $15/bbl lower than projected in last month's STEO. Based on current market balances, EIA expects downward price pressures to be concentrated in the first half of 2015 when global inventory builds are expected to be particularly strong. EIA projects that Brent prices will reach a 2015 monthly average low of $63/bbl for each month from March through May, and then increase through the remainder of the year to average $73/bbl during the fourth quarter.

The monthly average WTI crude oil spot price fell from an average of $84/bbl in October to $76/bbl in November. Like Brent crude oil prices, WTI prices have decreased considerably, falling by more than 28% since reaching their 2014 peak at an average of $106/bbl in June. EIA now expects WTI crude oil prices to average $75/bbl in the fourth quarter of 2014 and $63/bbl in 2015, $5/bbl and $15/bbl lower than projected in last month's STEO, respectively. The

discount of WTI to Brent crude oil is forecast to widen slightly from current levels, averaging $5/bbl in 2015.

However, the current values of futures and options contracts suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for March 2015 delivery, traded during the five-day period ending December 4, averaged $67/bbl. Implied volatility averaged 32%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in March 2015 at $51/bbl and $89/bbl, respectively. Last year at this time, WTI for March 2014 delivery averaged $96/bbl and implied volatility averaged 19%. The corresponding lower and upper limits of the 95% confidence interval were $82/bbl and $112/bbl.

The recent declines in oil price and associated increases in oil price volatility have created a particularly uncertain forecasting environment, and several factors could cause oil prices to deviate significantly from current projections. Among these is the responsiveness of supply to the lower price environment. Despite OPEC's recent decision to leave its crude oil production target at 30 million bbl/d, if crude oil prices continue to fall, Saudi Arabia and others could choose to cut production, tightening market balances. The level of crude oil production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Iran, Nigeria, and Venezuela. Additionally, the price and lag time required to cause a reduction in forecast non-OPEC supply growth, particularly U.S. tight oil, is not known. The degree to which non-OPEC supply growth is affected by lower oil prices will also affect market balances and prices.

Several OPEC and non-OPEC oil producers rely heavily on oil revenues to finance their fiscal budgets. Some producers have already started adjusting their upcoming budgets to reflect the crude oil price decline. If crude oil prices continue to fall or are sustained at a lower level, then oil-dependent producers will have to make tough policy decisions. This could potentially lead to austerity programs and fuel subsidy cuts that could spark social unrest, leaving some countries vulnerable to supply disruptions if protestors target oil infrastructure. Potential new supply disruptions are a real possibility in a lower-than-expected price climate and present an uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices averaged $2.78/gal on December 1, which marked a decrease of $0.21/gal since the beginning of November and the lowest weekly price average since October 4, 2010. U.S. average regular gasoline retail prices have fallen for nine consecutive weeks and are down by 25% since their summer peak in late June. Falling Brent crude oil prices have been largely responsible for falling retail gasoline prices. EIA expects that the current low crude oil prices will contribute to further declines in gasoline prices, with the December price expected to average $2.61/gal.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by 470,000 bbl/d (2.5%) in 2013, the largest increase since 2004. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain, increasing by 190,000 bbl/d (8.5%). In 2014, total liquid fuels consumption is expected to remain unchanged, with declines in the consumption of HGL, residual fuel oil, and other oils offsetting increases in distillate fuel and jet fuel. Total consumption is forecast to grow by 140,000 bbl/d in 2015, with HGL and distillate consumption accounting for most of the growth.

Motor gasoline consumption grew by 160,000 bbl/d (1.9%) in 2013, the largest increase since 2004. EIA expects gasoline consumption to remain mostly unchanged during the forecast period, as modest increases projected for 2014 are offset by small declines in 2015. This projection shows that continued improvements in new-vehicle fuel economy offset highway travel growth.

Distillate fuel consumption increases by 120,000 bbl/d (3.1%) in 2014, reflecting colder-than-average first-quarter weather and economic growth. Distillate consumption rises by an additional 90,000 bbl/d (2.2%) in 2015. Some of the growth in distillate fuel consumption in 2015 comes from Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions.

Residual fuel oil consumption, which falls to an estimated 240,000 bbl/d in 2014, is projected to decline further to 210,000 bbl/d in 2015, which would be the lowest level on record.

Liquid Fuels Supply. Forecast U.S. crude oil production increases from an average of 7.4 million bbl/d in 2013 to 8.6 million bbl/d in 2014 and 9.3 million bbl/d in 2015. Recent onshore Lower 48 states oil production has been higher than expected, causing an upward revision of 155,000 bbl/d from the previous forecast in the fourth quarter of 2014. However, given the reduction in the 2015 crude oil price forecast, with WTI crude oil prices expected to average $58/bbl in the second quarter of 2015, EIA expects 2015 drilling activity to decline due to unattractive economic returns in some areas of both emerging and mature oil production regions. Many companies will redirect investment away from marginal exploration and research drilling and into core areas of major tight oil plays. Oil prices remain high enough to support development drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian Basin, which contribute the majority of U.S. oil production growth. The Gulf of Mexico oil production forecast has been revised downward this month by 95,000 bbl/d in 2015, as some projects which started producing in 2014 are ramping up production slower than initially expected, while other projects' start dates have been pushed back into late 2014 and early 2015.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in September, is projected to increase to 3.3 million bbl/d by the end of 2015. Ethane and propane are expected to contribute most to the projected growth, with the majority of production

directed towards domestic petrochemical use or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical facility feedstock demand, while export terminal expansions will allow higher quantities of domestically-produced propane and butanes to reach the international market.

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 fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1969.

Petroleum Product Prices. U.S. average regular gasoline retail prices fell from a monthly average of $3.69/gal in June to $2.91/gal in November, the first month in which prices have averaged below $3.00/gal since December 2010. EIA expects that U.S. regular gasoline retail prices will fall to an average of $2.61/gal in December 2014. The U.S. regular gasoline retail price, which averaged $3.51/gal in 2013, is projected to average $3.37/gal in 2014 and $2.60/gal in 2015. Forecast retail gasoline prices for 2015 are $0.35/gal lower than in last month's STEO. Diesel fuel prices, which averaged $3.92/gal in 2013, are projected to fall to an average of $3.82/gal in 2014 and $3.07/gal in 2015. Forecast diesel fuel prices for 2015 are $0.31/gal lower than in last month's STEO.

The February 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged $1.85/gal for the five trading days ending December 4, 2014. An RBOB futures contract price of $1.85/gal is consistent with a monthly average regular-grade gasoline retail price less than $2.50/gal in March 2015. There is a 4% probability that the RBOB futures contract price at expiration may exceed $2.35/gal, consistent with a retail price of $3.00/gal or higher. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by $0.30/gal or more.

Lower projected crude oil prices also contribute to a reduction in the forecast residential heating oil price and average household heating oil expenditures this winter compared to last winter. The average household that uses heating oil as its primary space heating fuel is expected to pay an average of $3.09/gal this winter, $0.79/gal lower than last winter. The average household is now expected to spend $1,722 for heating oil this winter, $57 lower than in last month's STEO.

Natural Gas

After a record injection season, the 162-Bcf storage withdrawal for the week ending November 21 tied the record set last year for the largest November withdrawal. The large withdrawal reflected unseasonably cold weather east of the Rocky Mountains. As a result, this month's STEO revises downward end-of-March 2015 inventories to 1,431 Bcf, based on NOAA expectations that temperatures for the rest of the winter will be close to normal. EIA expects

the Henry Hub natural gas spot price to average $3.98/MMBtu this winter, close to last month's forecast.

Natural Gas Consumption. EIA expects total natural gas consumption to average 73.9 Bcf/d in 2014, an increase of 3.2% from 2013 and 1% higher than in last month's STEO. This upward revision largely reflects colder-than-forecast temperatures in November. In 2015, total natural gas consumption is expected to decline as lower residential and commercial consumption offset increases in the electric power and industrial sectors. Natural gas consumption in the power sector is expected to average 22.1 Bcf/d in 2014, a 0.8% decline compared to last year, reflecting higher natural gas prices this year. EIA expects natural gas consumption in the power sector to increase to 22.7 Bcf/d in 2015.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an annual rate of 5.5% in 2014 and 3.1% in 2015. EIA projects that the strong increases already seen in the Lower 48 states for most of this year will continue through 2015, more than offsetting the long-term trend of declining production in the Gulf of Mexico. As of September, the most recent month for which EIA data are available, dry natural gas production was 4.6 Bcf/d greater than it was in September 2013. Production usually declines in September due to seasonal maintenance; however, production this year increased slightly from August to September.

Growing domestic natural gas production is expected to reduce demand for imports from Canada and spur exports to Mexico. EIA expects exports to Mexico, particularly from the Eagle Ford Shale in South Texas, to increase because of growing demand from Mexico's electric power sector and flat Mexican production.

Liquefied natural gas (LNG) imports have fallen over the past four years because higher prices in Europe and Asia are more attractive to LNG exporters than the relatively low prices in the United States. EIA projects that the United States will become a net LNG exporter when Cheniere's LNG liquefaction plant begins service.

Natural Gas Inventories. Natural gas working inventories totaled 3,410 Bcf as of November 28, which was 227 Bcf lower than at the same time last year and 372 Bcf lower than the previous five-year (2009-13) average. Following last year's extremely cold winter, inventories fell to about 1,000 Bcf below the five-year average in mid-April. After a strong injection season, inventories were 237 Bcf below the five-year average on November 7. EIA projects that end-of-March 2015 inventories will total 1,431 Bcf, which is 225 Bcf below the five-year (2010-14) average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $4.12/MMBtu in November, an increase of 34 cents from October. EIA expects spot prices to remain above $4/MMBtu through January. Projected Henry Hub natural gas prices average $4.44/MMBtu in 2014 and $3.83/MMBtu in 2015.

Natural gas futures prices for March 2015 delivery (for the five-day period ending December 4) averaged $3.84/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for March 2015 contracts at $2.40/MMBtu and $6.13/MMBtu, respectively. At this time last year, the natural gas futures contract for March 2014 averaged $3.98/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.01/MMBtu and $5.26/MMBtu.

Coal

Total electric power sector coal stocks increased by 3.1 million short tons (MMst) in September compared with the previous month. This increase in stocks follows the typical seasonal pattern where coal plants build stocks during the autumn months in preparation for increased coal consumption in the winter. Despite the increase, end-of-September stocks are 28 MMst (18%) lower than last year and 23% lower than the previous four-year average for the month. The large year-over-year decrease in stocks reflects increased coal-fired electricity generation during the winter of 2013-14 across a large portion of the country and subsequent decreased coal deliveries because of lingering rail transportation issues.

Coal Supply. EIA estimates that coal production for the first 11 months of this year was 909 MMst, almost unchanged from the same period last year. EIA expects that annual production will grow by 1.2% in 2014 and remain flat in 2015.

Coal Consumption. Higher electricity demand and higher power sector natural gas prices are contributing to an increase in electric power sector coal consumption this year. EIA projects electric power coal consumption of 868 MMst in 2014, an increase of 1.2% from last year. Power sector coal consumption is projected to fall by 0.4% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, and electricity and natural gas prices fall relative to coal prices.

Coal Trade. Exports of coal are projected to decline to 96 MMst in 2014 from 118 MMst in 2013, primarily because of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. With no improvement in global market conditions, EIA projects coal exports to fall to 83 MMst in 2015, which would be the lowest since 2010.

EIA expects coal imports, which account for about 1% of U.S. coal consumption, to total 12.2 MMst in 2014 and fall to 10.8 MMst in 2015.

Coal Prices. The annual average coal price to the electric power industry fell from a historically high $2.39/MMBtu in 2011 to $2.35/MMBtu in 2013. EIA expects the average delivered coal price to be $2.36/MMBtu in 2014 and remain at that level in 2015.

Electricity

The electricity industry has closed a number of coal-fired power plants over the past two years. During 2013, an estimated 5,700 megawatts (MW) of coal capacity was retired in the United States. From January through September of 2014, the industry shut down an additional 2,265 MW of coal capacity, with another 895 MW of retirements planned through the end of the year. These retirements account for 2.9% of existing coal-fired capacity at the end of 2012. Coal-fired power plant retirements pick up significantly next year, when more than 12,800 MW of capacity is expected to be shut down.

Electricity Consumption. Temperatures throughout the United States were significantly below normal last month, with the exception of the Pacific Coast. U.S. HDD in November were 18% higher than the previous 10-year average. However, HDD for the remainder of the winter are expected to be about 1% lower than the 10-year average and 10% lower than the same period last winter. EIA forecasts that U.S. residential electricity sales during the 2014-15 winter (October-March) will average about 1.8% less than the previous winter. EIA forecasts that sales of electricity to the commercial sector this winter will grow by 0.8%, while industrial electricity sales will grow by 1.2% from last winter.

Electricity Generation. EIA estimates that U.S. electricity generation in 2014 will average 11.2 terawatthours per day, which would be 1.1% higher than average generation last year. Rising natural gas prices this year have encouraged the industry to use existing coal capacity at higher utilization rates than last year, leading to an expected increase in coal's share of total generation from 39.1% in 2013 to 39.4% in 2014, while the share supplied by natural gas falls from 27.4% to 27.1%. In 2015, EIA expects that natural gas's fuel share will rise to 27.6% and coal's fuel share will decline to 38.9% in response to lower natural gas prices and retirements of coal-fired power plants.

Electricity Retail Prices. EIA expects the U.S. residential price to average 12.5 cents per kilowatthour in 2014, which is 3.0% higher than the average last year. Prices increase in all regions of the country except along the Pacific Coast. Average U.S. residential electricity prices grow at a slower rate of 1.7% in 2015.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects that total renewables used for electricity and heat generation will grow by 1.8% in 2014. Conventional hydropower generation is projected to fall by 4.4%, while nonhydropower renewables rise by 5.1%. Nonhydropower renewables generation surpasses hydropower on an annual basis for the first time in 2014. In 2015, total renewables consumption for electric power and heat generation increases by 4.3% as a result of similar increases in both hydropower and nonhydropower renewables. Electricity generation from wind is projected to contribute 4.7% of total electricity generation in 2015.

EIA expects continued growth in utility-scale solar power generation, which is projected to average more than 60 gigawatthours per day in 2015. Despite the growth, this remains just 0.6% of total U.S. generation. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity slightly more than doubled in 2013. EIA expects that utility-scale solar capacity will nearly double again between the end of 2013 and the end of 2015, with about two-thirds of this new capacity being built in California.

Liquid Biofuels. Ethanol production reached a weekly record of 982,000 bbl/d during the week ending November 21, exceeding the previous record of 972,000 bbl/d set during the week ending June 13, 2014. Ethanol production in November also reached a monthly average record of 963,000 bbl/d, exceeding the previous record of 959,000 bbl/d set in December 2011. EIA expects ethanol production to average 931,000 bbl/d in 2014 and 948,000 bbl/d in 2015. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.5% in 2013 from the previous year. Emissions are forecast to rise by 1.3% in 2014, primarily because of cold weather early in the year, and then to remain flat in 2015.

U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) grew at an annualized rate of 3.9% from the second to third quarters. This was an upward revision from their earlier estimate of 3.5% growth because private inventory investment decreased less than previously estimated, and both personal consumption expenditures and nonresidential fixed investment increased more. Results from other economic data have been relatively positive as well. The Census Bureau reported that new home sales in October rose 0.7% over September 2014 levels, and 1.8% over October 2013 levels. Census also reported that new orders for durable goods rose 0.4% from August to September, but fell 0.9% excluding transportation. Real personal consumption expenditures rose 0.2% from September to October according to the BEA, and real personal disposable income rose 0.1% during this time.

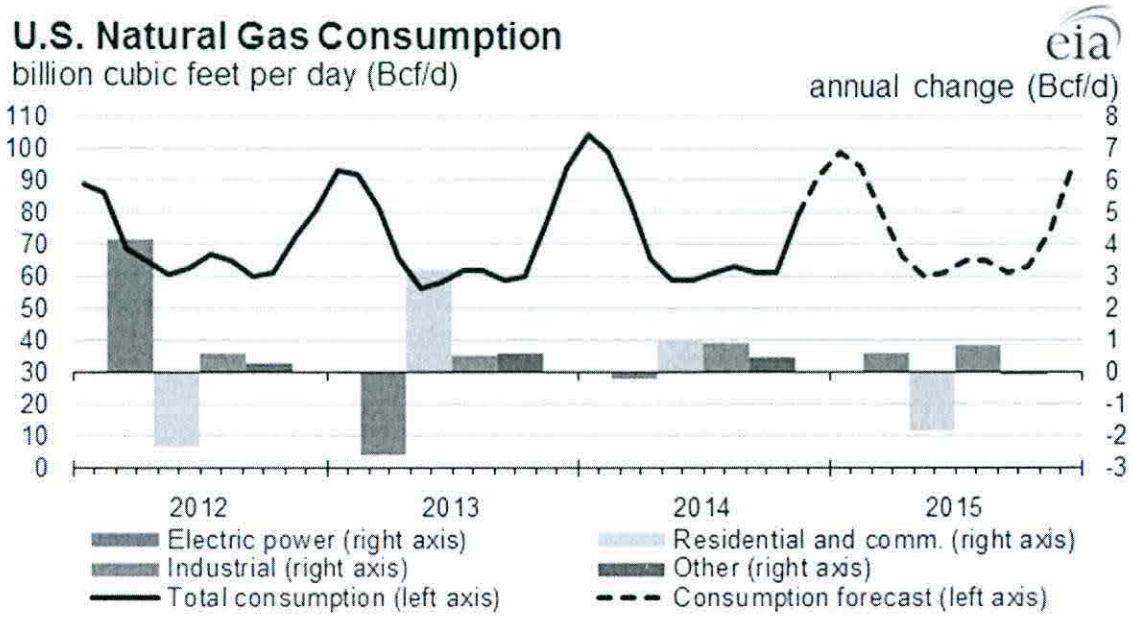
EIA used the November 2014 version of the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Production and Income. Real GDP growth reaches 2.2% in 2014 and rises to 2.4% in 2015, below the 2.3% and 2.7% forecast for 2014 and 2015 last month. Expected growth in 2014 is lower in this month's forecast because of less investment spending. Real GDP growth is lower in 2015 as a result of reduced exports—due to a stronger dollar and less demand from slower-growing economies. Real disposable income grows 2.7% in 2014, just above the 2.6% forecast

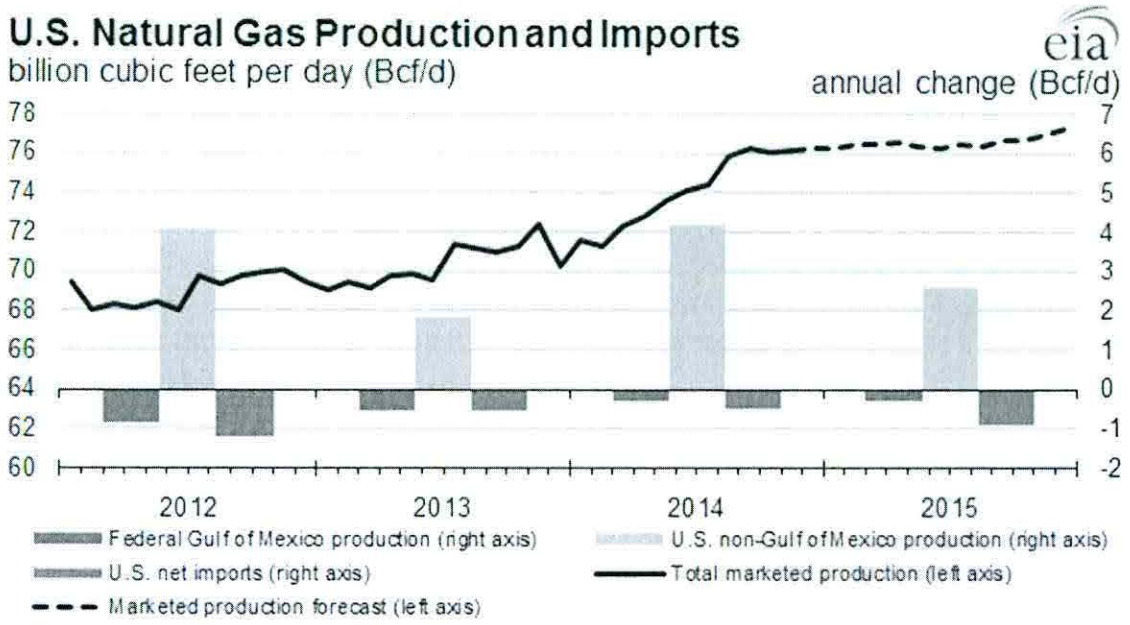
last month, and total industrial production grows at 4% in 2014. In 2015 real disposable income grows at 2.4% and industrial production grows at 2.3%.

Expenditures. Private real fixed investment growth averages 4.9% and 5.3% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow at 2.2% in 2014, the same rate as real GDP, but rise above the real GDP growth rate in 2015 to 2.5%. Durable goods expenditures drive consumption spending in both years. Export growth is 3.2% and 2.9% over 2014 and 2015, respectively, while import growth is 3.4% and 2.6% over the same two years. Total government expenditures fall by 0.2% in 2014, but increase by 0.2% in 2015.

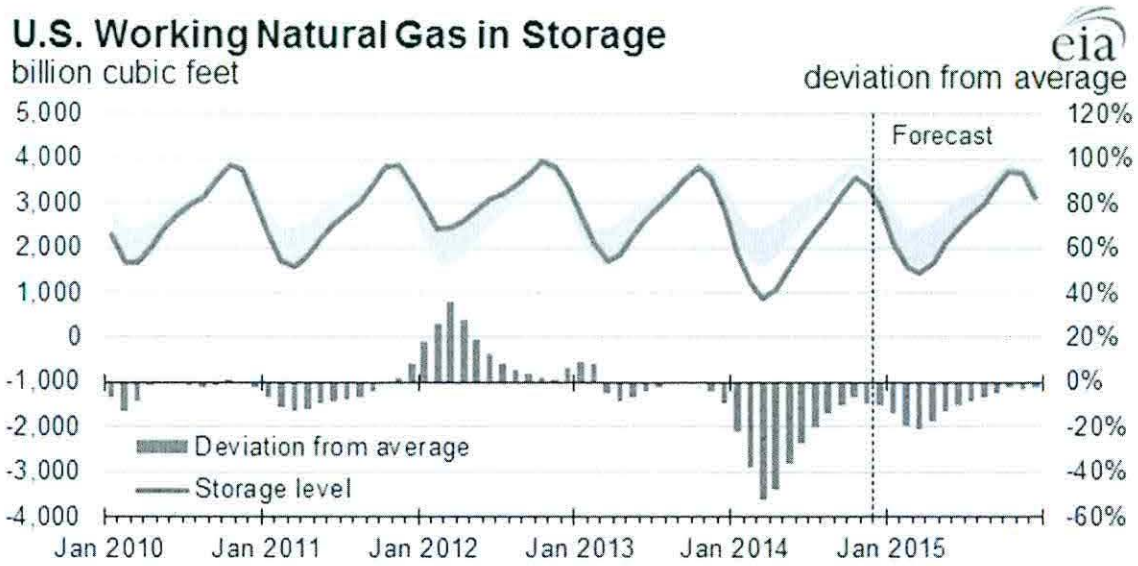
U.S. Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.8% in both 2014 and 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.7% at the end of 2015. The employment growth in 2014 and 2015 is the same as projected last month, while the decline in the unemployment rate has slowed. Housing starts grow at an average of 7.4% and 16.6% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.



Source: Short-Term Energy Outlook, December 2014.



Source: Short-Term Energy Outlook, December 2014.



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

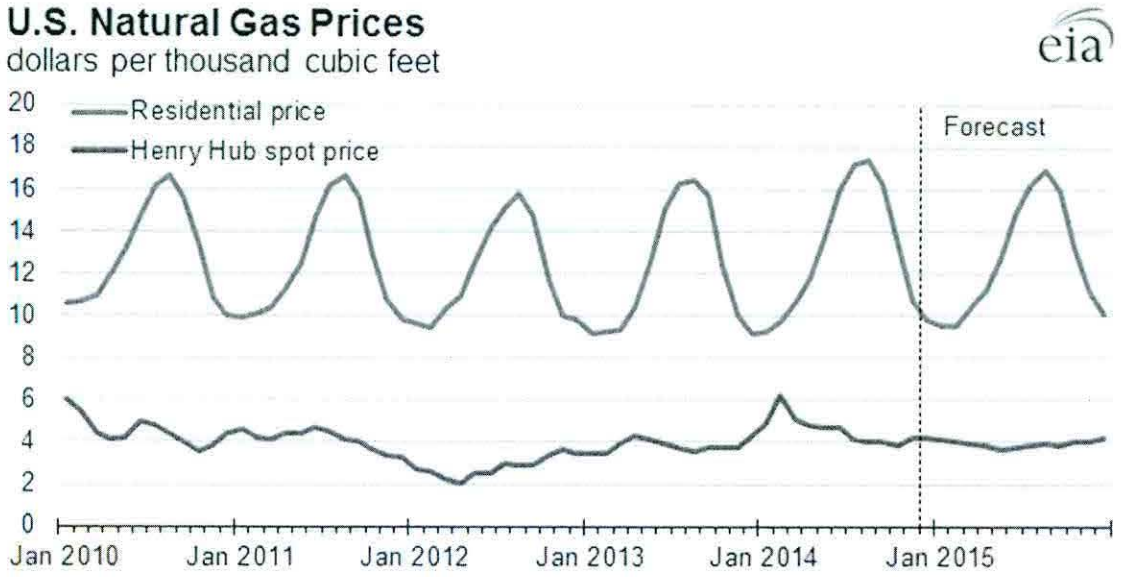
Source: Short-Term Energy Outlook, December 2014.

Henry Hub Natural Gas Price

dollars per million Btu

Note: Confidence interval derived from options market information for the 5 trading days ending Dec. 4, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, December 2014.



Source: Short-Term Energy Outlook, December 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, 2014									**$404,569**
May 2014	($15,520)	0	$2,700	($12,820)	18,641	$0.9614	$17,921	($30,741)	373,828
June	(1,551)	0	2,475	924	9,300	1.3462	10,015 2/	(9,092)	364,736
July	13,177	0	2,399	15,576	6,189	1.3462	8,331	7,245	371,981
August	13,687	0	2,437	16,124	5,378	1.3462	7,240	8,884	380,865
September	(855)	0	2,486	1,631	6,094	1.3462	8,204	(6,573)	374,292
October	5,798	0	2,424	8,222	9,358	1.3462	12,598	(4,376)	369,916
November	2,922	0	2,379	5,301	19,077	1.3462	25,681	(20,380)	349,536
Total	$17,658	0	$17,300	$34,958	74,037		$89,990	($55,033)	
Balance @ November 30, 2014									**$349,536**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,507.2 dk at $0.9614 and 2,792.4 dk at $1.3462.

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, 2014									**$388,932**
May 2014	($22,536)	0	$2,691	($19,845)	42,002	$0.0274	$1,151	($20,996)	367,936
June	(17,420)	0	2,515	(14,905)	19,772	0.9696	5,999 2/	(20,903)	347,033
July	(3,815)	0	2,344	(1,471)	11,279	0.9696	10,936	(12,407)	334,626
August	(6,429)	0	2,239	(4,190)	13,996	0.9696	13,571	(17,761)	316,865
September	(26,713)	0	2,095	(24,618)	13,155	0.9696	12,755	(37,373)	279,492
October	879	0	1,811	2,690	27,455	0.9696	26,620	(23,930)	255,562
November	7,159	0	1,626	8,785	31,401	0.9696	30,446	(21,661)	233,901
Total	($68,875)	0	$15,321	($53,554)	159,060		$101,478	($155,031)	
Balance @ November 30, 2014									**$233,901**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 13,980.6 dk at $0.0274 and 5,791.7 dk at $0.9696.