

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

March 30, 2015

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

Re: Cost of Gas Adjustment (COG)
April 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 (109th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (109th Revised Sheet No. 8), showing the April 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.5678 per dk for residential and firm general service customers and a decrease of \$0.5678 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for April 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.5678 per dk 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,

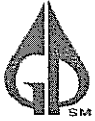
A handwritten signature in black ink, appearing to read "Tamie A. Aberle". The signature is fluid and cursive, with the first name "Tamie" being the most prominent.

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

Attachment A



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

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2

109th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 108th Revised Sheet No.1.1

Page 1 of 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 Over 10 dk	\$1.2869 1.0646	\$5.8597	\$7.1466 6.9243
Interruptible Gas Service - General	3	\$3.50 per month	First 400 dk Next 2,600 dk Over 3,000 dk	\$1.1506 0.9021 0.7486	\$3.8698	\$5.0204 4.7719 4.6184
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk	\$1.2516	\$3.8698	\$5.1214
Transportation Service	5	\$3.50 per month	First 400 dk Next 2,600 dk Over 3,000 dk	\$1.1506 0.9021 0.7486		\$1.1506 0.9021 0.7486

Date Filed: March 30, 2015

Effective Date: Service rendered on and after April 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
109th Revised Sheet No. 8
Canceling 108th Revised Sheet No. 8

COST OF GAS

Page 1 of 1

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.	1.5471	(1.7028)	1.3462	1.1905	(1.7028)	0.9696	(0.7332)
Current Adj.	0.0000	(0.5678)	0.0000	(0.5678)	(0.5678)	0.0000	(0.5678)
Total Adj.	1.5471	(2.2706)	1.3462	0.6227	(2.2706)	0.9696	(1.3010)
Total Rate	\$1.6133	\$2.9002	\$1.3462	\$5.8597	\$2.9002	\$0.9696	\$3.8698

Date Filed: March 30, 2015

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
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/ 2.9002		4,086,617	2.9002
Gas Cost Reconciliation Adjustment					1.3462
Total Current Firm Gas Cost				<u>\$6,359,848</u>	<u>5.8597</u>
Base Cost of Gas					<u>5.2370</u>
Accumulated Adjustment					<u>\$0.6227</u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.9002
Gas Cost Reconciliation Adjustment					0.9696
Total Current Interruptible Gas Cost					<u>3.8698</u>
Base Cost of Gas					<u>5.1708</u>
Accumulated Adjustment					<u>(\$1.3010)</u>

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
APRIL 2015**

Rates Effective April 1, 2015	<u>\$/Dk</u>	
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:	2.9002	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

<u>Firm</u>		
Demand 2/	\$0.0662	Per Dk
Commodity	5.1708	Per Dk
Total Firm Base Cost	<u>\$5.2370</u>	Per Dk

<u>Interruptible:</u>		
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 <u>0.99</u>	Therm Factor
	0.82	Per Dk/Mo.
Capacity	x 4,768	
Months	x <u>12</u>	
	46,814.13	
Volumes	/ <u>707,222</u>	
	0.0662	Per Dk

STATEMENT OF RATES
 (Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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		(\$0.0528)	

- 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

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

Eighth Revised Sheet No. 50
Superseding
Seventh Revised Sheet No. 50

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	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/		Market Area 3/		Field Mileage 5/		Carlton Surcharges 4/		Out-of-Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF	Receipt Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
	Market	0.0369	0.0200			0.0175	0.0000	0.0369	0.0200
	Field	0.0369	0.0200	0.0122	0.0040	0.0175	0.0000		
	Market			0.0122	0.0040				
	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 \$0.0010 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		FIELD-TO-FIELD					
		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	0.0369	0.0200			0.0175	0.0000	0.0369	0.0200
Field	Market	0.0369	0.0200	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/		Commodity 6/		Out-of-Balance 6/	
		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 \$0.0010 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

	<u>Percentages</u>
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.62%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	-0.09% 4/ 5/
FDD Storage Fuel	1.76%
	<u>Electric Compression</u>
COMMODITY RATES:	1/
Market Area	\$0.0010
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, 2014. For deliveries subject only to UAF, the UAF rate is zero; provided, however Northern will issue a volume credit on the Shipper's monthly imbalance statement equivalent to -0.09% for the period April 2015 through March 2016 for such deliveries.

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
April 2015**

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 April 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.

Reasons for the decrease in the monthly index price were production levels continuing to run at or near historical record high levels, and the moderating of temperatures with the arrival of the spring season resulting in reduced demand for space heating. The EIA reported nationwide storage levels as of March 20, 2015 at 11.6 percent below the five-year average and 63.6 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.



Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil prices averaged \$58/barrel (bbl) in February, an increase of \$10/bbl from the January average, and the first monthly average price increase since June 2014. The price increase reflects news of falling U.S. crude oil rig counts and announced reductions in capital expenditures by major oil companies, along with lower-than-expected Iraqi crude oil exports.
- EIA forecasts that Brent crude oil prices will average \$59/bbl in 2015, \$2/bbl higher than projected in last month's STEO, and \$75/bbl in 2016. West Texas Intermediate (WTI) prices in 2015 and 2016 are expected to average \$7/bbl and \$5/bbl, respectively, below Brent. The Brent-WTI spread for 2015 is more than twice the projection in last month's STEO, reflecting continuing large builds in U.S. crude oil inventories, including at the Cushing, Oklahoma storage hub.
- The current values of futures and options contracts continue to suggest very high uncertainty in the oil price outlook (*Market Prices and Uncertainty Report*). Although WTI futures contracts for June 2015 delivery traded during the five-day period ending March 5 averaged \$54/bbl, the market's expectations (at the 95% confidence interval) for monthly average WTI prices in June 2015 range from \$33/bbl to \$81/bbl. The band widens over time, with lower and upper limits of \$32/bbl and \$108/bbl for the broadly held December 2015 contract.
- Total U.S. crude oil production was estimated to average 9.4 million barrels per day (bbl/d) in February. Given EIA's price forecast, projected total crude oil production averages 9.3 million bbl/d in 2015 and 9.5 million bbl/d in 2016, close to the 9.6 million bbl/d highest annual average level of U.S. production in 1970.
- U.S. average regular gasoline retail prices increased for the sixth consecutive week from \$2.04/gallon (gal) on January 26 to \$2.49/gal on March 9, reflecting rising crude oil prices and several outages at West Coast refineries. EIA expects U.S. regular gasoline retail prices, which averaged \$3.36/gal in 2014, to average \$2.39/gal in 2015, an increase of \$0.05/gal from last month's STEO, and \$2.73/gal in 2016. The average household is expected to spend \$710 less for gasoline in 2015 compared with last year because of lower prices.

- Natural gas working inventories on February 27 totaled 1,710 billion cubic feet (Bcf), 492 Bcf (40%) above the level at the same time in 2014 but 143 Bcf (8%) below the previous five-year (2010-14) average. EIA expects the Henry Hub natural gas spot price, which averaged \$4.39/million British thermal units (MMBtu) in 2014, to average \$3.07/MMBtu in 2015 and \$3.48/MMBtu in 2016, largely unchanged from last month's STEO.
- Much of the eastern United States experienced a very cold February, which resulted in increased electricity demand for space heating. EIA estimates total U.S. generation during February 2015 averaged 11,800 gigawatthours (GWh) per day, which would be a monthly record for February. However, this estimated level of generation still falls short of the winter-month record for total U.S. power generation (12,178 GWh per day) during January 2014.

Global Petroleum and Other Liquids

Market fundamentals remain largely unchanged since last month's STEO, as global production continues to exceed demand, resulting in inventory builds. Global oil inventory builds are projected to average 1.3 million bbl/d through the first half of 2015, with the builds moderating during the second half of the year, as demand rises and non-OPEC supply growth slows, particularly in the United States, because of lower oil prices. The expected inventory builds in 2015 are on top of an estimated average 0.9 million bbl/d increase in 2014.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 92.2 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in both 2015 and 2016. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.6% in 2015 and by 3.1% in 2016.

Consumption outside of the Organization for Economic Cooperation and Development (OECD), which grew by 1.2 million bbl/d in 2014, is projected to grow by 0.8 million bbl/d in 2015 and by 1.1 million bbl/d in 2016. The reduction in forecast non-OECD consumption growth in 2015 is mostly attributable to a 0.2 million bbl/d decline in Russia's consumption as a result of its economic downturn. Russia's oil consumption is expected to decline by a similar amount in 2016. China's economic growth slowed in the second half of 2014, as key manufacturing indexes decreased. Nonetheless, China remains the main source of non-OECD oil consumption growth, with a projected annual average increase of 0.3 million bbl/d in both 2015 and 2016, down from growth of 0.4 million bbl/d in 2014.

OECD consumption, which fell by 0.3 million bbl/d in 2014, is expected to grow by 0.2 million bbl/d in 2015 and then stay relatively flat in 2016. Japan and Europe accounted for almost the entire 2014 decline in OECD oil consumption. Consumption in these areas is expected to continue declining over the next two years, albeit at a slower rate than in 2014. The United

States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million bbl/d in 2015 and by 0.1 million bbl/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 2.2 million bbl/d in 2014. EIA expects non-OPEC production to grow by 1.0 million bbl/d in 2015 and by 0.6 million bbl/d in 2016, in part because of lower projected oil prices. The slower growth in total non-OPEC supply is largely attributable to slower production growth in the United States and Canada and declining production in Europe and Eurasia. After a slight decline in 2015, production in Eurasia is projected to decline by 0.1 million bbl/d in 2016. The projected decline reflects reduced investment in Russia's oil sector stemming from low oil prices and international sanctions.

Unplanned supply disruptions among non-OPEC producers averaged slightly less than 0.6 million bbl/d in February 2015, similar to the previous month. South Sudan, Syria, and Yemen accounted for more than 85% of total non-OPEC supply disruptions in February. EIA estimates that unplanned non-OPEC supply disruptions averaged slightly more than 0.6 million bbl/d in 2014.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 30.1 million bbl/d in 2014, unchanged from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait offset production growth in Iraq and Iran. In EIA's forecast, OPEC crude oil production remains flat in 2015 and falls by 0.3 million bbl/d in 2016. Iraq is the largest contributor to OPEC production growth over the forecast period, but its growth is expected to be offset by production declines from other OPEC producers.

OPEC noncrude liquids production, which averaged 6.4 million bbl/d in 2014, is expected to increase by less than 0.1 million bbl/d in both 2015 and 2016, led by increases in Qatar and Kuwait.

In February 2015, unplanned crude oil supply disruptions among OPEC producers averaged 2.7 million bbl/d, an increase of 0.1 million bbl/d compared with the previous month. This increase was mainly attributable to rising outages in Iraq, Nigeria, and Libya. Unplanned OPEC crude supply disruptions averaged 2.4 million bbl/d in 2014, 0.5 million bbl/d higher than in the previous year. The high level of OPEC disruptions contributed to higher crude oil prices during the first half of 2014. Unplanned supply disruptions could still affect crude oil prices, but the threshold that the market can bear has risen in light of robust global production and increases in inventory levels.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to increase to an annual average of 2.1 million bbl/d in 2015 and 2.6 million bbl/d in 2016, after averaging about 2.0 million bbl/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million bbl/d is an indicator of a relatively tight

market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.75 billion barrels at the end of 2014, the highest end-of-year level on record and equivalent to roughly 60 days of consumption. Projected OECD oil inventories rise to 2.90 billion barrels at the end of 2015 and to 2.92 billion barrels by the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices increased by \$10/bbl from January to reach an average of \$58/bbl in February, the first month in which Brent prices increased since June 2014. Several factors supported Brent prices in February, including news of falling U.S. crude oil rig counts and announced reductions in capital expenditures by major oil companies, both of which contributed to expectations that oil supplies could decline more quickly than previous market expectations. Additionally, lower-than-expected Iraqi crude oil exports and a reduction in Libyan production contributed to an increase in global unplanned supply disruptions. However, the sustainability of the recent price increase is very uncertain, as it occurred amid strong global oil inventory growth, which is expected to continue in the coming months. Inventory builds are projected to moderate later in the year and provide support to crude oil prices.

The monthly average WTI crude oil spot price increased to an average of \$51/bbl in February, up \$3/bbl from January. WTI prices increased less than Brent prices in February as U.S. commercial crude oil inventories increased to 444 million barrels as of February 27, an increase of over 50 million barrels since the end of 2014. The record inventory levels have put downward pressure on the price of crude oil for prompt delivery relative to the price of crude oil for delivery in the future.

EIA projects the Brent crude oil price will average \$59/bbl in 2015, up \$2/bbl from last month's STEO, with prices rising from an average of \$56/bbl in the second quarter to an average of \$67/bbl in the fourth quarter. The Brent crude oil price is projected to average \$75/bbl in 2016. WTI prices in 2015 and 2016 are expected to average \$7/bbl and \$5/bbl, respectively, below Brent. The Brent-WTI spread for 2015 is more than twice the projection in last month's STEO, reflecting continuing large builds in U.S. crude oil inventories, including at the Cushing, Oklahoma storage hub.

The current values of futures and options contracts continue to suggest very high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for June 2015 delivery traded during the five-day period ending March 5 averaged \$54/bbl while implied volatility averaged 46%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in June 2015 at \$36/bbl and \$80/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of \$35/bbl and \$102/bbl for prices in December 2015. Last year at this time, WTI for June 2014 delivery averaged \$101/bbl, and implied volatility averaged 18%.

The corresponding lower and upper limits of the 95% confidence interval were \$87/bbl and \$118/bbl.

Given the high level of uncertainty in oil markets, several factors could cause oil prices to deviate significantly from current projections. Among these factors is the responsiveness of supply to lower prices. Despite OPEC's November 2014 decision to leave its crude oil production target at 30 million bbl/d, key producers could decide to reduce output, tightening market balances. The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Iran, Nigeria, and Venezuela. 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 revenue to finance their national budgets. Some producers have already started adjusting their upcoming budgets to reflect the crude oil price decline. If crude oil prices fall further or are sustained at current levels, oil-dependent producing countries will face tough decisions. These decisions could potentially lead to austerity programs and fuel subsidy cuts that could spark social unrest, leaving some countries vulnerable to supply disruptions if protesters target oil infrastructure. Potential new supply disruptions are a real possibility and present a major uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

U.S. average regular gasoline retail prices have increased for six consecutive weeks to \$2.49/gal as of March 9, after falling to \$2.04/gal on January 26, the lowest price in EIA's weekly survey of Monday prices since April 6, 2009. Rising crude oil prices, along with several outages at refineries on the West Coast, have contributed to the recent increase in retail gasoline prices.

In February, monthly average regional gasoline retail prices ranged from a low of \$1.96/gal in Petroleum Administration for Defense District (PADD) 4, the Rocky Mountain region, to a high of \$2.55/gal in PADD 5 along the West Coast. EIA expects U.S. retail gasoline prices to average \$2.26/gal during the first quarter of 2015 and \$2.39/gal for the full year, \$0.13/gal and \$0.05/gal higher than in last month's STEO, respectively.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 bbl/d (0.4%) in 2014. Motor gasoline consumption increased by 80,000 bbl/d (0.9%) reflecting an increase in highway travel that was partially offset by fleetwide increases in fuel efficiency. Distillate consumption grew by 180,000 bbl/d (4.8%) in 2014, as a result of colder-than-average weather in the first quarter as well as increases in industrial production. Jet fuel consumption increased by 40,000 bbl/d (2.5%). Hydrocarbon gas liquids (HGL) and residual fuel oil consumption in 2014 fell by an estimated 100,000 bbl/d (4.0%) and 60,000 bbl/d (19.2%), respectively.

In 2015, total liquid fuels consumption is forecast to grow by 310,000 bbl/d (1.6%). Lower pump prices contribute to a 70,000 bbl/d increase (0.8%) in motor gasoline consumption. EIA expects petrochemical plants to use more HGL as feedstock, which will reverse 2014's decline in HGL consumption, increasing by 160,000 bbl/d (6.8%). Consumption of distillate fuel is projected to increase by 80,000 bbl/d (2.0%), driven partially by expanding industrial production. Additionally, some of the growth in distillate fuel consumption 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. The increase in marine distillate use because of MARPOL regulations will displace the use of residual fuel oil.

EIA projects that in 2016 liquid fuels consumption growth will slow to 70,000 bbl/d (0.4%). Motor gasoline consumption is projected to decline by 50,000 bbl/d (0.6%), as the annual average retail regular gasoline price is projected to increase by 14% from the 2015 level. Continuing industrial growth contributes to an 80,000 bbl/d (3.1%) increase in HGL consumption and a 50,000 bbl/d (1.2%) increase in distillate consumption. Jet fuel consumption remains unchanged, as the effects of moderate increases in air transport activity offset the effects of improved fuel efficiency brought about by the introduction of new aircraft.

Liquid Fuels Supply. Forecast U.S. crude oil production increases from an average of 8.7 million bbl/d in 2014 to 9.3 million bbl/d in 2015 and to 9.5 million bbl/d in 2016. With WTI crude oil prices expected to average \$47/bbl in the first half of 2015, EIA expects 2015 onshore drilling activity to decline because of unattractive economic returns in some areas of both emerging and mature oil production regions. Many companies have begun redirecting investment away from marginal exploration and research drilling to focus on core areas of major tight oil plays. Projected 2015 oil prices remain high enough to support continued development drilling activity in the Bakken, Eagle Ford, Niobrara, and Permian basins. Companies with lower drilling and debt service costs that operate on acreage in the sweet spots of these regions are expected to continue to drill highly productive wells in 2015. Furthermore, a reduction of the backlog of wells drilled but not completed, which runs three to seven months in major producing regions, will bolster production by offsetting recent drops in drilling activity.

Nevertheless, EIA expects crude oil production to reach 9.4 million bbl/d in the second quarter of 2015, then decline by 170,000 bbl/d in the third quarter. With projected WTI crude oil prices rising in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for acreage leasing and drilling services, resulting in growing production despite the relatively low WTI price. However, the forecast remains particularly sensitive to actual prices available at the wellhead, drilling economics that vary across regions and operators, and whether additional production from the backlog of well completions materializes. Projected production in the federal offshore region rises during the forecast period, while production in Alaska falls. Production in these areas is less sensitive to short-term price movements than onshore production in the Lower 48 states.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in October, is projected to average 3.2 million bbl/d in 2015 and 3.5 million bbl/d in 2016. Ethane and propane are expected to contribute most to the projected growth, with most of the production supplying domestic petrochemical demand or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical plant 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 oil production has contributed to a significant decline in imports of crude oil and other liquids. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 26% in 2014. EIA expects the net import share to decline to 20% in 2016, which would be the lowest level since 1968.

Petroleum Product Prices. U.S. regular gasoline retail prices averaged \$2.22/gal in February, \$0.10/gal more than in January, which had the lowest monthly average price since April 2009. The U.S. regular gasoline retail price, which averaged \$3.36/gal in 2014, is projected to average \$2.39/gal in 2015, \$0.05/gal higher than forecast in last month's STEO, and \$2.73/gal in 2016, unchanged from last month's STEO. Diesel fuel retail prices, which averaged \$3.83/gal in 2014, are projected to fall to an average of \$2.89/gal in 2015, \$0.05/gal higher than in last month's STEO, and then rise to \$3.25/gal in 2016.

The June 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$1.91/gal for the five trading days ending March 5, 2015, and has a 27% probability of exceeding \$2.10/gal (consistent with a retail price of \$2.75/gal) at expiration. The current values of futures and options contracts suggest there is a 10% 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, and a 3% probability that the RBOB futures price may fall below \$1.35/gal, consistent with a retail price of \$2.00/gal or lower. 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.

Despite the recent cold weather, home heating costs this winter are still expected to be lower than last winter for households using heating oil or propane. Lower projected crude oil prices this winter compared with last winter contribute to retail heating oil prices that are expected to average \$3.02/gal this winter, \$0.86/gal lower than last winter. The average household that uses heating oil as its primary space-heating fuel is now expected to spend \$1,784 for heating this winter, about \$570 less than last winter. With propane supplies more ample this winter compared with last winter, propane prices are expected to be 16% lower in the Northeast and 27% lower in the Midwest, resulting in households spending 18% and 32% less on propane in those regions, respectively.

Natural Gas

December 2014 marketed natural gas production hit a record high of 78.8 Bcf/d, according to EIA's *Natural Gas Monthly*. The increase in production occurred despite declining prices and falling rig counts, and likely reflects increases in rig efficiency. For 2014 as a whole, natural gas production increased 6.1%, which was the strongest growth since 2011. Preliminary data indicate temporary declines in production in early 2015, largely attributable to freeze-offs during a few cold weeks in January and February. Based on increases in rig efficiency and December 2014 data, this month's STEO raises the outlook for production by 1 Bcf/d from last month's outlook for both 2015 and 2016.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will average 75.7 Bcf/d in 2015 and 76.2 Bcf/d in 2016, compared with an estimated 73.5 Bcf/d in 2014. Growth is largely driven by demand in the industrial and electric power sectors, while residential and commercial consumption are projected to decline in 2015 and 2016. EIA projects natural gas consumption in the power sector to grow by 8.1% in 2015 and by 1.9% in 2016. Industrial sector consumption increases by 6.6% and 2.1% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and industrial consumers take advantage of low natural gas prices.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 3.7 Bcf/d (5.0%) and 1.6 Bcf/d (2.0%) in 2015 and 2016, respectively, reflecting continuing production growth in the Lower 48 states, which more than offsets the long-term declining production in the Gulf of Mexico. Although natural gas prices have fallen dramatically in recent months, EIA expects that increases in drilling efficiency and growth in oil production (albeit at a slower rate) will continue to support growing natural gas production in the forecast. With most growth expected to come from the Marcellus Shale, a backlog of drilled but uncompleted wells will continue to support production growth, as new pipelines come online in the Northeast.

Increases in domestic natural gas production are expected to reduce demand for natural gas imports from Canada and to support growth in 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, coupled with flat Mexican natural gas production.

Liquefied natural gas (LNG) imports have fallen over the past five years because higher prices in Europe and Asia are more attractive to LNG exporters than the relatively low prices in the United States. Forecast LNG gross imports average 0.2 Bcf/d in both 2015 and 2016. EIA projects that LNG gross exports will increase from an average of 0.04 Bcf/d in 2014 to almost 0.8 Bcf/d in 2016.

Natural Gas Inventories. On February 27, natural gas working inventories totaled 1,710 Bcf, 492 Bcf (40%) above the level at the same time in 2014 and 143 Bcf (8%) below the previous five-

year (2010-14) average for the week. Following the extremely cold weather last winter, inventories were 1,000 Bcf below the five-year average in mid-April 2014. After strong builds over the summer and weak draws during the early winter, natural gas working inventories briefly surpassed the five-year average in mid-February. However, recent cold temperatures have contributed to inventory levels falling back below the five-year average. EIA projects that end-of-March 2015 inventories will total 1,587 Bcf, close to the five-year average and 730 Bcf more than at the end of last March.

Natural Gas Prices. The Henry Hub natural gas spot price averaged \$2.87/MMBtu in February, a decline of \$0.12/MMBtu from January. EIA expects monthly average spot prices to remain less than \$3/MMBtu through May, and less than \$4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages \$3.07/MMBtu in 2015 and \$3.48/MMBtu in 2016.

Natural gas futures contracts for June 2015 delivery traded during the five-day period ending March 5 averaged \$2.83/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for June 2015 contracts at \$1.92/MMBtu and \$4.18/MMBtu, respectively. At this time last year, the natural gas futures contract for June 2014 delivery averaged \$4.55/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.51/MMBtu and \$5.90/MMBtu.

Coal

Coal exports totaled 97.3 million short tons (MMst) in 2014, which was the first time since 2010 exports were below 100 MMst. Coal exports fall into two categories: metallurgical (met) coal, which is used in the production of steel, and steam coal, which is commonly used to fuel boilers that generate steam used to produce electricity, heat, or both. Steam coal exports fell by 34% in 2014 to slightly more than 34 MMst. In contrast, steam coal exports to Europe alone were nearly 31 MMst in 2013. Met coal exports declined by 4% in 2014, but met coal exports to Europe increased by nearly 20%.

Coal Trade. The 2014 decline in coal exports was primarily a result of slower growth in world coal demand, lower international coal prices, and higher coal output in other coal-exporting countries compared with 2013. EIA projects coal exports will fall from 97 MMst in 2014 to an annual average of 81 MMst in 2015 and 2016. Global market conditions for coal are not expected to change significantly through 2016.

Coal Supply. EIA estimates that U.S. coal production for 2014 totaled 997 MMst, 13 MMst (1.3%) higher than in 2013. EIA expects annual production to decline in 2015 to 943 MMst, before growing slightly to 951 MMst in 2016.

Coal Consumption. Electric power sector coal consumption decreased by 7 MMst (0.8%) in 2014. EIA projects power sector coal will decrease by 2.2% in 2015, despite an increase in electricity generation, because of lower natural gas prices and retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards. The full effect of the coal plant retirements will be felt in 2016, as projected coal consumption in the electric power sector declines by an additional 0.5%.

Coal Prices. The annual average coal price to the electric power sector fell from \$2.39/MMBtu in 2011 to an estimated \$2.36/MMBtu in 2014. EIA expects the delivered coal price to average \$2.31/MMBtu in 2015 and \$2.34/MMBtu in 2016.

Electricity

Much of the eastern United States experienced a very cold February, which resulted in increased electricity demand for space heating. EIA estimates total U.S. generation during February 2015 averaged 11,800 gigawatthours (GWh) per day, which would be a monthly record for February. However, this estimated level of generation still falls short of the winter-month record for total U.S. power generation (12,178 GWh per day) during January 2014.

Electricity Consumption. Milder January temperatures offset the cold February weather, leading to a forecast reduction of 6.2% in first-quarter heating degree days compared with the same period last year. The colder-than-expected temperatures in February contribute to an increase in EIA's projection of residential electricity sales for 2015, compared with last month's forecast. EIA expects U.S. retail residential sales of electricity will grow by 0.7% in 2015 and then decline by 0.3% in 2016. Projected U.S. sales of electricity to the commercial sector increase by 1.6% this year and by 1.1% in 2016. Projected industrial electricity sales rise by 1.9% in 2015 and by 1.3% in 2016.

Electricity Generation. EIA forecasts that U.S. electricity generation will grow by an average of 1.3% in 2015 and 0.6% in 2016. The cost of natural gas used for power generation fell in recent months, with the Henry Hub spot price declining from an average of \$4.29/MMBtu last summer to an average of \$2.87/MMBtu in February. This decline in fuel costs, combined with upcoming coal plant retirements, is expected to contribute to an increase in natural gas-fired generation. EIA expects the share of total generation fueled by natural gas to average 29.2% during 2015, up from 27.4% last year. In contrast, the share of generation provided by coal falls from 38.7% in 2014 to 37.2% in 2015.

Electricity Retail Prices. Average U.S. residential electricity prices increased in 2014 at the highest rate (3.1%) since 2008. EIA expects continued growth in average residential electricity prices over the forecast period, albeit at a slower pace than last year. The U.S. retail residential price is projected to increase by 1.0% in 2015 and by 1.8% in 2016.

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 2.9% in 2015. Conventional hydropower generation increases by 6.0%, while nonhydropower renewables generation increases by 1.4%. In 2016, total renewables consumption for electric power and heat generation increases by 1.8% as a result of a 3.6% decline in hydropower and a 4.6% increase in nonhydropower renewables.

Wind is the largest source of nonhydropower renewable generation, and it is projected to contribute 5.0% of total electricity generation in 2016. In 2014, wind generation produced more than 10% of total ERCOT electricity generation (most of Texas), which represented 20% of total U.S. wind generation.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 74 gigawatthours (GWh) per day in 2016. Despite this growth, utility-scale solar power averages only 0.6% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations, EIA expects that utility-scale solar capacity will increase by more than 60% between the end of 2014 and the end of 2016, with about half of this new capacity being built in California. Wind capacity, which grew by 7.6% in 2014, is forecast to increase by 11.4% in 2015 and by another 11.0% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute amount of the increase in capacity is more than twice that of solar: 15 GW of wind compared with 6 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. After reaching a record monthly average of 1,002,000 bbl/d in December 2014, ethanol production in February 2015 is estimated to have fallen to an average of 948,000 bbl/d. Ethanol production averaged 935,000 bbl/d in 2014, and EIA expects it to average 947,000 bbl/d in 2015 and 942,000 bbl/d in 2016. Biodiesel production averaged an estimated 83,000 bbl/d in 2014 and is forecast to average 84,000 bbl/d in both 2015 and 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 1.0% in 2014. Emissions are forecast to increase by 0.2% in 2015 and by 0.3% in 2016. These forecasts are sensitive to both weather and economic assumptions.

U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) grew at an annual rate of 2.2% in the fourth quarter of 2014, lower than the initial estimate of 2.6%. Estimated growth for 2014 as a whole is now 2.4%.

EIA used the February 2015 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Production, Income, and Employment. Forecast real GDP growth reaches 2.7% in 2015, then declines to 2.4% in 2016. Growth is expected to rise in 2015 because of greater business investment spending and increases in consumer purchases. However, a stronger dollar and lower demand from slower-growing economies are expected to reduce export growth and raise import growth. Real disposable income grows by 3.2% in 2015, below the 3.3% forecast last month, and by 2.4% in 2016. Total industrial production grows by 2.3% in 2015 and by 3.4% in 2016. Projected growth in nonfarm employment averages 2.1% in 2015 and 1.6% in 2016.

Expenditures. Forecast private real fixed investment growth averages 5.3% and 5.8% in 2015 and 2016, respectively, led by growth in equipment in 2015 and 2016 and by growth in equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.3% and 2.7%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 3.2% and 3.6% over the same two years, while import growth is 5.8% in 2015 and 4.5% in 2016. Total government expenditures rise 1.0% in 2015 and 0.5% in 2016.

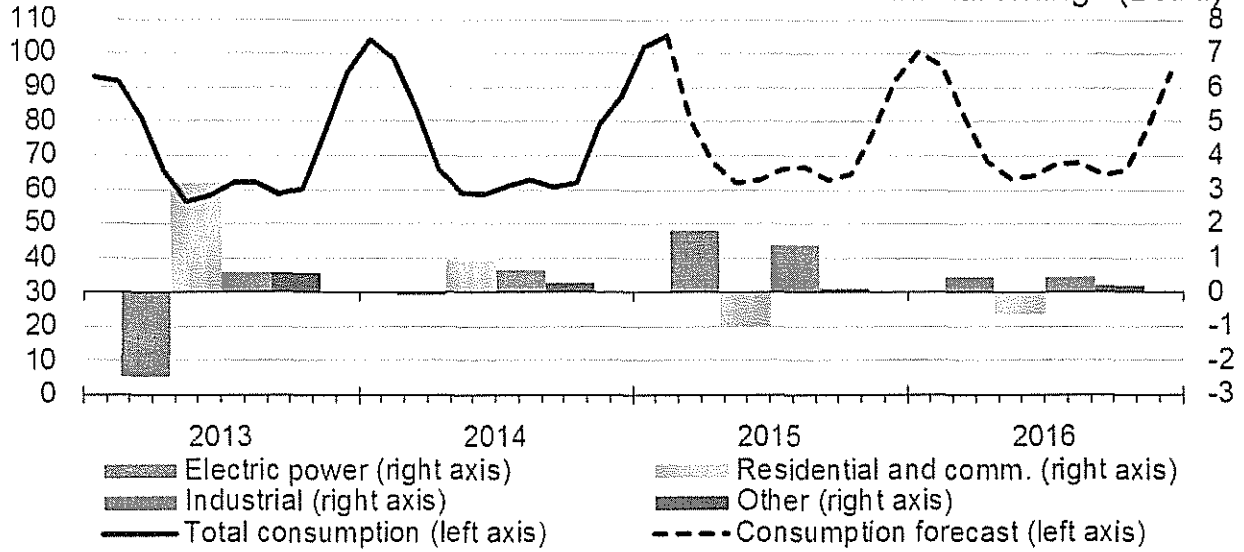
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)



annual change (Bcf/d)



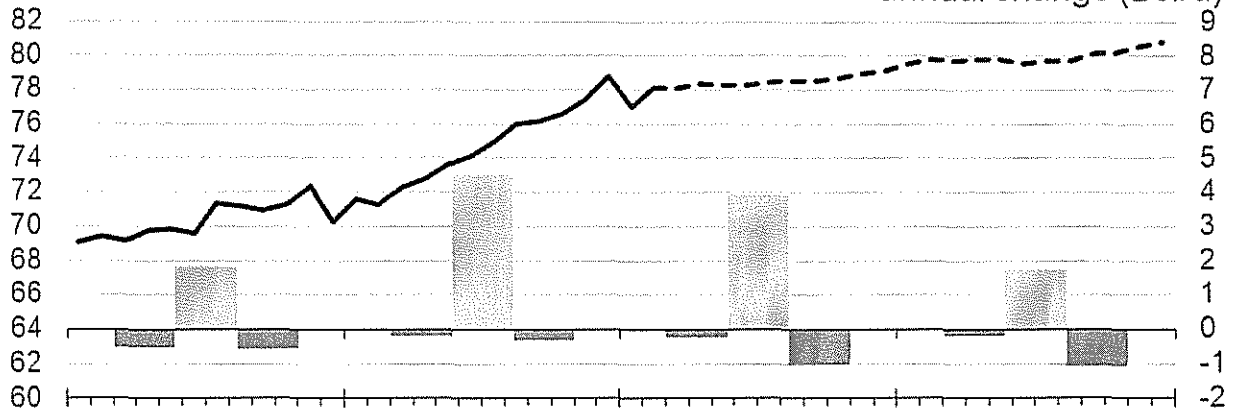
Source: Short-Term Energy Outlook, March 2015.

U.S. Natural Gas Production and Imports



billion cubic feet per day (Bcf/d)

annual change (Bcf/d)

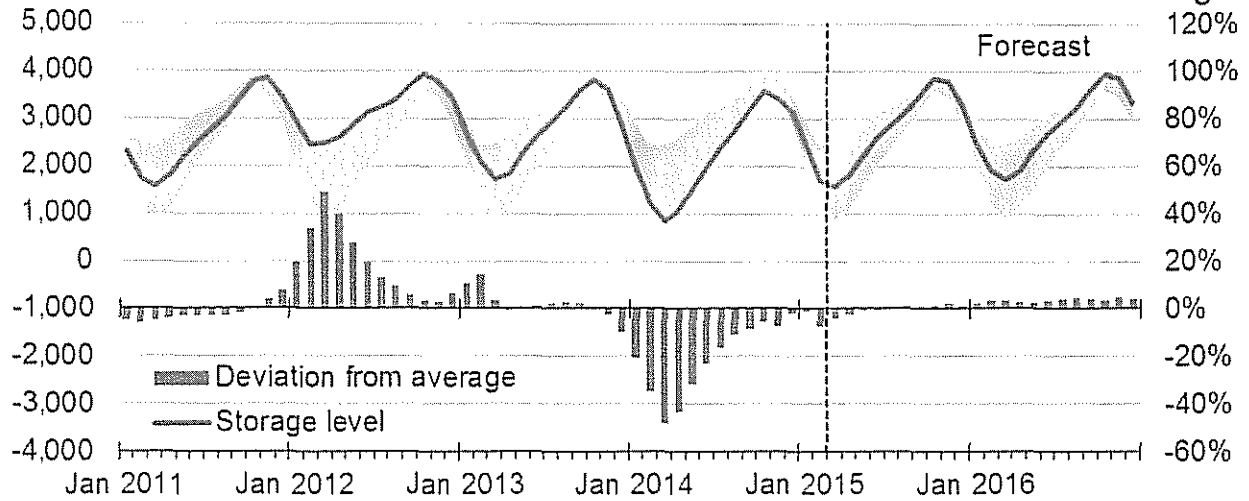


- Federal Gulf of Mexico production (right axis)
- U.S. non-Gulf of Mexico production (right axis)
- U.S. net imports (right axis)
- Total marketed production (left axis)
- - - Marketed production forecast (left axis)

Source: Short-Term Energy Outlook, March 2015.

U.S. Working Natural Gas in Storage

billion cubic feet

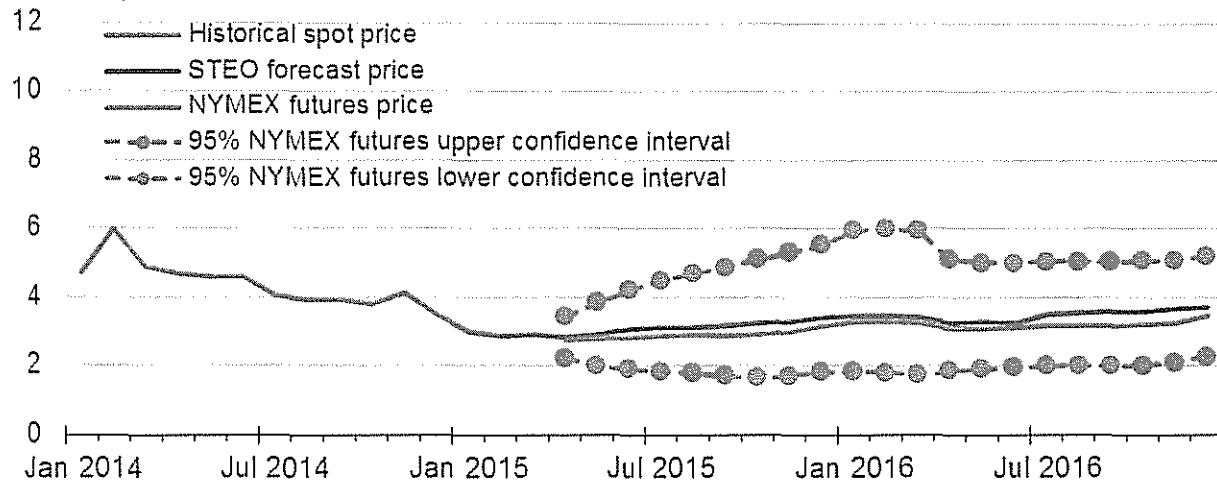


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.

Source: Short-Term Energy Outlook, March 2015.

Henry Hub Natural Gas Price

dollars per million Btu

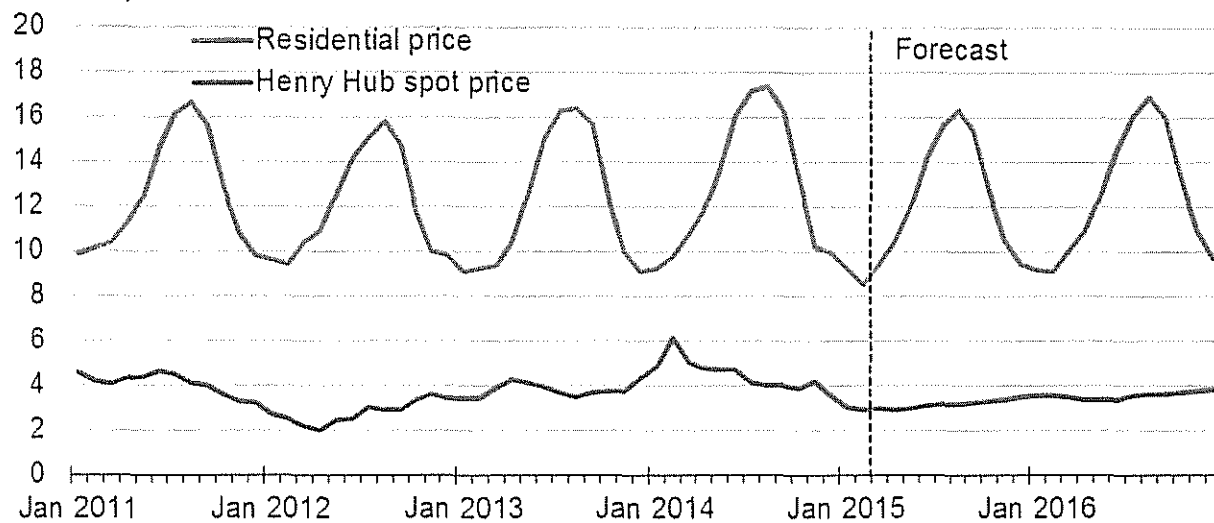


Note: Confidence interval derived from options market information for the 5 trading days ending Mar. 5, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, March 2015.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, March 2015.

**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									<u>\$404,569</u>
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
December	22,567	0	2,225	24,792	41,354	1.3462	55,671	(30,879)	318,657
January 2015	(20,659)	0	2,006	(18,653)	47,084	1.3462	63,384	(82,037)	236,620
February	(12,916)	0	1,424	(11,492)	45,293	1.3462	60,973	(72,465)	164,155
Total	<u>\$6,650</u>	<u>0</u>	<u>\$22,955</u>	<u>\$29,605</u>	<u>207,768</u>		<u>\$270,018</u>	<u>(\$240,414)</u>	<u>\$164,155</u>

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									<u>\$388,932</u>
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
December	204	0	1,459	1,663	30,496	0.9696	29,569	(27,906)	205,995
January 2015	8,505	0	1,248	9,753	48,709	0.9696	47,228	(37,475)	168,520
February	2,220	0	970	3,190	50,226	0.9696	48,699	(45,509)	123,011
Total	<u>(\$57,946)</u>	<u>0</u>	<u>\$18,998</u>	<u>(\$38,948)</u>	<u>288,491</u>		<u>\$226,974</u>	<u>(\$265,921)</u>	<u>\$123,011</u>

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.