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

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

January 30, 2015

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

Re: Cost of Gas Adjustment (COG)
February 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 (107th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (107th Revised Sheet No. 8), showing the February 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.4643 per dk for residential and firm general service customers and a decrease of $0.4643 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for February 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4643 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.

New rates will be implemented effective with service rendered on and after February 3, 2015, in order to accommodate the conversion to the new billing system.

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

107th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 106th 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	$6.1328	$7.4197
			Over 10 dk	1.0646		7.1974
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$4.1429	$5.2935
			Next 2,600 dk	0.9021		5.0450
			Over 3,000 dk	0.7486		4.8915
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$4.1429	$5.3945
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: January 30, 2015

Effective Date: Service rendered on and after February 3, 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
107th Revised Sheet No. 8
Canceling 106th 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.	1.5471	(1.5332)	1.3462	1.3601	(1.5332)	0.9696	(0.5636)
Current Adj.	0.0000	(0.4643)	0.0000	(0.4643)	(0.4643)	0.0000	(0.4643)
Total Adj.	1.5471	(1.9975)	1.3462	0.8958	(1.9975)	0.9696	(1.0279)
Total Rate	$1.6133	$3.1733	$1.3462	$6.1328	$3.1733	$0.9696	$4.1429

Date Filed: January 30, 2015

Effective Date: Service rendered on and after February 3, 2015

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
FEBRUARY 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/	3.1733		4,471,437	3.1733
Gas Cost Reconciliation Adjustment						1.3462
Total Current Firm Gas Cost					$6,744,668	6.1328
Base Cost of Gas						5.2370
Accumulated Adjustment						$0.8958

Interruptible	
Estimated Weighted Average Commodity Cost	$3.1733
Gas Cost Reconciliation Adjustment	0.9696
Total Current Interruptible Gas Cost	4.1429
Base Cost of Gas	5.1708
Accumulated Adjustment	($1.0279)

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
FEBRUARY 2015

Rates Effective February 3, 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:	3.1733	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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

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
February 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 February 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.

The colder than normal weather over the eastern portion of the U.S. resulted in substantial withdrawals from storage, which was offset by the increased imports from Canada, an increase in LNG imports, as well as continued strong domestic production, resulting in the expected decrease in the index price of natural gas. The EIA reported storage levels nationwide as of January 16, 2015 were 5.5 percent below the five-year average and 8.2 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

January 2015

Short-Term Energy Outlook (STEO)

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2016.

- December was the sixth consecutive month in which monthly average Brent prices decreased, falling $17/barrel (bbl) from November to a monthly average of $62/bbl, the lowest since May 2009. The December price decline reflects continued growth in U.S. tight oil production, strong global supply, and weakening outlooks for the global economy and oil demand growth.

- EIA forecasts that Brent crude oil prices will average $58/bbl in 2015 and $75/bbl in 2016, with annual average West Texas Intermediate (WTI) prices expected to be $3/bbl to $4/bbl below Brent. The current values of futures and options contracts suggest very high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for April 2015 delivery, traded during the five-day period ending January 8, averaged $51/bbl, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2015 at $34/bbl and $76/bbl, respectively. The 95% confidence interval for market expectations widens considerably over time, with lower and upper limits of $28/bbl and $112/bbl for prices in December 2015.

- Total U.S. crude oil production averaged an estimated 9.2 million barrels per day (bbl/d) in December. Forecast total crude oil production averages 9.3 million bbl/d in 2015. Under EIA's price forecast, projected crude oil production averages 9.5 million bbl/d in 2016, which would be the second-highest annual average level of production in U.S. history; the highest was 9.6 million bbl/d in 1970.

- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged $2.14/gallon (gal) on January 12, the lowest since May 4, 2009. U.S. regular gasoline retail prices are projected to average $2.16/gal in the first quarter of 2015. EIA expects U.S. regular gasoline retail prices, which averaged $3.36/gal in 2014, to average $2.33/gal in 2015. The average household is now expected to spend about $750 less for gasoline in 2015 compared with last year because of lower prices. The projected regular gasoline retail price increases to an average of $2.72/gal in 2016.

- Natural gas working inventories on January 2 totaled 3.09 trillion cubic feet (Tcf), 0.25 Tcf (9%) above the level at the same time a year ago and 0.07 Tcf (2%) below the previous five-year average (2010-14). EIA expects the Henry Hub natural gas spot price to average $3.52/million British thermal units (MMBtu) this winter compared with $4.51/MMBtu last winter, reflecting both lower-than-expected space heating demand and higher natural gas production this winter. Turning to annual measures, EIA expects the Henry Hub natural gas spot price to average $3.44/MMBtu in 2015 and $3.86/MMBtu in 2016, compared with $4.39/MMBtu in 2014.

Global Petroleum and Other Liquids

EIA estimates that global oil inventories increased by almost 0.8 million bbl/d in 2014, the largest build since 2008, when falling demand for oil caused prices to drop sharply during the second half of the year. However, unlike in 2008, the current market imbalance has been predominantly supply-driven, as production from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) grew by a record high of 2.0 million bbl/d in 2014. Global oil inventories are expected to continue to grow by 0.9 million bbl/d during the first half of 2015, but to taper off by the end of the year as non-OPEC supply growth, particularly from the United States, weakens because of lower oil prices.

EIA estimates that commercial oil inventories held by countries in the Organization for Economic Cooperation and Development (OECD) grew by a record 158 million barrels in 2014, after ending 2013 at the lowest end-of-year level since 2003. EIA expects OECD commercial inventories to grow by 68 million barrels in 2015 and to stay relatively flat in 2016. Throughout 2015 and 2016, OECD commercial inventories are expected to be above the previous five-year (2010-14) range.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 91.4 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 2.9% in 2015 and by 3.2% in 2016.

Non-OECD consumption, which grew by 1.2 million bbl/d in 2014, is projected to grow by 0.9 million bbl/d in 2015 and 1.1 million bbl/d in 2016. The biggest reduction in forecast non-OECD consumption growth in 2015 comes from a 0.2-million-bbl/d decline in Russia's consumption because of its economic downturn. Russia's consumption is expected to decline by a similar amount in 2016. China is the leading contributor to projected global consumption growth, with consumption expected to increase by an annual average of 0.3 million bbl/d over the next two years.

OECD consumption, which fell by 0.3 million bbl/d in 2014, is expected to grow by 0.1 million bbl/d in 2015 and remain relatively flat in 2016. Japan and Europe accounted for almost the

entire decline in 2014 and are expected to continue to decline over the next two years, albeit at a lesser 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 0.1 million bbl/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 2.0 million bbl/d in 2014, averaging 56.2 million bbl/d for the year. Non-OPEC supply growth is expected to slow over the next two years mostly because of lower projected oil prices. Non-OPEC production grows by 0.7 million bbl/d in 2015 and 0.5 million bbl/d in 2016, with the United States as the leading contributor. The slower growth in total non-OPEC supply is largely attributable to slower production growth in the United States, Canada, and Central and South America. Additionally, production in Europe and Eurasia is projected to decline.

Unplanned supply disruptions among non-OPEC producers averaged slightly less than 0.6 million bbl/d in December 2014, unchanged from the previous month. EIA estimates that unplanned non-OPEC supply disruptions averaged slightly more than 0.6 million bbl/d in 2014, 0.2 million bbl/d less than the previous year. South Sudan, Syria, and Yemen accounted for more than 80% of total non-OPEC supply disruptions in 2014.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2014, a slight decline from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait more than offset production growth in Iraq and Iran. EIA expects OPEC crude oil production to remain flat in 2015 and fall by 0.3 million bbl/d in 2016. Iraq is OPEC's largest contributor of growth over the next two years, but its growth is expected to be offset by production declines from other Persian Gulf producers. However, the threat of the Islamic State of Iraq and the Levant (ISIL) on northern Iraqi production and exports still looms, and as a result, Iraq is a major wild card in the world oil production forecast.

EIA estimates that OPEC produced 6.1 million bbl/d of noncrude oil liquids in 2014, close to production in 2013. OPEC noncrude liquids production is expected to increase by almost 0.1 million bbl/d in 2015 and 0.3 million bbl/d in 2016, led by Iran and Qatar.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.8 million bbl/d in December 2014, an increase of 0.1 million bbl/d compared with the previous month because of new production outages in Libya. Unplanned OPEC crude supply disruptions averaged 2.5 million bbl/d in 2014, 0.6 million bbl/d higher than the previous year. Libya and Iraq accounted for almost all of the growth in OPEC disruptions. The high level of OPEC disruptions contributed to higher crude oil prices during the first half of 2014. However, with continuous growth in non-OPEC production, continued strong production in Saudi Arabia, and relatively flat world demand growth, the current volume of supply disruptions has become less significant. 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.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to increase to 2.3 million bbl/d in 2015 and 2.7 million bbl/d in 2016, after averaging about 2.1 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 Commercial Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.71 billion barrels at the end of 2014, equivalent to roughly 57 days of consumption, and the highest end-of- year level on record. Projected OECD oil inventories rise to 2.78 billion barrels at the end of 2015 and 2.79 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged $62/bbl in December, the lowest monthly average Brent price since May 2009, down $17/bbl from the November average. 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).

EIA expects global oil inventories to continue to build in 2015, keeping downward pressure on oil prices. The forecast Brent crude oil price averages $58/bbl in 2015, $11/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 $49/bbl in January and February, and then increase through the remainder of the year to average $67/bbl during the fourth quarter.

The monthly average WTI crude oil spot price fell from an average of $76/bbl in November to $59/bbl in December. Like Brent crude oil prices, WTI prices have decreased considerably, with monthly average prices falling by more than 44% as of December after reaching their 2014 peak of $106/bbl in June. EIA now expects WTI crude oil prices to average $55/bbl in 2015, $8/bbl lower than in last month's STEO, and $71/bbl in 2016. The discount of WTI to Brent crude oil is forecast to widen slightly from current levels later in the forecast, averaging $3/bbl in 2015 and $4/bbl in 2016.

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 April 2015 delivery, traded during the five-day period ending January 8, averaged $51/bbl. Implied volatility averaged 48%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2015 at $34/bbl and $76/bbl, respectively. The 95% confidence interval for market expectations widens considerably over time, with lower and upper limits of $28/bbl and $112/bbl for prices in December 2015. Last year at this time, WTI for April 2014 delivery averaged $98/bbl, and implied volatility

averaged 16%. The corresponding lower and upper limits of the 95% confidence interval were $86/bbl and $113/bbl.

The recent declines in oil prices and associated increase in oil price volatility continue to contribute to a particularly uncertain forecasting environment, and 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 recent 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 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. 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 in a lower-than-expected price climate and present a major uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices averaged $2.14/gal on January 12, a decrease of $0.64/gal since the beginning of December and the lowest weekly price since May 4, 2009. Regional gasoline retail prices ranged from a low of $1.91/gal in Petroleum Administration for Defense District (PADD) 3 to a high of $2.49/gal in PADD 5. U.S. average regular gasoline retail prices are now down more than 40% from their summer peak in late June. Falling Brent crude oil prices have been largely responsible for falling retail gasoline prices. EIA expects retail gasoline prices to average $2.16/gal during the first quarter of 2015 and $2.33/gal for the full year.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 100,000 bbl/d (0.5%) in 2014. Motor gasoline consumption increased by 100,000 bbl/d (1.1%) because of increases in highway travel. Distillate consumption grew by 170,000 bbl/d (4.6%), as a result of colder-than-average weather in the first quarter as well as increases in industrial production during the year. Jet fuel usage increased by 30,000 bbl/d (2.3%). Hydrocarbon gas liquids (HGL) and residual fuel oil consumption fell by an estimated 100,000 bbl/d (4.0%) and 70,000 bbl/d (22%), respectively, in 2014.

In 2015, total liquid fuels consumption is forecast to grow by 260,000 bbl/d (1.4%). Lower pump prices result in a slight increase in motor gasoline consumption in 2015, but a decline in sales is

expected with higher prices in the following year. HGL consumption is expected to reverse 2014's decline and increase by 110,000 bbl/d (4.7%) in 2015.

Distillate consumption is projected to increase by 60,000 bbl/d (1.5%) in 2015 based on forecast assumptions of continuing economic growth. 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. This increase in marine distillate use because of MARPOL regulations will displace the use of residual fuel oil.

In 2016, EIA projects more moderate growth in liquid fuels consumption of 110,000 bbl/d (0.5%). HGL growth accounts for most of the overall growth, with HGL consumption projected to grow by 100,000 bbl/d (3.9%). EIA projects that distillate fuel consumption increases by 60,000 bbl/d (1.5%) in 2016, while residual fuel oil consumption stabilizes near the 2015 level.

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 9.5 million b/d in 2016. With WTI crude oil prices expected to average $49/bbl in the first half of 2015, EIA expects 2015 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 and focusing on core areas of major tight oil plays. Oil prices remain high enough to support some development drilling activity in 2015 in the Bakken, Eagle Ford, Niobrara, and Permian Basin, albeit lower than previously forecast. Companies that have lower drilling and debt costs and have acreage in the sweet spots of these regions will continue to drill highly productive wells in 2015. Nevertheless, EIA expects 2015 production to reach 9.4 million bbl/d in the second quarter, then decline by 190,000 bbl/d in the third quarter. With projected WTI crude oil prices starting to rise in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for both leasing acreage and drilling services, causing production to resume rising at a relatively low WTI crude oil price. However, this forecast remains particularly sensitive to actual prices available at the wellhead and drilling economics that vary across regions and operators. Projected production for the Federal offshore region and Alaska, which rise and fall respectively, are less sensitive to short-term price movements than Lower 48 onshore production.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in October, 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 most of the production supplying 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 crude oil and other liquids imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 27% 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. average regular gasoline retail prices fell from a monthly average of $3.69/gal in June to $2.54/gal in December, the lowest monthly average since July 2009. EIA expects that U.S. regular gasoline retail prices will fall to an average of $2.13/gal in January 2015. The U.S. regular gasoline retail price, which averaged $3.36/gal in 2014, is projected to average $2.33/gal in 2015, $0.26/gal lower than in last month's STEO, and $2.72/gal in 2016. Diesel fuel retail pump prices, which averaged $3.83/gal in 2014, are projected to fall to an average of $2.85/gal in 2015 but rise to $3.25/gal in 2016.

The April 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged $1.63/gal for the five trading days ending January 8, 2015. An RBOB futures contract price of $1.63/gal is consistent with a monthly average regular-grade gasoline retail price less than $2.35/gal in April 2015. The current values of futures and options contracts suggest there is a 2% 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 17% 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.

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 with last winter. The average household that uses heating oil as its primary space heating fuel is expected to pay an average of $2.90/gal this winter, $0.98/gal lower than last winter. The average household is now expected to spend $1,586 for heating oil this winter, $767 lower than last winter. Propane prices are expected to be 17% lower in the Northeast and 27% lower in the Midwest, resulting in households spending 24% and 35% less on propane in those regions, respectively.

Natural Gas

Natural gas futures prices have fallen more than $1/MMBtu since mid-November, and on December 31, the February 2015 futures contract settled at $2.89/MMBtu, the lowest settlement price for a front-month contract since September 2012. Prices remain at relatively low levels, reflecting abundant supplies. December 2014 was warmer than normal, which along with robust production contributed to lower-than-average storage withdrawals. The deficit of natural gas inventories to the previous five-year average narrowed to 67 Bcf at the end of December, from a 959-Bcf deficit at the end of March 2014.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will increase to an average of 73.8 Bcf/d in 2015 and 74.8 Bcf/d in 2016, compared with an estimated 73.6 Bcf/d in 2014. Growth is largely driven by the industrial and electric power sectors, while residential and commercial consumption is projected to decline in 2015, then remain flat in 2016. Natural gas consumption in the power sector is expected to average 23.0 Bcf/d in 2015, a 3.2% increase compared with 2014, and it is expected to grow by 1.8% to 23.4 Bcf/d in 2016. Industrial sector consumption increases by 4.5% and 2.1% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors.

Natural Gas Production and Trade. EIA expects that growth in marketed natural gas production will continue through 2015 and 2016. This increase is the result of continuing strong growth in the Lower 48 states, which more than offsets the long-term trend of declining production in the Gulf of Mexico. As of October, the most recent month for which EIA data are available, dry natural gas production was 4.6 Bcf/d greater than it was in October 2013. Although natural gas prices have declined, and this month's STEO lowers the Henry Hub spot price forecast, EIA expects that increases in drilling efficiency and growth in oil production (although at a slower rate) will continue to support growing natural gas production in the coming years. Additionally, with most growth coming from the Marcellus Shale, a backlog of drilled but uncompleted wells will continue to support production growth as new pipeline infrastructure comes online in the Northeast.

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 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. EIA projects that gross LNG exports will average 0.8 Bcf/d in 2016.

Natural Gas Inventories. Natural gas working inventories totaled 3,089 Bcf as of January 2, which is 250 Bcf greater than at the same time in 2014 and 67 Bcf lower than the previous five-year (2010-14) average. Following last year's extremely cold winter, inventories fell 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 1,665 Bcf, which is 9 Bcf greater than the five-year (2010-14) average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $3.48/MMBtu in December, a decline of $0.64/MMBtu from November. EIA expects monthly average spot prices to remain less than $4/MMBtu until the fourth quarter of 2016. The projected Henry Hub natural gas price averages $3.44/MMBtu in 2015 and $3.86/MMBtu in 2016.

Natural gas futures prices for April 2015 delivery (for the five-day period ending January 8) averaged $2.88/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for April 2015 contracts at $1.90/MMBtu and $4.36/MMBtu, respectively. At this time last year, the natural gas futures contract for April 2014 averaged $4.19/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.21/MMBtu and $5.46/MMBtu.

Coal

Despite railroad transportation problems and increased rail traffic for other commodities encountered in 2014, year-to-date coal railcar loadings through December 27 were 1% higher than the same period in 2013. Weekly carloads peaked at 120,914 during the week ending December 20, 2014.

Total electric power sector coal stocks increased by just over 12 million short tons (MMst) in October 2014 compared with the previous month, which was the largest stock build since a 12.5-MMst build in October 2011. The increase in coal inventories followed the typical seasonal pattern where coal plants build stocks during the autumn months in preparation for increased coal consumption during the winter. Despite the increase, end-of-October 2014 stocks of 136.3 MMst were 17 MMst (11%) lower than the previous year and 19% lower than the previous four-year average for the month. The large year-over-year decrease in stocks reflects high levels of coal-fired electricity generation during the winter of 2013-14 across a large portion of the country and subsequent decrease in coal deliveries because of rail transportation issues.

Coal Supply. EIA estimates that coal production for 2014 was 994 MMst, 1% (10 MMst) higher than in 2013. EIA expects that annual production will decline in both 2015 and 2016, to 984 MMst and 977 MMst, respectively.

Regional shifts in production are more significant. Appalachian coal production, which averaged 272 MMst in 2014, is projected to decline by 3.6% in 2015 and by nearly 2.9% in 2016 as a result of higher mining costs, weak demand from export markets, and a shift to higher-sulfur, lower-cost Interior region coal. Interior region coal production, which averaged 187 MMst in 2014, is projected to grow by 1.0% in 2015 and 1.3% in 2016. Many power generators have recently installed sulfur dioxide scrubbers in response to environmental regulations, allowing them to switch from Appalachian and Western region coal to Interior region coal.

Western region coal production, which averaged 535 MMst in 2014, is projected to remain largely unchanged in both 2015 and 2016.

Coal Consumption. Electric power sector coal consumption was largely unchanged in 2014. Power sector coal consumption is projected to increase by 0.3% in 2015, despite a 0.8% increase in electricity demand, as comparative natural gas prices decline and retirements of coal power

plants rise in response to the implementation of the Mercury and Air Toxics Standards. The full effect of the coal plant retirements is felt in 2016, as projected electric power sector coal consumption declines by 1.4%.

Coal Trade. Coal exports in 2014 were estimated at 98 MMst in 2014, a 17.1% decline from 118 MMst in 2013. The decline was primarily a result of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. EIA expects that there will be no improvement in global market conditions in 2015, and coal exports will fall to 83 MMst, which would be the lowest since 2010. In 2016, EIA projects a slight improvement in international markets (for steam coal), and exports are expected to increase by 1 MMst (1.6%).

Coal Prices. The annual average coal price to the electric power industry fell from a record-high $2.39/MMBtu in 2011 to an estimated $2.35/MMBtu in 2014. EIA expects the average delivered coal price to fall to $2.33/MMBtu in 2015 and to increase back to $2.35/MMBtu in 2016.

Electricity

The U.S. residential retail price averaged 12.54 cents per kilowatthour (kWh) between January and October 2014, which was 3.1% higher than the same period in 2013. Electricity rates rose the fastest in the New England states (10.9%) over this period, while residential prices in the West North Central region rose by 1.6%. Growth in residential electricity prices for the Pacific states in 2014 was relatively flat compared with 2013, as growth in regional rates was offset by credits to the electricity bills of some California residential customers. Retail electricity prices to the commercial and industrial sectors also increasedover 2013 levels: by 4.4% and 3.4%, respectively.

Electricity Consumption. Heating degree days (HDD) during the first quarter of 2015 are projected to be about 12% lower than last year. Milder forecast temperatures during the early part of 2015 should translate to lower household usage of electricity, especially for those households that use heat pumps for space heating. This contributes to EIA's forecast of a 0.3% decline in retail sales of electricity to the residential sector for the full year of 2015. Residential electricity sales grow by 0.6% in 2016.

Electricity Generation. EIA forecasts that U.S. electricity generation will grow by 1.1% in 2015 and then by 0.9% in 2016. The mix of energy sources used to produce this generation shifts over the next two years. The share of total generation fueled by coal falls from 39.0% in 2014 to 37.6% in 2016, as declining natural gas prices make that fuel more attractive for power generators and as coal-fueled plants retire in 2015. This decline in coal is balanced by an increase in natural gas generation, which rises from 27.3% of total generation in 2014 to 28.1% in 2016, and by an increase in renewable electricity (other than hydropower), which rises from 6.7% to 7.9%.

Electricity Retail Prices. EIA expects continued growth in average residential electricity prices over the forecast period, albeit at a slower pace than in 2014. The U.S. retail residential price is projected to increase by 1.1% in 2015 and by 1.8% in 2016. Most areas of the country should experience rising prices, with the exception of the West South Central states where residential prices fall by 3.2% this year. Projected price increases in 2015 are again highest in the New England states (3.8%).

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 3.3% in 2015. Conventional hydropower generation increases by 2.1%, while nonhydropower renewables generation increases by 3.9%. In 2016, total renewables consumption for electric power and heat generation increases by 4.8% as a result of a 1.1% increase in hydropower and a 6.6% increase in nonhydropower renewables.

In 2013, the electricity generation shares were 6.6% and 6.2% from hydropower and nonhydropower renewables, respectively. In 2014, 6.4% of generation came from hydropower and 6.7% from nonhydropower renewables. This trend is expected to continue, with the electricity generation share from nonhydropower renewables rising to 7.9% by 2016, and the hydropower share remaining at 6.4%. Wind is the largest source of nonhydropower renewable generation, and it is projected to contribute 5.3% of total electricity generation in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average almost 80 gigawatthours per day in 2016. Despite the growth, solar power remains just 0.7% of total U.S. utility-scale 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 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 10% between 2012 and 2014, is forecast to increase by about 23% between 2014 and 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 gigawatts of wind versus 6 gigawatts of utility-scale solar.

Liquid Biofuels. Ethanol production in December 2014 reached an estimated monthly average record of 979,000 bbl/d, exceeding the previous record of 968,000 bbl/d set the previous month. Ethanol production is estimated to have averaged 935,000 bbl/d in 2014, and EIA expects that ethanol production will average 936,000 bbl/d in 2015 and 937,000 bbl/d in 2016. Biodiesel production averaged an estimated 81,000 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 0.9% in 2014. Emissions are forecast to increase by 0.9% in 2015 and 0.3% in 2016. These forecasts are sensitive to both weather and economic assumptions.

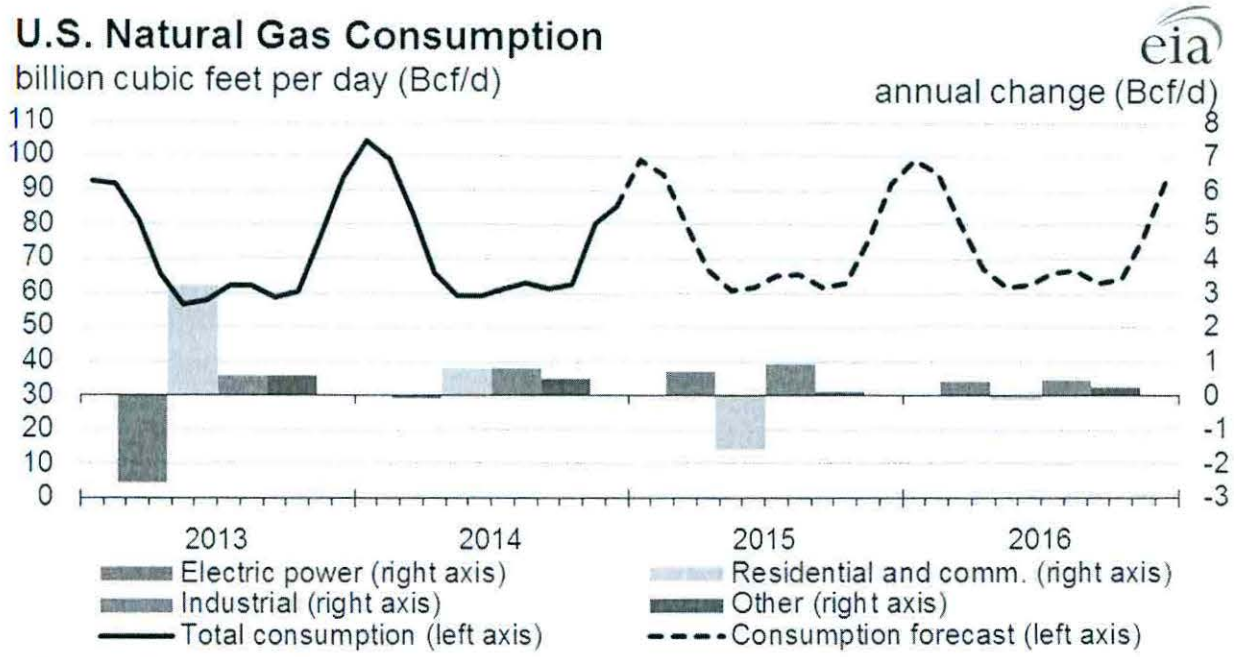
U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) grew at an annual rate of 5.0% in the third quarter of 2014. This rate was an upward revision from its earlier estimate of 3.9% growth because personal consumption expenditures and nonresidential fixed investment increased more than previously estimated.

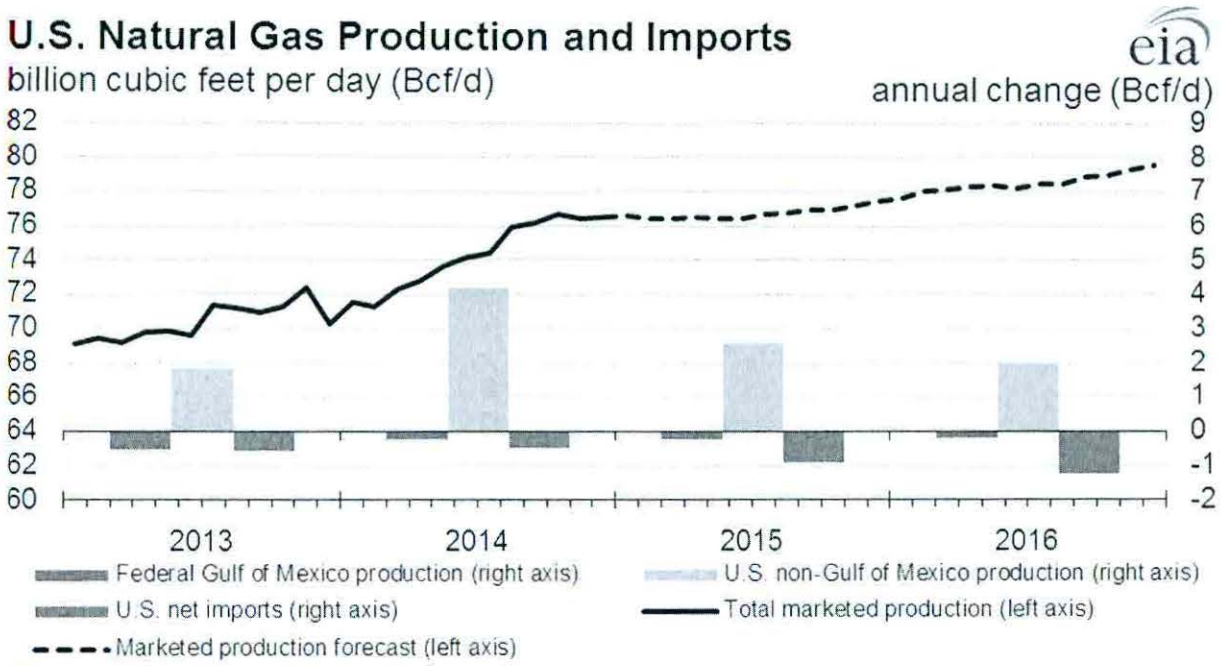
EIA used the December 2014 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Production, Income, and Employment. Forecast real GDP growth reaches 2.5% in 2015 and declines slightly to 2.4% in 2016. Growth is expected to rise in 2015 because of greater business investment spending, increases in consumer purchases, and recent declines in gasoline prices. 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 2.8% in 2015, above the 2.4% forecast last month, and by 2.7% in 2016. Total industrial production grows at 2.3% in 2015 and 3.3% in 2016. Projected growth in nonfarm employment averages 1.8% in 2015 and 1.3% in 2016.

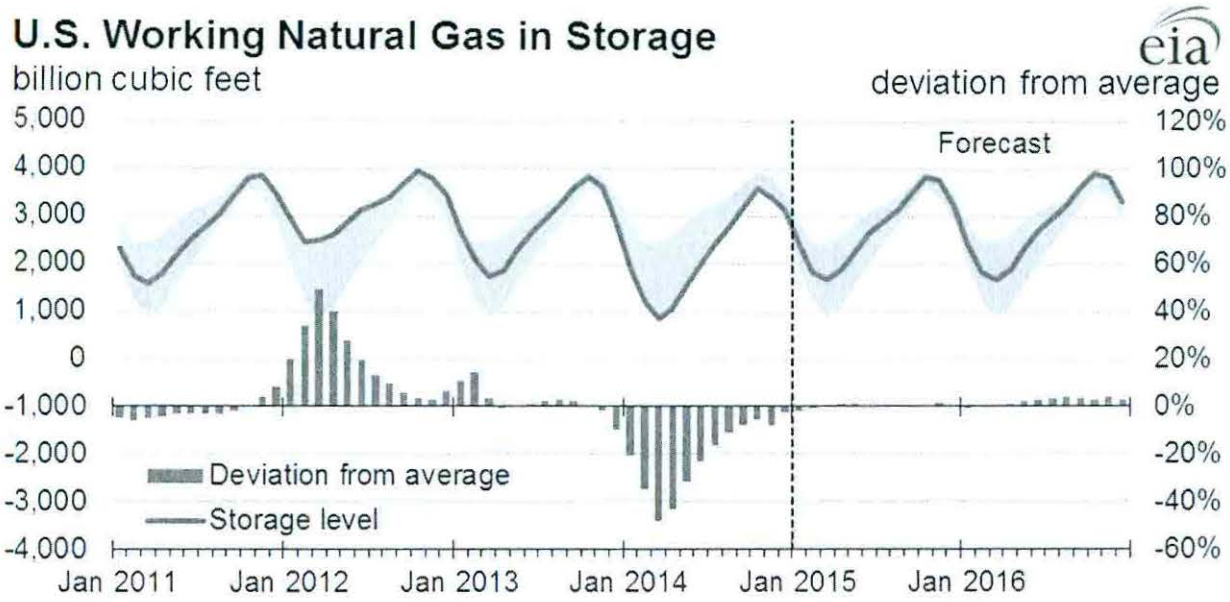
Expenditures. Forecast private real fixed investment growth averages 4.8% and 5.8% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 2.8% and 2.7%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 3.1% and 4.0% over the same two years, while import growth is 3.6% in 2015 and 6.1% in 2016. Total government expenditures rise 0.5% in both years.



Source: Short-Term Energy Outlook, January 2015.



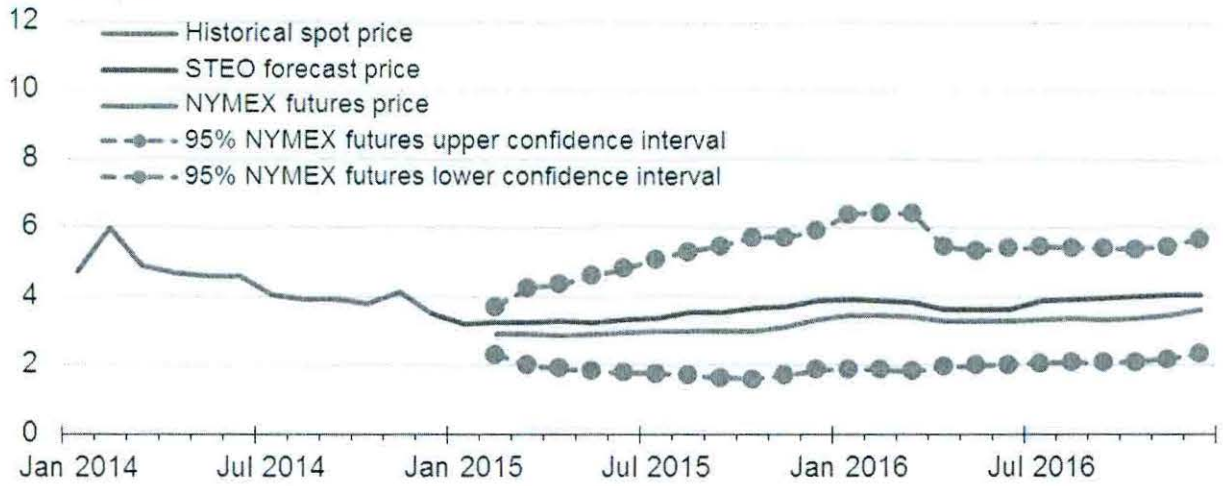
Source: Short-Term Energy Outlook, January 2015.



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.
Source: Short-Term Energy Outlook, January 2015.

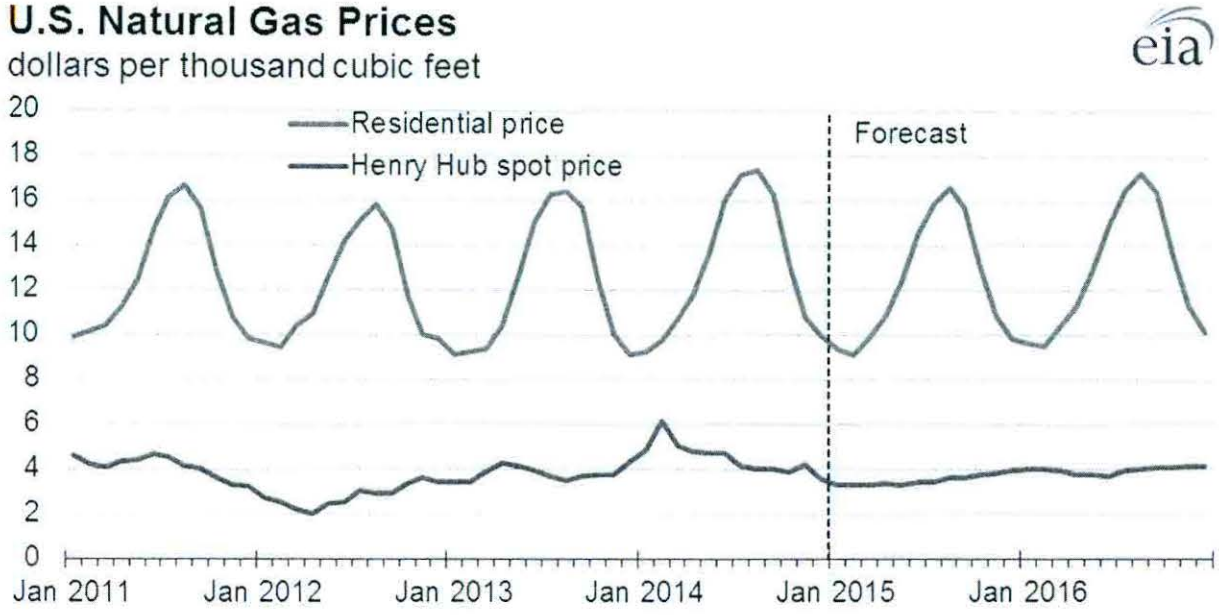
Henry Hub Natural Gas Price

dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending Jan. 8, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, January 2015.



Source: Short-Term Energy Outlook, January 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									**$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
December	22,567	0	2,225	24,792	41,354	1.3462	55,671	(30,879)	318,657
Total	$40,225	0	$19,525	$59,750	115,391		$145,661	($85,912)	
Balance @ December 31, 2014									**$318,657**

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
December	204	0	1,459	1,663	30,496	0.9696	29,569	(27,906)	205,995
Total	($68,671)	0	$16,780	($51,891)	189,556		$131,047	($182,937)	
Balance @ December 31, 2014									**$205,995**

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.