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

April 30, 2015

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

Re: Cost of Gas Adjustment (COG)
May 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 (110th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (110th Revised Sheet No. 8), showing the May 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.4371 per dk for residential and firm general service customers and a decrease of $0.4220 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for May 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4220 per dk since the last COG filing.

Attachment B shows the calculations supporting the gas costs for May 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4220 per dk for residential and firm general service customers and has decreased $0.4220 per dk for large and small interruptible customers since the last COG filing. There has been a decrease in pipeline charges of $0.0151 per dk due to an update in the three year normalized dk sales volumes. The net effect of these changes is a decrease of $0.4371 per Dk for residential and firm general service customers.

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

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

Great Plains submitted a check for $650.00 on November 26, 2014 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with the monthly COG filings.

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

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

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2

110th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 109th 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	$5.4226	$6.7095
			Over 10 dk	1.0646		6.4872
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$3.4478	$4.5984
			Next 2,600 dk	0.9021		4.3499
			Over 3,000 dk	0.7486		4.1964
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$3.4478	$4.6994
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: April 30, 2015

Effective Date: Service rendered on and after May 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
110th Revised Sheet No. 8
Canceling 109th 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	(2.2706)	1.3462	0.6227	(2.2706)	0.9696	(1.3010)
Current Adj.	(0.0151)	(0.4220)	0.0000	(0.4371)	(0.4220)	0.0000	(0.4220)
Total Adj.	1.5320	(2.6926)	1.3462	0.1856	(2.6926)	0.9696	(1.7230)
Total Rate	$1.5982	$2.4782	$1.3462	$5.4226	$2.4782	$0.9696	$3.4478

Date Filed: April 30, 2015

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$4.3706	12	$419,578	$0.2950
FT-A - Zone 1-1	5,000		4.7507	5	118,768	0.0835
FT-A Seasonal	2,000		4.7507	5	47,507	0.0334
TFX Seasonal	2,000		15.1530	5	151,530	0.1065
TFX - Winter	13,000		15.1530	5	984,945	0.6925
TFX - Summer	13,000		5.6830	7	517,153	0.3636
BP Seasonal Contract	500		2/	3	33,750	0.0237
Total Demand Charges					$2,273,231	1.5982
Estimated Weighted Average Commodity Cost	1,422,210	1/	2.4782		3,524,521	2.4782
Gas Cost Reconciliation Adjustment						1.3462
Total Current Firm Gas Cost					$5,797,752	5.4226
Base Cost of Gas						5.2370
Accumulated Adjustment						$0.1856
Interruptible						
Estimated Weighted Average Commodity Cost						$2.4782
Gas Cost Reconciliation Adjustment						0.9696
Total Current Interruptible Gas Cost						3.4478
Base Cost of Gas						5.1708
Accumulated Adjustment						($1.7230)

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
MAY 2015

Rates Effective May 1, 2015	$/Dk	
FT-A - Zone 1-1 (Category 1)	$4.7507	Per Dk/Mo.
FT-A - Zone 1-1 (Category 3)	4.3706	Per Dk/Mo.
FT-A - Seasonal	4.7507	Per Dk/Mo.
TFX	15.1530	Per Dk/Mo.
TFX Seasonal	15.1530	Per Dk/Mo.
Estimated Weighted Average Commodity Cost:	2.4782	Per Dk

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

Base Rate Calculation

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

Interruptible:		
Commodity	$5.1708	Per Dk

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

2/ Demand base rate calculation:

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$4.7507
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate 1/	$5.7394
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$3.3143
Zone 2-2 Minimum Rate	$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$4.5607
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$5.5494
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$3.1243
Zone 2-2 Minimum Rate	$0.0000
Category 3 (Contract Term of 5 or more Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$4.3706
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$5.3593
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.9343
Zone 2-2 Minimum Rate	$0.0000

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

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		($0.0528)	

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

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	0.0369	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

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.

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

Ninth Revised Sheet No. 51
Superseding
Eighth Revised Sheet No. 51

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	0.0369	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

	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 $0.0010 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

	Percentages
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%

	Electric Compression
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
May 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 May 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.

Mild temperatures and relatively low demand in most regions from both the heating and cooling sectors resulted in ongoing low prices for natural gas. Domestic production levels continue to run near record levels. The EIA reported nationwide storage levels as of April 17, 2015 at 5.8 percent below the five-year average and 82.6 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 21.

Independent Statistics & Analysis
U.S. Energy Information Administration

April 2015

Short-Term Energy and Summer Fuels Outlook (STEO)

Highlights

- On April 2, Iran and the five permanent members of the United Nations Security Council plus Germany (P5+1) reached a framework agreement that could result in the lifting of oil-related sanctions against Iran. Lifting sanctions could substantially change the STEO forecast for oil supply, demand, and prices by allowing a significantly increased volume of Iranian barrels to enter the market. If and when sanctions are lifted, the baseline forecast for world crude oil prices in 2016 could be reduced $5-$15/barrel (bbl) from the level presented in this STEO.

- Iran is believed to hold at least 30 million barrels in storage, and EIA believes Iran has the technical capability to ramp up crude oil production by at least 700,000 bbl/day (bbl/d) by the end of 2016. The pace and magnitude at which those volumes would reach the market would depend on the terms of a final agreement. For additional analysis of the possible oil market effects of a lifting of sanctions against Iran, please see the analysis box beginning on page 5.

- North Sea Brent crude oil prices averaged $56/bbl in March, a decrease of $2/bbl from the February average. EIA forecasts that Brent crude oil prices will average $59/bbl in 2015 and $75/bbl in 2016, both unchanged from last month's STEO. West Texas Intermediate (WTI) prices in 2015 and 2016 are expected to average $7/bbl and $5/bbl below Brent, respectively. 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 the broadly held December 2015 delivery traded during the five-day period ending April 2 averaged $52/bbl , the market's expectations (at the 95% confidence interval) for monthly average WTI prices in that month ranges from $32/bbl to $97/bbl.

- During the 2015 April-through-September summer driving season, regular gasoline retail prices are forecast to average $2.45/gallon (gal) compared with $3.59/gal last summer (see EIA Summer Fuels Outlook slideshow). Based on EIA's gasoline price forecast, the average U.S. household is expected to spend about $700 less on gasoline in 2015 compared with 2014, as annual motor fuel expenditures are on track to fall to their lowest level in 11 years.

- Total U.S. crude oil production averaged an estimated 9.3 million bbl/d in March but will decline in June through September before growth resumes. Given EIA's price forecast, projected total crude oil production will average 9.2 million bbl/d in 2015 and 9.3 million bbl/d in 2016.

- Natural gas working inventories were 1,461 billion cubic feet (Bcf) on March 27, which was 75% higher than a year earlier, but 12% lower than the previous five-year (2010-14) average. The winter withdrawal season typically ends in March, and April is typically the beginning of the injection season, which runs through October. EIA projects natural gas inventories will end October 2015 at 3,781 Bcf, a net injection of 2,310 Bcf. This would be the fourth-highest injection season on record, but it would be 420 Bcf lower than last year's net April–October injection.

- Power generators are using more natural gas than last year, primarily because of lower natural gas prices compared with coal prices. The use of natural-gas-fired generation is projected to average 30.4% of total generation in 2015 compared with 27.4% during 2014. U.S. coal production is expected to fall by 7.1% in 2015, as natural gas displaces coal for power generation.

Global Petroleum and Other Liquids

As in last month's STEO, global production continues to exceed demand, resulting in inventory builds. Global oil inventory builds are projected to average 1.7 million bbl/d through the first half of 2015. Inventory builds moderate during the second half of the year, as demand rises and non-Organization of the Petroleum Exporting Countries (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 1.0 million bbl/d increase in 2014.

If the new framework agreement between the P5+1 and Iran results in a comprehensive deal and a lifting of sanctions, it could significantly change the STEO forecast for oil supply, demand, and prices, which still assumes that Iran's production will stay close to the current level through 2016. An analysis box on page 5 discusses the implications of increased flows of oil from Iran.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 92.0 million bbl/d for the year. EIA expects global consumption will grow by 1.0 million bbl/d in 2015 and by 1.1 million bbl/d in 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. Lower 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 and in the beginning of 2015, 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 0.4 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 0.7 million bbl/d in 2015 and by 0.4 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 remaining relatively flat in 2015, production in Eurasia is projected to decline by more than 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 0.6 million bbl/d in March 2015, similar to the previous month. South Sudan, Syria, and Yemen accounted for nearly 90% of total non-OPEC supply disruptions in March. EIA estimates that unplanned non-OPEC supply disruptions averaged 0.6 million bbl/d in 2014. Yemen has maintained a crude oil output of more than 100,000 bbl/d despite the ongoing conflict in that country. However, sustained port closures could halt oil and liquefied natural gas (LNG) exports and force production shut-ins in the near future.

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 rises by 0.1 million bbl/d in 2015 and falls by 0.5 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 6.3 million bbl/d in 2014, is expected to increase by 0.2 million bbl/d in 2015 and by 0.1 million bbl/d in 2016, led by production increases in Qatar, Iran, and Kuwait.

In March 2015, unplanned crude oil supply disruptions among OPEC producers averaged 2.3 million bbl/d, a decrease of 0.2 million bbl/d compared with the previous month. This decrease

was mainly attributable to fewer outages in Iraq 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.

Nigeria's newly elected president, Muhammadu Buhari, will be inaugurated on May 29. Buhari may face significant challenges from groups associated with oil theft in the oil-rich Niger Delta and those receiving payments through the amnesty program. Buhari's campaign focused on curtailing corruption, and if those groups feel threatened by potential changes to the status quo, they might retaliate by disrupting oil production. For now, Nigeria's oil production forecast remains unchanged.

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 2.72 billion barrels at the end of 2014, the highest end-of-year level on record and equivalent to roughly 59 days of consumption. Projected OECD oil inventories rise to 2.88 billion barrels at the end of 2015 and fall slightly to 2.87 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices decreased by $2/bbl in March to a monthly average of $56/bbl. This decrease followed a $10/bbl increase in February, the first increase in eight months. Several factors put upward pressure on Brent prices in February, including news of falling U.S. crude oil rig counts and announced reductions in capital expenditures by major oil companies. This upward price pressure abated in March, as the combination of robust world crude oil supply growth and weak global demand contributed to an increase in the rate of global inventory builds. Total global oil inventories are estimated to have increased by 2.1 million bbl/d in March, compared with a 0.9 million bbl/d increase in February. Strong global oil inventory builds are 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 decreased to an average of $48/bbl in March, down $3/bbl from February. WTI prices fell in March in large part because of commercial crude oil inventories in Cushing, Oklahoma, which increased to a record 58.9 million barrels as of March 27. The record inventory levels have put downward pressure on the price of crude oil for prompt delivery compared with the price of crude oil for delivery in later months.

EIA projects the Brent crude oil price will average $59/bbl in 2015, unchanged 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. However, this price projection remains subject to the uncertainties surrounding the possible lifting of sanctions against Iran and other market events (see analysis box below). WTI prices in 2015 and 2016 are expected to average $7/bbl and $5/bbl, respectively, below Brent. The Brent-WTI spread for 2015 reflects continued 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 high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for July 2015 delivery traded during the five-day period ending April 2 averaged $52/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 $35/bbl and $78/bbl, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $32/bbl and $97/bbl for prices in December 2015. Last year at this time, WTI for July 2014 delivery averaged $99/bbl, and implied volatility averaged 17%. The corresponding lower and upper limits of the 95% confidence interval were $85/bbl and $115/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 potential lifting of sanctions against Iran if a comprehensive agreement is reached (see box below). The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, 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 major uncertainty in the world oil supply forecast.

Assessing oil market impacts of a potential comprehensive agreement with Iran

On April 2, Iran and the P5+1 reached a framework agreement to guide the next three months of negotiations, which will target a comprehensive agreement by June 30. Under the framework, U.S. and European Union nuclear-related sanctions (which includes oil-related sanctions) will be suspended after the International Atomic Energy Agency verifies that Iran has

complied with key nuclear-related steps. If a comprehensive agreement that results in the lifting of Iranian oil-related sanctions is reached, then this could significantly change the STEO forecast for oil supply, demand, and prices. However, the timing and order that sanctions could be suspended is uncertain. In addition, the pace and volume at which more Iranian oil can re-enter the market is uncertain and depends on how quickly Iran can move oil out of storage and ramp up production.

In this STEO, EIA's forecast of oil supply, demand, and price is mostly unchanged from last month. Given the preliminary nature of the recent developments, EIA has not changed its short-term projection for Iranian production, which assumes that production will stay close to the current level. However, if a comprehensive deal is reached, the re-entry of more Iranian barrels could result in a $5-$15/bbl lower baseline STEO price projection in 2016 compared with the current STEO.

Iran is believed to hold at least 30 million barrels in storage. It is possible that Iran will attempt to move oil out of storage more quickly sometime during the second half of 2015 in preparation to increase production if discussions on sanctions show progress. As a result, the global market may see incremental increases in Iran's crude oil exports before seeing a substantial increase to Iran's production, but the pace at which oil in storage could be withdrawn is uncertain.

EIA believes that Iran has the technical capability to ramp up crude oil production by at least 700,000 bbl/d by at least the end of 2016, of which 600,000 bbl/d represents capacity that was previously shut in and 100,000 bbl/d is new capacity. EIA's current STEO projects that growth in global inventories declines from 1 million bbl/d in 2015 to 100,000 bbl/d in 2016. If Iran ramps up production by 700,000 bbl/d by at least the end of 2016, then this could result in an annual average growth of about 500,000 bbl/d in global inventories in 2016, which would stress storage capacity limits and put downward pressure on prices. The potentially large inventory build in 2016 implies that production growth outside of Iran could be lower or that global consumption growth could be higher than projected in the current STEO.

Although the timing and volume of Iran's exports remain uncertain, the market perception surrounding increased future supplies will apply downward price pressure to near-term crude oil prices. Overall, North Sea Brent crude oil prices could be lower by about $1-$3/bbl in 2015, decreasing the 2015 annual Brent price from the current projection in the high $50/bbl range. If and when significantly increased volumes of Iranian barrels start entering the market, the price effect could be greater. The uncertainty of the impact lies in the secondary effects on production outside of Iran, including in the United States, as well as any increases in global consumption as a response to lower oil prices, among other factors.

U.S. Petroleum and Other Liquids

U.S. average regular gasoline retail prices averaged $2.46/gal in March, rising from $2.04/gal on January 26, the lowest price in EIA's weekly survey of Monday prices since April 6, 2009. In

March, monthly average regional gasoline retail prices ranged from a low of $2.21/gal in Petroleum Administration for Defense District (PADD) 3, the Gulf Coast region, to a high of $3.10/gal in PADD 5 along the West Coast.

Although crude oil prices are projected to be relatively flat in the coming months, the spring switchover from winter-grade to summer-grade gasoline is expected to contribute to a slight increase in U.S. regular gasoline retail prices from an average of $2.46/gal in March to a 2015 peak of $2.50/gal in April. EIA expects U.S. retail gasoline prices to average $2.40/gal for the full year of 2015.

For the first time, EIA is providing monthly data on rail movements of crude oil, which have significantly increased over the past five years. Total movements of crude oil by rail within the United States and between the United States and Canada were more than 1 million bbl/d in 2014, up from 55,000 bbl/d in 2010. In January 2015, shipments from PADD 2, which is the location of the Bakken tight oil formation, to PADD 1 on the East Coast accounted for about 40% of total crude oil shipped via rail in the United States including movements to and from Canada.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 bbl/d (0.4%) in 2014. In 2015, total liquid fuels consumption is forecast to grow by 330,000 bbl/d (1.7%). EIA projects that in 2016, liquid fuels consumption growth will slow to 90,000 bbl/d (0.5%).

Motor gasoline consumption, which rose by 80,000 bbl/d in 2014, increases by a projected 150,000 bbl/d (1.6%) in 2015 and then falls by 70,000 bbl/d (0.8%) in 2016, as higher prices next year remove some of the stimulus to current consumption growth. Compared with last month's STEO, EIA revised the gasoline consumption forecasts upward by 70,000 bbl/d in 2015 and by 50,000 bbl/d in 2016 because of the larger-than-expected growth in gasoline consumption over the past six months, strong employment growth, and upward revisions in the Federal Highway Administration highway travel statistics of 0.8% in 2013 and 0.7% in 2014. Over the past six months (October 2014–March 2015), gasoline consumption increased by an average of 2.7% from the same period last year, compared with 0.2% year-over-year growth during the six months before that period. According to the U.S. Bureau of Labor Statistics monthly employment survey, seasonally adjusted employment increased by 1.6 million between October 2014 and March 2015.

Hydrocarbon gas liquids (HGL) consumption, which fell by 100,000 bbl/d (4.0%) in 2014, is projected to increase by 110,000 bbl/d in both 2015 and 2016, as new petrochemical plant capacity increases the use of HGL as a feedstock. In addition, new HGL export terminal capacity contributes to an increase in HGL net exports from an average of 560,000 bbl/d in 2014 to 1.0 million bbl/d in 2016. HGL consumption is rising because of strong supply growth, with HGL production at natural gas processing plants forecast to increase by 550,000 bbl/d (19%) between 2014 and 2016.

Liquid Fuels Supply. U.S. crude oil production is projected to increase from an average of 8.7 million bbl/d in 2014 to 9.2 million bbl/d in 2015 and to 9.3 million bbl/d in 2016, which is 0.1 million bbl/d and 0.2 million bbl/d lower than forecast in last month's STEO, respectively. The reduction in the crude oil production forecast reflects rig counts falling faster than EIA had initially expected, as oil-directed rigs have declined to the lowest level in more than four years as of late March.

With WTI crude oil prices expected to average $48/bbl in the second quarter of 2015, EIA expects 2015 onshore production to decline beginning in that period because of unattractive economic returns in some areas of both emerging and mature oil production regions. Reductions in 2015 capital expenditures, cash flows, and low-cost credit availability have encouraged companies to defer investment or redirect 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 core areas of 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.

EIA expects U.S. crude oil production to reach 9.4 million bbl/d in the second quarter of 2015, then decline by 210,000 bbl/d in the third quarter. With projected WTI crude oil prices rising to an average of $57/bbl in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for acreage leasing, drilling, and well-completion services, resulting in growing production despite the relatively low WTI price. Furthermore, a reduction of the backlog of wells drilled but not completed will bolster production by offsetting recent drops in drilling activity. 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 is onshore production in the Lower 48 states.

HGL production at natural gas processing 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. 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 crude oil and other liquids production has contributed to a significant decline in imports. 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 21% in 2016, which would be the lowest level since 1969.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices will average $2.45/gal during the 2015 summer driving season (April through September), down from an average of $3.59/gal last summer. The projected monthly average regular retail gasoline price falls from $2.50/gal in April to $2.43/gal in September. Diesel fuel retail prices are projected to average $2.77/gal this summer, down from an average of $3.89 last summer. 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 exceeding the national average price by $0.40/gal or more. Any unforeseen refinery outages or other disruptions to supply also have the potential to increase regional product prices beyond forecast levels in the short term.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect slowly rising prices for crude oil, best represented by the Brent crude oil price, which will average about $58/bbl ($1.39/gal) this summer compared with an average of $106/bbl ($2.52/gal) last summer. Any difference between actual crude oil prices and EIA's forecast would be reflected in the retail price of motor fuels. Absent other factors specific to the gasoline and diesel fuel markets, each dollar per barrel of sustained change in crude oil prices compared with the forecast translates into approximately a 2.4-cent-per-gallon change in product prices.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the Brent crude oil price) will average 36 cents/gal this summer, less than 1 cent/gal higher than last summer and 2 cents/gal higher than the previous five-summer average. Forecast wholesale diesel fuel margins are 45 cents/gal, about 3 cents/gal above last summer's level and 4 cents/gal higher than the previous five-summer average.

As in the case of crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor RBOB futures contracts for July 2015 delivery traded over the five-day period ending April 2 averaged $1.77/gal. The probability that the RBOB futures price will exceed $2.35/gal (consistent with a U.S. average regular gasoline retail price above $3.00/gal) in July 2015 is about 5%.

Motor Gasoline. During the 2015 summer driving season (April through September), projected motor gasoline consumption averages 9.2 million bbl/d, an increase of 0.14 million bbl/d (1.6%) over last summer. Year-over-year increases in summer highway travel, projected to be 2.5%, are offset by a 0.9% increase in fleetwide fuel efficiency. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including gasoline blendstock output, will increase by almost 100,000 bbl/d from last summer.

Fuel ethanol blending into gasoline is projected to decrease by 10,000 bbl/d from last summer's level to 880,000 bbl/d, which is 9.6% of total gasoline consumption. Projected total gasoline net imports (including blending components) average 210,000 bbl/d, up 23% from last summer.

At the onset of the summer driving season (April 1), total gasoline stocks were 227 million barrels, up 7 million barrels from a year ago and 7 million barrels above the five-year average for beginning-of-season stocks. Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged only 40,000 bbl/d during the previous five summer seasons. This summer, the total gasoline stock draw is projected to average 55,000 bbl/d, compared with a 46,000 bbl/d draw last summer. Total gasoline inventories are projected to end the summer season at 217 million barrels, 5 million barrels above last year's level and 4 million barrels above the previous five-year average.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, averages 4.0 million bbl/d this summer, up 120,000 bbl/d (3.0%) from last summer. This growth is driven by increasing manufacturing output and foreign trade. 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 some residual fuel oil.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 5 million bbl/d this summer, up 30,000 bbl/d from last summer. The production of biodiesel is forecast to average 85,000 bbl/d this summer, almost unchanged from last summer. Projected distillate fuel net exports average 0.99 million bbl/d this summer, down from 1.05 million bbl/d last summer.

Distillate inventories are projected to start the summer at 126 million barrels, up from the 115 million barrels recorded at the start of last summer and below the five-year average of 133 million barrels. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 55,000 bbl/d, down from the 87,000 bbl/d build recorded last summer, but similar to the five-year average summer build of 48,000 bbl/d. End-of-summer stocks are 137 million barrels, up slightly from the 131 million barrels recorded at the end of last summer, but below the five-year end-of-summer average of 142 million barrels.

Natural Gas

Working gas in storage ended this year's heating season at an estimated 1,471 Bcf on March 31. A total of 2,116 Bcf of natural gas was withdrawn from storage inventories during this year's heating season, compared to an overall withdrawal of 2,960 Bcf during last year's heating

season. Although this year's winter was colder than normal, it was slightly warmer than last year's historically cold winter. Looking ahead to October, EIA projects inventories will end the injection season at 3,781 Bcf, which is slightly below the five-year average. This level would imply overall injections of 2,310 Bcf over the injection season. Strong projected electric power consumption of natural gas this summer are expected to keep injections below last year's refill, but the expected 2,310 Bcf refill is still significant compared with past years.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will average 76.3 billion cubic feet per day (Bcf/d) in 2015 and 75.8 Bcf/d in 2016, compared with an estimated 73.5 Bcf/d in 2014. Consumption 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 11.5% in 2015 and then fall by 2.2% in 2016. Low natural gas prices support increased natural gas-fired electric power consumption in 2015. Industrial sector consumption increases by 4.9% and 2.5% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and as industrial consumers take advantage of low natural gas prices.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 3.8 Bcf /d (5.0%) and 1.5 Bcf/d (1.9%) 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.

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 2015 and 2016. EIA projects that LNG gross exports will increase from an average of 0.04 Bcf/d in 2014 to over 0.79 Bcf/d in 2016.

Natural Gas Inventories. On March 27, natural gas working inventories totaled 1,461 Bcf, 628 Bcf (75%) above the level at the same time in 2014 and 190 Bcf (12%) below the previous five-year (2010-14) average for the week. A 12 Bcf injection for the week ending March 20 was the first net injection of 2015, although inventories posted a net withdrawal the week ending March

27. EIA projects that end-of-October 2015 inventories will total 3,781 Bcf, 17 Bcf less than the five-year average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $2.83/MMBtu in March, a decline of 4 cents/MMBtu from February. 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 $3.45/MMBtu in 2016.

Natural gas futures contracts for July 2015 delivery traded during the five-day period ending April 2 averaged $2.76/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for July 2015 contracts at $1.90/MMBtu and $4.00/MMBtu, respectively. At this time last year, the natural gas futures contract for July 2014 delivery averaged $4.46/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.40/MMBtu and $5.87/MMBtu.

Coal

Electric power sector coal inventories increased by 3% in January 2015 from the previous month, leaving them 16% higher than in January 2014. Coal inventories have now increased for five consecutive months. The month-to-month increase was unusual, as inventories generally decrease during the winter months as coal-fired generation increases to meet winter heating demand. Warmer-than-normal January temperatures in areas where coal-fired generation is important, coupled with lower natural gas prices, contributed to the inventory growth.

Coal Consumption. EIA projects coal consumption in the electric power sector will decrease by 6% in 2015, despite an increase in overall electricity generation. Milder weather in the first quarter of 2015 compared with the same quarter in 2014 and lower natural gas prices are primary factors driving the decline. The retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards also affect demand in the power sector and contribute to the decline. The full effect of the coal plant retirements will be felt in 2016, but projected rising electricity demand and higher natural gas prices increase the use of the remaining coal-fired fleet, mitigating the of the retirements as projected coal consumption in the electric power sector increases by 2%.

Coal Trade. Slower growth in world coal demand, lower international coal prices, and higher coal output in other coal-exporting countries have led to a two-year decline in coal exports. EIA projects coal exports will fall to an annual average of 83 million short tons (MMst) in 2015, then remain relatively flat in 2016. Global market conditions for coal are not expected to change significantly through 2016. U.S. coal imports, which increased by more than 2 MMst in 2014 to 11 MMst, are expected to remain near that level over the next two years.

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 926 MMst, as both domestic demand and exports continue to decline, before growing to 941 MMst in 2016.

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 $2.33/MMBtu in 2016.

Electricity

Residential electricity prices increased during 2014, with growth ranging from 1.3% in the Pacific Coast states to 9.8% in New England. Retail electricity rates have risen for various reasons. Many electric utilities purchase their power from regional wholesale electricity markets, which experienced higher prices last year. Other reasons commonly cited for higher retail electricity prices are the increased investment in transmission and distribution infrastructure, rising requirements to generate electricity from renewable energy sources, and utility investment in demand-side efficiency.

Electricity Consumption. Retail sales of electricity to the residential sector during the first quarter of 2015 are estimated to be 2.3% lower than sales during the same period in 2014, as average U.S. temperatures this winter were milder than last winter despite colder-than-normal February temperatures in most of the eastern United States. EIA expects U.S. retail residential sales of electricity for the remaining nine months of 2015 will average 1.8% more than the same period last year. Residential sales are forecast to fall by 0.5% in 2016. Projected U.S. sales of electricity to the commercial sector increase by 1.7% this year and by 1.4% in 2016. Projected industrial electricity sales rise by 1.3% in 2015 and by 1.1% in 2016.

Electricity Generation. The use of natural gas for power generation has exceeded expectations in recent months, and as a result, EIA has raised its projections for natural-gas-fired generation from last month's STEO. During the first quarter of 2015, EIA estimates that natural gas accounted for 28.5% of total generation, which is substantially higher than the 23.6% fuel share during the first quarter of 2014. This increased use of natural gas is driven by lower fuel costs. The Henry Hub natural gas price averaged $2.90/MMBtu in the first quarter of this year compared with $5.20/MMBtu during the same period of 2014. EIA expects the natural gas fuel share to average 30.4% for all of 2015, up from 27.4% during 2014. In contrast, the share of total generation fueled by coal falls from 38.7% in 2014 to 35.8% this year.

Electricity Retail Prices. Residential electricity rates in New England have continued to increase, with the January 2015 price averaging about 10% more than the price in November 2014. For the United States as a whole, 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 1.4% 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 3.4% in 2015. Conventional hydropower generation increases by 6.3%, while nonhydropower renewables generation increases by 1.9%. In 2016, total renewables consumption for electric power and heat generation increases by 2.6% as a result of a 2.5% decline in hydropower and a 5.2% increase in nonhydropower renewables.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 80 gigawatthours (GWh) per day in 2016. Despite this growth, utility-scale solar power averages only 0.7% 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 75% between the end of 2014 and the end of 2016, with about half of this new capacity being built in California. Other leading states include North Carolina, Nevada, Texas, and Utah, which combined with California, account for about 90% of the projected utility-scale capacity additions for 2015 and 2016. Utility-scale solar capacity additions during 2016 are about 1 GW (26%) higher than in last month's STEO, as EIA continues to receive new information about upcoming generation capacity builds. According to current law, projects coming online after the end of next year will see a significantly reduced federal investment tax credit of 10%, well below the 30% investment tax credit available for projects that come online before the end of 2016. This provides a strong incentive for projects to enter service before the end of 2016.

Wind capacity, which grew by 8.1% in 2014, is forecast to increase by 13.1% in 2015 and by another 10.9% 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: 17 GW of wind compared with 8 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. After ethanol production in December 2014 topped 1.0 million bbl/d for the first time, it is estimated to have fallen to an average of 944,000 bbl/d in March 2015. Ethanol production averaged 935,000 bbl/d in 2014, and EIA expects it to average 944,000 bbl/d in 2015 and 937,000 bbl/d in 2016. Biodiesel production averaged an estimated 83,000 bbl/d in 2014 and is forecast to average 82,000 bbl/d in 2015 and 84,000 bbl/d in 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 0.7% in 2014. Emissions are forecast to increase by 0.1% in 2015 and by 0.4% in 2016. These forecasts are sensitive to both weather and economic assumptions.

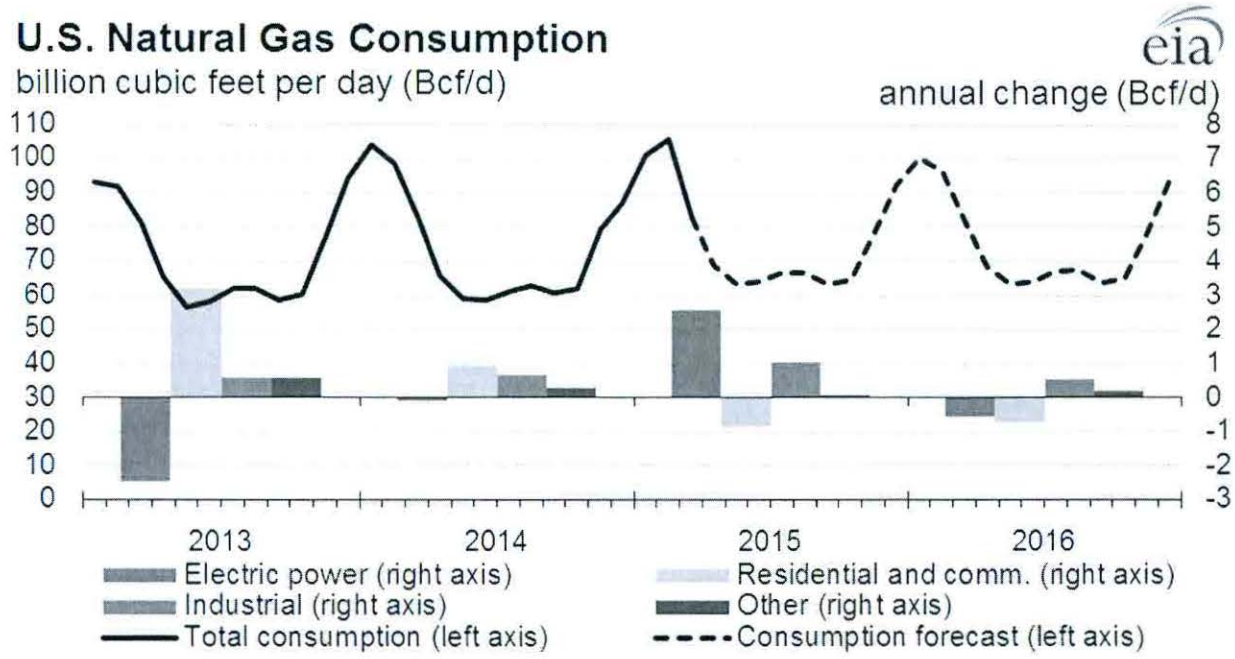
U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) grew at an annualized rate of 2.2% in the fourth quarter of 2014, the same as the previous estimate. With the latest estimate for the fourth quarter, private inventory investment increased less than previously estimated, while consumption increased more than previously estimated.

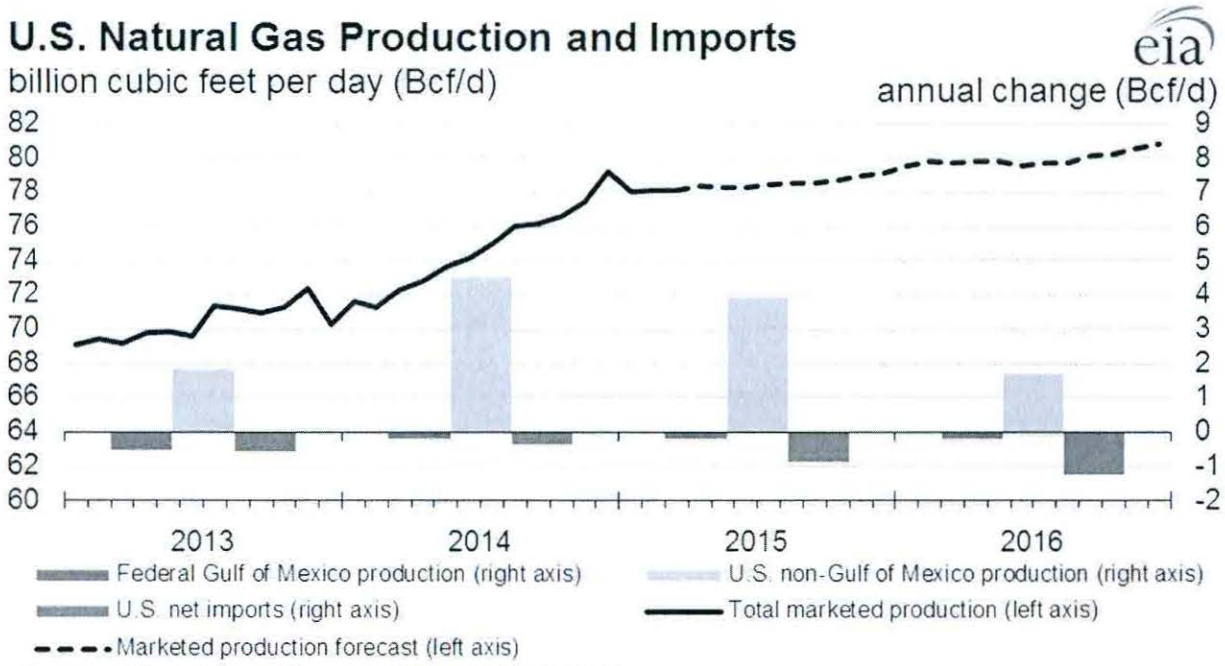
EIA used the March 2015 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Production, Income, and Employment. Forecast real GDP growth reaches 2.7% in 2015 and declines to 2.3% in 2016. Growth is expected to be higher 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 3.1% in 2015, below the 3.2% forecast last month, and by 2.2% in 2016. Total industrial production grows at 2.1% in 2015 and 2.8% in 2016. Projected growth in nonfarm employment averages 2.2% in 2015 and 1.5% in 2016.

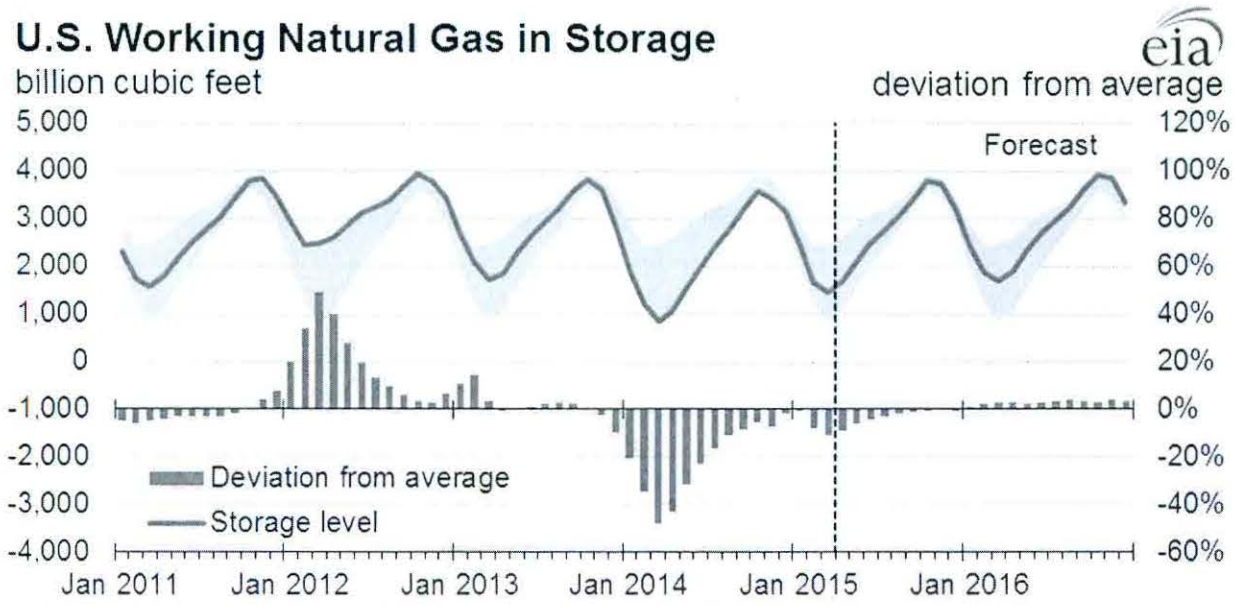
Expenditures. Forecast private real fixed investment growth averages 5.2% and 6.7% in 2015 and 2016, respectively, led by equipment in 2015 and by residential investment in 2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 3.2% and 2.6%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 2.2% and 3.2% over the same two years, while import growth is 4.4% in 2015 and 5.8% in 2016. Total government expenditures rise 0.9% in 2015 and 0.5% in 2016.



Source: Short-Term Energy Outlook, April 2015.



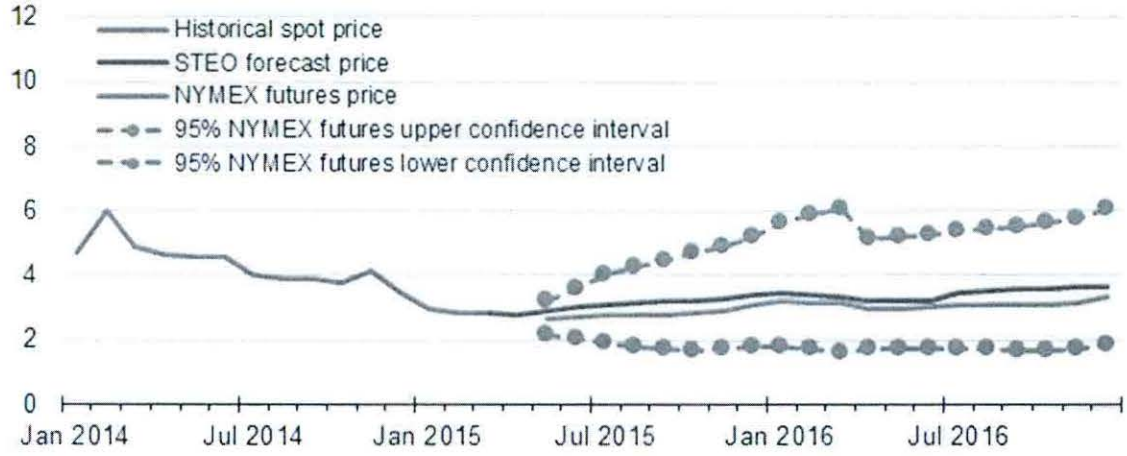
Source: Short-Term Energy Outlook, April 2015.



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

Henry Hub Natural Gas Price

dollars per million Btu

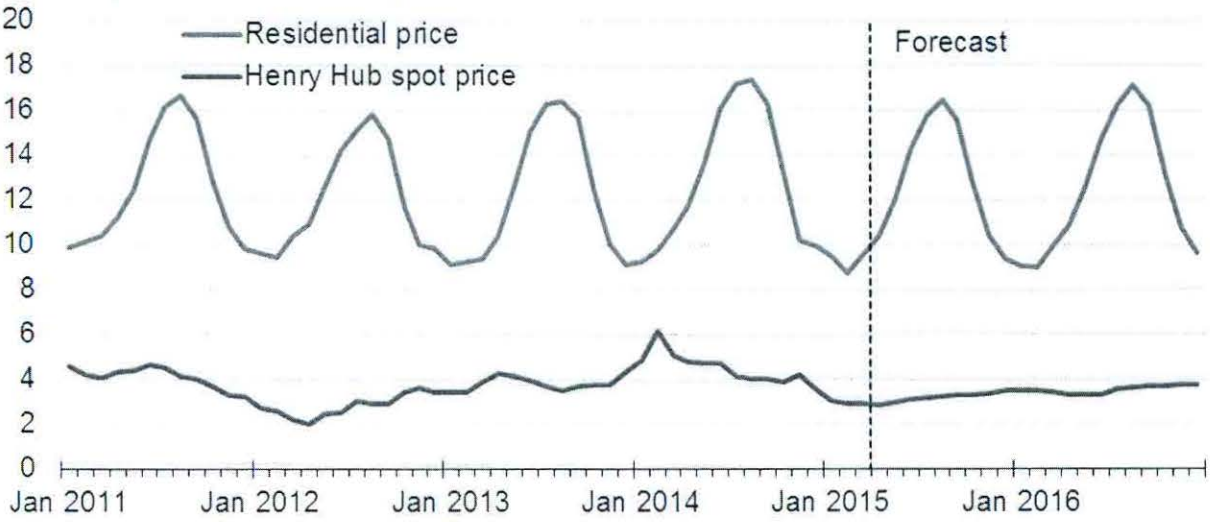


Note: Confidence interval derived from options market information for the 5 trading days ending Apr. 2, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, April 2015.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, April 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
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
March	2,475	0	913	3,388	47,447	1.3462	63,873	(60,485)	103,670
Total	$9,125	0	$23,868	$32,993	255,215		$333,891	($300,899)	
Balance @ March 31, 2015.									**$103,670**

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
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
March	24,229	0	636	24,865	62,798	0.9696	60,889	(36,024)	86,987
Total	($33,717)	0	$19,634	($14,083)	351,289		$287,863	($301,945)	
Balance @ March 31, 2015.									**$86,987**

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.