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

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June 30, 2015

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

Re: Cost of Gas Adjustment (COG)
July 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 (112th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (112th Revised Sheet No. 8), showing the July 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.0549 per dk for residential and firm general service customers and a decrease of $0.0549 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0549 per dk for all customers since the last COG filing due to a decrease in the market price of gas.

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, 2015.

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

112th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 111th 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	$4.5736	$5.8605
			Over 10 dk	1.0646		5.6382
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$2.8108	$3.9614
			Next 2,600 dk	0.9021		3.7129
			Over 3,000 dk	0.7486		3.5594
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$2.8108	$4.0624
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: June 30, 2015

Effective Date: Service rendered on and after July 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
112th Revised Sheet No. 8
Canceling 111th 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.	1.5320	(2.3512)	0.2107	(0.6085)	(2.3512)	0.0461	(2.3051)
Current Adj.	0.0000	(0.0549)	0.0000	(0.0549)	(0.0549)	0.0000	(0.0549)
Total Adj.	1.5320	(2.4061)	0.2107	(0.6634)	(2.4061)	0.0461	(2.3600)
Total Rate	$1.5982	$2.7647	$0.2107	$4.5736	$2.7647	$0.0461	$2.8108

Date Filed: June 30, 2015

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 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/	2.7647		3,931,984	2.7647
Gas Cost Reconciliation Adjustment						0.2107
Total Current Firm Gas Cost					$6,205,215	4.5736
Base Cost of Gas						5.2370
Accumulated Adjustment						($0.6634)
Interruptible						
Estimated Weighted Average Commodity Cost						$2.7647
Gas Cost Reconciliation Adjustment						0.0461
Total Current Interruptible Gas Cost						2.8108
Base Cost of Gas						5.1708
Accumulated Adjustment						($2.3600)

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
JULY 2015

Rates Effective July 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:	2.7647	Per Dk

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

Base Rate Calculation

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

Interruptible:		
Commodity	$5.1708	Per Dk

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

2/ Demand base rate calculation:

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

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

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

1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at http://www.ferc.gov.

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

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.00		$1.00
LMS – Daily Overrun Rate	$0.2003		$0.2003
LMS – Load Management Cost Reconciliation Adjustment		($0.0528)	

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.

RATE SCHEDULES TFX and LFT

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$5.683	$15.153	$5.473	$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0369	0.0200			0.0175	0.0000	0.0369	0.0200
Field	Market	0.0369	0.0200	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ 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
July 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 July monthly price for the NNG-Ventura Index is expected to be in the same range as the June 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 nationwide year over year increase of natural gas powered electric generation was offset by the increase of supply, mainly from the eastern region Marcellus and Utica production areas. National storage levels have rebounded and are slightly ahead of the five year average. The EIA reported nationwide storage levels as of June 19, 2015 at 1.4 percent above the five-year average and 38.3 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 19.

Independent Statistics & Analysis
U.S. Energy Information Administration

June 2015

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil prices averaged $64/barrel (b) in May, a $5/b increase from April and the highest monthly average of 2015. Despite estimated global inventories increasing by more than 2 million barrels per day (b/d) for the third consecutive month, several factors contributed to higher prices in May, including continued signals of higher global oil demand growth, expectations for declining U.S. tight oil production in the coming months, and the growing risk of unplanned supply outages in the Middle East and North Africa.

- EIA forecasts Brent crude oil prices will average $61/b in 2015 and $67/b in 2016. The 2016 price forecast is $3/b lower than in last month's STEO. West Texas Intermediate (WTI) prices in both 2015 and 2016 are expected to average $5/b less than the Brent price. The current values of futures and options contracts for December 2015 delivery suggest (*Market Prices and Uncertainty Report*) the market expects (at the 95% confidence interval) WTI prices in that month to range from $40/b to $92/b.

- U.S. regular gasoline monthly average retail prices reached a 2015 high of $2.72/gallon (gal) in May, an increase of 25¢/gal from April. The higher prices reflect rising crude oil prices and isolated outages at West Coast and Midwest refineries. EIA expects monthly average gasoline prices to decline from their May level through the rest of the year, averaging $2.43/gal during the second half of 2015. EIA forecasts U.S. regular gasoline retail prices to average $2.44/gal in 2015, 1¢/gal higher than in last month's STEO, and $2.55/gal in 2016, 8¢/gal lower than in last month's STEO.

- Total U.S. crude oil production averaged an estimated 9.6 million b/d in May, but it is expected to generally decline from June 2015 through early 2016 before growth resumes. Projected U.S. crude oil production averages 9.4 million b/d in 2015 and 9.3 million b/d in 2016. The forecast is 0.2 million b/d and 0.1 million b/d higher for 2015 and 2016, respectively, than in last month's STEO, primarily because of revisions to actual production data from the first quarter of 2015.

- In every week since the April start of the natural gas storage injection season, weekly inventory builds have surpassed the previous five-year (2010-14) average. The 132 billion cubic feet (Bcf) increase in working gas inventories for the week ending May 29 was the largest injection in more than a decade. EIA forecasts inventories will total 3,912 Bcf at the end of October 2015, which would be 115 Bcf above the previous five-year average.

- The National Oceanic and Atmospheric Administration (NOAA) forecasts warmer summer temperatures this year compared with the mild summer last year. The warmer temperatures are forecast to increase consumption of electricity to run air conditioners, which, combined with higher electricity prices, contributes to EIA's forecast of a 4.8% increase in the typical U.S. residential electricity bill this summer.

Global Petroleum and Other Liquids

Global liquids production continues to exceed consumption, resulting in inventory builds. Global oil inventory builds are projected to average 2.2 million b/d through the first half of 2015 and average 1.6 million b/d during the second half of the year, with the reduction in builds reflecting rising demand and slowing production growth outside of the Organization of the Petroleum Exporting Countries (OPEC), particularly in the United States. The expected inventory builds in 2015 are on top of an estimated average 1.1 million b/d increase in 2014. By 2016, expected inventory builds moderate to 0.8 million b/d as non-OPEC supply growth slows and demand continues to rise.

Global Petroleum and Other Liquids Consumption. EIA estimates global consumption of petroleum and other liquids grew by 0.9 million b/d in 2014, averaging 92.0 million b/d for the year. EIA expects global consumption to grow by 1.3 million b/d in both 2015 and 2016. Forecast global consumption growth was revised modestly upward from last month's STEO, as lower oil prices stimulate global demand growth more than previously expected. Projected real gross domestic product (GDP) weighted for oil consumption, which increased by an estimated 2.8% in 2014, is projected to grow by 2.4% in 2015 and by 3.0% in 2016.

Consumption of petroleum and other liquids outside of the Organization for Economic Cooperation and Development (OECD) countries grew by 1.2 million b/d in 2014 and is projected to grow by 0.8 million b/d in 2015 and by 1.2 million b/d in 2016. Lower forecast growth for non-OECD consumption in 2015 mostly reflects a 0.2 million b/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, although it is offset by growth elsewhere. China's economic growth slowed in the second half of 2014 and in the beginning of 2015. Nonetheless, China remains the main source of non-OECD oil consumption growth, with a projected annual average increase of 0.3 million b/d in both 2015 and 2016, down from growth of 0.4 million b/d in 2014. India's economic and manufacturing growth continued to rise in the first half of 2015, and projected petroleum and other liquids consumption growth is 0.2 million b/d in 2015 and 2016, compared with 0.1 million b/d in 2014.

OECD petroleum and other liquids consumption, which fell by 0.4 million b/d in 2014, is expected to grow by 0.4 million b/d in 2015 and by 0.2 million b/d in 2016. Japan and Europe accounted for nearly all of the 2014 decline in OECD oil consumption. Japan's consumption is expected to continue declining over the next two years, albeit at a slower rate than in 2014, while Europe's consumption is expected to grow slowly. The United States is the leading

contributor to projected OECD consumption growth in 2015, with U.S. consumption increasing by 0.4 million b/d, while consumption in both the United States and Europe increases by about 0.1 million b/d in 2016. The degree to which global oil demand responds to lower oil prices is only beginning to become apparent in the data, and, if that response deviates from forecast values, it could affect market balances and prices.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 2.3 million b/d in 2014, mainly as a result of output growth in the United States. EIA expects non-OPEC production to grow by 1.3 million b/d in 2015 and by 0.2 million b/d in 2016. Forecast non-OPEC production growth was revised upward from last month's STEO by an average of 0.5 million b/d in 2015, to account for historical revisions to first quarter U.S. production and increases to forecast Canadian production. After remaining relatively flat in 2015, production in Eurasia is projected to decline by almost 0.2 million b/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 about 0.7 million b/d in May 2015, nearly 0.1 million b/d higher than the previous month because of outages in Canada and Brazil. Wildfires in western Canada that started in the second half of May led to oil sands production outages averaging about 0.1 million b/d for the month. An explosion at the P-56 floating production and storage offloading facility at Brazil's Marlim Sul field at the end of May also increased the non-OPEC outage level. Before the explosion, P-56 produced less than 0.1 million b/d of oil. Recent violence in Yemen continues to interrupt operations at an oil port and refinery. South Sudan, Syria, and Yemen accounted for more than 80% of total non-OPEC supply disruptions in May.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 30.1 million b/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 0.6 million b/d in 2015 and falls by 0.2 million b/d in 2016. Iraq is expected to be the largest contributor to OPEC production growth in 2015. At the June 5 OPEC meeting, the group did not change its 30 million b/d crude oil production target. EIA forecasts OPEC crude oil production will continue to exceed that target over the forecast period, contributing to the expected global inventory builds.

On April 2, Iran and the five permanent members of the United Nations Security Council plus Germany (P5+1) reached a framework agreement to guide negotiations targeting a comprehensive agreement by June 30. A comprehensive agreement could result in the lifting of oil-related sanctions against Iran and a subsequent increase in Iran's crude oil production and exports, although the timing and details of any suspension of sanctions are uncertain. EIA has not changed its short-term projection for Iranian crude oil production, which assumes that production will stay close to the current level.

Iran produced 3.6 million b/d of crude oil in late 2011, before the recent round of sanctions was enacted, forcing Iran to shut in a substantial portion of its production. Iran's ability to bring online previously shut-in volumes and increase exports depends on several factors, including the current condition of oil fields and infrastructure that were shut in, the pace of sanctions relief, and the ability of Iran to find buyers in the present market. If a comprehensive agreement is reached, EIA estimates that the re-entry of more Iranian barrels could result in a $5/b-$15/b lower baseline STEO price forecast for 2016 (see the analysis box on page 5 of the April 2015 STEO for further discussion).

OPEC noncrude liquids production, which averaged 6.3 million b/d in 2014, is expected to increase by 0.1 million b/d in 2015 and by 0.2 million b/d in 2016, led by production increases in Qatar, Iran, and Kuwait.

In May, unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million b/d, almost 0.3 million b/d higher compared with the previous month, resulting from higher disruptions in Kuwait, Saudi Arabia, Libya, and Nigeria. Production at the Wafra field, located in the Neutral Zone that straddles Kuwait and Saudi Arabia, ceased in mid-May as the operators attempt to resolve a contract dispute. Suspension of Wafra's production increased disruptions in May by a total of 0.1 million b/d, split between Kuwait and Saudi Arabia. This suspension came on top of the previous shut-in production at the Khafji field. Protests and labor strikes at the El Feel field and at oil export facilities increased disruptions in Libya by more than 0.1 million b/d in May, while protests in Nigeria led to production disruptions in the Nembe oil field in the Niger Delta region in late May.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to decrease to an average of 1.8 million b/d in 2015 and increase to 2.1 million b/d in 2016, after averaging 2.0 million b/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million b/d is an indicator of a relatively tight oil market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant. Nonetheless, low surplus capacity heightens uncertainty about the market's ability to counteract unforeseen supply outages, particularly in the current geopolitical climate with conflicts in or next to major oil-producing countries in the Middle East and North Africa.

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 3.00 billion barrels at the end of 2015 and then to 3.09 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices increased by almost $5/b in May to a monthly average of $64/b, which was the highest monthly average for Brent so far this year. Several factors put upward pressure on crude oil prices in May. These factors included indications that global oil demand growth is accelerating, evidence that U.S. tight oil production could decline in the coming months, and the growing risk of unplanned supply outages in the

Middle East and North Africa. As of May 29, according to Baker Hughes, the number of rigs drilling for crude oil in the United States had fallen for 25 consecutive weeks and was 60% below its peak in October 2014. Brent crude oil prices increased despite estimated increases in global oil inventories, which rose in May by more than 2.0 million b/d for the third consecutive month, compared with an average build of 1.0 million b/d in March through May of last year. Inventory builds are projected to moderate somewhat in the coming months, but are expected to remain high compared with previous years.

The monthly average WTI crude oil spot price increased to an average of $59/b in May, up $5/b from April. After increasing for 20 consecutive weeks to a record 62.2 million barrels on April 17, crude oil inventories at Cushing, Oklahoma, have since fallen for six consecutive weeks by a total of 3.2 million barrels. Along with falling Cushing inventories, increasing U.S. refinery runs and production outages in Canada have put upward pressure on the price of WTI crude oil.

EIA projects the Brent crude oil price will average $61/b in 2015, unchanged from last month's STEO. The Brent crude oil price is projected to average $67/b in 2016, $3/b lower than in last month's STEO, reflecting an increase in forecast non-OPEC crude oil production growth in 2016. However, this price projection remains subject to the uncertainties surrounding the possible lifting of sanctions against Iran and other market events. WTI prices in both 2015 and 2016 are expected to average $5/b less than Brent.

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 September 2015 delivery traded during the five-day period ending June 4 averaged $60/b while implied volatility averaged 33%. These levels established the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in September 2015 at $45/b and $81/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $40/b and $92/b for prices in December 2015. Last year at this time, WTI for September 2014 delivery averaged $101/b, and implied volatility averaged 14%. The corresponding lower and upper limits of the 95% confidence interval were $89/b and $114/b.

U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices reached a 2015 high of $2.78/gal on June 1, an increase of 37¢/gal from early April. Rising crude oil prices and ongoing refinery outages in the Midwest and West Coast have pushed gasoline prices higher in the past two months. As a result of outages on the West Coast, gasoline prices in that region have increased by more than the U.S. average, with prices in Petroleum Administration for Defense District (PADD) 5 averaging $3.44/gal on June 1, an increase of 49¢/gal from the first week in April. In May, monthly average regional gasoline retail prices ranged from a low of $2.44/gal in PADD 3, the Gulf Coast region, to a high of $3.47/gal in PADD 5, the West Coast. EIA expects gasoline prices to fall from their current peaks, with the U.S. regular gasoline price averaging $2.43/gal over the second half of 2015.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 b/d (0.4%) in 2014. In 2015, total liquid fuels consumption is forecast to grow by 370,000 b/d (2.0%). EIA projects liquid fuels consumption growth will slow to 70,000 b/d (0.4%) in 2016. The 2015 and 2016 consumption forecasts are about 40,000 b/d higher than in last month's STEO.

Motor gasoline consumption, which rose by 80,000 b/d in 2014, increases by a projected 130,000 b/d (1.4%) in 2015 as the effects of employment growth and lower gasoline prices outweigh increases in vehicle fleet efficiency. Gasoline consumption is forecast to fall by 20,000 b/d (0.2%) in 2016, driven by higher prices and a long-term trend toward more-efficient vehicles.

Consumption of distillate fuel, which includes diesel fuel and heating oil, is forecast to rise by 90,000 b/d (2.3%) in 2015 and by 50,000 b/d (1.2%) in 2016. This growth is driven by increasing manufacturing output, foreign trade, and marine fuel use.

Hydrocarbon gas liquids (HGL) consumption, which fell by 100,000 b/d (4.0%) in 2014, is projected to increase by 120,000 b/d in 2015 and by 50,000 b/d in 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 b/d in 2014 to 1.0 million b/d in 2016.

Liquid Fuels Supply. U.S. crude oil production is projected to increase from an average of 8.7 million b/d in 2014 to 9.4 million b/d in 2015 and then decline to 9.3 million b/d in 2016. The forecast is 0.2 million b/d and 0.1 million b/d higher for 2015 and 2016, respectively, than in last month's STEO. The increase in the crude oil production forecast reflects upward revisions to estimated production in the first quarter of 2015.

EIA estimates that U.S. crude oil production averaged almost 9.6 million b/d in May 2015. This level is almost 0.4 million b/d higher than the average production during the fourth quarter of 2014, despite the 60% decline in the total U.S. oil-directed rig count since October 2014. Production has increased as producers work through the backlog of uncompleted wells (completing more wells than they are drilling) and achieve potentially better completions with higher initial production rates.

EIA expects U.S. crude oil production will begin to decline in June, with continuing declines through early 2016, when total production is forecast to average 9.2 million b/d in the first quarter. Production is forecast to begin rising in the second half of 2016, returning to an average of 9.6 million b/d in December as new projects are scheduled to come online in the Gulf of Mexico.

Projected crude oil production declines from June 2015 through February 2016 are largely attributable to unattractive economic returns in some areas of both emerging and mature onshore oil production regions, as well as seasonal factors such as anticipated hurricane-related production disruptions in the Gulf of Mexico. Reductions in 2015 capital expenditures and cash flows have prompted companies to defer investment or redirect investment away from marginal

exploration and research drilling to focus on core areas of major tight oil plays. Reduced investment has resulted in the lowest count of oil-directed rigs in five years.

Projected 2015 oil prices remain high enough to support continued development drilling in the core areas of the Bakken, Eagle Ford, Niobrara, and Permian basins. Forecast WTI crude oil prices create conditions in which continued increases in rig and well productivity and falling drilling and completion costs make resumption of onshore production growth possible in 2016. The forecast remains particularly sensitive to actual prices available at the wellhead and rapidly changing drilling economics that vary across regions and operators. Projected production in the Gulf of Mexico rises during the forecast period, while Alaska production 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 is estimated to have reached a record level of 3.2 million b/d in May 2015, and it is projected to average 3.2 million b/d in 2015 and 3.4 million b/d in 2016. EIA expects higher ethane recovery rates following planned increases in petrochemical plant feedstock demand. Export terminal expansions will allow higher quantities of domestically produced ethane, 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.

Petroleum Product Prices. Rising crude oil prices and several refinery outages in the Midwest and West Coast contributed to an increase in U.S. regular gasoline retail prices from a monthly average of $2.47/gal in April to $2.72/gal in May. EIA expects monthly average prices to decline through the summer as refineries in the Midwest and West Coast resolve outages and refineries in the rest of the country increase production of gasoline following the spring maintenance season. EIA projects regular gasoline retail prices to average $2.52/gal during the third quarter of 2015 and $2.33/gal in the fourth quarter.

The U.S. regular gasoline retail price, which averaged $3.36/gal in 2014, is projected to average $2.44/gal in 2015, 1¢/gal higher than in last month's STEO, and $2.55/gal in 2016, which is 8¢/gal lower than in last month's STEO.

The diesel fuel retail price, which averaged $3.83/gal in 2014, is projected to fall to an average of $2.88/gal in 2015, unchanged from last month's STEO, and then rise to $3.04/gal in 2016, 9¢/gal lower than in last month's STEO.

As with 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 reformulated blendstock for oxygenate blending (RBOB) futures contracts for September 2015 delivery traded over the five-day period ending June 4 averaged $1.97/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 September 2015 is about 10%.

Natural Gas

The spot price of natural gas at Henry Hub averaged $2.85/ million British thermal units (MMBtu) in May, after averaging $2.61/MMBtu in April. EIA expects monthly average natural gas prices to rise somewhat through the summer as air-conditioning demand increases, but remain below $4/MMBtu throughout the forecast period. While freeze-offs hampered some production this past winter, preliminary data sources indicate natural gas production growth resumed in April and May. EIA forecasts July production will exceed the previous monthly record set in December 2014.

Working natural gas inventories increased by 132 Bcf for the week ending May 29. Following last week's build, natural gas inventories exceeded the previous five-year average for only the second time since late 2013.

Natural Gas Consumption. EIA's forecast of U.S. total natural gas consumption averages 76.7 Bcf per day (Bcf/d) in 2015 and 76.6 Bcf/d in 2016, compared with 73.5 Bcf/d in 2014. Consumption growth in 2015 is largely driven by demand in the industrial and electric power sectors. EIA projects natural gas consumption in the power sector to grow by 13.7% in 2015 and then fall by 2.7% in 2016. Low natural gas prices support increased use of natural gas for electricity generation in 2015. Industrial sector consumption increases by 3.6% in both 2015 and 2016, as new industrial projects come online, particularly in the fertilizer and chemicals sectors, and as industrial consumers continue to take advantage of low natural gas prices. Consumption of natural gas in the residential and commercial sectors is projected to decline in 2015 and 2016.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 4.2 Bcf/d (5.7%) and by 1.6 Bcf/d (2.0%) in 2015 and 2016, respectively. This month's STEO lowers the 2015 production outlook by 0.3 Bcf/d to reflect revisions in historical data. However, production remains high and EIA expects continued growth through 2016, with increases in the Lower 48 states expected to more than offset the long-term declining production in the Gulf of Mexico. Increases in drilling efficiency will continue to support growing natural gas production in the forecast despite relatively low natural gas prices. Most growth is expected to come from the Marcellus Shale, as a backlog of drilled wells is completed and new pipelines come online to deliver Marcellus gas to markets in the Northeast. Preliminary data indicate significant production growth in April and the beginning of May.

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.

EIA projects that LNG gross exports will increase to 0.79 Bcf/d in 2016, with the startup of a major LNG liquefaction plant in the Lower 48 states.

Natural Gas Inventories. On May 29, natural gas working inventories totaled 2,233 Bcf, which was 751 Bcf (51%) above the level at the same time in 2014 and 22 Bcf (1%) above the previous five-year (2010-14) average for that week. So far during the inventory refill season, injections have surpassed the five-year average injections by a wide margin. EIA projects end-of-October 2015 inventories will total 3,912 Bcf, 115 Bcf above the five-year average for that time.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $2.85/MMBtu in May, an increase of 24¢/MMBtu from the April price. EIA expects monthly average spot prices to remain lower than $3/MMBtu through June, and lower than $4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages $2.97/MMBtu in 2015 and $3.32/MMBtu in 2016.

Natural gas futures contracts for September 2015 delivery traded during the five-day period ending June 4 averaged $2.69/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for September 2015 contracts at $1.79/MMBtu and $4.03/MMBtu, respectively. At this time last year, the natural gas futures contract for September 2014 delivery averaged $4.58/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.54/MMBtu and $5.92/MMBtu.

Coal

Coal Supply. EIA projects that lower coal demand for domestic consumption and exports contribute to a 70 million short ton (MMst) decline in production for 2015. Production is expected to decline in all coal-producing regions, with the largest decrease in Appalachia (34 MMst, or 13%). Declines in the Interior region and Western region are projected to be 3% and 6%, respectively. Coal production is projected to remain near 2015 levels in 2016.

In response to weak coal demand, several producers have recently announced cuts in production. The expected production cuts are reflected in announced employee layoffs. Previously announced employee layoffs primarily affected Central Appalachian producers, but the current planned reductions are more widespread, affecting production in Central and Northern Appalachia and in the Illinois Basin. Ohio-based Murray Energy announced it would lay off more than 1,800 miners in Illinois, Ohio, and West Virginia. Alpha Natural Resources (Alpha) stated that it was idling more than 400 employees in West Virginia, Kentucky, and Virginia. Earlier in May, Alpha had announced more than 60 layoffs at a mine in Kentucky. Although it is not reducing its workforce, Consol Energy announced it was switching to a four-day work week at several mines in Pennsylvania.

Coal Consumption. EIA expects a 7% decrease in coal consumption in the electric power sector in 2015, despite a 1% increase in total electric power generation. Lower natural gas prices are the main driver of the decline. Projected low natural gas prices make it more economical to run natural gas-fired generating units at higher utilization rates even in regions of the country (Midwest, South) that typically rely more heavily on coal-fired generation. Increased generation from wind, solar, and biomass is also expected to displace coal-fired generation, as several

biomass facilities have been converted from coal-burning facilities. The retirements of coal power plants in response to the implementation of the Mercury and Air Toxics Standards also reduce coal demand in the power sector in 2015. The full effect of the coal plant retirements on capacity will be felt in 2016, but projected rising electricity demand and higher natural gas prices are expected to contribute to higher utilization rates among the remaining coal-fired fleet. Coal consumption in the electric power sector is forecast to increase slightly in 2016.

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 U.S. coal exports. EIA projects coal exports will fall by 8 MMst, to 89 MMst, in 2015, and then increase by 1 MMst in 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 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 $2.30/MMBtu in 2015 and $2.31/MMBtu in 2016.

Electricity

Summer Residential Electricity Outlook. EIA forecasts that the average U.S. residential electricity customer will spend 4.8% more during the upcoming summer months (June, July, and August) than during the same period last year. This increase in the average residential bill reflects a projected 2.6% increase in average electricity usage and a 2.1% increase in the average retail price of electricity.

There is wide variation in the average electricity usage projections, with the typical residential customer in the Pacific states consuming 1.9% less electricity than last summer, while customers in the East North Central area consume 6.3% more electricity. Electricity prices in all areas of the United States except for the Middle Atlantic and the East South Central are expected to be higher this summer than last summer. Residential customers in New England are expected to see the largest increase in electricity bills because of a 15.4% projected increase in summer retail prices. Customers in the West South Central states are expected to experience the lowest overall increase in average electricity bills this summer (2.1%).

Electricity Consumption. NOAA projects warmer temperatures this summer than during last year's mild summer. U.S. cooling degree days during June, July, and August of 2015 are projected to total 7.3% more than the same period last year. Higher temperatures should lead to increased use of electricity for air conditioning. EIA forecasts U.S. retail sales of electricity to the residential sector in June, July, and August to average 3.5% more than last summer. Forecast annual U.S. residential electricity sales during 2015 average 0.2% higher than in 2014. EIA expects U.S. retail sales of electricity to the commercial and industrial sectors to grow by 1.6% and 0.4%, respectively, during 2015.

Electricity Generation. Total U.S. generation of electricity is forecast to average about 11,309 gigawatt hours per day (GWh/d) in 2015, which is 0.8% higher than total generation last year.

EIA forecasts coal's share of U.S. total generation will average 35.6% in 2015, down from 38.7% in 2014. In contrast, the natural gas fuel share averages 30.9% this year, up from 27.4% in 2014.

Electricity Retail Prices. EIA projects the U.S. retail price of electricity to the residential sector to average 2.3% more than in 2014. Utilities and retail suppliers in the New England states, especially Massachusetts, significantly increased electricity rates for residential customers late last year in anticipation of a repeat of winter price spikes in the regional wholesale power market. However, New England wholesale prices during the first quarter of 2015 averaged about half the level as in the same period last year, and EIA forecasts that these cost savings should be passed on to retail customers by the end of 2015.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA expects renewables used in the electric power sector will grow by 2.6% in 2015, as conventional hydropower generation decreases by 1.9%, while nonhydropower renewable power generation increases 6.9%. The 2015 decrease in hydropower generation reflects the effects of the California drought, which are only partially offset by use of hydropower elsewhere. Generation from hydropower is expected to increase by 5.4% in 2016. Total renewables consumption for electric power and heat generation decreases by 1.1% in 2015 but increases by 5.6% in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 85 GWh/d in 2016. Because the growth is from a small base, utility-scale solar power averages only 0.8% of total U.S. electricity generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations (rooftop panels), EIA expects utility-scale solar capacity will increase by 86% between the end of 2014 and the end of 2016, with more than 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 more than 90% of the projected utility-scale capacity additions for 2015 and 2016. According to current law, projects coming online after the end of next year will see a 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 impending decline in the tax credit provides a strong incentive for projects to enter service before the end of 2016.

Wind capacity, which grew by 8.2% in 2014, is forecast to increase by 12.9% in 2015 and by 12.0% in 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute increase in wind capacity is almost twice that of solar: 17 GW of wind compared with 9 GW of utility-scale solar between 2014 and 2016.

Liquid Biofuels. On May 29, the U.S. Environmental Protection Agency (EPA) proposed a rule setting Renewable Fuel Standard (RFS) targets for 2014 through 2016. Although these targets could be modified before the final rule is issued, they are used in developing the current STEO. Ethanol production, which averaged 935,000 b/d in 2014, is forecast to remain near current levels, averaging 936,000 b/d in 2015 and 933,000 b/d in 2016. Ethanol consumption, which averaged 878,000 b/d in 2014, is forecast to average 891,000 b/d in 2015 and 896,000 b/d in

2016, resulting in an average 9.9% ethanol share of the total gasoline pool in 2015 and 2016. EIA does not expect measurable increases in E15 or E85 consumption over the forecast period. The proposed RFS targets are expected to encourage imports of Brazilian sugarcane ethanol, which were just 3,000 b/d in 2014. Because of the increase in ethanol gross imports, net exports of ethanol are expected to fall from 51,000 b/d in 2014 to 44,000 b/d in 2015 and 36,000 b/d in 2016.

EIA expects the biggest effect of the proposed RFS targets to be on biomass-based diesel consumption, which contributes to meeting the biomass-based diesel, advanced biofuel, and total renewable fuel RFS targets. Biodiesel production averaged an estimated 81,000 b/d in 2014 and is forecast to average 90,000 b/d in 2015 and 98,000 b/d in 2016, which are 9,000 b/d and 14,000 b/d higher than in last month's STEO, respectively. Net imports of biomass-based diesel are also expected to increase from 16,000 b/d in 2014 to 26,000 b/d in 2015 and 35,000 b/d in 2016, which are 9,000 b/d and 19,000 b/d higher than in last month's STEO, respectively. EIA expects that a combination of higher biomass-based diesel consumption, higher consumption of domestic and imported ethanol, and banked Renewable Identification Numbers (RINs) will help meet the newly proposed RFS targets through 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew by 1.0% in 2014. Emissions are projected to decrease by 0.4% in 2015 and then rise by 0.2% in 2016. These forecasts are sensitive to both weather and economic assumptions.

U.S. Economic Assumptions

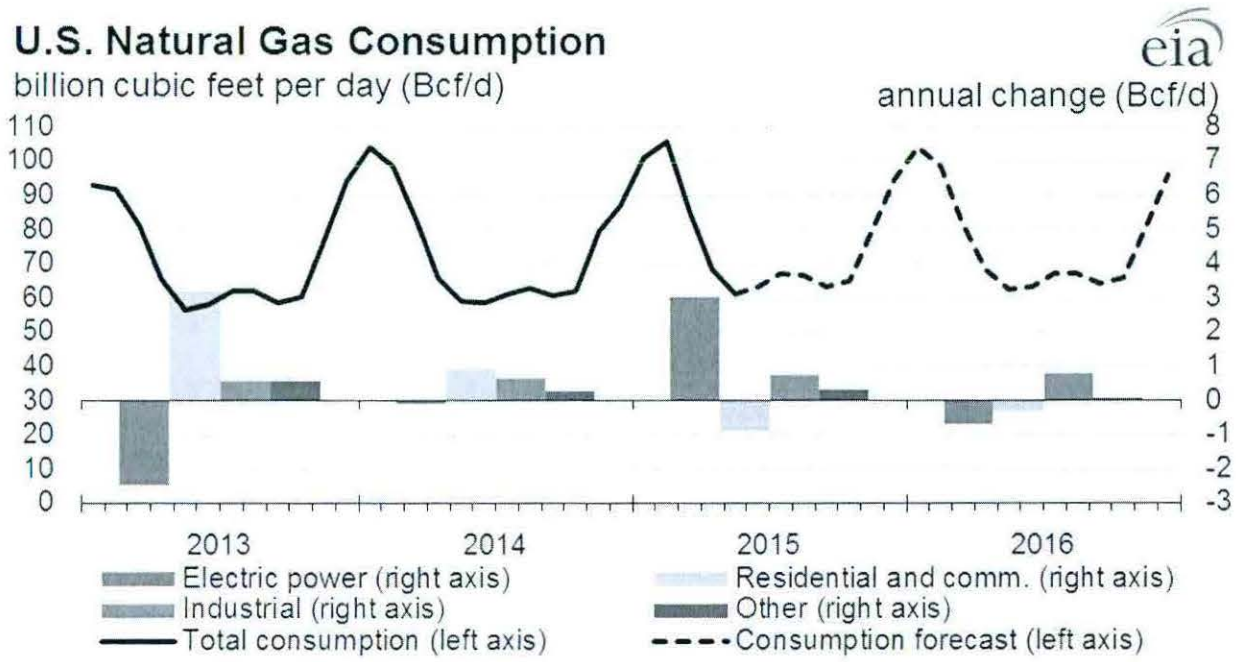
Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real GDP decreased at an annual rate of 0.7% in the first quarter of 2015. This second estimate is below the initial estimate of a 0.2% increase. With the second estimate for the first quarter, imports increased more and private inventory investment increased less than previously estimated.

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

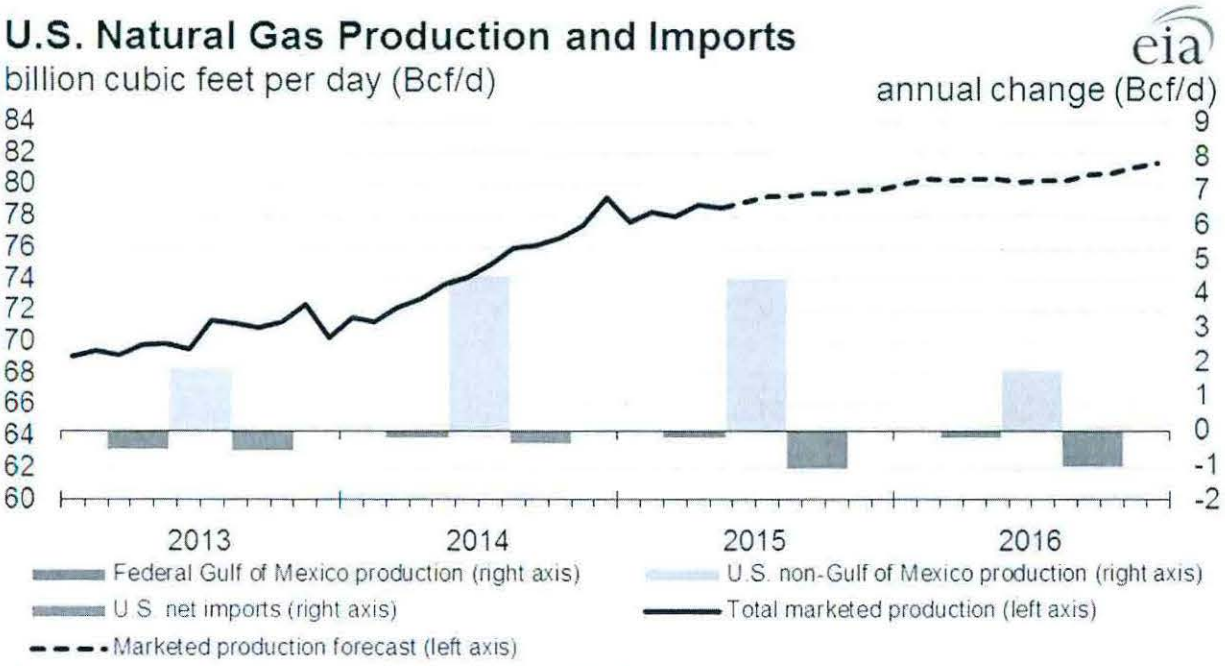
Production, Income, and Employment. Forecast real GDP grows by 2.2% in 2015 and by 2.6% in 2016. The 2015 growth is below the 2.6% forecast last month, while the 2016 growth is higher than the 2.4% forecast last month. Real disposable income grows by 3.3% in 2015 and by 2.2% in 2016. Total industrial production grows at 1.5% in 2015 and 2.8% in 2016. Projected growth in nonfarm employment averages 2.0% in 2015 and 1.3% in 2016.

Expenditures. Forecast growth in private real fixed investment averages 3.8% and 7.2% in 2015 and 2016, respectively, led by investment in equipment in 2015 and investment in equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015, at 2.9%, and the same as real GDP in 2016, at 2.6%. Durable goods expenditures drive consumption spending in both years. Export growth is 1.6% in 2015 and 4.7% in 2016, while

import growth is 4.8% in 2015 and 6.1% in 2016. Total government expenditures rise 0.8% in 2015 and 0.5% in 2016.

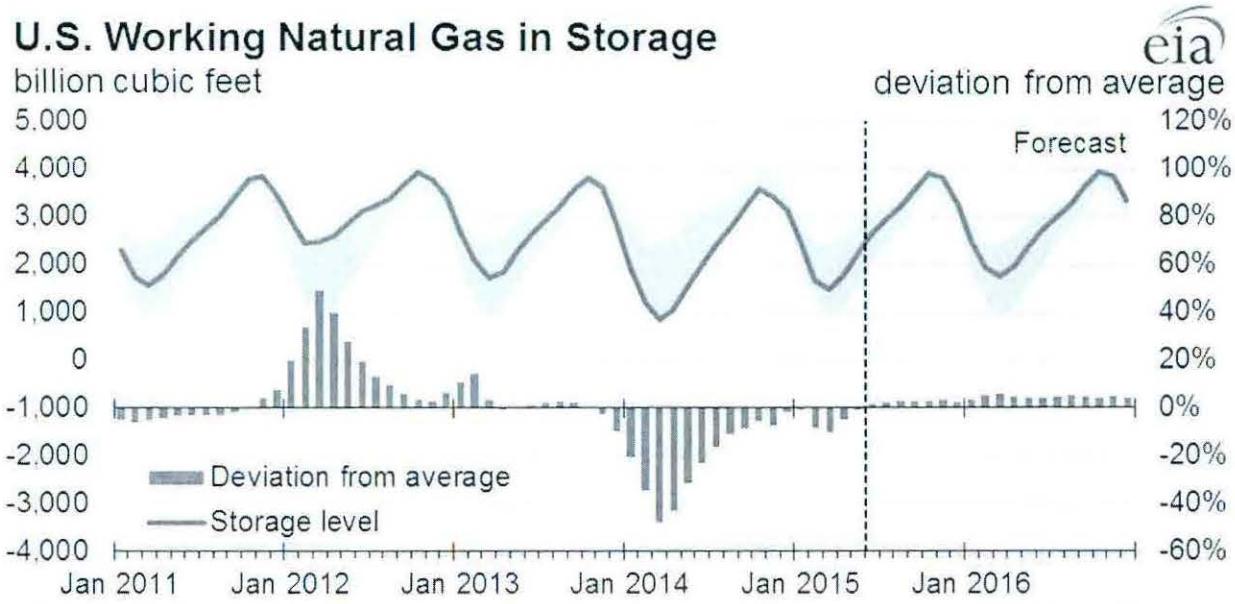


Source: Short-Term Energy Outlook, June 2015.



Source: Short-Term Energy Outlook, June 2015.

U.S. Working Natural Gas in Storage



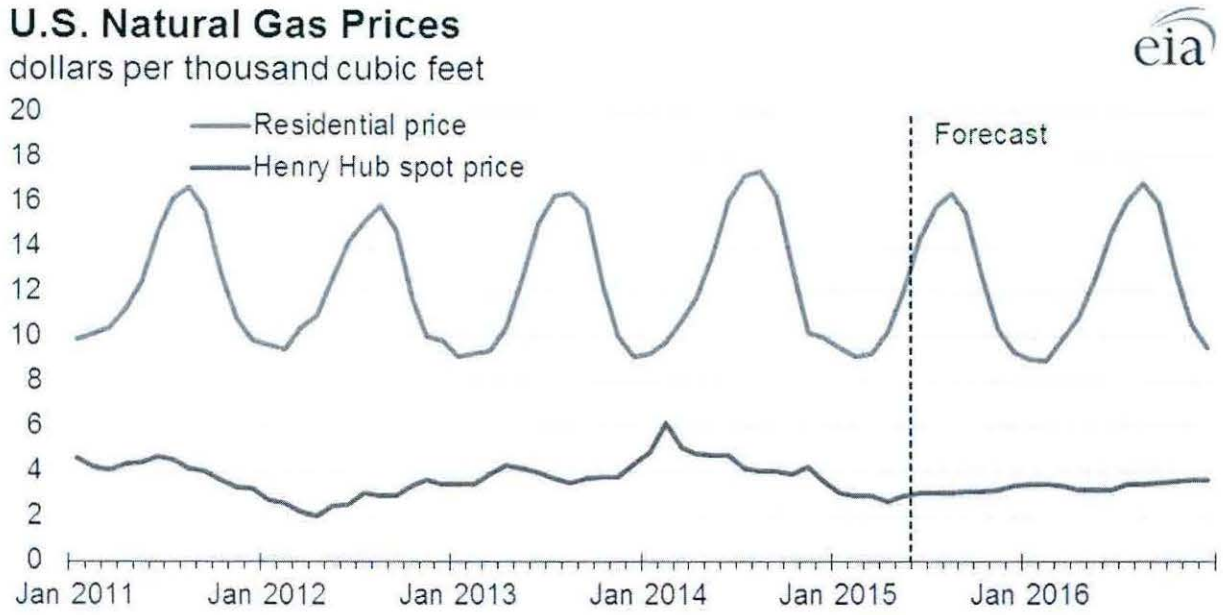
Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.
Source: Short-Term Energy Outlook, June 2015.

Henry Hub Natural Gas Price

dollars per million Btu

Note: Confidence interval derived from options market information for the 5 trading days ending Jun. 4, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, June 2015.



Source: Short-Term Energy Outlook, June 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 Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2015									**$74,482**
May 2015	($3,948)	0	$293	($3,655)	13,744	$1.3462	$18,502	($22,157)	52,325
Total	($3,948)	0	$293	($3,655)	13,744		$18,502	($22,158)	
Balance @ May 31, 2015.									**$52,325**

1/ Interest calculated at 13.3%, the authorized rate of return.

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 Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2015									**$35,759**
May 2015	($8,261)	0	$2	($8,259)	20,827	$0.9696	$20,194	($28,453)	7,306
Total	($8,261)	0	$2	($8,259)	20,827		$20,194	($28,453)	
Balance @ May 31, 2015.									**$7,306**

1/ Interest calculated at 13.3%, the authorized rate of return.