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

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August 28, 2015

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

Re: Cost of Gas Adjustment (COG)
September 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 (114th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (114th Revised Sheet No. 8), showing the September 2015 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.0938 per dk for residential and firm general service customers and a decrease of $0.0938 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for September 2015, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0938 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

114th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 113th 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	$4.5811	$5.8680
			Over 10 dk	1.0646		5.6457
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$2.8183	$3.9689
			Next 2,600 dk	0.9021		3.7204
			Over 3,000 dk	0.7486		3.5669
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$2.8183	$4.0699
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: August 28, 2015

Effective Date: Service rendered on and after September 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

114th Revised Sheet No. 8

Canceling 113th 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	(2.3048)	0.2107	(0.5621)	(2.3048)	0.0461	(2.2587)
Current Adj.	0.0000	(0.0938)	0.0000	(0.0938)	(0.0938)	0.0000	(0.0938)
Total Adj.	1.5320	(2.3986)	0.2107	(0.6559)	(2.3986)	0.0461	(2.3525)
Total Rate	$1.5982	$2.7722	$0.2107	$4.5811	$2.7722	$0.0461	$2.8183

Date Filed: August 28, 2015

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 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/	2.7722		3,942,651	2.7722
Gas Cost Reconciliation Adjustment						0.2107
Total Current Firm Gas Cost					$6,215,882	4.5811
Base Cost of Gas						5.2370
Accumulated Adjustment						($0.6559)
Interruptible						
Estimated Weighted Average Commodity Cost						$2.7722
Gas Cost Reconciliation Adjustment						0.0461
Total Current Interruptible Gas Cost						2.8183
Base Cost of Gas						5.1708
Accumulated Adjustment						($2.3525)

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
SEPTEMBER 2015

Rates Effective September 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:	2.7722	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.

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

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
September 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 September 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.

Continued strong production of natural gas in the lower 48 states, driven mainly by increases in the Marcellus and Utica, offset the increase in usage for power generation and kept the price of natural gas in the same range as last month. Production of natural gas continues to be at or near historical highs. The EIA reported nationwide storage levels as of August 14, 2015 at 2.7 percent above the five-year average and 19.2 percent above last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 20.

Independent Statistics & Analysis
U.S. Energy Information Administration

August 2015

Short-Term Energy Outlook (STEO)

Highlights

- North Sea Brent crude oil prices averaged $57/barrel (b) in July, a $5/b decrease from June. Brent crude oil spot prices fell further in early August, settling at $48/b on August 7. The recent price declines reflect concerns about lower economic growth in emerging markets, expectations of higher oil exports from Iran, and continuing actual and expected growth in global inventories.

- EIA forecasts that Brent crude oil prices will average $54/b in 2015 and $59/b in 2016, $6/b and $8/b lower than in last month's STEO, respectively. Forecast West Texas Intermediate (WTI) crude oil prices in both 2015 and 2016 average $5/b less than the Brent price. The current values of futures and options contracts for November 2015 delivery (*Market Prices and Uncertainty Report*) suggest the market expects WTI prices to range from $34/b to $64/b (at the 95% confidence interval) in November 2015.

- On July 14, the P5+1 (the five permanent members of the United Nations Security Council and Germany) and Iran announced an agreement that could result in relief from United States and European Union nuclear-related sanctions (which include some oil-related sanctions). If the agreement is implemented and sanctions relief occurs, it will put additional Iranian oil supplies on a global market that has already seen oil inventories rise significantly over the past year. This forecast assumes sanctions relief occurs in 2016, contributing to an annual average increase in Iranian crude oil production of 0.3 million b/d from 2015 to 2016, with most of the increase coming in the second half of 2016.

- U.S. regular gasoline monthly average retail prices averaged $2.79/gallon (gal) in July, a decrease of 1 cent/gal from June and 82 cents/gal lower than in July 2014. EIA expects monthly average gasoline prices to decline from their July level to an average of $2.11/gal during the fourth quarter of 2015. EIA forecasts U.S. regular gasoline retail prices to average $2.41/gal for all of 2015.

- EIA estimates total U.S. crude oil production declined by 100,000 barrels per day (b/d) in July compared with June. Production is expected to continue decreasing through mid-2016 before growth resumes late in 2016. Projected U.S. crude oil production averages 9.4 million b/d in 2015 and 9.0 million b/d in 2016, 0.1 million b/d and 0.4 million b/d lower, respectively, than in July's STEO.

- Natural gas working inventories were 2,912 billion cubic feet (Bcf) on July 31, which was 23% higher than a year earlier and 2% higher than the previous five-year average (2010-14). EIA projects inventories will close the injection season at the end of October at 3,867 Bcf, which would be the second-highest end-of-October level on record.

- U.S. population-weighted cooling degree days through the end of July were 14% more than in the same period last year. The hotter temperatures contribute to an EIA estimate that the typical residential electricity customer will use 3,134 kilowatthours in the months of June, July, and August this year, which is 4% more than during the same period in 2014.

Global Petroleum and Other Liquids

Global liquids production continues to outpace consumption, leading to strong inventory builds throughout the forecast period. Global oil inventory builds in the second quarter of 2015 averaged 2.7 million b/d, rising by 0.8 million b/d compared with the first quarter of the year. The pace of inventory builds is expected to slow in the second half of the year, to roughly 1.8 million b/d. In 2016, inventory builds are expected to slow to an average of 0.9 million b/d.

Global Petroleum and Other Liquids Consumption. EIA estimates global consumption of petroleum and other liquids grew by 1.1 million b/d in 2014, averaging 92.4 million b/d for the year. EIA expects global consumption of petroleum and other liquids to grow by 1.3 million b/d in 2015, unchanged from the previous month's STEO. Growth in 2016 global consumption was revised upward by 0.1 million b/d compared with last month to an average of 1.5 million b/d. Projected real gross domestic product (GDP) weighted for oil consumption, which increased by 2.8% in 2014, is projected to grow by 2.5% in 2015 and by 3.1% in 2016.

Consumption of petroleum and other liquids in countries outside of the Organization for Economic Cooperation and Development (OECD) grew by 1.4 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. Iran is expected to experience an uptick in economic activity and petroleum consumption, assuming implementation of the Joint Comprehensive Plan of Action (JCPOA) between Iran and the P5+1, which was announced on July 14.

Despite the slowdown in economic growth in the second half of 2014 and thus far in 2015, China continues to be the main driver of non-OECD consumption growth. China's consumption growth is expected to average 0.3 million b/d in 2015 and 2016, below the 0.4 million b/d growth in 2014.

After falling by 0.4 million b/d in 2014, OECD petroleum and other liquids consumption is expected to rise by 0.5 million b/d in 2015 and by 0.3 million b/d in 2016, reaching an average of 46.5 million b/d, the highest annual average level of OECD consumption since 2010. The increase in 2015 stems from both economic and weather factors, with the United States contributing most of the annual consumption growth. U.S. consumption is expected to grow by an average of 0.4 million b/d in 2015 and 0.2 million b/d in 2016. Several other OECD countries

saw economic conditions improve as they emerged from recessions, particularly countries in Europe and to a lesser extent in Asia. In addition, colder-than-normal weather early in 2015 across Europe contributes to a projected 0.1 million b/d increase in consumption in OECD Europe in 2015.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that petroleum and other liquids production in countries outside of the Organization of the Petroleum Exporting Countries (OPEC) grew by 2.3 million b/d in 2014, which mainly reflects production growth in the United States. EIA expects non-OPEC production to grow by 1.4 million b/d in 2015, but remain roughly flat in 2016. A number of producers will see output decrease amid lower prices, which have reduced investment. Furthermore, the ongoing corruption probe at state-owned Petrobras is expected to hurt Brazil's ability to expand production, limiting growth in 2016 to less than 0.1 million b/d, down from forecast growth of 0.2 million b/d in 2015. Brazil's relatively recent successes in bringing online a number of floating production, storage, and offloading (FPSO) facilities that had been delayed are driving the 2015 growth, with additional FPSOs slated to be delivered in 2016 at the Lula field.

Production growth in Canada is expected to average 0.3 million b/d in 2015 and increase to 0.4 million b/d in 2016, driven by continued expansion in oil sands projects. Although some previously announced oil sands projects have been put on hold, the vast majority continue as planned, including Imperial Oil and Cenovus oil sand projects scheduled to come online by the end of 2016.

Unplanned supply disruptions among non-OPEC producers averaged about 0.7 million b/d in July, about 0.1 million b/d lower compared with the previous month. In Canada, outages decreased and oil sands production returned to normal following the wildfires in western Canada. Additionally, output at Mexico's Abkatun Pol Chuc system continued to recover following an explosion at the offshore facility.

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. EIA forecasts OPEC crude oil production to increase by 0.8 million b/d in 2015 and remain relatively flat in 2016. Iraq is expected to be the largest contributor to OPEC production growth in 2015. In 2016, additional OPEC crude oil supply is expected to come from Iran, which is forecast to boost production if international sanctions targeting its oil sector are suspended.

On July 14, the P5+1 and Iran announced an agreement that could result in relief from United States and European Union nuclear-related sanctions (which include some oil-related sanctions). Sanctions relief is contingent on verification by the International Atomic Energy Agency that Iran has complied with key nuclear-related steps. The sanctions relief would put additional Iranian oil supplies on a global market that has already seen oil inventories rise significantly over the past year.

The JCPOA is currently undergoing a congressional review. As of the time of writing, Congress had not voted on the agreement, but for the purposes of this STEO, EIA assumes sanctions relief could occur in mid-2016. If sanctions relief occurs, EIA forecasts Iranian crude oil supplies will increase by about 0.3 million b/d on average in 2016, with most of the growth occurring in the second half of the year. While much uncertainty remains as to the timing of sanctions relief, EIA's updated Iran projection assumes that adoption takes place by the end of October 2015, with implementation occurring in the second quarter of 2016, clearing the way to easing of the sanctions.

Iran produced 3.6 million b/d of crude oil in late 2011, before the recent round of sanctions was enacted. The sanctions forced Iran to shut in a substantial portion of its production, with production currently averaging about 2.8 million b/d. 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 and the pace of sanctions relief.

Saudi Arabia and other OPEC member countries are not expected to cut production to accommodate additional Iranian volumes, although some producers will see production declines in the near term. For example, Saudi Arabia's production is expected to respond to lower direct crude burn for electric power generation as seasonal power demand abates. However, there is considerable uncertainty regarding Iraq's ability to sustain its higher production and export levels, particularly in light of infrastructure constraints in the southern terminals.

OPEC noncrude liquids production, which averaged 6.3 million b/d in 2014, is expected to increase by 0.2 million b/d in 2015 and by 0.3 million b/d in 2016, led by production increases in Iran, Qatar, and Kuwait.

In July, unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million b/d, remaining roughly unchanged compared with the previous month. Kuwait and Saudi Arabia continue to have a total of 0.5 million b/d disrupted at the Wafra and Khafji fields in the Neutral Zone that straddles the two countries.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to decrease to an average of 1.6 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 indicator of market conditions, and surplus capacity below 2.5 million b/d indicates a relatively tight oil market, but the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant. EIA does not expect any Iranian spare capacity to be available throughout the forecast period despite increases in effective capacity, as Iran is expected to produce crude oil at the maximum available level through the end of 2016 if and when sanctions are lifted.

OECD Petroleum Inventories. EIA estimates that OECD commercial crude oil and other liquids inventories totaled 2.69 billion barrels at the end of 2014, equivalent to roughly 59 days of consumption. Forecast OECD inventories rise to 2.99 billion barrels at the end of 2015 and then to 3.08 billion barrels at the end of 2016.

Crude Oil Prices. Brent crude oil spot prices decreased by $5/b in July to a monthly average of $57/b. Prices fell further at the end of July and into early August, with Brent spot prices settling at $48/b on August 7. Continuing increases in global liquids inventories put significant downward pressure on prices. Inventories rose by an estimated 2.3 million b/d through the first seven months of 2015, compared with an average build of 0.6 million b/d over the same period last year. Inventory builds are projected to moderate somewhat in the coming months, but are expected to remain high compared with previous years. Concerns over the pace of economic growth in emerging markets and the possibility of increasing volumes of Iranian crude oil on the market also contributed to the recent oil price decline.

The monthly average WTI crude oil spot price fell to an average of $51/b in July, down $9/b from June. Crude oil inventories at Cushing, Oklahoma, despite having decreased by 5.0 million barrels from their record high of 62.2 million barrels on April 17, remain about 40 million barrels higher than at the same time last year. U.S. crude oil inventories remain elevated compared with historical levels, despite strong U.S. refinery runs, which in recent weeks reached record highs over 17 million b/d.

EIA projects the Brent crude oil price will average $54/b in 2015 and $59/b in 2016, $6/b and $8/b lower than in July's STEO, respectively. WTI prices in both 2015 and 2016 are expected to average $5/b less than the Brent crude oil price. EIA's updated projection remains subject to significant uncertainties as the oil market moves toward balance. During this period of price discovery, oil prices could experience periods of heightened volatility. The oil market faces a host of uncertainties heading into 2016 including the pace and volume at which Iranian oil reenters the market, the strength of oil consumption growth, and the responsiveness of non-OPEC production to low oil prices. In the more immediate future, there is potential downward price pressure heading into the fourth quarter if refinery runs drop by more than expected during the fall maintenance season.

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 November 2015 delivery, traded during the five-day period ending August 6, averaged $47/b, while implied volatility averaged 37%. These levels established the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in November 2015 at $34/b and $64/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $27/b and $103/b for prices in December 2016. Last year at this time, WTI for November 2014 delivery averaged $96/b, and implied volatility averaged 16%. The corresponding lower and upper limits of the 95% confidence interval were $84/b and $111/b.

U.S. Petroleum and Other Liquids

On July 13, U.S. average diesel fuel retail prices fell below average regular gasoline prices for the first time since the week of August 10, 2009, and have remained lower for four consecutive weeks. Ongoing refinery outages in California, as well as strong demand for gasoline in both the

United States and abroad, have kept gasoline prices elevated over the past two months despite falling crude oil prices. Data from the U.S. Federal Highway Administration show Americans drove a record 1.26 trillion miles during the first five months of 2015, compared with the previous record of 1.23 trillion miles driven in the first five months of 2007. As a result, refinery wholesale gasoline margins (the difference between the wholesale price of gasoline and the price of Brent crude oil) have been strong in recent months, leading to record-high refinery runs. U.S. average wholesale gasoline margins averaged 73 cents/gal in July, 42 cents/gal higher than in July of last year and 40 cents/gal higher than the five-year average (2010-14) for July.

Refinery outages on the West Coast have contributed to gasoline prices in that region rising by more than the U.S. average over the past few months, as well as significant price volatility. After declining by 22 cents/gal from May 18 to an average of $3.30/gal on July 6, regular gasoline prices in Petroleum Administration for Defense District (PADD) 5 increased again to a new 2015 peak of $3.60/gal on July 20. PADD 5 retail prices have fallen to $3.36/gal as of August 10.

In July, monthly average regional gasoline retail prices ranged from a low of $2.49/gal in PADD 3, the Gulf Coast region, to a high of $3.51/gal in PADD 5. EIA expects gasoline prices to fall from their current levels, with the U.S. regular gasoline price averaging $2.11/gal in the fourth quarter of 2015.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 70,000 b/d (0.4%) in 2014. Total liquid fuels consumption is forecast to grow by 400,000 b/d (2.1%) in 2015 and by 190,000 b/d (1.0%) in 2016. The 2016 consumption forecast is about 70,000 b/d higher than forecast in last month's STEO.

Motor gasoline consumption, which rose by 80,000 b/d in 2014, increases by a projected 210,000 b/d (2.3%) in 2015 as the effects of employment growth and lower gasoline prices outweigh increases in vehicle fleet efficiency. Gasoline consumption is forecast to remain relatively flat in 2016, as a long-term trend toward more-fuel-efficient vehicles offsets the effects of continued economic growth.

Consumption of distillate fuel, which includes diesel fuel and heating oil, is forecast to rise by 40,000 b/d (1.1%) in 2015 and by an additional 100,000 b/d (2.4%) 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 90,000 b/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 b/d in 2014 to 1.1 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 decrease to 9.0 million b/d in 2016. The forecast is about 0.1 million b/d lower and 0.4 million b/d lower for 2015 and 2016, respectively, than in July's STEO. The decrease in the crude oil production forecast reflects a lower oil price

outlook that will reduce expected oil-directed rig counts and drilling and well-completion activities throughout the forecast period.

EIA estimates that U.S. crude oil production averaged 9.5 million b/d in the first half of 2015. This level is 0.3 million b/d higher than the average production during the fourth quarter of 2014, despite an almost 60% decline in the total U.S. oil-directed rig count since October 2014. The most recent production estimates indicate U.S. crude oil output was 9.5 million b/d in May. EIA estimates that total U.S. production was unchanged in April and began declining in May, falling 180,000 b/d from the April level. Some of this decline reflects outages in the Gulf of Mexico that are expected to be temporary. The decrease in total production was preceded by declines in onshore production, which began in April.

EIA expects U.S. crude oil production declines to continue through the third quarter of 2016, when total crude oil production is forecast to average 8.8 million b/d. Forecast production begins rising in late 2016, returning to an average of 9.1 million b/d in the fourth quarter. A total of 13 projects are scheduled to come online in the Gulf of Mexico in 2015 and 2016, pushing up Gulf of Mexico production from an average of 1.4 million b/d in the fourth quarter of 2014 to more than 1.6 million b/d in the same period of 2016.

Expected crude oil production declines from May 2015 through the third quarter of 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 cash flows and capital expenditures have prompted companies to defer 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 nearly five years and well completions that are significantly behind 2014 levels.

Oil prices, particularly in the second quarter of 2015, remained high enough to support continued development drilling in the core areas of the Bakken, Eagle Ford, Niobrara, and Permian basins, with July showing the first month-to-month increase in the oil-directed rig count since October 2014. However, the recent fall in crude oil prices and lowered outlook for oil prices over the forecast period are expected to prolong and deepen onshore production declines. Lower crude oil prices are anticipated to slow the rate of recovery in onshore drilling activities and well completion totals, despite continued increases in rig and well productivity and falling drilling and completion costs. The forecast remains sensitive to actual wellhead prices and rapidly changing drilling economics that vary across regions and operators.

While projected oil production in the Gulf of Mexico rises during the forecast period, Alaska oil production falls. Production in these areas is less sensitive to short-term price movements than onshore production in the Lower 48 states and reflects anticipated growth from new projects and declines from legacy fields.

HGL production at natural gas processing plants reached a record level of 3.31 million b/d in April 2015, and it is projected to average 3.28 million b/d in 2015 and 3.53 million b/d in 2016.

EIA expects higher ethane recovery rates in 2016 following planned increases in petrochemical plant feedstock demand. Export terminal expansions will allow for higher quantities of domestically produced ethane, propane, and butanes to reach the international market.

U.S. petroleum product gross exports continue to grow, up almost 0.5 million b/d (13%) in the first five months of 2015 compared with the same period in 2014. More than half of the growth in liquid fuel exports came from HGL. The increase in refined product exports, combined with the growth in domestic liquid fuels consumption, contributed to U.S. refinery utilization rates averaging 89.9% over the first five months, up from 88.1% last year and the highest rate for this period since 2005. Gross inputs to U.S. refineries exceeded 17 million b/d in each of the last four weeks of July, a level that had not previously been reached or exceeded in any week since EIA began publishing the data in 1990.

Petroleum Product Prices. Rising crude oil prices, strong demand for U.S. gasoline, 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 $2.79/gal in July. EIA expects monthly average prices to decline in the coming months as refineries continue to produce high levels of gasoline, as demand begins to decrease following the peak in the summer driving season, and as the market transitions to lower-cost winter-grade gasoline. EIA projects regular gasoline retail prices to average $2.60/gal during the third quarter of 2015 and $2.11/gal in the fourth quarter.

The U.S. regular gasoline retail price, which averaged $3.36/gal in 2014, is projected to average $2.41/gal in 2015, 7 cents/gal lower than in July's STEO, and $2.40/gal in 2016, which is 15 cents/gal lower than in July's STEO.

The diesel fuel retail price, which averaged $3.83/gal in 2014, is projected to fall to an average of $2.73/gal in 2015, 13 cents/gal lower than in July's STEO, and then rise to $2.81/gal in 2016, 23 cents/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 November 2015 delivery, traded over the five-day period ending August 6, averaged $1.45/gal. The probability that the RBOB futures price will exceed $1.85/gal (consistent with a U.S. average regular gasoline retail price above $2.50/gal) in November 2015 is about 7%.

Natural Gas

The natural gas storage injection season passed the halfway mark in mid-July, and inventories totaled 2,912 Bcf on July 31, which was 23% higher than a year earlier and 2% higher than the previous five-year average (2010-14). Inventories began the injection season about 173 Bcf lower than the five-year average, but have been greater than the five-year average since the end of May. EIA projects inventories will end October at 3,867 Bcf, which would be the second-highest October level on record. Year-over-year strength in production has boosted storage

injections this summer, despite warmer temperatures, which have increased natural gas use in the power sector to serve air conditioning demand.

Tallgrass Energy brought online the final phase of its east-to-west pipeline reversal on the Rockies Express Pipeline (REX) earlier this month. This expansion allows for 1.8 Bcf/d of Marcellus and Utica natural gas to flow westward from eastern Ohio to Missouri. REX began service in 2009 to move natural gas from the Rockies to Midwestern and Northeastern markets. Over the past several years, however, demand for Rockies natural gas in the east has declined because of exponential growth in Marcellus-area production.

Natural Gas Consumption. EIA's forecast of U.S. total natural gas consumption averages 76.5 Bcf/d in both 2015 and 2016, compared with 73.5 Bcf/d in 2014. EIA projects natural gas consumption in the power sector to increase by 13.9% in 2015 and then decrease by 3.4% in 2016. Relatively low natural gas prices support increased use of natural gas for electricity generation in 2015. Industrial sector consumption increases by 2.3% in 2015 and by 5.0% in 2016, as new industrial projects, particularly in the fertilizer and chemicals sectors, come online later this year and next year, and as industrial consumers continue to take advantage of low natural gas prices. Natural gas consumption in the residential and commercial sectors is projected to decline in both 2015 and 2016.

Natural Gas Production and Trade. EIA expects that marketed natural gas production will increase by 4.0 Bcf/d (5.4%) and by 1.8 Bcf/d (2.3%) in 2015 and 2016, respectively. Despite data showing month-over-month production declines in May and June, natural gas production remains higher than year-ago levels. EIA expects moderate growth through 2016, with increases in the Lower 48 states expected to more than offset long-term production declines 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 of the growth is expected to come from the Marcellus Shale, as the backlog of uncompleted wells is reduced and as new pipelines come online to deliver Marcellus natural gas to markets in the Northeast.

Increases in domestic natural gas production are expected to reduce demand for natural gas imports from Canada and are expected to support growth in exports to Mexico. EIA expects natural gas 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 LNG gross exports will increase to an average of 0.79 Bcf/d in 2016, with the startup of a major LNG liquefaction plant in the Lower 48 states.

Natural Gas Inventories. On July 31, natural gas working inventories totaled 2,912 Bcf, which was 535 Bcf (23%) above the level at the same time in 2014 and 64 Bcf (2%) above the five-year average for that week. To this point in the injection season, injections have surpassed the five-year average by a wide margin. EIA projects end-of-October 2015 inventories will total 3,867 Bcf, 69 Bcf (1.8%) above the five-year average for that time.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $2.84/million British thermal units (MMBtu) in July, an increase of 6 cents/MMBtu from the June price. The current STEO lowers the projection for prices slightly from last month's forecast; monthly average spot prices remain lower than $3/MMBtu through October, and lower than $4/MMBtu through the remainder of the forecast. The projected Henry Hub natural gas price averages $2.89/MMBtu in 2015 and $3.21/MMBtu in 2016.

Natural gas futures contracts for November 2015 delivery traded during the five-day period ending August 6 averaged $2.91/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for November 2015 contracts at $2.08/MMBtu and $4.06/MMBtu, respectively. At this time last year, the natural gas futures contract for November 2014 delivery averaged $3.96/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were $3.03/MMBtu and $5.16/MMBtu, respectively.

Coal

Recent changes in the global coal market contributed to lower U.S. coal production in the second quarter. Slower growth in world coal demand, lower international coal prices, and higher coal output in other coal-exporting countries have all led to a two-year decline in U.S. coal exports. Australia, the world's second-largest coal exporter, has seen exports continue to increase, but export earnings are expected to fall this year. Lower mining costs, cheaper transportation costs, and favorable exchange rates will continue to provide an advantage to Australian coal producers over their American counterparts in the forecast period. Other major coal-exporting countries (Indonesia, Colombia, Russia, and South Africa) currently have similar advantages compared with U.S. coal producers.

Activities in major coal consuming nations (China and India) have also affected the global coal market. India has seen an upswing in domestically produced coal, causing Indian coal import growth to be nearly flat. Chinese demand for coal and coal imports has fallen as well. Several factors have contributed to these developments, including slower electricity demand and industrial growth and the imposition of more stringent environmental regulations on the power and energy-intensive industries. Imported coal has also been affected by the levying of new taxes and stricter environmental quality testing, which has seen some imported shipments of coal being denied entry.

Coal Trade. EIA projects coal exports will fall by 14 million short tons (MMst), to 83 MMst, in 2015, and remain at that level 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 in 2015 and 2016.

Coal Supply. Lower domestic coal consumption and exports, combined with a slight increase in coal imports, are projected to contribute to an 83 MMst (8%) decline in production for 2015. Coal production is expected to decrease in all coal-producing regions in 2015. However, production is expected to increase by 10 MMst (1%) in 2016, driven by modest production

growth in the Interior region and the Western region, as coal use increases in the electric power sector.

Electric power sector stockpiles increased to 175 MMst in May (the most recent month for which data are available), a 4% increase from the previous month. This monthly increase (April to May) in coal inventories follows the normal spring pattern in which coal stockpiles are usually built up for use in the summer months. Coal inventories were 38 MMst higher than in May 2014 when inventories were still recovering from the effects of colder-than-normal temperatures earlier in the year, and they are only 2 MMst lower than the previous five-year average for the month.

Coal Consumption. EIA expects a 7% decrease in coal consumption in the electric power sector in 2015. Lower natural gas prices and the growth of renewable-based generation are the key factors driving the decrease in coal consumption. 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 that typically rely more heavily on coal-fired generation (Midwest and South). Nonhydropower renewable-based electricity generation is expected to grow by 4% in 2015, with the largest growth occurring in the South (8%). The retirements of coal-fired power plants in response to the implementation of the Mercury and Air Toxics Standards (MATS) also reduces coal-fired capacity in the power sector in 2015, but the full effect of the coal plant retirements on capacity will be felt in 2016.

Projected rising electricity demand and higher natural gas prices next year are expected to contribute to higher utilization rates among the remaining coal-fired fleet. Even with continued implementation of MATS, which the U.S. Supreme Court recently sent back to the U.S. Court of Appeals for the D.C. Circuit for further review, coal consumption in the electric power sector is forecast to increase by 1.9% in 2016.

Coal Prices. The annual average coal price to the electric power sector decreased from $2.39/MMBtu in 2011 to $2.36/MMBtu in 2014. EIA expects the delivered coal price to average $2.28/MMBtu in 2015 and 2016.

Electricity

Monthly data show 4,250 megawatts (MW) of new utility-scale generating capacity has come online in the United States this year through May, about the same amount that came online during the first five months of 2014. Generating units powered by renewable energy sources account for 55% of this year's new capacity, and new natural gas-fired capacity accounts for 44%. Texas is the state with the largest amount of new capacity this year (2,074 MW). Capacity additions in Texas are about evenly split between wind and natural gas.

Electricity Consumption. U.S. population-weighted cooling degree days so far in 2015 (through July) were 14% higher than the same period last year, which is a primary factor in the higher summer consumption of electricity. EIA estimates that the typical residential electricity

customer will use 3,134 kilowatthours of electricity during the months of June, July, and August this year, which is 4% more than in the same months in 2014.

EIA expects U.S. retail sales of electricity to the residential sector during 2015 to grow by 0.4% from 2014 levels. Residential sales of electricity are expected to fall by 1.0% in 2016, reflecting a forecast of milder summer and winter temperatures next year that reduces electricity use for cooling and heating-related demand.

Electricity Generation. U.S. generation of electricity fueled by natural gas exceeded coal-fired generation for the first time on record in April 2015, when the Henry Hub natural gas price hit a recent low of $2.61/MMBtu. Since then, natural gas prices have risen to an average of $2.84/MMBtu in July. EIA expects the price to continue increasing slowly through 2016, which contributes to projected coal-fired generation exceeding natural gas-fired generation through the short-term forecast horizon. EIA forecasts coal's share of U.S. total generation will average 35.6% in 2015, down from 38.7% in 2014. The natural gas fuel share averages 31.2% in 2015, up from 27.4% in 2014.

Electricity Retail Prices. The U.S. retail price of electricity to the residential sector is projected to average 12.7 cents per kilowatthour in 2015, which is 1.9% higher than the average price last year. This year-over-year increase in average electricity prices, combined with higher expected summer residential use, leads to a forecast 5.0% ($20) increase in the typical residential customer's summer electricity expenditures compared with last summer.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA expects total renewables used in the electric power sector will decrease by 2.6% in 2015. Conventional hydropower generation is forecast to decrease by 9.9%, and nonhydropower renewable power generation is forecast to increase by 4.5%. The 2015 decrease in hydropower generation reflects the effects of the California drought, which are only partially offset by growth in hydropower use elsewhere. Generation from hydropower in the electric power sector is expected to increase by 12.3% in 2016. Total renewables consumption for electric power and heat generation decreases by 4.0% in 2015 and increases by 7.6% in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average 87 gigawatthours per day (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 almost 100% (10 GW) between the end of 2014 and the end of 2016, with 3.9 GW of this new capacity being built in California. Other leading states in utility-scale solar capacity include North Carolina and Nevada, which, combined with California, account for almost 70% of the projected utility-scale capacity additions for 2015 and 2016. Power plant developers have notified EIA of plans to construct 13 projects in Georgia (totaling 607 MW) with expected 2015 or 2016 in-service dates. Five of these new projects (166 MW) will be built on U.S. military bases. Georgia currently has

66 MW of utility-scale solar capacity. According to current law, projects coming online after the end of 2016 will see a federal investment tax credit of 10%, 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% in 2014, is forecast to increase by 12% in 2015 and by 14% 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 twice that of solar: 18 GW of wind compared with 10 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) volumes for 2014 through 2016. Although these volumes 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 in 2015 and 2016. Ethanol consumption, which averaged 878,000 b/d in 2014, is forecast to average about 900,000 b/d in both 2015 and 2016, resulting in an average 9.9% ethanol share of the total gasoline pool those years. EIA does not expect significant 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 3,000 b/d in 2014. Because of the expected increase in ethanol gross imports, net exports of ethanol are forecast to fall from 51,000 b/d in 2014 to 43,000 b/d in 2015, and to 37,000 b/d in 2016.

EIA expects the largest effect of the proposed RFS targets to be on biodiesel 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 91,000 b/d in 2015 and 98,000 b/d in 2016. Net imports of biomass-based diesel are also expected to increase from 16,000 b/d in 2014 to 24,000 b/d in 2015, and to 35,000 b/d in 2016. 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 volumes through 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew by 1.0% in 2014. Emissions are projected to fall by 0.2% in 2015 and then rise by 0.7% in 2016. These forecasts are sensitive to both weather and economic assumptions. Monthly carbon dioxide emissions from the electric power sector were at a 27-year low in April, which is typically the month with the lowest generation level in each year.

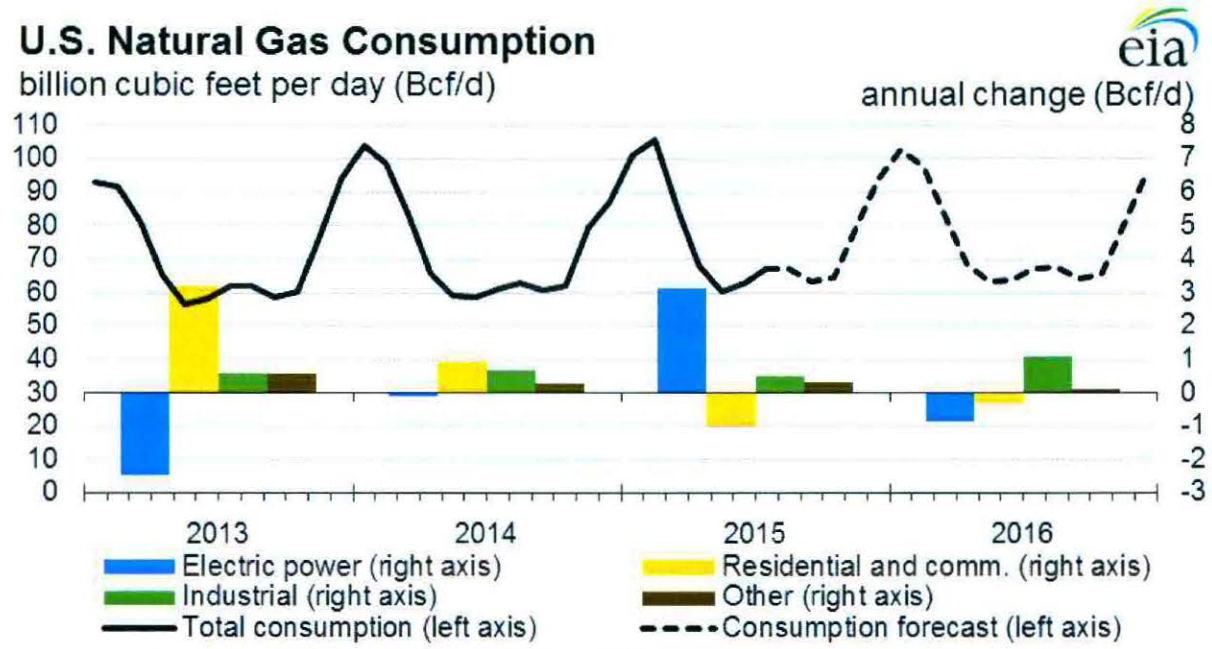
U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real GDP increased at an annual rate of 2.3% in the second quarter of 2015. The growth of real GDP was broad-based and reflected positive contributions from consumption, exports, state and local government spending, and residential fixed investment. The estimate of growth in the first quarter of 2015 was also revised up to 0.6%; the previous estimate was -0.2%.

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

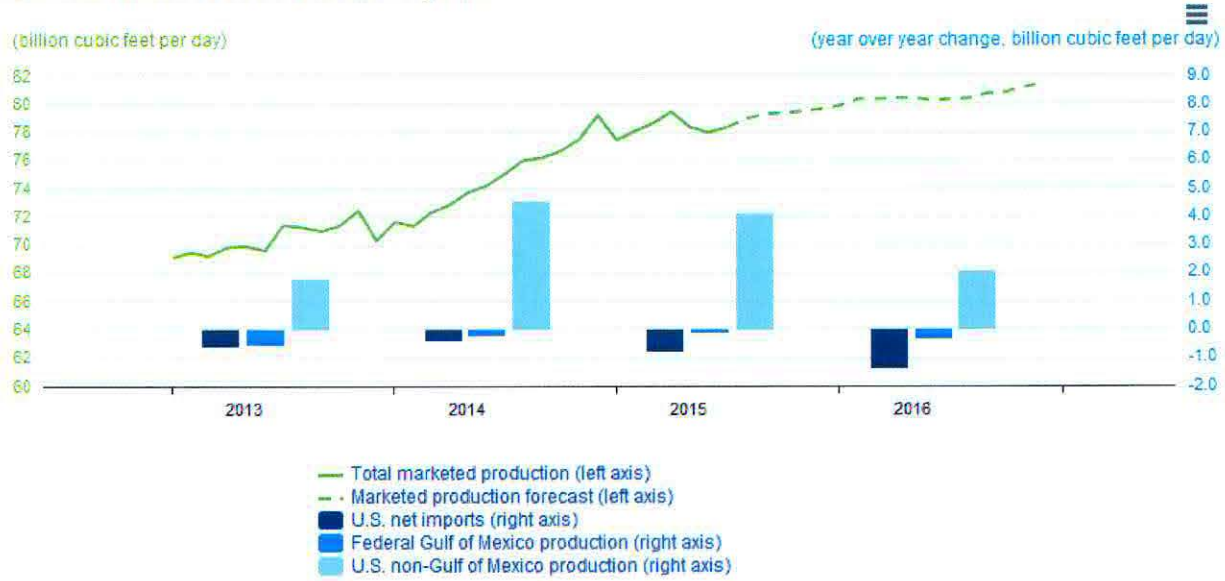
Production, Income, and Employment. Forecast real GDP growth reaches 2.2% in 2015 and rises to 3.0% in 2016. The 2015 growth is above the 2.0% forecast in last month's STEO, and the 2016 growth is also above the 2.8% July forecast. Real disposable income grows by 3.5% in 2015, the same as in the July forecast, and by 2.9% in 2016. Total industrial production grows at 1.8% in 2015 and 3.3% in 2016. Projected growth in nonfarm employment averages 2.1% in 2015 and 1.5% in 2016.

Expenditures. Forecast private real fixed investment growth averages 4.7% and 7.3% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015, at 3.0%, and the same as real GDP in 2016 at 3.0%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.2% and 4.6% over the same two years, while import growth is 6.0% in 2015 and 2016. Total government expenditures rise by 0.9% in 2015 and by 0.8% in 2016.

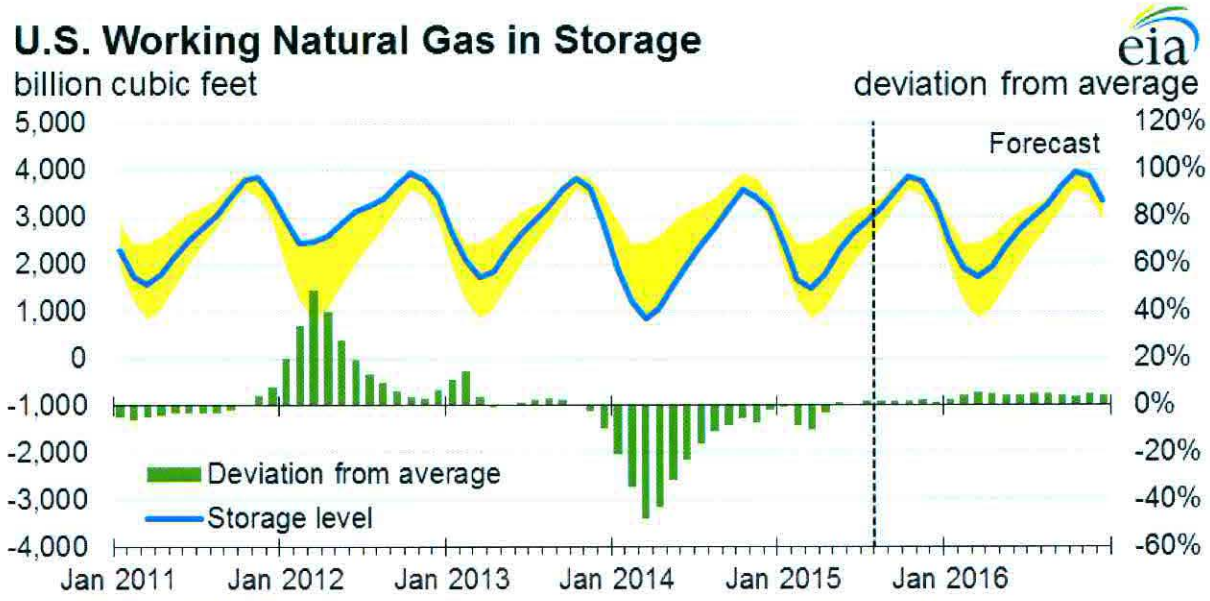


Source: Short-Term Energy Outlook, August 2015.

U.S. Natural Gas Production and Imports

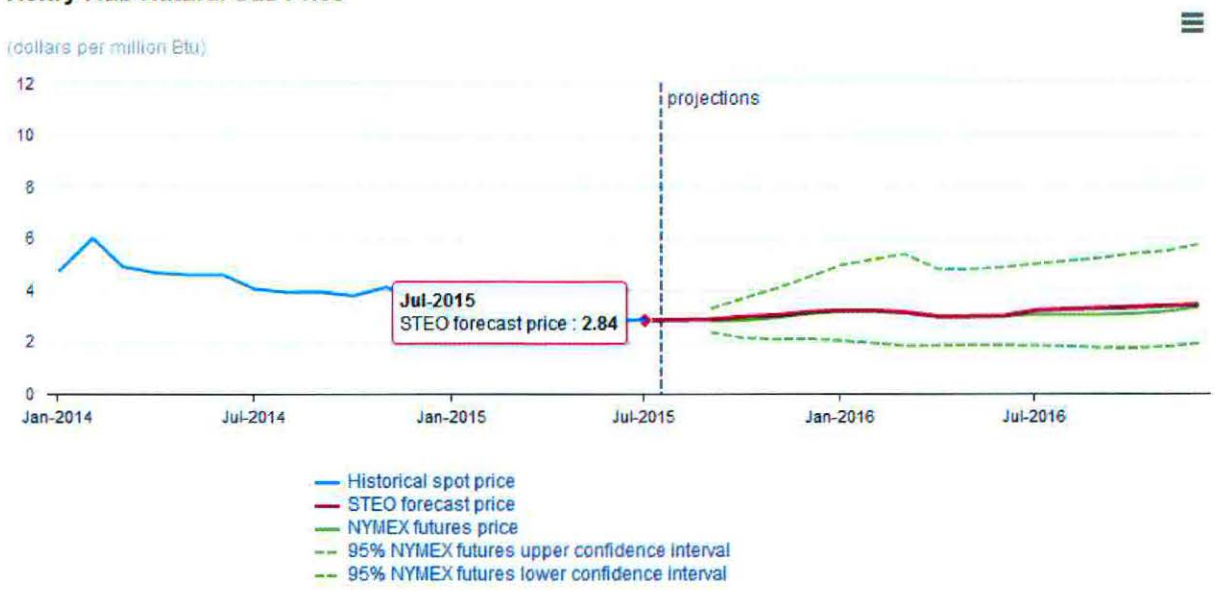


eia Source: Short-Term Energy Outlook, August 2015



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

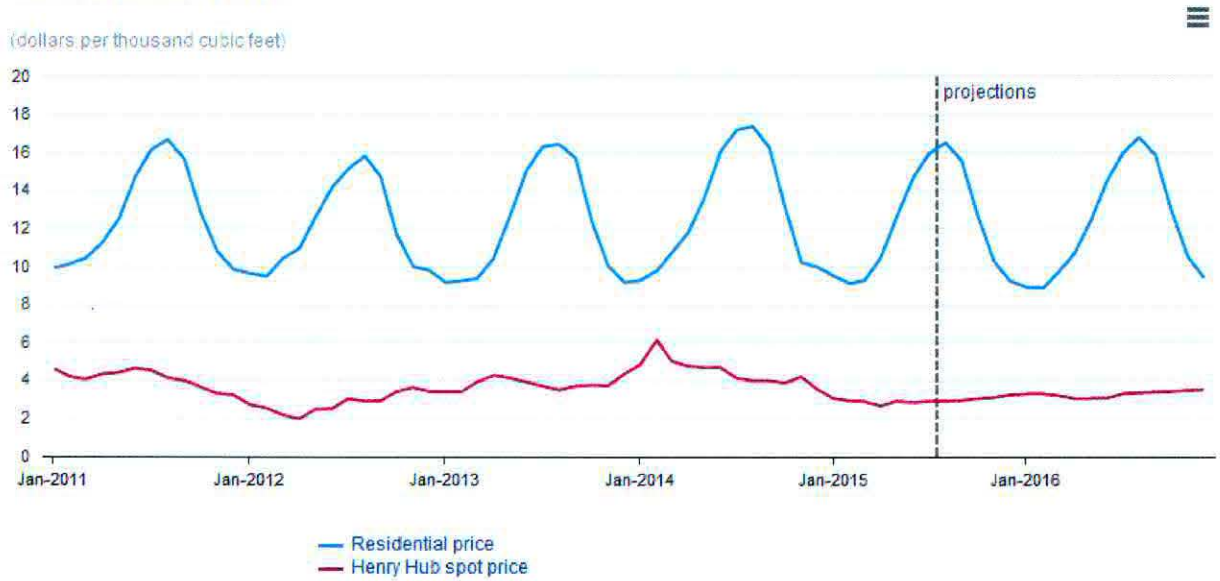
Henry Hub Natural Gas Price



eia Source: Short-Term Energy Outlook, August 2015

Note: Confidence interval derived from options market information for the 5 trading days ending Aug. 6 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

U.S. Natural Gas Prices



eia Source: Short-Term Energy Outlook, August 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
June	923	0	211	1,134	9,387	0.2107	9,293 2/	(8,159)	44,166
July	552	0	126	678	6,105	0.2107	1,286	(608)	43,558
Total	($2,473)	0	$630	($1,843)	29,236		$29,081	($30,924)	
Balance @ July 31, 2015.									**$43,558**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,442.6 dk @ $1.3462 and 2,944.3 dk @ $0.2107

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
June	(8,730)	0	(311)	(9,041)	28,071	0.0461	20,202 2/	(29,243)	(21,937)
July	(23,404)	0	(626)	(24,030)	41,181	0.0461	1,898	(25,928)	(47,865)
Total	($40,395)	0	($935)	($41,330)	90,079		$42,294	($83,624)	
Balance @ July 31, 2015.									**($47,865)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 20,473.8 dk @ $0.9696 and 7,597.5 dk @ $0.0461.