

General Office  
400 North Fourth Street  
Bismarck, ND 58501  
(701) 222-7900

July 2, 2013

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



Re: Cost of Gas Adjustment (COG)  
July 2013

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 (88<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (88<sup>th</sup> Revised Sheet No. 8), showing the July 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.4651 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for July 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.4651 since the last COG filing.

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

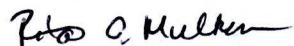
Attachment D shows the calculation of the balancing account since April 30, 2013.

Great Plains submitted a check for \$600.00 on January 2, 2013 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 this month's COG filing.

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

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

Sincerely,

A handwritten signature in black ink, appearing to read "Rita A. Mulkern". The signature is fluid and cursive, with a prominent initial "R".

Rita A. Mulkern  
Director of Regulatory Affairs

Attachments

**Attachment A**

**Attachment A**



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

**State of North Dakota  
 Gas Rate Schedule**

NDPSC Volume 2  
 88th Revised Sheet No. 1.1

**RATE SUMMARY SHEET**

Canceling 87th Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$6.2221	\$7.4961 7.2761
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$6.2221	\$8.3961 8.1761
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.7651	\$4.9042 4.6582 4.5062
Interruptible Gas Service - Highway 13	3.5	\$3.50 per month	First 400 MCF \$2.0391 Next 2,600 MCF 1.7931 Over 3,000 MCF 1.6411	\$3.7651	\$5.8042 5.5582 5.4062
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.7651	\$5.0042
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

**Date Filed:** July 2, 2013

**Effective Date:** Service rendered on and after July 1, 2013

**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  
88<sup>th</sup> Revised Sheet No. 8  
Canceling 87<sup>th</sup> 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	\$0.0658	\$5.1191	\$0.0000	\$5.1849	\$5.1191	\$0.0000	\$5.1191
Accumulated Adj.	1.4722	(0.9313)	0.9614	1.5023	(0.9163)	0.0274	(0.8889)
Current Adj.	0.0000	(0.4651)	0.0000	(0.4651)	(0.4651)	0.0000	(0.4651)
Total Adj.	1.4722	(1.3964)	0.9614	1.0372	(1.3814)	0.0274	(1.3540)
Total Rate:	\$1.5380	\$3.7227	\$0.9614	\$6.2221	\$3.7377	\$0.0274	\$3.7651

Date Filed: July 2, 2013

Effective Date: Service rendered on and after July 1, 2013

Issued By: Tamie A. Aberle  
Director - Regulatory Affairs

Case No.:

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
JULY 2013**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
FT-A	8,000	\$3.4671	12	\$332,842	\$0.2373
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0736
FT-A Seasonal	2,000	3.7671	5	37,671	0.0269
TFX Seasonal	2,000	15.1530	5	151,530	0.1080
TFX - Winter	13,000	15.1530	5	984,945	0.7023
TFX - Summer	13,000	5.6830	7	517,153	0.3687
LMS Demand 2/					0.0150
Total Demand Charges				\$2,136,019	1.5380
Estimated Weighted Average Commodity Cost	1,402,522 1/	3.7227		5,221,169	3.7227
Gas Cost Reconciliation Adjustment					0.9614
Total Current Firm Gas Cost				\$7,357,188	6.2221
Base Cost of Gas					5.1849
Accumulated Adjustment					\$1.0372

Interruptible

Estimated Weighted Average Commodity Cost					\$3.7227
Gas Cost Reconciliation Adjustment					0.0274
LMS Demand 2/					0.0150
Total Current Interruptible Gas Cost					3.7651
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.3540)

1/ Three year normalized average mcf sales

2/ Amount divided by 2010-2012 average interruptible sales volumes plus 2010-2012 average normalized firm sales volumes.

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0150

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
JULY 2013**

**Rates Effective July 1, 2013**

	<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.7227	Per dk

**Base Rate Effective September 1, 1981**

Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

**Base Rate Calculation**

Firm

Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf

Interruptible:

Commodity	\$5.1191	Per Mcf
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1/ Demand base rate calculation:  $4,768 \times 12 \times \$0.8100 / 707,222$

STATEMENT OF RATES  
(Rates Per Dekatherm)

## Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<hr/>	
Category 1 (Contract Term of Less than 3 Years)	
<hr/>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.7671
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.8871
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$2.1400
Zone 2-2 Minimum Rate	\$0.0000
<hr/>	
Category 2 (Contract Term of 3 Years to less than 5 Years)	
<hr/>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.6171
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.7371
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.9900
Zone 2-2 Minimum Rate	\$0.0000
<hr/>	
Category 3 (Contract Term of 5 or more Years)	
<hr/>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.4671
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.5871
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.8400
Zone 2-2 Minimum Rate	\$0.0000

Viking Gas Transmission Company  
FERC Gas Tariff  
Volume No. 1

Part 5.0  
Statement of Rates  
v. 12.0.0 superseding v. 11.0.0  
Page 3 of 3

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
<b>Commodity Rates</b>				
FT-A – Maximum Rates				
Zone 1-1	\$0.0130	\$0.0018	\$0.0148	0.36%
Zone 1-2	\$0.0130	\$0.0018	\$0.0148	0.47%
Zone 2-2	\$0.0130	\$0.0018	\$0.0148	0.11%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0018	\$0.1386	0.36%
Zone 1-2	\$0.1737	\$0.0018	\$0.1755	0.47%
Zone 2-2	\$0.0834	\$0.0018	\$0.0852	0.11%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0018 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.06% for Zone 1-1, 0.08 % for Zone 1-2, and 0.02% for Zone 2-2. Transportation entirely by backhaul 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	\$1.0000		\$1.0000
LMS – Daily Overrun Rate	\$0.1737		\$0.1737
LMS – Load Management Cost Reconciliation Adjustment		\$0.0001	

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	\$0.1737	\$0.0000
RPL Service:		
Daily Reservation Rate	\$0.1737	\$0.0000

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

Fifth Revised Sheet No. 50  
Superseding  
Fourth Revised Sheet No. 50

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12 Base	TF12 Variable	TF5	TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
Market	Market	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

- 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 total 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/ Maximum and Minimum rates include ACA of \$0.0018 and the Market Area Electric Compression charge of \$0.0000 where applicable.
- 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, Field Area Electric Compression charge of \$0.0000 and ACA will be added to the mileage based rates.

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

Fifth Revised Sheet No. 51  
Superseding  
Fourth Revised Sheet No. 51

RATE SCHEDULES TFX and LFT

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

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

GULF COAST		Reservation 1/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering		1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission		1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream		0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast		4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

- 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 total 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/ Maximum and Minimum rates include ACA of \$0.0018 and the Market Area Electric Compression charge of \$0.0000 where applicable.
- 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, Field Area Compression charge of \$0.0000 and ACA will be added to the mileage based rates.
- 6/ Maximum and Minimum rates include ACA of \$0.0018.

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

Sixth Revised Sheet No. 54  
Superseding  
Fifth Revised Sheet No. 54

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages -----
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.87%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.33% 4/ 5/
FDD Storage Fuel	1.55%
	Electric Compression -----
COMMODITY RATES:	1/
Market Area	\$0.0000
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, 2012.

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 & 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 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 2013**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for much 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 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.

Despite warmer weather in the Northeastern part of the country and the resultant increase in gas usage for electric generation for air conditioning demand, the national storage level has increased more than anticipated indicating an increase in natural gas supply. The Energy Information Administration (EIA) indicated that year over year dry production for mid-June had increased by two percent. The EIA reported storage levels nationwide as of June 21, 2013 were 1.2 percent below the five-year average and 17.1 percent below 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 17.



Independent Statistics & Analysis

U.S. Energy Information  
Administration

June 2013

## Short-Term Energy Outlook (STEO)

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### Highlights

- After increasing to \$119 per barrel in early February 2013, the Brent crude oil spot price fell to a low of \$97 per barrel in mid-April and then recovered to an average of \$103 per barrel in May. EIA expects that the Brent crude oil spot price will average \$102 per barrel over the second half of 2013, and \$100 per barrel in 2014.
- EIA expects the price of regular gasoline will average \$3.53 per gallon over the summer driving season (April through September). The annual average regular gasoline retail price is projected to decline from \$3.63 per gallon in 2012 to \$3.49 per gallon in 2013 and to \$3.37 per gallon in 2014. Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the projected levels.
- In April 2013, estimated total liquid fuels consumption in non-OECD (Organization for Economic Cooperation and Development) countries reached 44.5 million barrels per day (bbl/d), which was higher than consumption in OECD countries (44.3 million bbl/d) for the first time in history. EIA expects that consumption in OECD countries will average 45.5 million bbl/d in 2013 compared with 44.6 million bbl/d for non-OECD countries. EIA forecasts annual average non-OECD total liquids consumption to surpass OECD levels in 2014.
- EIA forecasts the summer 2013 average U.S. residential electric bill will total \$395 over the three-month period of June, July, and August, which is \$10 (2.5 percent) lower than the average customer's bill during summer 2012 (see [Summer 2013 Outlook for Residential Electric Bills](#)). Forecast milder temperatures than last summer contribute to a projected decline in average electricity usage per customer, which is partially offset by a projected 2-percent increase in average electricity prices.
- Based on the outlook from the National Oceanic and Atmospheric Administration (NOAA) for above-normal tropical weather activity this year, EIA estimates median outcomes for total shut-in production in the federal Gulf of Mexico (GOM) during the current hurricane season (June through November) of about 19 million barrels of crude oil and 46 billion cubic feet (Bcf) of natural gas (see [2013 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). Actual shut-ins are likely to differ significantly from this estimate depending on the number, track, and strength of hurricanes as the season progresses.

## Global Crude Oil and Liquid Fuels

In April 2013, estimated total liquid fuels consumption in non-OECD countries reached 44.5 million barrels per day (bbl/d), which was higher than consumption in OECD countries (44.3 million bbl/d) for the first time in history. The expected stronger seasonal increase in consumption among the developed economies in 2013 pushes OECD consumption back on top through early 2014. On an average annual basis, non-OECD use of liquid fuels is forecast to exceed OECD levels in 2014.

**Global Liquid Fuels Consumption.** World liquid fuels consumption grew by 0.8 million bbl/d in 2012 to reach 89.2 million bbl/d. EIA expects world consumption to grow by 0.9 million bbl/d in 2013 and by 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA expects refinery crude oil inputs in China to increase in 2013 as new refining capacity continues to come on line. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012. Recent indicators of weaker industrial data at the beginning of 2013 signaled slower economic growth than in prior years and a downside risk to robust oil demand growth. Projected consumption increases by 420,000 bbl/d in 2013 and by 430,000 bbl/d in 2014, compared with average annual growth of about 520,000 bbl/d from 2004 through 2012.

OECD liquid fuels consumption fell by 0.6 million bbl/d in 2012. EIA projects OECD consumption to decline by an additional 0.5 million bbl/d in 2013 and 0.2 million bbl/d in 2014, largely because of declining consumption in Europe and Japan.

**Non-OPEC Supply.** EIA projects liquid fuels production by countries that are not members of the Organization of the Petroleum Exporting Countries (OPEC) will increase by 1.2 million bbl/d in 2013 and by 1.6 million bbl/d in 2014. North America accounts for much of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands. EIA expects non-OPEC supply to also grow in Central and South America by an average of 160,000 bbl/d each year over the next two years, as Brazil and Colombia bring new production on line.

Total unplanned non-OPEC production outages averaged 1.0 million bbl/d in May 2013, up from 0.9 million bbl/d in last month's STEO. Sudan, South Sudan, Syria, and Yemen account for more than three-quarters of the disruptions. EIA expects supply disruptions to persist in Syria and Yemen over the forecast period. EIA has lowered its forecast of supply from Kazakhstan because of continued delays in the Kashagan field.

**OPEC Supply.** Projected OPEC total supply, which increased by 1.2 million bbl/d in 2012, falls by 0.4 million bbl/d in 2013 and by another 0.1 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth, although Saudi production

increases for the next few months because of seasonal demand. Iraq and Angola account for most of the increase in 2014. At the last OPEC meeting on May 31, 2013, the organization decided to retain its production target of 30 million bbl/d through the rest of 2013.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, averaged about 2.7 million bbl/d in the first quarter of 2013. This was higher than the 2.1-million-bbl/d average during the same period last year but lower than the first-quarter average of 3.8 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 4.6 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line because of the effects of U.S. and EU sanctions on Iran's oil sector.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to 57.7 days of supply. Projected OECD oil inventories stay relatively steady in 2013, ending the year at 2.64 billion barrels (57.3 days of supply). Projected inventories increase to 2.68 billion barrels (58.3 days of supply) at the end of 2014.

**Crude Oil Prices.** After declining to a 2013 year-to-date low of \$97 per barrel on April 17, Brent crude oil spot prices increased to an average of \$103 per barrel in May. EIA projects the Brent crude oil spot price will fall from an average of \$112 per barrel in 2012 to annual averages of \$105 per barrel and \$100 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries. After averaging \$94 per barrel in 2012, the forecast WTI crude oil spot price averages \$93 per barrel in 2013 and \$92 per barrel in 2014. By 2014, [several pipeline projects](#) from the midcontinent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a narrowing in the [price discount of WTI to Brent](#).

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures contracts for September 2013 delivery traded during the five-day period ending June 6, 2013 averaged \$93.75 per barrel. Implied volatility averaged 23 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in September 2013 at \$77 per barrel and \$114 per barrel, respectively. Last year at this time, WTI for September 2012 delivery averaged \$85 per barrel and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$63 per barrel and \$115 per barrel.

## U.S. Crude Oil and Liquid Fuels

Despite only slight increases in Brent crude oil prices in May, [refinery outages across the Midwest](#) helped bring the U.S. average regular gasoline retail price up from \$3.52 per gallon on April 29, 2013 to \$3.65 per gallon on June 3. The expected recovery in refinery production combined with lower crude oil prices contributes to lower projected regular gasoline retail

prices, averaging \$3.40 per gallon in the second half of 2013 and \$3.37 per gallon in 2014. The current values of futures and options contracts suggest that prices could differ significantly from this forecast. For example, there is a 12-percent probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed \$3.10 per gallon (consistent with a U.S. average regular gasoline retail price above \$3.75 per gallon) in September 2013.

**U.S. Liquid Fuels Consumption.** In 2012, total liquid fuels consumption declined 390,000 bbl/d (2.1 percent). During the first quarter of 2013, total liquid fuels consumption rose by 180,000 bbl/d compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Much of that increase was due to weather, with heating degree days in the Northeast 21 percent higher than the mild first quarter seen last year. For the year as a whole, the forecast of total liquid fuels consumption increases by an average 90,000 bbl/d, followed by a slight decline in 2014. Motor gasoline consumption remains flat during the forecast interval as continued increases in vehicle fuel efficiency offset gains in motor vehicle travel.

**U.S. Liquid Fuels Supply.** EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.3 million bbl/d in 2013 and 8.1 million bbl/d in 2014. Drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian Basins is expected to account for the bulk of forecast production growth over the next two years.

One current driver of production growth through 2014 is the continued exploration success seen in some of the major plays in the Permian Basin. Operators in the Bone Spring, Spraberry, and Wolfcamp plays are achieving greater success in finding sweet spots and hydraulically fracturing horizontal wells. EIA expects improvements in drilling and completing horizontal wells from multi-well drilling pads in the Permian Basin, which give operators greater access to large areas of resources in a number of stacked plays from a single surface location.

Gulf of Mexico oil production estimates have been revised downward by 160,000 bbl/d in May and 270,000 bbl/d in June from last month's STEO. Maintenance at the BP natural gas processing plant in Pascagoula, Mississippi, and on the NaKika offshore platform lowered production in May and early June. The Pascagoula plant is back in operation, and the NaKika system is scheduled to ramp up production by mid-June. Additional shut-in oil production will occur in June as Shell installs a new platform as part of the Mars B project, slated to begin producing during 2015.

The NOAA [\*Atlantic Hurricane Season Outlook\*](#) predicts that the Atlantic Basin likely will experience above-normal tropical weather activity during the current hurricane season. EIA estimates that the median outcome for shut-in crude oil production in the federally administered Gulf of Mexico because of disruptions during the 2013 hurricane season is 19 million barrels. There is a wide range of uncertainty around this forecast (see the [\*2013 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico\*](#)). EIA's simulation results

indicate a 58-percent probability of offshore crude oil production experiencing outages during the current hurricane season that are equal to or larger than the 14 million barrels of production shut in during the 2012 hurricane season.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 5.7 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to fall to 30 percent in 2014, which would be the lowest level since 1985.

**U.S. Petroleum Product Prices.** EIA expects that regular-grade gasoline retail prices, which averaged \$3.69 per gallon last summer, will average \$3.53 per gallon during the current summer (April through September) driving season. The projected monthly average regular retail gasoline price falls from \$3.61 per gallon in May to \$3.43 per gallon in September. Diesel fuel prices, which averaged \$3.95 per gallon last summer, are projected to average \$3.83 per gallon this summer. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents per gallon or more.

As is the case 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 RBOB futures contracts for September 2013 delivery traded over the five-day period ending June 6 averaged \$2.76 per gallon. The probability that the RBOB futures price will exceed \$3.10 per gallon (consistent with a U.S. average regular gasoline retail price above \$3.75 per gallon) in September 2013 is about 12 percent.

## Natural Gas

**U.S. Natural Gas Consumption.** EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.0 Bcf/d and 69.6 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures forecast for 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.5 Bcf/d in 2013 and 22.1 Bcf/d in 2014, although these forecast levels are still high by historical standards.

**U.S. Natural Gas Production and Trade.** Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 70.0 Bcf/d in 2013, and to 70.4 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production declines. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to

remain near their 2012 level over the forecast. LNG imports are expected to remain at minimal levels of around 0.4 Bcf/d in both 2013 and 2014.

Mexico's domestic natural gas consumption is rising faster than domestic production, leading to both record pipeline gas imports from the United States and growth in the country's imports of liquefied natural gas (LNG). Natural gas trade between Mexico and the United States has been growing; daily net exports from the United States to Mexico so far in 2013 (January 1-May 6) are estimated to average 1.6 billion cubic feet per day (Bcf/d), up almost 29 percent over the same period in 2012.

The NOAA *Atlantic Hurricane Season Outlook* predicts that the Atlantic Basin likely will experience above-normal tropical weather activity during the current hurricane season. EIA estimates that the median outcome for shut-in natural gas production in the federally administered Gulf of Mexico as a result of disruptions during the 2013 hurricane season is 46 Bcf (see the *2013 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). EIA's simulation results indicate a 58-percent probability of offshore natural gas production experiencing outages during the current hurricane season that are equal to or larger than the 32 Bcf of production shut in during the 2012 hurricane season.

**U.S. Natural Gas Inventories.** As of May 31, 2013, working gas stocks totaled 2,252 Bcf, which is 616 Bcf less than at the same time last year, but only 69 Bcf below the five-year (2008-12) average for the end of May. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,813 Bcf, about 117 Bcf below the level at the same time last year.

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$4.04 per MMBtu at the Henry Hub in May 2013, down 13 cents from the \$4.17-per-MMBtu average seen the previous month. EIA expects the Henry Hub price will increase from an average of \$2.75 per MMBtu in 2012 to \$3.92 per MMBtu in 2013 and \$4.10 per MMBtu in 2014.

Natural gas futures prices for September 2013 delivery (for the five-day period ending June 6, 2013) averaged \$3.97 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for September 2013 contracts at \$3.03 per MMBtu and \$5.21 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for September 2012 averaged \$2.48 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were \$1.51 per MMBtu and \$4.07 per MMBtu.

## Coal

Electric power sector coal stocks ended March 2013 at 173 million short tons (MMst), the lowest level since December 2011. It was the fourth consecutive month that stocks declined.

Inventories have fallen 6 percent (12 MMst) since the beginning of this year. Over the same period last year, electric power sector coal stocks increased by 13 percent (22 MMst).

**U.S. Coal Consumption.** EIA expects total coal consumption will increase by 7.1 percent from 890 MMst in 2012 to 954 MMst in 2013 as consumption in the electric power sector rises due to higher electricity demand and higher natural gas prices. Consumption grows at a more modest pace of 1.8 percent to 970 MMst in 2014.

**U.S. Coal Supply.** Coal production is expected to remain relatively stable, increasing by 0.5 percent, from 1,016 MMst in 2012 to 1,021 MMst in 2013. Inventory draws, combined with an increase in coal imports, meet most of the growth in consumption in 2013. Coal production is forecast to grow by 3.2 percent in 2014 to 1,054 MMst as inventories stabilize in the face of increasing consumption.

**U.S. Coal Exports.** EIA expects exports to decline from 126 MMst in 2012 to 110 MMst in 2013 despite a record 13.6 MMst exported in March. Exports are projected to be 107 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing supply in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

**U.S. Coal Prices.** Delivered coal prices to the electric power industry increased steadily over a 12-year period through 2012, when the delivered coal price averaged \$2.40 per MMBtu. EIA forecasts average delivered coal prices of \$2.36 per MMBtu in 2013 and \$2.40 per MMBtu in 2014.

## Electricity

This month's STEO includes a special supplement (*Summer 2013 Outlook for Residential Electric Bills*) describing EIA's expectations about residential electricity usage and electric bills during the summer months. EIA forecasts the average U.S. residential electric bill over the period of June-August 2013 will total \$395, about 2.5 percent lower than the average bill last summer. A reduction in the average summer electricity usage per customer, because of forecast milder temperatures, is offset somewhat by projected higher average U.S. retail electricity prices in most areas of the country. Average customer electricity usage projections will also now appear in [STEO Table 7a](#) and in the [STEO custom table builder](#).

The North American Electric Reliability Corporation (NERC) has issued its *2013 Summer Reliability Assessment* for the electricity industry during the upcoming summer months. NERC's key findings indicate that [Texas and California](#) may face challenges balancing electricity demand with available capacity under extreme weather or adverse supply conditions. Also, increased wind and solar generation capacity in certain regions and persisting drought conditions west of the Mississippi could result in increased supply uncertainty during peak demand periods.

**U.S. Electricity Consumption.** For the summer months of June through August of 2013, EIA expects the average U.S. residential customer will use a total of 3,200 kilowatthours of electricity, which is 4.6 percent lower than last summer. However, because of the relatively cold first quarter of 2013, EIA projects residential customers will use an average of 10,883 kWh for the entire year of 2013, which is 0.4 percent more than 2012. This growth in annual electricity usage, combined with a projected 0.7-percent increase in the number of residential customers, translates to a forecast increase of 1.3 percent in total retail sales of electricity to the residential sector during 2013. Retail sales of electricity to the commercial sector grow by 0.9 percent in 2013, while retail sales to the industrial sector stay relatively flat this year.

**U.S. Electricity Generation.** EIA expects total U.S. electricity generation will grow by 0.9 percent annually in both 2013 and 2014. Water supply in the Pacific Northwest this spring is lower than last year, leading to a 4-percent decline in the level of conventional hydroelectric generation during the first quarter of 2013 compared with the same period last year. EIA has revised its forecast for hydropower generation for the upcoming summer months to better reflect the NOAA water supply outlook. Generators have been running their existing coal capacity at higher rates so far this year in response to the increasing cost of natural gas relative to coal. This trend is expected to continue, leading to an 8.5-percent annual increase in U.S. electricity generation from coal and an 8.2-percent decline in U.S. natural gas generation during 2013.

**U.S. Electricity Retail Prices.** The U.S. residential electricity price averaged 11.9 cents per kWh in 2012. EIA expects the average residential price will grow by 1.1 percent in 2013 and by 1.9 percent in 2014. The residential price during the summer months this year (June-August) is expected to average 12.3 cents/kWh, a 2.2-percent increase from the price last summer.

## Renewables and Carbon Dioxide Emissions

**U.S. Electricity and Heat Generation from Renewables.** EIA projects renewable energy consumption for electricity and heat generation to increase by 3.0 percent in 2013. While hydropower declines by 4.4 percent, nonhydropower renewables used for electricity and heat grow by an average of 7.7 percent in 2013. In 2014, the growth in renewables consumption for power and heat generation is projected to continue at a rate of 5.3 percent, as a 3.9-percent increase in hydropower is combined with a 6.1-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 6 percent this year to nearly 63,000 megawatts, and reach almost 73,000 megawatts in 2014. However, electricity generation from wind is projected to increase by 19 percent in 2013, as capacity that came [on line at the end of 2012](#) is available for the entire year in 2013. Wind-powered generation is projected to grow by 8 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, both from central-station and distributed capacity, although the total amount remains a small share of total U.S. generation. Central-station capacity, which until recently experienced little growth compared

with distributed capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all central-station solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014. However, PV is still expected to account for the majority of central station and distributed capacity additions in 2013 and 2014.

**U.S. Liquid Biofuels.** Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.8 billion gallons per year) in the first half of 2012 to an average of 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. Ethanol production has partially recovered since April, averaging about 870,000 bbl/d in May 2013, driven in part by increasing Renewable Fuel Standard (RFS) targets and strong demand for Renewable Identification Numbers (RINs). EIA expects ethanol production to remain near current levels through the third quarter before recovering to pre-drought production levels, averaging 870,000 bbl/d for the year. Ethanol production is expected to average 930,000 bbl/d in 2014. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, is forecast to average about 81,000 bbl/d in 2013 and 82,000 bbl/d in 2014 (1.3 billion gallons per year). This forecast assumes that the 2014 renewable fuel volume obligations are identical to those in 2013, which is 1.6 billion gallons below the 2014 statutory target of 18.15 billion ethanol-equivalent gallons of total renewable fuels.

In 2013, the statutory RFS target of 16.55 billion ethanol-equivalent gallons of total renewable fuels would require refiners and importers of gasoline and diesel fuel to deliver RINs to the U.S. Environmental Protection Agency (EPA) equivalent to 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it), unless the EPA reduces this requirement in its final rulemaking for the 2013 RFS program year. The market price of ethanol RINs increased dramatically during the first quarter of 2013, from \$0.05 per gallon at the start of the year to as high as \$1.05 per gallon on March 11, and has averaged over \$0.80 per gallon during May 2013.

The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, although present RIN prices do not appear sufficient to make E85 an economical fuel choice, a higher ethanol RIN price tends to lower the market price of E85 gasoline relative to E10 gasoline. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate blending of biodiesel that exceeds the biodiesel blending requirements that EPA announced in a proposed rulemaking for the 2013 RFS program that has yet to be finalized.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as typical biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

**U.S. Energy-Related Carbon Dioxide Emissions.** EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.9 percent in 2012, and projects increases of 2.6 percent in 2013

and 0.5 percent in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

## U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI model used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will soon be replaced by a combination of income tax increases and spending cuts that are implemented in 2014. The GI model also assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury (the debt ceiling) in the near term.

**U.S. Current Trends.** Current economic indicators portray a mixed picture on the strength of the expansion to date. The [Reuters/University of Michigan Consumer Sentiment Index](#) showed an increase in May, after declining in April. The [U.S. Bureau of Economic Analysis \(BEA\)](#) reported real disposable income increased by 0.1 percent in April. The [U.S. Census Bureau](#) also reported that new orders for manufactured durable goods rose 3.3 percent from March to April, following a 5.9-percent decline from February to March. According to the [U.S. Commerce Department](#), sales of new single-family homes increased by 2.3 percent from March to April 2013. This was a 29-percent rise from April 2012. However, the [BEA](#) revised downward real GDP growth in the first quarter of 2013 from 2.5 to 2.4 percent. The [ISM Purchasing Managers Index](#) fell to 49 percent in May, its lowest level since June 2009. Most projections continue to show stronger economic growth in the second half of 2013.

**U.S. Production.** This STEO assumes U.S. real GDP growth of 1.8 percent in 2013, rising to 2.6 percent in 2014. Year-on-year real GDP growth begins to accelerate in 2014, eventually rising to 3.0 percent in its final quarter. Forecast real disposable income increases 0.6 percent in 2013 and 3.3 percent in 2014. Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at around 3.0 percent in each year. Industrial production growth in the manufacturing sector is 3.2 percent in 2013, but accelerates to 3.7 percent in 2014.

**U.S. Income and Expenditures.** Private fixed investment growth averages 6.5 and 8.3 percent over 2013 and 2014, respectively. This is driven partly by business equipment and software spending, as well as increasing expenditures on buildings. Real consumption expenditures grow faster than real GDP in 2013, at 2.1 percent, but slow below the rate of real GDP growth in 2014, at 2.2 percent. Export growth more than doubles from 2.0 to 5.2 percent over the same two years. Government expenditures fall by 2.8 percent in 2013, and rise by 0.3 percent in 2014.

**U.S. Employment, Housing, and Prices.** The unemployment rate in the forecast averages 7.6 percent over 2013, and gradually falls to 7.0 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.5 percent in both 2013 and 2014. Consistent with an

improving housing sector, housing starts grow an average of 23.8 percent and 25.8 percent over 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

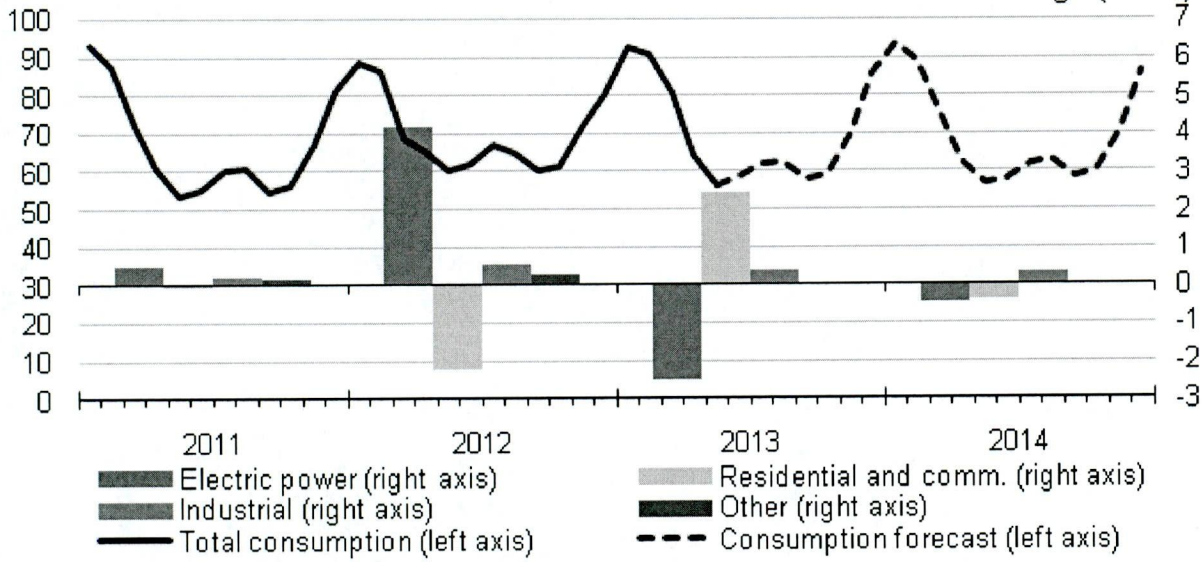
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views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

# U.S. Natural Gas Consumption



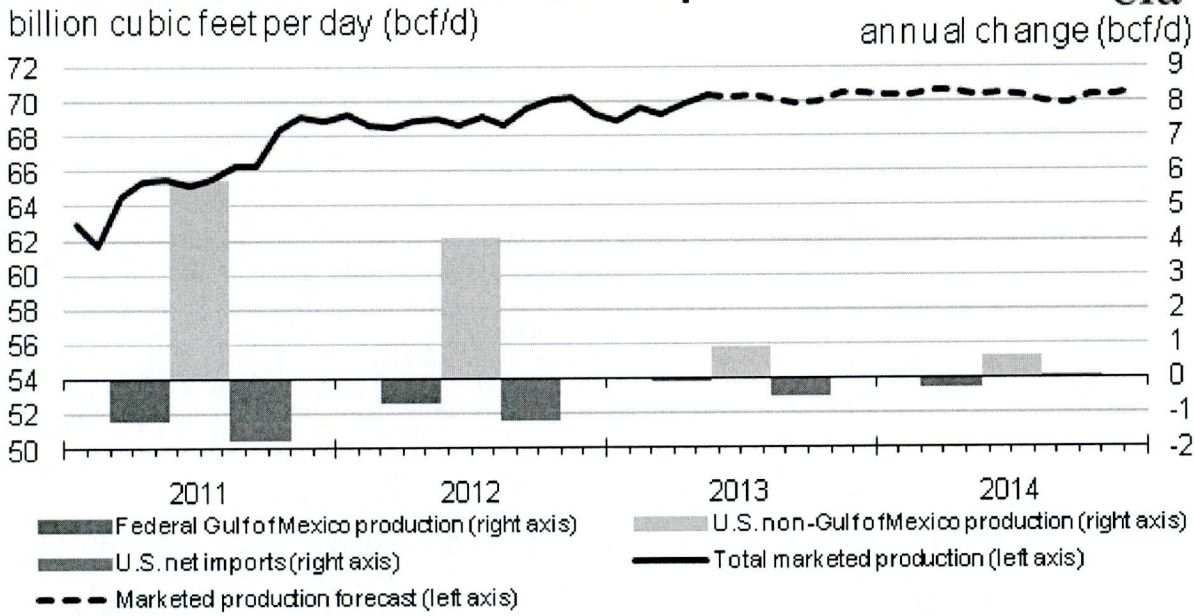
billion cubic feet per day (bcf/d)

annual change (bcf/d)



Source: Short-Term Energy Outlook, June 2013

# U.S. Natural Gas Production and Imports



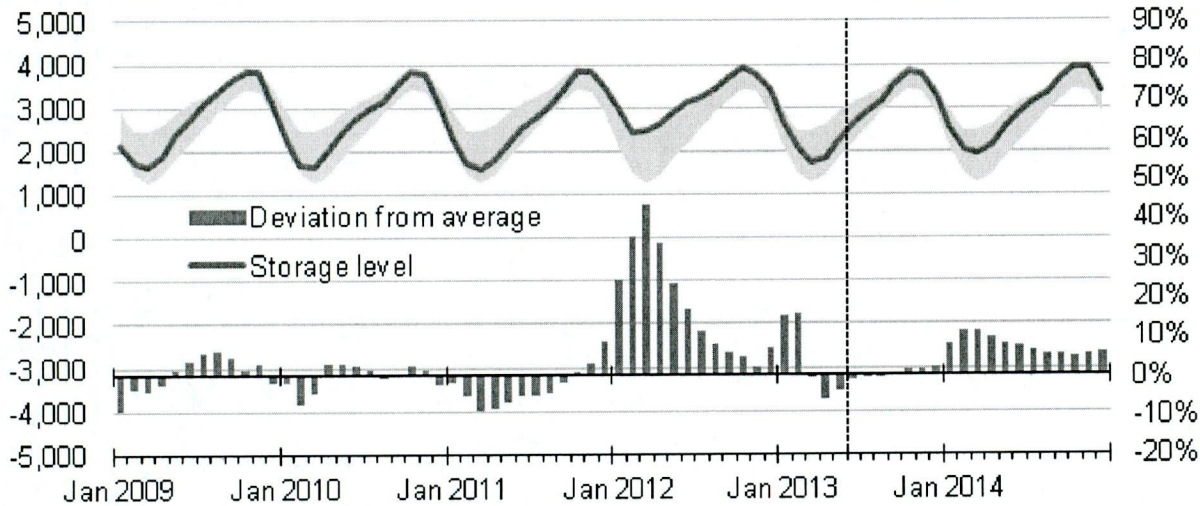
Source: Short-Term Energy Outlook, June 2013

# U.S. Working Natural Gas in Storage



billion cubic feet

deviation from average



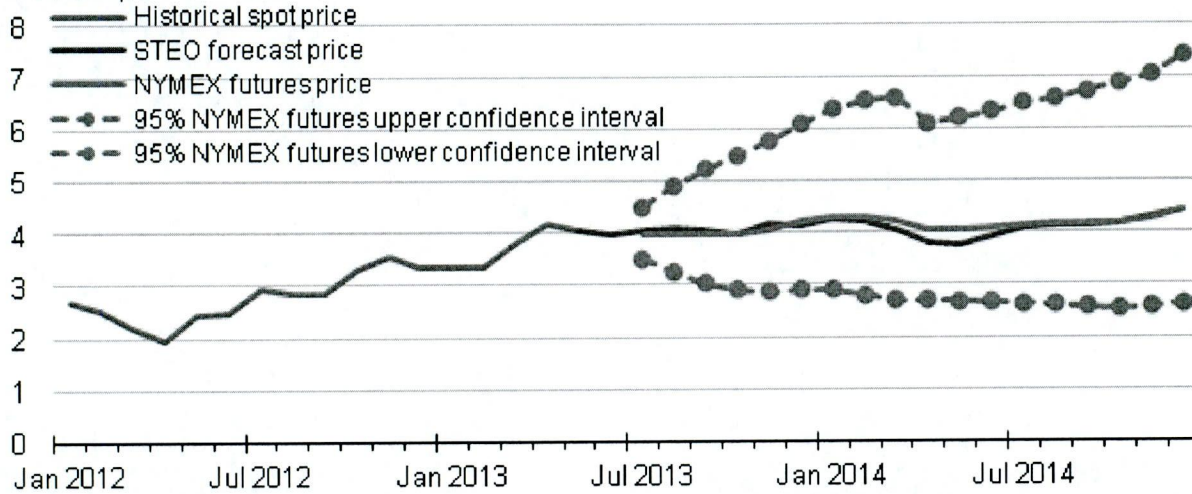
Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, June 2013

# HenryHub Natural Gas Price



dollars per million btu

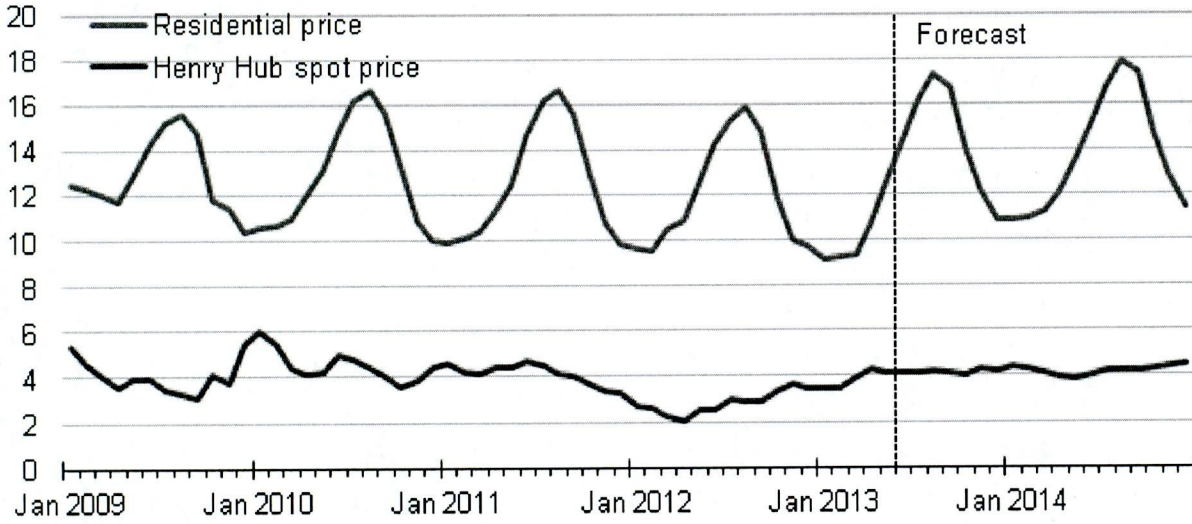


Note: Confidence interval derived from options market information for the 5 trading days ending June 6, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, June 2013

# U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, June 2013

**GREAT PLAINS NATURAL GAS CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
APPLICABLE TO NORTH DAKOTA  
FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ April 30, 2013</b>									<b><u>\$303,311</u></b>
May	(\$12,469)	0	\$1,860	(\$10,609)	21,400	\$1.0137	\$21,692	(\$32,301)	271,010
Total	(\$12,469)	0	\$1,860	(\$10,609)	21,400		\$21,692	(\$32,301)	
<b>Balance @ May 31, 2013</b>									<b><u>\$271,010</u></b>

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 Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
<b>Balance @ April 30, 2013</b>									<u><u>\$4,747</u></u>
May	(\$19,391)	0	(\$4)	(\$19,395)	49,736	(\$0.2915)	(\$14,498)	(\$4,897)	(150)
Total	(\$19,391)	0	(\$4)	(\$19,395)	49,736		(\$14,498)	(\$4,897)	
<b>Balance @ May 31, 2013</b>									<u><u>(\$150)</u></u>

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