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

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PO Box 176
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June 29, 2012

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

Re: Cost of Gas Adjustment (COG)
July 2012

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (76th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (76th Revised Sheet No. 8), showing the July 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.2567 per mcf for residential and firm general service customers and a decrease of $0.2023 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.2023 since the last COG filing. There has been a decrease in pipeline charges of $0.0544 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.2567 per mcf for residential and firm general service customers.

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

Attachment D shows the calculation of the balancing account since April 30, 2012.

Great Plains submitted a check for $600.00 on January 4, 2012 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,

Rita A. Mulkern
Regulatory Affairs Manager

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
76th Revised Sheet No. 1.1
Canceling 75th Revised Sheet No.1.1

RATE SUMMARY SHEET

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	$6.9312	$8.2052
			Over 10 MCF	1.0540		7.9852
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.9312	$9.1052
			Over 10 MCF	1.9540		8.8852
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$1.7616	$2.9007
			Next 2,600 MCF	0.8931		2.6547
			Over 3,000 MCF	0.7411		2.5027
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$1.7616	$3.8007
			Next 2,600 MCF	1.7931		3.5547
			Over 3,000 MCF	1.6411		3.4027
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$1.7616	$3.0007
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: June 29, 2012 **Effective Date:** July 1, 2012

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
76th Revised Sheet No. 8
Canceling 75th 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.	3.8678	(2.8785)	1.0137	2.0030	(2.8637)	(0.2915)	(3.1552)
Current Adj.	(0.0544)	(0.2023)	0.0000	(0.2567)	(0.2023)	0.0000	(0.2023)
Total Adj.	3.8134	(3.0808)	1.0137	1.7463	(3.0660)	(0.2915)	(3.3575)
Total Rate:	$3.8792	$2.0383	$1.0137	$6.9312	$2.0531	($0.2915)	$1.7616

Date Filed: June 29, 2012

Effective Date: Service rendered on and after July 1, 2012

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2012

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841		$3.4671	12	$326,226	$0.2331
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	0.0737
FT-A Seasonal	2,000		3.7671	5	37,671	0.0269
TFX Seasonal	2,000		15.1530	5	151,530	0.1083
NOVA - Demand Charge	7,947		14.8014	12	1,411,521	1.0085
Trans Canada - Demand Charge	7,947		23.2123	12	2,213,618	1.5815
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0655
NOVA - Seasonal	5,068		14.8014	5	375,067	0.2680
Trans Canada - Seasonal	5,068		23.2123	5	588,200	0.4202
BP Canada - Seasonal	5,068		0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068		3.0417	5	77,077	0.0551
LMS Demand 2/						0.0148
Total Demand Charges					$5,408,809	3.8792
Estimated Weighted Average Commodity Cost	1,399,684	1/	2.0383		2,852,976	2.0383
Gas Cost Reconciliation Adjustment						1.0137
Total Current Firm Gas Cost					$8,261,785	6.9312
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.7463

Interruptible	
Estimated Weighted Average Commodity Cost	$2.0383
Gas Cost Reconciliation Adjustment	(0.2915)
LMS Demand 2/	0.0148
Total Current Interruptible Gas Cost	1.7616
Base Cost of Gas	5.1191
Accumulated Adjustment	($3.3575)

1/ Three year normalized average Dk sales.
2/ Amount divided by 2008-2010 average interruptible sales volumes plus 2008-2010 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0148

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2012

Rates Effective July 1, 2012	$/Dk	
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 Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	14.8014	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.2123	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	14.8014	Per dk/Day
Trans Canada - Seasonal	23.2123	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	2.0383	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	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

1/ Demand base rate calculation: 4,768 X 12 X $0.8100 / 707,222

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	$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
Category 2 (Contract Term of 3 Years to less than 5 Years)	
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
Category 3 (Contract Term of 5 or more Years)	
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

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A – Maximum Rates				
Zone 1-1	$0.0130	$0.0018	$0.0148	1.16%
Zone 1-2	$0.0130	$0.0018	$0.0148	1.52%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.36%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	1.16%
Zone 1-2	$0.1737	$0.0018	$0.1755	1.52%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.36%
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: 0.18% for Zone 1-1, 0.23 % for Zone 1-2, and 0.05% 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		($0.0022)	

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

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12		
RESERVATION RATES	TF12 Base	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	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	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 $0.0001 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.

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	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	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/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ 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 $0.0001 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.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.67%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.43% 4/ 5/
FDD Storage Fuel	1.09%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0001
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, 2011.

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 2012

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The July monthly price for the AECO Index is expected to be slightly higher than the previous month index. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

Warmer weather and increased use of air conditioning along with inventory levels that seemed to be moderating compared to the five-year average likely contributed to the change in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of June 15, 2012 were 27.1 percent above the five-year average and 29.2 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 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

June 2012

Short-Term Energy Outlook

Highlights

- West Texas Intermediate (WTI) crude oil spot prices averaged more than $100 per barrel over the first 4 months of 2012. The WTI spot price then fell from $106 per barrel on May 1 to $83 per barrel on June 1, reflecting market concerns about world economic and oil demand growth. EIA projects the price of WTI crude oil to average about $95 per barrel over the second half of 2012 and the U.S. refiner acquisition cost of crude (RAC) to average $100 per barrel, both almost $11 per barrel lower than last month's *Outlook*. EIA expects crude oil prices to remain relatively flat in 2013. This forecast rests on the assumption that U.S. real gross domestic product (GDP) grows by 2.2 percent this year and 2.4 percent next year, while world oil-consumption-weighted real GDP grows by 3.1 percent and 3.5 percent in 2012 and 2013, respectively. The recent economic and financial news that points towards weaker economic outlooks could lead to lower economic growth forecasts and further downward revisions to EIA's crude oil price forecasts.

- EIA has lowered the average regular gasoline retail price forecast for the 2012 April-through-September summer driving season to $3.60 per gallon from $3.79 per gallon in last month's *Outlook*. EIA expects regular gasoline retail prices, which averaged $3.53 per gallon in 2011, to average $3.56 per gallon in 2012 and $3.51 per gallon in 2013.

- EIA expects U.S. total crude oil production to average 6.3 million barrels per day (bbl/d) in 2012, an increase of 0.6 million bbl/d from last year, and the highest level of production since 1997. Projected U.S domestic crude oil production increases to 6.7 million bbl/d in 2013.

- Natural gas working inventories ended May 2012 at an estimated 2.9 trillion cubic feet (Tcf), about 31 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is $2.55 per million British thermal units (MMBtu), which is $0.10 per MMBtu higher than last month's *Outlook*. EIA expects that Henry Hub spot prices will average $3.23 per MMBtu in 2013.

- Based on the outlook from the National Oceanic and Atmospheric Administration for the current Atlantic hurricane season, EIA estimates median outcomes for total shut-in production in the Federal Gulf of Mexico (GOM) during the upcoming hurricane season

(June through November) of about 4.5 million barrels of crude oil and 9.5 billion cubic feet (Bcf) of natural gas (see *2012 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

Global Crude Oil and Liquid Fuels Overview. Global oil markets have loosened in recent months, as world oil production outpaced consumption by 0.7 million bbl/d in the first quarter of 2012, and is forecast to exceed it by 1.2 million bbl/d in the second quarter. The oil production gains contributed to a counter-seasonal stock build during the first quarter of 2012, following the significant stock draws during 2011. Industry analysts have attributed some of the recent decline in oil prices to poor economic indicators for Europe, China, and the United States, in addition to reduced market anxiety over current and potential supply disruptions. Although EIA's economic growth assumptions are unchanged from last month, the crude oil price forecast has been lowered because of upward revisions to current and forecasted supply, primarily from countries outside of the Organization of the Petroleum Exporting Countries (OPEC), and to reflect changes in the relative strength of the upside and downside risks buffeting oil markets.

Despite the recent fall in crude oil prices, EIA expects that the average crude oil price in 2012 will be higher than in 2011. EIA expects the world oil market will tighten moderately in the third quarter of 2012 as world demand reaches its seasonal peak and total consumption exceeds production by about 0.7 million bbl/d. Additionally, spare production capacity levels are projected to be low enough to support a recovery in crude oil prices from current levels.

There are several uncertainties that could push oil prices higher or lower than projected. A number of non-OPEC countries continue to experience large and persistent supply disruptions. Oil prices could be higher than projected in this *Outlook* if recoveries from supply disruptions are slower than forecast, additional disruptions occur, or supply growth is lower than expected. Additionally, the effects of the impending European Union embargo and other sanctions targeting exports of Iranian crude oil and their associated payments are still uncertain. Some industry analysts believe that optimism about recent negotiations between Iran and its counterparts in the West has helped to ease prices in recent months, even though the outcome remains uncertain. EIA's projected oil market balance reflects the impacts from previous sanctions against Iran.

On the demand side, the recent negative economic news on Europe poses a risk to global economic growth. In the current *Outlook*, consumption in Europe is expected to fall year-over-year by 340 thousand bbl/d in 2012 and by a further 230 thousand bbl/d in 2013. If the economic situation in European Union countries deteriorates, then global economic growth could fall below current expectations and result in reduced oil demand and lower prices. Slower growth in China could also curb demand. EIA currently projects annual increases in

consumption in China of about 0.4 million bbl/d in both 2012 and 2013. Recent economic indicators point to some weakness in China's economic outlook.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 0.8 million bbl/d in 2011. EIA expects consumption growth of 0.8 million bbl/d in 2012 and 1.1 million bbl/d in 2013, with China, the Middle East, Central and South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for essentially all consumption growth (World Liquid Fuels Consumption Chart). Projected OECD liquid fuels consumption declines by 0.4 million bbl/d in 2012. In 2013, forecast OECD liquid fuels consumption remains essentially flat, with consumption growth in the United States offsetting some of the decline in Europe.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 0.8 million bbl/d in 2012 and by a further 1.2 million bbl/d in 2013. The largest area of non-OPEC growth is North America, where production increases by 890 thousand bbl/d and 470 thousand bbl/d in 2012 and 2013, respectively, resulting from continued production growth from U.S. onshore shale and other tight oil formations and Canadian oil sands. In Brazil, output is projected to rise by 20 thousand bbl/d in 2012 and 120 thousand bbl/d in 2013, with increased output from its offshore, pre-salt oil fields. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field next year, will increase its total production by 160 thousand bbl/d in 2013. Forecast production also rises in China, Russia, and Colombia over the next two years, while production declines in Mexico and the North Sea.

Several notable disruptions to non-OPEC production continue to persist in Sudan and South Sudan, Yemen, Syria, and the North Sea; however, unplanned outages have since abated from their highest level of 1.3 million bbl/d in March 2012 to about 900 thousand bbl/d in May 2012. The reduction is largely due to the completion of unplanned maintenance on three of Canada's largest oil sands operations, although some planned maintenance is still underway. In the former Sudan, an unresolved dispute between Sudan and South Sudan over transit fees and other issues caused the latter to shut in all of its production at the end of January. In April, the dispute intensified as military clashes along the poorly defined border resulted in damages to the Heglig oil field. This led to the temporary shut-in of half of Sudan's remaining production of almost 110 thousand bbl/d for most of April, but the field is reported to be back online and operating at partial capacity. EIA projects that total production from Sudan and South Sudan, which averaged about 460 thousand bb/d in 2011, will average 130 thousand bbl/d in 2012 and recover to 360 thousand bbl/d in 2013 (*Sudan and South Sudan Country Analysis Brief*).

In Yemen and Syria, internal conflicts continue to compromise a considerable portion of each country's oil output. Yemen's production is still impaired by an ongoing outage to the Marib pipeline. EIA projects that Yemen's production will average 150 thousand bbl/d over the next two years, down from the country's pre-crisis production level of around 260 thousand bbl/d (*Yemen Country Analysis Brief*). EIA expects Syria, which is subject to sanctions on its crude oil

exports, to produce 240 thousand bbl/d in 2012 and 340 thousand bbl/d in 2013, below the country's pre-crisis production level of 400 thousand bbl/d.

OPEC Supply. EIA expects that OPEC members will continue to produce more than 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil demand and to counterbalance supply disruptions. Projected OPEC crude oil production increases by about 0.9 million bbl/d in 2012, and then falls by 0.5 million bbl/d in 2013, as non-OPEC supply growth increases and stocks remain flat. OPEC non-crude petroleum liquids (condensates, natural gas liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, averaged 5.3 million bbl/d in 2011 and are forecast to increase by 0.4 million bbl/d in 2012 and by 0.1 million bbl/d in 2013.

EIA expects Iran's crude oil production to fall by about 850 thousand bbl/d by the end of 2012, and by an additional 200 thousand bbl/d in 2013, from its previous output level of 3.55 million bbl/d at the end of 2011. Iran's output decline began to accelerate during the last quarter of 2011 and has continued. EIA believes that this acceleration reflects a lack of investment, which is needed to offset natural production declines. A number of foreign companies that were investing in Iran's upstream have halted their activities as a result of previous sanctions against Iran that have made it difficult to do business with the country. EIA expects that the forecast decline in Iran's output will be offset by increased production in other OPEC member countries.

EIA's forecast of market balances does not factor in any potential effects of the more recent sanctions targeting Iran's central bank and the impending European Union embargo on Iran's crude oil production, or their possible impact on the production, spare capacity, or inventories of Iran and other OPEC member countries. As noted in EIA's April 27, 2012 report, *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*, there are indications that U.S. and European Union sanctions are already affecting sales of Iranian crude oil. Current and continuing difficulties in placing export volumes from Iran could result in a buildup of Iranian oil in storage, whether onshore or offshore. An increase in Iranian crude oil storage would drive an increase in global oil inventories. However, insofar as inventories held by Iran are building due to the effect of sanctions on its ability to sell oil, those volumes would not be available to consumers in the same way as traditional inventories.

Moreover, if Iran's difficulties in finding markets for its oil outstrip available storage capacity, Iran may have to shut in production. EIA expects that any volumes that are shut in could be replaced by increased production from spare capacity held by other OPEC member countries. In such a scenario, the shut-in production capacity in Iran may technically be counted as new spare capacity, but—like inventories that accumulate for similar reasons—would not be readily available to alleviate market tightness in the same manner as regular spare capacity not forced by sanctions.

OPEC members serve as the swing producers in the world market because only OPEC producers possess surplus or spare oil production capacity, with most of this in Saudi Arabia. EIA projects

that OPEC surplus production capacity will average 2.5 million bbl/d in 2012 and rise to an average 3.4 million bbl/d in 2013 (OPEC Surplus Crude Oil Production Capacity Chart). However, as discussed above, markets may be closely watching the composition of OPEC spare capacity, as well as its aggregate level, as the situation with respect to Iran evolves. Under plausible circumstances, the market may discount a portion of OPEC members' aggregate spare capacity.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2011 at 2.59 billion barrels, equivalent to 55.9 days of forward-cover (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories increase to 2.65 billion barrels and 57.7 days of forward-cover by the end of 2012, which would be the highest end-of-year level in nearly 15 years, because of the decline in OECD consumption.

Crude Oil Prices. EIA has lowered the forecast 2012 average U.S. refiner acquisition cost of crude oil by almost $8 per barrel from last month's *Outlook* to $102 per barrel, the same as the 2011 average price. EIA expects the price of WTI crude oil to average about $97 per barrel in 2012, about $7 per barrel lower than last month's *Outlook*, but $2 per barrel higher than the 2011 average price. EIA expects crude oil prices to remain relatively flat in 2013, with WTI and the U.S. refiner acquisition cost of crude oil averaging about $97 per barrel and $102 per barrel, respectively (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for September 2012 delivery during the 5-day period ending June 7, 2012 averaged $85 per barrel. Implied volatility averaged 35 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 2012 at $63 per barrel and $115 per barrel, respectively. Last year at this time, WTI for September 2011 delivery averaged $102 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $78 per barrel and $134 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption fell 340 thousand bbl/d (1.8 percent) last year. Motor gasoline consumption accounted for the bulk of that decline, shrinking by 260 thousand bbl/d (2.9 percent). In 2012, total consumption falls by a more moderate 70 thousand bbl/d (0.4 percent). In the first quarter, total consumption fell 700 thousand bbl/d (3.7 percent) from the same period last year (U.S. Liquid Fuels Consumption Chart) as high prices and record warm weather depressed consumption. For the second half of 2012, EIA expects a year-over-year increase of 230 thousand bbl/d (1.2 percent) in liquid fuels consumption. The bulk of that increase comes from distillate fuel because of projected economic growth and near-normal winter weather.

In 2013, total liquid fuels consumption grows by 120 thousand bbl/d (0.6 percent). Despite assumed growth in U.S. real disposable income of 1.8 percent next year, forecast motor gasoline consumption declines by a further 30 thousand bbl/d (0.4 percent) in 2013. This projection reflects continued slow growth in the driving-age population, an acceleration of the improvement in average fuel economy of new vehicles, and increased rates of retirement of older vehicles. However, consumption of all of the other fuels categories rises, led by a 90-thousand-bbl/d (2.3-percent) increase in distillate fuel consumption.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 200 thousand bbl/d (3.6 percent) to 5.67 million bbl/d in 2011. Forecast U.S. total crude oil production increases to 6.32 million bbl/d in 2012, an upward revision of 150 thousand bbl/d from last month's *Outlook*, and the highest annual level of production since 1997. Forecast lower-48 onshore crude oil production grows by a robust 660 thousand bbl/d in 2012, GOM output stabilizes after having fallen last year, but Alaskan output continues to decline by 30 thousand bbl/d (U.S. Crude Oil and Liquid Fuels Production Chart). In 2013, total crude oil output rises a further 400 thousand bbl/d, most of which is accounted for by increases in lower-48 onshore production. The projected increases in lower-48 onshore production is driven by increased oil-directed drilling activity, particularly in onshore tight oil formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes has increased from 777 at the beginning of 2011 to 1,386 on June 1, 2012.

Based on the outlook from the National Oceanic and Atmospheric Administration for the current Atlantic hurricane season, EIA estimates a 70-percent probability that total shut-in crude oil production in the GOM during the upcoming hurricane season (June through November) will fall somewhere between 2.8 and 7.2 million barrels, with a median outcome of 4.5 million barrels (an average 25 thousand bbl/d over the 6 months). There is a wide range of uncertainty around this forecast (see the *2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). The bulk of outages are expected during the late summer and early fall months of August, September, and October.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and products) has been falling since peaking at over 60 percent in 2005, and averaged 45 percent in 2011, down from 49 percent in 2010. EIA expects that the total net import share of consumption will continue to decline to 42 percent in 2012 and to 40 percent in 2013 as a result of the substantial increases in domestic crude oil production.

U.S. Petroleum Product Prices. As a result of higher crude oil costs, monthly average regular-grade gasoline prices peaked at $3.90 per gallon in April 2012 compared with an average of $3.53 per gallon in 2011. Due to the sharp decline in crude oil prices throughout May, EIA expects the regular gasoline retail prices during the summer season (April through September) to average $3.60 per gallon in 2012, compared with $3.79 per gallon in last month's *Outlook*. EIA expects regular gasoline retail prices to average $3.56 per gallon in 2012 and $3.51 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged $3.84 per gallon in 2011, will average $3.90 per gallon in 2012, down 16 cents per gallon from last month's *Outlook*. In 2013, diesel fuel retail prices are projected to decline slightly to an average $3.87 per gallon (U.S. Diesel Fuel and Crude Oil Prices Chart).

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) will average 44 cents per gallon and 41 cents per gallon in 2012 and 2013, respectively, slightly higher than the previous 5-year average of 40 cents per gallon. In contrast, wholesale diesel margins are robust during the forecast interval due to strong world-wide demand for the fuel. In 2012, those margins average 63 cents per gallon, 2 cents higher than the 2011 average and higher than the previous 5-year average of 52 cents per gallon. The diesel wholesale margin for 2013 falls slightly, averaging 61 cents per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.5 billion cubic feet per day (Bcf/d) in 2012, an increase of 2.7 Bcf/d (4.1 percent) from 2011 and a downward revision of 0.7 Bcf/d from last month's *Outlook*. This month's *Outlook* revises downward the forecast for residential and commercial consumption to reflect a decline in total projected 2012 heating degree-days as reported by the National Oceanic and Atmospheric Administration. EIA expects that large gains in electric power use will offset declines in residential and commercial use.

Projected consumption of natural gas in the electric power sector grows by nearly 20 percent in 2012, primarily driven by the increased relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector peaks in the third quarter of 2012, at 30.2 Bcf/d, when electricity demand for air conditioning is highest. This compares with 27.7 Bcf/d during the third quarter of 2011.

Growth in total natural gas consumption slows in 2013, with forecast consumption averaging 71.3 Bcf/d (U.S. Natural Gas Consumption Chart). However, unlike 2012, growth in 2013 is driven by consumption increases from the residential, commercial, and industrial sectors. A forecast of closer-to-normal winter temperatures drives increases in residential and commercial consumption in 2013 of 7.4 percent and 5.7 percent, respectively. Power-sector gas burn remains at historically high levels with little change from 2012 levels.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by 4.8 Bcf/d (7.9 percent) in 2011. This strong growth was driven in large part by increases in shale gas production. While EIA expects year-over-year production growth to continue in 2012, the projected increases occur at a slower rate than in 2011, as low prices reduce new drilling plans

(U.S. Natural Gas Production and Imports Chart). According to Baker Hughes, the natural gas rig count was 588 as of June 1, 2012, down from a 2011 high of 936 in mid-October, making it the lowest rig count since 1999. EIA's production survey indicates natural gas marketed production fell by 0.25 Bcf/d from February 2012 to March 2012, and February 2012 production was revised downward from previous estimates. EIA expects mostly flat production through the fall, but overall 2012 production still averages 2.3 Bcf/d (3.4 percent) above 2011 levels. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale are offset by growth in production from liquids-rich natural gas production areas such as the Eagle Ford and wet areas of the Marcellus Shale, and associated gas from the growth in domestic crude oil production.

Based on the outlook from National Oceanic and Atmospheric Administration for the current Atlantic hurricane season, EIA estimates a 70-percent probability that total shut-in natural gas production in the GOM during the upcoming hurricane season (June through November) will fall somewhere between 5.8 and 16.2 Bcf, with a median outcome of 9.5 Bcf (an average of 0.05 Bcf/d over the 6 months). There is a wide range of uncertainty around this forecast (see the *2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). The bulk of outages are expected during the late summer and early fall months of August, September, and October.

EIA expects pipeline gross imports will fall by 0.4 Bcf/d (4.3 percent) in 2012, as domestic supply displaces Canadian sources. The warm winter in the United States also added to the year-over-year decline in imports, particularly to the Northeast, where imported natural gas can serve as additional supply in times of very cold weather. EIA expects pipeline gross imports will increase by 4.8 percent in 2013, partially due to near-normal winter weather driving higher residential and commercial demand. Additionally, EIA expects increased pipeline imports to help meet continued high demand for natural gas for electric power generation. Pipeline gross exports grew by 1.0 Bcf/d (33 percent) in 2011, driven by increased exports to Mexico, but are expected to remain flat in 2012 and grow by 0.2 Bcf/d in 2013.

Liquefied natural gas (LNG) imports are expected to fall by 0.3 Bcf/d (33 percent) in 2012. EIA expects that an average of less than 0.7 Bcf/d will arrive in the United States (mainly at the Everett LNG terminal in New England and the Elba Island terminal in Georgia) in 2012 and 2013, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions.

U.S. Natural Gas Inventories. Working natural gas inventories continue to remain at high levels, although the surplus relative to last year's level and the five-year average (2007-2011) level has eroded in the past month. As of June 1, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,877 Bcf, 713 Bcf greater than last year's level and 687 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will set a new record high at 4,015 Bcf (U.S. Working Natural Gas in Storage Chart), although the record will largely be due to high levels already present at the start of the injection season. The

projected increase of 1,538 Bcf in working gas inventory during the 2012 injection season (from the end of March to the end of October) would be the smallest build since 1991. Limits on storage capacity, as well as high demand from the electric power sector this summer, will limit the overall level of injections. In 2013, working inventory levels recede from record highs, although they will still remain robust compared with recent history.

U.S. Natural Gas Prices. Natural gas spot prices averaged $2.43 per MMBtu at the Henry Hub in May 2012, up $0.48 per MMBtu from the April 2012 average and the first average monthly increase in price in almost a year. Despite the increase, prices remain at historically low levels; the May 2012 price averaged 44 percent less than the May 2011 price. Abundant supplies and lack of demand during the warm winter contributed to the current low prices. EIA expects the Henry Hub natural gas price will average $2.55 per MMBtu in 2012, a small upward revision from the $2.45 per MMBtu average in last month's *Outlook*. EIA revised its forecast for 2013 up to $3.23 per MMBtu, from $3.17 per MMBtu in last month's *Outlook* (U.S. Natural Gas Prices Chart).

Natural gas futures prices for September 2012 delivery (for the 5-day period ending June 7, 2012) averaged $2.48 per MMBtu, and the average implied volatility based on options and futures prices was 53 percent (*Market Prices and Uncertainty Report*). Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for September 2012 contracts at $1.51 per MMBtu and $4.07 per MMBtu, respectively. At this time last year, the September 2011 natural gas futures contract averaged $4.64 per MMBtu and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.30 per MMBtu and $6.50 per MMBtu.

Coal

U.S. Coal Consumption. EIA forecasts that electric power sector coal consumption will average slightly more than 800 million short tons (MMst) in both 2012 and 2013 (U.S. Coal Consumption Chart). Lower electric power sector natural gas prices in 2011 contributed to a significant increase in the share of natural-gas-fired generation, and EIA expects this trend to continue in 2012. EIA expects that electric power sector coal consumption will increase slightly in 2013, as projected power industry coal prices fall (4 percent) and natural gas prices increase (18 percent).

U.S. Coal Supply. EIA forecasts that coal production will decline by 9 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production for the first four months of 2012 was 28 MMst (8 percent) below last year's value for the same period. EIA predicts that production will continue to decline in 2013, but at a slower rate (4 percent). Despite declines in production, EIA projects that secondary inventories will increase in 2012, with electric power sector stocks exceeding 200 MMst, and inventories will remain at elevated levels in 2013 (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong but fall below the 107 MMst exported in 2011. Forecast U.S. coal exports are 106 MMst in 2012 and 97 MMst in 2013. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

U.S. Coal Prices. Delivered coal prices to the electric power industry had increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of $2.40 per MMBtu (a 6-percent increase from 2010). However, EIA expects the decline in demand for coal to generate electricity will put downward pressure on coal prices and contribute to the shut-in of higher-cost production. EIA forecasts the average delivered coal price in 2012 will be nearly 3 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be $2.25 per MMBtu, or 4 percent lower than the 2012 price.

Electricity

U.S. Electricity Consumption. Cooling-degree-days during the summer of 2011 (the second and third quarters) were nearly 22 percent higher than the 30-year normal. The National Oceanic and Atmospheric Administration projects temperatures this summer should again be above normal, but 14 percent lower than last year's level. This reduced need for summer cooling contributes to EIA's projection of a 3.7-percent decline in residential electricity sales in 2012. EIA expects total consumption of electricity to fall by 1.0 percent during 2012, and then grow by 1.9 percent in 2013 (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. The share of generation fueled by coal in the U.S. has declined dramatically in recent months. Coal's share of total power generation first fell below 40 percent in November of last year and averaged 36 percent during the first quarter of 2012, compared with an average of almost 45 percent during the same period last year. Much of this reduction has resulted from the decreased utilization of existing coal-fired capacity, including some capacity that is scheduled to be retired during the next few years. The reduction in coal generation has been offset by increased utilization of natural gas combined cycle plants. EIA expects that the higher natural gas costs projected later in 2012 and in 2013, along with record coal stocks, will encourage generators to increase their utilization of coal-fired power plants somewhat next year. After a projected decline of 13 percent in 2012, EIA forecasts total generation by coal across all sectors to rise by 3 percent in 2013. In contrast, total generation by natural gas is forecast to rise 22 percent this year and then rise by less than 1 percent in 2013 (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. EIA expects the average U.S. residential electricity price to rise from an average of 11.79 cents per kilowatthour in 2011 to 11.93 cents per kilowatthour this year, an increase of 1.2 percent (U.S. Residential Electricity Prices Chart). The projected decline in generation fuel costs during 2012, including a 33-percent decline in the cost of natural gas delivered to electric generators, should lead to a 2.8-percent drop in residential retail prices

next year as a result of the regulatory lags in passing through changing generation fuel costs to consumers.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 14 percent in 2011, total renewable energy supply is projected to decline by 1.1 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of hydropower resource levels beginning a return to the long-term average, with supply falling by 0.3 quadrillion Btu (10 percent). The decline in hydropower from the 2011 level more than offsets growth in other renewable energy supplies. Renewables supply remains flat in 2013 as hydropower continues to decline (6.3 percent) and offsets non-hydropower renewables growth of 3.3 percent.

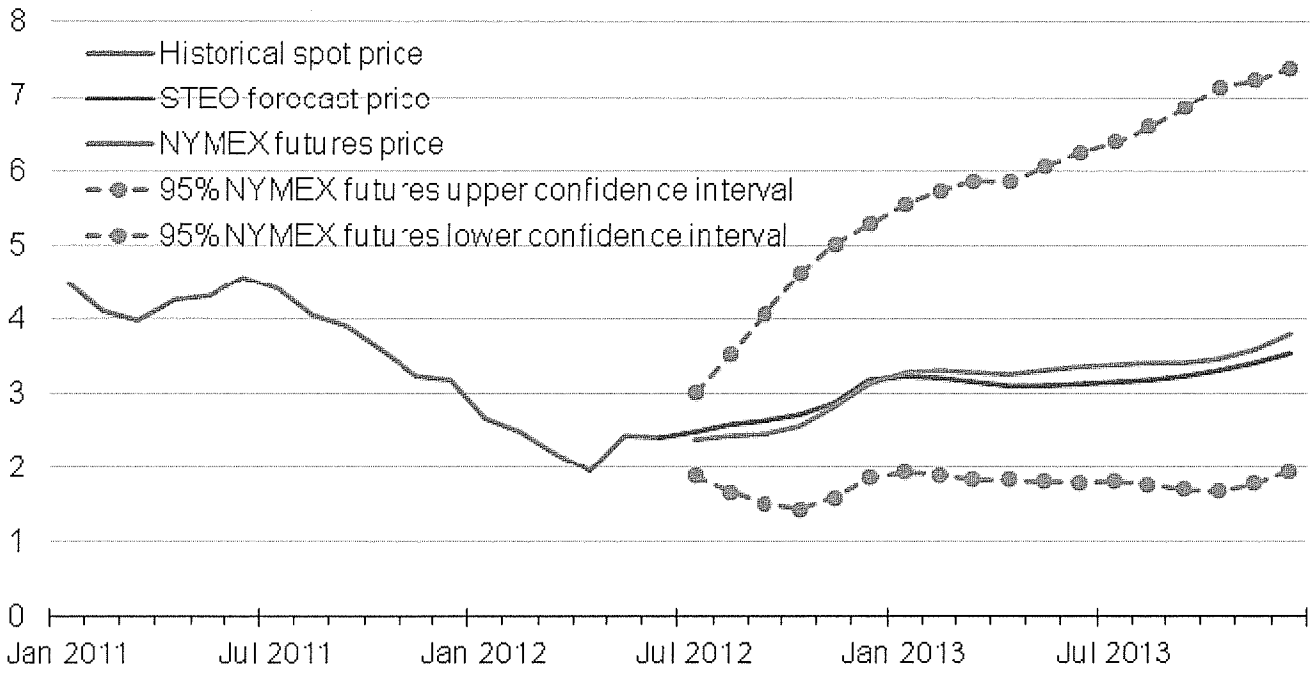
Under current law, federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 16 percent in 2012 and 6 percent in 2013. Despite the expiration of production tax credits, wind capacity is projected to grow by 3.7 percent in 2013, based on generators' capacity construction plans reported to EIA.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to remain steady from 2011 through 2012, averaging about 910 thousand bbl/d and increasing only slightly to 920 thousand bbl/d in 2013. This forecast assumes that E15 (gasoline blended with 15 percent ethanol by volume) does not yet reach the market in significant volumes. Consequently, U.S. ethanol production is projected to exceed the volume that can easily be used in the U.S. liquid fuels pool, so the Nation will continue to be a net exporter of ethanol over the next two years. EIA estimates that biodiesel production in 2011 averaged about 63 thousand bbl/d (971 million gallons of total annual production). Forecast biodiesel production averages 70 thousand bbl/d in 2012, and 75 thousand bbl/d in 2013.

U.S. Energy-Related Carbon Dioxide Emissions. After declining by 2.4 percent in 2011, fossil fuel emissions are projected to further decline by 2.5 percent in 2012, but increase by 1.3 percent in 2013. Petroleum emissions decline slightly in 2012 (0.4 percent) and then rise by 0.5 percent in 2013, while natural gas emissions rise by 4.6 percent and 2.4 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 10 percent, but rise by 1.6 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

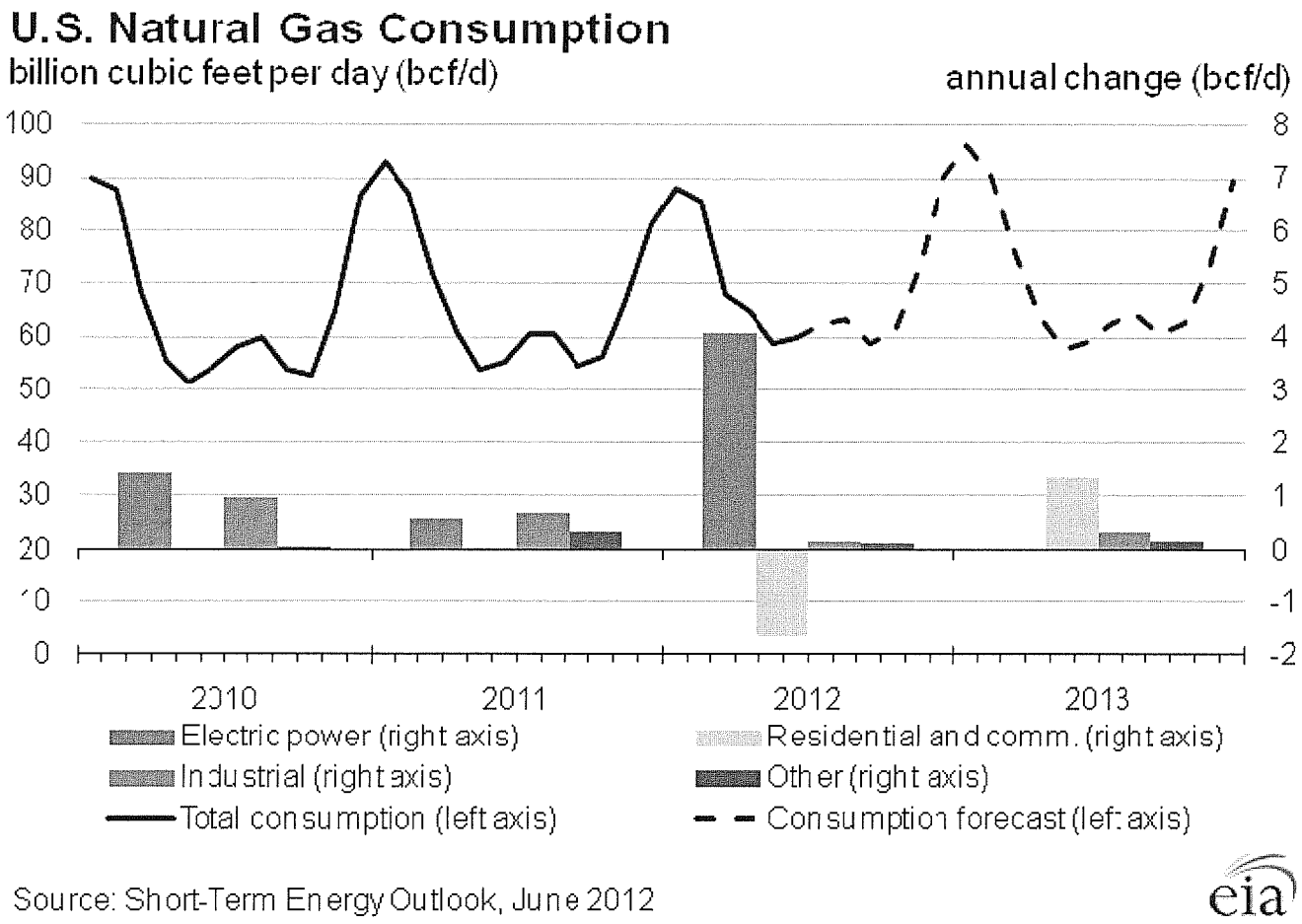
dollars per million btu



Note: Confidence interval derived from options market information for the 5 trading days ending June 7, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, June 2012

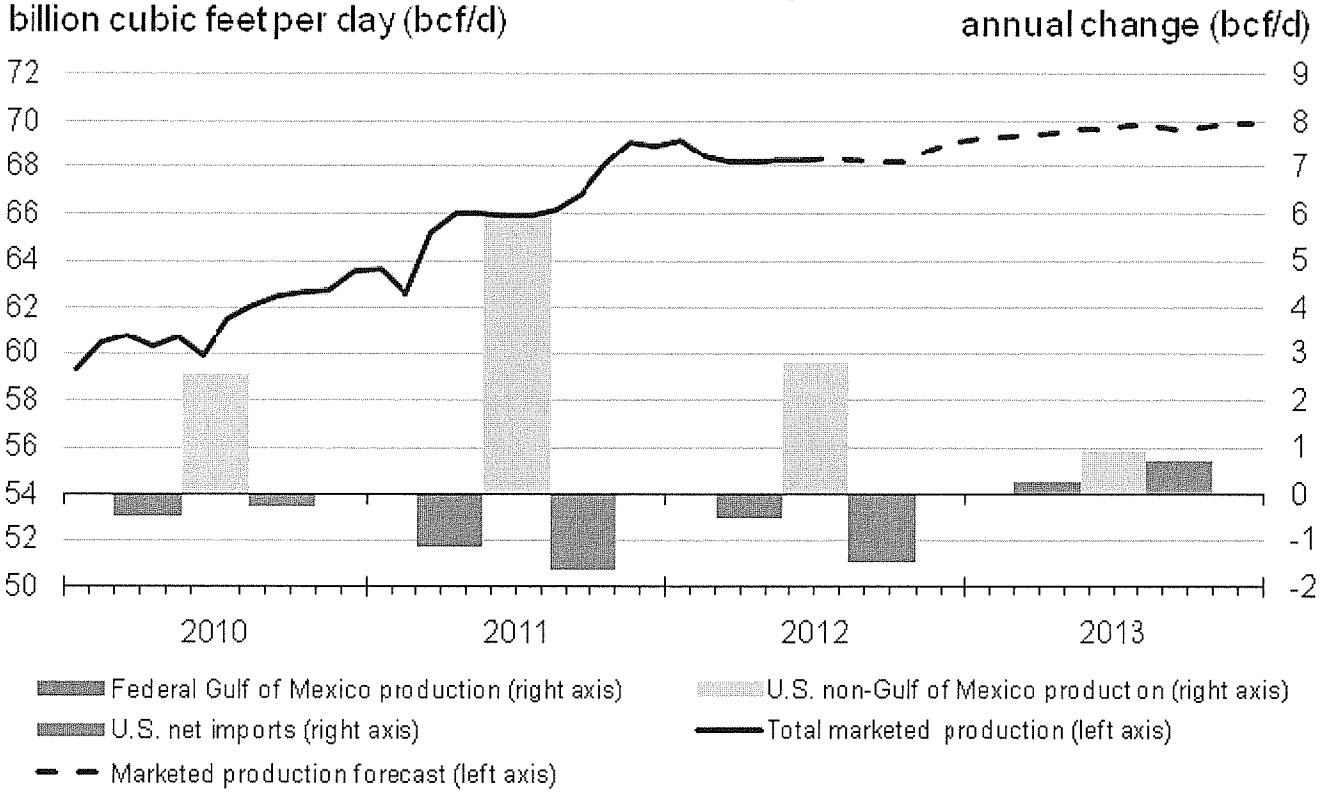
eia



Source: Short-Term Energy Outlook, June 2012

eia

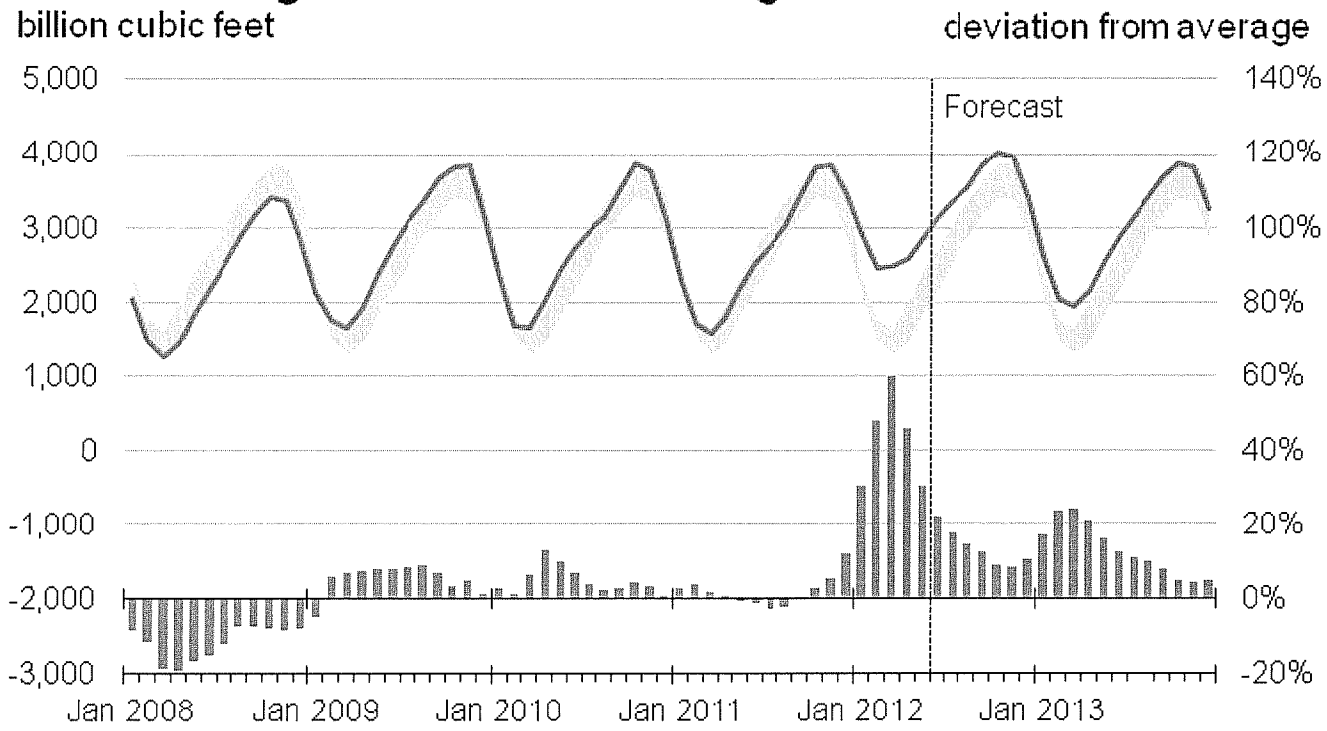
U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, June 2012

eia

U.S. Working Natural Gas in Storage



Note: Co ored band arourd storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, June 2012

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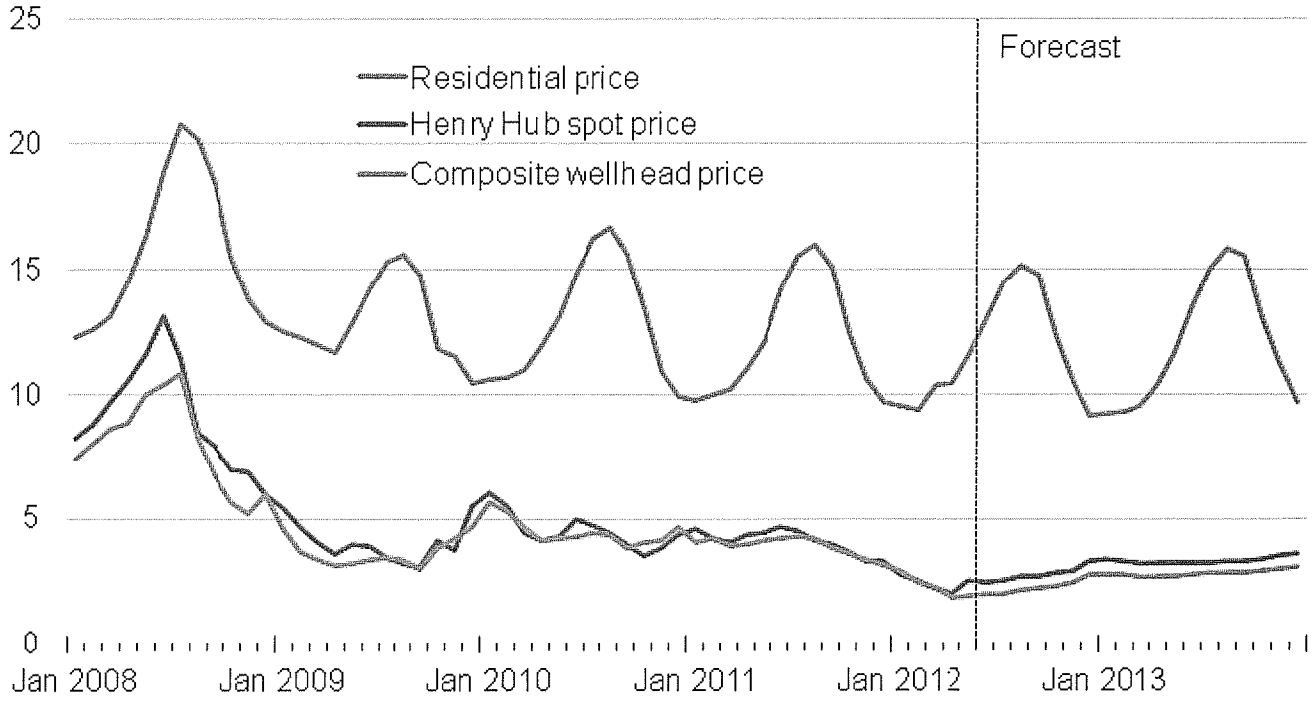
U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, June 2012

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2012									**$311,764**
May	$30,099	$0	$2,016	$32,115	13,138	$0.5102	$6,702	$25,413	337,177
Balance @ May 31, 2012									**$337,177**

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
Balance @ April 30, 2012									**($72,396)**
May	($11,426)	$0	($557)	($11,983)	23,670	($0.0178)	($422)	($11,561)	(83,957)
Balance @ May 31, 2012									**($83,957)**

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