



A Division of MDU Resources Group, Inc.

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July 31, 2012

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

Re: Cost of Gas Adjustment (COG)  
August 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 (77<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (77<sup>th</sup> Revised Sheet No. 8), showing the August 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.3483 per mcf for residential and firm general service customers and an increase of \$0.4047 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.4047 since the last COG filing. There has been a decrease in pipeline charges of \$0.0564 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.3483 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**

**Attachment A**

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# GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

## State of North Dakota Gas Rate Schedule

NDPSC Volume 2

77th Revised Sheet No. 1.1

Canceling 76th Revised Sheet No.1.1

### RATE SUMMARY SHEET

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	\$7.2795	\$8.5535 8.3335
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$7.2795	\$9.4535 9.2335
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	\$2.1663	\$3.3054 3.0594 2.9074
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	\$2.1663	\$4.2054 3.9594 3.8074
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$2.1663	\$3.4054
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 31, 2012

Effective Date: August 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  
77<sup>th</sup> Revised Sheet No. 8  
Canceling 76<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.	3.8134	(3.0808)	1.0137	1.7463	(3.0660)	(0.2915)	(3.3575)
Current Adj.	(0.0564)	0.4047	0.0000	0.3483	0.4047	0.0000	0.4047
Total Adj.	3.7570	(2.6761)	1.0137	2.0946	(2.6613)	(0.2915)	(2.9528)
Total Rate:	\$3.8228	\$2.4430	\$1.0137	\$7.2795	\$2.4578	(\$0.2915)	\$2.1663

**Date Filed:** July 31, 2012

**Effective Date:** Service rendered on and  
after August 1, 2012

**Issued By:** Tamie A. Aberle  
Regulatory Affairs Manager

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
AUGUST 2012**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
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	14.5578	12	1,388,290	0.9919
Trans Canada - Demand Charge	7,947	22.8007	12	2,174,366	1.5535
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0655
NOVA - Seasonal	5,068	14.5578	5	368,895	0.2636
Trans Canada - Seasonal	5,068	22.8007	5	577,770	0.4128
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	0.0148
Total Demand Charges				\$5,329,724	3.8228
Estimated Weighted Average Commodity Cost	1,399,684	1/ 2.4430		3,419,428	2.4430
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				\$8,749,152	7.2795
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.0946
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.4430
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					2.1663
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$2.9528)

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.

	<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	\$0.0148

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
AUGUST 2012**

<b>Rates Effective August 1, 2012</b>	<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 Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	14.5578	Per dk/Mo.
Trans Canada Pipeline Demand Charge	22.8007	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	14.5578	Per dk/Day
Trans Canada - Seasonal	22.8007	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:	2.4430	Per dk

**Base Rate Effective September 1, 1981**

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

**Base Rate Calculation**

<u>Firm</u>		
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
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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/
<b>Commodity Rates</b>				
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

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO- FIELD/MARKET DEMARCATIION
	TF12			TFF
	TF12 Base	Variable	TF5	
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	Receipt Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
	Market	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
	Field	0.0378	0.0209	0.0122	0.0040	0.0175	0.0000		
	Market			0.0122	0.0040				
	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		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	0.0378	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/		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 \$0.0001 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

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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

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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

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Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/

Rate Schedule SMS

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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  
August 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 August monthly price for the AECO Index is expected to increase from 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).

Commodity prices have risen due to higher demand for gas resulting from unseasonably warm temperatures across the country and an increase in gas-fired electric generation. This has also resulted in below average storage injections, reducing the above average gas levels for both the five year and prior year comparisons. The Energy Information Administration (EIA) reported storage levels nationwide as of July 20, 2012 were 15.8 percent above the five-year average and 18.0 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 16.



Independent Statistics & Analysis

U.S. Energy Information  
Administration

July 2012

## Short-Term Energy Outlook

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### Highlights

- EIA projects the West Texas Intermediate (WTI) crude oil spot price to average about \$88 per barrel over the second half of 2012 and the U.S. refiner acquisition cost (RAC) of crude oil to average \$93 per barrel, both about \$7 per barrel lower than last month's *Outlook*. EIA expects WTI and RAC crude oil prices to remain roughly at these second half levels in 2013. Beginning in this month's *Outlook*, EIA is also providing a forecast of Brent crude oil spot prices (see [Brent Crude Oil Spot Price Added to Forecast](#)), which are expected to average \$106 per barrel for 2012 and \$98 per barrel in 2013. These price forecasts assume that world oil-consumption-weighted real gross domestic product (GDP) grows by 2.9 percent in both 2012 and 2013.
- With crude oil prices falling over the last month, EIA has lowered the average regular gasoline retail price forecast for the third quarter of 2012 to \$3.39 per gallon. EIA expects regular gasoline retail prices, which averaged \$3.53 per gallon in 2011, to average \$3.49 per gallon in 2012 and \$3.28 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 June 2012 at an estimated 3.1 trillion cubic feet (Tcf), about 23 percent above the same time last year. EIA expects the Henry Hub natural gas spot price, which averaged \$4.00 per million British thermal units (MMBtu) in 2011, to average \$2.58 per MMBtu in 2012 and \$3.22 per MMBtu in 2013.
- In April 2012, the United States exported 12.5 million short tons of coal, which is a monthly record based on EIA data dating back to 1973. Although EIA projects coal exports to total 112 million tons in 2012, 4.6 percent higher than 2011, EIA expects that coal exports will fall by 15.5 million short tons (14 percent) in 2013.

## Global Crude Oil and Liquid Fuels

**Global Crude Oil and Liquid Fuels Overview.** The projected pace of global oil demand growth in this month's *Outlook* reflects less optimistic assumptions about the global economy. The forecast for global economic growth was lowered by 0.1 and 0.6 percentage points in 2012 and 2013, respectively, from last month's *Outlook*, and is now expected to average 2.9 percent in both years. The weaker growth outlook is prompted by increased economic concerns about the debt crisis in Europe and indications of slowing growth in China, both which could have spillover effects on other economies. The global liquid fuels consumption growth forecast for 2012 was lowered to 0.7 million bbl/d from 0.8 million bbl/d in last month's *Outlook*. Projected global consumption growth in 2013 was lowered by 0.4 million bb/d to 0.7 million bbl/d.

EIA recently released its recurring 60-day report on *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*. As noted in the report, oil markets have loosened over the last several months, which is reflected in a sharp decline in crude oil prices and backwardation since the end of April. EIA's historical supply and demand balance also shows signs of a looser market, as supply outpaced consumption by an average of 1.1 million bbl/d for the first half of 2012, and stocks built counter-seasonally during the first quarter – a marked contrast to significant stock draws during 2011.

EIA's downward price revisions reflect shifts in expectations about oil market balances and the additional downside risks that are currently dominating market sentiments. However, there are both upside and downside uncertainties. The possibility that the economic situation in European Union (EU) countries could deteriorate further poses a downside risk to global oil demand and prices, though the market's positive reaction to recent EU negotiations serves as a reminder that oil prices will fluctuate in both directions as perceptions about the likelihood of a deeper crisis evolve. In the current *Outlook*, consumption in Europe is expected to fall year-over-year by 0.3 million bbl/d in 2012 and by a further 0.4 million bbl/d in 2013. The prospect of slower growth in China, which has been a key driver of increased oil demand in recent years, could also curb demand. China's weakening exports, particularly to Europe, and slower industrial and domestic growth experienced in the first half of 2012 could continue to place downward pressure on oil prices. EIA currently projects annual increases in consumption in China of about 0.4 million bbl/d in both 2012 and 2013. On the supply side, 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.

EU sanctions, including an embargo on Iranian crude and an insurance ban on tankers carrying Iranian oil, became fully effective on July 1, shortly after the latest set of U.S. sanctions entered into force. The United States issued exceptions to all major importers of Iranian oil from sanctions that could have been imposed on foreign financial institutions which facilitated oil-related transactions with the Central Bank of Iran, but only after they had demonstrated or pledged significant reductions in their purchases of Iranian crude oil. The complete market effects of these sanctions are unknown and difficult to disentangle from previous rounds of sanctions, but EIA believes that most of their current and expected effects on Iranian oil supplies

have already been priced into the global oil market. Despite the market's mild reaction to the sanction start dates, upside price risks still persist, particularly if negotiations with Iran fail to progress.

**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 0.7 million bbl/d in both 2012 and 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 0.5 million bbl/d in 2012 and a further 0.3 million bbl/d in 2013.

In the third quarter of 2012, world demand will reach its seasonal peak, reflecting both the U.S. driving season and increased oil use for electricity generation in the Middle East. Projected consumption exceeds production by 0.7 million bbl/d, leading to global stock draws. Given overall lower demand expectations, the impact of seasonality on the tightness of global oil markets is expected to be substantially less than in 2010 or 2011, when third-quarter consumption outpaced supply by 1.5 million bbl/d and 1.8 million bbl/d, respectively.

**Non-OPEC Supply.** EIA expects crude oil and liquid fuels production by non-Organization of the Petroleum Exporting Countries (OPEC) to rise by 0.8 million bbl/d in 2012, and by a further 1.3 million bbl/d in 2013. The largest area of non-OPEC growth is North America, where production increases by 880 thousand bbl/d and 540 thousand bbl/d in 2012 and 2013, respectively, resulting from continued production growth from U.S. onshore shale and other tight oil formations and from Canadian oil sands. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field next year, will increase its total production by 170 thousand bbl/d in 2013. In Brazil, output is projected to rise by 120 thousand bbl/d in 2013, with increased output from its offshore, pre-salt oil fields. 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 commenced or intensified since the beginning of this year, as discussed in the June 26, 2012 report on [\*The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran\*](#). Unplanned outages to non-OPEC production totaled around 1.0 million bbl/d in June 2012, higher than the estimate given in the June 26th report. The increase is due to an offshore workers' strike in Norway that affected 230 to 250 thousand bbl/d of crude oil and natural gas liquids production, according to Statoil. On July 9, Norway's government ordered mandatory arbitration and an end to the strike, forestalling a threatened lockout that could have impacted all of Norway's offshore production.

Unplanned disruptions also rose slightly in the second half of June due to a labor protest in Argentina that lowered production from the Cerro Dragon oil field, which has a capacity of 100

thousand bbl/d. The field's operator is gradually ramping up production at the field as protestors have mostly withdrawn from the area.

**OPEC Supply.** EIA expects that OPEC members will continue to produce about 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil consumption and to counterbalance supply disruptions. Projected OPEC crude oil production increases by about 0.8 million bbl/d in 2012, and then falls by 0.9 million bbl/d in 2013, as non-OPEC supply growth increases and stocks rise slightly. OPEC non-crude oil liquids (condensates, natural gas liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, averaged 5.5 million bbl/d in 2011 and are forecast to increase by 0.3 million bbl/d in 2012 and less than 0.1 million bbl/d in 2013.

EIA expects Iran's crude oil production to fall by about 1 million bbl/d by the end of 2012 relative to an estimated output level of 3.6 million bbl/d at the end of 2011, and by an additional 200 thousand bbl/d in 2013. Iran's output decline has continued to accelerate since the fourth quarter of 2011. EIA believes that this acceleration reflects erosion in Iran's crude oil production capacity due to the country's inability to carry out investment projects that are necessary to offset the natural decline in production from existing wells, as well as the impact of lower Iranian crude oil exports due to recently enforced EU and U.S. sanctions. A number of foreign companies that were investing in Iran's upstream have halted their activities as a result of previous U.S. sanctions, which have been compounded by tighter measures enforced since the start of this year that have made it increasingly difficult to do business with the country. EIA expects that the forecast decline in Iran's output will be offset by increased production from other OPEC member countries.

The impacts of newly imposed EU and U.S. sanctions on supplies and exports of Iranian oil are not easily extricated from the effects of sanctions enacted in previous years, the more general decline in Iran's production capacity, and other oil market developments. Undoubtedly, the EU embargo eliminates a significant market for Iranian oil. U.S. financial sanctions and EU insurance provisions have also impeded other countries' transactions for Iranian oil, leading to reports that Iran's ability to produce oil has outstripped its ability to sell it. Until recently, Iran could react to lower demand for its oil by adjusting the amount of oil it uses domestically or holds in onshore and offshore storage, in order to temporarily maintain relatively normal, albeit declining, levels of production. However, EIA estimates that Iranian production fell faster than the prevailing trend in June as unsold or undelivered Iran cargoes tested the limits of available storage capacity and some combination of production shut-ins, greater-than-anticipated declines in production capacity, or overdue maintenance occurred. EIA bases this assessment on preliminary commercial data on tanker liftings from Iran, press reports, official Iranian statements, and other relevant information. However, this tentative interpretation of a very fluid situation could change as data are revised, independent estimates of Iranian production are issued, and more details about Iranian storage levels, refinery utilization, and domestic consumption emerge.

OPEC members serve as the swing producers in the world market because only OPEC producers possess surplus or spare oil production capacity, most of which is in Saudi Arabia. EIA projects that OPEC surplus production capacity will average 2.4 million bbl/d in 2012 and rise to an average 3.6 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 2.63 billion barrels and 57.3 days of forward-cover by the end of 2012, which is among the highest end-of-year levels in the last decade, because of the decline in OECD consumption.

**Crude Oil Prices.** Beginning in this month's *Outlook*, EIA is providing a forecast of Brent crude oil spot prices (see [Brent Crude Oil Spot Price Added to Forecast](#)). After WTI and Brent fell to year-to-date lows of \$78 per barrel and \$89 per barrel, respectively, on June 21, 2012, oil prices rose following news of a possible Euro-zone agreement regarding debt issues that have clouded the European and global economic outlooks. EIA projects the price of Brent crude oil to average \$106 per barrel in 2012 and \$98 per barrel in 2013. The WTI price forecast has been lowered by \$4 per barrel from last month's *Outlook* to \$93 per barrel in 2012 and by \$9 per barrel to \$89 per barrel in 2013 (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain ([Market Prices and Uncertainty Report](#)). WTI futures for October 2012 delivery during the 5-day period ending July 5, 2012 averaged \$85 per barrel. Implied volatility averaged 33 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in October 2012 at \$64 per barrel and \$114 per barrel, respectively. Last year at this time, WTI for October 2011 delivery averaged \$98 per barrel and implied volatility averaged 28 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$76 per barrel and \$125 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 further 150 thousand bbl/d (0.8 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 retail pump prices and increases in fleet-wide fuel efficiency depressed consumption of motor gasoline. In addition, record warm weather and low natural gas prices substantially reduced consumption of heating oil and residual fuel oil. The second quarter witnessed an estimated year-over-year decline of 200 thousand bbl/d due primarily to continued declines in distillate fuel oil and residual fuel oil

consumption. For the second half of 2012, EIA expects a turnaround in liquid fuels consumption with a projected year-over-year increase of 140 thousand bbl/d (0.7 percent). The bulk of that growth comes from natural gas liquids and distillate fuel, which rise because of continued growth in industrial production and the assumption of near-normal weather next winter. Motor gasoline consumption, however, remains unchanged from the same period last year as continued efficiency increases offset modest growth in highway travel. Residual fuel consumption levels off, albeit at close to record-low levels.

In 2013, total liquid fuels consumption grows by just 70 thousand bbl/d (0.4 percent), led by a 60-thousand-bbl/d (1.7-percent) increase in distillate consumption. Despite assumed growth in U.S. real disposable income of 1.8 percent next year, forecast motor gasoline consumption declines by a further 40 thousand bbl/d (0.5 percent) in 2013. This projection reflects continued slow growth in the driving-age population, the acceleration of improvements in the average fuel economy of new vehicles, and increased rates of retirement of older, less fuel-efficient vehicles.

**U.S. Liquid Fuels Supply and Imports.** Domestic crude oil production increased by an estimated 200 thousand bbl/d (3.7 percent) to 5.7 million bbl/d in 2011. Forecast U.S. total crude oil production increases to 6.3 million bbl/d in 2012, 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; output in the Gulf of Mexico (GOM) 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 410 thousand bbl/d, most of which is accounted for by increases in lower-48 onshore production. That increase 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 1,419 on July 6, 2012.

Based on the outlook from the National Oceanic and Atmospheric Administration for the current Atlantic hurricane season, EIA statistical analysis based on a historical averages derives a 70-percent probability that total shut-in crude oil production in the GOM during the current 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; see the [2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). In late June, Tropical Storm Debby caused several days of disruption to crude oil and natural gas production. During the peak of Debby-related outages, 600 thousand bbl/d was shut in, or about 44 percent of normal production. Almost all shut-in production resumed after a few days with a total production outage of about 1.3 million barrels.

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 41 percent in 2012 and to 39 percent in 2013 as a result of lower consumption and the substantial increases in domestic crude oil production. If the 2013

estimate holds true, it would be the first time the share of total U.S. consumption met by total liquid fuel imports is less than 40 percent since 1991.

**U.S. Petroleum Product Prices.** After a sharp increase in gasoline prices earlier this year, reaching a monthly average of \$3.90 per gallon in April 2012, gasoline prices have fallen for the second consecutive month, averaging \$3.54 per gallon in June 2012. Due to the sharp decline in crude oil prices throughout May and June, EIA expects regular gasoline retail prices to average \$3.39 per gallon during the third quarter of 2012, compared with \$3.51 per gallon in last month's *Outlook*, and \$3.63 per gallon during the same period last year. EIA projects that crude oil prices will remain near their current lower levels through 2013, resulting in regular gasoline retail prices averaging \$3.49 per gallon in 2012 and \$3.28 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.79 per gallon in 2012, down 11 cents per gallon from last month's *Outlook*. In 2013, diesel fuel retail prices are projected to decline another 21 cents to an average of \$3.58 per gallon (U.S. Diesel Fuel and Crude Oil Prices Chart).

## Natural Gas

**U.S. Natural Gas Consumption.** EIA expects that natural gas consumption will average 69.9 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.3 Bcf/d (4.9 percent) from 2011 and an upward revision of 0.5 Bcf/d from last month's *Outlook*. EIA expects that large gains in electric power use in 2012 will more than offset declines in residential and commercial use.

Projected consumption of natural gas in the electric power sector grows by 21 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 at 31.2 Bcf/d in the third quarter of 2012, 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 71.1 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 near-normal weather next winter drives 2013 increases in residential and commercial consumption of 7.7 percent and 4.5 percent, respectively. Although projected natural gas burn in the electric power sector declines by 1.9 percent from 2012, it remains at historically high levels in 2013.

**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. EIA expects continued year-over-year growth in 2012, though not as strong as the previous year (U.S. Natural Gas Production and Imports Chart). This month's *Outlook* revises

upward the forecast for marketed production for 2012, partially reflecting upward revisions to historical data for the first few months of the year. EIA, however, expects a small drop in production in the coming months, reflecting the decline in rigs since October 2011. According to Baker Hughes, the natural gas rig count was 542 as of July 6, 2012, up slightly from last week, which was the lowest rig count since 1999. EIA's production survey indicates natural gas marketed production fell between February and March 2012, but rebounded in April. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale is 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; see the [2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). In late June, Tropical Storm Debby caused several days of disruption to crude oil and natural gas production. During the peak of Debby-related outages, 1.6 Bcf/d of natural gas was shut in, or about 35 percent of normal production. Almost all shut-in production resumed after a few days with a total production outage of about 3.9 Bcf.

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.6 percent) in 2012, as domestic supply continues to displace 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 2.2 percent in 2013, partially due to near-normal winter weather driving higher residential and commercial demand. 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 0.4 Bcf/d (44 percent) in 2012. EIA expects that an average of about 0.6 Bcf/d will arrive in the United States (mainly at 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 remain at historically high levels for the time of year. As of June 29, 2012, according to EIA's [Weekly Natural Gas Storage Report](#), working inventories totaled 3,102 Bcf, 602 Bcf greater than last year's level and 573 Bcf above the five-year average. The weekly report from June 15, 2012, marked the first time in EIA's history that working inventories surpassed the 3,000 Bcf mark during the month of June. EIA expects that inventory levels at the end of October 2012 will set a new record high slightly above 4,000 Bcf (U.S. Working Natural Gas in Storage Chart), although the projected increase of 1,525 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. In 2013, working inventory levels recede from record highs, although they will still remain abundant compared with recent history.

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$2.47 per MMBtu at the Henry Hub in June 2012, up \$0.04 per MMBtu from the May average. Prices remain at historically low levels; the June 2012 price averaged 46 percent less than the June 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 \$2.58 per MMBtu in 2012, with modest monthly increases through the rest of the year. EIA expects 2013 prices will average \$3.22 per MMBtu (U.S. Natural Gas Prices Chart).

Natural gas futures prices for October 2012 delivery (for the 5-day period ending July 5, 2012) averaged \$2.90 per MMBtu, and the average implied volatility based on options and futures prices was 55 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 October 2012 contracts at \$1.74 per MMBtu and \$4.82 per MMBtu, respectively. At this time last year, the October 2011 natural gas futures contract averaged \$4.33 per MMBtu and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.12 per MMBtu and \$6.00 per MMBtu.

## Coal

**U.S. Coal Consumption.** Power-sector coal consumption fell from 975 million short tons (MMst) in 2010 to 929 MMst in 2011 (U.S. Coal Consumption Chart). Lower electric power sector natural gas prices have led to a significant increase in the share of natural-gas-fired generation in both 2011 and 2012. EIA expects coal consumption in the electric power sector to total slightly less than 800 MMst in 2012. Although EIA expects the price of natural gas relative to the price of coal at electric utilities to begin to show year-over-year increases beginning in early 2013, projected power sector coal consumption remains flat next year.

**U.S. Coal Supply.** EIA forecasts that coal production will decline by 9 percent in 2012 as domestic consumption falls (U.S. Coal Production Chart). Production for the first five months of 2012 was 25 MMst (6 percent) below last year's level for the same period. EIA predicts that production will continue to decline in 2013, but at a slightly slower rate (6 percent). Despite declines in production, EIA projects that secondary inventories will increase in 2012, reaching near-record levels. Electric power sector stocks are forecast to be 200 MMst by the end of the year (estimated stocks for April 2012 were 203 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 in 2012 and exceed the 107 MMst exported in 2011. The U.S. exported 12.5 MMst of coal in April, which is a monthly record based on EIA data dating back to 1973. Although EIA projects coal exports to total 112 million tons in 2012, forecast coal exports weaken slightly with year-over-year declines beginning in the fourth quarter of 2012. Major reasons for the export decline include China's economic slowdown and high coal stockpiles, and increased exports from Indonesia and Australia. EIA expects that coal exports will fall by 16 million short tons (14 percent) 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, combined with the large coal inventories, 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 0.4 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be \$2.33 per MMBtu, or nearly 3 percent (\$0.06) lower than the 2012 price.

## Electricity

**U.S. Electricity Consumption.** This year's summer season has started out with abnormally hot temperatures. According to the National Oceanic and Atmospheric Administration, U.S. cooling degree-days during June 2012 were about 14 percent higher than the 30-year average, but 4 percent lower than June 2011. EIA expects that temperatures during the third quarter of 2012, although above normal, will average about 16 percent lower than last year. This reduced need for summer cooling contributes to EIA's projection of a 3.8-percent decline in residential electricity sales in 2012. EIA expects total consumption of electricity to fall by 1.3 percent during 2012, and then grow by 1.3 percent in 2013 (U.S. Total Electricity Consumption Chart).

**U.S. Electricity Generation.** For the first time since EIA began compiling monthly statistics, the share of total generation fueled by natural gas during April 2012 rose to the point where it was nearly equal to the share fueled by coal (about 32 percent for each). However, this situation is likely temporary. The year-over-year gains in the share of generation fueled by natural gas should slow and eventually reverse as the higher natural gas costs projected for later in 2012 and in 2013, along with record coal stocks, encourage generators to increase their utilization of coal-fired power plants over the forecast horizon. EIA forecasts total generation by coal across all sectors will decline by 14 percent in 2012, followed by an increase of 1.3 percent in 2013. In contrast, total generation by natural gas is forecast to rise by 23 percent this year and then decline by 1.0 percent next year (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 12.03 cents per kilowatthour this

year, an increase of 2.0 percent (U.S. Residential Electricity Prices Chart). The forecast cost of natural gas delivered to the electric power sector is about 30 percent lower in 2012 compared with the previous year, which should slow the growth in retail electricity rates. EIA projects U.S. residential retail electricity prices to rise by only 0.2 percent in 2013, which would be the slowest growth rate in nominal prices in 10 years.

## Renewables and Carbon Dioxide Emissions

**U.S. Renewables.** After growing by 14 percent in 2011, total renewable energy supply is projected to decline by 1.3 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of hydropower resource levels beginning to return to the long-term average, with supply falling by 0.3 quadrillion Btu (11 percent). The decline in hydropower from the 2011 level more than offsets growth in other renewable energy supplies. Renewable energy supply increases slightly (0.5 percent) in 2013 as hydropower continues to decline (5.9 percent) but non-hydropower renewables grow by an average of 3.8 percent.

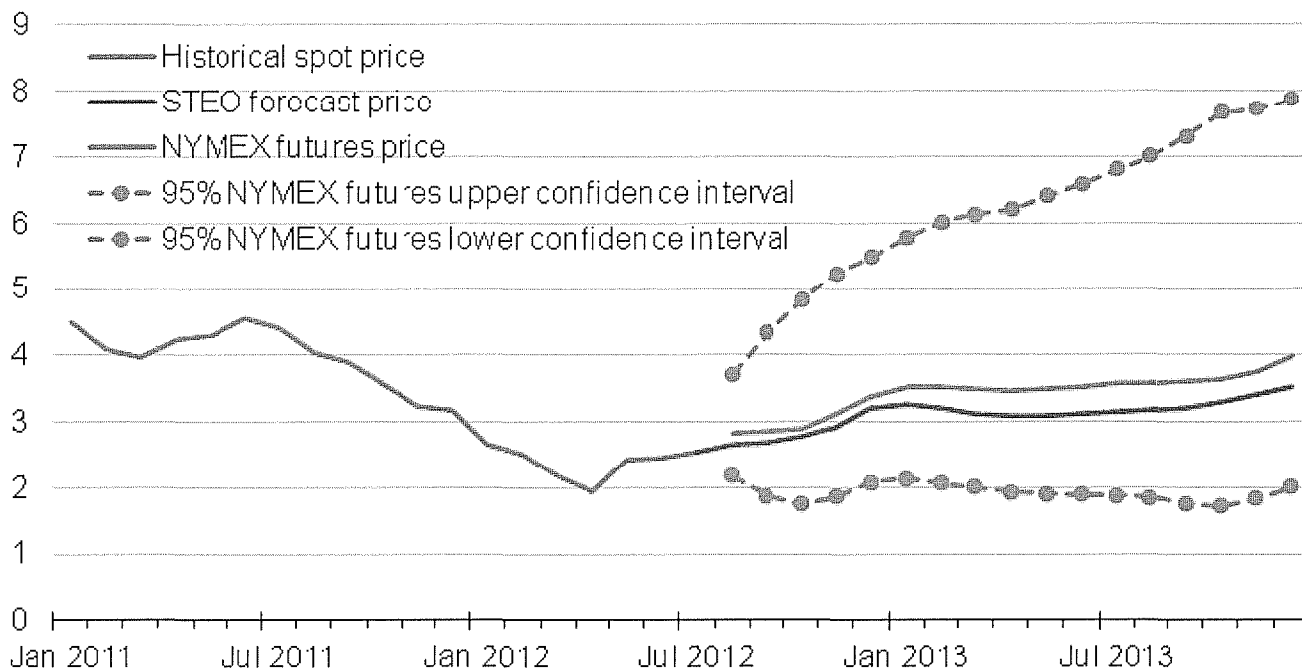
Under current law, Federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 17 percent in 2012. The outlook for wind capacity additions and generation in 2013 will likely respond to whatever decision is made regarding the extension of production tax credits.

EIA expects fuel ethanol production to average 901 thousand bbl/d in 2012 and 2013, almost the same level as last year. 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 3.0 percent in 2012, but increase by 0.8 percent in 2013. Petroleum emissions decline in 2012 (0.9 percent) and then rise by 0.3 percent in 2013, while natural gas emissions rise by 5.3 percent and 1.5 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 11 percent, but rise by 0.8 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 July 5, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

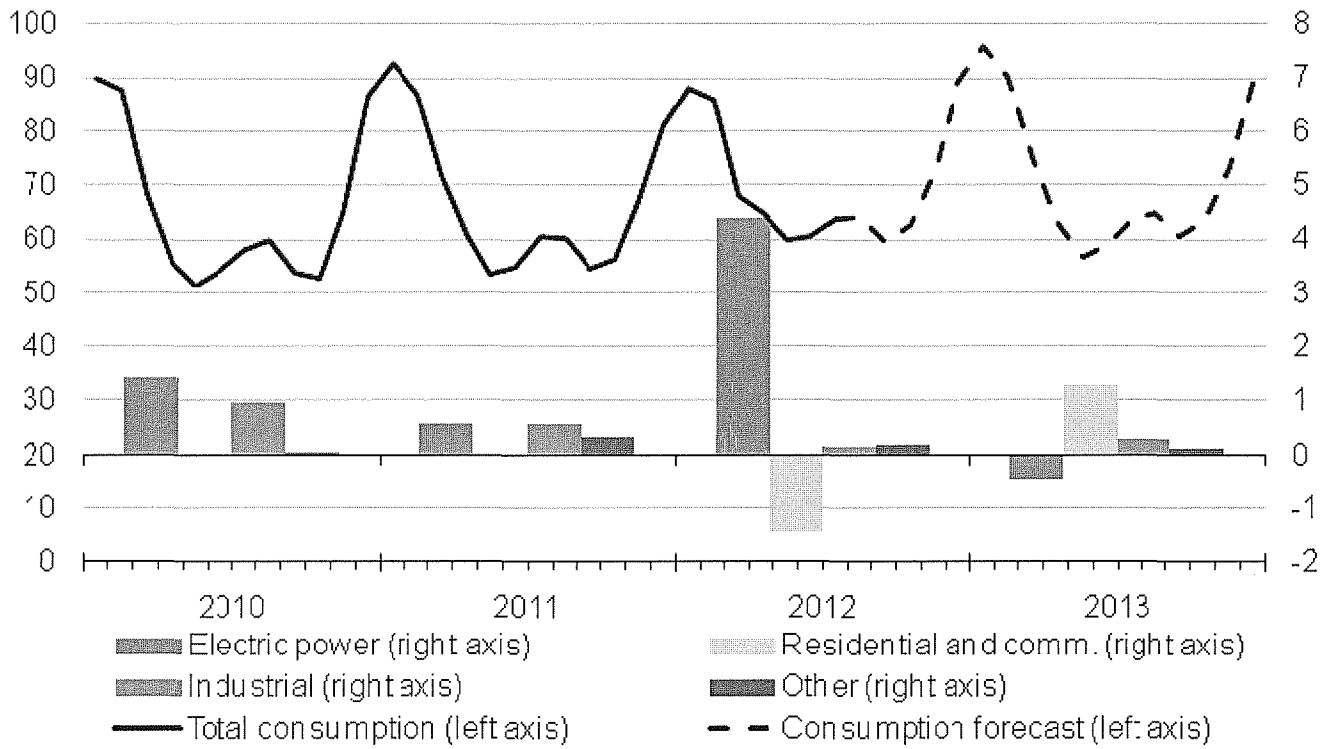
Source: Short-Term Energy Outlook, July 2012



# U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

annual change (bcf/d)



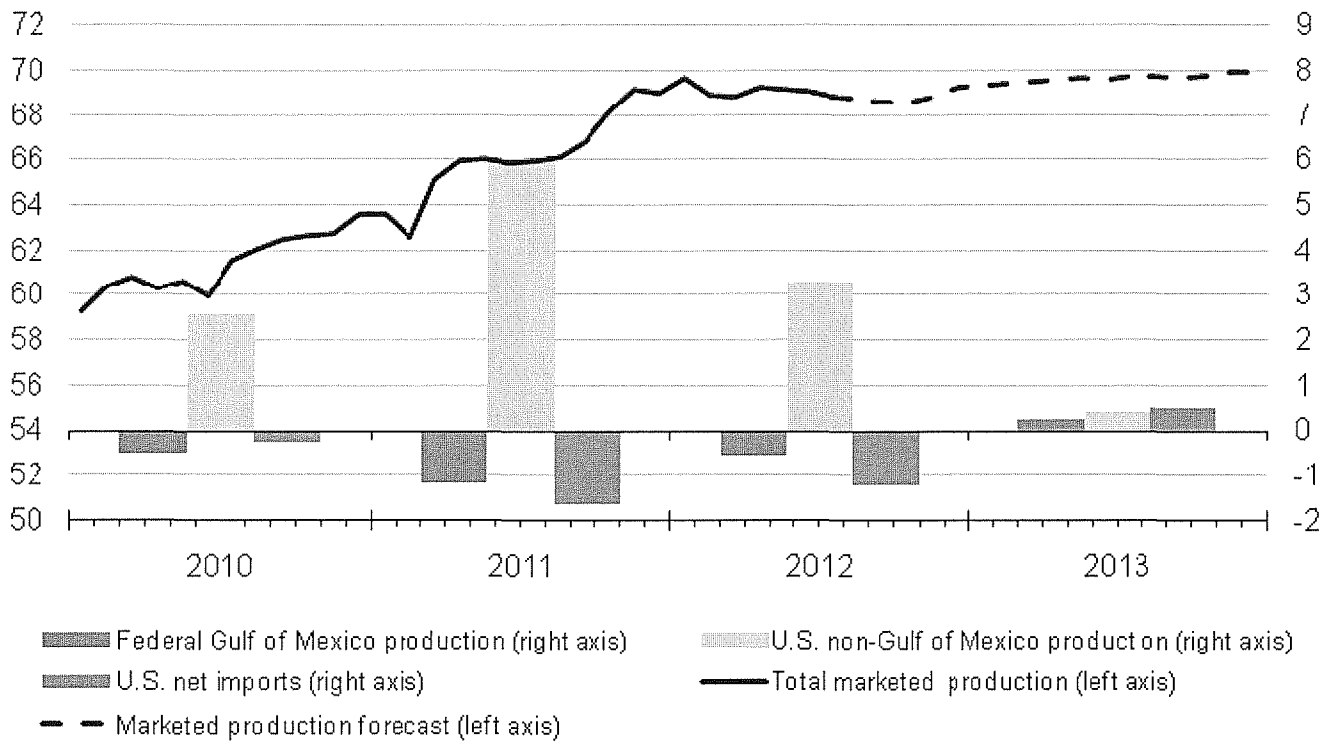
Source: Short-Term Energy Outlook, July 2012



## U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)



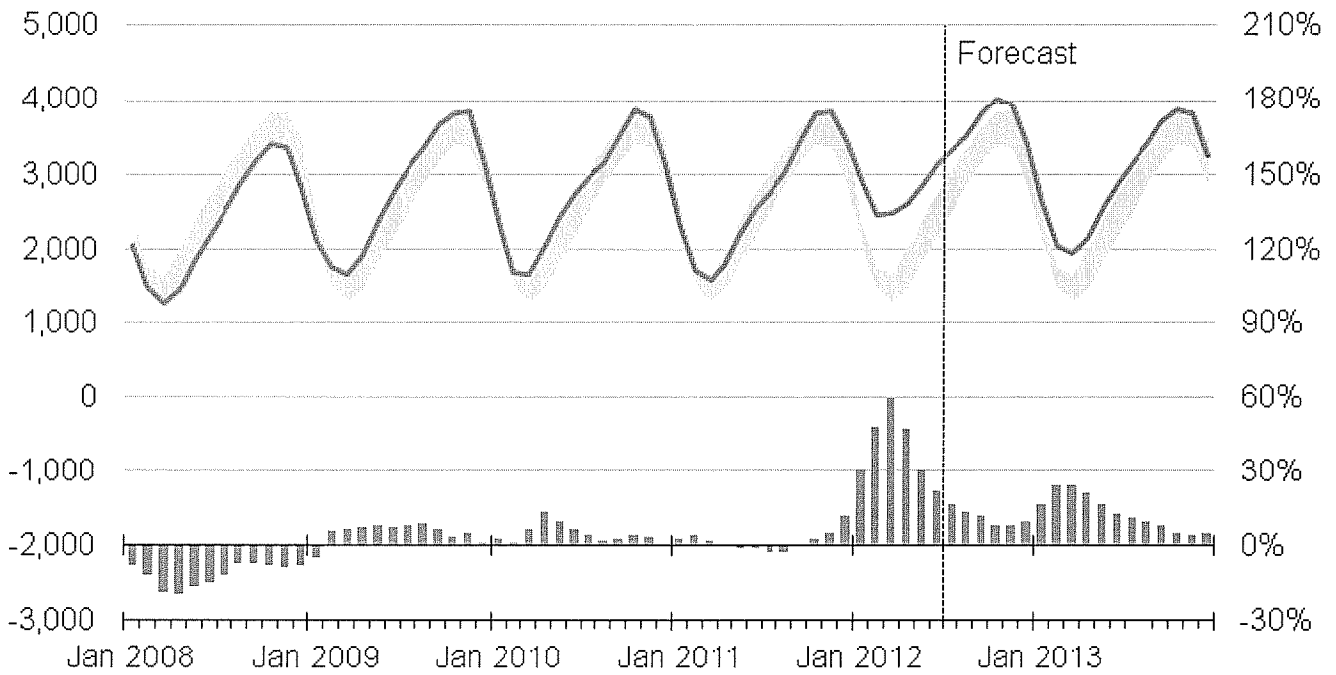
Source: Short-Term Energy Outlook, July 2012



# 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. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, July 2012



**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, 2012</b>									<b><u><u>\$311,764</u></u></b>
May	\$30,099	\$0	\$2,016	\$32,115	13,138	\$0.5102	\$6,702	\$25,413	337,177
June	52,819	0	2,192	55,011	6,558	1.0137	4,625 2/	50,386	387,563
<b>Balance @ June 30, 2012</b>									<b><u><u>\$387,563</u></u></b>

1/ Interest calculated at 13.3%, the authorized rate of return.  
 2/ Reflects 4,017.3 dk @ \$0.5102 and 2,540.6 dk @ \$1.0137.

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

	<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, 2012</b>									<b><u><u>(\$72,396)</u></u></b>
May	(\$11,426)	\$0	(\$557)	(\$11,983)	23,670	(\$0.0178)	(\$422)	(\$11,561)	(83,957)
June	(6,055)	0	(637)	(6,692)	13,697	(0.2915)	(1,509)	(5,183)	(89,140)
<b>Balance @ June 30, 2012</b>									<b><u><u>(\$89,140)</u></u></b>

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

2/ Reflects 9,073.4 dk @ (\$0.0178) and 4,623.6 dk @ (\$0.2915).