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September 28, 2012

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

Re: Cost of Gas Adjustment (COG)
October 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 (79th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (79th Revised Sheet No. 8), showing the October 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.1046 per mcf for residential and firm general service customers and an increase of \$0.0303 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for October 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.0303 since the last COG filing. There has been an increase in pipeline charges of \$0.0743 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.1046 per mcf for residential and firm general service customers.

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

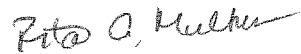
Attachment D shows the calculation of the balancing account since April 30, 2012.

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
Director of Regulatory Affairs

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2

79th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 78th Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$7.3758	\$8.6498 8.4298
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$7.3758	\$9.5498 9.3298
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	\$2.1460	\$3.2851 3.0391 2.8871
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	\$2.1460	\$4.1851 3.9391 3.7871
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$2.1460	\$3.3851
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: September 28, 2012

Effective Date: October 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
79th Revised Sheet No. 8
Canceling 78th 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.	3.7993	(2.7267)	1.0137	2.0863	(2.7119)	(0.2915)	(3.0034)
Current Adj.	0.0743	0.0303	0.0000	0.1046	0.0303	0.0000	0.0303
Total Adj.	3.8736	(2.6964)	1.0137	2.1909	(2.6816)	(0.2915)	(2.9731)
Total Rate:	\$3.9394	\$2.4227	\$1.0137	\$7.3758	\$2.4375	(\$0.2915)	\$2.1460

Date Filed: September 28, 2012

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

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
OCTOBER 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	15.0864	12	1,438,699	1.0279
Trans Canada - Demand Charge	7,947	23.6264	12	2,253,108	1.6097
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0655
NOVA - Seasonal	5,068	15.0864	5	382,289	0.2731
Trans Canada - Seasonal	5,068	23.6264	5	598,693	0.4277
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				\$5,493,192	3.9394
Estimated Weighted Average Commodity Cost	1,399,684	1/ 2.4227		3,391,014	2.4227
Gas Cost Reconciliation Adjustment					1.0137
Total Current Firm Gas Cost				\$8,884,206	7.3758
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.1909
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.4227
Gas Cost Reconciliation Adjustment					(0.2915)
LMS Demand 2/					0.0148
Total Current Interruptible Gas Cost					2.1460
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$2.9731)

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
OCTOBER 2012**

Rates Effective October 1, 2012	<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	15.0864	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.6264	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	15.0864	Per dk/Day
Trans Canada - Seasonal	23.6264	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:	2.4227	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
<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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/
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

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	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 Surcharges 4/		Out-of-Balance 3/	
TF12 Base	TF12 Var., TF5 & TFF	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		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

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
October 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 October monthly price for the AECO Index is expected to be in the same range as 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).

The effects of seasonal weather such as low heating and/or cooling demand, ample domestic supply and U.S. storage levels above last year's record levels likely contributed to the AECO index price remaining in the same trading range as the previous month's index. The Energy Information Administration (EIA) reported storage levels nationwide as of September 21, 2012 were 8.6 percent above the five-year average and 9.0 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 15.



Independent Statistics & Analysis

U.S. Energy Information
Administration

September 2012

Short-Term Energy Outlook

Highlights

- Brent crude oil spot prices have increased at a relatively steady pace from their 2012 low of \$89 per barrel on June 25 to their recent high of \$117 per barrel on August 23 because of the seasonal tightening of oil markets and continuing unexpected production outages. EIA expects Brent crude oil prices to fall from recent highs over the rest of 2012, averaging \$111 per barrel over the last 4 months of 2012 and \$103 per barrel in 2013. West Texas Intermediate (WTI) crude oil spot prices rose by a more modest \$17 per barrel between June 25 and August 23, as the WTI discount to Brent crude oil widened from \$10 per barrel to \$22 per barrel. EIA expects WTI spot prices to average \$93 per barrel in 2013, with the WTI discount to Brent narrowing to \$9 per barrel by the end of the 2013.
- Higher crude oil prices, refinery outages, a pipeline disruption, and concerns over Hurricane Isaac's impact on the Gulf Coast, the United States' major refining region, contributed to higher gasoline prices during August. EIA has increased the average regular-gasoline retail price forecast for the third quarter of 2012 to \$3.66 per gallon from \$3.49 per gallon in last month's *Outlook*. EIA expects retail gasoline prices to begin declining later this month as the gasoline market recovers and transitions from summer-grade to winter-grade gasoline specifications. Forecast regular gasoline retail prices average \$3.58 per gallon over the fourth quarter of 2012 and \$3.43 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 0.7 million bbl/d from last year. Projected U.S. domestic crude oil production increases to 6.8 million bbl/d in 2013, the highest level of production since 1993.
- Because of the projected increase in natural gas prices relative to coal, EIA expects the recent trend of substituting coal-fired electricity generation with natural gas generation to slow and likely reverse over the next year. From April through August 2012, average monthly natural gas prices to electric generators increased by 34 percent, while coal prices fell slightly. EIA expects that coal-fired electricity generation will increase by 9 percent in 2013, while natural gas generation will fall by about 10 percent.

- EIA expects carbon dioxide emissions from fossil fuels, which fell by 2.3 percent in 2011, to further decline by 2.4 percent in 2012. However, projected emissions increase by 2.8 percent in 2013, as coal regains some of its electric-power-generation market share.
- Natural gas working inventories ended August 2012 at an estimated 3.4 trillion cubic feet (Tcf), about 13 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 \$2.65 per MMBtu in 2012 and \$3.34 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. The oil market has tightened in recent months as the seasonal increase in global demand outpaced supply in August and unplanned production outages in countries outside of the Organization of the Petroleum Exporting Countries (OPEC) persist. Most recently, Hurricane Isaac led to the shut-in of 13 million barrels of crude oil production from August 25 through September 10 in the Gulf of Mexico. EIA expects oil markets to begin to loosen, with non-OPEC liquid fuels production growing by 1.2 million bbl/d in 2013 compared with world consumption growth of 1.0 million bbl/d. The possibility of a deteriorating economic situation in the countries of the European Union and slowing growth in China adds significant downside risk to future prices, though supply disruptions and lower-than-expected supply growth could raise prices. EIA expects stock builds during 2013, reflecting a looser oil market over that time period.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 1.0 million bbl/d in 2011. EIA expects consumption growth of 0.8 million bbl/d in 2012 and 1.0 million bbl/d in 2013, with China, Russia, the Middle East, Brazil, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for most of the consumption growth. Although forecast liquid fuels consumption in the United States increases by 0.1 million bbl/d in 2013, total OECD liquid fuels consumption falls by 0.2 million bbl/d in 2013, led by declines in consumption in Europe and Japan.

Non-OPEC Supply. EIA expects non-OPEC liquid fuels production to rise by 0.5 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 1.0 million bbl/d and 0.6 million bbl/d in 2012 and 2013, respectively, due to continued production growth from U.S. onshore shale and other tight oil formations and from Canadian oil sands. EIA expects that Kazakhstan will commence commercial production in the Kashagan field next year, increasing its total production by 160 thousand bbl/d in 2013. In Brazil, EIA projects output to rise by 200 thousand bbl/d in 2013, with increased output from its offshore, pre-salt oil fields. Forecast production also rises in Columbia, Russia, and China over the next two years, while production declines in Mexico and the North Sea.

Unplanned non-OPEC disruptions declined in recent months, from almost 1 million bbl/d in June to around 0.8 million bbl/d in August, mainly due to the temporary completion of unplanned maintenance activities in the North Sea and the repair of the Marib pipeline in Yemen. Sudan and South Sudan reached an understanding on pipeline transit and processing fees, as well as having South Sudan pay compensation for loss of oil revenue due to the split. Also, both sides intend to reach an agreement on border security, particularly in the contested Abyei oil region, before resuming oil production and exports.

OPEC Supply. EIA expects that OPEC member countries will continue to produce more than 30 million bbl/d of crude oil over the next two years. Projected OPEC crude oil production increases by about 1.0 million bbl/d in 2012 and 0.1 million bbl/day 2013. The growth in OPEC supply is due in part to Iraq, where new infrastructure has enabled the country to increase production to the highest level since 1989. Following a disruption in early July, Libya restored oil production and exports to about 1.5 million bbl/d in August. OPEC non-crude oil 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. EIA forecasts that non-crude oil liquids will increase by 0.3 million bbl/d in 2012 and by 0.2 million bbl/d in 2013.

EIA's forecast of Iranian crude oil production is unchanged from last month's *Outlook*, with forecast production falling 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 0.2 million bbl/d in 2013.

OPEC members serve as the swing producers in the world market because only OPEC producers possess surplus crude oil production capacity, most of which is in Saudi Arabia. EIA projects that OPEC surplus production capacity will average 2.2 million bbl/d in 2012 and rise to an average of just under 2.4 million bbl/d in 2013.

OECD Petroleum Inventories. EIA estimates that OECD commercial liquid fuel inventories ended 2011 at 2.60 billion barrels, equivalent to 56 days of forward cover. OECD stocks at the end of August 2012 are estimated to be about 22 million barrels higher than at the end of 2011, but are projected to fall back to 2.60 billion barrels by the end of 2012. OECD commercial inventories increase to 2.65 billion barrels and 57 days of forward cover by the end of 2013.

Crude Oil Prices. EIA projects the price of Brent crude oil will average \$112 per barrel in 2012 and \$103 per barrel in 2013, both about 3 percent higher than last month's *Outlook*. EIA expects the WTI price to average \$93 per barrel in the second half of 2012 and largely remain at this level throughout the forecast period. EIA expects that the WTI crude oil spot price discount to the Brent crude oil spot price will continue, averaging \$17 per barrel in the fourth quarter of 2012 and then falling to \$9 per barrel by the end of 2013.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for December 2012 delivery during the five-day period ending September 6, 2012 averaged \$96.11 per barrel. Implied volatility averaged 31 percent, establishing the lower and upper

limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in December 2012 at \$74 per barrel and \$126 per barrel, respectively. Last year at this time, WTI for December 2011 delivery averaged \$89 per barrel and implied volatility averaged 40 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$62 per barrel and \$127 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total liquid fuels consumption fell 230 thousand bbl/d (1.2 percent) in 2011. Motor gasoline consumption accounted for the bulk of the decline, shrinking 240 thousand bbl/d (2.7 percent). In 2012, total consumption decreases an additional 280 thousand bbl/d (1.5 percent). The year-over-year decline in total consumption narrowed from 660 thousand bbl/d in the first quarter of 2012 to 140 thousand bbl/d in the second quarter. EIA expects some in total liquid fuels consumption in 2013, with a projected year-over-year increase of 80 thousand bbl/d (0.5 percent). Most of the recovery comes from distillate fuel oil and natural gas liquids consumption, which rise because of continued growth in freight shipments and industrial use and because of the assumption of near-normal weather this coming winter.

Despite higher assumed growth in U.S. real disposable income and projected declines in retail pump prices of almost 6 percent in 2013, forecast motor gasoline consumption is flat because of slow growth in the driving-age population, 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 180 thousand bbl/d (3.3 percent) to 5.66 million bbl/d in 2011. Forecast crude oil production increases to 6.34 million bbl/d in 2012. Forecast lower-48 crude oil production grows by a robust 740 thousand bbl/d in 2012, primarily from the Bakken, Permian basin, and Eagle Ford producing areas. In 2013, total crude oil output rises a further 490 thousand bbl/d, most of which is accounted for by increases in lower-48 production. The number of onshore oil-directed drilling rigs reported by Baker Hughes has increased from 777 at the beginning of 2011 to 1,191 at the start of 2012, and to 1,409 as of September 7, 2012.

Significant events have occurred since last month's *Outlook*. There have been fires at Chevron's Richmond, California refinery ([*This Week In Petroleum, An Update on West Coast Gasoline Markets*](#), August 22, 2012) and PDVSA's Amuay refinery in Venezuela. The Richmond fire contributed to gasoline price increases in California, while the fire at the Amuay refinery caused a short-term increase in the price of gasoline and diesel fuel in the eastern United States. Hurricane Isaac led to a peak shut-in of 1.3 million bbl/d of U.S. crude oil production (a total of 13.0 million barrels from August 25 through September 10) in the Gulf of Mexico and curtailed Gulf Coast refinery runs with a decline in crude oil inputs of 0.7 million bbl/d for the week ending August 31.

The share of total U.S. consumption met by total liquid fuel net imports of both crude oil and products has been falling since peaking at over 60 percent in 2005. In 2011, it averaged 45 percent, 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 because of the substantial increases in domestic crude oil production. If the 2013 forecast 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 retail gasoline prices earlier this year, the monthly average price for regular grade gasoline reached \$3.90 per gallon in April. Prices then fell for three consecutive months, averaging \$3.44 per gallon in July. Rising crude prices contributed to an increase in regular gasoline retail prices to \$3.84 per gallon on September 3. EIA expects retail gasoline prices to begin declining later this month as the gasoline market recovers and transitions from summer-grade to winter-grade gasoline specifications. Projected regular gasoline retail prices average \$3.58 per gallon during the fourth quarter of 2012, up from the \$3.30 per gallon projected in last month's *Outlook*. Projected regular gasoline retail prices average \$3.64 per gallon in 2012 and \$3.43 per gallon in 2013, both about 11 cents per gallon higher than in last month's *Outlook*. EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.96 per gallon and \$3.73 per gallon in 2012 and 2013, respectively.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.8 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.2 Bcf/d (4.8 percent) from 2011. Large gains in electric power use in 2012 more than offset declines in residential and commercial use. Projected consumption of natural gas in the electric power sector averages 25.2 Bcf/d in 2012, 21 percent higher than in 2011, primarily driven by the improved relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector during 2012 peaks at 31.1 Bcf/d in the third quarter, when electricity demand for air conditioning is highest.

Total natural gas consumption increases by 0.2 Bcf/d (0.2 percent) in 2013. Expected increases in residential, commercial, and industrial consumption offset expected declines in the electric power sector. A forecast of near-normal weather during the upcoming winter drives 2013 increases in residential and commercial consumption of 9.9 percent and 9.3 percent, respectively. Although higher natural gas prices contribute to an 8.4 percent decline in forecast natural gas consumption in the electric power sector in 2013, consumption in the power sector next year is still expected to be about 2.3 Bcf/d higher than 2011 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. EIA expects continued year-over-year growth in 2012 of 2.6 Bcf/d. EIA, however, expects a small drop in production in the coming months, reflecting both losses from hurricanes (*2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*) and declines related to recent drops in the rig count. Hurricane Isaac hit the Gulf of Mexico on August 28 and has affected natural gas production for several days, with shut-ins in the Gulf of Mexico totaling 27.9 Bcf through September 10. According to Baker Hughes, the natural gas rig count was 452 as of September 7, 2012, compared with 811 at the start of 2012.

EIA forecasts that production growth will slow to 0.5 Bcf/d in 2013, as the slowdown in drilling activity 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.

EIA expects pipeline gross imports will fall by 0.1 Bcf/d (1.4 percent) in 2012, as domestic supply continues to displace Canadian sources. The warm winter in the United States early this year 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 little change in pipeline gross imports in 2013. 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 0.1 Bcf/d in 2013.

Liquefied natural gas (LNG) imports are expected to fall by about one-half in 2012 from the year before. EIA expects that an average of about 0.4 Bcf/d will arrive in the United States (mainly at the Elba Island terminal in Georgia) both 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. Higher prices for LNG, particularly in Asian markets, have made the United States a market of last resort for LNG suppliers.

U.S. Natural Gas Inventories. Working natural gas inventories remain at historically high levels for this time of year. As of August 31, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 3,402 Bcf, which is 395 Bcf greater than last year's level and 329 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will set a new record of 3,950 Bcf. Because of very high inventories at the start of the summer injection season this year, working inventories have remained high and stock builds since April, with a few exceptions, have been below the five-year average and below last year's levels. The projected increase of 1,473 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.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$2.84 per MMBtu at the Henry Hub in August 2012, down \$0.11 per MMBtu from the July average and \$1.21 per MMBtu (30 percent) lower than the August 2011 average. While abundant supplies have kept prices relatively low, a hot summer and associated increases in demand for natural gas for power generation contributed to the increase in prices in July. EIA expects the Henry Hub natural gas price will

average \$2.65 per MMBtu in 2012, with prices remaining below \$3.00 per MMBtu until December. EIA expects 2013 prices will average \$3.34 per MMBtu.

Natural gas futures prices for December 2012 delivery (for the five-day period ending September 6, 2012) averaged \$3.20 per MMBtu, and the average implied volatility based on options and futures prices was 40 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 December 2012 contracts at \$2.20 per MMBtu and \$4.65 per MMBtu, respectively. At this time last year, the December 2011 natural gas futures contract averaged \$4.29 per MMBtu and implied volatility averaged 32 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.18 per MMBtu and \$6.21 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption in the electric power sector, which averaged over 1 billion short tons annually from 2003 through 2008, will not reach that threshold for a fourth consecutive year in 2012. EIA forecasts coal consumption in the electric power sector to total 829 million short tons (MMst) in 2012. Lower electric power sector natural gas prices have led to a significant increase in the share of natural gas-fired generation. EIA projects power sector coal consumption to grow by 7.8 percent to 894 MMst in 2013 as electricity consumption increases and higher natural gas prices lead to a reduction in natural gas-fired generation.

U.S. Coal Supply. EIA forecasts that coal production will decline by 6.1 percent in 2012 as domestic consumption falls. Production for the first seven months of 2012 was 33 MMst (5 percent) below last year's level for the same period. EIA expects that production will total 1,028 MMst in 2012, 66 MMst below the 2011 total. EIA expects production to grow by 1.4 percent (14 MMst) in 2013 to meet the increase in consumption. Electric power sector stocks, which ended 2011 at 175 MMst, are forecast to total 192 MMst at the end of the 2012. Inventories are expected to decline slightly in 2013, but they will remain at elevated levels.

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong in 2012 and exceed the 107 MMst exported in 2011. The United States exported 12.7 MMst of coal in June, topping April's record-setting amount, and it was the third consecutive month with exports exceeding 12 MMst. EIA projects coal exports to total a record 124 MMst in 2012. EIA expects that coal exports will decline in 2013 but remain above 100 MMst. The primary reasons for the export decline include China's slower economic growth and increased exports from major coal-exporting countries, particularly Indonesia and Australia. U.S. exports could be higher if there are supply disruptions from any of the major coal-exporting countries. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

U.S. Coal Prices. Delivered coal prices to the electric power industry have 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 begin to put downward pressure on coal prices and contribute to the shut-in of higher-cost production. EIA forecasts that the delivered coal price in 2012 will average \$2.39 per MMBtu, and remain at that level in 2013.

Electricity

U.S. Electricity Consumption. Average daily retail sales of electricity to the residential sector during the first half of this year were about 6.6 percent lower than the same period in 2011, as a result of mild winter temperatures in the south where many households heat using electricity. Although summer temperatures this year were much warmer than normal, cooling degree days during June, July and August were about 4 percent lower than last summer. Residential sales for the entire year are projected to average about 3.5 percent lower than sales during 2011. Projected sales of electricity to the residential sector grow by 1.6 percent in 2013.

U.S. Electricity Generation. Recent power generation and fuel cost data indicate that over the last few quarters the generation fuel mix has been much more responsive to changes in relative fossil fuel prices than it has been in past years (see [Fuel Competition in Power Generation and Elasticities of Substitution](#)). The share of total generation fueled by natural gas during the first half of 2012 averaged 30.4 percent compared with 22.3 percent during the same period last year. This increase in fuel share was driven by a cost of natural gas that was very low relative to the cost of coal. However, in June, the average Henry Hub natural gas spot price surpassed the average spot price for Central Appalachian coal for the first time since October 2011, indicating that the recent trend of substituting coal-fired generation with natural-gas-fired generation may be slowing and will likely reverse. In light of the data indicating that power generators have recently been more responsive to changes in relative fuel costs, EIA has revised its projections for the generation fuel mix during 2013. EIA now expects that the higher natural gas prices next year will lead to a 9.5-percent decline in natural gas-fired generation while coal-fired generation increases by 9.3 percent.

U.S. Electricity Retail Prices. EIA expects the nominal U.S. residential electricity price will rise by 1.0 percent during 2012 to an average of 11.91 cents per kilowatthour. During 2013, U.S. residential retail electricity prices increase 0.9 percent over the average 2012 price. When measured in real terms, the U.S. residential electricity price declines by an annual average of 0.8 percent in both 2012 and 2013.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 13.8 percent in 2011, total renewable energy consumption is projected to decline by 2.3 percent in 2012. This decrease is the result of hydropower resource levels beginning to return to the long-term average, with consumption falling by 0.4 quadrillion Btu (13.9 percent). The decline in hydropower from 2011 to 2012 more than offsets the projected growth in the consumption of other renewable energy forms. Renewable energy consumption increases 2.0 percent in 2013 as hydropower continues to decline (2.2 percent) but non-hydropower renewables grow by an average of 4.1 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 18 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.

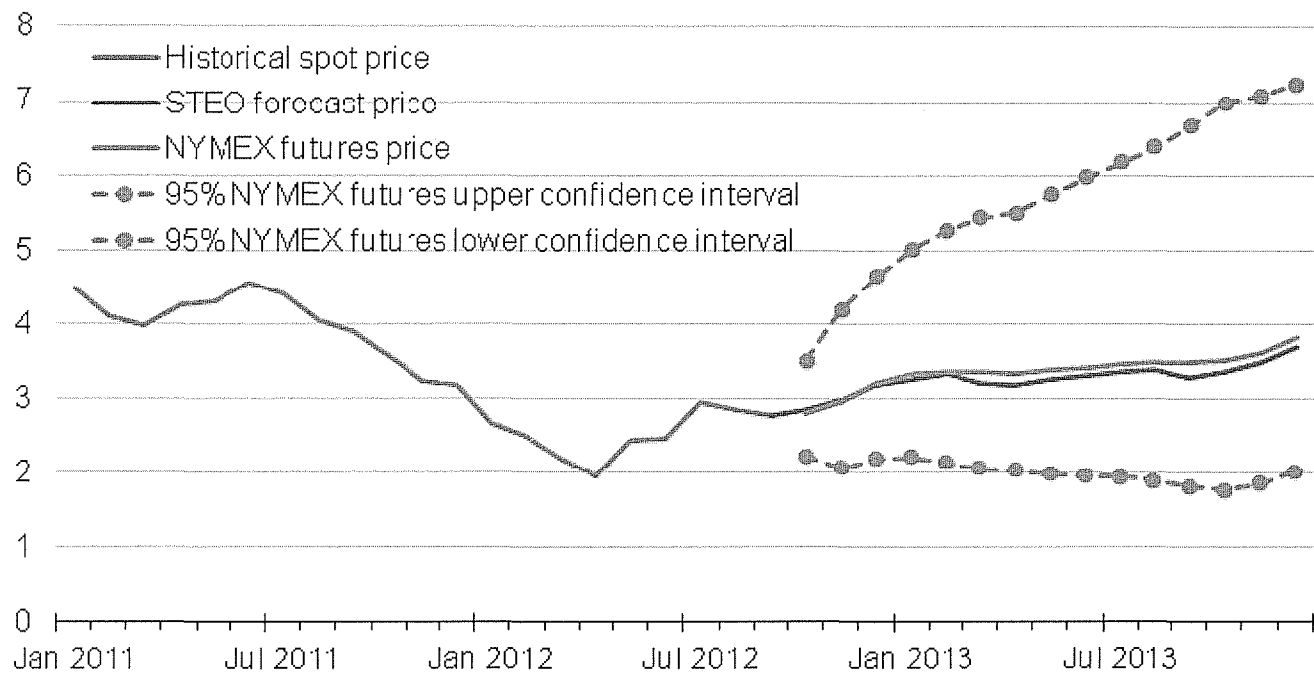
As a result of drought conditions affecting corn harvests throughout the Midwest, ethanol production fell from an average of 887 thousand bbl/d in June 2012 to 808 thousand bbl/d in July, and then modestly rebounded to 822 thousand bbl/d in August. EIA expects ethanol production will average 830 thousand bbl/d over the second half of 2012. Forecast ethanol production recovers in the second half of 2013, averaging 870 thousand bbl/d (13.3 billion gallons) for the year. The projected lower ethanol production is generally matched by lower ethanol exports.

Biodiesel production averaged about 63 thousand bbl/d (967 million gallons) in 2011. 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 2.3 percent in 2011, fossil fuel emissions are projected to further decline by 2.4 percent in 2012, but this decline is followed by an increase of 2.8 percent in 2013. Petroleum emissions decline in 2012 (1.4 percent) and grow only 0.2 percent in 2013. Natural gas emissions rise by 5.2 percent and 0.1 percent in 2012 and 2013, respectively. Coal emissions decline 8.9 percent in 2012, but their projected rise of 8.5 percent in 2013 is spurred by a 19-percent increase in the cost of natural gas for electricity while the cost of coal for power generation stays flat.

Henry Hub Natural Gas Price

dollars per million btu



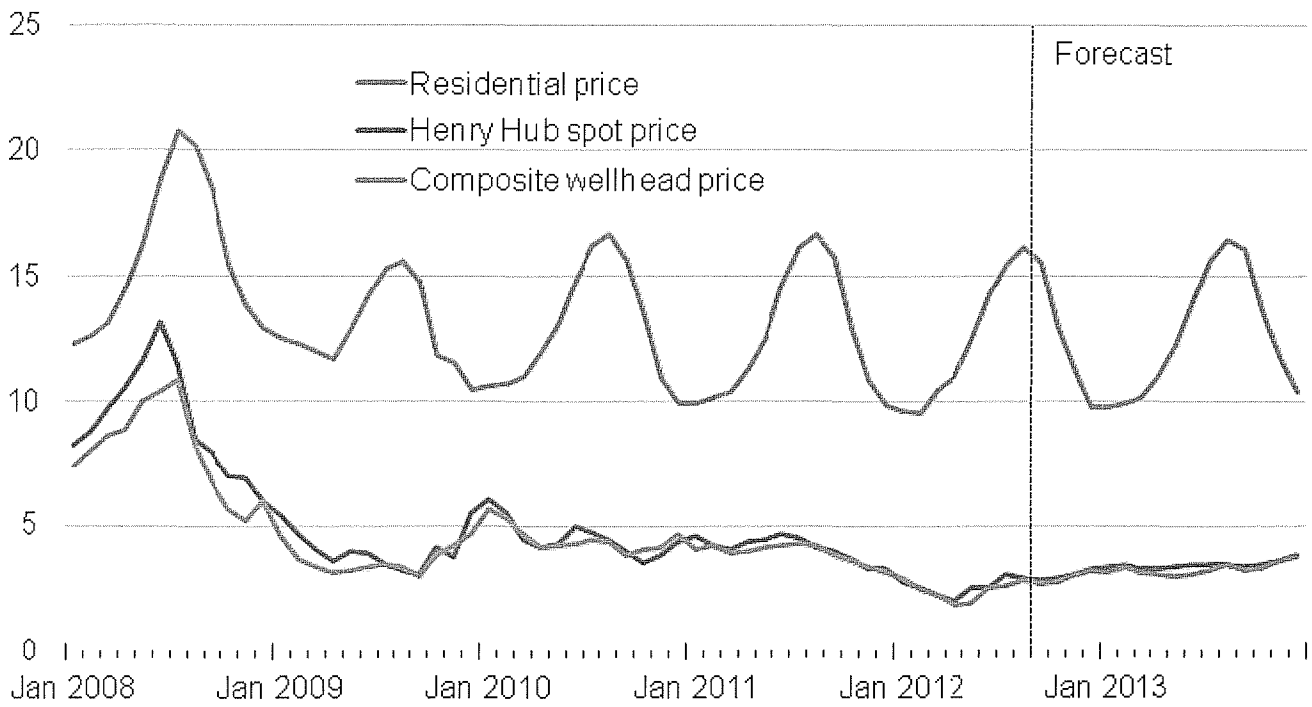
Note: Confidence interval derived from options market information for the 5 trading days ending September 6, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts

Source: Short-Term Energy Outlook, September 2012



U.S. Natural Gas Prices

dollars per thousand cubic feet



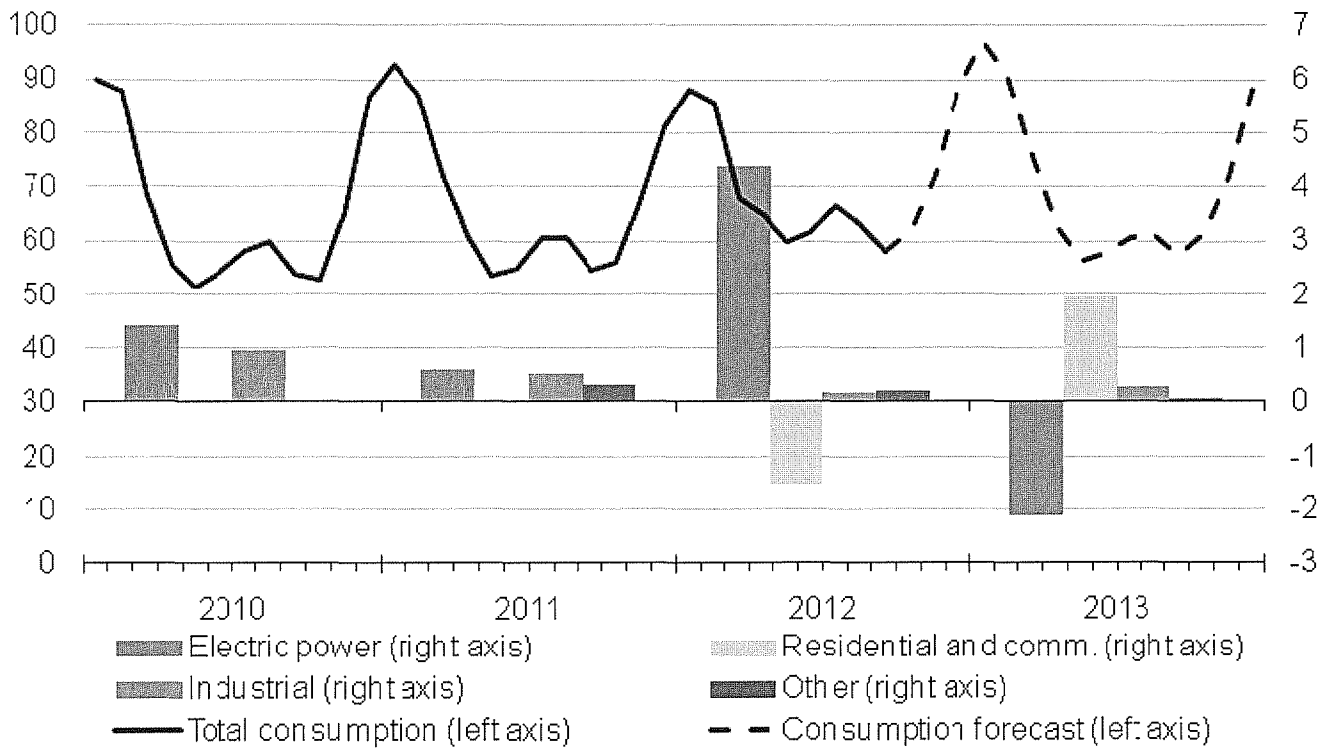
Source: Short-Term Energy Outlook, September 2012



U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

annual change (bcf/d)



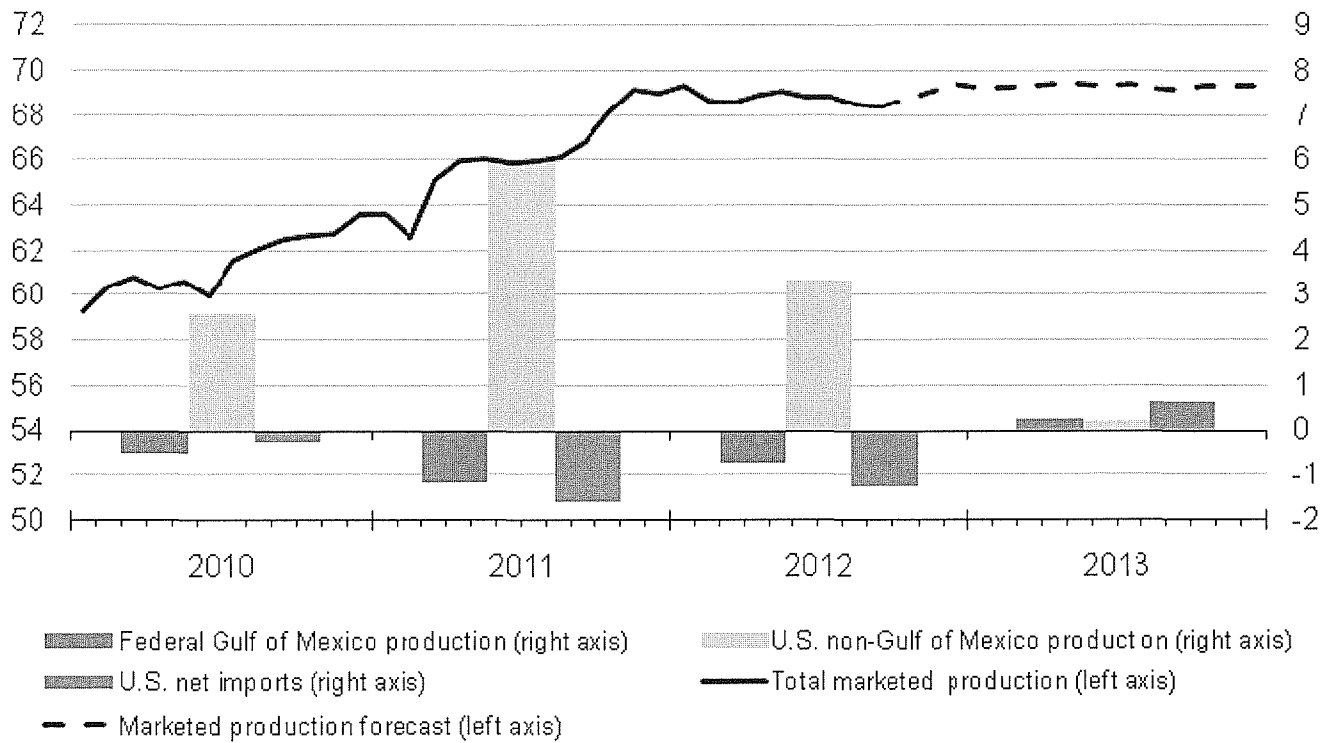
Source: Short-Term Energy Outlook, September 2012



U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)



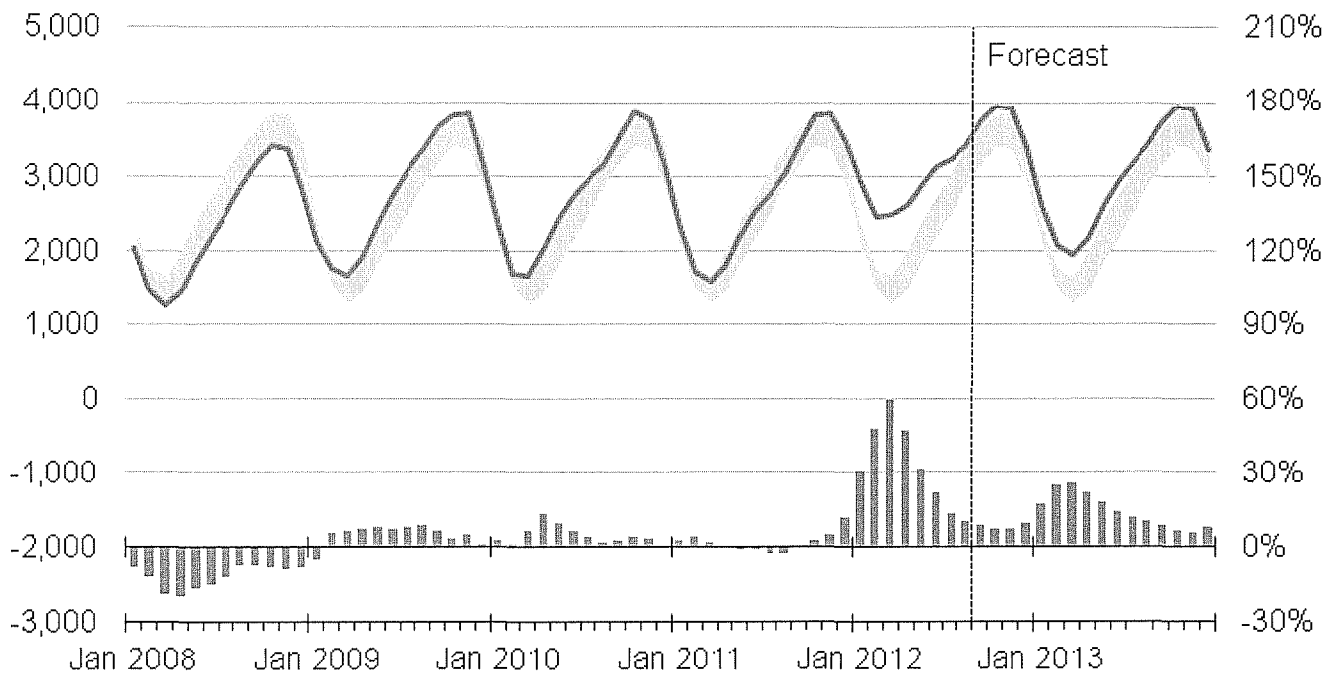
Source: Short-Term Energy Outlook, September 2012



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, September 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 & 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>
Balance @ April 30, 2012									<u><u>\$311,764</u></u>
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
July	57,568	0	2,542	60,110	5,776	1.0137	5,855	54,255	441,818
August	58,888	0	2,918	61,806	5,143	1.0137	5,213	56,593	498,411
Balance @ August 31, 2012									<u><u>\$498,411</u></u>

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**

	(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									<u>(\$72,396)</u>
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) 2/	(5,183)	(89,140)
July	(16,584)	0	(671)	(17,255)	13,108	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	0	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
Balance @ August 31, 2012									<u>(\$101,557)</u>

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).