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February 28, 2012

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

**RECEIVED**

FEB 29 2012

**PUBLIC SERVICE COMMISSION**

Re: Cost of Gas Adjustment (COG)  
March 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 (72<sup>nd</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (72<sup>nd</sup> Revised Sheet No. 8), showing the March 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.3157 per mcf for residential and firm general service customers and a decrease of \$0.2034 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for March 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.2034 since the last COG filing. There has been a decrease in pipeline charges of \$0.1123 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.3157 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, 2011.

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.

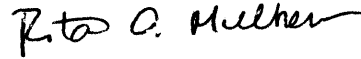
Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

GREAT PLAINS NATURAL GAS CO.

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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**



# GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

## State of North Dakota Gas Rate Schedule

NDPSC Volume 2

72nd Revised Sheet No. 1.1

### RATE SUMMARY SHEET

Canceling 71st 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 Over 10 MCF	\$1.2740 1.0540	\$6.8485	\$8.1225 7.9025
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF Over 10 MCF	\$2.1740 1.9540	\$6.8485	\$9.0225 8.8025
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF Next 2,600 MCF Over 3,000 MCF	\$1.1391 0.8931 0.7411	\$2.4723	\$3.6114 3.3654 3.2134
Interruptible Gas Service - Highway 13	3.5	\$3.50 per month	First 400 MCF Next 2,600 MCF Over 3,000 MCF	\$2.0391 1.7931 1.6411	\$2.4723	\$4.5114 4.2654 4.1134
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF	\$1.2391	\$2.4723	\$3.7114
Transportation Service	5	\$3.50 per month	First 400 MCF Next 2,600 MCF Over 3,000 MCF	\$1.1391 0.8931 0.7411		\$1.1391 0.8931 0.7411

Date Filed: February 28, 2012

Effective Date: March 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  
72<sup>nd</sup> Revised Sheet No. 8  
Canceling 71<sup>st</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.	3.9092	(2.4401)	0.5102	1.9793	(2.4256)	(0.0178)	(2.4434)
Current Adj.	(0.1123)	(0.2034)	0.0000	(0.3157)	(0.2034)	0.0000	(0.2034)
Total Adj.	<u>3.7969</u>	<u>(2.6435)</u>	<u>0.5102</u>	<u>1.6636</u>	<u>(2.6290)</u>	<u>(0.0178)</u>	<u>(2.6468)</u>
Total Rate:	\$3.8627	\$2.4756	\$0.5102	\$6.8485	\$2.4901	(\$0.0178)	\$2.4723

**Date Filed:** February 28, 2012

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

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

**Case No.:**

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

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
FT-A	7,841	\$3.4671	12	\$326,226	\$0.2325
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0736
FT-A Seasonal	2,000	3.7671	5	37,671	0.0268
TFX Seasonal	2,000	15.1530	5	151,530	0.1080
NOVA - Demand Charge	7,947	14.8030	12	1,411,673	1.0061
Trans Canada - Demand Charge	7,947	23.1339	12	2,206,141	1.5723
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068	14.8030	5	375,108	0.2673
Trans Canada - Seasonal	5,068	23.1339	5	586,213	0.4178
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0549
LMS Demand 2/					0.0145
Total Demand Charges				\$5,399,538	3.8627
Estimated Weighted Average Commodity Cost	1,403,100	1/ 2.4756		3,473,514	2.4756
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				\$8,873,052	6.8485
Base Cost of Gas					5.1849
Accumulated Adjustment					\$1.6636
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.4756
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					2.4723
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$2.6468)

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</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0145

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

<b>Rates Effective March 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	14.8030	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.1339	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	14.8030	Per dk/Day
Trans Canada - Seasonal	23.1339	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:	2.4756	Per dk

<b>Base Rate Effective September 1, 1981</b>		
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	<u>5.1191</u>	Per Mcf
Total Firm Base Cost	\$5.1849	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
<hr/>	
Category 1 (Contract Term of Less than 3 Years)	
<hr/>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.7671
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.8871
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$2.1400
Zone 2-2 Minimum Rate	\$0.0000
<hr/>	
Category 2 (Contract Term of 3 Years to less than 5 Years)	
<hr/>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.6171
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.7371
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.9900
Zone 2-2 Minimum Rate	\$0.0000
<hr/>	
Category 3 (Contract Term of 5 or more Years)	
<hr/>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$3.4671
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$4.5871
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$1.8400
Zone 2-2 Minimum Rate	\$0.0000

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
<b>Commodity Rates</b>				
<b>FT-A – Maximum Rates</b>				
Zone 1-1	\$0.0130	\$0.0018	\$0.0148	1.66%
Zone 1-2	\$0.0130	\$0.0018	\$0.0148	1.91%
Zone 2-2	\$0.0130	\$0.0018	\$0.0148	0.25%
Minimum Rate	\$0.0130	\$0.0018	\$0.0148	
<b>IT and AOT</b>				
Zone 1-1	\$0.1368	\$0.0018	\$0.1386	1.66%
Zone 1-2	\$0.1737	\$0.0018	\$0.1755	1.91%
Zone 2-2	\$0.0834	\$0.0018	\$0.0852	0.25%
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: 0.08% for Zone 1-1, 0.09 % for Zone 1-2, and 0.01% 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		\$0.0265	

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
<b>PAL</b>		
<b>NPL, OPL, and APL Service:</b>		
Daily Commodity Rate	\$0.1737	\$0.0000
<b>RPL Service:</b>		
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		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
Market	Market	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	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 \$0.0005 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	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	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 \$0.0005 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)	1.12%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.20% 4/ 5/
FDD Storage Fuel	1.21%
	Electric Compression -----
COMMODITY RATES:	1/
Market Area	\$0.0005
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, 2010.

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 &amp; 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  
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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  
-----

Reservation Fee	2.1800	
Commodity Rate	0.0208	

1/ Minimum Rate is zero.

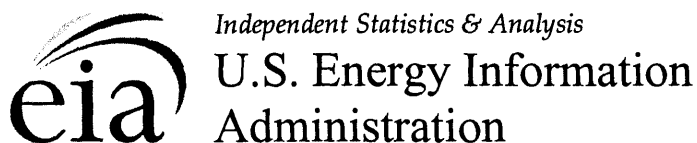
**Great Plains Natural Gas Co.  
Market Conditions for Wahpeton's Natural Gas  
March 2012**

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 March monthly price for the AECO Index is expected to decrease slightly 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).

Continued strong domestic supply and the high levels of gas in storage likely contributed to an expected decrease in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of February 17, 2012 were 40.2 percent above the five-year average and 40.9 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.



February 2012

## Short-Term Energy Outlook

February 7, 2012 Release

### Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$100 per barrel in 2012, almost \$6 per barrel higher than the average price last year. Based on recent futures and options data, the market believes there is about a one-in-fifteen chance that the average WTI price in June 2012 will exceed \$125 per barrel, and about a one-in-fifty chance that it would exceed \$140 per barrel. For 2013, EIA expects WTI prices to continue to rise, reaching \$106 per barrel in the fourth quarter of next year. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 2.0 percent in 2012 and 2.4 percent in 2013, while world real GDP (weighted by oil consumption) grows by 2.9 percent and 3.7 percent in 2012 and 2013, respectively.
- This is the third consecutive monthly *Outlook* in which the forecast of average household expenditures for heating fuels has been lowered because of the continuing unusually warm weather for most of the Nation. Average household heating oil expenditures are now expected to increase by only 1 percent this winter heating season (October 1 to March 31) compared with last winter. Natural gas and propane expenditures are projected to decline by 11 percent and 5 percent, respectively, and electricity expenditures are 4 percent lower than last winter's levels.
- EIA expects regular-grade motor gasoline retail prices to average \$3.55 per gallon in 2012, compared with \$3.53 cents per gallon last year, and then average \$3.59 per gallon in 2013. During the April through September peak driving season each year, prices are forecast to average about 7 cents per gallon higher than the annual average. Recent options and futures price data imply that the market believes that there is about a one-in-four chance that the U.S. average pump price of regular gasoline could exceed \$4 in June of this year.

- Natural gas working inventories continue to set new record seasonal highs and ended January 2012 at an estimated 2.86 trillion cubic feet (Tcf), about 24 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is \$3.35 per million British thermal units (MMBtu), a decline of about \$0.65 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$4.07 per MMBtu in 2013.

## Global Crude Oil and Liquid Fuels

**Crude Oil and Liquid Fuels Overview.** Absent a significant oil supply disruption, EIA expects world markets to continue to gradually tighten in 2012 and 2013, as increases in global consumption outpace production growth in countries outside of the Organization of the Petroleum Exporting Countries (OPEC). World liquid fuels consumption grows by an annual average of 1.3 million barrels per day (bbl/d) in 2012 and 1.5 million bbl/d in 2013. Supply from non-OPEC countries increases by 0.8 million bbl/d in 2012 and 0.9 million bbl/d in 2013. EIA expects that the market will rely on both inventories and increases in production of crude oil and non-crude liquids from OPEC members to meet world demand growth.

There are many significant uncertainties that could push oil prices higher or lower than projected. Should a significant oil supply disruption occur, and OPEC members do not increase production, or projected non-OPEC projects come online more slowly than expected, oil prices could be significantly higher than projected in this *Outlook*. If the pace of global economic growth fails to accelerate in Organization for Economic Cooperation and Development (OECD) countries, or if economic growth slows in non-OECD countries, reduced demand could result in lower prices.

**Global Crude Oil and Liquid Fuels Consumption.** World liquid fuels consumption grew by an estimated 0.8 million bbl/d to 87.9 million bbl/d in 2011. EIA expects that this growth will accelerate over the next two years, with consumption reaching 89.3 million bbl/d in 2012 and 90.7 million bbl/d in 2013. OECD consumption fell by 490 thousand bbl/d in 2011 and is expected to decline again in 2012 as very modest consumption growth in the United States and Japan will be more than offset by a decline in consumption in Europe. Non-OECD countries are expected to account for most of the world's consumption growth over the next two years, with the largest contributions coming from China and the Middle East (World Liquid Fuels Consumption Chart). EIA expects that non-OECD consumption growth will increase from 1.3 million bbl/d in 2011 to 1.5 million bbl/d in 2012, and then slow to 1.3 million bbl/d in 2013.

**Non-OPEC Supply.** EIA expects non-OPEC crude oil and liquid fuels production to rise by 770 thousand bbl/d in 2012 and by a further 850 thousand bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 350 thousand bbl/d and 260 thousand bbl/d in 2012 and 2013, respectively, resulting from continuing growth in production from U.S. onshore shale formations and Canadian oil sands. Other major growth areas include Brazil, where production increases annually by an average of 170 thousand bbl/d over the next two years with increased output from its offshore, pre-salt oil fields, and Kazakhstan, which will commence commercial production in the Kashagan field in 2013, increasing its production annually by an average of 140 thousand bbl/d. Production also increases in Colombia, Norway, and China. Production declines in Russia, Mexico, and the United Kingdom.

The most notable revision in this month's *Outlook* occurs in Sudan, where an unresolved dispute between the Khartoum government and newly independent South Sudan over transit fees and other issues has caused the latter to shut in production. EIA now projects that total Sudan and South Sudan production, which averaged about 425 thousand bbl/d in 2011, will average 210 thousand bbl/d in 2012 and recover to 340 thousand bbl/d in 2013.

**OPEC Supply.** EIA expects that OPEC members' crude oil production will continue to rise over the next two years to accommodate increasing world oil consumption. Projected OPEC crude oil production increases by about 250 thousand bbl/d and 520 thousand bbl/d in 2012 and 2013, respectively. OPEC non-crude petroleum liquids (condensates, natural gas liquids, and gas-to-liquids), which are not subject to production targets, increase by 640 thousand bbl/d in 2012 and by 80 thousand bbl/d in 2013. EIA expects that OPEC surplus production capacity will increase from about 2.2 million bbl/d in December 2011 to 3.9 million bbl/d at the end of 2013, as the assumed recovery of Libyan production to pre-disruption levels allows other OPEC producers to scale back production (OPEC Surplus Crude Oil Production Capacity Chart).

**OECD Petroleum Inventories.** EIA estimates that commercial oil inventories held in the OECD ended 2011 at 2.64 billion barrels, equivalent to about 56.8 days of forward-cover (days-of-supply). Although the December 2011 inventory is slightly lower than the 2.66 billion barrel level at the end of December 2010, the days of forward-cover is the highest end-of-year level since 1994 because of a decline in OECD consumption last year. Projected OECD oil inventories decline slightly over the forecast, with OECD inventories falling to 2.59 billion barrels, or 55.5 days of forward cover, at the end of 2013 (Days of Supply of OECD Commercial Stocks Chart).

**Crude Oil Prices.** EIA's forecast of the WTI spot price is unchanged from last month's *Outlook*, averaging about \$100 per barrel in 2012 and \$104 per barrel in 2013 (West Texas Intermediate Crude Oil Price Chart). The projected WTI price discount to other U.S. and world crude oils narrows over the forecast. The projected average refiner acquisition cost (RAC) of crude oil averages \$105 per barrel and \$106 per barrel in 2012 and 2013, respectively.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for April 2012 delivery during the 5-day period ending February 2, 2012 averaged \$98.52 per barrel. Implied volatility averaged 30 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in April 2012 at \$81 per barrel and \$120 per barrel, respectively. Last year at this time, WTI for April 2011 delivery averaged \$93 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$76 per barrel and \$114 per barrel.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** In 2011, total U.S. liquid fuels consumption fell by 340 thousand bbl/d (1.8 percent) from 2010 (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounted for much of that decline, shrinking by 250 thousand bbl/d (2.8 percent). In contrast, distillate fuel oil consumption rose by 60 thousand bbl/d (1.5 percent), brought about by recovery in industrial output and freight transport.

Despite the prospects for continued economic recovery and projections of slight increases in petroleum product prices, the next two years are expected to see only small increases in total liquid fuels consumption, with growth of about 30 thousand bbl/d (0.1 percent) in 2012 and 90 thousand bbl/d (0.5 percent) in 2013. Motor gasoline consumption, constrained by slowing driving-age population growth and the improving fuel economy of new vehicles, is forecast to fall slightly in both 2012 and 2013. Distillate fuel consumption, however, continues to rise by an annual average of 60 thousand bbl/d through 2013.

**U.S. Liquid Fuels Supply and Imports.** Domestic crude oil production increased by an estimated 110 thousand bbl/d to 5.59 million bbl/d in 2011. A 380-thousand bbl/d increase in lower-48 onshore production in 2011 was partly offset by a 40-thousand bbl/d decline in Alaska and a 230-thousand bbl/d decline in output in the Federal Gulf of Mexico (GOM).

Forecast total crude oil production increases by 240 thousand bbl/d in 2012 and by a further 90 thousand bbl/d in 2013. Continued increases in lower-48 onshore crude oil production of 340 thousand bbl/d in 2012 and 110 thousand bbl/d in 2013 overshadow declines averaging about 20 thousand bbl/d in Alaskan output each year and a 90 thousand bbl/d decrease in 2012 GOM production (U.S. Crude Oil and Liquid Fuels Production Chart). The rise in production is driven by increased oil-directed drilling activity, particularly in onshore shale formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes increased from 777 at the beginning of 2011 to 1,245 on February 3, 2012.

For the first time since 1949, the United States was a net exporter of refined petroleum products in 2011, with gross product exports averaging 420 thousand bbl/d more than gross product imports (product exports averaged almost 2.5 million barrels per day less than gross product imports in 2005). EIA expects that the United States will continue to be a net product exporter, with net product exports averaging 350 thousand bbl/d in 2012 and 320 thousand bbl/d in 2013.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and refined products), which has been falling since 2005, averaged 45 percent in 2011, down substantially from 49 percent in 2010. EIA expects that the total net import share of consumption will remain near 2011 levels in 2012 and 2013, as continued growth in domestic crude oil output exceeds the growth in liquid fuels consumption and total inventory levels stabilize.

***U.S. Petroleum Product Prices.*** Regular-grade gasoline retail prices averaged \$3.53 per gallon in 2011, which was \$0.74 per gallon (27 percent) higher than the 2010 average. Higher crude oil costs (\$0.60 per gallon) and refinery gasoline margins (\$0.11 per gallon) accounted for most of that increase. EIA expects the regular-grade gasoline retail price to average \$3.55 per gallon in 2012 as higher crude oil prices are offset by lower refinery gasoline margins (U.S. Gasoline and Crude Oil Prices Chart). Forecast regular-grade gasoline prices increase to an average \$3.59 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.91 per gallon in 2012 and \$3.99 per gallon in 2013 (U.S. Diesel Fuel and Crude Oil Prices Chart).

Between 1990 and 2004, annual average wholesale gasoline prices ranged from 5 cents per gallon to 11 cents per gallon above wholesale diesel prices. Beginning in 2005, wholesale gasoline prices fell below wholesale diesel fuel prices in all years except 2009, as world demand growth for diesel fuel, primarily in the emerging economies, outpaced gasoline demand growth. EIA expects the gasoline wholesale price to

remain lower than diesel wholesale prices, with gasoline prices averaging 18 cents per gallon below diesel in 2012 and 22 cents per gallon lower in 2013.

## Natural Gas

**U.S. Natural Gas Consumption.** EIA expects that natural gas consumption will average 68.5 billion cubic feet per day (Bcf/d) in 2012, an increase of 1.6 Bcf/d (2.4 percent) from 2011. Consumption increases in all sectors, with the largest volume increase (1.2 Bcf/d) coming from the electric power sector. Natural gas consumption growth continues into 2013, with projected total consumption averaging 69.7 Bcf/d (U.S. Natural Gas Consumption Chart). Increases in the consumption of natural gas for power generation are likely to continue as domestic production continues to grow and natural gas remains a relatively inexpensive option for generators.

**U.S. Natural Gas Production and Imports.** Total marketed production grew by an estimated 4.8 Bcf/d (7.8 percent) in 2011, the largest year-over-year volumetric increase in history. This strong growth was driven in large part by increases in shale gas production. While EIA expects production growth to continue in 2012 and 2013, the projected increases occur at a much lower rate than in 2011 as low prices reduce new drilling plans. According to Baker Hughes, the natural gas rig count has fallen to 745 as of February 3, 2012, from a 2011 high of 936 in mid-October. Declines in production have not accompanied declines in the rig count, partly reflecting improving drilling efficiency. That fact, combined with high initial production rates from new wells, associated natural gas production from oil drilling, and a backlog of uncompleted or unconnected wells contribute to EIA's forecast of further production increases in 2012 and 2013.

Pipeline gross imports are expected to fall by 0.5 Bcf/d (5.5 percent) in 2012 as domestic production grows and displaces Canadian sources. This follows a 0.6 Bcf/d (6.4 percent) decline in pipeline gross imports in 2011. Pipeline gross exports grew by 1.0 Bcf/d in 2011, largely the result of increased exports to Mexico. Pipeline gross exports are expected to continue to grow, though at a slower rate, in 2012 and 2013.

Liquefied natural gas (LNG) imports are expected to decline by 0.3 Bcf/d (28 percent) in 2012. EIA predicts an average of about 0.7 Bcf/d will arrive at terminals in the United States in both 2012 and 2013, either to take advantage of temporarily high local prices due to cold snaps and disruptions or to fulfill long-term contract obligations.

**U.S. Natural Gas Inventories.** Working natural gas inventories continue to set new seasonal record highs as the unusually warm winter has contributed to much lower-than-normal inventory draws. As of January 27, 2012, according to EIA's *Weekly*

*Natural Gas Storage Report*, working inventories totaled 2,966 Bcf, 586 Bcf greater than last year's level. EIA expects the winter heating season will end March 31 with inventories over 2,000 Bcf, and inventory levels at the end of October 2012 and 2013 are expected to set new record highs as well (U.S. Working Natural Gas in Storage Chart).

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$2.67 per MMBtu at the Henry Hub in January 2012, down \$0.50 per MMBtu from the December 2011 average and the lowest average monthly price since 2002. Abundant storage levels, as well as ample supply, have contributed to the recent low prices. EIA expects the Henry Hub spot price will begin to recover after this winter's inventory draw season ends and will average \$3.35 per MMBtu in 2012 and \$4.07 per MMBtu in 2013, down \$0.18 per MMBtu and \$0.07 per MMBtu from last month's *Outlook*, respectively (U.S. Natural Gas Prices Chart).

Natural gas futures prices for April 2012 delivery (for the 5-day period ending February 2, 2012) averaged \$2.71 per MMBtu, and the average implied volatility was 52 percent (*Market Prices and Uncertainty Report*). The lower and upper bounds for the 95-percent confidence interval for April 2012 contracts are \$1.84 per MMBtu and \$4.01 per MMBtu. At this time last year, the April 2011 natural gas futures contract averaged \$4.39 per MMBtu and implied volatility averaged 34 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.40 per MMBtu and \$5.66 per MMBtu.

## Coal

**U.S. Coal Consumption.** Coal consumption for electricity generation fell by 40 million short tons (MMst) (4 percent) in 2011 (U.S. Coal Consumption Chart). Electric power sector coal consumption is forecast to decline by an additional 2 percent in 2012 as generation from natural gas, nuclear, and wind increases and electricity consumption grows by less than 1 percent. EIA expects electric power sector coal consumption to continue declining in 2013 as increased output from other generation sources meets growing demand for electricity.

**U.S. Coal Supply.** U.S. coal production remained nearly flat in 2011 as production growth in the Interior and Appalachian regions offset a decline in the Western region (U.S. Coal Production Chart). The significant increase in coal exports in 2011 was balanced by lower domestic consumption and a drawdown in inventories. EIA expects coal production to decline by about 2 percent in 2012 as domestic consumption and exports fall. EIA forecasts that the decline in production will

continue in 2013 as consumption falls slightly and inventory withdrawals continue (U.S. Electric Power Sector Coal Stocks Chart).

**U.S. Coal Trade.** U.S. coal exports of 107 MMst in 2011 were the highest since 1991. In anticipation of continued strong exports, several North American ports have announced plans to expand facilities to export coal. Facilities have been upgraded in the Hampton Roads, VA, area, and significant terminal upgrades to Gulf Coast coal-handling facilities are currently underway. Canada's Pacific coal terminals are undergoing expansion to meet Asian demand for coal and to help facilitate increasing exports from the U.S. Western Region. Several potential sites for new coal export facilities have been identified in the Pacific Northwest (Oregon and Washington), but no final decisions have been made.

**U.S. Coal Prices.** Delivered coal prices to the electric power sector 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 (5.8 percent increase from 2010). Looking forward, several factors are exerting downward pressure on the average delivered coal price, including lower demand for coal to generate electricity due to lower natural gas prices and concerns about the effects of the implementation of pending environmental requirements. EIA forecasts the average delivered coal price to be slightly lower than the 2011 level in 2012 and 2013.

## Electricity

**U.S. Electricity Consumption.** EIA expects that total U.S. consumption of electricity will rise slightly during 2012 and then grow by 1.8 percent during 2013 (U.S. Total Electricity Consumption Chart). Much of the growth in consumption during 2012 will come from the commercial and industrial sectors. In contrast, moderate weather this year leads to reduced consumption in the residential sector. Temperatures during January were much warmer than normal, particularly in the Southeast, where a large proportion of homes heat with electricity. This lower winter consumption of electricity combined with projected lower summer temperatures is expected to push electricity sales to the residential sector down 1.2 percent in 2012. The total number of U.S. households is expected to grow 1.3 percent during 2013, which would be the highest growth rate since 1998. The increased number of households is projected to lead to a relatively strong 2.1 percent increase in residential electricity consumption in 2013.

**U.S. Electricity Generation.** EIA projects that total U.S. generation by all sectors will average 11.3 terawatt-hours per day during 2012. Coal is expected to fuel about 41.7 percent of this generation, down 0.8 percentage point from last year. During 2013,

EIA expects coal's share of generation to fall to 41.2 percent. In contrast, the share of generation fueled by natural gas is forecast to rise quite rapidly this year, growing from 24.6 percent in 2011 to 26.1 percent in 2012, primarily as a result of lower hydroelectric generation in the West and low natural gas fuel costs. The natural gas share of generation rises slightly in 2013 to 26.2 percent (U.S. Electricity Generation Chart).

**U.S. Electricity Retail Prices.** Average U.S. residential electricity prices are forecast rise by 0.5 percent in 2012 before falling by a similar amount in 2013 (U.S. Residential Electricity Prices Chart). Regional price changes during 2012 vary from a decline of 2.5 percent in the Mountain region to an increase of 2.2 percent in New England.

### **Renewables and Carbon Dioxide Emissions**

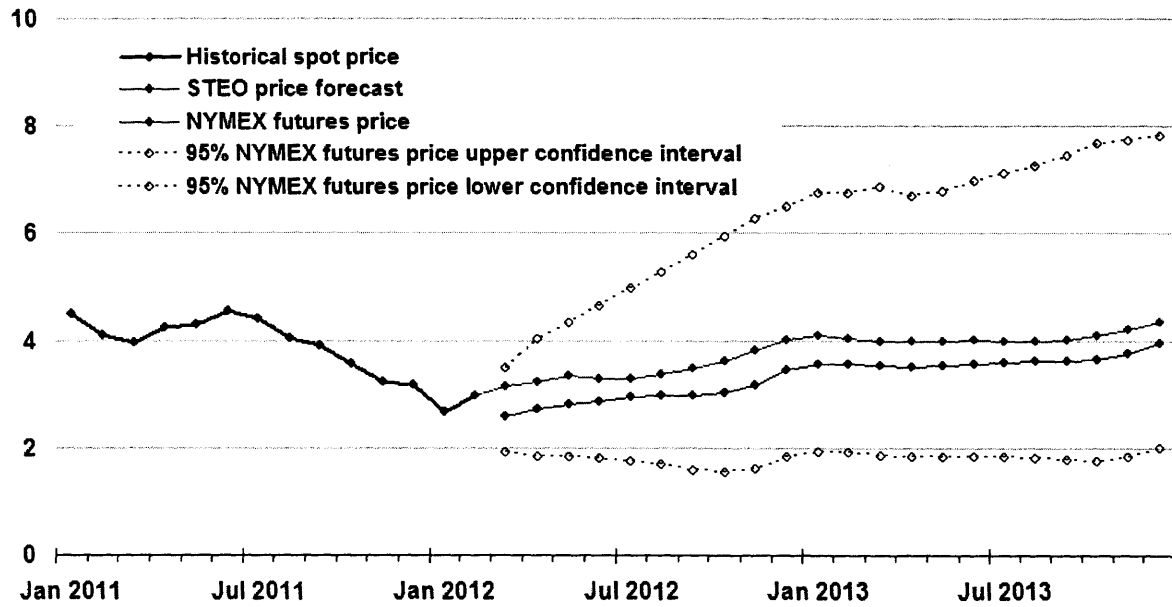
**U.S. Renewables.** After growing 13 percent in 2011, EIA expects the total renewable energy supply to decline by 3.6 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of a return to long-term average hydropower resource levels with hydropower supply falling by 0.5 quadrillion Btu (16 percent). The decline in hydropower from the 2011 level offsets growth in other renewable energy supplies. In 2013, renewables supply increases 2.1 percent, as non-hydropower renewables continue to increase.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to grow from an average of 909 thousand bbl/d in 2011 to 933 thousand bbl/d in 2012, and 938 thousand bbl/d in 2013. EIA estimates that biodiesel production in 2011 averaged about 58 thousand bbl/d (885 million gallons of total annual production). Forecast biodiesel production remains at 58 thousand bbl/d in 2012, then grows to 67 thousand bbl/d in 2013.

**U.S. CO<sub>2</sub> Emissions.** After declining by 1.2 percent in 2011, fossil fuel emissions are projected to increase by 0.2 percent in 2012 and remain flat in 2013. This modest change is the result of increasing emissions from natural gas while petroleum and coal emissions are either flat or declining over these projection years. (U.S. Carbon Dioxide Emissions Growth Chart).

## Henry Hub Natural Gas Price

dollars per million Btu

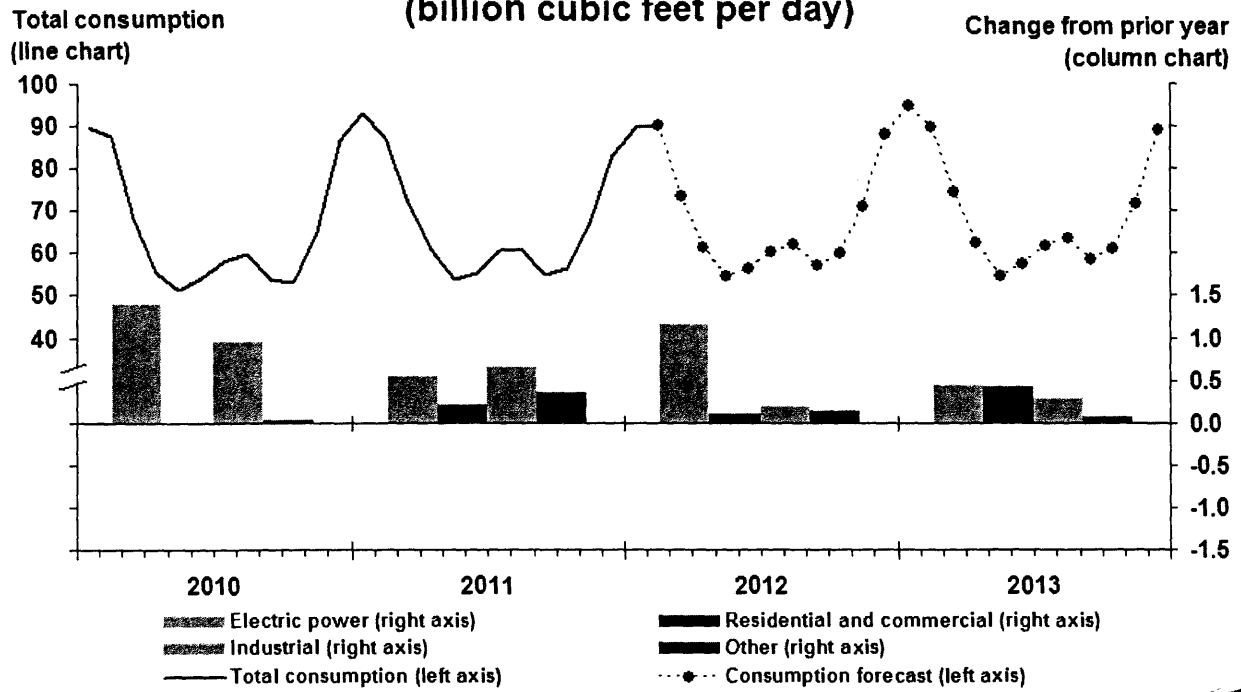


Note: Confidence interval derived from options market information for the 5 trading days ending February 2, 2012  
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, February 2012



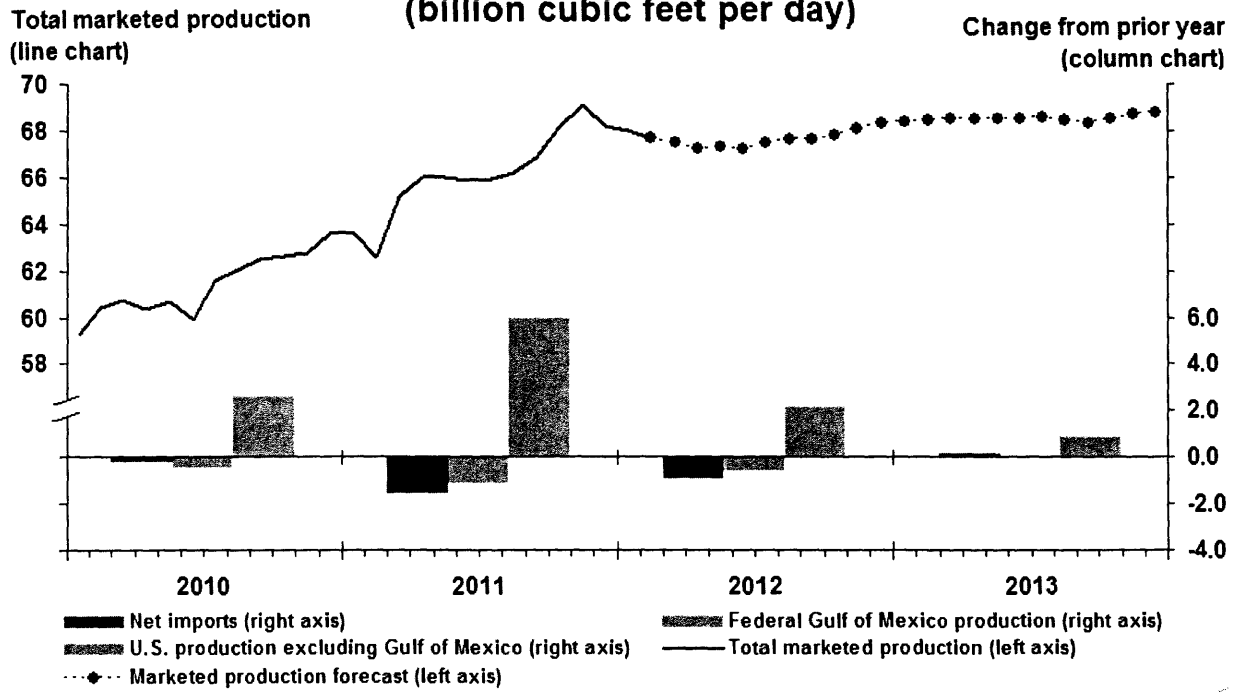
## U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, February 2012



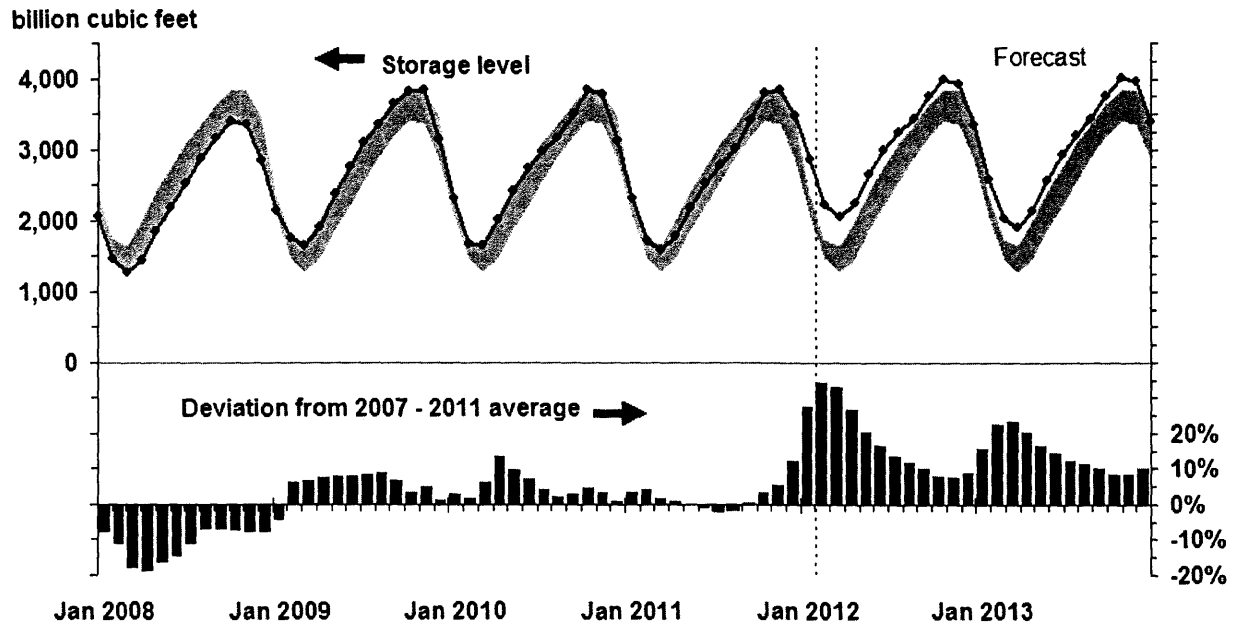
## U.S. Natural Gas Production and Imports (billion cubic feet per day)



Source: Short-Term Energy Outlook, February 2012



### U.S. Working Natural Gas in Storage



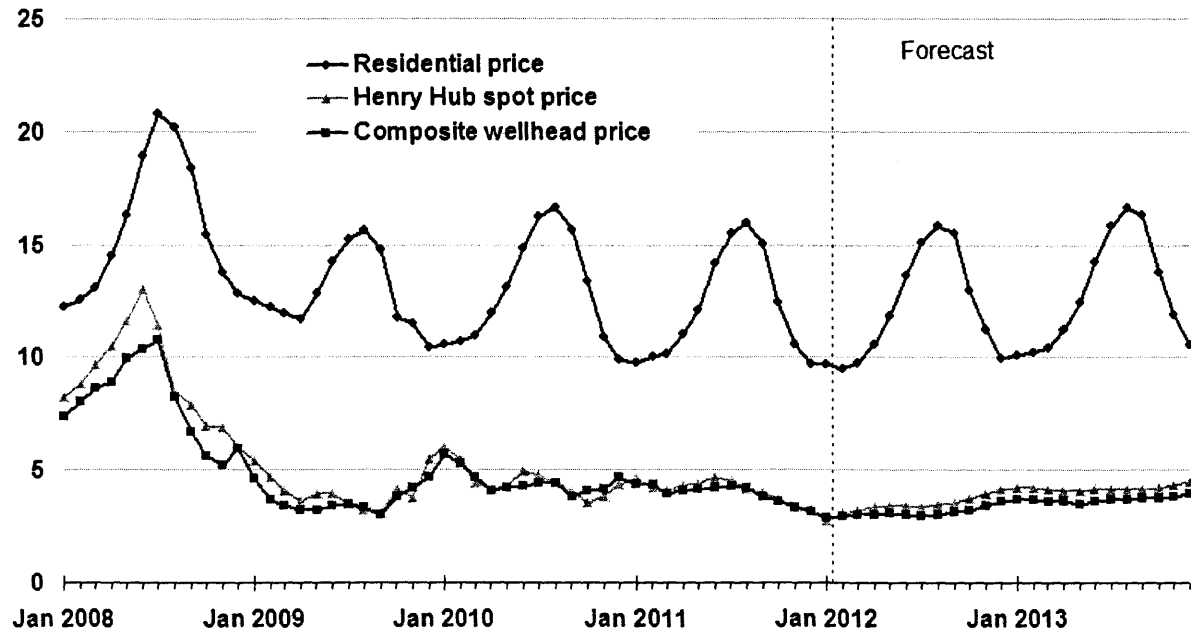
Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, February 2012



### U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, February 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, 2011</b>									<b><u><u>\$148,188</u></u></b>
May	(\$1,396)	\$0	\$892	(\$504)	17,596	\$0.3941	\$6,935	(\$7,439)	140,749
June	33,915	0	837	34,752	9,855	0.5102	4,258 2/	30,494	171,243
July	68,988	0	1,054	70,042	6,564	0.5102	3,349	66,693	237,936
August	76,995	0	1,530	78,525	5,973	0.5102	3,047	75,478	313,414
September	25,141	0	2,066	27,207	6,611	0.5102	3,373	23,834	337,248
October	54,572	0	2,227	56,799	8,236	0.5102	4,202	52,597	389,845
November	18,005	0	2,594	20,599	17,707	0.5102	9,034	11,565	401,410
December	12,176	0	2,668	14,844	29,901	0.5102	15,255	(411)	400,999
January 2012	(8,290)	0	2,661	(5,629)	35,493	0.5102	18,108	(23,737)	377,262
<b>Balance @ January 31, 2012</b>									<b><u><u>\$377,262</u></u></b>

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

2/ Reflects 6,634.4 dk @ \$0.3941 and 3,220.6 dk @ \$0.5102.

**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, 2011</b>									<b><u><u>(\$5,922)</u></u></b>
May	(\$17,358)	\$0	(\$95)	(\$17,453)	22,049	(\$0.1136)	(\$2,505)	(\$14,948)	(20,870)
June	(11,488)	0	(208)	(11,696)	8,011	(0.0178)	(653) 2/	(11,043)	(31,913)
July	(4,652)	0	(288)	(4,940)	9,020	(0.0178)	(161)	(4,779)	(36,692)
August	(3,906)	0	(320)	(4,226)	9,676	(0.0178)	(172)	(4,054)	(40,746)
September	(25,158)	0	(348)	(25,506)	10,802	(0.0178)	(192)	(25,314)	(66,060)
October	(1,098)	0	(529)	(1,627)	13,245	(0.0178)	(236)	(1,391)	(67,451)
November	(4,349)	0	(535)	(4,884)	24,583	(0.0178)	(438)	(4,446)	(71,897)
December	6,776	0	(564)	6,212	34,308	(0.0178)	(611)	6,823	(65,074)
January 2012	9,788	0	(513)	9,275	33,208	(0.0178)	(591)	9,866	(55,208)
<b>Balance @ January 31, 2012</b>									<b><u><u>(\$55,208)</u></u></b>

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

2/ Reflects 5,327.7 dk @ (\$0.1136) and 2,683 dk @ (\$0.0178).