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

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PO Box 176
Fergus Falls, MN 56538-0176
1-877-267-4764

January 31, 2012

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

Re: Cost of Gas Adjustment (COG)
February 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 (71st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (71st Revised Sheet No. 8), showing the February 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.4239 per mcf for residential and firm general service customers and a decrease of $0.4312 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for February 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4312 since the last COG filing. There has been an increase in pipeline charges of $0.0073 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.4239 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.

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

Rita A. Mulkern
Regulatory Affairs Manager

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
71st Revised Sheet No. 1.1
Canceling 70th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$7.1642	$8.4382
			Over 10 MCF	1.0540		8.2182
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$7.1642	$9.3382
			Over 10 MCF	1.9540		9.1182
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$2.6757	$3.8148
			Next 2,600 MCF	0.8931		3.5688
			Over 3,000 MCF	0.7411		3.4168
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$2.6757	$4.7148
			Next 2,600 MCF	1.7931		4.4688
			Over 3,000 MCF	1.6411		4.3168
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$2.6757	$3.9148
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: January 31, 2012 **Effective Date:** February 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
71st Revised Sheet No. 8
Canceling 70th 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.	3.9019	(2.0089)	0.5102	2.4032	(1.9944)	(0.0178)	(2.0122)
Current Adj.	0.0073	(0.4312)	0.0000	(0.4239)	(0.4312)	0.0000	(0.4312)
Total Adj.	3.9092	(2.4401)	0.5102	1.9793	(2.4256)	(0.0178)	(2.4434)
Total Rate:	$3.9750	$2.6790	$0.5102	$7.1642	$2.6935	($0.0178)	$2.6757

Date Filed: January 31, 2012

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

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
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		16.3454	12	1,558,763	1.1109
Trans Canada - Demand Charge	7,947		22.8961	12	2,183,464	1.5562
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068		16.3454	5	414,192	0.2952
Trans Canada - Seasonal	5,068		22.8961	5	580,187	0.4135
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					$5,557,009	3.9750
Estimated Weighted Average Commodity Cost	1,403,100	1/	2.6790		3,758,905	2.6790
Gas Cost Reconciliation Adjustment						0.5102
Total Current Firm Gas Cost					$9,315,914	7.1642
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.9793

Interruptible	
Estimated Weighted Average Commodity Cost	$2.6790
Gas Cost Reconciliation Adjustment	(0.0178)
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	2.6757
Base Cost of Gas	5.1191
Accumulated Adjustment	($2.4434)

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

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0145

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

Rates Effective February 1, 2012	$/Dk	
FT-A - Zone 1-1	$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	16.3454	Per dk/Mo.
Trans Canada Pipeline Demand Charge	22.8961	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.3454	Per dk/Day
Trans Canada - Seasonal	22.8961	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:	2.6790	Per dk

Base Rate Effective September 1, 1981		
Demand Charge	$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation		
Firm		
Demand 1/	$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

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

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A – Maximum Rates				
Zone 1-1	$0.0130	$0.0018	$0.0148	1.66%
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	
IT and AOT				
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
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	$0.1737	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1737	$0.0000

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

Third Revised Sheet No. 50
Superseding
Second Revised Sheet No. 50

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	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 Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$5.683	$15.153	$5.473	$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	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/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

1/ The minimum reservation rate is equal to zero.
2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0005 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.

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

Third Revised Sheet No. [illegible]
Superseding
Second Revised Sheet No. 54

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	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.

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

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

Low space heating demand resulting from mild weather across much of the U.S., record levels of natural gas in storage and strong domestic supply likely contributed to the decrease in the index price from the previous month. The Energy Information Administration (EIA) reported storage levels nationwide as of January 20, 2012 were 21.4 percent above the five-year average and 20.7 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

January 2012

Short-Term Energy Outlook

January 10, 2012 Release

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2013.

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $100 per barrel in 2012, $5 per barrel higher than the average price last year. 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 1.8 percent in 2012 and 2.5 percent in 2013, while world real GDP (weighted by oil consumption) grows by 2.9 percent and 3.8 percent in 2012 and 2013, respectively.

- The forecast of average household heating expenditures for all heating fuels has been lowered from the first forecast for the current winter published in the October 2011 *Outlook*, primarily as a result of the warm first half of this heating season. Average household heating oil expenditures are now expected to increase by 4 percent this winter heating season (October 1 to March 31) compared with last winter. In contrast, natural gas and propane expenditures are projected to decline by 7 percent and 1 percent, respectively, and electricity expenditures are 2 percent lower than last winter's levels.

- EIA expects regular-grade motor gasoline retail prices to average $3.48 per gallon in 2012, 4 cents per gallon lower than last year, and $3.55 per gallon in 2013. During the April through September peak driving season each year, prices are forecast to average about 5 cents per gallon higher than the annual average. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the April through September period.

- Natural gas working inventories continue to set new record highs and ended December 2011 at an estimated 3.5 trillion cubic feet (Tcf), about 12 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot

price forecast is $3.53 per million British thermal units (MMBtu), a decline of almost $0.50 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average $4.14 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Absent a significant oil supply disruption, EIA expects the recent tightening of world oil markets to moderate in 2012 and resume in 2013. World oil 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-Organization of the Petroleum Exporting Countries (non-OPEC) countries increases by 0.9 million bbl/d in 2012 and 0.8 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 in OPEC member countries 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, OPEC members not increase production, or projected non-OPEC projects come online more slowly than expected, oil prices could be significantly higher. 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 lower prices.

Global Crude Oil and Liquid Fuels Consumption. World oil consumption grew by an estimated 1.0 million bbl/d in 2011 to 88.1 million bbl/d. EIA expects that this growth will accelerate over the next two years, with consumption reaching 89.4 million bbl/d in 2012 and 90.9 million bbl/d in 2013. OECD consumption fell by 420 thousand bbl/d in 2011 and is expected to decline again in 2012 as very modest demand growth in North America will be more than offset by demand decline in Europe. A projected European economic recovery contributes to a small increase in forecast OECD consumption in 2013. Non-OECD countries are expected to account for most of the world's growth over the next two years, with the largest contributions coming from China, the Middle East, and Brazil (World Liquid Fuels Consumption Chart). EIA expects non-OECD consumption growth will slow slightly, from 1.5 million bbl/d in 2011 to 1.4 million bbl/d in 2012 and to 1.3 million bbl/d in 2013.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 910 thousand bbl/d in 2012 and a further 760 thousand bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 290 thousand bbl/d and 250 thousand bbl/d in 2012 and 2013, respectively, stemming 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 production in the Kashagan field in 2013 and increase production annually by an average of 125 thousand bbl/d. Production also increases in Colombia, Norway, and China. Notable production declines occur in Russia, Mexico, and Sudan and the United Kingdom.

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 90 thousand bbl/d and 590 thousand bbl/d in 2012 and 2013, respectively. OPEC non-crude petroleum liquids, which are not subject to production targets, increase by 410 thousand bbl/d in 2012 and by 250 thousand bbl/d in 2013. EIA expects that OPEC surplus production capacity will increase from about 2.3 million bbl/d at the end of 2011 to 3.7 million bbl/d at the end of 2013, in part due to the assumed recovery of Libyan production to pre-disruption levels over the forecast period (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 56.4 days of forward-cover (days-of-supply), which is the highest end-of-year level in terms of forward-cover since 1994. Projected OECD oil inventories decline slightly over the forecast, with days of forward-cover falling from current levels to 54.9 days at the end of 2013 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. At this time last year, EIA had projected that the WTI crude oil price would average about $93 per barrel in 2011, rising to an average $99 per barrel in the fourth quarter 2012. The final average WTI price for 2011 was $95 per barrel. A monthly average high of $109.53 per barrel for April followed the disruption in Libyan crude oil production, while a monthly low of $85.52 for September, stemming from deteriorating expectations of world economic growth, contributed to lower demand growth forecasts. EIA's current forecast for WTI crude oil spot prices averages $101 per barrel in the fourth quarter 2012, rising to an average of $106 per barrel in the fourth quarter of 2013 (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for March 2012 delivery during the 5-day period ending January 5, 2012 averaged $101.47 per barrel. Implied volatility averaged 35 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in March 2012 of $81 per barrel and $127

per barrel, respectively. Last year at this time, WTI for March 2011 delivery averaged $91 per barrel and implied volatility averaged 28 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $76 per barrel and $109 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. In 2011, total U.S. liquid fuels consumption fell by an estimated 310 thousand bbl/d (1.6 percent) from 2010 (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounted for most of the decline for the year, falling by 240 thousand bbl/d (2.7 percent). In contrast, distillate fuel oil consumption rose by 50 thousand bbl/d (1.4 percent). Recovery in industrial output as well as increases in non-petroleum imports were the main reasons for the distillate fuel consumption growth.

The next two years are expected to see only small changes in total liquid fuels consumption, with growth of about 90 thousand bbl/d in 2012 and about half that amount in 2013. Motor gasoline consumption, constrained by slowing driving-age population growth and the improving fuel economy of new vehicles, falls by 20 thousand bbl/d (0.2 percent) annually in both 2012 and 2013. Distillate fuel consumption, however, continues to rise at an average 80 thousand bbl/d (2.0 percent) each year, buoyed by continued growth in industrial output and non-petroleum imports.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 90 thousand bbl/d in 2011 to 5.57 million bbl/d. A 370-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 240-thousand bbl/d decline in output in the Federal Gulf of Mexico (GOM). GOM production for 2011 was revised downwards from last month's *Outlook* based on currently available production data reported by the Bureau of Ocean Energy Management.

Forecast total crude oil production increases by 170 thousand bbl/d in 2012 and by a further 80 thousand bbl/d in 2013. Continued increases in lower-48 onshore production of 270 thousand bbl/d in 2012 and 110 thousand bbl/d in 2013 overshadow declines of about 30 thousand bbl/d in Alaskan output each year as well as a decline of 80 thousand bbl/d in GOM production in 2012 (U.S. Crude Oil and Liquid Fuels Production Chart). This rising trend in production continues to be 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 1,193 on December 29, 2011.

In 2011, three southeastern Pennsylvania refineries – Sunoco's Marcus Hook and Philadelphia refineries along with ConocoPhillip's Trainer refinery - that comprise over 50% of the total refining capacity in the Northeast were proposed for sale. Two of these refineries (Marcus Hook and Trainer) have already been idled. Some of the lost capacity is offset by the return to full operations in October 2011 of the 182,000 bbl/d Delaware City, Delaware refinery, owned by PBF Energy Company. The Gulf Coast is likely to be a significant alternate supplier with a recent major capacity addition at Marathon Petroleum Corporation's Garyville, Lousiana refinery and a planned expansion at Motiva's Port Arthur, Texas refinery, due to be completed in 2012. In addition, a recent expansion at Conoco Phillip's Wood River refinery in Illinois may free up some supply that had come to the Midwest from the Gulf Coast. EIA also expects increased gasoline imports into the Northeast. However, reduced short-term product supply flexibility due to longer delivery times and potential transportation bottlenecks for sources outside the region could contribute to higher Northeast prices and price volatility. For a more detailed analysis on Northeast Refining Activity, see EIA's *Reductions in Northeast Refining Activity: Potential Implications for Petroleum Product Markets*.

For the first time since 1949, the United States was a net exporter of refined petroleum products in 2011, with gross product exports averaging 380 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 through the forecast horizon, with net product exports averaging 310 thousand bbl/d in 2012 and 290 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 the total net import share of consumption will remain near 2011 levels in 2012 and 2013, as continued growth in domestic crude oil output exceeding the growth in liquid fuels consumption offsets an expected reduction in the drawdown in domestic commercial and government stocks from the 2011 level of 160 thousand bbl/d.

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, as higher crude oil costs ($0.59 per gallon) and refinery gasoline margins ($0.12 per gallon) pushed retail prices up. EIA expects the regular-grade gasoline retail price to average $3.48 per gallon in 2012 as slightly higher crude oil prices are more than offset by lower refinery gasoline margins (U.S. Gasoline and Crude Oil Prices Chart). The projected continuing increase in crude oil prices in 2013 contributes

to the increase in the forecast average annual regular-grade gasoline retail price to $3.55 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged $3.84 per gallon in 2011, will average $3.85 per gallon in 2012 and $3.93 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. In 2011 gasoline prices fell below wholesale diesel prices by 16 cents per gallon. EIA expects the gasoline wholesale price to weaken further relative to diesel wholesale prices, averaging 19 cents per gallon below diesel in 2012 and 21 cents per gallon lower in 2013.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 68.2 billion cubic feet per day (Bcf/d) in 2012, an increase of 1.3 Bcf/d (2.0 percent) from 2011. From 2011 to 2012, projected consumption increases in all sectors, with the largest volume increase (0.7 Bcf/d) coming from the electric power sector. Natural gas consumption growth continues into 2013, with projected total consumption averaging 69.1 Bcf/d. 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 4.5 Bcf/d (7.4 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. EIA expects production to grow by 1.4 Bcf/d (2.2 percent) in 2012 and 0.7 Bcf/d (1.0 percent) in 2013 as low prices reduce new drilling plans and consumption grows at a measured pace. In the face of continued low spot and future prices as well as record high storage levels for this time of year, drillers appear to have begun cutting back on new production plans for 2012. According to Baker Hughes, the natural gas rig count has fallen to 809 as of December 29, 2011, from a 2011 high of 936 in mid-October. However, high initial production rates from new wells, associated natural gas production from oil drilling, and a backlog of uncompleted or unconnected wells contribute to our forecast of further production increases in 2012, albeit at a significantly lower rate than 2011.

Pipeline gross imports are expected to fall by 0.4 Bcf/d (4.1 percent) in 2012 as domestic production grows and displaces Canadian sources. This follows a 0.6 Bcf/d (6.8 percent) decline in gross imports in 2011. Pipeline gross exports are expected to grow by 0.2 Bcf/d (4.5 percent) in 2012 as production grows near the Mexican border area, particularly in the Eagle Ford shale play.

Liquefied natural gas (LNG) imports are expected to decline by 0.2 Bcf/d (26 percent) in 2012 as higher global LNG market prices reduce LNG's competitiveness in the U.S. market. A small amount of LNG will continue to arrive at U.S. terminals in 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 ended December at 3,472 Bcf, a record high for this time of year. An unusually warm winter so far combined with the domestic production increases throughout the year has contributed to large storage accumulations. Inventory levels at the end of October 2012 and 2013 are expected to set new record highs at about 3,960 Bcf and 3,990 Bcf, respectively. Total natural gas working storage design capacity of active fields was estimated at 4,388 Bcf in April 2011, but regional storage constraints could occur below that level. Unusually warm winters or mild summers could potentially strain available storage capacity over the next two years, leading to temporary shut-in production and lower prices for natural gas.

U.S. Natural Gas Prices. At this time last year, EIA had projected that the Henry Hub natural gas spot price would average $4.02 per MMBtu in 2011, rising to an average $4.50 per MMBtu in 2012. The final average Henry Hub spot price for 2011 was $4.00 per MMBtu. The current forecast for 2012 natural gas prices is significantly lower than at this time last year, as continued growth in production and a very warm start to the winter have contributed to record-high natural gas inventories. EIA now expects the Henry Hub spot price will average $3.53 per MMBTU in 2012. In 2013, the forecast spot price rises to an average of $4.14 per MMBtu.

Natural gas futures prices for March 2012 delivery (for the 5-day period ending January 5, 2012) averaged $3.05 per MMBtu, and the average implied volatility was 40 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for March 2012 contracts are $2.29 per MMBtu and $4.06 per MMBtu. At this time last year, the March 2011 natural gas futures contract averaged $4.39 per MMBtu and implied volatility averaged 43 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.21 per MMBtu and $6.02 per MMBtu.

Coal

U.S. Coal Consumption. Coal consumption for electricity generation fell by 30 million short tons (MMst) (3.1 percent) in 2011. Electric power sector coal consumption is forecast to decline by an additional 2.1 percent in 2012 as generation from natural gas, nuclear and wind increases and electricity consumption remains flat. EIA expects the decline in electric power sector coal consumption to continue in 2013, although at a slower rate, as increases from other sources continue to displace coal-fired electricity generation.

U.S. Coal Supply. U.S. coal production remained at nearly the same level for a second consecutive year in 2011, as production growth in the Appalachian and Interior regions offset declines 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 2 percent in 2012 as domestic consumption and exports fall. Coal production in the Western region, which is primarily used for power generation, is projected to grow slightly in 2012 while production from the Appalachian and Interior regions declines. EIA forecasts that the decline in production will continue in 2013 as consumption falls and inventory withdrawals continue. EIA expects the drawdown of inventories at electric power plants will continue at a slower rate in 2012 and 2013 (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. EIA expects U.S. coal exports will remain higher than recent levels but stay below the 2011 level, as supply from other major coal-exporting countries recovers from disruptions. Forecast U.S. coal exports are at 98 MMst in 2012 and 2013.

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 (6.0 percent increase). Looking forward, several factors are exerting downward pressure on the average delivered coal price, including lower demand for coal to generate electricity, lower natural gas prices, and concerns about the effects of the U.S. Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) and the timing of its implementation. EIA forecasts the average delivered coal price to remain close to its 2011 level in 2012 and 2013.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity will rise slightly during 2012 and then grow by 1.6 percent during 2013 (U.S. Total

Electricity Consumption Chart). Cooling degree-days throughout the United States during 2010 and 2011 were about 18 percent higher than the 30-year average. The National Oceanic and Atmospheric Administration projects summer temperatures in 2012 will be very close to the 30-year normal. As a result, less electricity is consumed for air conditioning, pushing electricity sales to the residential sector down by 0.5 percent this year. An increase in the growth rate in the number of households drives a 2.1 percent increase in residential electricity consumption during 2013. Increasing growth in economic activity over the next two years should contribute to 0.8-percent growth in retail sales of electricity to the industrial sector during 2012 and 1.7-percent growth in 2013.

U.S. Electricity Generation. On December 21, 2011, EPA finalized its Mercury and Air Toxics Standards (MATS) rule regarding maximum achievable control technology for power plants. On December 30, the U.S. Court of Appeals in the District of Columbia issued a stay on the implementation of the EPA's Cross-State Air Pollution Rule (CSAPR), which was originally scheduled to become effective January 1, 2012. Both CSAPR and MATS introduce extra uncertainty into EIA's projections of the mix of fuels used for electricity generation. The timing and pace of change in industry generation dispatch patterns remains unclear. EIA expects coal to fuel 42.2 percent of total generation this year and 41.5 percent in 2013, down from a share of 43 percent during 2011. In contrast, the share of generation fueled by natural gas is forecast to rise from 24.4 percent in 2011 to 25.4 percent in 2012 and 25.8 percent in 2013 (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. After having risen by 2.1 percent between 2010 and 2011, EIA expects average U.S. residential electricity prices to rise only 0.6 percent in 2012 and then stay flat in 2013 (U.S. Residential Electricity Prices Chart).

Renewables and Carbon Dioxide Emissions

U.S. Renewables. The time period from 2011 to 2013 presents a complex landscape in terms of renewable energy projections. A 30-percent grant available for renewables that could be taken in lieu of both an investment tax credit (ITC) and a production tax credit (PTC) expired at the end of 2011. Both the PTC and ITC for wind expire for projects built after 2012, and these credits for other eligible renewables at the end of 2013. Solar energy is not eligible for the PTC but has its own ITC that is reduced from 30 percent to 10 percent at the end of 2016.

After growing 12 percent in 2011, EIA expects the total renewable energy supply to decline by 2.3 percent in 2012 as a 13-percent decline in hydropower from the 2011

level offsets growth in other renewable energy supplies. In 2013, renewable energy supply is projected to increase by 2.1 percent.

Wood and wood waste is second only to hydropower in terms of the total energy supplied by renewable sources. After declining by 1.6 percent between 2010 and 2011, it is projected to grow in 2012 and 2013 by 1.7 percent and 2.2 percent, respectively.

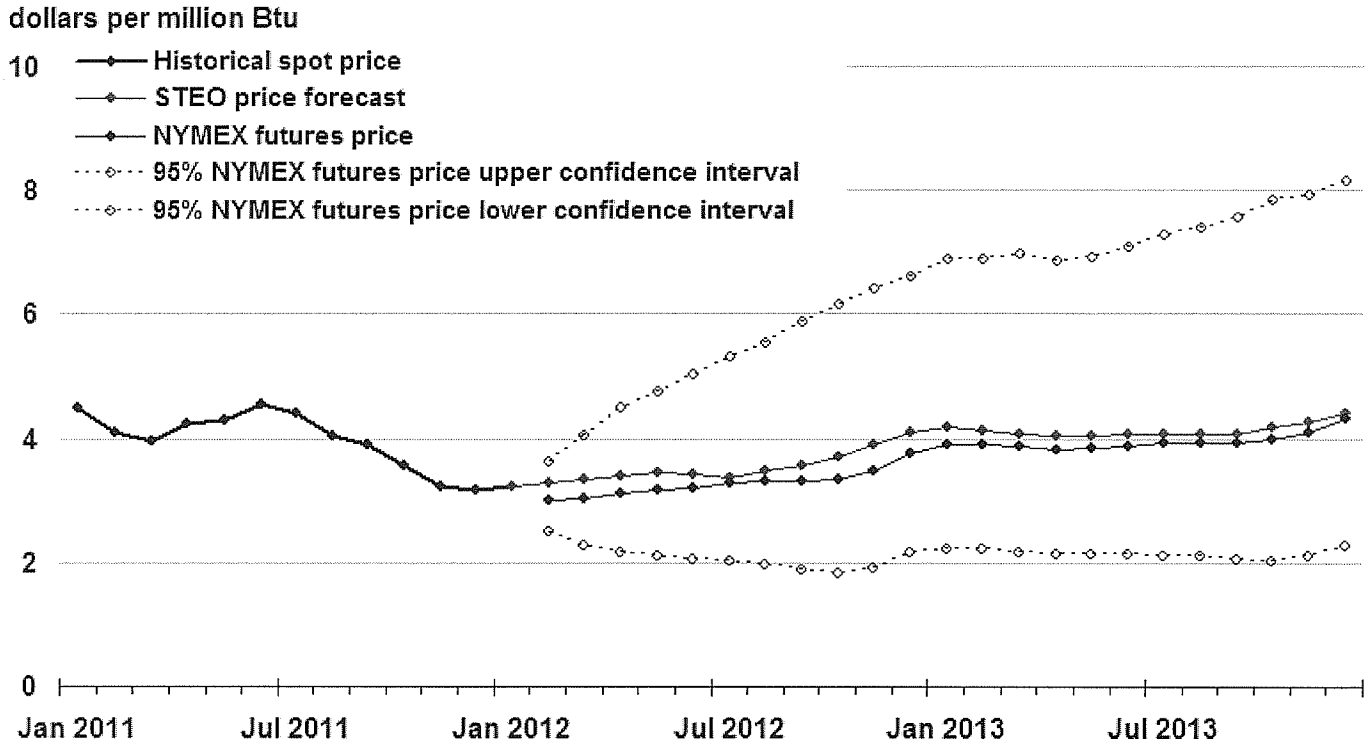
While wind energy has shown robust growth in recent years (24 percent between 2010 and 2011), its growth is projected to slow relative to recent rates. It is projected to grow 9.4 percent in 2012 and 11.3 percent in 2013, as capacity added by the end of 2012 is available for the entire year in 2013.

The solar energy supply is projected to grow by 6.7 percent and 8.5 percent in 2012 and 2013, respectively, reaching a total of 0.13 quadrillion Btu in 2013. About 80 percent of the near-term growth in central-station solar energy (both solar photovoltaic and solar thermal) is from projects being developed in the southwestern United States where resources are abundant and of high quality. However, on a Btu basis, 89 percent of solar energy in 2010 was related to residential consumption in the form of photovoltaic and solar thermal collectors. This percentage is projected to decline as more central power station projects come on line.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to grow from an average of 907 thousand bbl/d in 2011 to 929 thousand bbl/d in 2012 and 934 thousand bbl/d in 2013. EIA estimates that biodiesel production in 2011 averaged about 56 thousand bbl/d (860 million gallons total annual production). Forecast biodiesel production grows slightly higher to 62 thousand bbl/d in 2012 and 75 thousand bbl/d in 2013.

U.S. Energy-Related CO_2 Emissions. Fossil fuel emissions are projected to remain flat in 2012 and 2013, as increasing emissions from natural gas are offset by declines in coal emissions (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

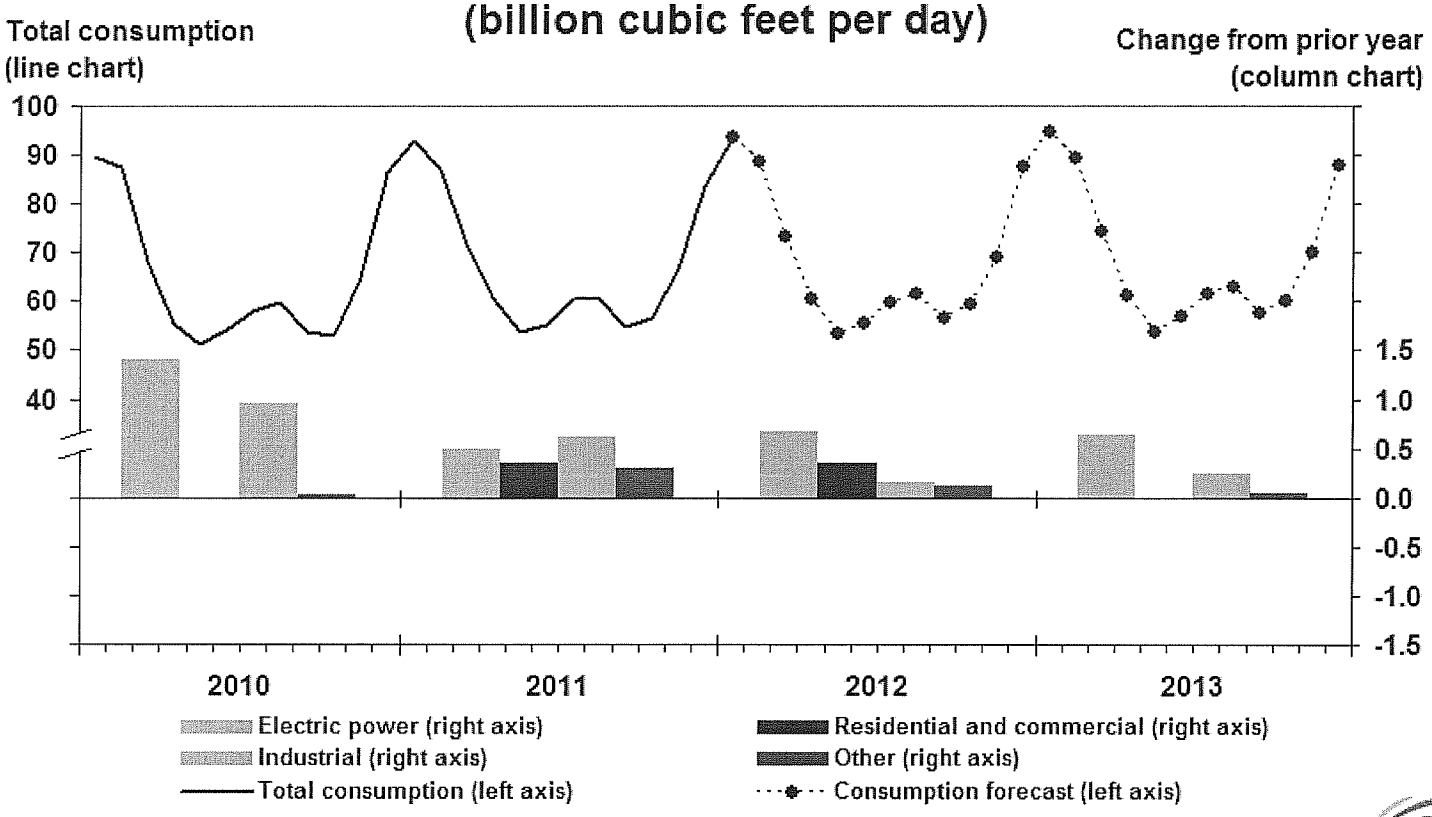


Note: Confidence interval derived from options market information for the 5 trading days ending January 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, January 2012

eia

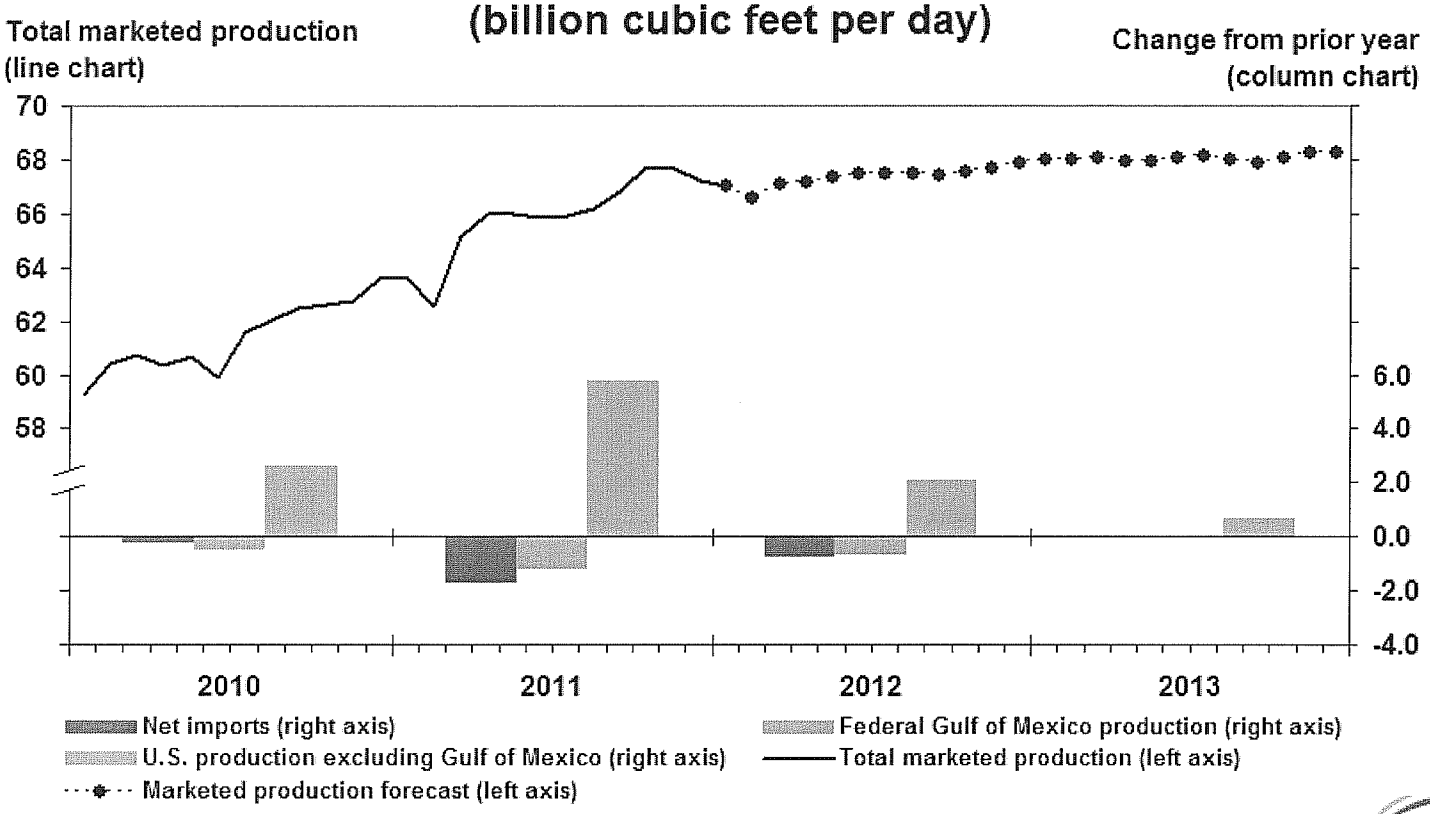
U.S. Natural Gas Consumption
(billion cubic feet per day)



Source: Short-Term Energy Outlook, January 2012

eia

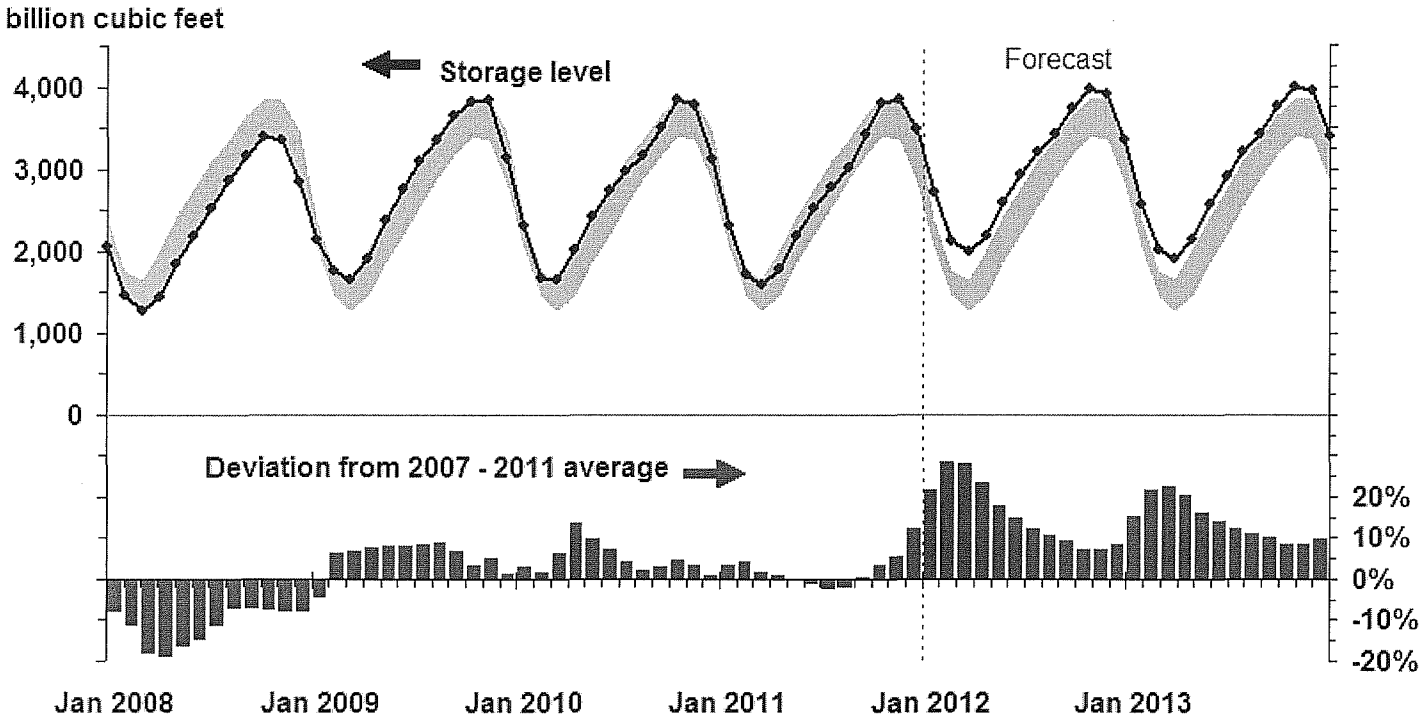
U.S. Natural Gas Production and Imports
(billion cubic feet per day)



Source: Short-Term Energy Outlook, January 2012

eia

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, January 2012

eia

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2011										**$148,188**
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
Balance @ December 31, 2011										**$400,999**

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

	(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, 2011									**($5,922)**
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)
Balance @ December 31, 2011									**($65,074)**

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).