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

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
1-877-267-4764

March 29, 2012

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

Re: Cost of Gas Adjustment (COG)
April 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 (73rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (73rd Revised Sheet No. 8), showing the April 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.4264 per mcf for residential and firm general service customers and a decrease of $0.4779 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for April 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.4779 since the last COG filing. There has been an increase in pipeline charges of $0.0515 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.4264 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
73rd Revised Sheet No. 1.1
Canceling 72nd Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$6.4221	$7.6961
			Over 10 MCF	1.0540		7.4761
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.4221	$8.5961
			Over 10 MCF	1.9540		8.3761
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$1.9944	$3.1335
			Next 2,600 MCF	0.8931		2.8875
			Over 3,000 MCF	0.7411		2.7355
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$1.9944	$4.0335
			Next 2,600 MCF	1.7931		3.7875
			Over 3,000 MCF	1.6411		3.6355
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$1.9944	$3.2335
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: March 29, 2012 **Effective Date:** April 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
73rd Revised Sheet No. 8
Canceling 72nd 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.	3.7969	(2.6435)	0.5102	1.6636	(2.6290)	(0.0178)	(2.6468)
Current Adj.	0.0515	(0.4779)	0.0000	(0.4264)	(0.4779)	0.0000	(0.4779)
Total Adj.	3.8484	(3.1214)	0.5102	1.2372	(3.1069)	(0.0178)	(3.1247)
Total Rate:	$3.9142	$1.9977	$0.5102	$6.4221	$2.0122	($0.0178)	$1.9944

Date Filed: March 29, 2012

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

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 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		15.0126	12	1,431,662	1.0204
Trans Canada - Demand Charge	7,947		23.5224	12	2,243,190	1.5987
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068		15.0126	5	380,419	0.2711
Trans Canada - Seasonal	5,068		23.5224	5	596,058	0.4248
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					$5,471,732	3.9142
Estimated Weighted Average Commodity Cost	1,403,100	1/	1.9977		2,802,973	1.9977
Gas Cost Reconciliation Adjustment						0.5102
Total Current Firm Gas Cost					$8,274,705	6.4221
Base Cost of Gas						5.1849
Accumulated Adjustment						$1.2372

Interruptible	
Estimated Weighted Average Commodity Cost	$1.9977
Gas Cost Reconciliation Adjustment	(0.0178)
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	1.9944
Base Cost of Gas	5.1191
Accumulated Adjustment	($3.1247)

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
APRIL 2012

Rates Effective April 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	15.0126	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.5224	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	15.0126	Per dk/Day
Trans Canada - Seasonal	23.5224	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:	1.9977	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

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	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.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
April 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 April 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).

Seasonal record storage levels resulting from warm winter temperatures nationwide likely contributed to the expected decrease in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of March 23, 2012 were 58.6 percent above the five-year average and 50.3 percent above last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: http://www.eia.doe.gov.

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 17.

Independent Statistics & Analysis
U.S. Energy Information Administration

March 2012

Short-Term Energy Outlook

March 6, 2012 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $106 per barrel in 2012, $5 per barrel higher than in the previous *Outlook* and $11 per barrel higher than the average price last year. Supply disruptions in the Middle East and Africa contributed to a significant increase in world crude oil prices during February. EIA has increased the forecast 2012 average cost of crude oil to U.S. refiners from $105 per barrel in last month's *Outlook* to $115 per barrel. Constraints in transporting crude oil from the U.S. midcontinent region contribute to the expected continuing discount for WTI relative to other world crude oil prices. EIA expects WTI prices to remain relatively flat in 2013, averaging about $106 per barrel, while the U.S. refiner average cost of crude oil averages $110 per barrel.

- EIA expects regular-grade motor gasoline retail prices to average $3.79 per gallon in 2012 and $3.72 per gallon in 2013, compared with $3.53 per gallon in 2011. During the April through September summer driving season this year, prices are forecast to average about $3.92 per gallon with a peak monthly average price of $3.96 per gallon in May. The June 2012 New York Harbor Reformulated Blendstock for Oxygenate Blending (RBOB) futures contract averaged $3.26 for the five trading days ending March 1. Based on the market value of futures and options contracts, there is a 39 percent probability that its price at expiration will exceed $3.35 per gallon, consistent with a monthly average regular-grade gasoline retail price of roughly $4.00 per gallon in June. The value of futures and options contracts imply a 2 percent probability that its price at expiration will exceed $4.35 per gallon, consistent with a monthly average regular-grade gasoline retail price of approximately $5.00 per gallon.

- The warm weather this winter has resulted in natural gas working inventories that continue to set new record seasonal highs, with February 2012 ending at an estimated 2.44 trillion cubic feet (Tcf), about 41 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is $3.17 per million British thermal units (MMBtu), a decline of about $0.83 per MMBtu

from the 2011 average spot price. EIA expects that Henry Hub spot prices will average $3.96 per MMBtu in 2013.

- EIA expects electricity generation from coal to decline by nearly 5 percent in 2012 as generation from natural gas increases by about 9 percent. EIA forecasts that electricity generation from coal will increase by 3.8 percent in 2013, as projected coal prices to the power sector fall slightly while natural gas prices increase, and coal regains some of its power sector generation share.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects increases in global consumption to outpace production growth in countries outside of the Organization of the Petroleum Exporting Countries (OPEC) during the forecast period. World liquid fuels consumption grows by an annual average of 1.1 million barrels per day (bbl/d) in 2012 and 1.4 million bbl/d in 2013. Supply from non-OPEC countries increases by 0.7 million bbl/d in 2012 and by 0.8 million bbl/d in 2013. EIA expects that the market will rely on both inventories and increases in crude oil and non-crude liquids production from OPEC members to meet world demand growth.

Significant uncertainties could push oil prices higher or lower than projected. A number of non-OPEC countries are currently undergoing supply disruptions. Oil prices could be higher than projected in this *Outlook* if current disruptions intensify, new non-OPEC projects come online more slowly than expected, or OPEC members do not increase production. On the demand side, if the pace of global economic growth fails to recover in countries belonging to the Organization for Economic Cooperation and Development (OECD), or if economic growth slows in non-OECD countries, prices could be lower.

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 89.0 million bbl/d in 2012 and 90.3 million bbl/d in 2013. Non-OECD countries will account for essentially all of the world's consumption growth over the next two years, with the largest contributions coming from China, the Middle East, and Central and South America (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 690 thousand bbl/d in 2012 and by a further 750 thousand bbl/d in 2013. The largest area of forecast non-OPEC growth will be North America, where production increases by 360 thousand bbl/d and 190 thousand bbl/d in 2012 and 2013,

respectively, resulting from continued production growth from U.S. onshore shale formations and Canadian oil sands. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field in the next year, will increase its total production annually by an average of 170 thousand bbl/d in both 2012 and 2013. In Brazil, production increases annually by an average of 120 thousand bbl/d over the next two years, with increased output from its offshore, pre-salt oil fields. Production also increases in Colombia and China over the next two years, while production declines in Russia, Mexico, and the North Sea.

Several notable disruptions to non-OPEC production commenced or intensified over the last two months, leaving an average of around 1 million bbl/d offline in February. In the former Sudan, an unresolved dispute between Sudan and the newly independent South Sudan over transit fees and other issues caused the latter to shut in all of its production at the end of January. EIA now projects that total production from Sudan and South Sudan, which averaged about 430 thousand bb/d in 2011, will average 200 thousand bbl/d in 2012 and recover to 370 thousand bbl/d in 2013.

In Yemen and Syria, civil conflict continues to compromise a considerable portion of each country's oil output. Yemen's production is already impaired by an ongoing outage to the Marib pipeline and was further curtailed in February by a strike at the country's largest oil field. EIA projects that Yemen's production will average 180 thousand bbl/d in 2012, and 200 thousand bbl/d in 2013, down from the country's pre-crisis production level of around 260 thousand bbl/d. In Syria, damage to a major pipeline that feeds one of the country's two refineries has exacerbated the country's production problems. EIA now expects Syria to produce 260 thousand bbl/d in 2012 and recover to 360 thousand bbl/d in 2013, still below the country's pre-crisis production level of 400 thousand bbl/d.

Disruptions stemming from technical issues have temporarily curbed production in the United Kingdom and Canada, but production is expected to recover in the near future.

OPEC Supply. EIA expects that OPEC members' crude oil production will continue to rise over the next two years to accommodate the projected increase in world oil demand. Projected OPEC crude oil production increases by about 490 thousand bbl/d and 560 thousand bbl/d in 2012 and 2013, respectively. EIA's forecast does not factor in any potential effects that the impending European Union embargo and other sanctions may have on Iran's crude oil production because it is too early to assess the country's ability to place its supply elsewhere. However, EIA estimates that Iran's crude oil production has fallen since mid-2011 and is projected to continue to decline through the forecast period. OPEC non-crude petroleum liquids (condensates,

natural gas liquids, coal-to-liquids, and gas-to-liquids), which is not covered by OPEC's production quotas, will increase by 220 thousand bbl/d in 2012 and by 60 thousand bbl/d in 2013.

OPEC members serve as the "swing" producers in the world market, because only OPEC producers possess surplus or "spare" oil production capacity. EIA expects that OPEC surplus production capacity will increase from about 2.4 million bbl/d in January 2012 to 3.7 million bbl/d at the end of 2013, as Libyan production capacity recovers to pre-disruption levels, allowing 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 56.9 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 are at 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 2.57 billion barrels, or 55.4 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 higher than last month's *Outlook*, averaging about $106 per barrel in both 2012 and 2013 (West Texas Intermediate Crude Oil Price Chart), compared with $100 and $104 per barrel for 2012 and 2013, respectively, in the previous *Outlook*. The projected WTI price discount to the average U.S. refiner acquisition cost of crude oil narrows over the forecast from about $10 per barrel in the second quarter of 2012 to $4 per barrel by the fourth quarter of 2013, as physical pipeline capacity constraints diminish. The projected average refiner acquisition cost (RAC) of crude oil averages $115 per barrel in 2012 and $110 per barrel in 2013.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for May 2012 delivery during the 5-day period ending March 1, 2012 averaged $108.60 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 May 2012 at $88 per barrel and $134 per barrel, respectively. Last year at this time, WTI for May 2011 delivery averaged $101 per barrel and implied volatility averaged 36 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $79 per barrel and $129 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 the 2010 average level (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounted for much of that decline, shrinking by 260 thousand bbl/d (2.9 percent). In contrast, distillate fuel oil consumption rose by 50 thousand bbl/d (1.3 percent), brought about by recovery in industrial output and freight transport.

Even with forecast U.S. real gross domestic product growth of 2.2 percent in 2012 and 2.4 percent in 2013, the next two years are expected to see only small changes in total liquid fuels consumption, with a decline of about 60 thousand bbl/d (0.3 percent) in 2012 and an increase of 110 thousand bbl/d (0.6 percent) in 2013. Motor gasoline consumption, constrained by slowing growth in the driving-age population and the improving fuel economy of new vehicles, is forecast to fall by 60 thousand bbl/d in 2012 and decline by 10 thousand bbl/d in 2013. Distillate fuel consumption, however, continues to rise.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 120 thousand bbl/d to 5.60 million bbl/d in 2011. A 390-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 U.S. total crude oil production increases by 230 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 overshadow declines averaging about 20 thousand bbl/d in Alaskan output and a 90-thousand bbl/d decrease in 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 1,293 on March 2, 2012.

Since the idling of two refineries late last year, the East Coast lost another important source of supply last month when HOVENSA closed its St. Croix refinery in the U.S. Virgin Islands. The market transition on the East Coast thus far has been relatively smooth. However, if Sunoco's Philadelphia refinery closes in July 2012, as Sunoco has announced may occur if no buyer is found, the Northeast could be significantly affected, as replacing the additional lost volumes will be complicated by reduced access to distribution systems. Adequate refining capacity is available outside of the East Coast to replace product supplies, but logistical constraints to delivering product

to the Northeast in the short term may present significant challenges. For a more detailed analysis on Northeast refining issues, see EIA's "*Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets*."

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

U.S. Petroleum Product Prices. Regular-grade gasoline retail prices averaged $3.53 per gallon in 2011, $0.74 per gallon (27 percent) higher than the 2010 average. The price increase in 2011 largely reflected higher crude oil costs ($0.60 per gallon) and higher refinery gasoline margins ($0.10 per gallon). EIA expects the regular-grade gasoline retail price to increase to an average of $3.79 per gallon in 2012 due to higher crude oil prices (U.S. Gasoline and Crude Oil Prices Chart), and regular-grade gasoline prices this summer are expected to average close to $4.00 per gallon in May. Forecast regular-grade gasoline prices decline to an average of $3.72 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged $3.84 per gallon in 2011, will average $4.15 per gallon in 2012, and $4.11 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 gasoline wholesale prices to remain lower than diesel wholesale prices, with gasoline prices averaging 17 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 68.9 billion cubic feet per day (Bcf/d) in 2012, an increase of 2.1 Bcf/d (3.1 percent) from 2011. EIA expects that large gains in electric power use will offset declines in residential and commercial use. Because of the much-warmer-than-normal winter this year, EIA expects residential and commercial consumption to fall by 0.5 percent and 0.1 percent, respectively, in 2012, reflecting a downward revision in projected consumption from last month's *Outlook*.

Projected consumption of natural gas in the electric power sector grows by close to 9 percent in 2012, primarily driven by the relative advantages of natural gas over coal for power generation in a growing number of economic dispatch decisions. Consumption in the electric power sector peaks in the third quarter of 2012, when electricity demand for air conditioning is highest.

Growth in total natural gas consumption continues into 2013, with forecast consumption averaging 69.3 Bcf/d (U.S. Natural Gas Consumption Chart). Consumption in the residential and commercial sectors increases in 2013 because of the forecast return to near-normal temperatures next winter. The increase in consumption in these sectors more than offsets a decline in power sector natural gas burn stemming from the projected increase in natural gas prices relative to coal prices later this year and next.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by an estimated 4.8 Bcf/d (7.9 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 year-over-year 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 fell to 691 as of March 2, 2012, from a 2011 high of 936 in mid-October. So far, the lower rig count has not impacted production levels, partly reflecting improved drilling efficiency. However, fewer horizontal natural gas wells, particularly in areas such as the Haynesville Shale, contribute to small short-term production declines through June 2012. These declines reverse later in the year as prices rise, wet natural gas production rises, and associated gas production from oil wells increases.

Pipeline gross imports are expected to fall by 0.6 Bcf/d (7.0 percent) in 2012 as domestic supply displaces Canadian sources. The warm winter in the United States also adds to the year-over-year decline in imports, particularly to the Northeast, where imported natural gas is often a marginal source of supply. Pipeline gross exports grew by 1.0 Bcf/d in 2011, driven by increased exports to Mexico, and are expected to continue to grow, although at a slower rate, in 2012 and 2013.

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

U.S. Natural Gas Inventories. Working natural gas inventories continue to set new seasonal record highs as a v ery warm winter has contributed to much-lower-than-normal inventory draws. As of February 24, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,513 Bcf, 756 Bcf greater than last year's level. EIA expects the winter heating season, which goes through March 31, will end with working inventories of about 2,270 Bcf, which would be highest end-of-March level on record. In the last 20 years, end-of-March inventories have not risen over 1,700 Bcf, and prior to that, rose above 2,100 Bcf just once, in 1983. With only a few exceptions, weekly inventory withdrawals have been smaller than the previous five-year average during this year's winter heating season. EIA expects inventory levels at the end of October in both 2012 and 2013 will set new record highs as well (U.S. Working Natural Gas in Storage Chart).

U.S. Natural Gas Prices. Natural gas spot prices averaged $2.50 per MMBtu at the Henry Hub in February 2012, down $0.17 per MMBtu from the January 2012 average and the lowest average monthly price since February 2002. Abundant storage levels, as well as ample production, have contributed to the recent low prices. EIA expects that the Henry Hub spot price will begin to recover soon and will average $3.17 per MMBtu in 2012, and $3.96 per MMBtu in 2013, down $0.18 per MMBtu and $0.11 per MMBtu from last month's *Outlook*, respectively (U.S. Natural Gas Prices Chart).

Natural gas futures prices for May 2012 delivery (for the 5-day period ending March 1, 2012) averaged $2.69 per MMBtu, and the average implied volatility was 42 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for May 2012 contracts are $1.96 per MMBtu and $3.69 per MMBtu. At this time last year, the May 2011 natural gas futures contract averaged $3.98 per MMBtu and implied volatility averaged 33 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.09 per MMBtu and $5.11 per MMBtu.

Coal

U.S. Coal Consumption. Electric power sector coal consumption is forecast to decline by nearly 5 percent in 2012 as generation from natural gas, nuclear, and wind increases (U.S. Coal Consumption Chart). EIA expects electric power sector coal consumption to drop below 900 million short tons (MMst) for the first time since 1996. Projected power sector coal prices fall slightly next year while natural gas prices increase. In response, EIA expects that electric power sector coal consumption will increase by 1.9 percent in 2013 as the economic competitiveness of coal-fired generation improves.

U.S. Coal Supply. EIA expects coal production to decline by 4.4 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production declines are expected in all coal-producing regions, with the largest occurring in the Interior region (19.3 MMst). EIA projects that secondary inventories will rise in 2012, but decline in the following year, primarily in the electric power sector, as consumption grows (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong but be below the 107 MMst exported in 2011. Forecast U.S. coal exports are 99 MMst in both 2012 and 2013. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

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). However, EIA expects the decline in demand for coal to generate electricity will put downward pressure on coal prices and contribute to the shut-in of higher-cost production. Several companies have recently announced the curtailment of operations, particularly in Appalachia, where production costs at some older mines are high. EIA forecasts the average delivered coal price in 2013 will be about 3 percent lower than the 2011 average price.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity will fall slightly during 2012, and then grow by 1.9 percent during 2013 (U.S. Total Electricity Consumption Chart). Growth in retail sales of electricity to the commercial and industrial sectors during 2012 of 0.7 percent and 0.8 percent, respectively, will be offset by a 2.1 percent decline in residential sector consumption. Residential consumption falls this year as a result of milder weather compared with last year. EIA estimates that U.S. residential electricity consumption during January and February was about 9 percent lower than during the same months of 2011, primarily because of the 17-percent decline in heating degree-days nationwide. Similarly, the projected 15-percent year-over-year decline in U.S. cooling degree-days this year is expected to lead to reduced electricity demand this summer. The total number of U.S. households is expected to grow by 1.4 percent during 2013, which would be the highest growth rate since 1998.

U.S. Electricity Generation. Recent data show that the trend in displacing coal with natural gas as a generation fuel has accelerated in response to the current low price of natural gas delivered to electric generators. U.S. generation fueled by natural gas in December 2011 was 11.6 percent higher than in December 2010. In contrast, coal-fired

generation declined by 20.7 percent over the same period. EIA expects this fuel displacement pattern to continue at least through the first half of 2012, causing the annual average share of total generation fueled by natural gas to rise from 24.8 percent in 2011 to 27.1 percent for 2012. As delivered natural gas prices begin increasing later this year, in response to higher demand and flattening growth in production, EIA expects the trend in fuel displacement will reverse slightly in 2013, with natural gas' share of U.S. generation falling back to an annual average of 26.1 percent (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. The price of natural gas delivered to electric generators is estimated to have averaged about $3.30 per MMBtu in February 2012, which would be its lowest nominal value in 10 years. EIA expects these low fuel costs to be passed through to residential electricity consumers over the next two years. Average U.S. residential electricity prices are forecast to rise by 0.4 percent in 2012, and then fall by 0.9 percent in 2013 (U.S. Residential Electricity Prices Chart). These growth rates compare with an average annual increase of 2.6 percent during the past five years.

Renewables and Carbon Dioxide Emissions

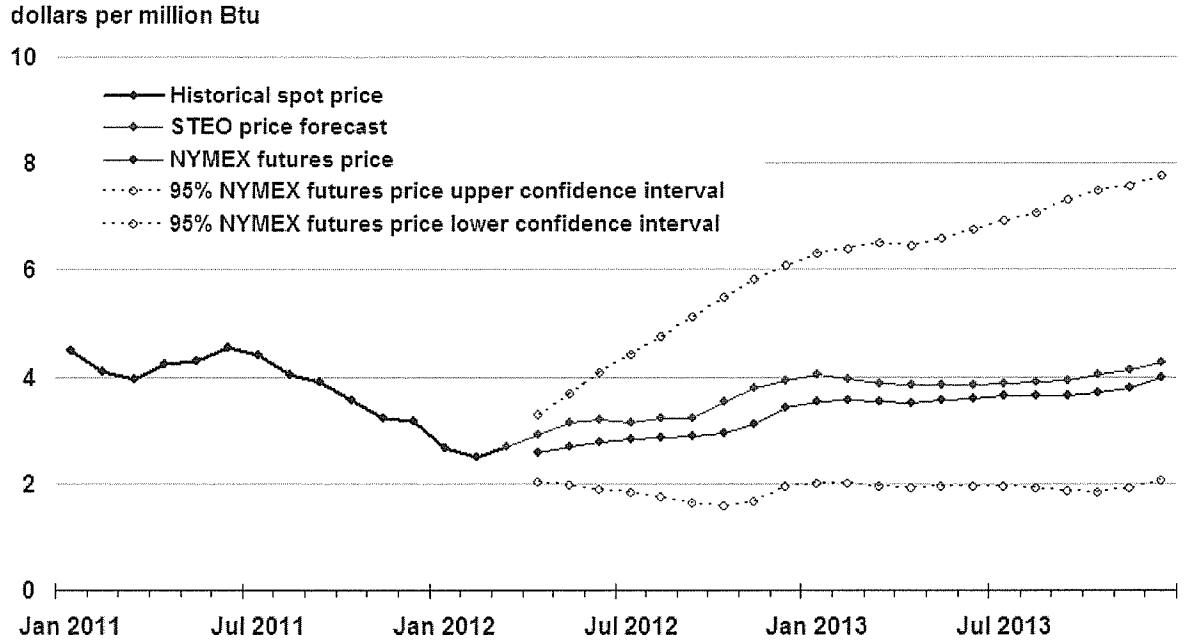
U.S. Renewables. After a banner year in 2011, U.S. hydropower production is assumed to return to long-term average production levels in 2012 and beyond. The strong growth in hydropower combined with growth in other renewables led to a 14 percent increase in total renewable energy supply in 2011. EIA expects the total renewable energy supply to decline by 3.8 percent in 2012 as the reduction in hydropower production offsets continued growth in other renewables (U.S. Renewable Energy Supply Chart). In 2013, renewables supply increases 1.4 percent as non-hydropower renewables continue to increase.

EIA expects fuel ethanol production to grow from an average of 910 thousand bbl/d in 2011 to 920 thousand bbl/d in 2012, and to 930 thousand bbl/d in 2013. U.S. ethanol production is projected to exceed the volume that can easily be used in the U.S. liquid fuels pool, so the Nation will continue to be a net exporter of ethanol over the next two years. EIA estimates that biodiesel production in 2011 averaged about 61 thousand bbl/d (939 million gallons of total annual production). Forecast biodiesel production averages 64 thousand bbl/d in 2012 and 65 thousand bbl/d in 2013.

U.S. CO_2 Emissions. After declining by 2.0 percent in 2011, fossil fuel emissions are projected to fall an additional 0.4 percent in 2012, but increase by 0.9 percent in 2013. After falling by 2.1 percent last year, petroleum emissions continue to decline slightly in 2012, and then increase by 0.4 percent in 2013. Natural gas emissions rise in both

2012 and 2013. Coal emissions fall in 2012 by 3.4 percent, but rise by 1.9 percent in 2013 (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 March 1, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, March 2012

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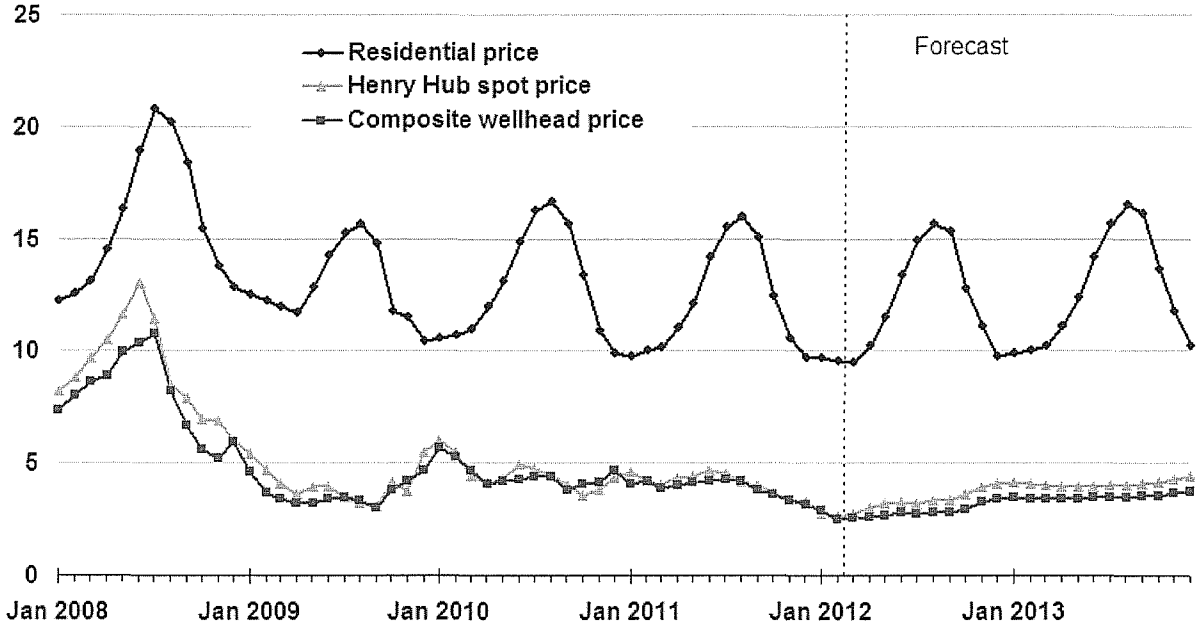
U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, March 2012

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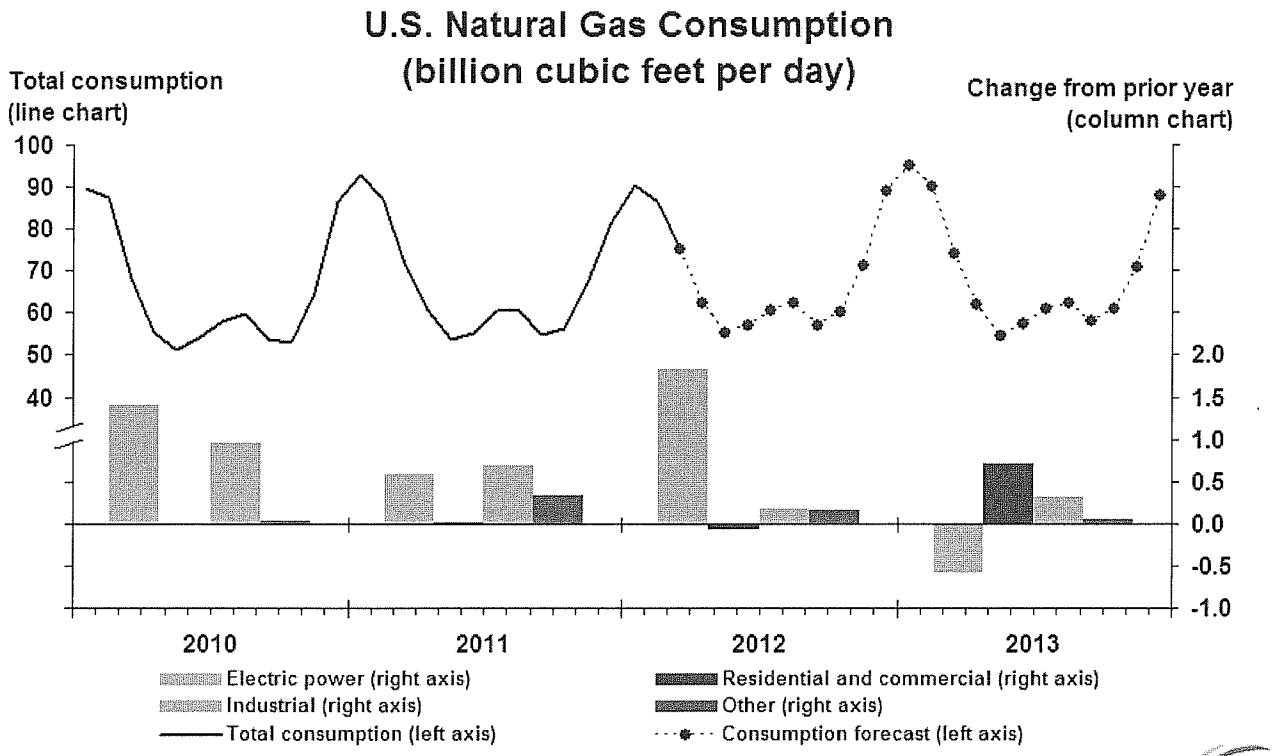
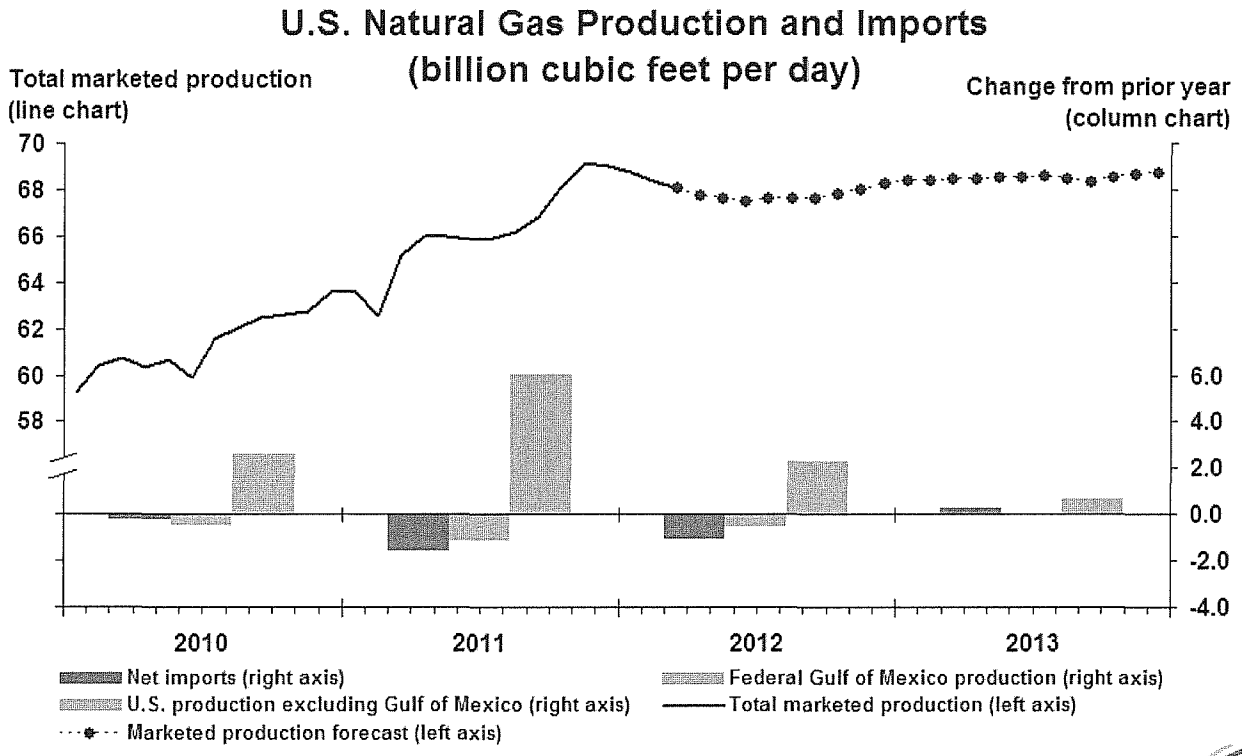
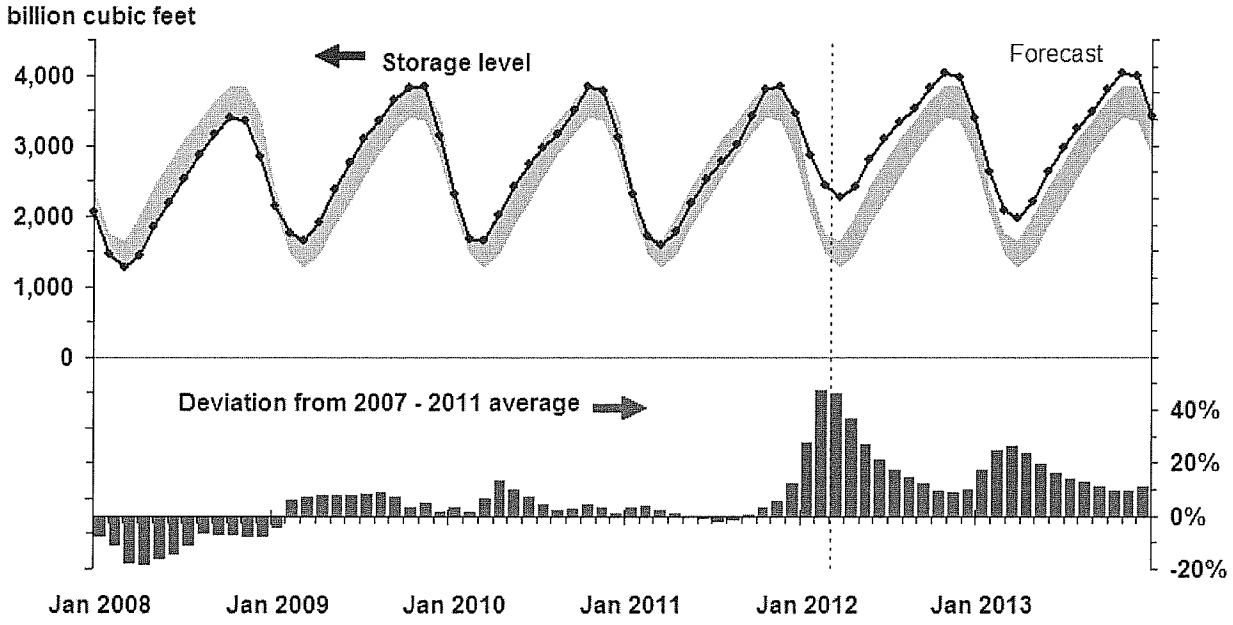


Source: Short-Term Energy Outlook, March 2012



Source: Short-Term Energy Outlook, March 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, March 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
January 2012	(8,290)	0	2,661	(5,629)	35,493	0.5102	18,108		(23,737)	377,262
February	(33,507)	0	2,489	(31,018)	39,715	0.5102	20,262		(51,280)	325,982
Balance @ February 29, 2012										**$325,982**

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)
January 2012	9,788	0	(513)	9,275	33,208	(0.0178)	(591)	9,866	(55,208)
February	(378)	0	(440)	(818)	23,400	(0.0178)	(417)	(401)	(55,609)
Balance @ February 29, 2012									**($55,609)**

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).