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

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May 2, 2011

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

Re: Cost of Gas Adjustment (COG)
May 2011

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 (62nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (62nd Revised Sheet No. 8), showing the May 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.0305 per mcf for residential and firm general service customers and no change for interruptible customers.

Attachment B shows the calculations supporting the gas costs for May 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has not changed since the last COG filing. There has been an increase in pipeline charges of $0.0305 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $0.0305 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, 2010.

Great Plains submitted a check for $600.00 on January 10, 2011 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the $50.00 filing fee associated with this month's COG filing.

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

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Rita A. Mulkern
Regulatory Affairs Manager

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
62nd Revised Sheet No. 1.1
Canceling 61st 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	$8.6587	$9.9327
			Over 10 MCF	1.0540		9.7127
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.9247	$5.0638
			Next 2,600 MCF	0.8931		4.8178
			Over 3,000 MCF	0.7411		4.6658
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.9247	$5.1638
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: May 2, 2011

Effective Date: May 1, 2011

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
62nd Revised Sheet No. 8
Canceling 61st 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.	4.1445	(1.0953)	0.3941	3.4433	(1.0808)	(0.1136)	(1.1944)
Current Adj.	0.0305	0.0000	0.0000	0.0305	0.0000	0.0000	0.0000
Total Adj.	4.1750	(1.0953)	0.3941	3.4738	(1.0808)	(0.1136)	(1.1944)
Total Rate:	$4.2408	$4.0238	$0.3941	$8.6587	$4.0383	($0.1136)	$3.9247

Date Filed: May 2, 2011 **Effective Date:** May 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2011

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	3,000		3.7671	5	56,507	0.0403
TFX Seasonal	3,000		15.1530	5	227,295	0.1620
NOVA - Demand Charge	7,947		17.5434	12	1,673,009	1.1924
Trans Canada - Demand Charge	7,947		24.0026	12	2,288,984	1.6314
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068		17.5434	5	444,550	0.3168
Trans Canada - Seasonal	5,068		24.0026	5	608,226	0.4335
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					$5,929,773	4.2408
Estimated Weighted Average Commodity Cost	1,403,100	1/	4.0238		5,645,794	4.0238
Gas Cost Reconciliation Adjustment						0.3941
Total Current Firm Gas Cost					$11,575,567	8.6587
Base Cost of Gas						5.1849
Accumulated Adjustment						$3.4738

Interruptible	
Estimated Weighted Average Commodity Cost	$4.0238
Gas Cost Reconciliation Adjustment	(0.1136)
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	3.9247
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.1944)

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
MAY 2011

Rates Effective May 1, 2011	$/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	17.5434	Per dk/Mo.
Trans Canada Pipeline Demand Charge	24.0026	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.5434	Per dk/Day
Trans Canada - Seasonal	24.0026	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:	4.0238	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	$0.0019	$0.0149	1.47%
Zone 1-2	$0.0130	$0.0019	$0.0149	1.98%
Zone 2-2	$0.0130	$0.0019	$0.0149	0.51%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1-1	$0.1368	$0.0019	$0.1387	1.47%
Zone 1-2	$0.1737	$0.0019	$0.1756	1.98%
Zone 2-2	$0.0834	$0.0019	$0.0853	0.51%
Minimum Rate	$0.0130	$0.0019	$0.0149	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0019 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: 0.17% for Zone 1-1, 0.22 % for Zone 1-2, and 0.05% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
LMS – Load Management Cost Reconciliation Adjustment		$0.0265	

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 Commodity Rate Per Dekatherm, Per Day	Minimum Commodity Rate Per Dekatherm, Per Day
PAL	$0.1737	$0.0000

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

Second Revised Sheet No. 50
Superseding
First Revised Sheet No. 50

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
RESERVATION RATES	TF12 Base	TF12 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	0.0383	0.0214			0.0175	0.0000	0.0383	0.0214
Field	Market	0.0383	0.0214	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

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 $0.0019 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.

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

Second Revised Sheet No. 51
Superseding
First Revised Sheet No. 51

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	0.0383	0.0214			0.0175	0.0000	0.0383	0.0214
Field	Market	0.0383	0.0214	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

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	0.0019	0.0019	0.0019	0.0019
MOPS Transmission	1.5337	0.0000	0.0019	0.0019	0.0019	0.0019
Tivoli - Downstream	0.6827	0.0000	0.0019	0.0019	0.0019	0.0019
Other Gulf Coast	4.8169	0.0000	0.0019	0.0019	0.0019	0.0019

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 $0.0019 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 $0.0019.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
May 2011

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 May monthly price for the AECO Index is expected to remain in the same range as the previous month index. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

The anticipated price stability from last month's index price is due to record levels of domestic production offsetting the effects of lingering cool weather over portions of the eastern U.S. which prolonged the usage of natural gas for space heating. The EIA reported a record daily production of domestic natural gas of 64.5 bcf on March 31, 2011. The year over year price comparison indicates the anticipated May 2011 AECO price will be approximately five percent higher than the May 2010 index price. The Energy Information Administration (EIA) reported storage levels nationwide as of April 15, 2011 were 1.4 percent above the five-year average and 9.1 percent below last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 16.

Independent Statistics & Analysis
U.S. Energy Information Administration

April 2011

Short-Term Energy and Summer Fuels Outlook

April 12, 2011 Release

Highlights

- West Texas Intermediate (WTI) crude oil spot prices averaged $89 per barrel in February and $103 per barrel in March. The WTI price has continued to rise in recent days, reaching $112 on April 8. Crude oil prices are currently at their highest level since 2008. EIA expects oil markets to continue to tighten over the next two years given expected robust growth in world oil demand and slow growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries. These conditions result in an expected drawdown of global petroleum stocks and a call for increasing production from OPEC member countries, which will reduce surplus crude oil production capacity at a time when the disruption of crude oil exports from Libya and continuing unrest in other Middle East and North African (MENA) countries already highlight significant supply risks. Projected WTI prices average $106 in 2011 and $114 per barrel in 2012, increases of $5 per barrel and $9 per barrel, respectively, from last month's *Outlook*.

- The rise in crude oil prices is reflected in higher petroleum product prices. EIA projects that the retail price of regular-grade motor gasoline will average $3.86 per gallon during this summer's driving season (the period between April 1 and September 30), up from $2.76 per gallon last summer. EIA forecasts the annual average regular retail gasoline price will increase from $2.78 per gallon in 2010 to $3.70 per gallon in 2011 and to $3.80 per gallon in 2012. Current market prices of futures and options contracts for gasoline suggest a 33-percent probability that the national monthly average retail price for regular gasoline could exceed $4.00 per gallon during July 2011.

- Natural gas working inventories ended March 2011 at 1.6 trillion cubic feet (Tcf), slightly below the 2010 end-of-March level. EIA expects that working gas inventories will remain relatively high throughout 2011. The projected Henry Hub natural gas spot price averages $4.10 per million Btu (MMBtu) in 2011, $0.29 per MMBtu lower than the 2010 average. EIA expects the natural gas

market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average of $4.55 per MMBtu.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. The forecast for total world oil consumption grows by an annual average of 1.5 million bbl/d in 2011 and 2012. Supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries grows an average of about 0.4 million bbl/d annually through 2012. Consequently, EIA expects that in order to meet projected demand growth the market will rely on both a drawdown of inventories and significant increases in the production of crude oil and non-crude liquids in OPEC member countries at a time when the disruption of crude oil exports from Libya and continuing unrest in other MENA countries already highlight significant supply risks.

Among the major uncertainties that could push oil prices above or below our current forecast are: the continued unrest in producing countries and its potential impact on supply; decisions by key OPEC member countries regarding their production response to the global increase in oil demand; the rate of economic growth, both domestically and globally; fiscal issues facing national and sub-national governments; and China's efforts to address concerns regarding its growth and inflation rates.

Global Crude Oil and Liquid Fuels Consumption. World crude oil and liquid fuels consumption grew by an estimated 2.3 million bbl/d in 2010 to a record-high level of 86.7 million bbl/d. EIA expects that world liquid fuels consumption will grow by 1.5 million bbl/d in 2011 and by an additional 1.6 million bbl/d in 2012 (World Liquid Fuels Consumption Chart). Countries outside the Organization for Economic Cooperation and Development (OECD) will make up almost all of the growth in consumption over the next two years, with the largest increases coming from China, Brazil, and the Middle East. EIA expects that, among the OECD regions, only North America will show growth in oil consumption over the next two years, offsetting declines in OECD Europe and Japan.

Non-OPEC Supply. EIA projects that non-OPEC crude oil and liquid fuels production will increase by 550,000 bbl/d in 2011, and 230,000 bbl/d in 2012 (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). The greatest increases in non-OPEC oil production during 2011 occur in China, Brazil, and in countries that were formerly part of the Soviet Union where EIA expects annual average production growth of 140,000 bbl/d, 170,000 bbl/d, and 270,000 bbl/d, respectively. In 2012, EIA expects Canadian production to grow by 180,000 bbl/d while China and Brazil grow by 140,000 and 110,000 bbl/d, respectively. Other non-OPEC areas are expected to

decline, including a decrease in North Sea production of 110,000 bbl/d in 2011 and a further 230,000 bbl/d in 2012. Projected U.S. crude oil and liquid fuels production is flat in 2011 and then falls by 130,000 bbl/d in 2012.

OPEC Supply. Forecast OPEC crude oil production increases by only 0.1 million bbl/d in 2011, followed by a significantly larger 1.1 million bbl/d increase in 2012. EIA assumes that about one-half of Libya's production will resume by the end of 2012. EIA has revised its projected OPEC surplus capacity downward, compared with the last *Outlook*. EIA projects that OPEC surplus capacity will fall from 4.2 million bbl/d at the end of 2010 to 3.4 million bbl/d at the end of 2011, followed by a further decline to 2.7 million bbl/d by the end of 2012 (OPEC Surplus Crude Oil Production Capacity Chart). Forecast OPEC non-crude liquids production increases by 0. 7 million bbl/d in 2011 and by 0.3 million bbl/d in 2012.

OECD Petroleum Inventories. EIA expects that OECD onshore inventories will decline from the elevated levels of 2010 following the steep drop in floating storage that has already occurred. Projected on-shore OECD stocks fall by about 78 million barrels in 2011, followed by an additional 43 million barrel decline in 2012. Days of supply (total inventories divided by average daily consumption) drops from a relatively high 58 days during the fourth quarter 2010 to 55.8 days in the last quarter of 2011. EIA expects that the continued increase in consumption and decline in inventories in 2012 will leave inventories at 54.6 days of supply at the end of that year (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. WTI crude oil spot prices averaged $89 per barrel in February then rose to $108 per barrel by the end of March. Projected WTI prices average $106 in 2011 and $114 per barrel in 2012, increases of $5 per barrel and $9 per barrel, respectively, from last month's *Outlook* (West Texas Intermediate Crude Oil Price Chart). Growing volumes of Canadian crude oil imported into the United States contributed to record-high storage levels at Cushing, Oklahoma, and a price discount for WTI compared with similar quality world crudes such as Brent. Consequently, the projected U.S. refiner average acquisition cost of crude oil, which was about $2.50 per barrel below WTI in 2009 and 2010, is $2.20 per barrel above WTI in 2011 and $0.25 per barrel above WTI in 2012.

All energy price forecasts are highly uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for June 2011 delivery over the 5-day period ending April 7 averaged $109 per barrel and implied volatility averaged 30 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in that month of $90 per barrel and $132 per barrel, respectively. Last year at this time, WTI for June 2010 delivery averaged

$83 per barrel with the limits of the 95-percent confidence interval at $68 per barrel and $101 per barrel. Based on WTI futures and options prices, the probability that the monthly average price of WTI crude oil will exceed $120 per barrel in December 2011 is about 32 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below $100 per barrel is about 38 percent.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of petroleum and non-petroleum liquid fuels increased by 380,000 bbl/d (2.0 percent) to 19.1 million bbl/d in 2010 (U.S. Liquid Fuels Consumption Growth Chart). Projected total U.S. liquid fuels consumption increases by 210,000 bbl/d (1.1 percent) in 2011, and by a further 160,000 bbl/d (0.9 percent), to 19.5 million bbl/d, in 2012. Transportation fuels (motor gasoline distillate fuel, and jet fuel) account for about 75 percent of the growth in total consumption in 2011 and almost all of the growth in 2012.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 150,000 bbl/d in 2010 to 5.51 million bbl/d, declines by 30,000 bbl/d in 2011 and by a further 120,000 bbl/d in 2012 (U.S. Crude Oil Production Chart). The forecast includes Alaska production declines of 60,000 bbl/d in 2011 and 10,000 bbl/d in 2012. EIA expects production from the Federal Gulf of Mexico (GOM) to fall by 190,000 bbl/d in both 2011 and 2012. The forecast production declines in Alaska and the GOM are partially offset by projected increases in lower-48 non-GOM production of 220,000 bbl/d in 2011 and 70,000 bbl/d in 2012.

Liquid fuel net imports, including both crude oil and refined products, fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010, primarily because of the decline in consumption during the recession and rising domestic production. EIA forecasts that liquid fuel net imports will average 9.5 million bbl/d in 2011 and 9.9 million bbl/d in 2012, comprising 49 percent and 51 percent of total consumption, respectively.

Summer Transportation Fuels Outlook

The continuing economic recovery tends to boost gasoline and diesel fuel consumption, while the effect of higher retail prices tends to dampen it. These counter-balancing forces are expected to be prominent features of the summer driving season, which EIA defines as April 1 through September 30.

Prices. EIA expects regular-grade gasoline retail prices, which averaged $2.76 per gallon last summer, will average $3.86 per gallon during the current driving season.

The projected monthly average regular retail gasoline price peaks this year at $3.91 per gallon in early summer. Diesel fuel prices, which averaged $2.98 per gallon last summer, are projected to average $4.09 this summer. Weekly and daily national average prices can differ significantly from monthly and seasonal averages, and there is are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 25 cents per gallon or more.

As in the case of crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures options contracts. New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures contracts for July 2011 delivery over the 5-day period ending April 7, averaged $3.15 per gallon. The probability the RBOB futures price will exceed $3.30 per gallon (consistent with a U.S. average regular gasoline retail price above $4 per gallon) in July 2011 is about 33 percent.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in crude oil prices and wholesale margins. Crude oil prices that differ from our forecast would be reflected in the price of motor fuels. Each dollar per barrel of sustained change in crude oil prices relative to the forecast translates into approximately a 2.4 cent-per-gallon change in product prices, absent the consideration of factors specific to the gasoline and diesel fuel markets.

Retail price projections reflect higher prices for the refiner acquisition cost of crude oil, expected to average $112.50 per barrel this summer compared with last summer's average of $74.70 per barrel. EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) to average 53 cents per gallon this summer compared to 36 cents per gallon last summer, largely brought about by continuing strength in world-wide liquid fuels consumption. Similarly, EIA forecasts higher wholesale diesel margins this summer (60 cents per gallon) than last summer (40 cents per gallon).

The projected increase in gasoline prices suggests that vehicle fueling costs for the average U.S. household will be about $825 higher in 2011 than they were in 2010. According to the 2009 National Household Travel Survey (Transportation Energy Data Book, Tables 4.1 and 8.6), U.S. households drove an average 20,251 miles with an average passenger car fuel efficiency of 22.6 miles per gallon. Assuming no change in travel or average fuel economy, the increase in the average annual gasoline retail price (all grades) from $2.40 per gallon in 2009 to $2.83 per gallon in 2010 and a projected $3.75 per gallon in 2011 implies an increase in average annual household expenditures on gasoline from $2,150 in 2009 to $2,535 in 2010 and $3,360 in 2011.

Motor Gasoline. During this summer season, projected motor gasoline consumption increases by 0.5 percent over last summer. Finished motor gasoline is supplied by four sources: domestic refinery output, domestic production and net imports of fuel ethanol for gasoline blending, primary inventories, and net imports of gasoline and gasoline blending components. EIA expects that domestic refinery production will increase by 0.6 percent from last summer, in line with growth in consumption. Projected blending of fuel ethanol increases by 5 percent from last summer. Forecast total gasoline net imports are projected to decline by about 10 percent from the previous summer. Fuel ethanol blending into gasoline averaged 868,000 bbl/d during summer 2010 and EIA forecasts an average 912,000 bbl/d this summer, which is about 9.8 percent of total gasoline consumption.

At the onset of the summer driving season (April 1) total gasoline stocks, at 215.7 million barrels, are 8.3 million barrels below the level of a year-ago, but still about 1 million barrels more than the previous 5-year average for beginning-of-season stocks. (U.S. Gasoline and Distillate Inventories Chart). Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years and are projected to average 48,000 bbl/d this summer, compared with 26,000 bbl/d last summer.

For the 2011 summer season, EIA expects net imports of motor gasoline and blending components to average 630,000 bbl/d, which is lower than the average 700,000 bbl/d seen last summer, due primarily to continued growth in domestic supplies and continuing strength in gasoline export markets.

Diesel Fuel. Projected distillate fuel consumption, which includes diesel fuel and heating oil, averages 3.81 million bbl/d this summer, up 2.3 percent from last summer. That growth is buoyed by continued strength in manufacturing output and foreign trade.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. Refinery output of distillate fuel is projected to average 4.36 million bbl/d this summer, up slightly from the 4.35 million bbl/d last summer.

Biodiesel is a small but growing part of the distillate pool. Biodiesel consumption averaged 20,000 bbl/d last summer and is expected to grow to about 46,000 bbl/d this summer, due in part to the resumption of the biodiesel tax credit..

Distillate inventories are projected to start the summer at 153.5 million barrels, up from 146.0 million barrels last year at this time and a new record for the start of the summer season. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 40,000 bbl/d, far less than the 113,000 bbl/d recorded last summer and the 5-year average summer build of 121,000 bbl/d. As a result, end-of-summer stocks are 161 million barrels, down from the record 166.7 million barrels recorded last summer, but still 11 million barrels above the previous 5-year end-of-summer average.

Continuing strong world demand for distillate fuels is forecast to contribute to continuing high U.S. net exports of distillate fuel averaging 500,000 bbl/d this summer, down slightly from 520,000 bbl/d last summer. In contrast, the United States was a net importer of distillate fuel, averaging 120,000 bbl/d during the summers of 2000 through 2007.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to rise slightly from 2010 levels to 66.7 billion cubic feet per day (Bcf/d) in 2011, primarily because of the increase in consumption in the industrial sector (U.S. Total Natural Gas Consumption Chart). Forecast industrial consumption rises 3.6 percent to 18.7 Bcf/d in 2011, largely driven by the natural-gas-weighted industrial production index, which is expected to increase by 4.3 percent.

Total consumption growth increases by 0.7 percent in 2012 to 67.2 Bcf/d. Natural gas consumption in the industrial and electric power sectors grow by 1.3 percent and 2.9 percent, respectively, which offsets forecast declines in residential and commercial consumption (note, however, that consumption changes relative to 2010 are affected by changes in EIA's methodology for collecting and reporting natural gas consumption data that were implemented in the middle of 2010 to provide more accurate data on seasonal patterns of natural gas use.)

U.S. Natural Gas Production and Imports. EIA expects the growth in natural gas production to slow from the 2.6 Bcf/d (4.5 percent) increase seen in 2010. Total marketed production grows 1.5 Bcf/d (2.4 percent) to 63.3 Bcf/d in 2011 and by 0.5 Bcf/d (0.8 percent) in 2012. For both 2011 and 2012, declines in Federal GOM production are more than offset by increases in production in the lower-48 states.

Marketed natural gas production in December 2010 of 64.0 Bcf/d was the highest rate since February 1973. The latest EIA data for monthly natural gas production show a decline in production in the lower-48 States for January 2011. Some of this decline is

because of "freeze-offs" during the very cold weather that forced some producers to temporarily shut down some production. Production is expected to recover from these freeze-offs before beginning modest declines that will continue through the year because of a falling gas-directed drilling rig count. The number of rigs drilling for natural gas, as reported by Baker Hughes Inc., has fallen from 973 in April 2010 to 889 as of April 8, 2011. The large price difference between petroleum liquids and natural gas on an energy-equivalent basis contributes to an expected shift towards drilling for liquids rather than for dry gas. Increasing consumption in 2012, led by strong growth in the electric power sector, contributes to higher prices and to an economic incentive for producers to resume drilling.

Growing domestic production continues to reduce U.S. reliance on natural gas imports. Pipeline gas from Canada remains the dominant source of U.S. natural gas imports. Because of the earthquake in Japan and subsequent nuclear outages, Japan's demand for LNG as a replacement fuel for electric power generation is expected to increase, contributing to higher global LNG prices. Japan is already the largest importer of LNG in the world, with daily imports averaging more than 9 Bcf/d in 2010. EIA now projects U.S. imports of LNG will average 1.05 Bcf/d in 2011, down from 1.18 Bcf/d in 2010.

U.S. Natural Gas Inventories. On April 1, 2011, working natural gas in storage stood at 1,579 Bcf, slightly below last year's level at this time (U.S. Working Natural Gas in Storage Chart). Cold temperatures and production freeze-offs in January and February contributed to some relatively large draws on inventories despite year-over-year increases in production. EIA expects that inventories, though somewhat below their 2010 levels for the first half of the year, will remain robust.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $3.97 per MMBtu in March, 12 cents lower than the average price in February and 6 cents lower than the March forecast in last month's Outlook (Henry Hub Natural Gas Price Chart). EIA expects that the Henry Hub price will average $4.10 per MMBtu over 2011, a decline of 29 cents from 2010. However, the projected Henry Hub price rises to $4.55 per MMBtu in 2012.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for June 2011 delivery (for the 5-day period ending April 7) averaged $4.29 per MMBtu, and the average implied volatility over the same period was 34 percent. The lower and upper bounds for the 95-percent confidence interval for June 2011 contracts are $3.37 per MMBtu and $5.47 per MMBtu, respectively. At this time last year, the natural gas June 2010 futures contract averaged $4.04 per MMBtu and implied volatility averaged 41 percent. The

corresponding lower and upper limits of the 95-percent confidence interval were $3.00 per MMBtu and $5.50 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA expects an increase of 0.2 percent in total U.S. electricity consumption during 2011 (U.S. Total Electricity Consumption Chart). Retail sales of electricity to the residential sector this year fall 1.9 percent in response to the assumed 16-percent decline in cooling degree-days compared with the hot summer of 2010. Improved economic conditions during 2011 should spur growth in sales of electricity to the commercial and industrial sectors of 1.0 percent and 2.5 percent, respectively. During 2012, total U.S. electricity consumption should grow by 2.3 percent.

U.S. Electricity Generation. EIA projects that total generation by the electric power sector will fall by 0.1 percent during 2011 (U.S. Electric Power Sector Generation Growth Chart). Higher-than-normal precipitation in the Pacific Northwest over the past month has led to increased hydroelectric generation, which is expected to grow by 7.3 percent during 2011. Increases in other renewable generation, especially wind power (up 19 percent during 2011), are offset by declines in coal-fired generation (down 1.8 percent) and nuclear power (down 1.6 percent). During 2012, EIA expects a 2.5-percent increase in total electric power sector generation, fueled primarily by increased coal and natural gas generation.

U.S. Electricity Retail Prices. During 2010, retail prices for electricity distributed to the residential sector averaged 11.58 cents per kilowatthour, about the same level as in 2009. EIA expects residential prices to rise by 2.3 percent in 2011, followed by little change in 2012 (U.S. Residential Electricity Prices Chart). The effect of lower generation fuel costs should be more evident during 2011 in retail prices for electricity distributed to the industrial sector, which EIA projects will increase by only 0.9 percent during 2011 then fall slightly, by 0.2 percent next year.

Coal

U.S. Coal Consumption. EIA estimates that coal consumption in the electric power sector grew by 5 percent in 2010, primarily the result of higher electricity consumption during the hot summer. EIA projects that coal consumption in the electric power sector will decrease slightly in 2011. Forecast coal consumption in the electric power sector grows by 3.0 percent in 2012, and reaches 1 billion short tons for the first time since 2008. The electric power sector consumed an average of 1 billion short tons annually from 2003 through 2008 (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Coal production in 2010 grew by only 1 percent despite the 5-percent increase in total U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase (U.S. Electric Power Sector Coal Stocks Chart). EIA projects that coal production will increase just slightly in 2011 as total coal consumption shows little change (U.S. Annual Coal Production Chart), followed by a 2.3-percent increase in 2012.

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, resulted in sharp increases in U.S. coal exports in 2010. Metallurgical coal's share of total U.S. coal exports grew from 52 percent in 2008 to 69 percent in 2010. Supply disruptions in several key coal exporting countries (Australia, Colombia, Indonesia, and South Africa) have greatly affected the amount of coal available on the world market. Consequently, EIA expects U.S. coal exports to increase by 7.3 percent to 88 million short tons in 2011. Forecast U.S. coal exports fall back to more typical historical levels (about 80 million short tons) in 2012 as supply from other major coal-exporting countries recovers.

The strong global demand for coal outside the U.S., also contributed to a 14.5 percent decline in U.S. coal imports in 2010 (to 19.4 million short tons) despite an increase in consumption. EIA expects the trend of lower U.S. coal imports to continue, with imports below 19 million short tons in 2011 and 2012. U.S. coal imports averaged about 31 million short tons annually from 2004 through 2009.

U.S. Coal Prices. Electric power sector coal prices have been rising relatively steadily over the last 10 years, reflecting longer-term coal contracts initiated during a period of high energy prices, rising transportation costs, and increased consumption. However, EIA expects that the power sector coal price will remain stable in 2011 and 2012 as coal competes with natural gas for market share. The projected power sector delivered coal price, which averaged $2.26 per MMBtu in 2010, averages $2.30 per MMBtu and $2.27 per MMBtu in 2011 and 2012, respectively.

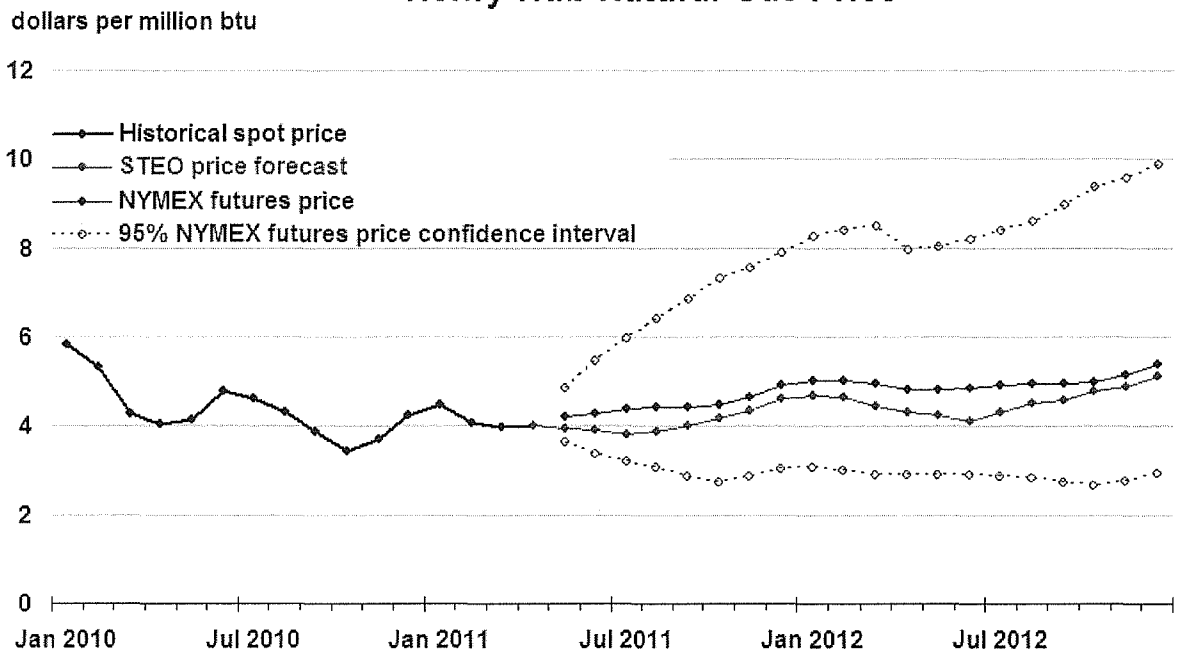
U.S. Carbon Dioxide Emissions

EIA estimates that fossil-fuel CO_2 emissions increased by 3.7 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Coal- and natural gas-related CO_2 emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Forecast fossil-fuel CO_2 emissions remain relatively flat in 2011. Projected increases in petroleum consumption and natural gas consumption in the industrial sector are

offset by declines in natural gas consumption in both the residential and commercial sectors. Expected increases in electricity generation and the improvement in economic growth in 2012 contribute to a 1.8-percent increase in fossil-fuel CO_2 emissions.

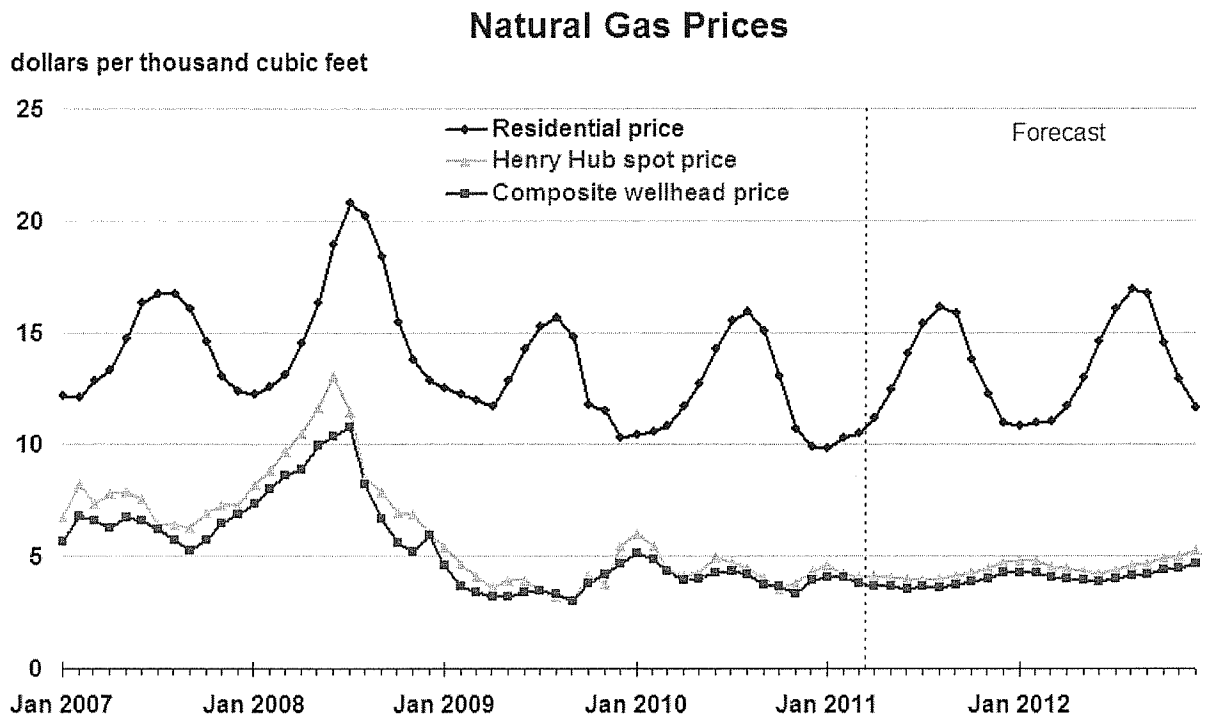
Henry Hub Natural Gas Price



Note: Confidence interval derived from options market information for 5 trading days ending April 7, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, April 2011

eia



Source: Short-Term Energy Outlook, April 2011

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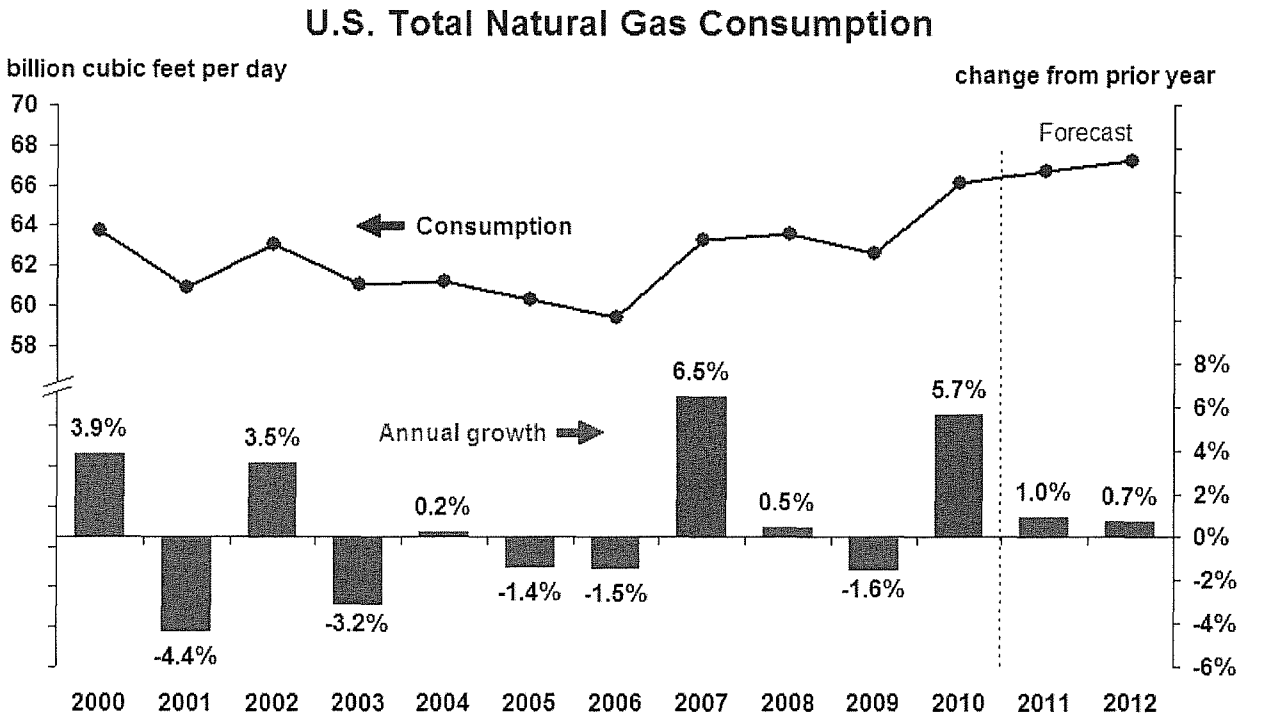
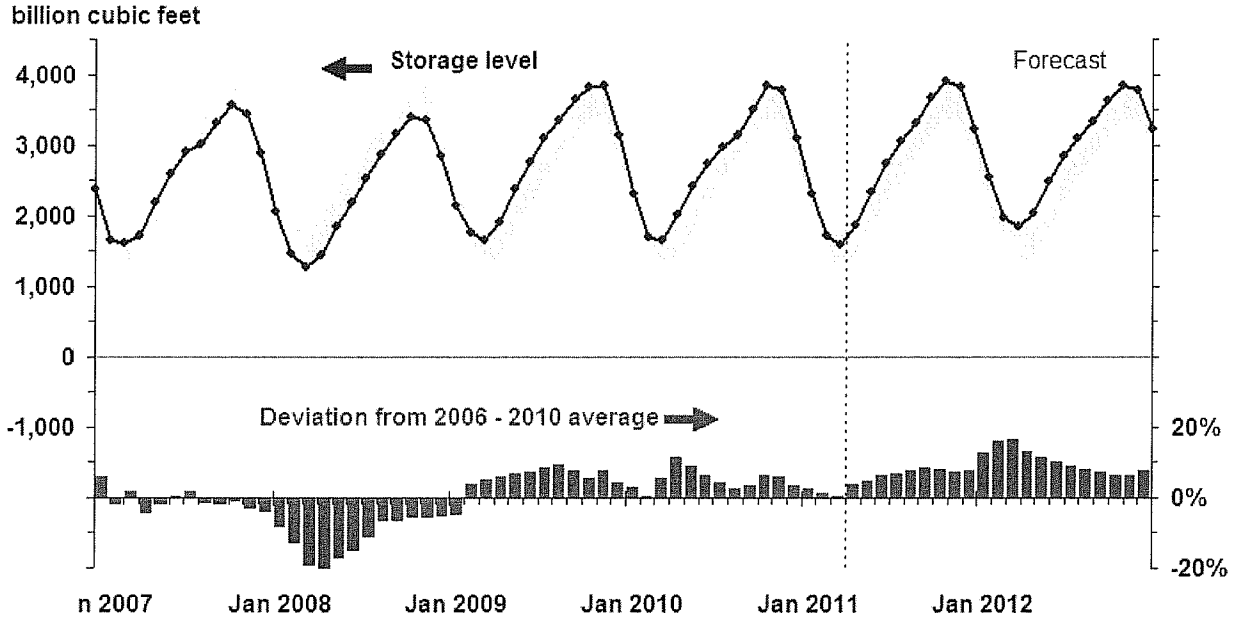


Source: Short-Term Energy Outlook, April 2011

U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010

Source: Short-Term Energy Outlook, April 2011

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, 2010									**$114,988**
May	$29,734	$0	$723	$30,457	12,466	$0.2343	$2,921	$27,536	142,524
June	11,277	0	917	12,194	8,311	0.3941	2,356 2/	9,838	152,362
July	20,585	0	982	21,567	6,200	0.3941	2,444	19,123	171,485
August	86,747	0	1,115	87,862	5,953	0.3941	2,347	85,515	257,000
September	92,220	0	1,725	93,945	6,368	0.3941	2,509	91,436	348,436
October	34,666	0	2,373	37,039	8,070	0.3941	3,181	33,858	382,294
November	23,805	0	2,602	26,407	17,808	0.3941	7,018	19,389	401,683
December	(6,120)	0	2,728	(3,392)	38,100	0.3941	15,015	(18,407)	383,276
January 2011	(60,299)	0	2,587	(57,712)	47,283	0.3941	18,633	(76,345)	306,931
February	(63,560)	0	2,033	(61,527)	48,059	0.3941	18,940	(80,467)	226,464
March	(31,931)	0	1,453	(30,478)	42,816	0.3941	16,874	(47,352)	179,112
Balance @ March 31, 2011									**$179,112**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,750.5 dk @ $0.2343 and 2,560.2 dk @ $0.3941.

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, 2010									**($30,590)**
May	$576	$0	($199)	$377	10,944	($0.7419)	($8,120)	$8,497	(22,093)
June	(8,617)	0	(146)	(8,763)	11,808	(0.1136)	(6,678) 2/	(2,085)	(24,178)
July	(8,501)	0	(169)	(8,670)	10,612	(0.1136)	(1,205)	(7,465)	(31,643)
August	(1,507)	0	(224)	(1,731)	9,466	(0.1136)	(1,075)	(656)	(32,299)
September	422	0	(230)	192	13,953	(0.1136)	(1,585)	1,777	(30,522)
October	4,873	0	(219)	4,654	26,958	(0.1136)	(3,062)	7,716	(22,806)
November	4,335	0	(170)	4,165	36,122	(0.1136)	(4,104)	8,269	(14,537)
December	6,272	0	(119)	6,153	29,056	(0.1136)	(3,301)	9,454	(5,083)
January 2011	(971)	0	(58)	(1,029)	17,350	(0.1136)	(1,971)	942	(4,141)
February	3,038	0	(56)	2,982	28,670	(0.1136)	(3,257)	6,239	2,098
March	(3,891)	0	(19)	(3,910)	34,060	(0.1136)	(3,870)	(40)	2,058
Balance @ March 31, 2011									**$2,058**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 8,493.0 dk @ ($0.7419) and 3,315.3 dk @ ($0.1136).