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

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PO Box 176
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March 1, 2010

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

Re: Cost of Gas Adjustment (COG)
March 2010

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 (48th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (48th Revised Sheet No. 8), showing the March 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.5259 per mcf for residential and firm general service customers and a decrease of $0.5541 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for March 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.5541 per mcf since the last COG filing. There has been an increase in pipeline charges of $0.0282 per mcf due to changes in pipeline charges. The net effect of these changes is a decrease of $0.5259 per mcf for residential and firm general service customers.

Attachment C discusses the market conditions of the gas commondity.

Attachment D shows the calculation of the balancing account since April 30, 2009.

Great Plains submitted a check for $600.00 on January 19, 2010 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 Analysis 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
48th Revised Sheet No. 1.1
Canceling 47th Revised Sheet No.1.1
Page 1 of 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	$8.3220	$9.5960
			Over 10 MCF	1.0540		9.3760
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$4.1592	$5.2983
			Next 2,600 MCF	0.8931		5.0523
			Over 3,000 MCF	0.7411		4.9003
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$4.1592	$5.3983
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 1, 2010 **Effective Date:** March 1, 2010

Issued By: Donald R. Ball
Vice President - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
48th Revised Sheet No. 8
Canceling 47th 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.	3.0926	0.3361	0.2343	3.6630	0.3361	(0.7419)	(0.4058)
Current Adj.	0.0282	(0.5541)	0.0000	(0.5259)	(0.5541)	0.0000	(0.5541)
Total Adj.	3.1208	(0.2180)	0.2343	3.1371	(0.2180)	(0.7419)	(0.9599)
Total Rate:	$3.1866	$4.9011	$0.2343	$8.3220	$4.9011	($0.7419)	$4.1592

Date Filed: March 1, 2010 **Effective Date:** March 1, 2010

Issued By: Donald R. Ball
Vice President – Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2010

Firm	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841	$3.4671	12	$326,226	$0.2084
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0659
FT-A Seasonal	3,000	3.7671	5	56,507	0.0361
TFX Seasonal	3,000	15.1530	5	227,295	0.1452
NOVA - Demand Charge	7,947	16.8522	12	1,607,093	1.0265
Trans Canada - Demand Charge	7,947	16.6477	12	1,587,591	1.0141
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	16.8522	5	427,035	0.2728
Trans Canada - Seasonal	5,068	16.6477	5	421,853	0.2695
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0156
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0492
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				$4,988,576	3.1866
Estimated Weighted Average Commodity Cost	1,565,565 1/	4.9011		7,672,991	4.9011
Gas Cost Reconciliation Adjustment					0.2343
Total Current Firm Gas Cost				$12,661,567	8.3220
Base Cost of Gas					5.1849
Accumulated Adjustment					$3.1371

Interruptible	
Estimated Weighted Average Commodity Cost	$4.9011
Gas Cost Reconciliation Adjustment	(0.7419)
Total Current Interruptible Gas Cost	4.1592
Base Cost of Gas	5.1191
Accumulated Adjustment	($0.9599)

1/ Authorized in MN Docket No. G004/GR-04-1487 plus Wahpeton volumes.

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MARCH 2010

Rates Effective March 1, 2010	$/Dk	
FT-A - Zone 1-1	$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	16.8522	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.6477	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.8522	Per dk/Day
Trans Canada - Seasonal	16.6477	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:	4.9011	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

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Twenty-Seventh Revised Sheet No. 5B
Superseding
Twenty-Sixth Revised Sheet No. 5B

STATEMENT OF RATES
(Rates Per Dekatherm)

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	0.74%
Zone 1 - 2	$0.0130	$0.0019	$0.0149	0.87%
Zone 2 - 2	$0.0130	$0.0019	$0.0149	0.13%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1 - 1	$0.1368	$0.0019	$0.1387	0.74%
Zone 1 - 2	$0.1737	$0.0019	$0.1756	0.87%
Zone 2 - 2	$0.0834	$0.0019	$0.0853	0.13%
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: .05% for Zone 1-1, .06% for Zone 1-2, and .01% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

Issued by: Ron Mucci, Vice President of Regulatory
Issued on: September 23, 2009
Effective on: November 1, 2009

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Fourteenth Revised Sheet No. 5C
Superseding
Thirteenth Revised Sheet No. 5C

STATEMENT OF RATES
(Rates Per Dekatherm)

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		$0.0080	

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.

Issued by: J. Phill May, Vice President Commercial
Issued on: February 20, 2009
Effective on: April 1, 2009

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	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.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0003 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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	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.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0003 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
March 2010

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

Increased volumes of liquefied natural gas and gas imported from Canada along with the continued strong domestic supply of gas likely contributed to the anticipated decrease in the index prices. The Energy Information Administration (EIA) reported storage levels nationwide as of February 19, 2010 were 0.7 percent above the five-year average and 2.9 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 13.

U.S. Energy Information Administration

February 2010

Short-Term Energy Outlook

February 10, 2010 Release

Highlights

- Crude oil prices continue to fluctuate. The West Texas Intermediate (WTI) spot price increased from $69.48 per barrel on December 14 to $83.12 on January 6 and then fell to $72.85 on January 29. EIA expects the crude oil market to strengthen again this spring with WTI rising to an average of about $81 per barrel over the second half of this year and $84 per barrel in 2011. The crude oil price forecast is unchanged from last month's *Outlook*. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 2.3 percent in 2010 and by 2.5 percent in 2011, while world oil-consumption-weighted real GDP grows by 2.7 percent and 3.6 percent in 2010 and 2011, respectively.

- EIA forecasts that the annual average regular-grade retail gasoline price will increase from $2.35 per gallon in 2009 to $2.84 in 2010 and $2.97 in 2011 because of the rising average crude oil price forecast. Pump prices may exceed $3 per gallon at times during the approaching spring and summer. Projected annual average retail diesel fuel prices are $2.95 and $3.16 per gallon, respectively, in 2010 and 2011.

- EIA expects this year's annual average natural gas Henry Hub spot price to be $5.37 per million Btu (MMBtu), a $1.42-per-MMBtu increase over the 2009 average of $3.95. EIA projects continuing price increases in 2011, averaging $5.86 per MMBtu for the year. EIA expects working gas inventories to end the first quarter at about 1,644 billion cubic feet (Bcf) compared with 1,734 Bcf in the previous *Outlook*, because of colder-than-normal weather in early January.

- The annual average residential electricity price changes only slightly over the forecast period, falling from 11.6 cents per kilowatthour (kWh) in 2009 to 11.5 cents in 2010, and then rising to 11.7 cents per kWh in 2011. These projections are unchanged from the previous *Outlook*.

- Projected carbon dioxide (CO_2) emissions from fossil fuels, which declined by 6.3 percent in 2009, will increase by 1.5 percent and 1.3 percent in 2010 and 2011, respectively, as economic recovery contributes to higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. The world oil market should gradually tighten in 2010 and 2011, as the global economic recovery continues and world oil demand begins to grow again. Continuation of the production targets set by the Organization of the Petroleum Exporting Countries (OPEC), as well as lower overall growth in non-OPEC supply over the 2010-2011 forecast period, would also contribute to a firming of crude oil prices to above $80 per barrel this summer. However, the combination of high commercial inventories among members of the Organization for Economic Cooperation and Development (OECD) and ample OPEC surplus production capacity should help dampen the likelihood of any large upward swings in prices.

Global Crude Oil and Liquid Fuels Consumption. EIA has revised upward slightly its projections for global liquid fuels consumption growth in this *Outlook*, as the Asian-led recovery continues. China's apparent liquid fuels consumption in December increased by 0.9 million barrels per day (bbl/d), or 12 percent, above year-earlier levels, as China's economic stimulus package continued to help push up both oil usage and economic growth. While Japan is expected to continue its long-term decline in consumption, signs of an economic turnaround in that country lead EIA to be less pessimistic about the Japanese decline in liquid fuels consumption for 2010-2011. EIA's revised outlook is for global liquid fuels consumption to grow by 1.2 million bbl/d in 2010 and 1.6 million bbl/d in 2011 after showing annual declines in 2008 and 2009 (World Liquid Fuels Consumption Chart). Non-OECD countries are expected to account for the majority of this growth in both 2010 and 2011.

Non-OPEC Supply. Non-OPEC supply increased by 560,000 bbl/d in 2009, the largest annual increase since 2004. However, EIA does not expect this level of supply growth to continue during the forecast period. Non-OPEC supply is projected to increase by 430,000 bbl/d in 2010. The largest source of growth in 2010 is the United States, followed by Brazil and Azerbaijan. Offsetting this growth, production is forecast to decline in Mexico, the United Kingdom, and Norway. Non-OPEC supply is expected to fall by 120,000 bbl/d in 2011, as declining production in mature areas overwhelms any new production growth (see STEO Supplement: Outlook for non-OPEC Oil Supply in 2010-2011).

OPEC Supply. OPEC cut its crude oil production by 2.2 million bbl/d in 2009, one reason why WTI crude oil prices stabilized between $70 to $80 per barrel since the middle of last year. This range is consistent with the "fair price" range for crude oil proposed by King Abdullah of Saudi Arabia at the beginning of 2009. Oil prices hovered in this range despite sustained high levels of oil inventories and rising spare production capacity, which rose, in part, because of cuts in OPEC production. OPEC surplus crude oil production capacity currently stands at about 5 million bbl/d and could grow to 6 million bbl/d by the end of the forecast period. However, most of this surplus capacity is concentrated in Saudi Arabia, which is not likely to use it as long as the oil market is stable and its price target range is being met. In contrast, OPEC surplus crude oil production capacity averaged 2.8 million bbl/d during the 1999-2009 period (OPEC Surplus Crude Oil Production Capacity Chart).

EIA expects annual OPEC crude oil production will increase by an average of 0.4 million bbl/d in 2010 and again in 2011 as global oil demand recovers. In addition, EIA expects OPEC non-crude petroleum liquids, which are not subject to OPEC production targets, to grow by 0.6 to 0.7 million bbl/d each year through 2011, for a total of up to 2.2 million bbd/d of increased OPEC liquids production over the next two years. OPEC is scheduled to meet in Vienna on March 17, 2010, to reassess market conditions.

OECD Petroleum Inventories. EIA estimates OECD commercial oil inventories were 2.69 billion barrels at the end of 2009, equivalent to about 58 days of forward cover, and about 90 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories remain at the upper end of the historical range over the forecast period.

Crude Oil Prices. WTI crude oil spot prices averaged $78.33 per barrel in January 2010, almost $4 per barrel higher than the prior month's average and matching the $78-per-barrel forecast in last month's *Outlook.* The WTI spot price peaked at $83.12 on January 6 and then fell to $72.85 on January 29 as the weather turned warm and concerns about the strength of world economic recovery increased. EIA forecasts that WTI spot prices will remain near current levels over the next few months, averaging $76 per barrel in February and March, before rising to about $82 per barrel in the late spring and to $85 by late next year (West Texas Intermediate Crude Oil Price Chart).

Expected WTI price volatility was fairly steady over the month. April 2010 implied volatility (based on options prices) averaged 35 percent per annum during January, and, over the 5 days ending February 4, 2010, it was slightly over 34 percent. April 2010 WTI futures averaged $75 per barrel over that same 5-day window, yielding a

lower and upper limit for the 95-percent confidence interval of $60 and $94 per barrel, respectively (see Energy Price Volatility and Forecast Uncertainty).

One year ago, April-delivered WTI into Cushing, Oklahoma, was priced at $45 per barrel, and implied volatility, at 74 percent, was more than twice the rate now trading in the options markets. Thus, the 95-percent confidence interval for April 2009 WTI futures had lower and upper limits of $28 and $72 per barrel at that time, respectively.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption declined by 820,000 bbl/d (4.2 percent) to 18.7 million bbl/d in 2009, the second consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). Motor gasoline was the only major petroleum product whose annual consumption did not decline, having remained relatively unchanged. Distillate fuel consumption declined by 330,000 bbl/d (8.4 percent), in 2009, led by a sharp economy-related decline in transportation usage. Jet fuel usage fell by 130,000 bbl/d (8.6 percent).

Despite the cold weather that gripped much of the Nation in late December 2009 and early January 2010, total U.S. liquid fuels consumption in those 2 months still fell below the levels seen in the same months a year earlier. Nevertheless, EIA projects that total petroleum products consumption will rise by 180,000 bbl/d in 2010 because of the economic recovery that began in late 2009. All major products contribute to that increase. The projected continuing economic recovery in 2011 boosts total petroleum products consumption by 210,000 bbl/d. Motor gasoline consumption increases by 70,000 bbl/d and distillate consumption rises by 100,000 bbl/d in 2011. Throughout the forecast, continued increases in aircraft efficiencies result in flat jet-fuel consumption despite growth in air activity.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production averaged 5.32 million bbl/d in 2009, up 370,000 bbl/d from 2008 (U.S. Crude Oil Production Chart). Projected growth in domestic output is slower in 2010, increasing by about 190,000 bbl/d, and then falls slightly in 2011 by 30,000 bbl/d. Ethanol production continues to grow to meet the volume requirements of the Renewable Fuel Standard. Projected ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 800,000 bbl/d in 2010 and 850,000 bbl/d in 2011. EIA forecasts that liquid fuel net imports (including both crude oil and refined products) will fall by 150,000 bbl/d in 2010 and then rise by 160,000 bbl/d in 2011, after having fallen by 1.42 million bbl/day during 2009.

U.S. Petroleum Product Prices. Monthly average regular-grade gasoline prices averaged $2.35 per gallon in 2009, increasing from $1.79 per gallon in January 2009 to $2.61 per gallon in December. EIA expects these prices will average $2.84 per gallon in 2010 and $2.97 per gallon in 2011. Gasoline retail prices have followed crude oil prices over the last few months with the troughs and peaks in gasoline prices following those of crude oil by about 1 week. Average regular-grade pump prices may top $3 per gallon at times during the upcoming spring and summer and will easily pass that benchmark in high-cost regions, such as the West Coast. Due to forecast growth in motor gasoline consumption, the difference between the average gasoline retail price and the average cost of crude oil increases slightly in both 2010 and 2011.

On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.95 per gallon in 2010 and $3.16 in 2011 in this forecast. As with motor gasoline, the expected recovery in the consumption of diesel fuel in the United States, as well as growth in distillate fuel usage outside the United States, strengthens refining margins for distillate throughout the forecast period.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to increase 0.4 percent to 62.5 billion cubic feet per day (Bcf/d) in 2010 and another 0.4 percent in 2011 (Total U.S. Natural Gas Consumption Growth Chart). Very cold weather during the first half of January, particularly in the Southeast, contributed to an 8.4-percent jump in the monthly estimate for electric-power-sector natural gas consumption from the previous forecast. The latest estimate for electric-power-sector consumption in January would be a new record for the month. Although natural gas consumption in the electric power sector has been strong so far this year, an increase in coal-fired generation capacity and higher natural gas prices through the remainder of the year should reduce the share of natural-gas-fired generation in the baseload power mix in 2010. This is despite lower-than-normal snowpack in the Northwest, which we expect to reduce hydroelectric generation in that region in 2010 to about 8 percent below last year's level and boost natural gas consumption. The projected 1.3-percent decline in electric-power-sector natural gas use is offset by growth in the residential, commercial, and industrial sectors in the 2010 forecast. The outlook for growth in total natural gas consumption in 2011 comes from increases in the industrial sector as a result of improved economic conditions.

U.S. Natural Gas Production and Imports. Total marketed natural gas production declines 2.6 percent to 58.7 Bcf/d in 2010 and increases by 1.3 percent in 2011 in this forecast. Working natural gas rigs hit a low of 665 in mid-July 2009, and EIA

anticipates that the impact of lower drilling activity last year will contribute to the production decline in 2010. While the number of working natural gas rigs is currently about 25 percent below the year-ago level, the number has increased during the last month by about 100 rigs to a total of 861 rigs at the end of January. Current 2010 futures market prices between $5.50 and $6.70 per MMBtu appear to provide the necessary economic incentive to expand drilling programs even further. As a result, EIA expects monthly natural gas production to begin to slowly increase later this year and continue on an upward trend through the end of 2011.

Projected U.S. pipeline imports decline by 8.3 percent (0.7 Bcf/d) to 8.1 Bcf/d in 2010 due to the sustained impact of lower Canadian drilling activity and production, as well as increasing demand from oil sands projects in western Canada. A portion of the decline in pipeline imports this year is expected to be offset by imports of liquefied natural gas (LNG), which were double year-ago levels in January as temperatures plummeted and prices jumped. The outlook for higher U.S. LNG imports in 2010 is largely due to recent global LNG supply additions in Russia, Yemen, Qatar, and Indonesia. EIA expects net imports of natural gas to decline in 2011 as flows from Canada remain limited and global demand for LNG strengthens.

U.S. Natural Gas Inventories. On January 29, 2010, working natural gas in storage was 2,406 Bcf (U.S. Working Natural Gas in Storage Chart), 150 Bcf above the previous 5-year average (2005–2009) and 199 Bcf above the level during the corresponding week last year. Colder-than-normal temperatures in the first half of January led to the largest consecutive-week withdrawal on record as a total of 511 Bcf was pulled from storage during the weeks ending January 8 and 15. The withdrawals over these 2 weeks were a combined 317 Bcf above the average withdrawal for the corresponding weeks over the previous 5 years. However, weather turned considerably warmer during the second half of January, and working gas stocks over the last 2 weeks fell by 201 Bcf, compared with the previous 5-year average withdrawal of 357 Bcf. Despite the large inventory draws in December and early January, EIA expects working gas inventories to finish the first quarter of 2010 at about 1,644 Bcf, or 7 percent higher than the previous 5-year average.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $5.83 per MMBtu in January 2009, $0.49 per MMBtu higher than the average spot price in December and $0.36 per MMBtu higher than the forecast for January in last month's *Outlook* (Henry Hub Natural Gas Price Chart). The Henry Hub spot price peaked at $7.51 per MMBtu on January 7, as colder-than-normal weather tightened its grip on much of the country. Temperatures eased and the Henry Hub spot price fell to about $5.30 per MMBtu by the end of the month. While the early cold spell contributed to a substantial withdrawal from working natural gas inventories, prices are projected to

reflect an end-of-winter storage level that is still above the 5-year average. The relatively high inventory level combined with the increased supply potential from domestic resources should keep prices from rising dramatically this year. However, in addition to anomalous weather, unforeseen consumption increases in the electric power and industrial sectors could elevate prices above the current forecast. The Henry Hub spot price forecast averages $5.37 per MMBtu in 2010 and $5.86 per MMBtu in 2011.

Both March and April implied volatilities based on natural gas futures market options contracts started the month in the 55-to-60 percent range and finished the month slightly below 50 percent. Implied volatility for April natural gas options averaged 46 percent per annum for the 5 days ending February 4, 2010. With the average April delivery price at $5.35 per MMBtu for the 5 days ending February 4, the lower and upper limits of the 95 percent confidence interval were $3.80 and $7.50 per MMBtu, respectively. (See Energy Price Volatility and Forecast Uncertainty for a discussion of how confidence intervals are calculated.)

Natural gas delivered to the Henry Hub during April 2009 was trading at $4.60 per MMBtu at this time last year. Options market participants were pricing the April 2009 implied volatility at 60 percent, producing a lower and upper limit for the 95-percent confidence interval of $3 and $7 per MMBtu, respectively.

Electricity

U.S. Electricity Consumption. January heating degree-days in the South Census Region, where about 60 percent of households use electricity as their primary space heating fuel, were 13 percent higher than in January 2009. Consequently, residential electricity sales in the South region also increased by about 12 percent to an average of 2,250 gigawatthours per day. Temperatures across the United States this summer are expected to be about 2.5 percent cooler than last summer, limiting overall growth in electricity sales. Projected total U.S. consumption of electricity grows by 1.9 percent in 2010 and by 1.7 percent in 2011 (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. The large increase in South Atlantic electricity consumption during January was likely supplied in large part by natural gas generation. In addition, low snowpack levels in the Pacific Northwest are likely to reduce hydropower generation and boost natural gas consumption, as noted previously. However, offsetting these increases, the projected higher price of natural gas compared with last year reduces its attractiveness as a baseload fuel. The projected 1.6 percent decline in natural gas consumption for electricity generation in 2010 is lower than the 3.0 percent decline in last month's *Outlook*.

U.S. Electricity Retail Prices. The estimated November 2009 U.S. residential electricity price was 11.2 cents per kWh, 2.4 percent lower than November 2008. EIA projects U.S. residential electricity prices will fall by 1.0 percent in 2010, followed by an increase of 1.9 percent in 2011 resulting primarily from higher natural gas generation fuel costs (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Estimated coal consumption by the electric power sector fell by more than 10 percent in 2009, a slightly larger decline than estimated in last month's *Outlook*. The most recent consumption estimate for November 2009 is nearly 8 percent lower than was expected in last month's *Outlook*. Anticipated increases in electricity demand and higher natural gas prices, both of which are higher than in last month's *Outlook*, will contribute to modest growth in coal-fired generation in 2010 and 2011. Forecast coal consumption in the electric power sector increases by almost 4 percent in 2010, though staying under 1 billion short tons. EIA projects coal consumption in the electric power sector will increase by 1.6 percent in 2011, but remain below the 1-billion-short-ton level for the third consecutive year. Consumption of coal at coke plants rises over the forecast period as economic conditions improve, increasing by nearly 6 million short tons (38 percent) in 2010, followed by a small increase (less than 1 percent) in 2011. A higher forecast for raw steel production is the primary reason for higher coke plant consumption than in the previous *Outlook* (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. EIA estimates that 2009 coal production fell by nearly 8 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 4.0 percent in 2010 in this forecast despite increases in domestic consumption and exports. The balance between production and consumption is satisfied through significant reductions in both producer and end-user inventories. EIA projects a 5.4-percent increase in coal production in 2011 to meet continued growth in coal consumption and exports (U.S. Annual Coal Production Chart).

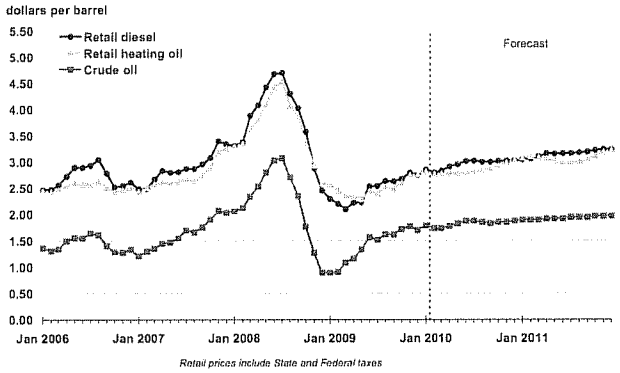
U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by 7 percent in 2009 despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal is due to the significant portion of longer-term power-sector coal contracts that were initiated during a period of high prices for all fuels. The projected

electric-power-sector delivered coal price falls by almost 8 percent to average $2.04 per MMBtu in 2010 and declines by an additional 1.6 percent in 2011.

U.S. Carbon Dioxide Emissions

CO_2 emissions from fossil fuels fell by an estimated 6.3 percent in 2009. Emissions from coal led the drop in 2009 CO_2 emissions, falling by nearly 11 percent. Declines in energy consumption in the industrial sector (a result of the weak economy) and changes in electricity generation sources are the primary reasons for the decline in CO_2 emissions (U.S. Carbon Dioxide Emissions Growth Chart). Looking forward, projected improvements in the economy contribute to an expected 1.5-percent increase in CO_2 emissions in 2010. Increased use of coal in the electric-power sector, and continued economic growth, combined with the expansion of travel-related petroleum consumption, lead to a 1.3-percent increase in CO_2 emissions in 2011. However, even with increases in 2010 and 2011, projected CO_2 emissions in 2011 are lower than annual emissions from 1999 through 2008.

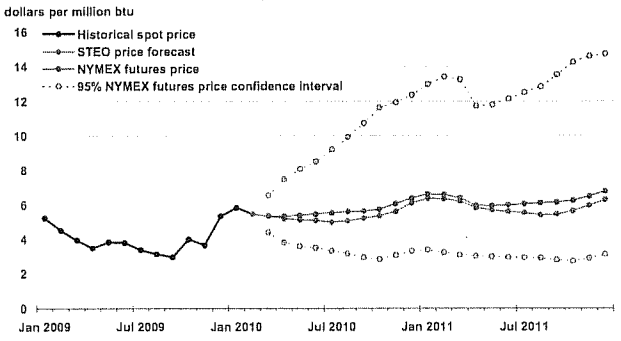
U.S. Diesel Fuel and Crude Oil Prices



Retail prices include State and Federal taxes

Source: Short-Term Energy Outlook, February 2010

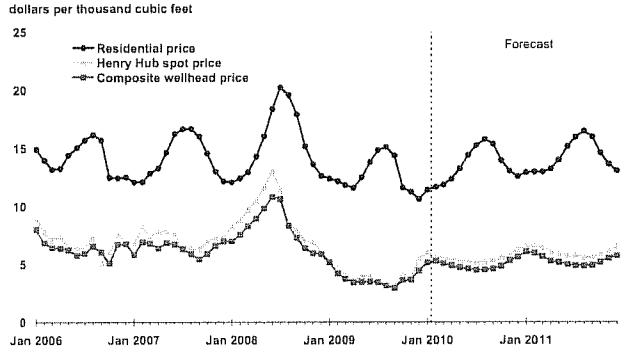
Henry Hub Natural Gas Price



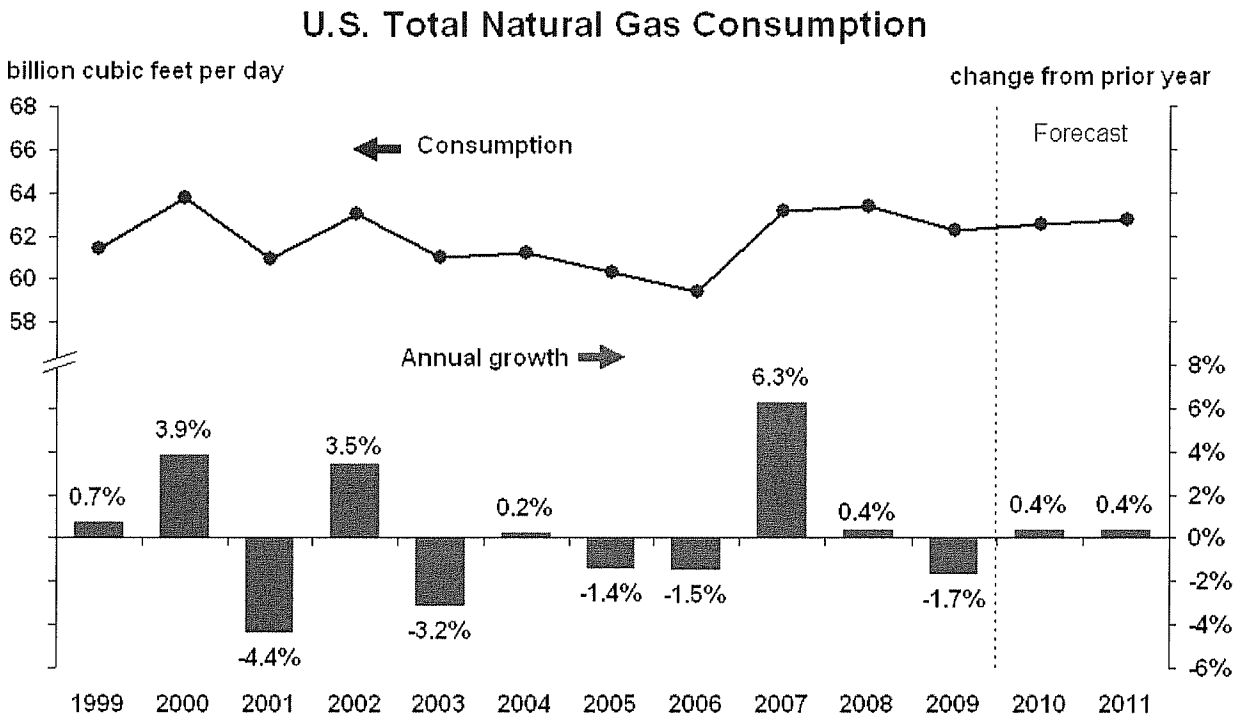
Note: Confidence interval derived from options market information from 5 trading days ending February 4, 2010.
Intervals not calculated for months with sparse trading in "close-to-the-money" options contracts.

Source: Short-Term Energy Outlook, February 2010

Natural Gas Prices



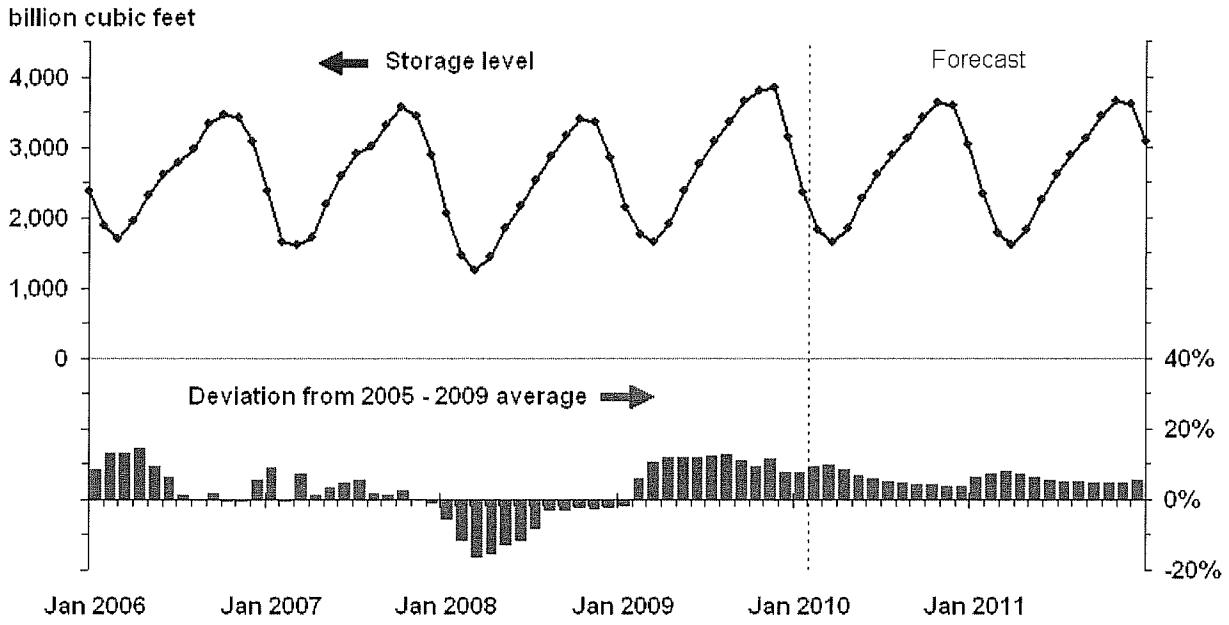
Source: Short-Term Energy Outlook, February 2010



Source: Short-Term Energy Outlook, February 2010

U.S. Energy Information Administration

U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009

Source: Short-Term Energy Outlook, February 2010

U.S. Energy Information Administration

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, 2009									**$65,941**
May	($2,105)	$0	$671	($1,434)	16,822	($0.1857)	($3,124)	$1,690	67,631
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
July	39,344	0	629	39,973	6,447	0.2343	1,511	38,462	131,625
August	39,771	0	902	40,673	5,943	0.2343	1,392	39,281	170,906
September	(2,165)	0	1,179	(986)	5,775	0.2343	1,353	(2,339)	168,567
October	35,022	0	1,154	36,176	11,535	0.2343	2,703	33,473	202,040
November	(980)	0	1,387	407	19,033	0.2343	4,459	(4,052)	197,988
December	25,639	0	1,349	26,988	32,413	0.2343	7,595	19,393	217,381
January 2010	(39,169)	0	1,480	(37,689)	48,707	0.2343	11,412	(49,101)	168,280
Balance @ January 31, 2010.									**$168,280**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,097.5 dk @ ($0.1857) and 3,009.9 dk @ $0.2343.

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, 2009									**($110,191)**
May	($5,411)	$0	($1,024)	($6,435)	15,426	($0.7309)	($11,275)	$4,840	(105,351)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
July	(3,038)	0	(592)	(3,630)	7,435	(0.7419)	(5,516)	1,886	(98,546)
August	(4,584)	0	(581)	(5,165)	9,775	(0.7419)	(7,252)	2,087	(96,459)
September	(14,605)	0	(571)	(15,176)	9,230	(0.7419)	(6,848)	(8,328)	(104,787)
October	(9,999)	0	(634)	(10,633)	16,552	(0.7419)	(12,280)	1,647	(103,140)
November	(15,225)	0	(633)	(15,858)	18,004	(0.7419)	(13,357)	(2,501)	(105,641)
December	(354)	0	(663)	(1,017)	22,135	(0.7419)	(16,422)	15,405	(90,236)
January 2010	(5,220)	0	(567)	(5,787)	25,285	(0.7419)	(18,759)	12,972	(77,264)
Balance @ January 31, 2010.									**($77,264)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 7,849.5 dk @ ($0.7309) and 3,029.9 dk @ ($0.7419).