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

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September 30, 2010

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

Re: Cost of Gas Adjustment (COG)
October 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 (55th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (55th Revised Sheet No. 8), showing the October 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.4041 per mcf for residential and firm general service customers and $0.4042 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for October 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.4042 per mcf since the last COG filing due to an increase in the market price of gas. There has been a decrease in pipeline charges of $0.0001 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $0.4041 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 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
55th Revised Sheet No. 1.1
Canceling 54th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$7.5039	$8.7779
			Over 10 MCF	1.0540		8.5579
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.4374	$4.5765
			Next 2,600 MCF	0.8931		4.3305
			Over 3,000 MCF	0.7411		4.1785
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.4374	$4.6765
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: September 30, 2010

Effective Date: October 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff 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
55th Revised Sheet No. 8
Canceling 54th 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.	3.4931	(1.9723)	0.3941	1.9149	(1.9723)	(0.1136)	(2.0859)
Current Adj.	(0.0001)	0.4042	0.0000	0.4041	0.4042	0.0000	0.4042
Total Adj.	3.4930	(1.5681)	0.3941	2.3190	(1.5681)	(0.1136)	(1.6817)
Total Rate:	$3.5588	$3.5510	$0.3941	$7.5039	$3.5510	($0.1136)	$3.4374

Date Filed: September 30, 2010 **Effective Date:** October 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841		$3.4671	12	$326,226	$0.2329
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	0.0737
FT-A Seasonal	3,000		3.7671	5	56,507	0.0403
TFX Seasonal	3,000		15.1530	5	227,295	0.1623
NOVA - Demand Charge	7,947		16.7974	12	1,601,867	1.1436
Trans Canada - Demand Charge	7,947		16.6725	12	1,589,956	1.1351
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068		16.7974	5	425,646	0.3039
Trans Canada - Seasonal	5,068		16.6725	5	422,481	0.3016
BP Canada - Seasonal	5,068		0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068		3.0417	5	77,077	0.0550
LMS Demand	2,500		1.0000	12	30,000	0.0214
Total Demand Charges					$4,984,954	3.5588
Estimated Weighted Average Commodity Cost	1,400,774	1	3.5510		4,974,148	3.5510
Gas Cost Reconciliation Adjustment						0.3941
Total Current Firm Gas Cost					$9,959,102	7.5039
Base Cost of Gas						5.1849
Accumulated Adjustment						$2.3190
Interruptible						
Estimated Weighted Average Commodity Cost						$3.5510
Gas Cost Reconciliation Adjustment						(0.1136)
Total Current Interruptible Gas Cost						3.4374
Base Cost of Gas						5.1191
Accumulated Adjustment						($1.6817)

1/ Three year normalized average Dk sales.

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

Rates Effective October 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	16.7974	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.6725	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.7974	Per dk/Day
Trans Canada - Seasonal	16.6725	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:	3.5510	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	1.02%
Zone 1-2	$0.0130	$0.0019	$0.0149	1.38%
Zone 2-2	$0.0130	$0.0019	$0.0149	0.36%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1-1	$0.1368	$0.0019	$0.1387	1.02%
Zone 1-2	$0.1737	$0.0019	$0.1756	1.38%
Zone 2-2	$0.0834	$0.0019	$0.0853	0.36%
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: .10% for Zone 1-1, .13% for Zone 1-2, and .03% 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		$0.0453	

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

R A T E S C H E D U L E T F

	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	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	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 $0.0006 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	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	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 $0.0006 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
October 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 October monthly price for the AECO Index is expected to increase 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).

The threat of hurricanes and potential storms throughout the month of September along with warm temperatures in the lower 48, which led to increased natural gas fired electric generation, contributed to the increase in the price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of September 17, 2010 were 6.2 percent above the five-year average and 5.0 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

September 2010

Short-Term Energy Outlook

September 8, 2010 Release

Highlights

- These projections reflect updated expectations for economic activity, with forecasted U.S. real gross domestic product (GDP) growth of 2.8 percent in 2010 and 2.3 percent in 2011, down from the previous *Outlook's* growth projections of 3.1 and 2.7 percent for 2010 and 2011, respectively. The 2011 world oil-consumption-weighted real GDP growth rate is also lowered, to 3.3 percent from the 3.6 percent level in last month's *Outlook*.

- EIA projects that the West Texas Intermediate (WTI) spot price, which averaged $77 per barrel in August, will average $77 per barrel in the fourth quarter of 2010 and $82 per barrel in 2011, slightly below the forecasts in last month's *Outlook*.

- EIA expects that regular-grade motor gasoline retail prices, which averaged $2.35 per gallon last year, will average $2.69 per gallon over the second half of 2010, down 7 cents per gallon from the average for the first half of the year. In 2011, higher projected crude oil prices combined with strengthening refiner margins are expected to boost annual average motor gasoline prices to $2.90 per gallon.

- The projected Henry Hub natural gas spot price averages $4.54 per million Btu (MMBtu) for 2010, a $0.60-per-MMBtu increase over the 2009 average, but down $0.15 per MMBtu from the forecast in last month's *Outlook*. EIA expects the Henry Hub spot price will average $4.76 per MMBtu in 2011, down $0.22 per MMBtu from last month's *Outlook*.

- The annual average residential electricity price increases only moderately over the forecast period, averaging 11.6 cents per kilowatthour (kWh) in 2010, compared with 11.5 cents per kWh in 2009, and rising to 11.9 cents per kWh in 2011. These projections are virtually unchanged from the previous *Outlook*.

- Estimated U.S. carbon dioxide (CO_2) emissions from fossil fuels, which declined by 6.9 percent in 2009, are expected to increase by 3.6 percent in 2010. In 2011, projected CO_2 emissions increase by a further 0.4 percent as the expected milder summer reduces electricity use. However, even with these increases, CO_2 emissions remain below their level in any year from 1999 through 2008.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. For the third month in a row, EIA's view of the world oil market remains largely unchanged. Despite a slight reduction in forecast global demand growth and the drop in world oil prices in recent weeks, the projected gradual reduction in global oil inventories over the forecast period should lend support to firming oil prices. World oil prices are expected to rise slowly as global economic growth leads to higher global oil demand, growth in non-OPEC oil supply slows in 2011, and members of the Organization of the Petroleum Exporting Countries (OPEC) continue to support world oil prices.

Global Crude Oil and Liquid Fuels Consumption. EIA projects world oil consumption growth of 1.6 million barrels per day (bbl/d) in 2010. Countries outside of the Organization for Economic Cooperation and Development (OECD), especially China, the Middle East countries, and Brazil, represent most of the expected growth in world oil consumption (World Liquid Fuels Consumption Chart). Projected global oil consumption growth in 2011 is 1.4 million bbl/d, down slightly from the previous *Outlook* due to lower GDP forecast growth.

Non-OPEC Supply. EIA projects non-OPEC oil supply will increase by 0.7 million bbl/d in 2010 with the growth coming mainly from the United States, Brazil, and the former Soviet Union. Forecasted non-OPEC supply falls by 160,000 bbl/d in 2011, primarily because of declining total North Sea production and lower supply originating in the former Soviet Union, particularly Russia. This would be only the third time in the last 15 years that non-OPEC supplies fail to grow year-over-year, following non-OPEC production declines in 2005 and 2008, which were primarily the result of supply disruptions in the Gulf of Mexico.

OPEC Supply. EIA expects OPEC crude oil production to rise slightly through 2011 to accommodate increasing world oil demand and to maintain OPEC market objectives. OPEC crude oil production is projected to increase by 0.3 and 0.5 million bbl/d in 2010 and 2011, respectively, with non-crude petroleum liquids expected to increase by 0.6 million bbl/d in 2010 and 0.7 million bbl/d in 2011. OPEC surplus capacity should

remain near 5 million bbl/d compared with 4.3 million in 2009 and 1.5 million in 2008 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. Commercial inventories held by OECD countries stood at an estimated 2.75 billion barrels at the end of the second quarter of 2010, equivalent to about 61 days of forward cover, and roughly 95 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories decline throughout the forecast period, although days-forward-cover should remain high by historical standards.

Crude Oil Prices. WTI crude oil spot prices averaged about $77 per barrel in August 2010, very close to the July average, but $3 per barrel lower than projected in last month's *Outlook*. WTI spot prices averaged almost $82 per barrel over the first 10 days of August but then fell by $9 per barrel over the next 2 weeks as the market reacted to a series of reports of a stumbling economic recovery. EIA has lowered the average fourth quarter 2010 forecasted WTI spot price to $77 per barrel, compared with $81 per barrel in last month's *Outlook*. WTI spot prices are projected to rise to $84 per barrel by the end of next year (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain, as history has shown (Energy Price Volatility and Forecast Uncertainty). WTI futures for November 2010 delivery for the 5-day period ending September 2 averaged $75 per barrel, and implied volatility averaged 32 percent. This made the lower and upper limits of the 95-percent confidence interval $61 and $94 per barrel, respectively, for WTI delivered November 2010. Last year at this time, WTI for November 2009 delivery averaged $70 per barrel, and implied volatility averaged 47 percent, with the limits of the 95-percent confidence interval at $51 and $96 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total liquid fuels consumption grows by 160,000 bbl/d (0.8 percent) in 2010, and 130,000 bbl/d (0.7 percent) in 2011 as all of the major petroleum products register consumption growth (U.S. Liquid Fuels Consumption Growth Chart). This reverses the trend of falling consumption during 2006-2009. A year-over-year decline in total liquid fuels consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise averaging 440,000 bbl/d in the second quarter of 2010, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, gasoline consumption is projected to increase by 0.3 percent and distillate consumption is projected to grow by 2.0 percent. Projected gasoline consumption growth increases to

0.8 percent in 2011 while distillate fuel consumption growth moderates to 0.7 percent. Jet fuel consumption grows at an average annual rate of about 0.7 percent through 2011.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 410,000 bbl/d in 2009, is projected to increase by 70,000 bbl/d in 2010 (U.S. Crude Oil Production Chart). Crude oil production shut in by hurricanes during June, July, and August averaged 47,000 bbl/d, about half of EIA's original forecast of 96,000 bbl/d for those 3 months. Forecast total domestic crude oil production rises by 10,000 bbl/d to 5.44 million bbl/d in 2011. That projection includes a 120,000 bbl/d decline in the federal Gulf of Mexico (GOM) and a 150,000 bbl/d increase in lower-48 non-GOM production next year. These projections reflect EIA's estimates of an average reduction in crude oil output of about 82,000 bbl/d in 2011 resulting from the current 6-month moratorium on deepwater drilling. Projected ethanol production, which averaged 710,000 bbl/d in 2009, increases to an average of 850,000 bbl/d in 2010 and 880,000 bbl/d in 2011.

EIA forecasts that liquid fuel net imports (including both crude oil and refined products), which fell from 57 percent to 51 percent of total U.S. consumption between 2008 and 2009, will average about 50 percent of total consumption in 2010 and 2011.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average $2.35 per gallon in 2009 to an average $2.72 per gallon in 2010 and $2.90 per gallon in 2011. Forecast regular-grade pump prices average $2.76 per gallon this summer, an increase of 33 cents from last summer. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.93 per gallon in 2010 and $3.10 in 2011 in this forecast. Refining margins, which have been at their lowest levels since 2003, are projected to average about $2 per barrel higher next year because of growing global product demand and shutdowns of excess global refining capacity.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will increase by 4.0 percent from 2009 levels to 65.0 billion cubic feet per day (Bcf/d) in 2010 and then remain relatively flat in 2011 (Total U.S. Natural Gas Consumption Growth Chart). The power generation and industrial sectors account for the bulk of the projected increase in consumption in 2010 over 2009.

Projected consumption of natural gas for power generation grows by nearly 1.3 Bcf/d to 20.2 Bcf/d in 2010. The use of natural gas for electric power generation surged this year because of the 23 percent increase in U.S. cooling degree- days, resulting in an

over 300 Bcf (11 percent) increase in natural gas consumption in the power generation sector over the last 4 months compared with the same period last year. Projected natural gas consumption in the power generation sector falls by 0.4 Bcf/d (2.0 percent) next year because of the expected return to near-normal summer temperatures.

Projected use of natural gas in the industrial sector also grows significantly in 2010, increasing by 6.4 percent, from 16.8 Bcf/d in 2009 to 17.9 Bcf/d in 2010. Forecasted industrial-sector consumption growth slows to 1.2 percent in 2011 as the projected increase in the natural-gas-weighted industrial production index slows from 7.0 percent in 2010 to 2.1 percent in 2011.

U.S. Natural Gas Production and Imports. EIA predicts total marketed natural gas production will increase by 1.2 Bcf/d (2.1 percent) to 61.2 Bcf/d in 2010. Projected production declines gradually in 2011, falling by 1.2 Bcf/d (1.9 percent) as relatively low prices depress drilling activity.

A total of 7.9 Bcf of natural gas production was shut in because of hurricanes during June, July, and August, compared with EIA's original projection of 57.4 Bcf for those 3 months. Nevertheless, the next 2 months are typically the height of the hurricane season and additional outages are included in this forecast. Based on the latest NOAA hurricane forecast, during the final 3 months of the hurricane season this forecast includes 66.3 Bcf in outages with almost two-thirds of that total occurring in September.

EIA forecasts gross pipeline imports of 9.2 Bcf/d in 2010, an increase of 1.3 percent from 2009. Forecasted imports of liquefied natural gas (LNG) average 1.25 Bcf/d in 2010 and 1.32 Bcf/d in 2011. Low U.S. prices have discouraged imports, and ample domestic natural gas production has reduced the need for large quantities of LNG despite significantly higher consumption.

U.S. Natural Gas Inventories. On August 27, working natural gas in storage was 3,106 Bcf (U.S. Working Natural Gas in Storage Chart), which is 208 Bcf less than the previous year's level and 169 Bcf greater than the 5-year (2005-2009) average. Weekly U.S. natural gas inventory builds this year have fallen below last year's builds in 16 of the last 18 weeks. This was primarily the result of the very warm summer and the resulting increase in natural gas consumption in the power generation sector. EIA expects working gas inventories in the United States to total 3,687 Bcf at the end of the injection season, about 3 percent below the record level reached at the end of the injection season last year.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.32 per MMBtu in August, $0.31 per MMBtu lower than the average spot price in July (Henry Hub Natural Gas Price Chart). EIA expects prices will fall below $4 per MMBtu in September and October before rebounding at the onset of colder weather. EIA now expects prices will average $4.76 per MMBtu in 2011; this is a downward revision from the $4.98 per MMBtu forecast in last month's *Outlook*.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for November 2010 delivery for the 5-day period ending September 2 averaged $4.07 per MMBtu, and the average implied volatility over the same period was 48 percent. This produced lower and upper bounds for the 95-percent confidence interval of $2.84 and $5.83 per MMBtu, respectively. At this time last year, the natural gas November 2009 futures contract averaged $3.89 per MMBtu and implied volatility averaged 75 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $2.22 and $6.81 per MMBtu.

Electricity

U.S. Electricity Consumption. During the first half of 2010, total consumption of electricity rose an estimated 4.2 percent compared with the first half of last year. Growth during the second half is projected to be slightly higher, rising 5.2 percent compared with the same period in 2009. High temperatures during July and August have pushed up sales of electricity in the residential and commercial sectors, especially in the Midwest and Northeast. Projected electricity sales to the industrial sector increase by 6 percent in 2010, but growth slows to 0.2 percent next year as expected growth in industrial output moderates. Total forecast consumption of electricity falls slightly in 2011 since summer temperatures are forecast to return to near-normal levels (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. Total U.S. electric-power-sector generation grew by about 3 percent during the first half of this year compared with the same period in 2009. Generation from coal increased by 6.1 percent, and natural gas generation increased by 4.7 percent. Hydropower output declined by nearly 8 percent as water runoff in the Pacific Northwest was low this spring compared with last year. Some areas of the United States set hourly peak load records during July and August and much of this peak demand was fueled by natural gas, boosting projected year-over-year growth in natural gas generation during the second half of 2010 to over 8 percent.

U.S. Electricity Retail Prices. Overall, the average U.S. residential electricity price was down slightly during the first half of 2010 compared with the first half of 2009 in response to lower fuel costs for generating power. The largest price declines occurred

in New England (-7.7 percent) and the West South Central region (-5.3 percent). In contrast, residential prices in the Middle Atlantic region were up 6.2 percent during the first half of the year as some of the price caps in Pennsylvania began to expire. Generation fuel costs have increased this year, which is expected to boost U.S. residential electricity prices by about 2.1 percent in the second half of 2010 compared with the same period last year, and by 2.4 percent during 2011 (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Projected coal consumption in the electric power sector increases by 6.2 percent in 2010 because of the warm summer weather and associated increase in electricity generation. With a small projected decline (0.4 percent) in electricity consumption in 2011, coal-fired electricity generation and related coal consumption are projected to decline at a slightly higher rate (0.8 percent), primarily because of forecasted increases in nuclear and renewable-based electricity generation (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Drawdowns in both producer and end-user inventories (U.S. Electric Power Sector Coal Stocks Chart) are forecasted to meet the increased coal consumption in 2010. Consequently, projected coal production falls by 0.3 percent in 2010. EIA forecasts a 1.8-percent increase in coal production in 2011 (U.S. Annual Coal Production Chart).

U.S. Coal Trade. U.S. coal gross imports and gross exports fell by 34 percent and 28 percent in 2009, respectively. Forecast coal exports will grow by 25 percent in 2010, driven in part by rising demand for metallurgical coal. Forecast coal exports in 2011 are relatively unchanged from 2010 levels. Metallurgical coal currently constitutes a larger share of the U.S. coal export market than steam coal.

EIA projects coal imports to decline an additional 15 percent in 2010 as increased consumption is met by draws on domestic inventories. Projected coal imports grow by 35 percent in 2011, but the annual tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons.

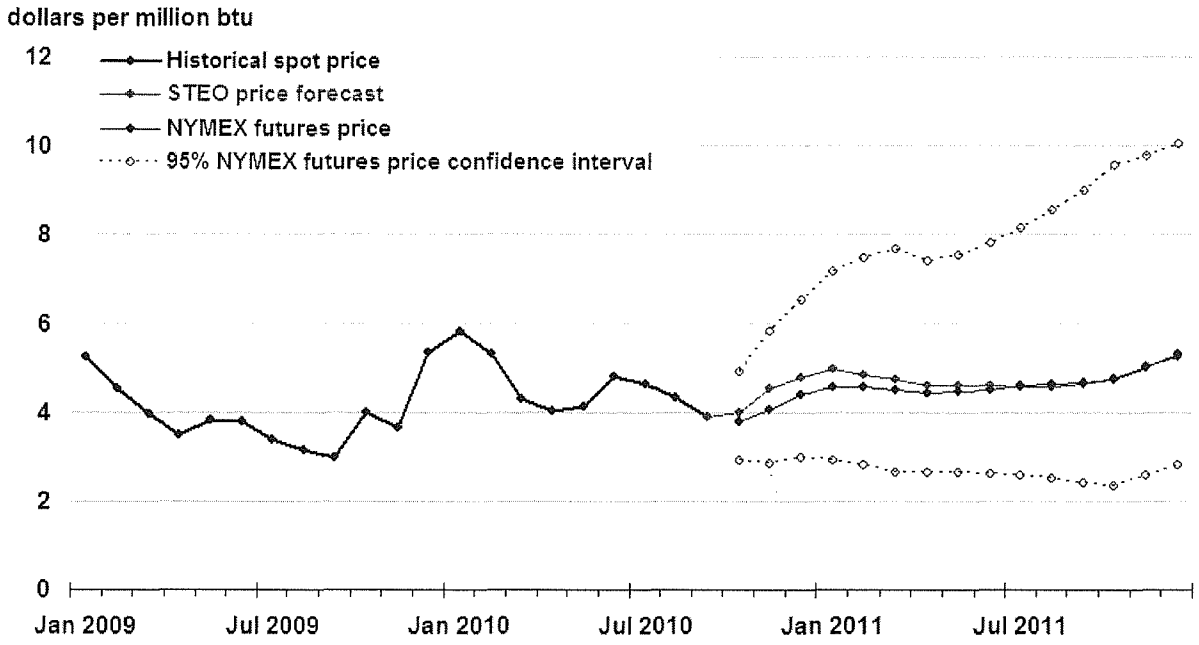
U.S. Coal Prices. The 2009 delivered electric-power-sector coal price increased by 6.7 percent despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflected the impacts of longer-term power-sector coal contracts initiated during a period of high prices and rising transportation costs. The projected electric-power-

sector delivered coal price increases by 1.7 percent to average $2.25 per MMBtu in 2010, and then declines to an average of $2.19 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Forecasted economic growth combined with increased use of coal and natural gas is expected to contribute to increases in fossil-fuel CO_2 emissions of 3.6 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Projected coal-related CO_2 emissions increase by 6.8 percent in 2010 primarily because of increased electricity sector coal usage. Higher natural gas consumption in the industrial and electric power sectors is expected to lead to a 4.3-percent increase in CO_2 emissions from natural gas. Demand for petroleum in the transportation sector (motor gasoline, diesel fuel, and jet fuel) combined with continued industrial sector fossil fuel demand growth contribute to the projected 0.4-percent increase in fossil-fuel CO_2 emissions in 2011. However, even with these increases, projected CO_2 emissions in 2010 and 2011 remain below their level in any year from 1999 through 2008.

Henry Hub Natural Gas Price

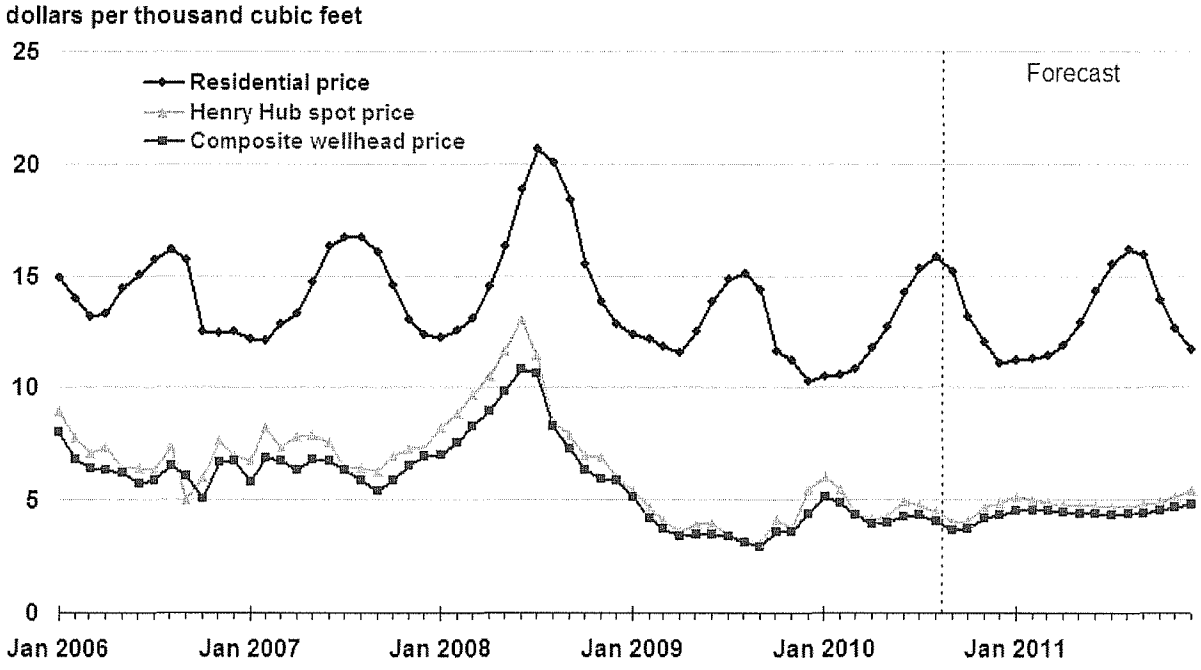


Note: Confidence interval derived from options market information for the 5 trading days ending September 2, 2010
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

U.S. Energy Information Administration

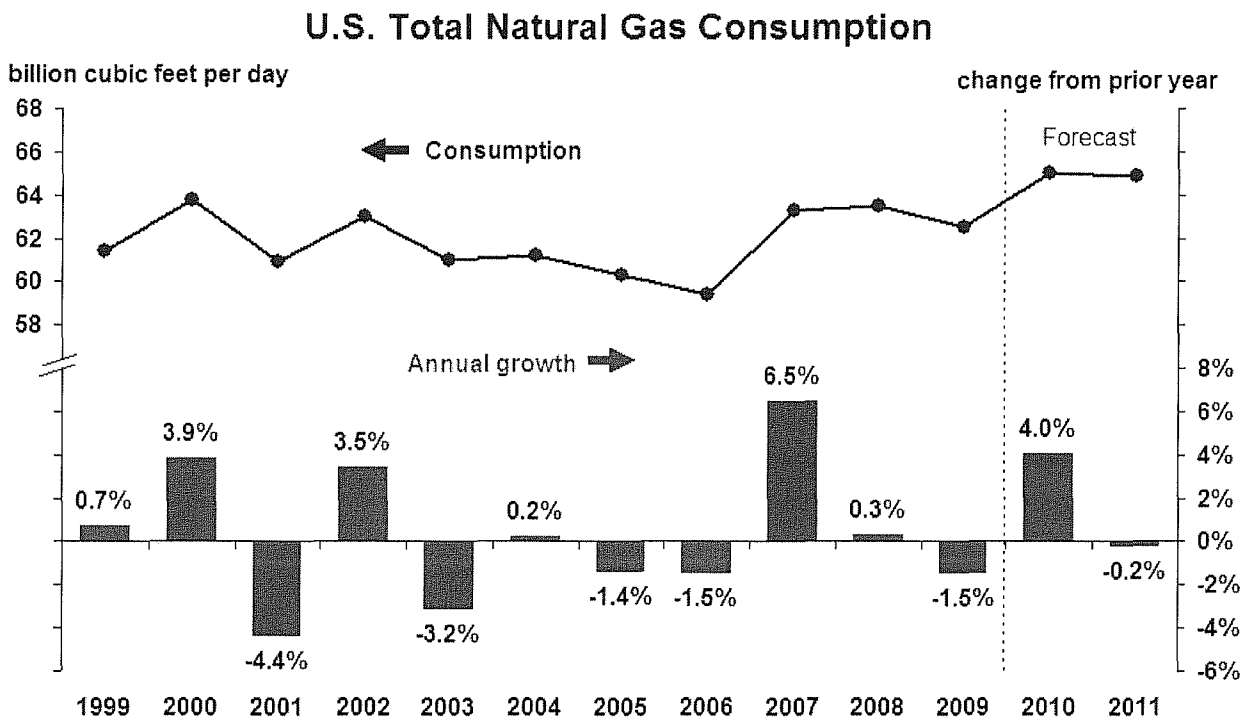
Source: Short-Term Energy Outlook, September 2010; Reuters News Service; and CME Group

Natural Gas Prices



U.S. Energy Information Administration

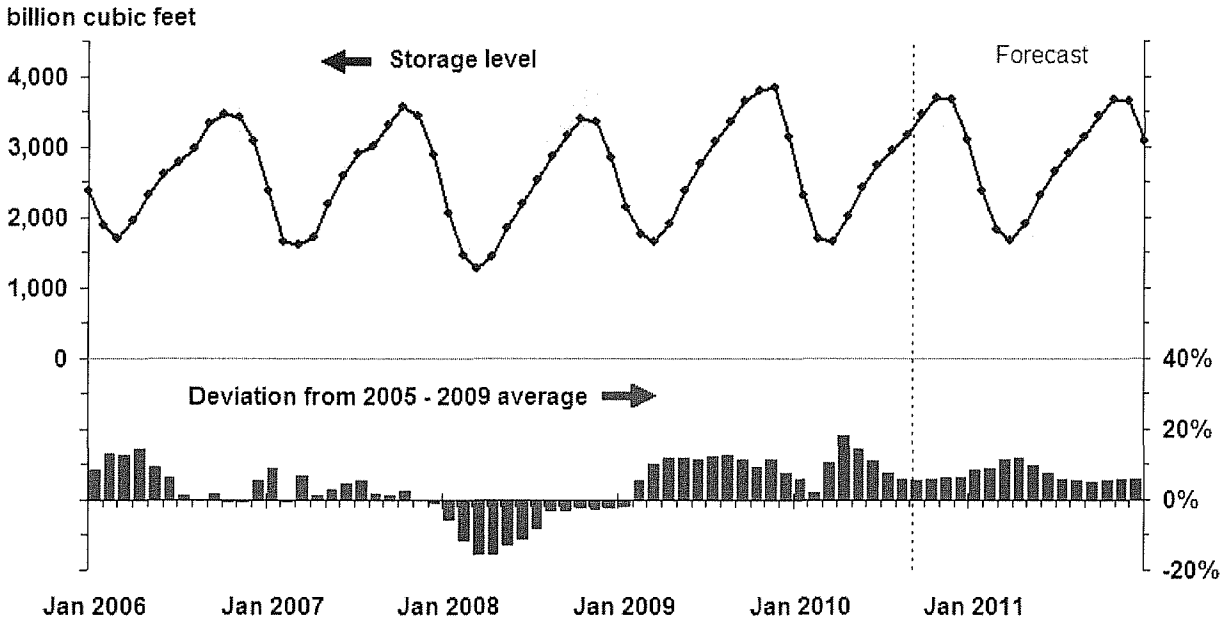
Source: Short-Term Energy Outlook, September 2010; Reuters News Service



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, September 2010

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, September 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, 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
Balance @ Aug 31, 2010									**$257,000**

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)
Balance @ Aug 31, 2010									**($32,299)**

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).