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

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PO Box 176
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April 30, 2009

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

Re: Cost of Gas Adjustment (COG)
May 2009

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 (38th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (38th Revised Sheet No. 8), showing the May 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.5273 per mcf for residential and firm general service customers and $0.5032 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for May 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.5032 per mcf since the last COG filing due to a decrease in the market price of gas. There has been a decrease in pipeline charges of $0.0241 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.5273 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, 2008.

Great Plains submitted a check for $600.00 on December 30, 2008 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
38th Revised Sheet No. 1.1
Canceling 37th 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	$5.0044	$6.2784
			Over 10 MCF	1.0540		6.0584
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$2.2025	$3.3416
			Next 2,600 MCF	0.8931		3.0956
			Over 3,000 MCF	0.7411		2.9436
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$2.2025	$3.4416
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 1, 2009

Effective Date: May 1, 2009

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
38th Revised Sheet No. 8
Canceling 37th 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.	2.2150	(1.6825)	(0.1857)	0.3468	(1.6825)	(0.7309)	(2.4134)
Current Adj.	(0.0241)	(0.5032)	0.0000	(0.5273)	(0.5032)	0.0000	(0.5032)
Total Adj.	2.1909	(2.1857)	(0.1857)	(0.1805)	(2.1857)	(0.7309)	(2.9166)
Total Rate:	$2.2567	$2.9334	($0.1857)	$5.0044	$2.9334	($0.7309)	$2.2025

Date Filed: April 30, 2009 **Effective Date:** May 1, 2009

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

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2009

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
FT-A Seasonal	1,000	3.7671	4	15,068	0.0096
TFX Seasonal	4,000	15.1530	5	303,060	0.1936
NOVA - Demand Charge	7,947	10.9498	12	1,044,217	0.6670
Trans Canada - Demand Charge	7,947	9.7376	12	928,616	0.5932
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	10.9498	5	277,468	0.1772
Trans Canada - Seasonal	5,068	9.7376	5	246,751	0.1576
ProGas - Seasonal	5,068	0.9612	5	24,357	0.0156
ProGas 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				$3,532,889	2.2567
Estimated Weighted Average Commodity Cost	1,565,565 1/	2.9334		4,592,428	2.9334
Gas Cost Reconciliation Adjustment					(0.1857)
Total Current Firm Gas Cost				$8,125,317	5.0044
Base Cost of Gas					5.1849
Accumulated Adjustment					($0.1805)
Interruptible					
Estimated Weighted Average Commodity Cost					$2.9334
Gas Cost Reconciliation Adjustment					(0.7309)
Total Current Interruptible Gas Cost					2.2025
Base Cost of Gas					5.1191
Accumulated Adjustment					($2.9166)

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

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2009

Rates Effective May 1, 2009	$/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	10.9498	Per dk/Mo.
Trans Canada Pipeline Demand Charge	9.7376	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	10.9498	Per dk/Day
Trans Canada - Seasonal	9.7376	Per dk/Mo.
ProGas - Seasonal	0.9612	Per dk/Mo.
ProGas Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	2.9334	Per dk

Base Rate Effective July 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)

Attachment B
Page 3 of 7

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

Attachment B
Page 4 of 7

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	$0.0017	$0.0147	0.64%
Zone 1 - 2	$0.0130	$0.0017	$0.0147	0.89%
Zone 2 - 2	$0.0130	$0.0017	$0.0147	0.25%
Minimum Rate	$0.0130	$0.0017	$0.0147	
IT and AOT				
Zone 1 - 1	$0.1368	$0.0017	$0.1385	0.64%
Zone 1 - 2	$0.1737	$0.0017	$0.1754	0.89%
Zone 2 - 2	$0.0834	$0.0017	$0.0851	0.25%
Minimum Rate	$0.0130	$0.0017	$0.0147	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0017 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, .07% for Zone 1-2, and .02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

Attachment B
Page 5 of 7

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.

Attachment B
Page 6 of 7

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	0.0379	0.0210			0.0175	0.0000	0.0379	0.0210
Field	Market	0.0379	0.0210	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0293	0.0107

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 $0.0017 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

Attachment B
Page 7 of 7

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	0.0379	0.0210			0.0175	0.0000	0.0379	0.0210
Field	Market	0.0379	0.0210	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0293	0.0107

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	0.0017	0.0017	0.0017	0.0017
MOPS Transmission	1.5337	0.0000	0.0017	0.0017	0.0017	0.0017
Tivoli - Downstream	0.6827	0.0000	0.0017	0.0017	0.0017	0.0017
Other Gulf Coast	4.8169	0.0000	0.0017	0.0017	0.0017	0.0017

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 $0.0017 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 $0.0017.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
May 2009

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 decrease from the previous month. 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 seasonal reduction in demand contributed to the decline in prices, along with the fact that nationwide storage levels, as reported by the Energy Information Administration (EIA), as of April 17, 2009 were 22.7 percent above the five-year average and 35.8 percent above last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 13.

www.eia.doe.gov
Energy Information Administration

April 2009

Short-Term Energy and Summer Fuels Outlook

April 14, 2009 Release

Highlights

- The price of West Texas Intermediate (WTI) crude oil averaged $100 per barrel in 2008. The global economic slowdown is projected to reduce the average price to $53 per barrel this year. Assuming an economic recovery next year, WTI prices are expected to average $63 in 2010.

- Regular-grade gasoline prices have increased to more than $2 per gallon, rising slowly but steadily since the beginning of the year in conjunction with rising crude oil prices and refiner margins recovering from recent near-historic lows. During this summer driving season (April through September) regular gasoline retail prices are projected to average $2.23 per gallon, down almost $1.60 from last summer. The average regular gasoline price for all of 2009 is expected to be $2.17 per gallon, increasing to an average of $2.42 in 2010. Diesel prices are projected to average about $2.27 per gallon during this driving season and to average $2.30 and $2.69 per gallon annually in 2009 and 2010, respectively.

- Total consumption of natural gas is projected to fall by nearly 2 percent in 2009, leading to lower natural gas prices. Industrial natural gas consumption is expected to decline by more than 7 percent, as industrial production declines during the current economic downturn. However, natural gas consumption in the electric power sector is projected to increase by almost 1 percent, since the lower natural gas prices will back out some coal consumption in this sector. The Henry Hub natural gas spot price is projected to decline from an average of $9.13 per thousand cubic feet (Mcf) in 2008 to $4.24 per Mcf in 2009, then increase in 2010 to an average of more than $5.80 per Mcf.

Global Petroleum

Overview. Despite high oil inventories in Organization for Economic Cooperation and Development (OECD) countries, crude oil prices rose steadily in March. Lower crude oil production by members of the Organization of the Petroleum Exporting

Countries (OPEC) has lowered world petroleum supplies, substantially offsetting reduced oil demand caused by the global economic recession. Higher oil prices, as well as the change in market sentiment to a slightly less pessimistic outlook, may also reflect the market's belief that economic recovery policies from central banks and governments have slowed down the decline in demand and even improved the chances for an economic upturn and, consequently, higher oil demand, later this year.

The timing and pace of the global economic recovery will determine whether the higher crude oil prices seen during March are sustainable. The prospects of limited growth in non-OPEC production and the expected start of economic recovery later this year, that should increase oil consumption and the demand for OPEC oil, are the main factors supporting the upward price path. If economic recovery begins earlier and is stronger than assumed in this *Outlook*, there is an upside risk of higher oil prices than currently projected. The downside risk to oil prices is a scenario of a prolonged economic downturn followed by a weak recovery, which could produce a greater decline in consumption than currently expected. This latter scenario would challenge the willingness of OPEC's members to sustain lower output levels for a longer period.

Consumption. World oil consumption is expected to drop by 1.35 million barrels per day (bbl/d) in 2009 compared with year-earlier levels, due to the global economic recession. EIA assumes that the global gross domestic product (GDP), weighted by oil consumption, will fall by 0.8 percent this year. Consumption is expected to fall by 1.6 million bbl/d in the OECD countries and rise by 270,000 bbl/d in non-OECD nations. The bulk of the decline is expected to be concentrated in the first half of the year (World Liquid Fuels Consumption). World oil consumption is expected to grow by 1.1 million bbl/d in 2010, driven by a recovery of global GDP growth to 2.6 percent.

Non-OPEC Supply. Non-OPEC supplies in 2009 are expected be close to last year's levels. The United States, Brazil, and Azerbaijan will show large growth in supplies this year. However, these increases in production are offset by large declines in production from Mexico, the North Sea, and Russia (Non-OPEC Crude Oil and Liquid Fuels Production Growth). Even this pessimistic forecast still contains considerable downside risk, especially from additional project delays and higher-than-anticipated decline rates. Non-OPEC supply is expected to increase by a modest 260,000 bbl/d in 2010, due to increasing production from Brazil, the United States, and the former Soviet Union.

OPEC Supply. OPEC left its production targets unchanged from last month, citing concern that reducing production further might harm the world economy. Estimated OPEC crude oil production fell by 1.1 million bbl/d during the fourth quarter of 2008,

reaching 30.6 million bbl/d, then fell by an additional 2.1 million bbl/d in the first quarter of 2009 to 28.5 million bbl/d. EIA expects production to remain close to that level in the second quarter, then gradually increase to about 29.2 million bbl/d in the fourth quarter. EIA expects OPEC crude oil production in 2009 to average 28.8 million bbl/d, then rise to 29.8 million bbl/d in 2010 in response to an expected increase in world oil consumption. In addition, EIA expects that OPEC production of non-crude liquids will grow by 420,000 bbl/d in 2009 and by 720,000 bbl/d in 2010.

Inventories. OECD commercial inventories at year-end 2008 stood at 2.68 billion barrels. At 56 days of forward cover, OECD commercial inventories were above average levels for that time of year (Days of Supply of OECD Commercial Stocks). Preliminary estimates suggest that OECD commercial inventories at the end of March 2009, measured in terms of days of forward supply, continued to remain substantially above average levels for this time of year.

U.S. Crude Oil and Liquid Fuels

Consumption. Total U.S. consumption of liquid fuels in 2008 declined by almost 1.3 million bbl/d, or 6.1 percent, from that of 2007 (U.S. Liquid Fuels Consumption Growth). The major factors contributing to the fall in consumption were a rapid rise in retail prices to record levels during the first half of 2008 and a deteriorating economy in the second half of the year. Total liquid fuels consumption for 2009 is projected to fall by a further 430,000 bbl/d, or 2.2 percent, because of a continued weak economy. The economic recovery is projected to boost total liquid fuels consumption in 2010 by 270,000 bbl/d, or 1.4 percent, with all of the major fuels registering consumption increases.

Production. Crude oil production declined by 110,000 bbl/d in 2008, primarily due to hurricane outages, and is projected to increase by 440,000 bbl/d in 2009 to an average of 5.40 million bbl/d (U.S. Crude Oil Production). This would be the first increase in production since 1991. Output is projected to rise by an additional 150,000 bbl/d in 2010. Contributing to the increases in output are two platforms in the Gulf of Mexico: Thunder Horse, which is already in production, and Tahiti, which is expected to come on stream later this year.

Prices. Under current economic and world crude oil supply assumptions, EIA expects WTI prices to average $53 per barrel in 2009 and $63 per barrel in 2010 (Crude Oil Prices). A stronger-than-expected economic recovery, lower non-OPEC production because of the current low oil prices and financial market constraints, or more aggressive action to cut production by OPEC countries could lead to a faster and stronger rise in oil prices.

Regular-grade gasoline prices, which averaged $3.26 per gallon in 2008, are projected to average $2.17 per gallon in 2009 and $2.42 per gallon in 2010. On-highway diesel fuel retail prices are projected to average $2.30 per gallon in 2009 and $2.69 in 2010. The expected continuing decline in diesel fuel consumption in the United States this year as well as the growing weakness in distillate fuel usage outside the United States are projected to result in lower refining margins for distillate throughout the forecast period. Because of the global weakness in industrial output and the onset of a recovery in motor gasoline consumption, domestic diesel prices could fall below gasoline prices this summer.

Summer Transportation Fuels Outlook

The increase in consumption provided by the dramatic fall in petroleum prices from last year is being offset by the weak economy. These counter-balancing forces are expected to be prominent features of the summer driving season, defined as the period from April 1 to September 30.

Prices. Regular-grade gasoline retail prices, which averaged $3.81 per gallon last summer, are projected to average $2.23 per gallon during the current driving season. The monthly average gasoline price is expected to peak at about $2.30 per gallon late this summer. Diesel fuel prices, which averaged $4.37 per gallon last summer, are projected to average $2.27 this summer. However, because short-term prices can be quite volatile, weekly prices will be higher (or lower) than the monthly average. In addition, if consumption turns out to be greater than projected in this *Outlook*, there could be increases in the monthly price averages.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by the change in crude oil prices and wholesale margins. These retail price projections reflect lower prices for the refiner's average acquisition cost of crude oil, projected to average about $52 per barrel this summer, significantly lower than the $116 per barrel average last summer. Wholesale gasoline margins (the difference between the wholesale price of gasoline and the average cost of crude oil) are expected to be relatively unchanged from the average of 39 cents per gallon last summer. Wholesale diesel margins, on the other hand, are projected to be significantly lower this summer (31 cents per gallon) than last summer (80 cents per gallon) because of global weakness in distillate markets.

Motor Gasoline. During the summer season, motor gasoline consumption is projected to increase by 1.0 percent to 9.1 million bbl/d. Gasoline consumption last summer was low due to the high gas prices and hurricane-related distribution

problems, and consumption is not expected to begin showing consistent year-over-year growth until the third quarter.

Motor gasoline is supplied by four sources: domestic crude oil refinery output, domestic production and imports of fuel ethanol for gasoline blending, primary inventories, and net imports of motor fuel and blending components. This summer's domestic refinery gasoline supply is expected to increase by about 240,000 bbl/d from last summer's average. Refinery production of gasoline was depressed last year as refiners maximized distillate production because of the much stronger diesel fuel market relative to gasoline. This year the diesel market is being hit the hardest by the economic downtown, and refiners are expected to lean toward more gasoline production.

Fuel ethanol blending into gasoline increased from an average of 437,000 bbl/d during the summer of 2007 to 635,000 bbl/d during the summer of 2008, and is projected to average 670,000 bbl/d this summer. EIA expects the growth in ethanol plant capacity and production over the last few years to slow dramatically in 2009 as lower gasoline prices depress ethanol production profits, and financial market constraints curtail construction plans and contribute to the temporary shutdown of several facilities.

At the onset of the summer driving season (April 1), total gasoline stocks, at 217 million barrels, are estimated to be ample. That level is 4 million barrels below last year, but 8 million barrels above the previous 5-year average (U.S. Gasoline and Distillate Inventories). Because of the lower current inventory level than last year, EIA projects the average stock draw will be about 60,000 bbl/d, compared with last summer's 173,000 bbl/d stock draw and the average of 45,000 bbl/d over the last 5 years.

For the current summer season, net imports of motor gasoline and blending components are projected to average 900,000 bbl/d, down almost 80,000 bbl/d from last summer's average because of the expected higher refinery gasoline yields and increase in ethanol blending this year.

Diesel Fuel. Distillate fuel consumption, which includes both diesel fuel and heating oil, is projected to be about 170,000 bbl/d, or 4.5 percent, lower than last summer's average.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. Refinery production this summer is projected to average about 300,000 bbl/d lower than last summer's record average of 4.33 million bbl/d. Refiners maximized production of distillate fuel last year since

diesel fuel wholesale prices were about 40 cents per gallon higher than gasoline wholesale prices. Biodiesel is a small part of the distillate pool. Biodiesel blending averaged about 20,000 bbl/d last summer and is expected to grow to about 35,000 bbl/d this summer as refiners and blenders adjust to the 500-million-gallon biodiesel blending mandate for 2009 under the Renewable Fuels Standard.

Distillate inventories are projected to start the summer season at a record 142 million barrels, about 30 million barrels higher than the previous 5-year average. While distillate stocks normally build during the summer season in preparation for winter heating demand by an average of 21 million barrels during the five previous summers, inventories this summer are expected to show little change.

Continuing strong world demand for distillate fuels last year despite record-high prices contributed to U.S. net exports of distillate fuel averaging almost 420,000 bbl/d during last summer. During the previous five summers (2003 – 2007) the United States was a net importer of distillate fuel, at an average of 120,000 bbl/d. This summer, despite the cutback in domestic refinery production, the United States is expected to continue be a net exporter, averaging about 380,000 bbl/d.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 1.8 percent in 2009 and remain relatively unchanged in 2010 (Total U.S. Natural Gas Consumption Growth). EIA expects the current decline in economic activity will have a significant impact on natural gas consumption in the industrial sector, which is forecast to fall by 7.4 percent this year. In the residential and commercial sectors, where consumption is influenced more by weather than by macroeconomic conditions, natural gas use is expected to increase slightly in 2009. The expected 0.7-percent increase in natural gas consumption in the electric power sector this year is supported by a projection of lower natural gas prices for power generation relative to coal, particularly in the Southeast. The outlook for natural gas consumption in 2010 remains subject to uncertainty about the status of future economic conditions. If the economy begins to recover later this year as currently expected and weather remains near normal, small consumption growth in the industrial and electric power sectors should be offset by small declines in the residential and commercial sectors.

Production and Imports. Total U.S. marketed natural gas production is expected to decline by 0.3 percent in 2009 and by 1.0 percent in 2010. Total working natural gas rigs in the United States have declined from slightly more than 1,600 in late August 2008 to slightly below 800 as of April 9, according to Baker Hughes. The precipitous drop in drilling activity and declining productivity of wells already in place are

expected to cause production to steadily decline as the year progresses. The resultant impact of lower production in the lower-48 non-Gulf of Mexico (GOM) during the second half of 2009 is expected to more than offset higher year-over-year production during the first half of the year. Additional supply curtailments may be necessary as natural gas storage levels approach capacity later this summer. Marketed production from the Federal GOM is expected to increase by 1.9 percent in 2009 because of continued recovery from the 2008 hurricane season and new supplies associated with the startup of offshore oil production facilities. Despite expectations of higher prices and the recovery of drilling programs next year, total production in 2010 is expected to be lower in both the lower-48 non-GOM and Federal GOM regions.

Projected U.S. liquefied natural gas (LNG) imports are expected to increase to about 480 billion cubic feet (Bcf) in 2009, from 352 Bcf in 2008, because of lower global economic activity and the start up of new liquefaction capacity in the Middle East and other parts of the world. Depressed LNG demand in Asia and Europe should tend to increase the amount of LNG available to the United States. However, the LNG projection is subject to considerable uncertainty. Initial production from new liquefaction capacity has been slowed or delayed for extended periods, and U.S. natural gas demand is also projected to be lower in 2009. As a result, expanded LNG flows into the United States likely would depend on there being less domestic natural gas production or imports from Canada than forecast. In the current outlook, U.S. pipeline imports are expected to decline by about 11 percent in 2009.

Inventories. On April 3, 2009, working natural gas in storage was 1,674 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 310 Bcf above the 5-year average (2004–2008) and 438 Bcf above the level during the corresponding week last year. This year's end-of-March working natural gas storage level was the second highest recorded since 1991, exceeded only by the 1,692 Bcf recorded at the end of March 2006. Working natural gas inventories are projected to rise to possibly new record-high levels by the end of the summer injection season.

Prices. The Henry Hub spot price averaged $4.08 per Mcf in March, $0.57 per Mcf below the average spot price in February. Lower consumption, brought about by the economic slowdown, and higher production levels have been the primary contributors to lower natural gas prices. Henry Hub spot prices began April below $4 per Mcf and, absent signs of dramatic economic recovery, are expected to remain below $4 until seasonal space heating demand picks up this fall. Higher prices are expected in 2010 as the economy improves. In addition to demand recovery, the current drilling cutback and limited access to credit for producers could lead to even higher prices if supply fails to keep pace with demand in the short-term. On the other hand, a larger-than-expected increase in LNG import volumes coupled with sustained

economic weakness could keep prices depressed. The Henry Hub spot price is expected to average $4.24 per Mcf in 2009 and $5.83 per Mcf in 2010.

Electricity

Consumption. Cooling degree-days this summer are projected to be 5 percent lower than during the summer of 2008 (U.S. Summer Cooling Degree-Days). The reduced need for air conditioning combined with the impact of the recession on electricity sales, especially in the industrial sector, are expected to reduce total electricity consumption by 1.6 percent in 2009. Consumption is expected to return to a more normal growth rate of 1.4 percent in 2010 (U.S. Total Electricity Consumption).

Prices. The reduction in electricity sales has increased the average cost of electricity for many utilities. Under cost-of-service regulation, fixed capital costs are spread out among a declining number of kilowatthours, in some cases offsetting the reduction in variable fuel costs. As a result, residential electricity prices are projected to increase slowly, at an average annual rate of about 1.8 percent in both 2009 and 2010 (U.S. Residential Electricity Prices).

Generation. Coal-fired generation in the electric power sector is expected to decline by 3.2 percent in 2009 while generation fueled by natural gas is expected to increase by 1.6 percent, primarily due to the favorable natural gas prices compared with delivered coal prices. Difficulties in obtaining credit reportedly have hampered the addition of windpower capacity by some developers. Thus, growth in wind generation is expected to slow appreciably through 2010, after having grown 50 percent last year.

Coal

Consumption. Coal consumption in the electric power sector fell by 0.3 percent in 2008. A decline in overall electricity generation, combined with projected increases from other fossil-based (natural gas and petroleum) and renewable generation sources (hydroelectric and wind), are projected to lead to a 2.6-percent decline in electric-power-sector coal consumption. An expected increase in total electricity generation of 1.5 percent in 2010 is expected to lead to a 1.1-percent increase in electric-power-sector coal consumption. Consumption growth in the coke plant sector is expected to continue falling over the forecast period (U.S. Coal Consumption Growth).

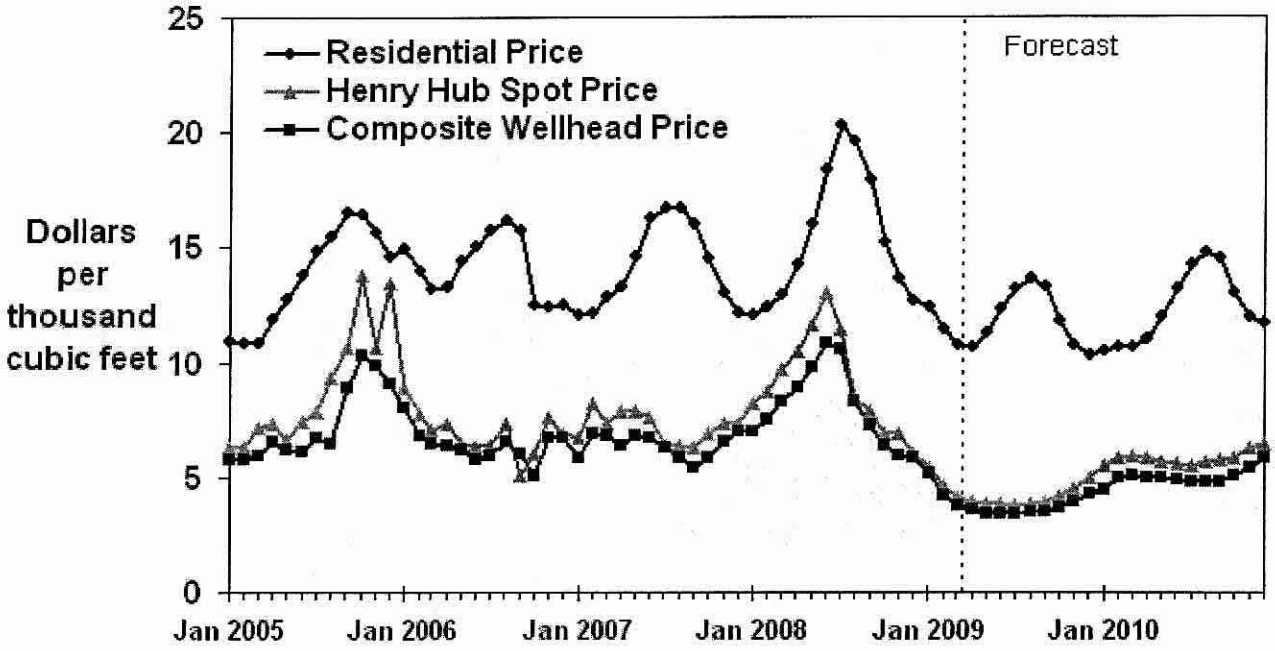
Production. A significant increase in coal exports in 2008 contributed to a 2.2-percent increase in coal production. Production is expected to fall by 5.3 percent in 2009 as lower total domestic coal consumption is combined with export declines. Production

is projected to increase by 2.3 percent in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production).

Exports. Reductions in global coal demand, coupled with the return to normal supply conditions in other major coal-producing and exporting countries, are expected to reduce U.S. coal exports by about 9 million short tons, an 11-percent decrease, in 2009 relative to 2008. The improving global economy in 2010 is expected to increase global coal demand and lead to a projected 11-percent increase in exports.

Prices. The average delivered coal price to the electric power sector is estimated to have increased by more than 17 percent in 2008, to an average $2.07 per million Btu. Although record increases in spot prices (some well over 100 percent) for several types of coal contributed to the increase in the cost of coal, a rise in transportation charges was the primary reason for the cost increase. Declines in electricity demand and lower transportation costs should cause the annual average delivered coal price to decline to $2.03 per million Btu in 2009 and $1.91 in 2010.

Natural Gas Prices



Short-Term Energy Outlook, April 2009

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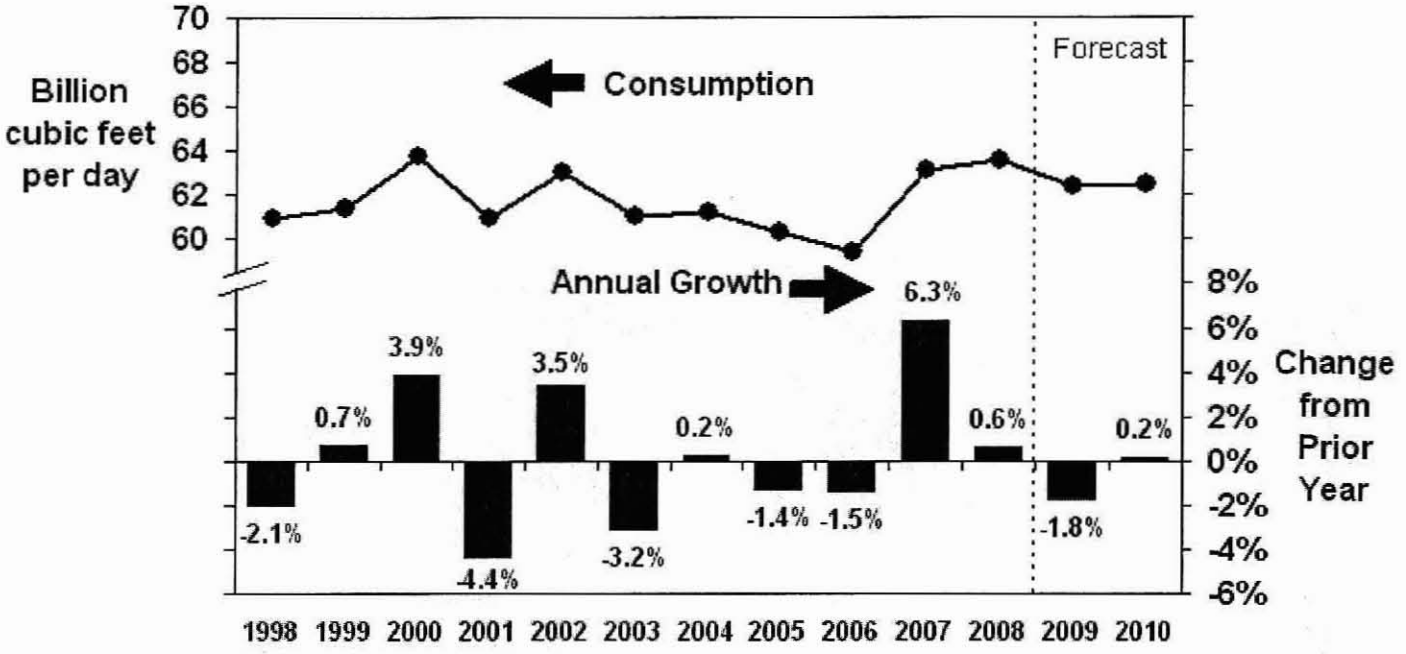
U.S. Total Natural Gas Consumption



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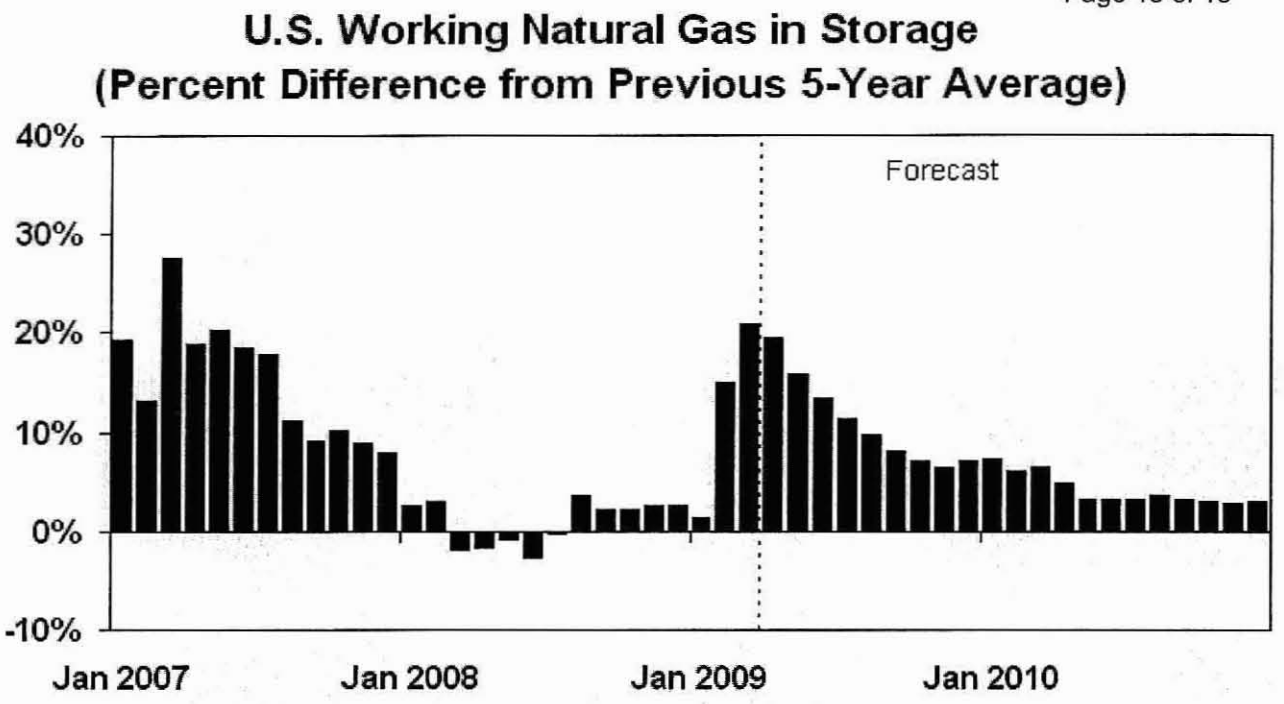

Short-Term Energy Outlook, April 2009

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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, 2008									**($46,836)**
May	($7,154)	$0	($671)	($7,825)	17,007	$0.7009	$11,920	($19,745)	(66,581)
June	25,399	0	(868)	24,531	9,026	(0.1857)	(1,676)	26,207	(40,374)
July	12,556	0	(565)	11,991	6,909	(0.1857)	(1,283)	13,274	(27,100)
August	47,784	0	(408)	47,376	5,577	(0.1857)	(1,036)	48,412	21,312
September	26,255	0	135	26,390	6,028	(0.1857)	(1,119)	27,509	48,821
October	13,043	0	440	13,483	8,294	(0.1857)	(1,540)	15,023	63,844
November	16,133	0	605	16,738	18,404	(0.1857)	(3,418)	20,156	84,000
December	(4,149)	(2,340) 2/	829	(5,660)	34,013	(0.1857)	(6,316)	656	84,656
January 2008	(35,023)	0	840	(34,183)	55,308	(0.1857)	(10,271)	(23,912)	60,744
February	(17,882)	0	587	(17,295)	44,492	(0.1857)	(8,262)	(9,033)	51,711
March	1,709	0	498	2,207	44,866	(0.1857)	(8,332)	10,539	62,250
Balance @ March 31, 2009.									**$62,250**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ December 2008 Northern Natural Gas refund.

Attachment D
Page 1 of 2

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, 2008									**($111,189)**
May	($7,255)	$0	($1,155)	($8,410)	8,115	$0.1814	$1,472	($9,882)	(121,071)
June	(7,516)	0	(1,252)	(8,768)	7,134	(0.7309)	(5,214)	(3,554)	(124,625)
July	(44,216)	0	(1,282)	(45,498)	11,473	(0.7309)	(8,386)	(37,112)	(161,737)
August	(2,975)	0	(1,685)	(4,660)	8,162	(0.7309)	(5,966)	1,306	(160,432)
September	(10,606)	0	(1,655)	(12,261)	8,741	(0.7309)	(6,389)	(5,872)	(166,304)
October	(6,575)	0	(1,707)	(8,282)	12,016	(0.7309)	(8,782)	500	(165,804)
November	4,717	0	(1,689)	3,028	19,205	(0.7309)	(14,037)	17,065	(148,739)
December	(1,569)	(3) 2/	(1,492)	(3,064)	12,982	(0.7309)	(9,489)	6,425	(142,314)
January 2008	339	0	(1,410)	(1,071)	10,874	(0.7309)	(7,948)	6,877	(135,437)
February	553	0	(1,325)	(772)	10,203	(0.7309)	(7,457)	6,685	(128,752)
March	2,876	0	(1,241)	1,635	12,560	(0.7309)	(9,180)	10,815	(117,937)
Balance @ March 31, 2009.									**($117,937)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ December 2008 Northern Natural Gas refund.