

July 1, 2009

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

Re: Cost of Gas Adjustment (COG)
July 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 (40th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (40th Revised Sheet No. 8), showing the July 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.2049 per mcf for residential and firm general service customers and \$0.2013 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.2013 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of \$0.0036 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.2049 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, 2009.

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
Regulatory Analysis Manager

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

**State of North Dakota
Gas Rate Schedule**

NDPSC Volume 2

40th Revised Sheet No. 1.1

Canceling 39th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

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 Over 10 MCF 1.0540	\$6.0830	\$7.3570 7.1370
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$2.6947	\$3.8338 3.5878 3.4358
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$2.6947	\$3.9338
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: July 1, 2009

Effective Date: July 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
40th Revised Sheet No. 8
Canceling 39th 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.	2.3427	(1.8838)	0.2343	0.6932	(1.8838)	(0.7419)	(2.6257)
Current Adj.	0.0036	0.2013	0.0000	0.2049	0.2013	0.0000	0.2013
Total Adj.	2.3463	(1.6825)	0.2343	0.8981	(1.6825)	(0.7419)	(2.4244)
Total Rate:	\$2.4121	\$3.4366	\$0.2343	\$6.0830	\$3.4366	(\$0.7419)	\$2.6947

Date Filed: July 1, 2009

Effective Date: July 1, 2009

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

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2009**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
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	12.0254	12	1,146,790	0.7325
Trans Canada - Demand Charge	7,947	10.6784	12	1,018,335	0.6505
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	12.0254	5	304,724	0.1946
Trans Canada - Seasonal	5,068	10.6784	5	270,591	0.1728
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				<u>\$3,776,277</u>	<u>2.4121</u>
Estimated Weighted Average Commodity Cost	1,565,565	1/ 3.4366		<u>5,380,221</u>	<u>3.4366</u>
Gas Cost Reconciliation Adjustment					<u>0.2343</u>
Total Current Firm Gas Cost				<u>\$9,156,498</u>	<u>6.0830</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$0.8981</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.4366
Gas Cost Reconciliation Adjustment					(0.7419)
Total Current Interruptible Gas Cost					<u>2.6947</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>(\$2.4244)</u>

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

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2009**

Rates Effective July 1, 2009	<u>\$/Dk</u>	
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	12.0254	Per dk/Mo.
Trans Canada Pipeline Demand Charge	10.6784	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	12.0254	Per dk/Day
Trans Canada - Seasonal	10.6784	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:	3.4366	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	<u>5.1191</u>	Per Mcf
Total Firm Base Cost	\$5.1849	Per Mcf

Interruptible:

Commodity	\$5.1191	Per Mcf
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1/ Demand base rate calculation: $4,768 \times 12 \times \$0.8100 / 707,222$

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

Issued by: Raymond D. Nepl, Vice President

Issued on: November 29, 2005

Effective on: January 1, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket
 No. RP02-132-002, issued November 8, 2002, 01 FERC ¶ 61,170

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 4 of 7

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.

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 5 of 7

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.

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

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	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/		Market Area 3/		Field Mileage 5/		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base	TF12 Var., TF5 & TFF	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.

R A T E S C H E D U L E S T F X a n d L F T

Attachment B
 Page 7 of 7

RESERVATION RATES		MARKET-TO-MARKET		FIELD-TO-FIELD		Apr-Oct		Nov-Mar	
		Apr-Oct	Nov-Mar	Apr-Oct	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/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	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.

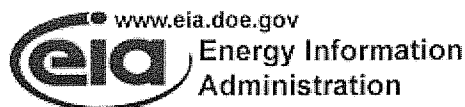
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
July 2009**

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 July monthly price for the AECO Index is expected to increase 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).

Likely factors contributing to rising natural gas prices include increased cooling demand for natural gas and rising crude oil prices. The AECO index price for July 2009 is expected to be approximately 70 percent less than the July 2008 price of \$11.25. The Energy Information Administration (EIA) reported storage levels nationwide as of June 19, 2009 were 22.2 percent above the five-year average and 31.2 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 11.



June 2009

Short-Term Energy Outlook

June 9, 2009 Release

Highlights

- Spot prices for crude oil and petroleum products have increased over the past month. The price of West Texas Intermediate (WTI) crude oil is expected to average \$67 per barrel for the second half of 2009, an increase of about \$16 compared with the first half of the year.
- The average U.S. price for regular-grade gasoline, at \$2.62 per gallon on June 8, was almost 60 cents per gallon higher than its price at the end of April. Regular-grade gasoline prices are expected to reach their summer seasonal peak in July, with a monthly average close to \$2.70 per gallon. The annual average regular-grade gasoline retail price in 2009 is expected to be \$2.33 per gallon, rising to \$2.56 in 2010. The annual average diesel fuel retail prices are expected to be \$2.40 and \$2.67 per gallon in 2009 and 2010, respectively.
- The monthly average Henry Hub natural gas spot price is expected to stay under \$4 per thousand cubic feet (Mcf) until late in the year as abundant natural gas supplies converge with weak demand driven by an 8-percent decline in industrial sector consumption. The price is projected to increase from an average of \$4.13 per Mcf in 2009 to an average \$5.49 per Mcf in 2010 as expected economic growth boosts industrial consumption of natural gas.
- Based on the current Atlantic hurricane season outlook from the National Oceanic and Atmospheric Administration (NOAA), EIA estimates expected production shut-ins on the U.S. Gulf Coast during the upcoming hurricane season (June through November) of about 4.5 million barrels for crude oil and 36 billion cubic feet for natural gas (see the [*2009 Outlook for Hurricane Production Outages in the Gulf of Mexico*](#)). Actual shut-ins are likely to differ significantly from this expectation depending on the number, track, and strength of hurricanes as the season progresses.

Global Petroleum

Overview. Oil prices rose for the third consecutive month in May, driven in part by expectations of a global economic recovery and future increases in oil consumption. In addition, a weaker dollar and increasing financial market activity are prompting higher prices for commodities, overshadowing weak oil supply and demand fundamentals. The weaker dollar may indicate that economic activity abroad, especially in Asia, is stronger than currently estimated, which would provide an upside risk to the oil price forecast. Downside risks, such as continuing weak demand as indicated by sluggish first quarter 2009 oil consumption data, high inventories, and increased surplus production capacity levels within the Organization of the Petroleum Exporting Countries (OPEC) could moderate the upward price pressure, especially if the global economic recovery is delayed and/or weaker than expected.

Consumption. World crude oil and liquid fuels consumption remains below year-ago levels. Total consumption during the fourth quarter of 2008 was 2.8 million barrels per day (bbl/d) below fourth quarter 2007 levels because of the global economic downturn. The year-over-year decline in total consumption increased in the first quarter of 2009 to an estimated 3.4 million bbl/d. Oil consumption in countries that are members of the Organization for Economic Cooperation and Development (OECD) fell by 2.4 million bbl/d in the first quarter of 2009, compared to the first quarter of 2008, accounting for more than 70 percent of the total decline. The rate of consumption decline is expected to moderate later in the year. After falling by an average 1.8 million bbl/d in 2009, global consumption is projected to grow by 0.7 million bbl/d in 2010 in response to expected positive global economic growth ([World Liquid Fuels Consumption Chart](#)).

Non-OPEC Supply. After falling by 270,000 bbl/d in 2008, total non-OPEC supply is projected to rise by 400,000 bbl/d in 2009 and remain almost flat at the 2009 level in 2010. Over the forecast period, higher output in a few countries, such as Brazil, the United States, and Azerbaijan, is expected to offset declining production in Mexico, the North Sea, and Russia ([Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart](#)).

OPEC Supply. OPEC crude oil production is estimated to have averaged approximately 28.7 million bbl/d in the first quarter of 2009 and is projected to average 28.6 million bbl/d in the second quarter. This represents a roughly two-thirds compliance rate with announced production cuts. OPEC, which held production targets steady at its May 28 meeting, plans to meet again on September 9 in Vienna to review market conditions. Over the forecast period, prospects for an economic recovery and a rebound in oil consumption signal higher demand for OPEC oil.

OPEC crude oil production is projected to average 28.5 million bbl/d in 2009, before rising slightly to 28.8 million bbl/d in 2010. However, OPEC production capacity is expected to rise by 1.2 million bbl/d by the end of next year, relative to the end of 2008, which will increase surplus production capacity and help mitigate upward price pressure.

Inventories. Revised data indicate that OECD commercial inventories at year-end 2008 stood at 2.7 billion barrels. At 57 days of forward cover, OECD commercial inventories were well above average levels for that time of year (Days of Supply of OECD Commercial Stocks Chart). Preliminary estimates suggest that OECD commercial inventories increased by 46 million barrels during the first quarter of 2009, rather than declining seasonally, reaching 60 days of forward cover. The United States was responsible for this counter-seasonal build in OECD commercial inventories, with other OECD-member commercial stocks declining slightly. However, with the expected global demand increase in 2010 not forecast to be fully matched by increased supply, global inventories are expected to fall slightly over the forecast period.

U.S. Crude Oil and Liquid Fuels

Consumption. Based on the weak economy, total consumption of liquid fuels and other petroleum products is projected to contract by 550,000 bbl/d (2.9 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart), including a decline of 220,000 bbl/d (5.5 percent) in distillate fuel consumption and about 100,000 bbl/d (6.9 percent) in jet fuel consumption. Motor gasoline, however, is projected to increase by 30,000 bbl/d (0.3 percent) as a result of the substantial declines in retail prices from last summer and the stabilization of real disposable income. The gradual economic recovery in 2010 is expected to contribute to a 300,000-bbl/d (1.6 percent) increase in total liquid fuels consumption.

Production. Total domestic crude oil production averaged 4.96 million bbl/d in 2008, down from 5.06 million bbl/d in 2007 (U.S. Crude Oil Production Chart). Production is expected to increase to an average of 5.27 million bbl/d in 2009 and 5.32 million bbl/d in 2010, including an estimated expectation, with a wide range of uncertainty, of hurricane-induced outage of about 4.5 million barrels for the offshore region in 2009 (see the 2009 Outlook for Hurricane Production Outages in the Gulf of Mexico).

Prices. WTI crude oil prices, which averaged \$99.57 per barrel in 2008 (Crude Oil Prices Chart), are projected to average \$58.70 per barrel in 2009 and \$67.42 per barrel in 2010. As always, energy price forecasts are highly uncertain. One measure of how the market reflects this uncertainty is the sizable participation in near-term options on

crude oil futures contracts at strike prices that are significantly different from current futures market prices. This reflects the tendency for crude oil prices to fluctuate within a wide range in a relatively short period.

EIA projects that regular-grade motor gasoline retail prices, which averaged \$3.26 per gallon in 2008, will average \$2.33 per gallon this year, up 21 cents per gallon from last month's *Outlook* projection. These prices are projected to rise to \$2.56 per gallon in 2010, 26 cents above that projected in the previous *Outlook*. Diesel fuel retail prices, which averaged \$3.80 per gallon in 2008, are projected to average \$2.40 per gallon in 2009, up 14 cents from the previous *Outlook*. Diesel fuel retail prices are projected to average \$2.67 per gallon in 2010, up 19 cents per gallon from the previous *Outlook*.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 2.2 percent in 2009 and then increase slightly in 2010 (Total U.S. Natural Gas Consumption Growth Chart). While total natural gas consumption remains hampered by the broad economic downturn, the persistence of low natural gas prices into the fourth quarter of 2009 is expected to lead to a 2.7-percent increase in electric power sector consumption in 2009, offsetting a portion of the 8-percent decline expected in industrial sector consumption. Additional declines expected in the residential and commercial sectors this year also contribute to the lower 2009 consumption estimate. The anticipation of some economic recovery in 2010 is the basis for slight consumption increases in the commercial and industrial sectors next year, with little change expected in the residential sector. Furthermore, if the dollar remains weak and natural gas prices remain relatively low, consumption in the industrial sector may be bolstered by increased exports of natural-gas-intensive products. Finally, consumption in the electric power sector is expected to remain flat in 2010 as natural gas prices rise relative to coal prices.

Production and Imports. Total U.S. marketed natural gas production is expected to decline by 1.1 percent in 2009 and by 2.6 percent in 2010. Low natural gas prices brought about by the current economic slump have had a dramatic impact on recent drilling activity. According to Baker Hughes, total working natural gas rigs are now down 56 percent from the September 2008 peak. Although a corresponding decline in production has yet to appear in data through March 2009, total U.S. marketed production is expected to drop by nearly 5 billion cubic feet (Bcf) per day between the first and fourth quarters of 2009. The decline in annual production is expected to occur almost exclusively in the Lower-48 non-Gulf of Mexico (GOM) this year, more than offsetting the small expected increase in GOM output. This projection includes an estimated expectation of hurricane-induced outage of about 36 Bcf for the offshore

region in 2009 (see the [2009 Outlook for Hurricane Production Outages in the Gulf of Mexico](#))

The lagged effect of this year's drilling pullback is also expected to result in lower natural gas production in 2010. However, EIA does not anticipate that working rigs and natural gas prices need to return to 2008 levels for production to increase. Recent improvements in technology have reduced finding and development costs, lowered completion times, and greatly enhanced well productivity, increasing the production potential from domestic sources. As a result, production is expected to respond adequately, with a shorter lag, to sustained increases in demand.

U.S. liquefied natural gas (LNG) imports are expected to increase to about 495 Bcf in 2009, from 352 Bcf in 2008, due to weakness in demand for LNG in the global market. The severe economic contractions in the LNG-consuming countries of Asia have increased the amount of available LNG in the global market, elevating LNG purchases in Europe, where natural gas prices remain slightly above those in the United States. In the coming months, as storage facilities in Europe are replenished and new liquefaction capacity comes online, available LNG cargoes are expected to be directed to U.S. terminals. While there is still a degree of uncertainty associated with the start-up of new liquefaction capacity and the availability of shipments, higher than expected LNG imports would almost certainly have a dampening effect on prices and cause lower domestic natural gas production or pipeline imports.

Inventories. On May 29, 2009, working natural gas in storage was 2,337 Bcf ([U.S. Working Natural Gas in Storage Chart](#)). Current inventories are now 423 Bcf above the 5-year average (2003–2007) and 546 Bcf above the level during the corresponding week last year. The estimated inventory build in May was 465 Bcf, the largest increase for this particular month since at least 1976, when records were first kept. Working natural gas stocks are now expected to reach 3,659 Bcf at the end of the 2009 injection season (October 31), roughly 94 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

Prices. The Henry Hub spot price averaged \$3.96 per Mcf in May, \$0.33 per Mcf above the average spot price in April. Prices remain low as natural gas supplies continue to seep into a weak market. As working natural gas inventory nears storage capacity limits, prices may need to decline further to induce necessary adjustments in supply or stimulate demand. Anticipated economic recovery and seasonal space-heating demand are expected to contribute to some price strength in early 2010, and enhanced production capability from domestic supply sources is expected to limit sustained upward price movements throughout the forecast period. The Henry Hub spot price is expected to average \$4.13 per Mcf in 2009 and \$5.49 per Mcf in 2010.

Electricity

Consumption. During the first quarter of 2009, total consumption of electricity fell by an estimated 3 percent compared to the same period last year primarily because of weak industrial consumption. Growth in residential retail sales during the second half of this year is expected to slightly offset continued declines in industrial electricity sales. Total consumption is projected to fall by 1.8 percent for the entire year of 2009 and then rise by 1.2 percent in 2010 ([U.S. Total Electricity Consumption Chart](#)).

Prices. Retail residential electricity prices increased an estimated 8 percent during the first quarter of 2009 compared to the first quarter of 2008 ([U.S. Residential Electricity Prices Chart](#)) because of regulatory lags in the pass-through of fuel costs. However, lower fuel costs for generation are expected to be passed through to retail consumers later this year, keeping the annual 2009 growth in prices around 5.0 percent. Residential prices are expected to grow by just 2.4 percent during 2010.

Coal

Consumption. A decline in overall electricity generation, combined with projected increases from natural gas, nuclear, and renewable (hydroelectric and wind) generation sources, are projected to lead to a 4.6-percent decline in coal consumption in the electric power sector this year. The projected electric power sector consumption of 994 million short tons (MMst) in 2009 is the first time since 2002 that annual consumption would be below the billion short ton level. An expected increase in total electricity generation of 1.5 percent in 2010 is expected to lead to a 1.7-percent increase in electric-power-sector coal consumption. Non-power-sector coal consumption, for both steam and coke production, is projected to decline by 33 percent in 2009, reflecting very weak industrial activity ([U.S. Coal Consumption Growth Chart](#)).

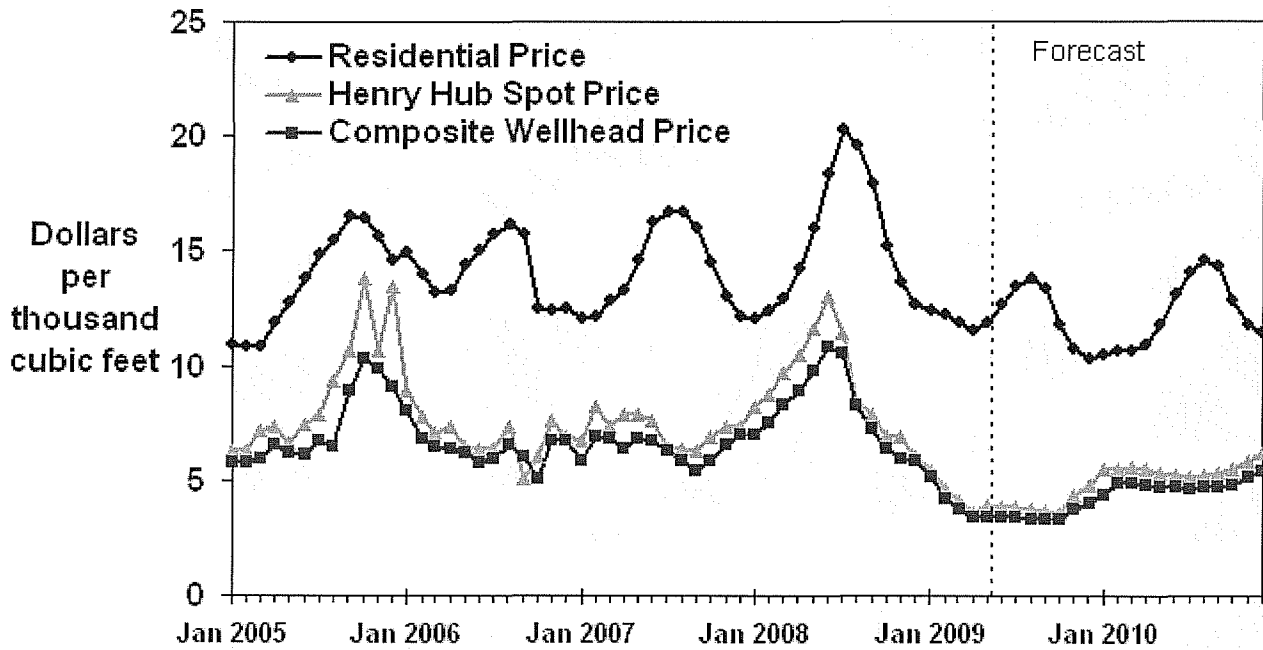
Production. Production is expected to fall by about 7 percent in 2009 in response to lower total domestic coal consumption, export declines, and high coal inventories. The April 2009 production estimate of 88.3 MMst is the lowest monthly coal production figure since May 2004. Conversely, the estimated March 2009 secondary coal inventories of 183.9 MMst is the highest in over 20 years (secondary inventories were 185.5 MMst in December 1987). Production is projected to increase slightly (0.6 percent) in 2010 as domestic consumption and exports increase with an improving economy ([U.S. Annual Coal Production Chart](#)).

Exports. Reductions in global coal demand are expected to reduce U.S. coal exports by about 16.5 million short tons, a 20-percent decrease, in 2009. The projected

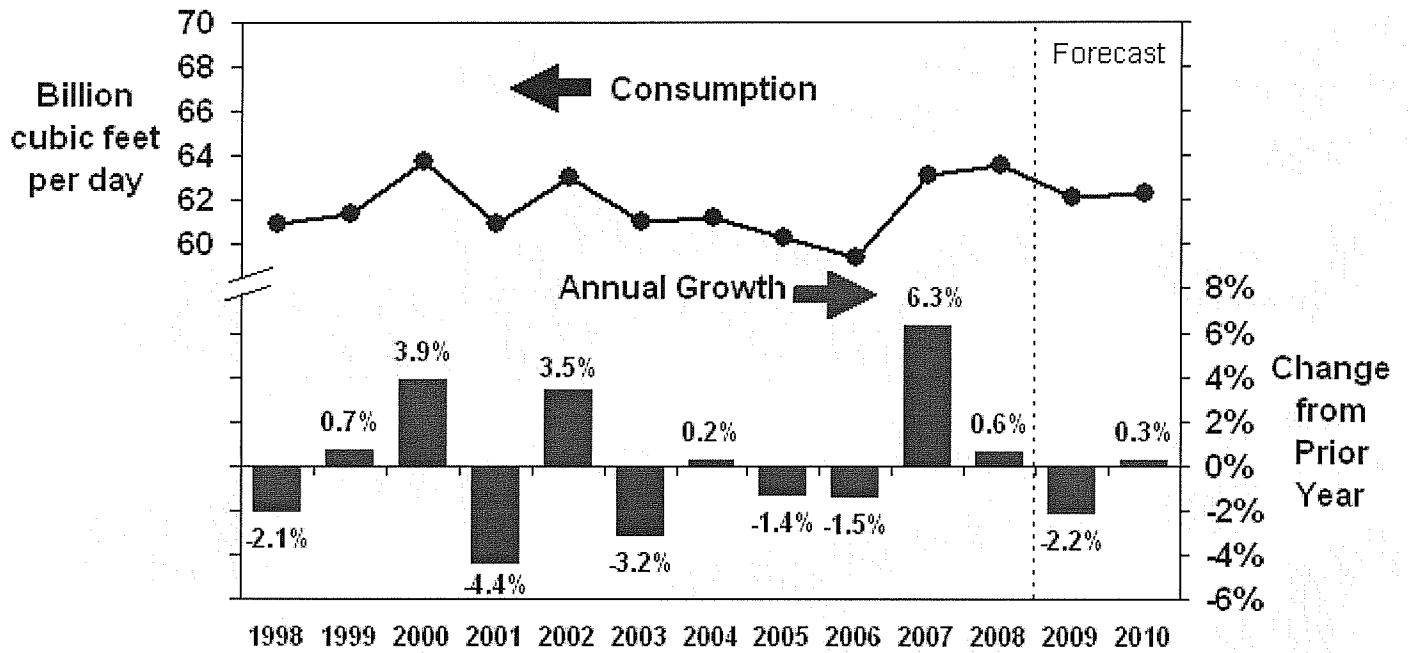
rebound in global economic activity is expected to increase global coal demand and lead to a 24-percent increase in exports in 2010.

Prices. Despite declines in electricity demand and lower fuel costs, the annual average delivered coal price is projected to increase to \$2.16 per million Btu (MMBtu) in 2009 due to a pricing lag between mine-mouth and delivered coal prices caused by long-term coal contracts. Current delivered prices were set when contracts were entered into during a period of high prices for all fuels one year or more ago. 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, spot market purchases make up only a small portion of total coal consumed. The average delivered coal price is expected to decline to \$1.98 per MMBtu in 2010, as expiring high-priced contracts are replaced.

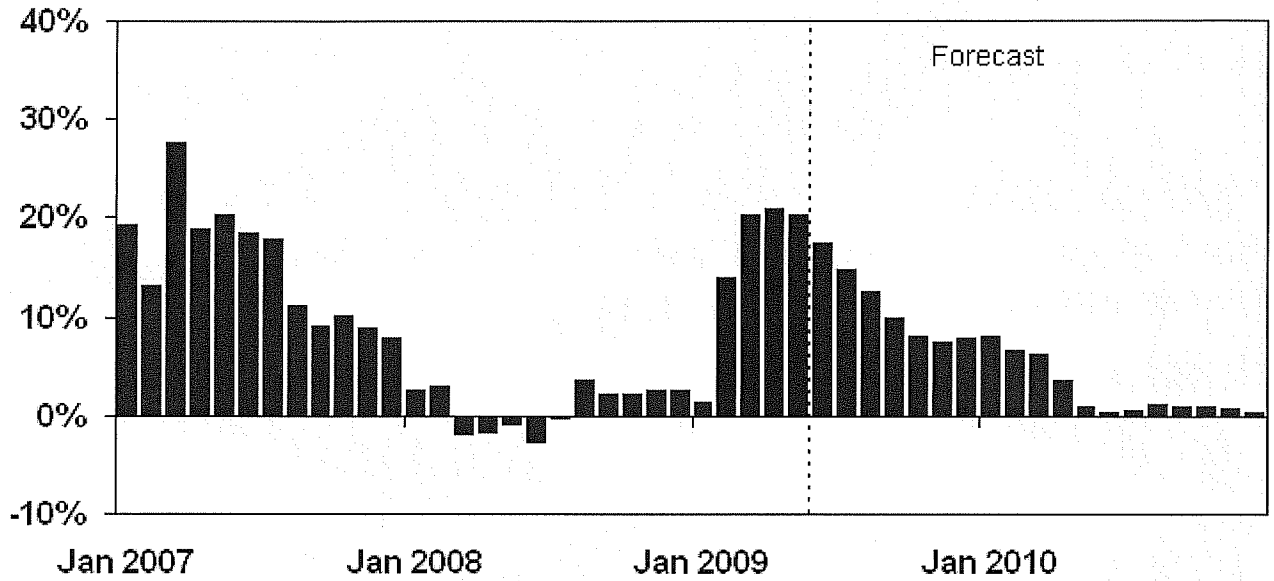
Natural Gas Prices



U.S. Total Natural Gas Consumption



U.S. Working Natural Gas in Storage (Percent Difference from Previous 5-Year Average)



**GREAT PLAINS NATURAL GAS CO.
 COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
 APPLICABLE TO NORTH DAKOTA
 FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2009									<u>\$65,941</u>
May	(\$2,105)	\$0	\$671	(\$1,434)	16,822	(\$0.1857)	(\$3,124)	\$1,690	67,631
Balance @ May 31, 2009.									<u>\$67,631</u>

1/ Interest calculated at 13.3%, the authorized rate of return.

**GREAT PLAINS NATURAL GAS CO.
 COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
 APPLICABLE TO NORTH DAKOTA
 INTERRUPTIBLE**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2009									<u>(\$110,191)</u>
May	(\$5,411)	\$0	(\$1,024)	(\$6,435)	15,426	(\$0.7309)	(\$11,275)	\$4,840	(105,351)
Balance @ May 31, 2009.									<u>(\$105,351)</u>

1/ Interest calculated at 13.3%, the authorized rate of return.