

August 3, 2009

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

Re: Cost of Gas Adjustment (COG)
August 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 (41st Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (41st Revised Sheet No. 8), showing the August 2009 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.3437 per mcf for residential and firm general service customers and \$0.4529 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2009, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.4529 per mcf since the last COG filing due to a decrease in the market price of gas. There has been an increase in pipeline charges of \$0.1092 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.3437 per mcf for residential and firm general service customers.

Attachment C explains the reasons for the change in the market price of gas.

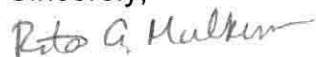
Attachment D shows the calculation of the balancing account since April 30, 2009.

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
41st Revised Sheet No. 1.1

Canceling 40th Revised Sheet No.1.1

Page 1 of 1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$5.7393	\$7.0133 6.7933
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	\$2.2418	\$3.3809 3.1349 2.9829
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$2.2418	\$3.4809
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: August 3, 2009

Effective Date: August 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
 41st Revised Sheet No. 8
 Canceling 40th 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.	2.3463	(1.6825)	0.2343	0.8981	(1.6825)	(0.7419)	(2.4244)
Current Adj.	0.1092	(0.4529)	0.0000	(0.3437)	(0.4529)	0.0000	(0.4529)
Total Adj.	2.4555	(2.1354)	0.2343	0.5544	(2.1354)	(0.7419)	(2.8773)
Total Rate:	\$2.5213	\$2.9837	\$0.2343	\$5.7393	\$2.9837	(\$0.7419)	\$2.2418

Date Filed: August 3, 2009

Effective Date: August 1, 2009

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

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
AUGUST 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	12.7618	12	1,217,016	0.7774
Trans Canada - Demand Charge	7,947	11.3569	12	1,083,039	0.6918
ProGas - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	12.7618	5	323,384	0.2066
Trans Canada - Seasonal	5,068	11.3569	5	287,784	0.1838
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>\$3,947,060</u>	<u>2.5213</u>
Estimated Weighted Average Commodity Cost	1,565,565	1/ 2.9837		<u>4,671,176</u>	<u>2.9837</u>
Gas Cost Reconciliation Adjustment					<u>0.2343</u>
Total Current Firm Gas Cost				<u><u>\$8,618,236</u></u>	<u><u>5.7393</u></u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u><u>\$0.5544</u></u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$2.9837
Gas Cost Reconciliation Adjustment					(0.7419)
Total Current Interruptible Gas Cost					<u>2.2418</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u><u>(\$2.8773)</u></u>

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

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

Rates Effective August 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	12.7618	Per dk/Mo.
Trans Canada Pipeline Demand Charge	11.3569	Per dk/Mo.
ProGas - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	12.7618	Per dk/Day
Trans Canada - Seasonal	11.3569	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:	2.9837	Per dk
Base Rate Effective August 1, 1981		
Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf
Base Rate Calculation		
<u>Firm</u>		
Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf
<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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. Neppel, 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		TF5	TFF
	TF12 Base	Variable		
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.

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			
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.

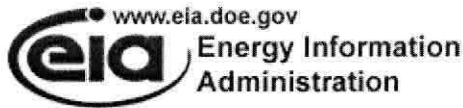
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
August 2009**

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 August monthly price for the AECO Index is expected to decrease from the previous month index, which is approximately \$0.45 per dk less than the estimated July PGA. 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 the price on natural gas remaining in the same range as the July index price is relatively little change in the price of crude oil, signs of an economic recovery offset by high levels of natural gas in storage. The AECO index price for August 2009 is expected to be approximately 67 percent less than the August 2008 price of \$8.69. The Energy Information Administration (EIA) reported storage levels nationwide as of July 24, 2009 were 18.8 percent above the five-year average and 23.3 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 10.



July 2009

Short-Term Energy Outlook

July 7, 2009 Release

Highlights

- After climbing for much of the year, the spot price of West Texas Intermediate (WTI) crude oil hovered around \$70 per barrel through most of June. The price of WTI crude oil is expected to average near \$70 per barrel through the second half of 2009, an increase of about \$18 compared with the average for the first half of the year. The WTI spot price is projected to rise slowly as economic conditions improve, and to average about \$72 per barrel in 2010.
- U.S average prices for regular-grade gasoline, which reached \$2.69 per gallon in EIA's June 22 weekly survey, have fallen back slightly. Gasoline prices are expected to stay near current levels but will be strongly influenced by any changes in crude oil prices. The annual average regular-grade gasoline retail price in 2009 is expected to be \$2.36 per gallon. Higher projected crude oil prices next year are expected to boost the average price to \$2.69 per gallon in 2010. Annual average diesel fuel retail prices are expected to be \$2.46 and \$2.79 per gallon in 2009 and 2010, respectively.
- The monthly average Henry Hub natural gas spot price is expected to remain below \$4 per thousand cubic feet (Mcf) until late in the year given plentiful U.S. natural gas supplies and weak demand, particularly in the industrial sector. The Henry Hub price is projected to increase from an average of \$4.22 per Mcf in 2009 to an average of \$5.93 per Mcf in 2010 as expected economic growth increases industrial consumption of natural gas.

Global Petroleum

Overview. Crude oil prices rose in June for the fourth consecutive month, in part because of stronger-than-anticipated global economic activity, primarily in Asia. Market sentiment continues to reflect expectations of an economic recovery and a future rebound in oil demand that are outweighing weak current oil consumption and high inventory levels. Continued production restraint by members of the

Organization of the Petroleum Exporting Countries (OPEC) and unrest in Iran and Nigeria, respectively OPEC's second- and seventh-biggest oil producers, are also supporting prices. The downside price risks of this forecast are a delayed or weaker-than-expected global economic recovery, ample global surplus production capacity, and high commercial inventories.

Consumption. The global economic downturn curtailed world oil consumption during the second half of 2008 and the first half of 2009. Compared with the year prior, world oil consumption was down an average of 3.0 million barrels per day (bbl/d) from the fourth quarter of 2008 through the second quarter of 2009. However, the consumption decline rate is expected to moderate later this year because of comparison with a lower level of consumption last year and projected gradual global economic improvement. In particular, there has been stronger economic activity in Asia than was previously anticipated, and the current forecast reflects higher expected oil consumption in that region. As a result, a smaller decline in global oil consumption is expected in 2009, with oil consumption projected to fall by 1.6 million bbl/d compared with a decline of 1.7 million bbl/d in the June *Outlook*. Global consumption is projected to grow by 0.9 million bbl/d in 2010 in response to expected positive global economic growth (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Total non-OPEC supply is expected to rise by 360,000 bbl/d in 2009 and to remain fairly flat in 2010. Over the forecast period, higher output from Brazil, the United States, Azerbaijan, and Kazakhstan is expected to offset falling 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 be 28.6 million bbl/d in the second quarter of 2009, down slightly from first quarter levels, but down 3.1 million bbl/d from the third quarter of 2008. OPEC crude output is expected to remain near current levels through the end of the year, then trend upward moderately in 2010 in response to higher demand. Substantial surplus production capacity, located mostly in Saudi Arabia, should help moderate upward price pressure until higher demand begins to erode the global supply cushion.

Inventories. Preliminary data indicate that commercial inventories held by Organization for Economic Cooperation and Development (OECD) countries stood at 2.7 billion barrels at the end of the first quarter of 2009. At 60 days of forward cover, OECD commercial inventories were well above average levels at the end of March (Days of Supply of OECD Commercial Stocks Chart). Preliminary estimates suggest that OECD commercial inventories held fairly steady during the second quarter of 2009, rather than rising seasonally, but still remain well above the historic average.

Crude oil in floating storage, which is not included in the OECD stock totals, has reportedly declined from a high of more than 120 million barrels at the beginning of 2009 to about 80 million barrels.

U.S. Crude Oil and Liquid Fuels

Consumption. Total consumption of liquid fuels and other petroleum products is projected to decrease by 650,000 bbl/d (3.3 percent) in 2009 (U.S. Petroleum Products Consumption Growth Chart), including a decline of 280,000 bbl/d (7.0 percent) in distillate fuel consumption and 140,000 bbl/d (8.7 percent) in jet fuel consumption. Motor gasoline consumption is projected to remain virtually flat as the significant price decline from last summer offsets some of the impact of the economic downturn. Modest economic recovery in 2010 is expected to contribute to a 310,000-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 5.23 million bbl/d in 2009 and 5.36 million bbl/d in 2010. Oil production from the new Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields is expected to account for about 14 percent of Lower-48 crude oil production by the fourth quarter of 2010.

Prices. WTI crude oil prices, which averaged \$99.57 per barrel in 2008, are projected to average \$60.35 per barrel in 2009 and \$72.42 per barrel in 2010 (Crude Oil Prices Chart). This projection represents a \$2-to-\$5-per-barrel increase over that of the previous *Outlook*.

Regular-grade motor gasoline retail prices, which averaged \$3.26 per gallon in 2008, are expected to average \$2.36 per gallon this year. Higher projected crude oil prices in 2010 (\$12 per barrel higher on average, or 29 cents per gallon) are expected to boost average motor gasoline prices to \$2.69 per gallon next year. Diesel fuel retail prices, which averaged \$3.80 per gallon in 2008, are projected to average \$2.46 per gallon in 2009 and \$2.79 in 2010.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 2.3 percent in 2009 and remain unchanged in 2010 (Total U.S. Natural Gas Consumption Growth). Poor economic conditions are expected to prolong the current slump in natural gas demand over the coming months, led by an 8.2-percent drop among industrial users

in 2009. While consumption is expected to fall in the residential and commercial sectors as well this year, competitive natural gas prices relative to coal are projected to lead to a 2.4-percent increase in electric power sector consumption in 2009. Slight consumption increases in the residential, commercial, and industrial sectors next year are expected to result from the projected economic recovery. Natural gas consumption in the electric power sector is expected to decline by 1 percent in 2010 as natural gas prices rise and coal regains a larger share of the baseload generation mix.

Production and Imports. Total U.S. marketed natural gas production is expected to decline by 0.6 percent in 2009 and by 2.9 percent in 2010. As both consumption and prices have waned amid the recent economic downturn, natural gas producers have responded with a dramatic reduction in drilling activities. According to Baker Hughes, total working natural gas rigs are now down 57 percent since September 2008. The resulting production decline from the drop in rigs is expected to occur almost exclusively in the Lower-48 non-Gulf of Mexico (GOM) region during the second half of this year. While the drop in natural gas drilling rigs is expected to result in lower natural gas production in 2010, recent improvements in drilling technology have lowered costs, reduced drilling time, and increased well productivity. These factors should improve the responsiveness of producers to changes in demand, limiting the extent of sustained upward price movements through the forecast period.

U.S. liquefied natural gas (LNG) imports are expected to increase to about 506 billion cubic feet (Bcf) in 2009 from 352 Bcf in 2008, because of a combination of weak demand and growing supply in the global LNG market. Lower demand for LNG in Japan and South Korea has increased the amount of available LNG in the global market, leading to larger LNG purchases in China and Europe. However, with limited natural gas storage capacity in Asia and Europe, lower global demand is expected to increase available LNG cargoes for import by the United States.

Inventories. On June 26, 2009, working natural gas in storage was 2,721 Bcf ([U.S. Working Natural Gas in Storage](#)). Current inventories are now 467 Bcf above the 5-year average (2003–2007) and 615 Bcf above the level during the corresponding week last year. Through the first 3 months of the injection season (March 27 through June 26) the estimated inventory build was 1,067 Bcf, the largest increase for this period since 2001, and 157 Bcf more than the average build during this period since 2001. Working natural gas stocks are now expected to reach 3,670 Bcf at the end of the 2009 injection season (October 31), about 105 Bcf above the previous record of 3,565 Bcf reported for the end of October 2007.

Prices. The Henry Hub spot price averaged \$3.91 per Mcf in June, which was 5 cents below the average spot price in May. Prices continue to reflect the disparity between weak demand and strong supply. Despite low prices, natural gas marketed production in the Lower-48 non-GOM increased by 1.9 Bcf/d (3.7 percent) on a year-over-year basis in April, the most current available monthly data. Although U.S. natural gas production is projected to decline over the coming months, historically high storage levels and limits to storage capacity may cause prices to decline further this fall. Prices are expected to recover in early 2010 as the market balance tightens. However, rising prices are expected to be tempered by improvements in the productive capacity of domestic onshore supply sources throughout the forecast period. The Henry Hub spot price is expected to average \$4.22 per Mcf in 2009 and \$5.93 per Mcf in 2010.

Electricity

Consumption. Retail sales of electricity in the industrial sector continue to decline, having fallen by 12 percent during the first quarter of 2009 compared with year-ago levels. Total consumption of electricity is projected to fall by 2.0 percent for the entire year of 2009 and then rise by 0.8 percent in 2010 ([U.S. Total Electricity Consumption Chart](#)).

Prices. Residential electricity prices rose by 8 percent during the first quarter of 2009 compared with the first quarter of 2008 ([U.S. Residential Electricity Prices Chart](#)). Lower generation fuel costs are expected to be passed through to retail consumers later this year, keeping the annual average growth in prices at around 4.7 percent and 3.3 percent in 2009 and 2010, respectively.

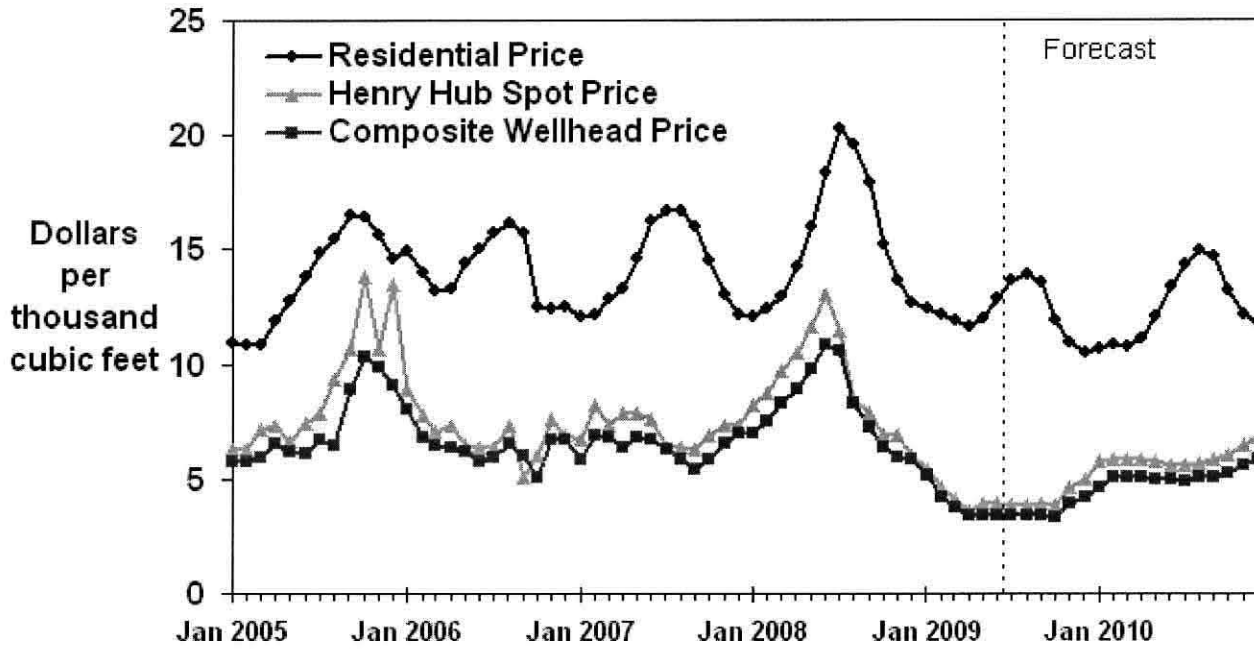
Coal

Consumption. The projected electric-power-sector consumption of about 990 million short tons of coal in 2009 would be the first time since 2002 that annual consumption would be below the billion-short-ton level. The 5.2-percent decline in coal consumption in the electric power sector is the result of lower total electricity generation coupled with projected increases from other generating sources, including natural gas, nuclear, hydroelectric, and wind. Coal consumption in the electric power sector is expected to increase by 1.6 percent in 2010 as natural gas prices rise and coal regains a larger share of the baseload generation mix. Coal consumption for both steam and coke production is projected to decline by 29 percent in 2009, reflecting very weak industrial activity ([U.S. Coal Consumption Growth Chart](#)).

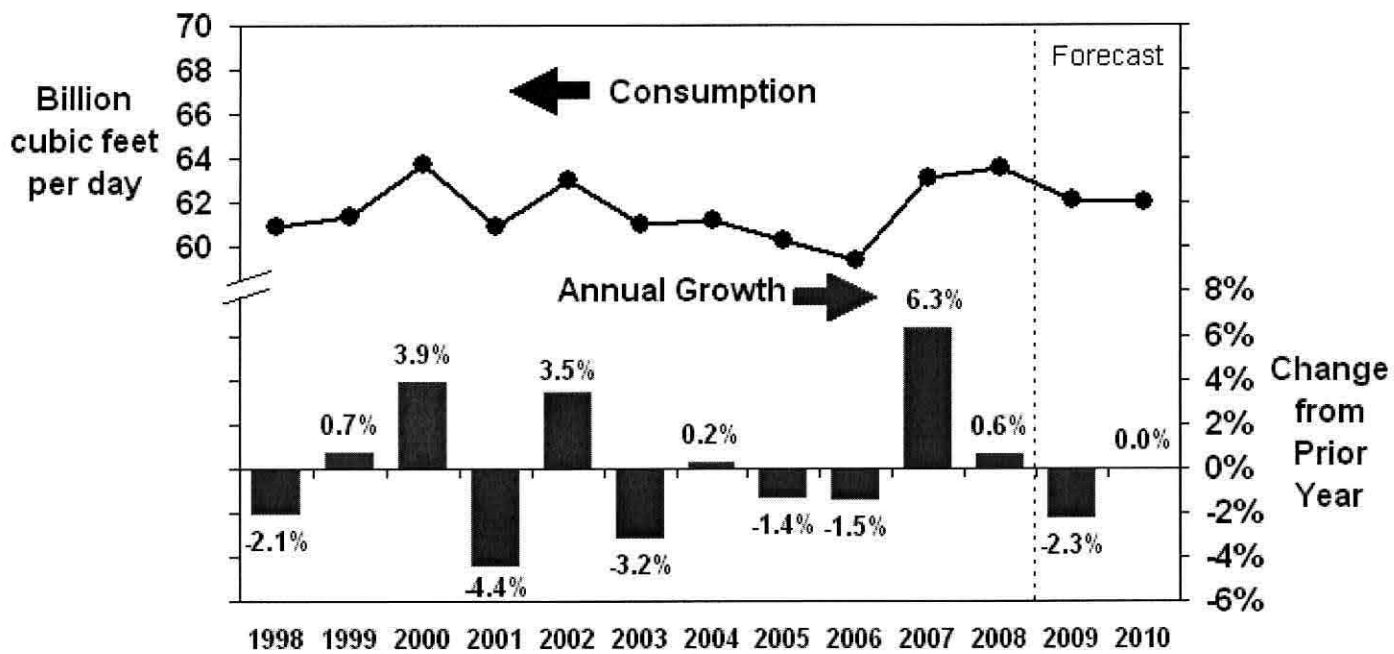
Production. Coal production is expected to fall by about 8 percent in 2009 in response to lower domestic coal consumption, fewer exports, and higher coal inventories. The May 2009 production estimate is the lowest monthly coal production figure since December 2000. Production is projected to increase slightly (0.5 percent) in 2010 as domestic consumption and exports increase with an improving economy ([U.S. Annual Coal Production Chart](#)).

Prices. Despite declines in electricity demand, decreases in spot coal prices, and lower costs for other fossil fuels, the average delivered electric-power-sector coal price is projected to increase from an average of \$2.07 per million Btu in 2008 to \$2.15 per million Btu in 2009. A significant portion of power-sector coal contracts were entered into during a period of high prices for all fuels. Although record increases in spot prices last year (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 coal consumed in the power sector. The average delivered power-sector coal price is expected to decline to \$2.02 per million Btu in 2010 as expiring high-priced contracts are replaced.

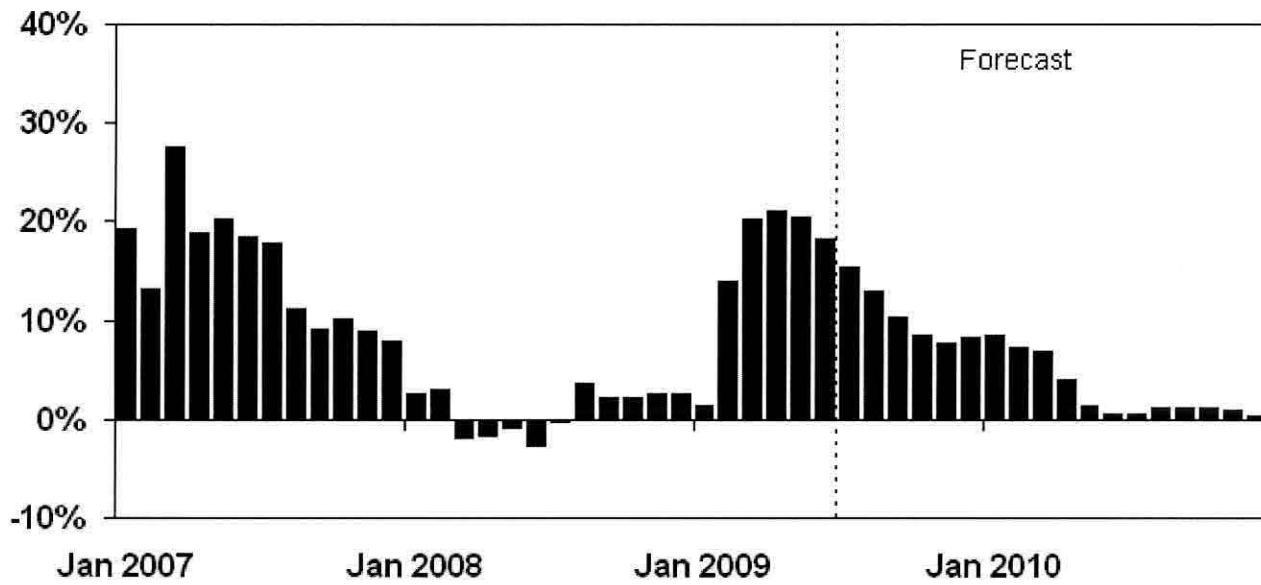
Natural Gas Prices



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
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
Balance @ June 30, 2009.									<u>\$93,163</u>

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

2/ Reflects 6,097.5 dk @ (\$0.1857) and 3,009.9 dk @ \$0.2343.

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

	<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)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
Balance @ June 30, 2009.									<u>(\$100,432)</u>

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

2/ Reflects 7,849.5 dk @ (\$0.7309) and 3,029.9 dk @ (\$0.7419).