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RECEIVED

AUG 01 2008

August 1, 2008

PUBLIC SERVICE COMMISSION

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

Re: Purchased Gas Cost Adjustment (PGA)
August 2008

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Purchased Gas Cost Adjustment (PGA) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (29th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Purchased Gas Adjustment Tariff (29th Revised Sheet No. 8), showing the August 2008 cost of gas and the resulting Purchased Gas Cost Adjustment. The net effect of this filing is a decrease of \$2.7864 per mcf for residential and firm general service customers and \$2.7823 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$2.7823 per mcf since the last PGA filing due to a decrease in the market price of gas. There has been a decrease in pipeline charges of \$0.0041 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$2.7864 per mcf for residential and firm general service customers.

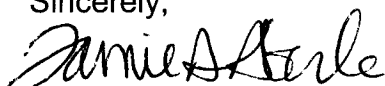
Attachment C explains the reasons for the change in the market price of gas.

Attachment D shows the calculation of the balancing account since April 30, 2008.

Great Plains 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,

A handwritten signature in black ink that reads "Tamie A. Aberle". The signature is written in a cursive style with a large, prominent initial "T".

Tamie A. Aberle
Pricing & Tariff 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

29th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 28th Revised Sheet No.1.1

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	\$11.6387	\$12.9127
			Over 10 MCF	1.0540		12.6927
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF	\$1.1391	\$8.4908	\$9.6299
			Next 2,600 MCF	0.8931		9.3839
			Over 3,000 MCF	0.7411		9.2319
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF	\$1.2391	\$8.4908	\$9.7299
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: August 1, 2008

Effective Date: August 1, 2008

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
29th Revised Sheet No. 8
Canceling 28th 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.	2.5410	6.8849	(0.1857)	9.2402	6.8849	(0.7309)	6.1540
Current Adj.	(0.0041)	(2.7823)	0.0000	(2.7864)	(2.7823)	0.0000	(2.7823)
Total Adj.	2.5369	4.1026	(0.1857)	6.4538	4.1026	(0.7309)	3.3717
Total Rate:	\$2.6027	\$9.2217	(\$0.1857)	\$11.6387	\$9.2217	(\$0.7309)	\$8.4908

Date Filed: August 1, 2008

Effective Date: August 1, 2008

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

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
AUGUST 2008**

<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 Sesaonal	3,000	3.7671	5	56,507	0.0361
TFX Seasonal	4,000	15.1530	5	303,060	0.1936
NOVA - Demand Charge	7,947	10.8725	12	1,036,845	0.6623
Trans Canada - Demand Charge	7,947	14.4855	12	1,381,395	0.8824
ProGas - Demand Charge	7,947	0.9104	12	86,819	0.0555
NOVA - Seasonal	5,068	10.8725	5	275,509	0.1760
Trans Canada - Seasonal	5,068	14.4855	5	367,063	0.2345
ProGas - Seasonal	5,068	0.9104	5	23,070	0.0147
ProGas Winter Surcharge	5,068	3.0049	5	76,144	0.0486
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				<u>\$4,074,516</u>	<u>2.6027</u>
Estimated Weighted Average Commodity Cost	1,565,565	1/ 9.2217		<u>14,437,171</u>	<u>9.2217</u>
Gas Cost Reconciliation Adjustment					<u>(0.1857)</u>
Total Current Firm Gas Cost				<u>\$18,511,687</u>	<u>11.6387</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$6.4538</u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$9.2217
Gas Cost Reconciliation Adjustment					<u>(0.7309)</u>
Total Current Interruptible Gas Cost					<u>8.4908</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>\$3.3717</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 2008**

Rates Effective August 1, 2008	<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	10.8725	Per dk/Mo.
Trans Canada Pipeline Demand Charge	14.4855	Per dk/Mo.
ProGas - Demand Charge	0.9104	Per dk/Mo.
NOVA - Seasonal	10.8725	Per dk/Day
Trans Canada - Seasonal	14.4855	Per dk/Mo.
ProGas - Seasonal	0.9104	Per dk/Mo.
ProGas Winter Surcharge	3.0049	
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	9.2217	Per dk

Base Rate Effective July 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

Interruptible:

Commodity	\$5.1191	Per Mcf
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STATEMENT OF RATES (Rates Per Dekatherm)	
Currently Effective Term-Differentiated Rates	
Rate Schedule	Base Tariff Rate

Category 1 (Contract Term of less than 3 Years)	

Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	\$3.7671
Zone 1 - 1 Minimum Rate	\$0.0000
Zone 1 - 2 Maximum Rate	\$4.8871
Zone 1 - 2 Minimum Rate	\$0.0000
Zone 2 - 2 Maximum Rate	\$2.1400
Zone 2 - 2 Minimum Rate	\$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	

Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	\$3.6171
Zone 1 - 1 Minimum Rate	\$0.0000
Zone 1 - 2 Maximum Rate	\$4.7371
Zone 1 - 2 Minimum Rate	\$0.0000
Zone 2 - 2 Maximum Rate	\$1.9900
Zone 2 - 2 Minimum Rate	\$0.0000
Category 3 (Contract Term of 5 or more Years)	

Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	\$3.4671
Zone 1 - 1 Minimum Rate	\$0.0000
Zone 1 - 2 Maximum Rate	\$4.5871
Zone 1 - 2 Minimum Rate	\$0.0000
Zone 2 - 2 Maximum Rate	\$1.8400
Zone 2 - 2 Minimum Rate	\$0.0000

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

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

Twenty-Second Revised Sheet No. 5B
Superseding
Twenty-First Revised Sheet No. 5B

STATEMENT OF RATES (Rates Per Dekatherm)				
Rate Schedule =====	Base Tariff Rate =====	Adjustment Under Section 19 1/ =====	Rate After Current Adjustment =====	Fuel and Loss Retention Percentages 2/ =====
Commodity Rates				
FT-A - Maximum Rates				
Zone 1 - 1	\$0.0130	\$0.0019	\$0.0149	1.16%
Zone 1 - 2	\$0.0130	\$0.0019	\$0.0149	1.57%
Zone 2 - 2	\$0.0130	\$0.0019	\$0.0149	0.41%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1 - 1	\$0.1368	\$0.0019	\$0.1387	1.16%
Zone 1 - 2	\$0.1737	\$0.0019	\$0.1756	1.57%
Zone 2 - 2	\$0.0834	\$0.0019	\$0.0853	0.41%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0019 per Dekatherm shall be added to other charges under Company's Rate Schedules.				
2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.				
Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: .09% for Zone 1-1, .10% for Zone 1-2, and .01% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.				

Issued by: J. Phill May, Vice President Commercial
Issued on: February 29, 2008

Effective on: April 1, 2008

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		(\$0.0286)	

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

Attachment B
 Page 6 of 7

FIELD-TO-
 FIELD/MARKET
 DEMARCATION

MARKET-TO-MARKET

RESERVATION RATES	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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

- 1/ The minimum reservation rate is equal to zero.
- 2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 where applicable.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where Applicable, Field Area Electric Compression charge of \$0.0000 and ACA will be added to the mileage based rates.

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	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

GULF COAST		Reservation 1/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering		1.0514	0.0000	0.0019	0.0019	0.0019	0.0019
MOPS Transmission		1.5337	0.0000	0.0019	0.0019	0.0019	0.0019
Tivoli - Downstream		0.6827	0.0000	0.0019	0.0019	0.0019	0.0019
Other Gulf Coast		4.8169	0.0000	0.0019	0.0019	0.0019	0.0019

- 1/ The minimum reservation rate is equal to zero.
- 2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 where applicable.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where applicable, Field Area Compression charge of \$0.0000 and ACA will be added to the mileage based rates.
- 6/ Maximum and Minimum rates include ACA of \$0.0019.

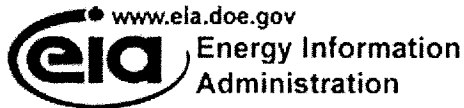
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
August 2008**

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 decreased 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 price decline from the previous month can be attributed to falling crude oil prices and easing concerns about the sufficiency of natural gas being injected into storage despite warm temperatures across much of the lower 48 states during the month of July. The Energy Information Administration (EIA) reported storage levels nationwide as of July 25, 2008 were 12.7 percent below last years balance and 0.5 percent below the five-year average.

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 2008

Short-Term Energy Outlook

July 8, 2008 Release

Highlights

- The spot price of West Texas Intermediate (WTI) crude oil increased from \$122 per barrel on June 4 to \$145 per barrel on July 3. Global supply uncertainties, combined with significant demand growth in China, the Middle East, and Latin America are expected to continue to pressure oil markets. WTI prices, which averaged \$72 per barrel in 2007, are projected to average \$127 per barrel in 2008 and \$133 per barrel in 2009.
- Regular-grade gasoline is expected to average \$3.84 per gallon in 2008, more than \$1 per gallon above the 2007 average price. The U.S. average regular-grade gasoline price, about \$4.10 per gallon on June 30, is projected to remain over \$4 per gallon until the fourth quarter of 2009. Retail diesel fuel prices, which averaged \$2.88 in 2007, are projected to average \$4.35 per gallon in 2008 and \$4.48 per gallon in 2009.
- World consumption of liquid fuels and other petroleum is projected to grow by almost 900,000 barrels per day (bbl/d) in 2008 and by an additional 1.4 million bbl/d in 2009, while U.S. consumption is expected to decline by about 400,000 bbl/d in 2008. Adjusting for increased ethanol use, U.S. petroleum consumption is projected to fall by 530,000 bbl/d in 2008.
- The Henry Hub natural gas spot price averaged \$7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average \$11.86 per Mcf in 2008 and \$11.62 per Mcf in 2009.
- Rapidly increasing delivered fuel costs for power generation, particularly for natural gas, are pushing up electricity prices. Residential electricity prices are projected to increase by an annual average of about 5.2 percent in 2008 and 9.8 percent in 2009 compared with an increase of 2.2 percent in 2007.

Global Petroleum

The oil market remains tight, evidenced by rising prices, low surplus production capacity, and the concern that global supply growth may not keep pace with demand growth over the near term. Preliminary estimates indicate that higher oil consumption in the second quarter and a modest increase in production left Organization for Economic Cooperation and Development (OECD) commercial inventories below the 5-year average at the end of June.

Saudi plans to raise production from 9.4 million bbl/d in June to 9.7 million bbl/d in July, a 27-year high for the nation, have not resulted in an easing of prices. Supply losses in Nigeria and heightened tensions between Iran and Israel raised new concerns about future supplies. Moreover, while the Saudi action adds supplies to the market, remaining available surplus production capacity during the third quarter is at the low level of about 1.2 million bbl/d, all concentrated in Saudi Arabia.

Consumption. World oil consumption continues to grow despite 7 consecutive years of rising prices. Preliminary data indicate that world oil consumption during the first half of 2008 rose by roughly 520,000 bbl/d compared with year-earlier levels. Compared to year-ago levels, this increase reflects a 170,000-bbl/d gain in the first quarter, followed by an 870,000-bbl/d increase in the second quarter. A 760,000-bbl/d decline in consumption in OECD countries during the first half of 2008, mainly concentrated in the United States, was more than offset by a 1.3-million-bbl/d increase in consumption in non-OECD nations led by China and the Middle East (World Oil Consumption). World oil consumption is projected to rise by almost 1.2 million bbl/d during the second half of the year, reflecting the impact of higher expected prices, lower economic growth, and growing pressure in some countries (such as India, Malaysia, Indonesia, and China) to ease price subsidies, which could dampen consumption growth. Global consumption in 2009 is expected to increase by 1.4 million bbl/d because of upward revisions in projected 2009 economic growth in some regions, such as Latin America. If financial strains in the United States spread to foreign nations, depressing economic growth, consumption growth would also slow.

Non-OPEC Supply. The pace of supply growth in non-Organization of the Petroleum Exporting Countries (OPEC) is another key determinant of future market conditions. Despite higher prices and recent past projections of substantial growth in non-OPEC supplies that matched or exceeded consumption growth, actual non-OPEC production fell far short of both expectations and consumption growth. Faster declines in older fields and delays in expansion projects have limited supply growth. At the beginning of this year, non-OPEC supply growth was projected to rise by 860,000 bbl/d in 2008 and by over 1.5 million bbl/d in 2009. Production is now

expected to rise by only 230,000 bbl/d in 2008 and by 830,000 bbl/d in 2009. Lower-than-expected production from Russia and the North Sea, along with lowered expectations for Brazil, are the principal reasons for lower non-OPEC supply levels. Second-half 2008 non-OPEC supply is expected to increase by about 700,000 bbl/d, driven by growth in Brazil and Azerbaijan (Non-OPEC Oil Production Growth). Given recent history, possible additional delays in key projects as well as accelerating production declines in some older fields cannot be ruled out. As a result, net non-OPEC production gains could be less than the current forecast, leading to both higher demand for OPEC oil and higher prices than currently projected.

OPEC Supply. OPEC crude production in the second quarter of 2008 averaged an estimated 32.3 million bbl/d, up only slightly from 32.2 million bbl/d in the first quarter. Higher production in Iraq and Angola more than offset lower production in Nigeria caused by security problems and worker strikes. Assuming that Saudi Arabia's announcement of raising July output to 9.7 million bbl/d results in a higher sustained rate of production through at least September, OPEC crude production is projected to average 32.7 million bbl/d during the third quarter. At these production levels, available surplus production capacity during the third quarter would be only 1.2 million bbl/d, marking the third consecutive quarter that surplus capacity stood at or below 1.5 million bbl/d. All of this capacity is held by Saudi Arabia (OPEC Surplus Oil Production Capacity). Any industry operating at close to 99 percent of capacity will remain vulnerable to surprises that either boost consumption or disrupt production. Such surprises would place additional upward pressure on prices and contribute to oil price volatility. In this tight global oil market, OPEC countries have also faced delays in adding new production capacity, notably in Algeria and in Saudi Arabia, whose 500,000 bbl/d Khursaniyah project has been pushed back to the end of 2008.

Inventories. OECD commercial inventories declined during the first quarter of 2008 by 39 million barrels. During the second quarter, inventories increased by only 36 million barrels, well below the average build of 83 million barrels during this time of year. At the end of the second quarter, estimated OECD commercial inventories stood at 2.57 billion barrels, 26 million barrels below the 5-year average and equal to 53 days of forward consumption (Days of Supply of OECD Commercial Stocks).

U.S. Petroleum

Production. In 2008, total domestic crude oil output is projected to average 5.14 million bbl/d, up slightly from the 2007 average of 5.10 million bbl/d (U.S. Crude Oil Production). Production growth in the Lower-48 region is expected to more than offset declines in Alaskan output. In 2009, total production is projected to increase to

5.27 million bbl/d, due mostly to the Thunder Horse and Tahiti platforms coming on-stream in late 2008 and 2009, respectively. This projection includes an expectation of hurricane-induced outages of an estimated 11 million barrels for the offshore region in 2008 (see Hurricane Outlook). Fuel ethanol production is projected to increase from an annual average of 420,000 bbl/d in 2007 to 560,000 bbl/d in 2008 and to 640,000 bbl/d in 2009.

Consumption. Total petroleum consumption is projected to shrink by 400,000 bbl/d in 2008, a sharper drop than the nearly 300,000 bbl/d projected in the previous *Outlook*, based on prospects for a weak economy and record high crude oil and product prices extending into 2009 (U.S. Petroleum Products Consumption Growth). In 2009, total consumption is projected to remain almost flat at the 2008 level.

Prices. WTI crude oil prices, which averaged \$72 per barrel in 2007 (Crude Oil Prices), are projected to average \$127 per barrel in 2008 and \$133 per barrel in 2009.

Regular-grade motor gasoline retail prices, which averaged \$2.81 per gallon in 2007, are projected to rise to an average of \$3.84 per gallon this year and \$4.06 per gallon in 2009. These prices hit a record of \$4.10 per gallon on June 30. For the remainder of 2008, pump prices are projected to remain well above \$4.00 per gallon. This forecast reflects very weak gasoline margins because of the decline in gasoline consumption and growth in ethanol supply.

Diesel fuel retail prices in 2008 are projected to average \$4.35 per gallon, up from \$2.88 per gallon last year, and increase to an average of \$4.48 per gallon in 2009. These higher prices reflect strength in diesel demand, particularly in emerging markets, which has significantly increased the margins between diesel prices and crude oil costs from those of last year. Over the next few months, these prices are projected to remain near the June 30 price of \$4.65 per gallon as refiner margins begin to weaken slightly, offsetting the projected rise in crude oil costs.

Natural Gas

Consumption. Total natural gas consumption is expected to increase by 2.1 percent in 2008 and by 1.1 percent in 2009 (Total U.S. Natural Gas Consumption Growth). Year-over-year increases are expected in every sector in 2008 and have been largely weather-driven thus far. In 2009, residential and commercial sector consumption is expected to be relatively unchanged while natural gas consumption for electricity generation is expected to increase by 3.2 percent. Growth in the industrial sector continues its recent upward trend, while demand for natural-gas-based fertilizers is expected to increase in the near-term as growers begin to replant following floods in

the Midwest. Consumption in the industrial sector is expected to increase by 1.6 percent in 2008 and by 0.6 percent in 2009.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 6.4 percent in 2008 and by 1.6 percent in 2009. Production from the Federal Gulf of Mexico, which is now expected to decline by 1.3 percent in 2008, has been limited due to unplanned repairs on key infrastructure in the region. Production in the Lower-48 onshore region is expected to increase by 7.9 percent in 2008, more than offsetting declining production in the Gulf. In 2009, marketed natural gas production from the Federal Gulf of Mexico is projected to increase by 2.5 percent while the Lower-48 onshore region is expected to increase by 1.4 percent.

Import volumes of liquefied natural gas (LNG) to the United States continue to sag. Through the first half of 2008, LNG imports were roughly 60 percent below the amount received during the corresponding period last year. While demand for LNG supplies remains strong in Asia-Pacific and Europe, prices in the United States are becoming more competitive and may attract additional shipments in the coming months. LNG imports in 2007 totaled about 770 billion cubic feet (Bcf), however, delays in new liquefaction projects and persistent world demand are expected to result in a 290-Bcf decline in U.S. LNG imports in 2008 compared with 2007. In 2009, LNG imports are expected to reach nearly 790 Bcf as new supply enters the global market.

Inventories. On June 27, 2008, working natural gas in storage was 2,118 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 57 Bcf below the 5-year average (2003-2007) and 381 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged \$13.07 per Mcf in June, \$1.42 per Mcf above the average spot price in May. Despite significant onshore production growth, the natural gas market continues to be pressured by high oil prices, low LNG imports, and a widening year-over-year storage deficit. In addition, summer cooling demand was strong in June (cooling degree-days in June were 15.7 percent more than last year and 23.5 percent more than normal), which increases the amount of natural gas used in the electric power sector. On an annual basis, the Henry Hub spot price is expected to average about \$11.86 per Mcf in 2008 and \$11.62 per Mcf in 2009.

Electricity

Prices. Within the past few weeks, a number of utilities have requested permission from State regulators to raise electricity rates in response to rapidly increasing

delivered fuel costs for power generation. It is likely that most other utilities will soon need to pass through these increased costs to retail customers as well. As a result, the forecast for growth in electricity prices is significantly higher than it was in last month's *Outlook*. Average U.S. residential electricity prices are expected to increase by 5.2 percent in 2008 and by 9.8 percent in 2009 (U.S. Residential Electricity Prices).

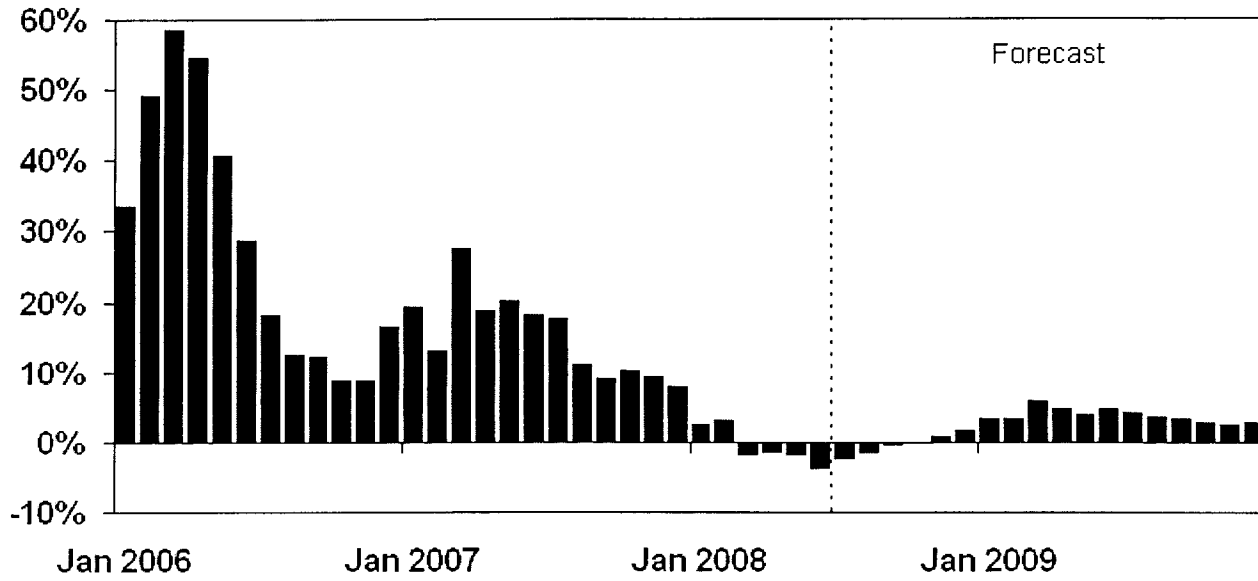
Consumption. This summer began with June about 20 percent warmer than the 30-year average (U.S. Summer Cooling Degree Days). However, the National Oceanic and Atmospheric Administration projects temperatures for the rest of the summer will be slightly cooler than normal. The reduced need for air conditioning and slow economic growth for the remainder of the year should keep electricity consumption during 2008 at about the same level as last year. Consumption is expected to grow by 1.4 percent in 2009 (U.S. Total Electricity Consumption).

Coal

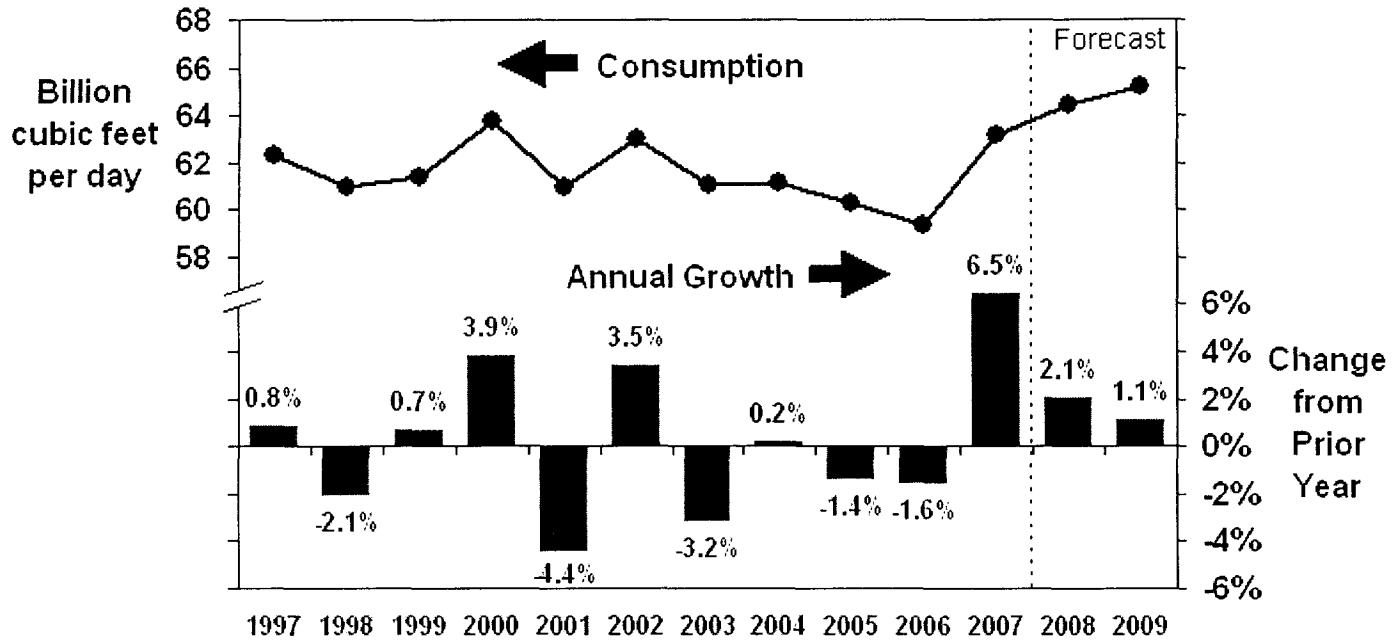
Consumption. Electric-power-sector coal consumption grew by 1.9 percent in 2007. Slow growth in total electricity consumption is expected to limit growth in electric-power-sector coal consumption to 0.6 percent in 2008. Projected increases from other generation sources (nuclear, natural gas, hydroelectric, and wind) in 2009 will continue to dampen electric-power-sector coal consumption growth, projected to be 0.4 percent in 2009 (U.S. Coal Consumption Growth).

Production and Inventories. U.S. coal production (U.S. Annual Coal Production) fell by 1.5 percent in 2007. Growth in domestic consumption and exports will contribute to a 2.9-percent increase in coal production in 2008. Secondary (consumer-held) coal stocks are estimated to have grown by 5.5 percent in 2007 to 159 million short tons. Consumer stocks are expected to remain stable in 2008 and grow by an average of 2.8 percent in 2009. Primary stocks, held by coal producers/distributors, are projected to decline by more than 6 million short tons between the end of 2007 and the end of 2009.

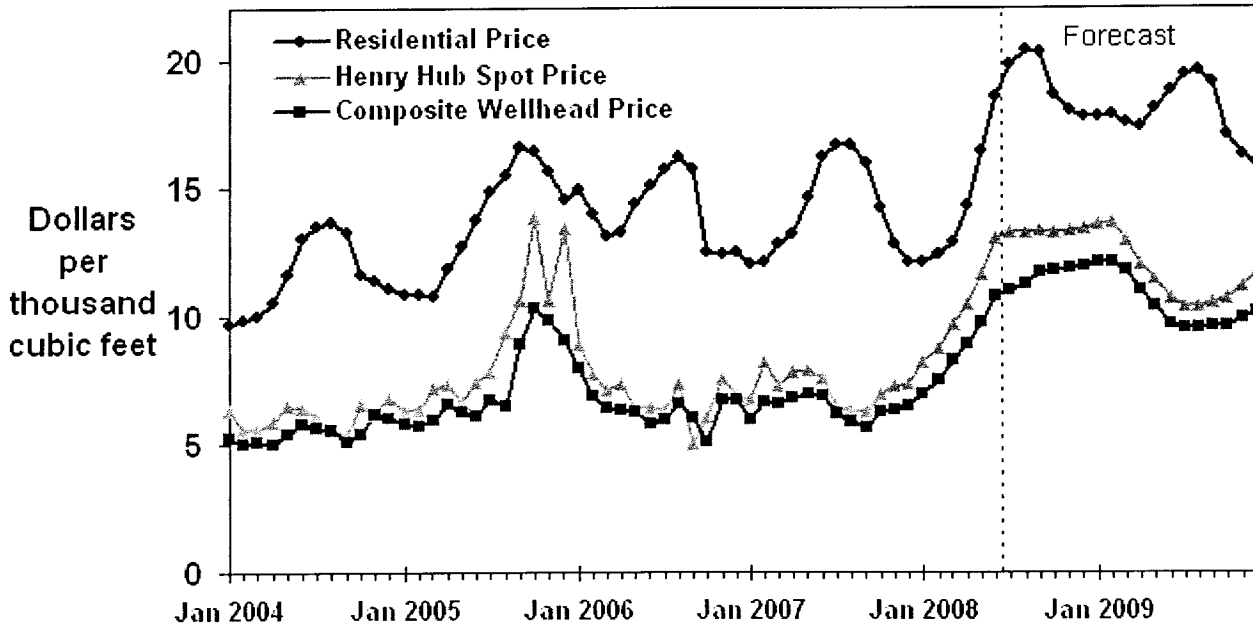
U.S. Working Natural Gas in Storage (Percent Difference from Previous 5-Year Average)



U.S. Total Natural Gas Consumption



Natural Gas Prices



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									<u><u>(\$46,836)</u></u>
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)
Balance @ June 30, 2008									<u><u>(\$40,374)</u></u>

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									<u>(\$111,189)</u>
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)
Balance @ June 30, 2008									<u>(\$124,625)</u>