



A Division of MDU Resources Group, Inc.

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April 1, 2008

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

Re: Cost of Gas (COG) Adjustment
April 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 Cost of Gas (COG) Adjustment pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (25th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (25th Revised Sheet No. 8), showing the April 2008 cost of gas and the resulting adjustment. The net effect of this filing is an increase of \$0.0542 per mcf for residential and firm general service customers and \$0.0373 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for April 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.0373 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 \$0.0169 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.0542 per mcf for residential and firm general service customers.

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

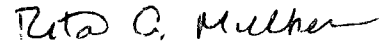
Attachment D shows the calculation of the balancing account since April 30, 2007.

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.

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

25th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 24th 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 Over 10 MCF 1.0540	\$11.6383	\$12.9123 12.6923
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	\$8.7151	\$9.8542 9.6082 9.4562
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$8.7151	\$9.9542
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: April 1, 2008

Effective Date: April 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
25th Revised Sheet No. 8
Canceling 24th 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.	2.3210	3.3773	0.7009	6.3992	3.3773	0.1814	3.5587
Current Adj.	0.0169	0.0373	0.0000	0.0542	0.0373	0.0000	0.0373
Total Adj.	2.3379	3.4146	0.7009	6.4534	3.4146	0.1814	3.5960
Total Rate:	\$2.4037	\$8.5337	\$0.7009	\$11.6383	\$8.5337	\$0.1814	\$8.7151

Date Filed: April 1, 2008

Effective Date: April 1, 2008

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

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
APRIL 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	11.1267	12	1,061,087	0.6778
Trans Canada - Demand Charge	7,947	11.6357	12	1,109,627	0.7088
ProGas - Demand Charge	7,947	0.9264	12	88,345	0.0564
NOVA - Seasonal	5,068	11.1267	5	281,951	0.1801
Trans Canada - Seasonal	5,068	11.6357	5	294,849	0.1883
ProGas - Seasonal	5,068	0.9264	5	23,475	0.0150
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>\$3,763,149</u>	<u>2.4037</u>
Estimated Weighted Average Commodity Cost	1,565,565	1/ 8.5337		<u>13,360,062</u>	<u>8.5337</u>
Gas Cost Reconciliation Adjustment					<u>0.7009</u>
Total Current Firm Gas Cost				<u>\$17,123,211</u>	<u>11.6383</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$6.4534</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$8.5337
Gas Cost Reconciliation Adjustment					<u>0.1814</u>
Total Current Interruptible Gas Cost					<u>8.7151</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>\$3.5960</u>

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

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

Rates Effective April 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	11.1267	Per dk/Mo.
Trans Canada Pipeline Demand Charge	11.6357	Per dk/Mo.
ProGas - Demand Charge	0.9264	Per dk/Mo.
NOVA - Seasonal	11.1267	Per dk/Day
Trans Canada - Seasonal	11.6357	Per dk/Mo.
ProGas - Seasonal	0.9264	Per dk/Mo.
ProGas Winter Surcharge	3.0049	
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	8.5337	Per dk

Base Rate Effective July 1, 1981

Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation

Firm

Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf

Interruptible:

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

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

Twelfth Revised Sheet No. 5
Superseding
Eleventh Revised Sheet No. 5

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. Neppl, 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

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/		Market Area 3/		Field Mileage 5/		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	
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

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- 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.

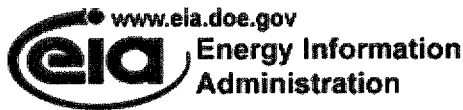
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
April 2008**

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

Storage withdrawals were close to normal during March setting up an anticipated high injection level during the upcoming injection months. This, coupled with persistent high oil prices, contributed to the continued strength in price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide were 2.7 percent above the five-year average as of March 21, 2008.

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.



March 2008

Short-Term Energy Outlook

March 11, 2008 Release

Highlights

- The slowing economy combined with high petroleum prices is expected to constrain growth in U.S. consumption of liquid fuels and other petroleum products to just 40,000 barrels per day (bbl/d) in 2008. After accounting for increased ethanol use, U.S. petroleum consumption falls by 90,000 bbl/d. U.S. real gross domestic product is expected to decline slightly in the first half of the year and then start growing again, with growth for 2008 as a whole at 1.3 percent, the slowest annual rate since 2001.
- Tight fundamentals, reflected by low available crude oil surplus production capacity, combined with supply concerns in several oil exporting countries, have continued to put upward pressure on world crude oil prices. The outlook over the next 2 years points to some easing of the oil market balance due to increased production outside of the Organization of the Petroleum Exporting Countries (OPEC) and planned additions to OPEC capacity. However, delays to capacity additions in both OPEC and non-OPEC nations could alter the outlook, as could OPEC production decisions.
- WTI averaged \$95 per barrel in February and is expected to average \$102 in March (the spot price of WTI closed at nearly \$108 per barrel on March 10, 2008 but is expected to decrease over the second half of the month). The annual average WTI price, which was \$72 per barrel in 2007, is projected to average \$94 per barrel in 2008, but ease somewhat to about \$86 per barrel in 2009.
- The projected higher costs for crude oil in 2008 are likely to be passed on to all petroleum products. Retail prices for motor gasoline are expected to average \$3.21 per gallon or 40 cents above the 2007 price. The monthly average gasoline price is projected to peak near \$3.50 per gallon this spring. It is important to note, however, that even if the national average monthly gasoline price peaks near that level, there is a significant possibility that prices during some shorter time period, or in some region or sub-region, will cross the \$4 per gallon threshold.

- Diesel prices are projected to show larger gains in 2008, averaging \$3.45 per gallon, or 57 cents above the 2007 average price. The monthly average gasoline price is projected to peak near \$3.50 per gallon this spring, while diesel prices are expected average close to \$3.70 per gallon for March and April.
- The Henry Hub natural gas spot price averaged \$7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average \$8.18 per Mcf in 2008 and \$7.95 per Mcf in 2009.

Global Petroleum

Tight fundamentals, evidenced by low available surplus capacity and Organization for Economic Cooperation and Development (OECD) inventories that are below 5-year average levels, continue to put upward pressure on oil prices. In addition, recent events such as Turkey's incursion into northern Iraq against Kurdish rebels, militant attacks against Nigeria's oil infrastructure, and Venezuela's threat to disrupt exports to the United States over its dispute with ExxonMobil have contributed to upward price pressure. Despite high prices, OPEC left production targets unchanged at its March 5 meeting.

Looking beyond 2008, market conditions will depend on trends in consumption and production capacity. If, as EIA projects, planned increases in non-OPEC production capacity outpace oil consumption growth and OPEC countries complete planned expansion projects on time, global surplus capacity could reach 4 million bbl/d or higher by the end of 2009, so prices should ease (OPEC Surplus Oil Production Capacity). EIA recognizes, however, the possibility that prices would be higher if the economic slowdown is short-lived and consumption remains robust, or if oil production capacity expansion levels turn out to be lower than expected.

Consumption. World oil consumption is expected to grow by 1.3 million bbl/d in both 2008 and 2009, slightly lower than projected in last month's report, in response to higher projected oil prices and increased risks of a global economic slowdown. Non-OECD countries are expected to account for 1.1 million bbl/d of world consumption growth in 2008, with gains concentrated in China, the Middle East oil-producing countries, India, and other Asian countries. OECD countries are expected to register a gain of over 0.2 million bbl/d in consumption in 2008, compared with a decline of 0.2 million bbl/d in 2007, reflecting both weather factors and increased demand for oil in Japan for power generation caused by nuclear facility outages. Japan's oil input at electric utilities in January 2008 was up by 225,000 bbl/d compared with year-earlier levels (World Oil Consumption).

Non-OPEC Supply. About 0.7 million bbl/d of non-OPEC supply growth is projected in 2008, revised down by 0.2 million bbl/d from the last *Outlook*. This change represents a revision to expected project schedules as well as a re-evaluation of decline rates at existing fields. Brazil is expected to account for about half of the expected gain in non-OPEC supply in 2008. Azerbaijan, Sudan, and Russia are also expected to record net additions to capacity, while the United Kingdom, Mexico, and Norway are among countries expected to experience declines. The pace and timing of non-OPEC supply growth will continue to be subject to possible delays in key projects. EIA's *Outlook* incorporates an expectation of some further delays. As a result, uncertainty about non-OPEC supply growth introduces both upside and downside risk to our price outlook.

OPEC Supply. EIA projects that OPEC crude oil production will average about 32.2 million bbl/d during the first quarter of 2008, or about 0.6 million bbl/d above fourth quarter 2007 levels. The increase mainly reflects higher production from Saudi Arabia, Angola, and the United Arab Emirates. Based on EIA projections of consumption and non-OPEC supply, OPEC crude production is expected to average slightly above first quarter levels for the remainder of the year. If consumption rises more slowly than expected and OECD inventories climb relative to the 5-year average, OPEC members would be likely to consider holding their output below our projected level. Based on country plans, EIA expects OPEC crude production capacity to rise in 2008 by 1.2 million bbl/d and by 0.8 million bbl/d in 2009. OPEC's non-crude liquids production is also expected to increase by about 0.3 million bbl/d in 2008 and by 0.8 million bbl/d in 2009.

Inventories. OECD commercial inventories declined by 136 million barrels in 2007, an average of 0.4 million bbl/d, in response to higher consumption and OPEC production restraint. OECD commercial inventories stood at 2.54 billion barrels at the end of 2007, 20 million barrels below the previous 5-year average, compared with 127 million barrels above the 5-year average at the end of 2006 (Days of Supply of OECD Commercial Stocks). Preliminary 2008 data for the U.S. and Japan indicate current inventory trends are mixed, improving in the United States but declining relative to the 5-year average in Japan. Expected oil production and oil consumption levels should keep total OECD inventories below the 5-year average at the end of March, before rising to the 5-year average by the end of the year.

U.S. Petroleum

Consumption. Total petroleum consumption of liquid fuels and other petroleum products averaged 20.7 million bbl/d in 2007, up only 10,000 bbl/d from 2006 (U.S. Petroleum Products Consumption Growth). Consumption of liquid fuels and other

petroleum products is projected to grow by 40,000 bbl/d in 2008, a downward revision of 100,000 bbl/d from the previous *Outlook*. After accounting for projected increases in ethanol use, U.S. petroleum consumption falls by 90,000 bbl/d. Based on the forecast of declining real GDP during the first half of this year as well as record high motor gasoline prices, gasoline consumption, having increased only 0.4 percent last year, is projected to increase only 0.3 percent this year and 0.7 percent in 2009. Distillate fuel consumption growth is projected to slow from 1.2 percent in 2007 to 0.7 percent this year before rising slightly to 1.0 percent in 2009.

Production. In 2007, domestic crude oil output is estimated to have averaged 5.1 million bbl/d, unchanged from 2006 (U.S. Crude Oil Production), but is projected to decline slightly in 2008. Output in the Federal Gulf of Mexico, where the Atlantis deepwater platform began production in late 2007, is projected to grow this year, but Alaska and the Lower-48 States are expected to see declines. In 2009, output is projected to grow by 5.1 percent, or about 260,000 bbl/d, mainly because of the start-up of the Thunder Horse and Tahiti platforms in the Gulf of Mexico.

Prices. WTI crude oil prices, which averaged \$72.32 per barrel in 2007, are projected to average \$94.11 and \$85.92 per barrel, respectively, in 2008 and 2009 (Crude Oil Prices). Regular grade gasoline retail prices, which averaged \$2.81 per gallon in 2007, are projected to average \$3.21 and \$3.06 per gallon, respectively, in 2008 and 2009. Diesel fuel prices, which averaged \$2.88 per gallon last year, are projected to average \$3.45 and \$3.22 per gallon, respectively, in 2008 and 2009. The monthly average gasoline price is projected to peak at just under \$3.50 per gallon this spring, while diesel prices are expected to average around \$3.70 per gallon in March and April.

Inventories. At the onset of the peak driving season (April 1), total gasoline stocks are projected to be 224 million barrels, 22.3 million barrels above last year and 18.6 million barrels above the 5-year average (U.S. Gasoline and Distillate Inventories). Although distillate fuel (diesel fuel and heating oil) inventories ended February about 6 million barrels below the same time last year, they are at the 5-year average and are projected to stay close to the average over the forecast period.

Natural Gas

Consumption. Growth in total natural gas consumption is expected to slow from 6.4 percent in 2007 to 0.7 percent in 2008 and 0.8 percent in 2009 (Total U.S. Natural Gas Consumption Growth). In 2009 total natural gas consumption is expected to reach a record 23.4 trillion cubic feet. Natural gas consumption in the electric power sector, which makes up about 30 percent of total natural gas consumption, grew by over 10 percent in 2007 but is expected to decline slightly in 2008 because of the projected

milder summer temperatures. Natural gas consumption in the industrial sector is also projected to decline by 0.2 percent in 2008 because of slowing economic growth.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 2.9 percent in 2008 and by 0.3 percent in 2009. New deepwater supply infrastructure, which came online at the end of 2007, is expected to drive growth of 5.8 percent in the Gulf of Mexico in 2008. In addition, production from the Lower-48 onshore region is expected to increase by 2.5 percent in 2008 led by the development of unconventional supply sources.

Imports of liquefied natural gas (LNG) are projected to be about 770 billion cubic feet (Bcf) for 2008, or about the same amount imported in 2007. Trinidad and Tobago is expected to remain the primary source of U.S. LNG imports through the forecast period. New liquefaction capacity under construction in Qatar and recent startups in Equatorial Guinea, Nigeria, and Norway are expected to boost the global supply of LNG and contribute to an increase in LNG shipments to the United States later this year and in 2009. Next year, volumes are projected to total 995 Bcf.

Inventories. On February 29, 2008, working natural gas in storage was 1,484 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 63 Bcf above the 5-year average (2003-2007) and 169 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged \$8.76 per Mcf in February, \$0.51 per Mcf more than the average January spot price. Cold weather so far in the first quarter has kept pressure on prices, which are expected to decline as space heating demand begins to wane in April. On an annual basis, the Henry Hub spot price is expected to average about \$8.18 per Mcf in 2008 and \$7.95 per Mcf in 2009.

Electricity

Consumption. Total electricity consumption is expected to grow by only 0.4 percent in 2008, then return to a growth rate of 1.5 percent in 2009 (U.S. Total Electricity Consumption). Growth in natural-gas-fired generation is expected to be relatively flat this year due to the assumption that summer temperatures will fall back to near-normal levels. On the other hand, generation by wind power is expected to grow by 37 percent in 2008. Power generators have responded to renewable portfolio standards by rapidly installing wind turbines, which accounted for 25 percent of new electric generating capacity in 2007.

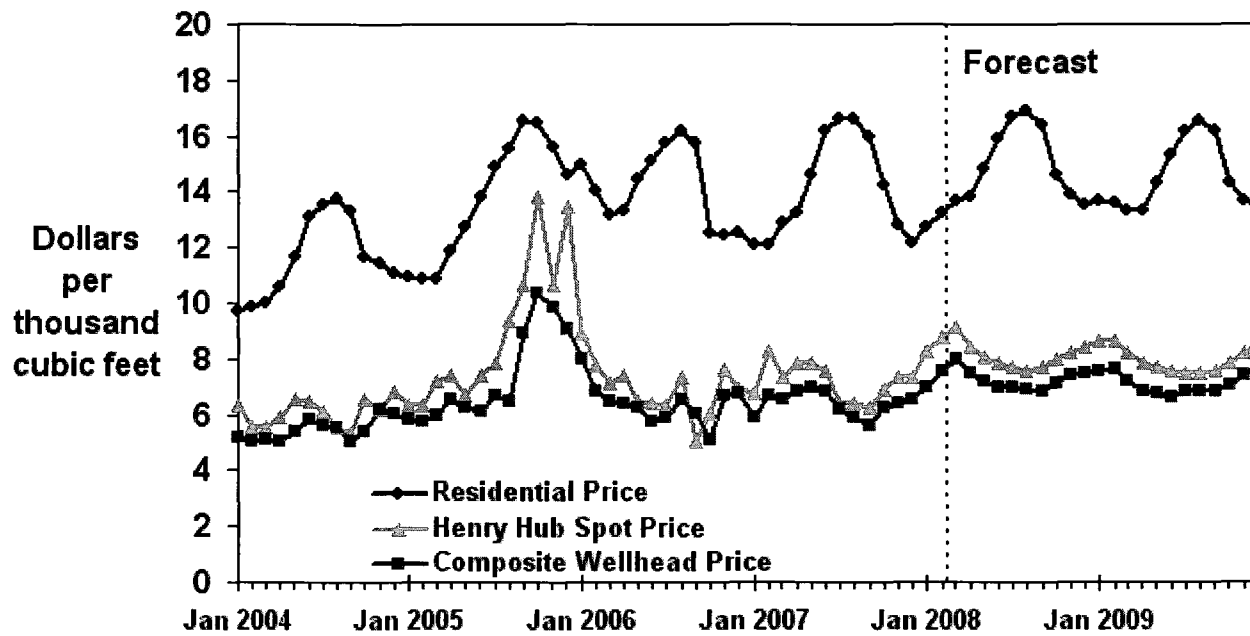
Prices. Residential electricity prices are expected to increase by 2.4 percent this year, slightly higher than the 2008 growth projection in last month's *Outlook*, and then grow by 2.9 percent in 2009 (U.S. Residential Electricity Prices).

Coal

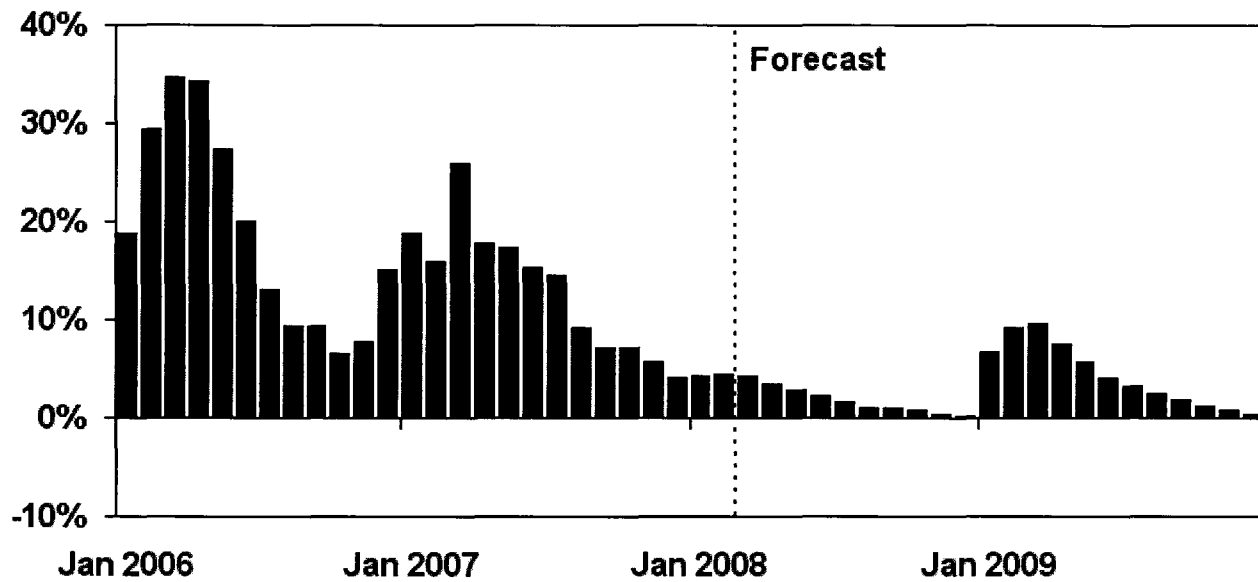
Consumption. Electric-power-sector coal consumption grew by 1.9 percent in 2007. Slow growth in electricity consumption, combined with increases in hydroelectric generation, will dampen growth in electric-power-sector coal consumption to 0.3 percent in 2008. Electric-power-sector coal consumption is projected to increase by an additional 0.4 percent in 2009 (U.S. Coal Consumption Growth).

Production and Inventories. U.S. coal production (U.S. Coal Production) is estimated to have fallen by 1.3 percent in 2007. Projected weak demand for coal in 2008 and 2009 will result in only a 0.1-percent increase in coal production in 2008 followed by 0.2-percent growth in 2009. In the Western region, the Nation's largest coal-producing region, production is expected to increase by 0.7 percent in 2008, but decrease by 0.6 percent in 2009. Total coal stocks are estimated to have grown by 1.6 percent in 2007 to 190 million short tons. Total coal stocks are expected to rise by 1.1 percent in 2008 and remain at that level (192 million short tons) in 2009.

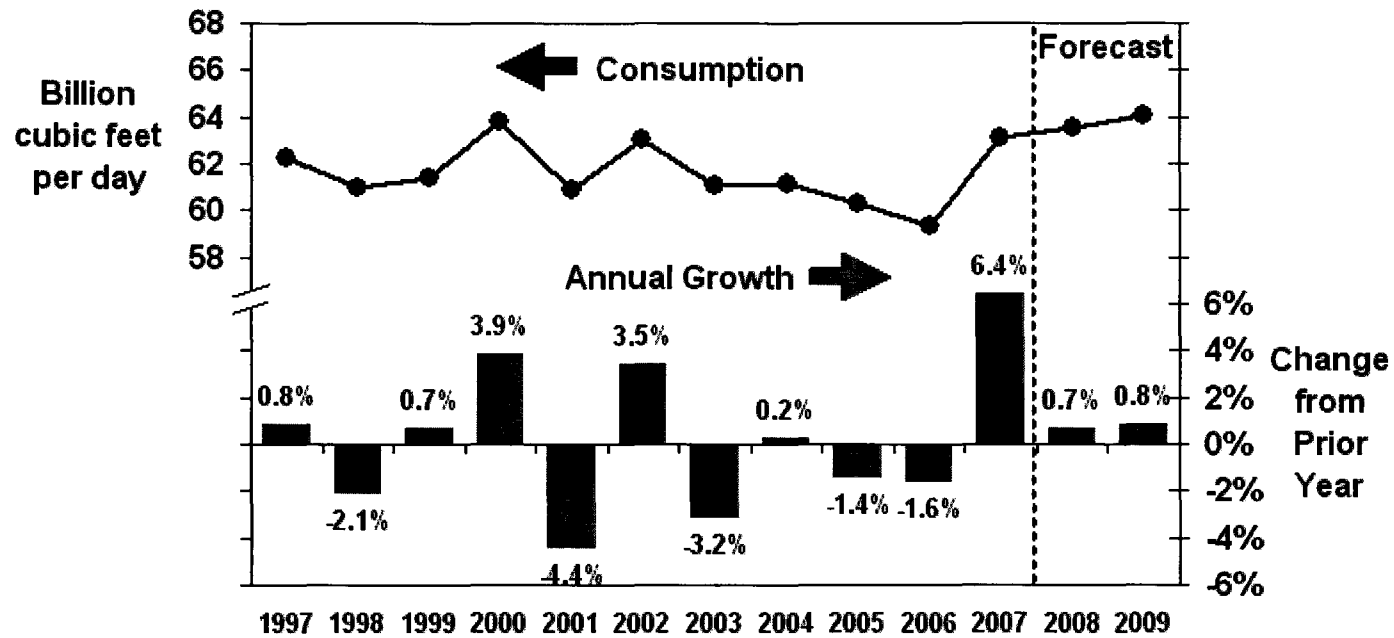
Natural Gas Prices



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



U.S. Total Natural Gas Consumption



**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, 2007									<u>\$222,976</u>
May	\$38,933	\$0	\$1,439	\$40,372	14,596	\$0.4317	\$6,301	\$34,071	257,047
June	35,218	0	1,676	36,894	7,192	0.7009	5,041	31,853	288,900
July	47,378	0	1,897	49,275	6,558	0.7009	4,597	44,679	333,579
August	47,698	(93,447) 2/	(5,491)	(51,240)	6,236	0.7009	4,371	(55,611)	277,968
September	20,333	0	1,851	22,184	7,074	0.7009	4,958	17,226	295,194
October	5,416	0	1,966	7,382	9,512	0.7009	6,667	715	295,909
November	4,635	0	1,962	6,597	19,329	0.7009	13,548	(6,951)	288,958
December	(19,536)	(1,731) 3/	1,904	(19,363)	38,177	0.7009	26,758	(46,121)	242,837
January 2008	(25,367)	0	1,581	(23,786)	48,813	0.7009	34,213	(57,999)	184,838
February	(68,866)	0	1,177	(67,689)	56,621	0.7009	39,686	(107,375)	77,463
Balance @ February 29, 2008									<u>\$77,463</u>

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

2/ Adjustment to correct allocation of the annual true-up of calendar month sales to actual sales.

3/ Northern Natural Gas SLA rebate and Viking refund net of reallocation.

**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, 2007									<u>\$36,819</u>
May	(\$893)	\$0	\$277	(\$616)	8,175	(\$0.5873)	(\$4,801)	\$4,185	41,004
June	660	0	301	961	4,884	0.1814	886	75	41,079
July	3,323	0	299	3,622	7,131	0.1814	1,294	2,328	43,407
August	3,672	(60,494) 2/	(4,673)	(61,495)	10,131	0.1814	1,838	(63,333)	(19,925)
September	(4,525)	0	(110)	(4,635)	9,955	0.1814	1,806	(6,441)	(26,366)
October	(13,931)	0	(156)	(14,087)	12,898	0.1814	2,340	(16,426)	(42,792)
November	(10,203)	0	(275)	(10,478)	21,922	0.1814	3,977	(14,455)	(57,247)
December	(8,157)	83 3/	(379)	(8,453)	15,445	0.1814	2,802	(11,255)	(68,502)
January 2008	1,931	0	(458)	1,473	11,924	0.1814	2,163	(690)	(69,192)
February	(8,331)	0	(461)	(8,792)	14,540	0.1814	2,638	(11,430)	(80,622)
Balance @ February 29, 2008									<u>(\$80,622)</u>

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

2/ Adjustment to correct allocation of the annual true-up of calendar month sales to actual sales.

3/ Northern Natural Gas SLA rebate and Viking refund net of reallocation.