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August 29, 2008

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

Re: Purchased Gas Cost Adjustment (PGA)
September 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 (30th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Purchased Gas Adjustment Tariff (30th Revised Sheet No. 8), showing the September 2008 cost of gas and the resulting Purchased Gas Cost Adjustment. The net effect of this filing is a decrease of \$1.7666 per mcf for residential and firm general service customers and \$1.7807 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for September 2008, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$1.7807 per mcf since the last PGA filing due to a decrease in the market price of gas. There has been an increase in pipeline charges of \$0.0141 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$1.7666 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,

Rita A. Mulkern

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

30th Revised Sheet No. 1.1

Canceling 29th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$9.8721	\$11.1461 10.9261
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	\$6.7101	\$7.8492 7.6032 7.4512
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$6.7101	\$7.9492
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 29, 2008

Effective Date: September 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
 30th Revised Sheet No. 8
 Canceling 29th 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.	2.5369	4.1026	(0.1857)	6.4538	4.1026	(0.7309)	3.3717
Current Adj.	0.0141	(1.7807)	0.0000	(1.7666)	(1.7807)	0.0000	(1.7807)
Total Adj.	2.5510	2.3219	(0.1857)	4.6872	2.3219	(0.7309)	1.5910
Total Rate:	\$2.6168	\$7.4410	(\$0.1857)	\$9.8721	\$7.4410	(\$0.7309)	\$6.7101

Date Filed: August 29, 2008

Effective Date: September 1, 2008

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

Case No.:

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

Attachment B
Page 1 of 7

<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	10.9967	12	1,048,689	0.6698
Trans Canada - Demand Charge	7,947	14.5427	12	1,386,850	0.8858
ProGas - Demand Charge	7,947	0.9140	12	87,163	0.0557
NOVA - Seasonal	5,068	10.9967	5	278,656	0.1780
Trans Canada - Seasonal	5,068	14.5427	5	368,512	0.2354
ProGas - Seasonal	5,068	0.9140	5	23,161	0.0148
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>\$4,096,846</u>	<u>2.6168</u>
Estimated Weighted Average Commodity Cost	1,565,565 1/	7.4410		<u>11,649,369</u>	<u>7.4410</u>
Gas Cost Reconciliation Adjustment					<u>(0.1857)</u>
Total Current Firm Gas Cost				<u>\$15,746,215</u>	<u>9.8721</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$4.6872</u>
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$7.4410
Gas Cost Reconciliation Adjustment					<u>(0.7309)</u>
Total Current Interruptible Gas Cost					<u>6.7101</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>\$1.5910</u>

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

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

Attachment B
Page 2 of 7

Rates Effective September 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	10.9967	Per dk/Mo.
Trans Canada Pipeline Demand Charge	14.5427	Per dk/Mo.
ProGas - Demand Charge	0.9140	Per dk/Mo.
NOVA - Seasonal	10.9967	Per dk/Day
Trans Canada - Seasonal	14.5427	Per dk/Mo.
ProGas - Seasonal	0.9140	Per dk/Mo.
ProGas Winter Surcharge	3.0049	
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	7.4410	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. 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

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

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

Thirteenth Revised Sheet No. 5C
Superseding
Substitute Twelfth Revised Sheet No. 5C

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.

Issued by: J. Phill May, Vice President Commercial

Issued on: February 29, 2008

Effective on: April 1, 2008

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/ 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				
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.

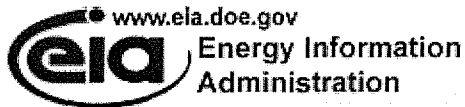
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
September 2008**

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 September 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 strong year over year production increases in the lower 48 states, a significant build in the storage inventory and falling crude oil prices. The Energy Information Administration (EIA) reported storage levels nationwide as of August 26, 2008 were 2.6 percent above the five-year average and 6.8 percent below last years balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 11.



August 2008

Short-Term Energy Outlook

August 12, 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, in part because of perceptions of tenuous supply in several of the major exporting countries. By August 5, the price fell back to less than \$120 per barrel. WTI prices, which averaged \$72 per barrel in 2007, are projected to average \$119 per barrel in 2008 and \$124 per barrel in 2009.
- The recent fall in crude oil prices has pulled down the retail prices for both gasoline and diesel fuel. The weekly price of regular-grade gasoline, which peaked at \$4.11 per gallon on July 14, averaged \$3.81 per gallon on August 11, a decrease of 30 cents. Diesel fuel fell from \$4.76 per gallon on July 14 to \$4.35 on August 11, a drop of 41 cents. Annual average gasoline prices are projected to be \$3.65 and \$3.82 per gallon, respectively, for 2008 and 2009, compared with \$2.81 in 2007. Diesel prices are projected to average \$4.18 and \$4.27 per gallon, respectively, in 2008 and 2009, compared with \$2.88 in 2007.
- The Henry Hub natural gas spot price averaged \$7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average \$10 per Mcf in 2008 and \$9 per Mcf in 2009.
- Residential heating oil prices during the upcoming heating season (October through March) are projected to average \$4.34 per gallon compared with \$3.31 during the last heating season, an increase of about 31 percent. Residential natural gas prices over the same period are projected to average \$15.58 per Mcf compared with \$12.72 per Mcf, during the last heating season, an increase of about 22 percent.

Global Petroleum

Overview. Prospects for improved oil market fundamentals over the next 18 months point to an easing in the market balance and price weakness over the near term. The combination of slower U.S. and global oil consumption growth, increased production capacity for crude oil and natural gas liquids in the Organization of the Petroleum Exporting Countries (OPEC) beginning in the third quarter 2008 and continuing through 2009, and higher non-OPEC supply, raises the prospect for a drop in demand for OPEC crude oil and an increase in surplus capacity. Downward price pressures would increase if the economic slowdown proves deeper or longer than expected, and if higher prices lead to lower consumption and lower demand for OPEC crude than currently anticipated. There is also a risk that any weakness in oil prices could be minimal or short-lived, especially if consumption growth exceeds current expectations or if oil production capacity expansion plans in either OPEC or non-OPEC nations turn out to be lower than expected. Supply risks in Iraq, Nigeria, and Iran, as well as threats of hurricanes over the near term, continue to influence market expectations. In addition, OPEC production behavior that would lead to voluntary production cuts aimed at keeping inventories fairly tight would also limit downward price pressure.

Consumption. Preliminary data indicates that global consumption rose by roughly 500,000 barrels per day (bbl/d) during the first half of 2008 compared with year-earlier levels, as a 1.3-million bbl/d rise in consumption outside of the Organization for Economic Cooperation and Development (OECD) was partially countered by an 800,000 bbl/d drop in U.S. consumption compared with year-earlier levels. The decline in U.S. consumption in the first half of 2008, reflecting slower economic growth and the impact of high prices, was the largest half-year consumption decline in volume terms in the last 26 years, when, in the first half of 1982, consumption dropped by nearly 800,000 bbl/d. Total world oil consumption is expected to grow by a little over 1 million bbl/d during the second half of 2008 and by almost 1 million bbl/d in 2009 compared with year-earlier levels. The projection for 2009 consumption is about 460,000 bbl/d lower than last month's assessment, reflecting lower expectations for consumption in the United States and other OECD countries. Over the next year and a half, lower OECD consumption is expected to be more than offset by continued non-OECD consumption growth, led by China, the Middle East, Latin America, and India ([World Oil Consumption](#)). Further consumption declines in the OECD nations, coupled with the move to reduce subsidies in large parts of the developing world, should limit future world consumption growth.

Non-OPEC Supply. EIA is revising this month's outlook for non-OPEC supply growth in 2008 compared with last month's, largely because of project delays in Asia, lower

output growth now expected in the Former Soviet Union, lower growth in Canada caused by the upward revision of 2007 data, and reduced production in Azerbaijan due to the closure of the BTC pipeline. If new projects come online as now anticipated, total non-OPEC supply is projected to rise by about 510,000 bbl/d in the second half of 2008 and by 850,000 bbl/d in 2009 compared with year-earlier levels. This compares with a 330,000 bbl/d decline in non-OPEC supply recorded during the first half of 2008. Non-OPEC supply growth through 2009 is expected to be led by Brazil, the United States, 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. For example, Russian oil output was down by almost 1 percent in the first half of the year, raising the chances for the first annual decline in output since 1998. 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 oil production is expected to rise to 32.9 million bbl/d during the third quarter of 2008, up from 32.3 million bbl/d in the second quarter. The forecast assumes that Saudi Arabia will maintain its July 9.7 million bbl/d production level through the third quarter, representing a 400,000 bbl/d rise from second quarter levels. OPEC crude oil production is projected to drop to about 32.4 million bbl/d in the fourth quarter of 2008, and to decline to 31.6 million bbl/d in 2009. Lower crude production combined with planned increases in OPEC total liquids production capacity suggests OPEC surplus crude production capacity could increase from 1.2 million bbl/d currently to about 3.6 million bbl/d by the end of next year (OPEC Surplus Oil Production Capacity). Although an increase in the supply cushion could ease upward price pressure, it does not appear large enough to trigger a sharp price decline. Moreover, possible delays in adding supply capacity, proactive OPEC decisions to cut output, or expectations that supply growth in the post-2009 period will have a difficult time keeping pace with demand, could minimize and shorten any market weakness.

Inventories. OECD commercial inventories during the second quarter of 2008 increased by only 490,000 bbl/d, well below the average build of 910,000 bbl/d during this time of the year. At the end of the second quarter, estimated commercial inventories stood at 2.58 billion barrels, 17 million barrels below the 5-year average and equal to about 53 days of forward consumption (Days of Supply of OECD Commercial Stocks). OECD commercial inventories are projected to rise by 340,000 bbl/d in the third quarter compared with the average seasonal build of 450,000 bbl/d, which would leave OECD commercial inventories about 30 million barrels below the 5-year average at the end of the third quarter.

U.S. Petroleum

Consumption. Total U.S. petroleum and other liquids consumption is projected to shrink by almost 500,000 bbl/d in 2008 based on prospects for a weak economy and continuing high crude oil and product prices extending into 2009 (U.S. Petroleum Products Consumption Growth). Preliminary June and July 2008 weekly survey data indicate that year-over-year declines in total consumption, which began in August 2007, have narrowed since earlier this year. During the first 5 months of 2008, total petroleum consumption fell by an average of almost 900,000 bbl/d from the same period in 2007. During June and July, the year-over-year declines narrowed to just over 400,000 bbl/d. The year-over-year declines in consumption are not expected to be as large over the forecast period, with 2009 average total consumption about 120,000 bbl/d lower than the 2008 average.

Supply. In 2008, total domestic crude oil output is projected to average 5.15 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 5.36 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 about 10 million barrels for the offshore region in 2008 (see Hurricane Outlook). Fuel ethanol production is projected to increase from an annual average of 430,000 bbl/d in 2007 to 590,000 bbl/d in 2008 and to 650,000 bbl/d in 2009. Because of declining petroleum consumption and growing ethanol production, crude oil net imports are expected to fall by 240,000 bbl/d and petroleum product net imports by 400,000 bbl/d in 2008. Total net imports of crude oil and petroleum products, which peaked at 60.3 percent of total petroleum consumption in 2005, are expected to fall to 56.4 percent and 54.5 percent, respectively, of total consumption in 2008 and 2009.

Prices. WTI crude oil prices, which averaged \$72 per barrel in 2007 (Crude Oil Prices), are projected to average \$119 per barrel in 2008 and \$124 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 \$3.65 per gallon this year and \$3.82 per gallon in 2009. The weekly price of regular-grade gasoline, which peaked at \$4.11 per gallon on July 14, averaged \$3.81 per gallon on August 11, a decrease of 30 cents. Gasoline prices are expected to continue falling slowly, averaging just less than \$3.80 per gallon over the next few months. This forecast reflects continuing 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 \$4.18 per gallon, up from \$2.88 per gallon in 2007, and increase to an average of \$4.27 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.

Natural Gas

Consumption. Total natural gas consumption is expected to increase by 3 percent in 2008 and by 1.7 percent in 2009 (Total U.S. Natural Gas Consumption Growth). Consumption increases are expected in every sector in 2008. The strongest growth during the forecast period is expected to come from the electric power sector (3.4 percent in 2008 and 3.1 percent in 2009) as natural gas-fired generation continues to take on a larger share of electric power supply. Growth in natural gas consumption in the industrial sector has continued, although higher natural gas prices and the weakening economy add uncertainty to the current outlook. In annual terms, consumption in the industrial sector is expected to increase by 1.6 percent in 2008 and by 0.8 percent in 2009.

Production and Imports. Total U.S. marketed natural gas production is expected to increase by 8.0 percent in 2008 and by 3.7 percent in 2009. Robust growth from unconventional production basins in the Lower-48 onshore region is expected to continue, while production is projected remain unchanged in the Federal Gulf of Mexico in 2008. Marketed natural gas production from the Federal Gulf of Mexico is projected to increase by 3.5 percent in 2009 while sustained drilling activity is expected to lead to production growth next year of 3.9 percent in the Lower-48 onshore region.

Imports of liquefied natural gas (LNG) remain low as demand for natural gas in Asia-Pacific and Europe continues to attract cargoes with higher relative prices. On the supply side, repairs, maintenance and delays in new liquefaction projects have limited the availability of LNG so far this year. While a significant increase in global liquefaction capacity is projected in 2009, continuing natural gas demand growth and higher relative prices in Europe and Asia are expected to attract much of the new supply. As reported on the Intercontinental Exchange (ICE), the recent price of natural gas for January delivery in the United Kingdom is about double the current January price for natural gas on the New York Mercantile Exchange (NYMEX). LNG imports are expected to total 390 billion cubic feet (Bcf) in 2008, and 480 Bcf in 2009, compared with 771 Bcf in 2007.

Inventories. On August 1, 2008, working natural gas in storage was 2,517 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 6 Bcf below the 5-year

average (2003–2007) and 353 Bcf below the level during the corresponding week last year.

Prices. The Henry Hub spot price averaged \$11.45 per Mcf in July, \$1.62 per Mcf below the average spot price in June. The spot price decline marks the end of consecutive increases in the monthly average price that began in October 2007. While warmer-than-normal weather in July increased natural gas demand in the electric power sector, the decline in crude oil prices and continuing supply growth contributed to the decline in natural gas prices over the past month. Looking ahead, strong domestic production is expected to limit the impact of lower LNG and Canadian imports on natural gas prices. While extreme weather anomalies present a notable risk to the current outlook, spot prices are expected to remain below \$10 per Mcf until December, when space heating demand rises. On an annual basis, the Henry Hub spot price is expected to average about \$10 per Mcf in 2008 and \$9 per Mcf in 2009.

Electricity

Consumption. So far this summer (April-July) cooling degree-days have been about 8 percent higher than last year (U.S. Summer Cooling Degree-Days). Temperatures have been particularly warm along the east and west coasts. Despite the increased need for cooling so far this summer, milder temperatures forecast for August and September compared with last year and low economic growth should limit growth in electricity consumption during 2008 and 2009 to an annual average of about 1.2 percent (U.S. Total Electricity Consumption).

Prices. Many utilities are continuing to pursue retail electricity rate increases in response to power generation fuel costs that have risen dramatically over the last 2 years. For example, the delivered cost of natural gas to the electric power sector in March was \$9.29 per million Btu, 25 percent higher than the average cost in March 2007. Average U.S. residential electricity prices are expected to increase by 5 percent in 2008 and by 10 percent in 2009 (U.S. Residential Electricity Prices).

Coal

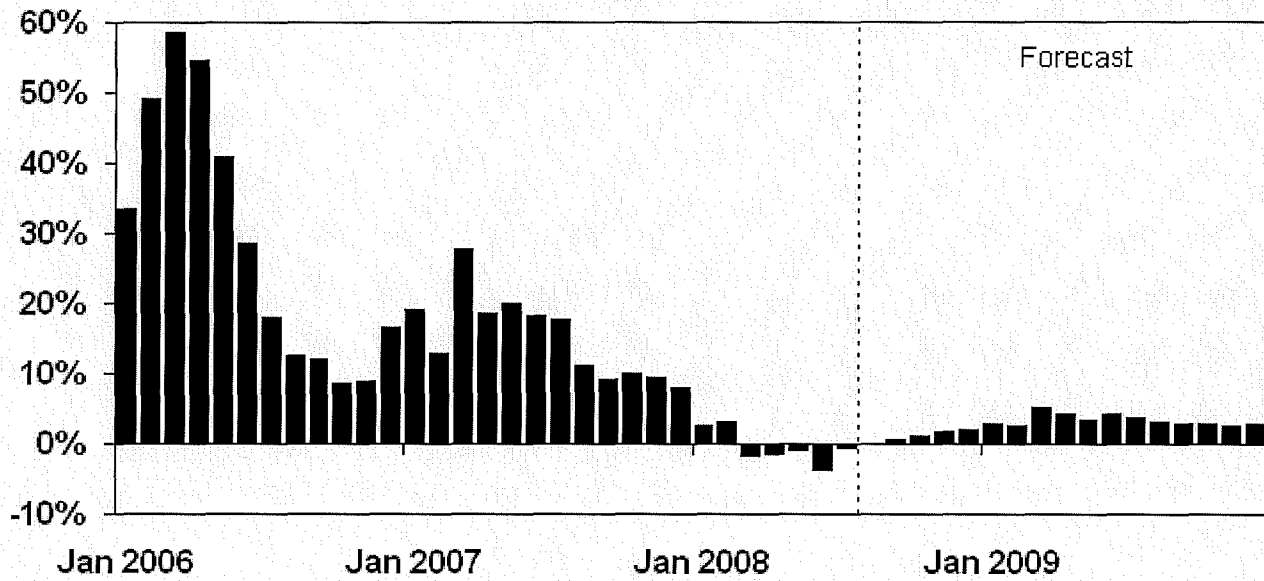
Consumption. Electric-power-sector coal consumption grew by 1.9 percent in 2007. Although first quarter 2008 electric-power-sector coal consumption grew by about 2 percent compared with first quarter 2007, slow growth in total electricity consumption is expected to limit growth in the sector to just 0.3 percent in 2008. In 2009, continued slow growth in total electricity consumption combined with projected increases from other generation sources (nuclear, natural gas, hydroelectric, and wind) will continue

to dampen electric-power-sector coal consumption growth, projected to be flat at the 2008 level (U.S. Coal Consumption Growth).

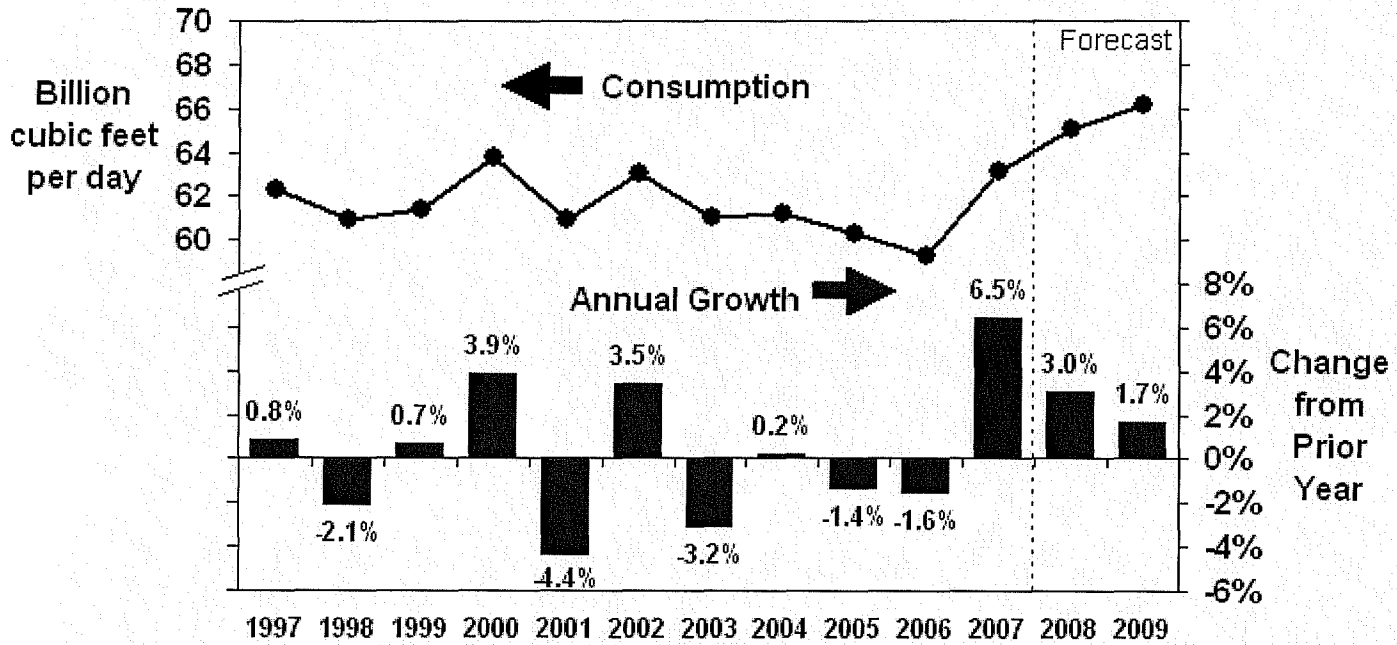
Production and Inventories. U.S. coal production (U.S. Annual Coal Production) fell by 1.4 percent in 2007. Growth in both exports and domestic consumption is expected to contribute to a 2-percent increase in coal production in 2008. Secondary (consumer-held) coal stocks are estimated to have grown by 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 2.7 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.

Exports. In first quarter 2008, U.S. coal exports increased by 4.7 million short tons (42 percent) over first quarter 2007 shipments. Strong global demand for coal, combined with supply disruptions in several key coal exporting countries (Australia, South Africa, and China) were the primary factors for the increase in coal exports. Although the supply disruptions have ended, continued robust worldwide demand for coal is projected to lead to an overall 45-percent increase in U.S. coal exports in 2008. Coal exports are projected to be 76.9 million short tons in 2009. This is a 10 percent decline from 2008, but it is still significantly higher than the 59.2 million short tons exported in 2007.

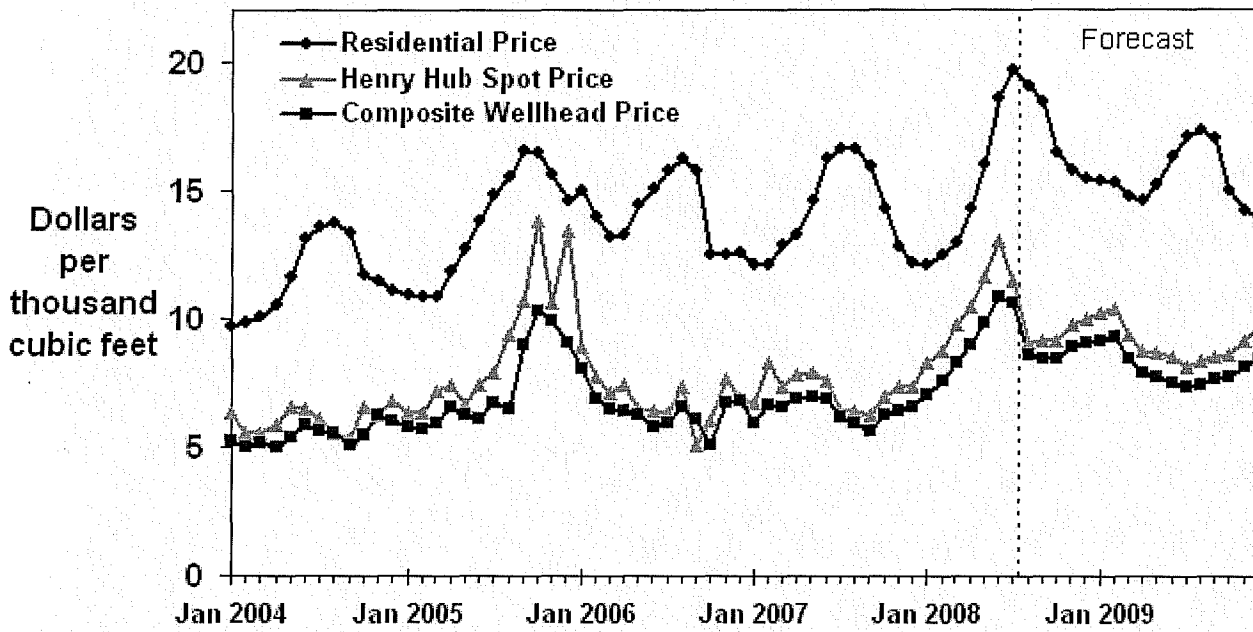
U.S. Working Natural Gas in Storage (Percent Difference from Previous 5-Year Average)



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**

	<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, 2008									<u>(\$46,836)</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)
July	12,556	0	(565)	11,991	6,909	(0.1857)	(1,283)	13,274	(27,100)
Balance @ July 31, 2008									<u>(\$27,100)</u>

**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, 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)
July	(44,216)	0	(1,282)	(45,498)	11,473	(0.7309)	(8,386)	(37,112)	(161,737)
Balance @ July 31, 2008									<u>(\$161,737)</u>