

July 1, 2010

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

Re: Cost of Gas Adjustment (COG)
July 2010

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

Attachment A is the Rate Summary Sheet (52nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (52nd Revised Sheet No. 8), showing the July 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.5995 per mcf for residential and firm general service customers and \$0.3132 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.3132 per mcf since the last COG filing due to an increase in the market price of gas. There has been a decrease in pipeline charges of \$0.0887 per mcf due to changes in pipeline rates and an increase of \$0.3751 per mcf due to changes in volumes used to calculate the PGA. The net effect of these changes is an increase of \$0.5996 per mcf for residential and firm general service customers.

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

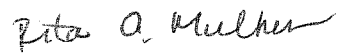
Attachment D shows the calculation of the balancing account since April 30, 2010.

Great Plains submitted a check for \$600.00 on January 19, 2010 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,



Rita A. Mulkern
Regulatory Analysis Manager

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

**State of North Dakota
Gas Rate Schedule**

NDPSC Volume 2
52nd Revised Sheet No. 8
Canceling 51st 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.	3.2127	(1.3762)	0.3941	2.2306	(1.3762)	(0.1136)	(1.4898)
Current Adj.	0.2864	0.3132	0.0000	0.5996	0.3132	0.0000	0.3132
Total Adj.	3.4991	(1.0630)	0.3941	2.8302	(1.0630)	(0.1136)	(1.1766)
Total Rate:	\$3.5649	\$4.0561	\$0.3941	\$8.0151	\$4.0561	(\$0.1136)	\$3.9425

Date Filed: July 1, 2010

Effective Date: July 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:



GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota Gas Rate Schedule

NDPSC Volume 2

52nd Revised Sheet No. 1.1

Canceling 51st 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	\$8.0151	\$9.2891 9.0691
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	\$3.9425	\$5.0816 4.8356 4.6836
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.9425	\$5.1816
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: July 1, 2010

Effective Date: July 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2010**

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
FT-A	7,841	\$3.4671	12	\$326,226	\$0.2329
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0737
FT-A Seasonal	3,000	3.7671	5	56,507	0.0403
TFX Seasonal	3,000	15.1530	5	227,295	0.1623
NOVA - Demand Charge	7,947	16.8462	12	1,606,521	1.1469
Trans Canada - Demand Charge	7,947	16.6960	12	1,592,197	1.1367
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068	16.8462	5	426,883	0.3047
Trans Canada - Seasonal	5,068	16.6960	5	423,077	0.3020
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0550
LMS Demand	2,500	1.0000	12	30,000	0.0214
Total Demand Charges				<u>\$4,993,682</u>	<u>3.5649</u>
Estimated Weighted Average Commodity Cost	1,400,774 1/	4.0561		<u>5,681,679</u>	<u>4.0561</u>
Gas Cost Reconciliation Adjustment					<u>0.3941</u>
Total Current Firm Gas Cost				<u>\$10,675,361</u>	<u>8.0151</u>
Base Cost of Gas					<u>5.1849</u>
Accumulated Adjustment					<u>\$2.8302</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.0561
Gas Cost Reconciliation Adjustment					<u>(0.1136)</u>
Total Current Interruptible Gas Cost					<u>3.9425</u>
Base Cost of Gas					<u>5.1191</u>
Accumulated Adjustment					<u>(\$1.1766)</u>

1/ Three year normalized average Dk sales.

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 2010**

Rates Effective July 1, 2010	<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	16.8462	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.6960	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.8462	Per dk/Day
Trans Canada - Seasonal	16.6960	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	4.0561	Per dk

Base Rate Effective September 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. Neopl, 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-Eighth Revised Sheet No. 5B
Superseding
Twenty-Seventh 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	1.02%
Zone 1 - 2	\$0.0130	\$0.0019	\$0.0149	1.38%
Zone 2 - 2	\$0.0130	\$0.0019	\$0.0149	0.36%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1 - 1	\$0.1368	\$0.0019	\$0.1387	1.02%
Zone 1 - 2	\$0.1737	\$0.0019	\$0.1756	1.38%
Zone 2 - 2	\$0.0834	\$0.0019	\$0.0853	0.36%
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: .10% for Zone 1-1, .13% for Zone 1-2, and .03% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

Issued by:
Issued on: February 26, 2010

Effective on: April 1, 2010

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

Fifteenth Revised Sheet No. 5C
Superseding
Fourteenth 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		\$0.0453	

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:
Issued on: February 26, 2010

Effective on: April 1, 2010

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

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12 Base	TF12 Variable	TF5	TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/ 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	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	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 \$0.0006 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.

Northern Natural Gas Company
FERC Gas Tariff
Fifth Revised Volume No. 1

80 Revised Sheet No. 51
Superseding
79 Revised Sheet No. 51

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

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	0.0384	0.0215			0.0175	0.0000	0.0384	0.0215
Field	Market	0.0384	0.0215	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 \$0.0006 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
July 2010**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The July monthly price for the AECO Index is expected to increase from the previous month index. 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).

Cooling demand from summer temperatures across much of the country leading to additional demand for electric power generation, and the National Oceanic and Atmospheric Administration predicting a more-active-than-normal hurricane season, likely led to the increased price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of June 18, 2010 were 13.3 percent above the five-year average and 0.5 percent below last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 14.



June 2010

Short-Term Energy Outlook

June 8, 2010 Release

Highlights

- Crude oil prices fluctuated considerably last month, with the West Texas Intermediate (WTI) spot price ranging from a high of \$86 per barrel on May 3 to a low of \$65 on May 25, before ending the month at \$74. According to some market analysts, uncertainty over the global economic recovery, particularly with respect to Europe's debt crisis and the tightening of credit by China, and liquidation of futures contracts contributed to the crude price decline. Moreover, WTI prices fell further than most other crudes because of record high inventories in Cushing, Oklahoma. EIA projects WTI crude oil spot prices will average \$79 per barrel this year and \$83 per barrel in 2011, both about \$3 lower than in last month's *Outlook*.
- EIA forecasts that regular-grade motor gasoline retail prices will average \$2.79 per gallon during this summer's driving season (the period between April 1 and September 30), up from \$2.44 per gallon last summer. The summer gasoline price forecast is down considerably (\$0.15) from last month's *Outlook* primarily as a result of the lower crude oil price forecast.
- Based on the current Atlantic hurricane season outlook from the National Oceanic and Atmospheric Administration (NOAA), EIA estimates median outcomes for total shut-in production in the Federally-administered Gulf of Mexico during the upcoming hurricane season (June through November) of 26 million barrels of crude oil and 166 billion cubic feet (Bcf) of natural gas (see [*2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*](#)). Actual shut-ins are likely to differ significantly from this expectation depending on the number, track, and strength of hurricanes as the season progresses.
- This *Outlook* includes EIA's preliminary estimates of reductions in production resulting from a 6-month deepwater drilling moratorium announced by Secretary Salazar on May 27. The reductions in crude oil production resulting

from the moratorium are estimated to average about 26,000 barrels per day (bbl/d) in the fourth quarter of 2010 and roughly 70,000 bbl/d in 2011. EIA will refine its moratorium impacts as additional information becomes available.

- EIA expects the Henry Hub natural gas spot price to average \$4.49 per million Btu (MMBtu) this year, a \$0.54-per-MMBtu increase over the 2009 average. EIA expects the Henry Hub spot price to average \$5.06 per MMBtu in 2011, down \$0.28 per MMBtu from last month's *Outlook*.
- The annual average residential electricity price changes only moderately over the forecast period, averaging 11.6 cents per kilowatthour (kWh) in 2010, up slightly from 11.5 cents per kWh in 2009, and rising to 11.9 cents per kWh in 2011.
- Estimated U.S. carbon dioxide (CO₂) emissions from fossil fuels, which declined by 7.0 percent in 2009, are expected to increase by 2.9 percent and 1.4 percent in 2010 and 2011, respectively, as economic growth spurs higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA has lowered its projections for world oil prices slightly for 2010. Uncertainty about economic growth in China and in the Euro zone has continued to weigh on oil markets, and declines in equity markets have led to fears that the economic recovery may not progress as fast as had been hoped. To date, the Organization of the Petroleum Exporting Countries (OPEC) has publicly made no suggestions that it would adjust its supply targets despite some downward adjustments in oil prices.

Global Crude Oil and Liquid Fuels Consumption. EIA projects that world oil consumption will grow by 1.5 million bbl/d in 2010 and 1.6 million bbl/d in 2011, about the same as in last month's *Outlook*. The growth in oil consumption is expected to be largely concentrated in the Asia-Pacific and Middle East regions ([World Liquid Fuels Consumption Chart](#)).

Non-OPEC Supply. Non-OPEC supply is projected to increase by 500,000 bbl/d in 2010, 160,000 bbl/d lower than in last month's *Outlook*. A more pessimistic outlook for supply growth in Brazil and Central Asia is the principle source of the downward revision, though these two areas (along with the United States) still constitute the bulk of expected non-OPEC supply growth in 2010. In the case of Brazil, the lower production outlook is the result of a re-assessment of production from established

fields. Offsetting projected supply growth in 2010 are further declines in mature basins in Mexico, the United Kingdom, and Norway. Even though EIA still expects that production in Mexico will decline in 2010, recent data have been surprisingly strong, which has moderated that forecast. Non-OPEC supplies are expected to fall by 190,000 bbl/d in 2011, as supply growth from the United States slows.

OPEC Supply. EIA projects that OPEC, which did not change its production targets at its March meeting, will keep its crude oil production largely unchanged for the remainder of 2010. The countries that have the bulk of OPEC's spare capacity – Saudi Arabia, Kuwait, and the United Arab Emirates – have maintained their quota discipline at current levels for an extended period and are expected to continue doing so barring significant changes in the world oil market outlook. OPEC crude oil production is projected to increase by 0.5 million bbl/d in 2011 as new capacity is added in countries such as Angola. Surplus crude oil production capacity is not expected to increase significantly in 2010-2011 from first-quarter 2010 levels ([OPEC Surplus Crude Oil Production Capacity Chart](#)). OPEC production of non-crude petroleum liquids (which are not subject to OPEC production targets) are expected to increase by 0.6 million bbl/d in 2010 and 0.7 million bbl/d in 2011.

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the Organization for Economic Cooperation and Development (OECD) stood at 2.70 billion barrels at the end of the first quarter of 2010, equivalent to about 58 days of forward cover, and roughly 102 million barrels more than the 5-year average for the corresponding time of year ([Days of Supply of OECD Commercial Stocks Chart](#)). Although OECD oil inventories are still projected to remain at the upper end of the historical range over the forecast period, they are falling as a result of a combination of higher oil consumption and OPEC production restraint.

Crude Oil Prices. WTI crude oil spot prices averaged less than \$74 per barrel in May 2010, almost \$11 per barrel below the prior month's average and \$7 per barrel lower than forecast in last month's *Outlook*. EIA projects WTI prices will average about \$79 per barrel over the second half of this year and rise to \$84 by the end of next year ([West Texas Intermediate Crude Oil Price Chart](#)).

Energy price forecasts are highly uncertain, as history has shown ([Energy Price Volatility and Forecast Uncertainty](#)). Implied volatility in the crude oil futures options market rose in May. WTI futures for August 2010 delivery for the 5-day period ending June 3 averaged \$74.95 per barrel, and implied volatility averaged 39 percent. This made the lower and upper limits of the 95-percent confidence interval \$58 and \$97 per barrel, respectively.

Last year at this time, WTI for August 2009 delivery averaged \$64.52 per barrel, and implied volatility averaged 44 percent, rendering the limits of the 95-percent confidence interval \$47 and \$88 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption is beginning to show signs of recovery after having fallen by an average 810,000 bbl/d in 2009, the fourth consecutive annual decline ([U.S. Liquid Fuels Consumption Growth Chart](#)). Total liquid fuels consumption fell by an average 20,000 bbl/d in the first quarter compared with the same period last year. Projected total consumption for the current quarter, however, rises 490,000 bbl/d per day compared with the same period last year, with motor gasoline consumption increasing 70,000 bbl/d and distillate consumption up 220,000 bbl/d. Projected total liquid fuels consumption grows by an average 230,000 bbl/d in 2010 and 200,000 bbl/d in 2011 as all of the major petroleum products register consumption growth.

U.S. Liquid Fuels Supply and Imports. Projected domestic crude oil production increases by about 70,000 bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)), which is 110,000 bbl/d less than in last month's *Outlook*, primarily because of the new NOAA forecast of a more active hurricane season this year. EIA estimates a median outcome of 17 million barrels of total shut-in crude oil production because of tropical storm activity in the Gulf of Mexico this year (see [2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)).

Forecast crude oil production in 2011 falls by 20,000 bbl/d to 5.38 million bbl/d, which is also about 110,000 bbl/d less than in the previous *Outlook*. The lower production forecast includes EIA's preliminary estimates of the total cumulative reductions in the output of crude oil from the deepwater Gulf of Mexico of 2.4 million barrels in 2010 and 25 million barrels in 2011 because of the recently-imposed 6-month drilling moratorium. The reductions in crude oil production increase from a monthly average of about 9,000 bbl/d in September 2010 to 80,000 bbl/d by December 2011.

Projected ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 860,000 bbl/d in 2010 and 890,000 bbl/d in 2011. EIA forecasts that liquid fuel net imports (including both crude oil and refined products), which declined by 1.4 million bbl/d in 2009, will fall by a further 110,000 bbl/d in 2010. In 2011, projected total liquid fuel net imports increase by 90,000 bbl/d.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices average \$2.76 per gallon in 2010 and \$2.92 per gallon in 2011. These projections are 10 and 6

cents per gallon, respectively, lower than those in the previous *Outlook* as a result of lower crude oil price projections. Forecast regular-grade pump prices average \$2.79 per gallon this summer, up by 35 cents from the previous summer.

On-highway diesel fuel retail prices, which averaged \$2.46 per gallon in 2009, average \$2.96 per gallon in 2010 and \$3.11 in 2011 in this forecast.

Natural Gas

U.S. Natural Gas Consumption. Total natural gas consumption is about 0.5 Bcf/d higher in this forecast than in last month's *Outlook*, averaging 64.9 Bcf/d and 64.6 Bcf/d in 2010 and 2011, respectively (Total U.S. Natural Gas Consumption Growth Chart). Projected consumption grows by an average 2.4 Bcf/d (3.8 percent) in 2010 led by strong growth in the electric power and industrial sectors. Forecast natural gas consumption in the electric power sector increases by an average 1.0 Bcf/d (5.5 percent) in 2010 over last year, driven primarily by higher electricity demand. EIA's projected natural-gas-weighted industrial production index (a measure of industrial activity in natural-gas-intensive industries) increases by 6.7 percent in 2010, leading to a 1.0 Bcf/d (6.1-percent) increase in natural gas consumption in the industrial sector.

Projected natural gas consumption falls slightly in 2011 as forecast growth in the industrial sector slows to 0.2 Bcf/d. This growth is more than offset by the projected 0.5 Bcf/d decline in natural gas consumption in the electric power sector.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production to increase by 1.2 Bcf/d (2.1 percent) to 61.2 Bcf/d in 2010, an upward revision of 0.5 Bcf/d from last month's *Outlook*. Natural gas production grew steadily over the first 3 months of this year as the number of working natural gas rigs reported by Baker-Hughes increased from 759 to 941. The production forecast was revised upwards as the number of working rigs continued to increase to almost 970 at the end of May.

The increase in production is partially offset by new estimates of shut-in production based on NOAA's latest hurricane forecast. Tropical storm activity and the accompanying production outages are expected to be significantly higher this year than last year. EIA estimates the median outcome for projected total shut-in production due to tropical storms from June through November 2010 is 166 Bcf compared with an estimated 19 Bcf shut-in production last year (2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico).

Forecast natural gas marketed production in 2011 falls almost 0.5 Bcf/d to 60.8 Bcf/d in 2011. This forecast includes EIA's preliminary estimates of the total cumulative

reductions in output of natural gas from the deepwater Gulf of Mexico of 8 Bcf in 2010 and 74 Bcf in 2011 because of the 6-month drilling moratorium. The reductions in natural gas production increase from a monthly average of about 0.03 Bcf/d in September 2010 to 0.24 Bcf/d by December 2011.

Projected liquefied natural gas (LNG) imports increase by 0.27 Bcf/d (22 percent) and 0.16 Bcf (11 percent) in 2010 and 2011 respectively. Despite this growth, high prices in the European and Asian markets relative to the United States will continue to draw LNG cargoes, with the United States serving as a secondary market. Forecast pipeline imports in 2010 have been increased by 0.29 Bcf/d from last month's *Outlook*. Pipeline imports are expected to play an important role in offsetting forecast hurricane-related production outages in the Gulf of Mexico.

U.S. Natural Gas Inventories. On May 28, 2010, working natural gas in storage was 2,357 Bcf ([U.S. Working Natural Gas in Storage Chart](#)), 306 Bcf above the previous 5-year average (2005–2009) and 38 Bcf above the level during the corresponding week last year. EIA expects working gas inventories at the end of October 2010 to be about 3,805 Bcf, slightly below the level reached at the end of October last year and the peak inventory of 3,837 Bcf reached on November 27, 2009.

U.S. Natural Gas Prices. Sustained low natural gas prices this summer are expected to contribute to a decline in natural gas drilling activity over the next several months. As a result, the current 2011 forecast of higher prices comes as production begins to decline later this year and next. The projected Henry Hub spot price averages \$4.49 per MMBtu in 2010 and \$5.06 per MMBtu in 2011 ([Henry Hub Natural Gas Price Chart](#)).

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for August 2010 delivery for the 5-day period ending June 3 averaged \$4.47 per MMBtu, and the average implied volatility over the same period was 44 percent. This produced lower and upper bounds for the 95-percent confidence interval of \$3.22 and \$6.20 per MMBtu, respectively. At this time last year the natural gas August 2009 futures contract averaged \$3.87 per MMBtu and implied volatility averaged almost 71 percent. This rendered the lower and upper limits of the 95-percent confidence interval were at \$2.21 and \$6.76 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA projects that retail sales of electricity to the residential sector from April through September will grow by 5 percent compared with the same period last year. Retail sales in the Midwest will be particularly strong

this summer since the forecast is for temperatures to return to normal levels after a very mild summer last year. Total consumption of electricity across all sectors is projected to grow by 3.1 percent during 2010 and by 0.9 percent next year ([U.S. Total Electricity Consumption Chart](#)).

U.S. Electric-Power-Sector Generation. Although the level of electric-power-sector generation from natural gas was 9 percent lower in March compared with the same month last year, EIA expects that electricity generation from natural gas in April and May should prove to have been about 11 percent higher than during the same period of 2009. This growth in generation from natural gas over last year should continue over the next few months until higher natural gas fuel costs begin to favor increased dispatch of coal-fired generation in areas where the two fuels compete closely for the baseload power market.

U.S. Electricity Retail Prices. Estimated residential electricity prices during the first quarter of this year averaged 10.8 cents per kilowatt-hour, down from 11.2 cents during the same period in 2009. However, rising fuel costs for natural gas and coal generation compared with last year are likely to push up retail prices later this year, keeping the annual growth rate for residential electricity prices relatively flat during 2010. Forecast residential electricity prices average 11.6 cents per kilowatt-hour (kWh) in 2010 and 11.9 cents per kWh in 2011 ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. Projected electricity demand growth is the primary cause of the projected 3.9-percent growth in coal consumption in the electric power sector in 2010. Continued electricity demand growth and the projected decline in natural-gas-fired generation results in an additional 2.3-percent increase in electric-power-sector coal consumption in 2011 ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. EIA projects that coal production will fall by 1.8 percent in 2010 despite increases in domestic consumption and exports lower imports. The balance between production and consumption is satisfied through significant reductions in both producer (14 percent) and end-user inventories (15 percent) ([U.S. Electric Power Sector Coal Stocks chart](#)). EIA projects a 3.8-percent increase in coal production in 2011 to meet continued growth in coal consumption and exports ([U.S. Annual Coal Production Chart](#)).

U.S. Coal Trade. U.S. coal imports fell by more than one third in 2009, and the slightly more than 22 million short tons imported was the smallest amount received since 2002. Imports decline another 17 percent in 2010 in this forecast as increased domestic

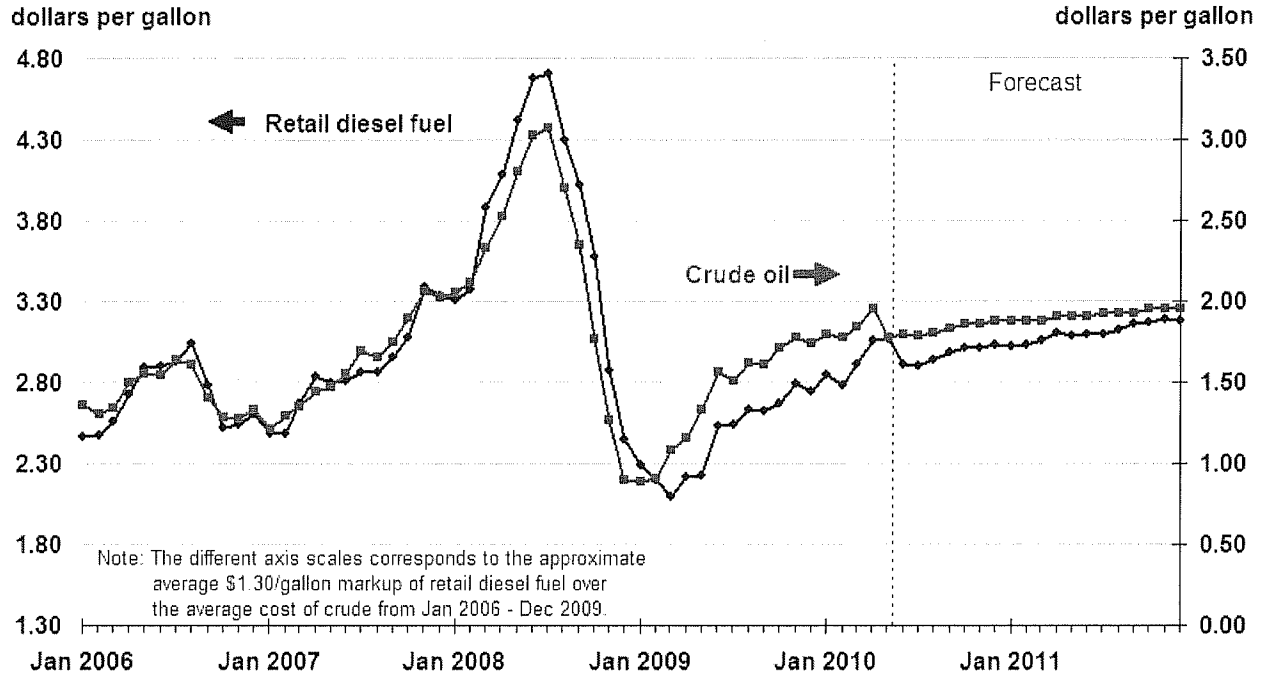
consumption is met by draws on U.S. coal inventories. Projected coal imports grow by 38 percent in 2011, but the annual tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons.

U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by about 7 percent despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflected the impact of longer-term power-sector coal contracts that were initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price increases slightly (by 1.5 percent) to average \$2.24 per MMBtu in 2010, and then declines to an average of \$2.18 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Forecast economic growth combined with increased use of coal in the electric power sector contribute to increases in CO₂ emissions from fossil fuels of 2.9 percent and 1.4 percent in 2010 and 2011, respectively ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Increased demand for petroleum in the transportation sector (motor gasoline, diesel fuel and jet fuel) also contributes to the increases in fossil-fuel CO₂ emissions. However, even with increases in 2010 and 2011, projected CO₂ emissions are lower than annual emissions were from 1999 through 2008.

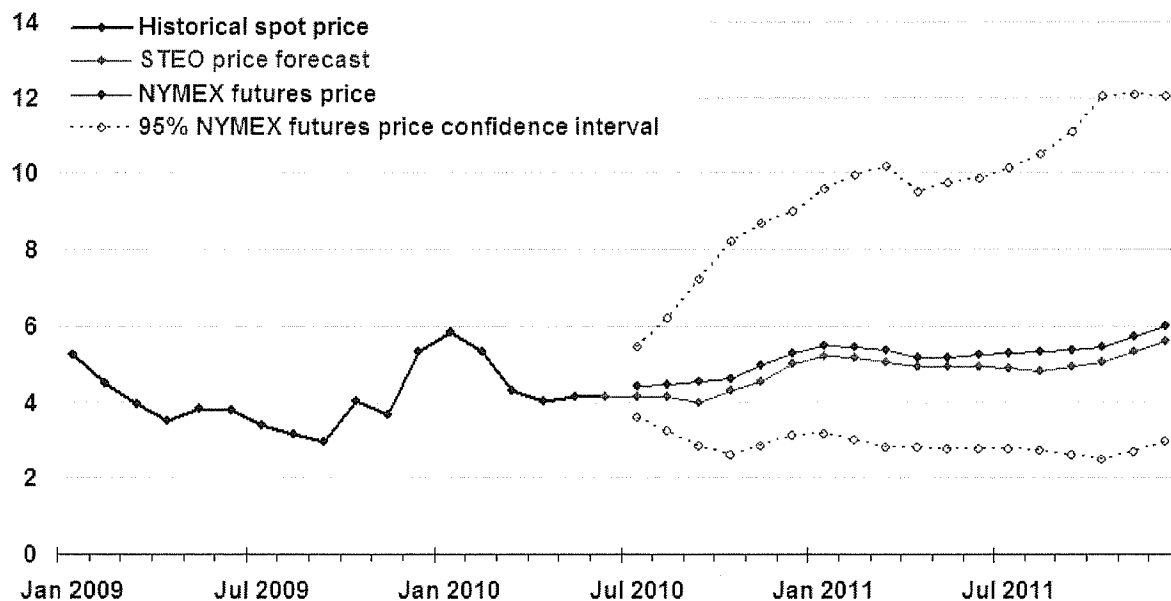
U.S. Diesel Fuel and Crude Oil Prices



Source: Short-Term Energy Outlook, June 2010

Henry Hub Natural Gas Price

dollars per million btu



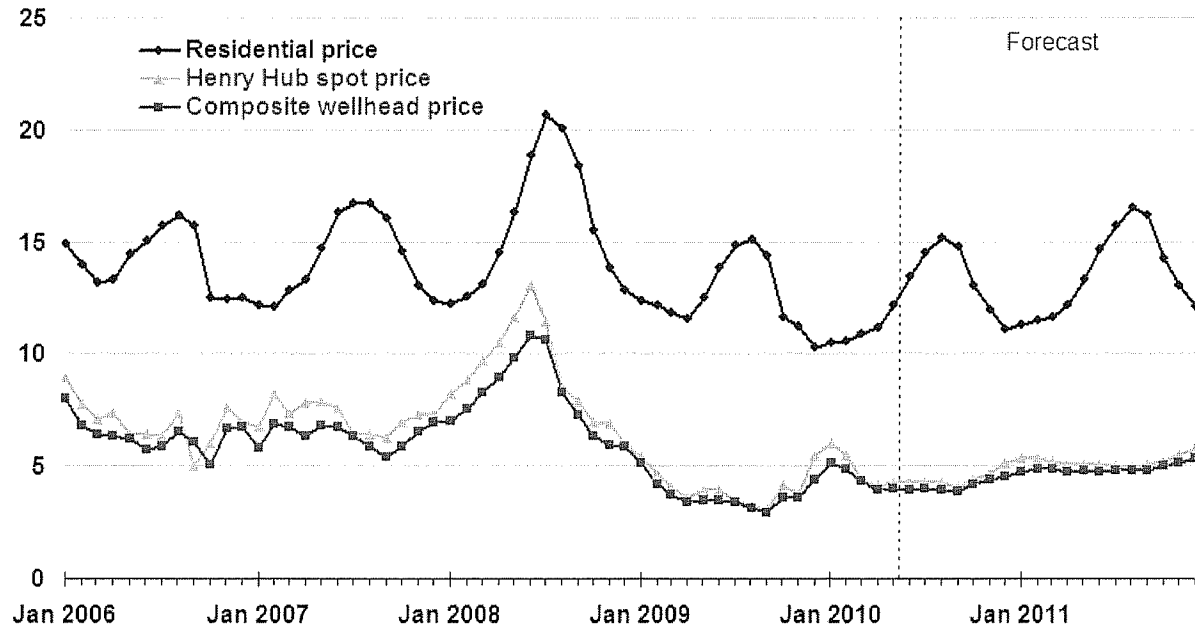
Note: Confidence interval derived from options market information for the 5 trading days ending June 3, 2010
Intervals not calculated for months with sparse trading in "near-the-money" options contracts



Source: Short-Term Energy Outlook, June 2010; Reuters News Service; and CME Group

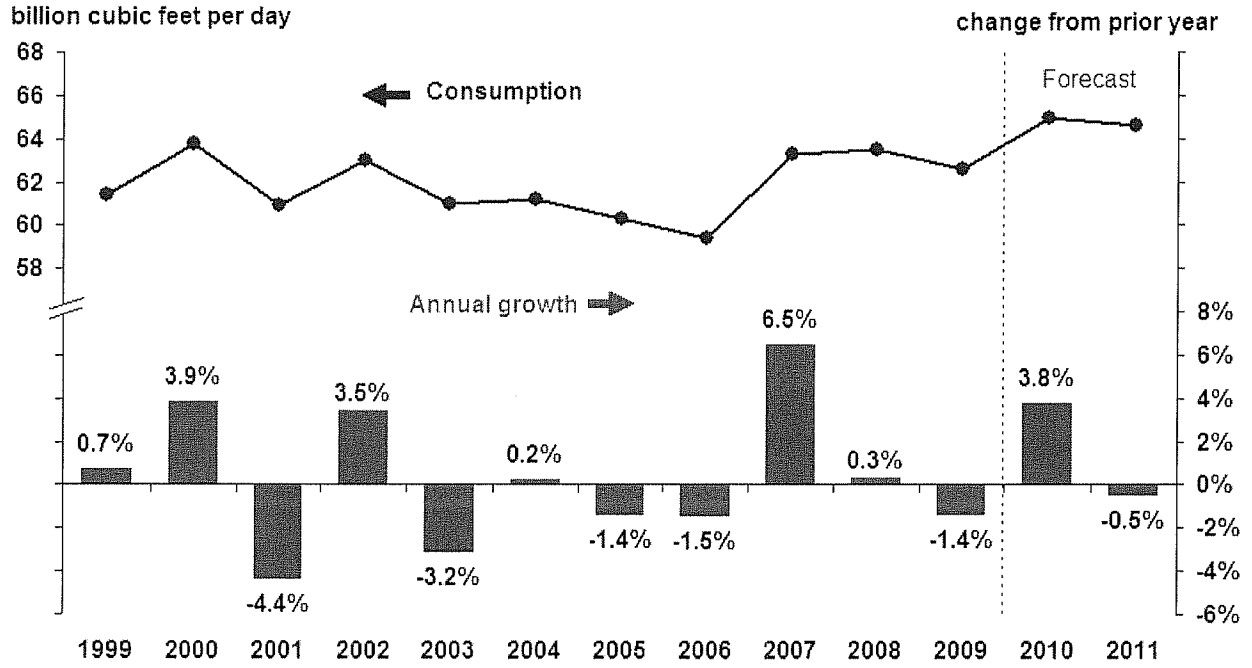
Natural Gas Prices

dollars per thousand cubic feet



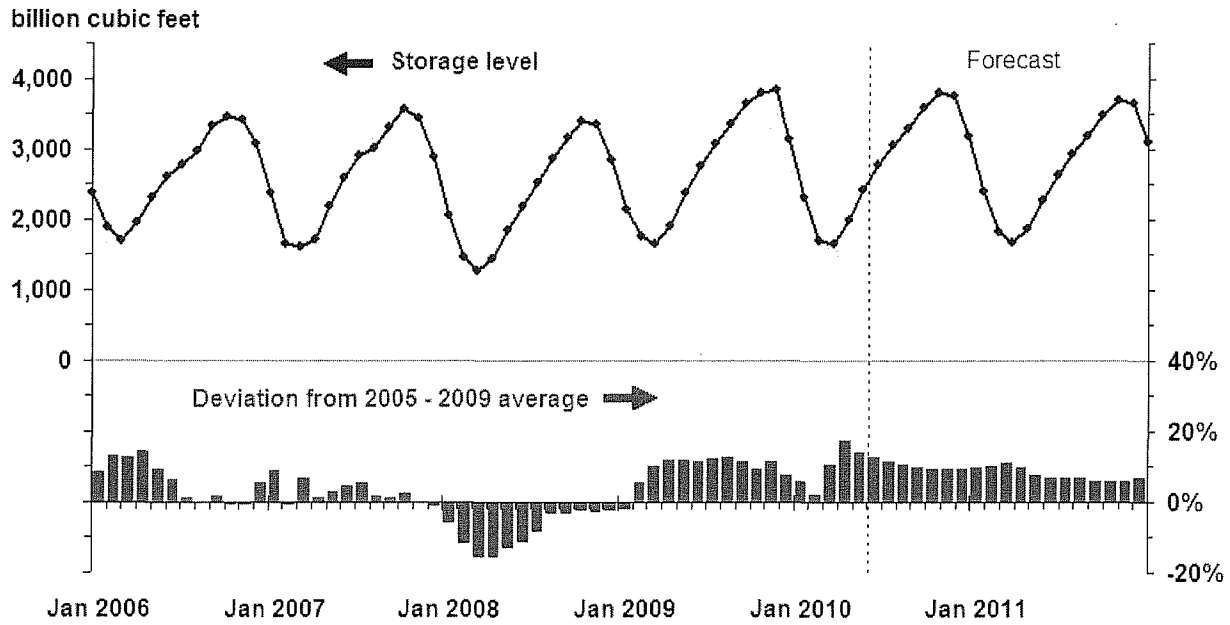
Source: Short-Term Energy Outlook, June 2010; Reuters News Service

U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, June 2010

U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009



Source: Short-Term Energy Outlook, June 2010

**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, 2010									<u>\$114,988</u>
May	\$29,734	\$0	\$723	\$30,457	12,466	\$0.2343	\$2,921	\$27,536	142,524
Balance @ May 31, 2010									<u>\$142,524</u>

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Mcf Sales</u>	<u>Adjustment Per Mcf</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2010									<u><u>(\$30,590)</u></u>
May	\$576	\$0	(\$199)	\$377	10,944	(\$0.7419)	(\$8,120)	\$8,497	(22,093)
Balance @ May 31, 2010									<u><u>(\$22,093)</u></u>

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