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

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PO Box 176
Fergus Falls, MN 56538-0176
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May 3, 2010

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

Re: Cost of Gas Adjustment (COG)
May 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 (50th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (50th Revised Sheet No. 8), showing the May 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.1827 per mcf for residential and firm general service customers and an increase of $0.0505 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for May 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.0505 per mcf since the last COG filing. There has been an increase in pipeline charges of $0.1322 per mcf due to changes in pipeline charges. The net effect of these changes is an increase of $0.1827 per mcf for residential and firm general service customers.

Attachment C discusses the market conditions of the gas commodity.

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

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

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
50th Revised Sheet No. 1.1
Canceling 49th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$7.3907	$8.6647
			Over 10 MCF	1.0540		8.4447
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.1829	$4.3220
			Next 2,600 MCF	0.8931		4.0760
			Over 3,000 MCF	0.7411		3.9240
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.1829	$4.4220
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: May 3, 2010 **Effective Date:** May 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
50th Revised Sheet No. 8
Canceling 49th 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.	3.0336	(1.2448)	0.2343	2.0231	(1.2448)	(0.7419)	(1.9867)
Current Adj.	0.1322	0.0505	0.0000	0.1827	0.0505	0.0000	0.0505
Total Adj.	3.1658	(1.1943)	0.2343	2.2058	(1.1943)	(0.7419)	(1.9362)
Total Rate:	$3.2316	$3.9248	$0.2343	$7.3907	$3.9248	($0.7419)	$3.1829

Date Filed: May 3, 2010 **Effective Date:** May 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2010

Firm	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
FT-A	7,841	$3.4671	12	$326,226	$0.2084
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0659
FT-A Seasonal	3,000	3.7671	5	56,507	0.0361
TFX Seasonal	3,000	15.1530	5	227,295	0.1452
NOVA - Demand Charge	7,947	17.1128	12	1,631,945	1.0424
Trans Canada - Demand Charge	7,947	16.9721	12	1,618,527	1.0338
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	17.1128	5	433,638	0.2770
Trans Canada - Seasonal	5,068	16.9721	5	430,073	0.2747
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0156
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0492
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				$5,059,187	3.2316
Estimated Weighted Average Commodity Cost	1,565,565 1/	3.9248		6,144,530	3.9248
Gas Cost Reconciliation Adjustment					0.2343
Total Current Firm Gas Cost				$11,203,717	7.3907
Base Cost of Gas					5.1849
Accumulated Adjustment					$2.2058

Interruptible	
Estimated Weighted Average Commodity Cost	$3.9248
Gas Cost Reconciliation Adjustment	(0.7419)
Total Current Interruptible Gas Cost	3.1829
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.9362)

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

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2010

Rates Effective May 1, 2010	$/Dk	
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	17.1128	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.9721	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.1128	Per dk/Day
Trans Canada - Seasonal	16.9721	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:	3.9248	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	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

1/ Demand base rate calculation: 4,768 X 12 X $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-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

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	TF12 Variable	TF5	FIELD-TO-FIELD/MARKET DEMARCATION 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.

RATE SCHEDULES TFX and LFT

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD 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/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ 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
May 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 May monthly price for the AECO Index is expected to increase slightly from the cost of gas included in the April COG filing. 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 reason the price is expected to remain in the same range as the previous month is likely a result of the continuing strength in the domestic production of natural gas and the balance of supply and demand in North America. The Energy Information Administration (EIA) reported storage levels nationwide as of April 23, 2010 were 18.8 percent above the five-year average and 5.6 percent above last year's balance.

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

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 15.

U.S. Energy Information Administration

April 2010

Short-Term Energy and Summer Fuels Outlook

April 6, 2010 Release

Highlights

- EIA's projections for West Texas Intermediate (WTI) crude oil spot prices have changed very little over the last five *Outlooks* even as spot crude oil prices continue to fluctuate on a daily basis. EIA expects WTI prices to average above $81 per barrel this summer, slightly less than $81 per barrel for 2010 as a whole, and $85 per barrel by the fourth quarter of 2011.

- EIA forecasts that regular-grade motor gasoline retail prices will average $2.92 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 forecast has the annual average regular grade retail gasoline price increasing from $2.35 per gallon in 2009 to $2.84 in 2010 and to $2.96 in 2011, primarily because of projected rising crude oil prices. Average U.S. pump prices for regular gasoline are likely to exceed $3 per gallon at times during the driving season, and already exceed $3 per gallon in some areas. Projected annual average retail diesel fuel prices are forecast at $2.95 and $3.12 per gallon in 2010 and 2011, respectively.

- EIA expects the Henry Hub natural gas spot price to average $4.44 per million Btu (MMBtu) this year, a $0.49-per-MMBtu increase over the 2009 average, but a significant downward revision from the $5.17 per MMBtu projected in last month's *Outlook*. The price outlook is lower primarily because of an average 2 billion cubic feet per day (Bcf/d) upward revision to the 2010 domestic natural gas production forecast.

- The annual average residential electricity price changes only slightly over the forecast period, averaging 11.5 cents per kilowatthour (kWh) in both 2009 and 2010 and then rising to 11.7 cents per kWh in 2011.

- Estimated carbon dioxide (CO_2) emissions from fossil fuels, which declined by 6.6 percent in 2009, increase by 2.1 percent and 1.1 percent in 2010 and 2011, respectively, as economic growth fuels higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA's assessment of world oil markets is largely unchanged from last month's *Outlook*, and world oil prices will likely continue to firm and increase slightly in response to the global economic recovery. As long as the global economy continues to recover, and the Organization of the Petroleum Exporting Countries (OPEC) remains satisfied with its constrained supply targets, global oil markets should remain in this situation. Major uncertainties include the pace of global economic recovery and the extent to which the largest economies continue their stimulus and other economic policies.

Global Crude Oil and Liquid Fuels Consumption. EIA projects that world oil consumption will grow by 1.5 million barrels per day (bbl/d) in 2010 and 1.6 million bbl/d in 2011, similar to the forecast of last month. This growth is the result of an expected recovery in the global economy, with world gross domestic product (GDP, on an oil-weighted basis) assumed to rise by more than 3 percent per year. EIA has revised its assessment for Asia upwards and Europe downwards for 2010 in response to preliminary first-quarter data for those regions. Most of the growth in oil consumption is expected in the Asia-Pacific and Middle East regions (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Non-OPEC supply is projected to increase by 600,000 bbl/d in 2010, about 50,000 bbl/d more than last month's *Outlook,* because of a revised forecast for production in North America. Non-OPEC supplies are then expected to fall slightly in 2011, as declining production in mature areas more than offsets any new production growth. The largest source of growth in 2010 is the United States, followed by Brazil, Azerbaijan, and Kazakhstan. Offsetting this projected supply growth in 2010 are further declines in mature fields in Mexico, the United Kingdom, and Norway.

OPEC Supply. OPEC left its production policy unchanged at its last meeting in Vienna on March 17, 2010, and is not scheduled to meet again until October 14 to review its crude oil production targets. EIA projects that OPEC production of crude oil will increase by 0.3 million bbl/d in 2010, primarily in Angola and Nigeria. However, 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. Overall, EIA also projects a slight increase in OPEC surplus

crude oil production capacity through 2011 from first-quarter 2010 levels (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the Organization for Economic Cooperation and Development (OECD) countries stood at 2.67 billion barrels at the end of the first quarter of 2010. This level is equivalent to about 58 days of forward cover, and is about 69 million barrels more than the previous 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 higher oil consumption and OPEC production restraint.

Crude Oil Prices. WTI crude oil spot prices averaged $81 per barrel in March 2010, almost $5 per barrel above the prior month's average and $3 per barrel higher than forecast in last month's *Outlook*. Oil prices rose from a low this year of $71.15 per barrel on February 5 to $80 per barrel by the end of February, generally on news of robust economic and energy demand growth in non-OECD Asia and the Middle East, and held near $81 until rising to $85 at the start of April. EIA expects WTI prices to average above $81 per barrel this summer, slightly less that $81 for 2010 as a whole, and $85 per barrel by the fourth quarter 2011 (West Texas Intermediate Crude Oil Price Chart). As always, these energy price forecasts are highly uncertain, as both recent experience and the sizable participation in near-term futures options contracts (with a wide range of strike prices) clearly demonstrate that prices can move within a wide range in a relatively short period.

Over the 5-day period ending April 1, June 2010 WTI futures contracts averaged $83.07 per barrel. Over the same 5-day period, the lower and upper limits for the 95-percent confidence interval for June 2010 futures were $68 and $101 per barrel, respectively, based on the June 2010 implied volatility of 28 percent calculated from New York Mercantile Exchange (NYMEX) near-the-money options on WTI futures (see Energy Price Volatility and Forecast Uncertainty). One year ago, futures contracts for WTI delivered into Cushing, Oklahoma, in June 2009 averaged about $45 per barrel and implied volatility, at 74 percent, was more than twice the rate now trading in the options markets.

The market's assessment of the probability of the realized WTI spot price exceeding $100 per barrel during 2010 increases from 3 percent for the June 2010 contract to 21 percent for the December 2010 contract. These probabilities showed little change across the forward curve in March. The probability for each month is calculated using the futures price for that contract, its implied volatility, and its time to expiration. Like the confidence intervals reported by EIA, this is a market-based probability

estimate derived using traded futures and options prices (see STEO Supplement, Probabilities of Possible Future Prices).

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption declined by 810,000 bbl/d (4.2 percent) to 18.7 million bbl/d in 2009, the fourth consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). Motor gasoline was the only major petroleum product whose annual consumption did not decline, having remained unchanged from the previous year. Distillate fuel consumption declined by 310,000 bbl/d (8.0 percent) in 2009, led by a sharp economy-related drop in transportation usage.

The economic recovery contributes to projected growth in total liquid fuels consumption of 160,000 bbl/d in 2010 and 210,000 bbl/d in 2011. Nevertheless, expected U.S. consumption in 2011 is lower than it was in 1999 and is 1.7 million bbl/d lower than the highest level of annual consumption, reached in 2005.

U.S. Liquid Fuels Supply. Domestic crude oil production averaged 5.32 million bbl/d in 2009, up about 370,000 bbl/d from 2008 (U.S. Crude Oil Production Chart). Projected growth in domestic crude oil production moderates to 200,000 bbl/d in 2010 and 70,000 bbl/d in 2011. The primary contributors to the production growth in 2009 and 2010 are the Thunder Horse, Tahiti, Shenzi, and Atlantis offshore fields in the Federal Gulf of Mexico (GOM).

Several new GOM hubs and fields are scheduled to begin production this year, such as the Great White field in the Perdido Spar and the Petrobras floating production storage and offloading (FPSO) vessel operating in the Chinook and Cascade fields. Despite this new production, projected GOM production declines by 100,000 bbl/d in 2011 because of declining output from existing wells. Offsetting the projected decline in GOM production are forecast increases in production from lower-48 non-GOM fields of 50,000 bbl/d and 200,000 bbl/d in 2010 and 2011, respectively.

Summer Transportation Fuels Outlook

The boost to gasoline consumption from the economic recovery is being countered by higher gasoline prices compared with last year. These counter-balancing forces are expected to be prominent features of the summer driving season.

Prices. Regular-grade gasoline retail prices, which averaged $2.44 per gallon last summer, are projected to average $2.92 per gallon during the current driving season.

The monthly average gasoline price is expected to peak at about $2.97 per gallon in early summer. Average U.S. pump prices likely will exceed $3 per gallon at times during the forthcoming spring and summer driving season. Diesel fuel prices, which averaged $2.46 per gallon last summer, are projected to average $2.97 this summer. However, because short-term prices can be quite volatile, weekly prices will differ from the monthly average.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in crude oil prices and wholesale margins. As noted in our discussion of crude oil markets, the current value of options contracts implies a 95 percent confidence band for future crude oil prices that is wide and widens further over time. Realized crude oil prices that differ from our forecast would be reflected in the price of motor fuels, with each dollar per barrel sustained difference in crude oil prices relative to the forecast translating into approximately a 2.4 cent-per-gallon change in prices absent consideration of factors specific to the markets for gasoline and diesel fuel.

Retail price projections reflect higher prices for the refiner acquisition cost of crude oil, expected to average about $79 per barrel this summer compared with the $62 per barrel average of last summer. EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) to average 43 cents per gallon this summer, up 5 cents per gallon from last summer. Similarly, EIA forecasts higher wholesale diesel margins this summer (33 cents per gallon) than last summer (25 cents per gallon) because of the expected worldwide recovery in distillate markets.

Motor Gasoline. During this summer season, projected motor gasoline consumption increases by 0.5 percent over last summer, substantially lower than the 0.8-percent growth rate recorded last summer. Gasoline consumption last summer was stimulated by both the beginning of economic recovery and a $1.37-per-gallon decline in gasoline prices from the previous year. In addition, there was a reversal in the trend of public transportation usage, which fell by 3.8 percent in 2009 after having risen by 4 percent in 2008 (American Public Transportation Association). This summer, the stimulus to demand from the continuing modest economic recovery is constrained by the projected $0.48-per-gallon average increase in gasoline prices over last summer.

Motor gasoline is supplied by four sources: domestic crude oil refinery output, domestic production and imports of fuel ethanol for gasoline blending, primary inventories, and net imports of gasoline and gasoline blending components. Refinery production of gasoline will be under considerable downward pressure from growth

in fuel ethanol blending and the current high level of gasoline inventories. This summer's domestic refinery gasoline supply is expected to decline by about 120,000 bbl/d from last summer's average.

Fuel ethanol blending into gasoline increased from an average of 645,000 bbl/d during the summer of 2008 to 717,000 bbl/d during the summer of 2009 and is projected to average 816,000 bbl/d this summer, about 8.9 percent of the total gasoline consumed. The growth in ethanol blending is driven by the Renewable Fuel Standard, which requires an increase in renewable fuels from a total of 10.6 billion gallons in 2009 to 12.3 billion gallons in 2010 (excluding the biomass-based diesel fuel volume requirement). The growth in ethanol consumption is being met primarily by domestic production. EIA expects the month-to-month growth in ethanol plant capacity and production to slow significantly in 2010 as the boom in ethanol plant construction and startups over the last 3 years comes to an end.

At the onset of the summer driving season (April 1) total gasoline stocks, at 224 million barrels, are 7 million barrels above the level of year-ago and 11 million barrels above the previous 5-year average (U.S. Gasoline and Distillate Inventories). Because of the higher current inventory level than last year, EIA projects the average stock draw over the summer will be about 87,000 bbl/d compared with last summer's 25,000 bbl/d average stock draw and the 5-year-average of 55,000 bbl/d.

For the current summer season, EIA expects net imports of motor gasoline and blending components to average 721,000 bbl/d, up slightly from last summer.

Diesel Fuel. Forecast distillate fuel consumption, which includes both diesel fuel and heating oil, is about 70,000 bbl/d, or 2.1 percent, higher than last summer's average. Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. Refinery production this summer is projected to average about 50,000 bbl/d lower than last summer.

Biodiesel is a small part of the distillate pool. Biodiesel blending averaged 28,000 bbl/d last summer and is expected to grow to about 40,000 bbl/d this summer as refiners and blenders adjust to the 650-million-gallon biodiesel blending mandate for 2010 under the Renewable Fuel Standard.

Distillate inventories are projected to start the summer season at 143.1 million barrels, almost matching last year's record-high 143.6 million barrels, and 24 million barrels higher than the previous 5-year average. Distillate stocks normally build during the summer season in preparation for winter heating demand. This summer's projected

15-million-barrel stock build is lower than the average 23-million-barrel build over the five previous summers and the 29 million barrel build last summer.

Continuing strong world demand for distillate fuels contributed to U.S. net exports of distillate fuel averaging 430,000 bbl/d during last summer. Before 2008, the United States was typically a net importer of distillate fuel, averaging 160,000 bbl/d over the summers of 2000 through 2007. Projected distillate net exports this summer decline slightly, averaging about 390,000 bbl/d.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to increase by 1.9 percent to 63.8 Bcf/d in 2010 and decline by 0.6 percent in 2011 (Total U.S. Natural Gas Consumption Growth Chart). Total U.S. heating degree-days (HDDs) during the first quarter 2010 were about 0.7 percent higher than last year. However, in the South region, first-quarter HDDs were about 20 percent higher than the same period last year. The cold weather helped boost year-over-year natural gas consumption in the electric power sector, adding to the increase in industrial sector consumption brought about by the improved economic conditions.

In last month's *Outlook*, EIA revised upward the forecast for natural gas consumption in the electric power sector for this year largely because of the higher space heating demand due to cold weather in the South. This month's *Outlook* includes another upward revision to the electric power sector consumption forecast. However, this revision reflects EIA's expectation that lower natural gas prices relative to coal prices will increase the utilization of natural-gas-fired generating facilities in the baseload power supply.

EIA's forecast for 2011 includes consumption declines in all sectors except the industrial sector. The projected return to near-normal weather reduces consumption in the residential and commercial sectors, while higher natural gas prices reverse the coal-to-gas switching trend observed in 2009 and forecast to continue in 2010. Consumption in the industrial sector, supported by continued economic growth, is projected to increase by 1.7 percent in 2011.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production to increase by 0.4 Bcf/d (0.7 percent) to 60.9 Bcf/d in 2010 and decrease by 0.7 Bcf/d (1.2 percent) in 2011. In last month's *Outlook*, domestic production growth was forecast to decline by 0.5 Bcf/d in 2010, reflecting the lagged effect of lower drilling rates last year. The higher production forecast in this *Outlook* reflects the latest January 2010 production estimate from the EIA-814 survey and the continuing

increase in the number of working natural gas rigs over the last month. Any significant revision to estimated January 2010 natural gas production (see Changes to the EIA-914 Sampling and Estimation Processes) would affect this forecast. The number of working natural gas rigs has increased by almost 200 since the end of last year. With no further increase from the current 950 natural gas rigs currently working, EIA expects production to begin to show month-to-month declines beginning in the second quarter this year. However, production is not expected to begin to show year-over-year declines until the first quarter of 2011.

EIA expects U.S. net natural gas imports to decline in 2010 as higher imports of liquefied natural gas (LNG)--and lower pipeline exports--are more than offset by a steep decline in pipeline imports as Canadian natural gas production drops off. The global LNG market appears to be well-supplied in 2010. In addition to the ramp-up of new global liquefaction capacity brought on-stream last year, about 3 Bcf/d of new capacity is set to start up this year. Spain, which relies on LNG in part for electricity generation, currently has hydroelectric reserves 34 percent above last year and 47 percent above the previous 5-year average. While EIA currently expects U.S. LNG imports to increase by about 0.5 Bcf/d this year over last, the failure of global demand to keep pace with increased global supply could lead to even higher U.S. LNG imports than currently forecast. EIA expects that an increase in global LNG demand next year will keep U.S. LNG imports roughly unchanged from 2010.

U.S. Natural Gas Inventories. On March 26, 2010, working natural gas in storage was 1,638 Bcf (U.S. Working Natural Gas in Storage Chart), 160 Bcf above the previous 5-year average (2005–2009) and 16 Bcf below the level during the corresponding week last year. Warmer-than-normal weather in March (HDDs were 10 percent below the 30-year normal for the month) contributed to an estimated monthly storage withdrawal of about 49 Bcf, or around 116 Bcf below the previous 5-year average for the month. Natural gas stocks at the end of March (the end of the withdrawal season) are estimated to be 1,656 Bcf, an amount comparable to stocks at the end of March last year. EIA expects continued production strength to contribute to high inventories again this fall. The current forecast for the end of October is 3,771 Bcf, only slightly below the record storage volume reached last fall. The forecast injection of 2,063 Bcf between March and November is about 5 percent below the stock build that occurred over the corresponding period last year, but it is more than 6 percent above the previous 5-year average.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.29 per MMBtu in March, $1.03 per MMBtu lower than the average spot price in February and $0.64 per MMBtu lower than the forecast for March in last month's Outlook (Henry Hub Natural Gas Price Chart). In the same way that colder-than-normal weather

contributed to higher prices in January and February, warmer-than-normal weather contributed to lower prices in March. In particular, prices touched a 4-month low during the final days of the month as lower demand and higher production resulted in storage injections. EIA expects prices to remain low for the next several months. With strong production and the absence of meaningful space-heating demand, lower-priced natural gas will once again compete with coal for a share of the baseload electricity supply—particularly in the spring and fall. Sustained low prices could reduce drilling activity over time. As a result, EIA expects production to decline and prices to increase in 2011. The Henry Hub spot price forecast averages $4.44 per MMBtu in 2010 and $5.33 per MMBtu in 2011.

Volatility in the June 2010 futures and options markets trended lower during the first half of March but rose in the second half as natural gas spot prices fell to $4 per MMBtu. For the 5-day period ended April 1, implied volatility for June 2010 natural gas options averaged 41 percent per annum, while June 2010 futures prices averaged $4.04 per MMBtu. The lower and upper limits of the 95-percent confidence interval, therefore, were $3.00 and $5.50 per MMBtu, respectively.

A year earlier, natural gas delivered to the Henry Hub in June 2009 was trading at $3.90 per MMBtu and implied volatility averaged about 63 percent. This generated a lower and upper limit for the 95-percent confidence interval of $2.45 and $6.20 per MMBtu, respectively.

Despite the increase in the implied volatilities during March, the probability of the Henry Hub realized price rising above $6.50 million Btu in December 2010 fell from 30 percent last month to 19 percent this month (see STEO Supplement, Probabilities of Possible Future Prices).

Electricity

U.S. Electricity Consumption. Residential retail sales of electricity grew by an estimated 7.6 percent in the first quarter of 2010 compared with the same period last year. Much of this growth was the consequence of the cold weather experienced during January and February in the South, where many households use electricity for space heating. EIA expects residential electricity sales to grow by about 7 percent during the third quarter of 2010 as summer temperatures are expected to return to normal levels after the cool summer experienced last year. Total consumption of electricity across all sectors is projected to grow by 2.9 percent during 2010 and by 1.2 percent next year (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. Last year, electricity generation from coal declined by 10.8 percent while generation from natural gas increased by 5.1 percent as lower natural gas prices motivated fuel switching in the electric power sector. Although natural gas prices are projected to be higher this year than last year, EIA still expects significant incentives to remain for electricity generation from natural gas, particularly in the South. EIA projects total natural gas generation in the electric power sector to grow by 2.0 percent in 2010. Low snow pack in the Northwest indicates hydropower generation will be low during 2010, falling by an estimated 7.6 percent for the entire United States compared with last year.

U.S. Electricity Retail Prices. The average U.S. residential electricity price during the first quarter of 2010 was estimated to be about 10.8 cents per kWh, almost 3 percent lower than in the same period last year. However, the annual average residential electricity price changes only slightly over the forecast period, averaging 11.5 cents per kWh in both 2009 and 2010 and then rising to 11.7 cents per kWh in 2011 because of higher coal and natural gas generation fuel costs (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Weather-related increases in electricity demand will contribute to the projected 4.2-percent growth in coal consumption in the electric power sector in 2010. Forecast coal consumption in the electric power sector grows by an additional 1.1 percent in 2011, though staying under 1 billion short tons for the third consecutive year. Coal consumption in the electric power sector had been over 1 billion short tons from 2003 through 2008 (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. EIA estimates that 2009 coal production fell by more than 8 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 4 percent in 2010 in this forecast despite increases in domestic consumption and exports. The balance between production and consumption is satisfied through significant reductions in both producer (primary) and end-user (secondary) inventories. EIA projects a 5-percent increase in coal production in 2011 to meet continued growth in coal consumption and exports as existing inventories are reduced (U.S. Annual Coal Production Chart).

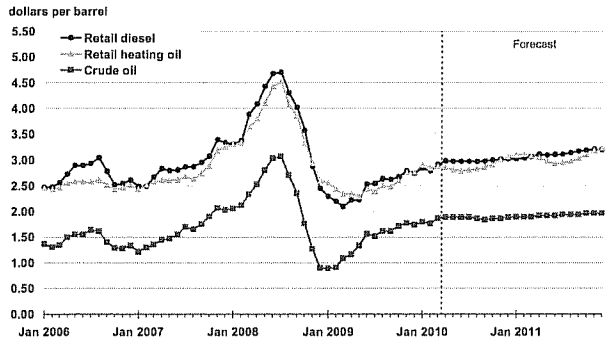
U.S. Coal Trade. U.S. coal imports fell by more than a third in 2009, and the slightly more than 22 million short tons imported was the smallest amount received since 2002. Forecast increases in coal consumption will lead to higher imports in 2010 and 2011; imports grow by 4.5 percent in 2010 and by an additional 16.6 percent in 2011.

U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by nearly 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 reflects 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 falls by more than 3 percent to average $2.14 per MMBtu in 2010 and declines by an additional 2.3 percent in 2011.

U.S. Carbon Dioxide Emissions

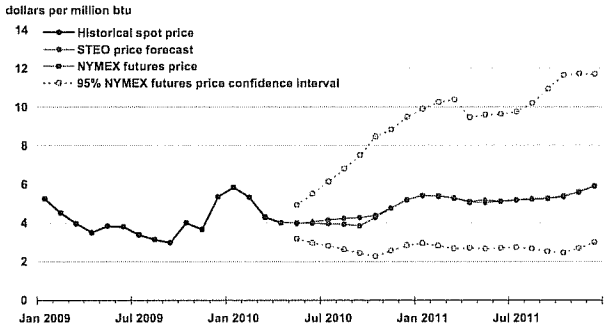
Forecast continued economic growth combined with increased use of coal in the electric power sector contribute to expected increases in CO_2 emissions of 2.1 percent and 1.1 percent in 2010 and 2011, respectively (U.S. Carbon Dioxide Emissions Growth Chart). However, even with increases in 2010 and 2011, projected CO_2 emissions in 2011 are lower than annual emissions from 1999 through 2008.

U.S. Diesel Fuel and Crude Oil Prices



Source: Short-Term Energy Outlook, April 2010

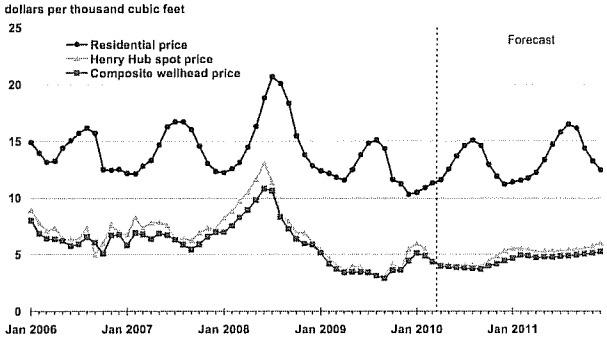
Henry Hub Natural Gas Price



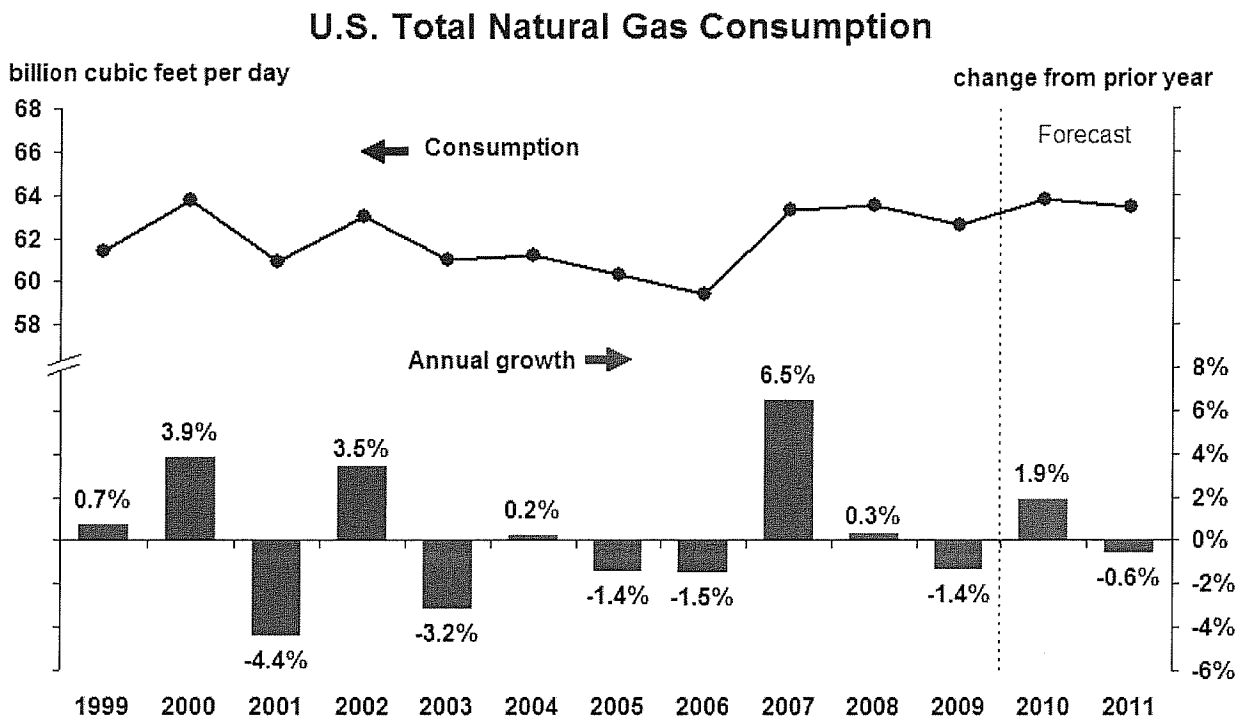
Note: Confidence interval derived from options market information from 5 trading days ending April 1, 2010
Intervals not calculated for months with sparse trading in "close-to-the-money" options contracts

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

Natural Gas Prices



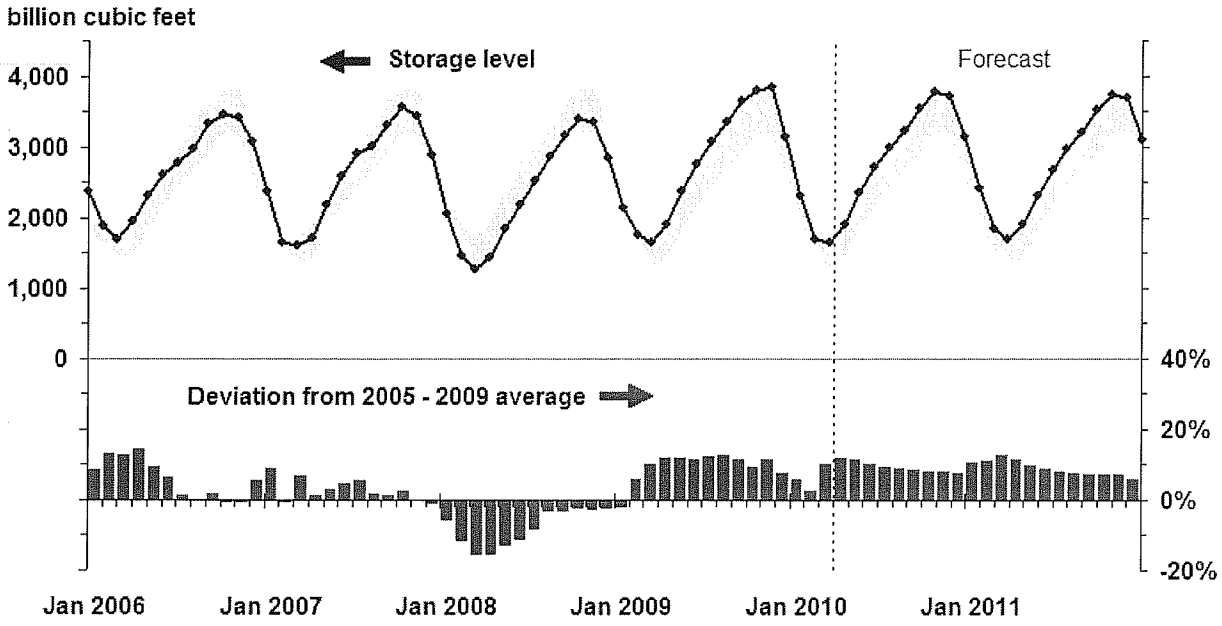
Source: Short-Term Energy Outlook, April 2010; Reuters News Service



Source: Short-Term Energy Outlook, April 2010

U.S. Energy Information Administration

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, April 2010

U.S. Energy Information Administration

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2009									**$65,941**
May	($2,105)	$0	$671	($1,434)	16,822	($0.1857)	($3,124)	$1,690	67,631
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
July	39,344	0	629	39,973	6,447	0.2343	1,511	38,462	131,625
August	39,771	0	902	40,673	5,943	0.2343	1,392	39,281	170,906
September	(2,165)	0	1,179	(986)	5,775	0.2343	1,353	(2,339)	168,567
October	35,022	0	1,154	36,176	11,535	0.2343	2,703	33,473	202,040
November	(980)	0	1,387	407	19,033	0.2343	4,459	(4,052)	197,988
December	25,639	0	1,349	26,988	32,413	0.2343	7,595	19,393	217,381
January 2010	(39,169)	0	1,480	(37,689)	48,707	0.2343	11,412	(49,101)	168,280
February	(54,257)	0	1,119	(53,138)	45,646	0.2343	10,695	(63,833)	104,447
March	(4,038)	0	653	(3,385)	36,916	0.2343	8,650	(12,035)	92,412
Balance @ March 31, 2010									**$92,412**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,097.5 dk @ ($0.1857) and 3,009.9 dk @ $0.2343.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2009									**($110,191)**
May	($5,411)	$0	($1,024)	($6,435)	15,426	($0.7309)	($11,275)	$4,840	(105,351)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
July	(3,038)	0	(592)	(3,630)	7,435	(0.7419)	(5,516)	1,886	(98,546)
August	(4,584)	0	(581)	(5,165)	9,775	(0.7419)	(7,252)	2,087	(96,459)
September	(14,605)	0	(571)	(15,176)	9,230	(0.7419)	(6,848)	(8,328)	(104,787)
October	(9,999)	0	(634)	(10,633)	16,552	(0.7419)	(12,280)	1,647	(103,140)
November	(15,225)	0	(633)	(15,858)	18,004	(0.7419)	(13,357)	(2,501)	(105,641)
December	(354)	0	(663)	(1,017)	22,135	(0.7419)	(16,422)	15,405	(90,236)
January 2010	(5,220)	0	(567)	(5,787)	25,285	(0.7419)	(18,759)	12,972	(77,264)
February	(1,595)	0	(492)	(2,087)	20,513	(0.7419)	(15,218)	13,131	(64,133)
March	987	0	(413)	574	19,857	(0.7419)	(14,732)	15,306	(48,827)
Balance @ March 31, 2010									**($48,827)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 7,849.5 dk @ ($0.7309) and 3,029.9 dk @ ($0.7419).