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December 1, 2010

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

Re: Cost of Gas Adjustment (COG)
December 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 (57th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (57th Revised Sheet No. 8), showing the December 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.7504 per mcf for residential and firm general service customers and \$0.6118 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for December 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.6118 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of \$0.1386 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.7504 per mcf for residential and firm general service customers.

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

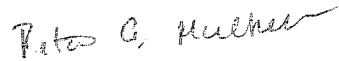
Attachment D shows the calculation of the balancing account since April 30, 2010.

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

57th Revised Sheet No. 1.1

RATE SUMMARY SHEET

Canceling 56th Revised Sheet No.1.1

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF	
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF	\$1.2740	\$8.0479	\$9.3219
			Over 10 MCF	1.0540		9.1019
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF	\$1.1391	\$3.8412	\$4.9803
			Next 2,600 MCF	0.8931		4.7343
			Over 3,000 MCF	0.7411		4.5823
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF	\$1.2391	\$3.8412	\$5.0803
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: December 1, 2010

Effective Date: December 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
57th Revised Sheet No. 8
Canceling 56th 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.	3.5091	(1.7906)	0.3941	2.1126	(1.7761)	(0.1136)	(1.8897)
Current Adj.	0.1386	0.6118	0.0000	0.7504	0.6118	0.0000	0.6118
Total Adj.	3.6477	(1.1788)	0.3941	2.8630	(1.1643)	(0.1136)	(1.2779)
Total Rate:	\$3.7135	\$3.9403	\$0.3941	\$8.0479	\$3.9548	(\$0.1136)	\$3.8412

Date Filed: December 1, 2010

Effective Date: December 1, 2010

Issued By: Tamie A. Aberle
Pricing & Tariff Manager

Case No.:

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

Firm	Billing		Demand		Amount
	Determinants	Rate	Months	Amount	Per dk
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	18.2908	12	1,744,284	1.2452
Trans Canada - Demand Charge	7,947	17.0559	12	1,626,519	1.1612
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0654
NOVA - Seasonal	5,068	18.2908	5	463,489	0.3309
Trans Canada - Seasonal	5,068	17.0559	5	432,197	0.3085
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/					0.0145
Total Demand Charges				\$5,181,493	3.7135
Estimated Weighted Average Commodity Cost	1,400,774	1/ 3.9403		5,519,470	3.9403
Gas Cost Reconciliation Adjustment					0.3941
Total Current Firm Gas Cost				\$10,700,963	8.0479
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.8630
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.9403
Gas Cost Reconciliation Adjustment					(0.1136)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					3.8412
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.2779)

1/ Three year normalized average Dk sales.

2/ Amount divided by 2009 interruptibles sales volumes plus three year normalized firm Dk Sales. 2,073,950

LMS Demand	Billing		Demand		Amount
	Determinants	Rate	Months	Amount	Per dk
	2,500	\$1.0000	12	\$30,000	\$0.0145

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

Rates Effective December 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	18.2908	Per dk/Mo.
Trans Canada Pipeline Demand Charge	17.0559	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	18.2908	Per dk/Day
Trans Canada - Seasonal	17.0559	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:	3.9403	Per dk

Base Rate Effective September 1, 1981		
Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation

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

<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Part 5.0
Statement of Rates
v. 1.0.0

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
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
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
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
<u>Category 3 (Contract Term of 5 or more Years)</u>	
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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Part 5.0
Statement of Rates
v. 1.0.0

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	1.92%
Zone 1-2	\$0.0130	\$0.0019	\$0.0149	2.23%
Zone 2-2	\$0.0130	\$0.0019	\$0.0149	0.31%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0019	\$0.1387	1.92%
Zone 1-2	\$0.1737	\$0.0019	\$0.1756	2.23%
Zone 2-2	\$0.0834	\$0.0019	\$0.0853	0.31%
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: 0.16% for Zone 1-1, 0.18% for Zone 1-2, and 0.02% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

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.

Rate Schedule	Maximum Commodity Rate Per Dekatherm, Per Day	Minimum Commodity Rate Per Dekatherm, Per Day
PAL	\$0.1737	\$0.0000

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

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
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.

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.
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- 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.

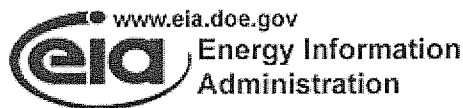
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
December 2010**

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 December 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).

Despite continued robust domestic natural gas production and record levels of working gas in storage, natural gas prices increased as a result of seasonal temperatures and increased heating demand for natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of November 19, 2010 were 9.5 percent above the five-year average and 0.1 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 14.



November 2010

Short-Term Energy Outlook

November 9, 2010 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$83 per barrel this winter (October 1 to March 31), a \$5.50-per-barrel increase over last winter and \$3 per barrel more than in last month's *Outlook*. Projected WTI prices rise gradually to \$87 per barrel by the fourth quarter of 2011 as U.S. and global economic conditions improve. EIA's forecast assumes U.S. gross domestic product (GDP) grows by 2.6 percent in 2010 and 2.2 percent in 2011, while world real GDP weighted by oil consumption grows by 3.9 percent and 3.3 percent, respectively.
- EIA expects regular-grade motor gasoline retail prices to average \$2.84 per gallon this winter, 19 cents per gallon higher than last winter. Retail diesel fuel prices are expected to average \$3.09 per gallon this winter, an increase of 29 cents per gallon over last winter. In 2011, higher crude oil prices combined with strengthening refiner margins push annual average prices for motor gasoline and diesel fuel to \$2.97 and \$3.19 per gallon, respectively.
- Natural gas working inventories have reached more than 3.8 trillion cubic feet (Tcf), which is about the same as last year's record-setting level for the underground storage quantity at the end of October. The projected Henry Hub natural gas spot price averages \$4.35 per million Btu (MMBtu) for 2010, a \$0.40-per-MMBtu increase over the 2009 average, but down \$0.12 per MMBtu from the forecast in last month's *Outlook*. EIA expects the Henry Hub spot price will average \$4.31 per MMBtu in 2011, down \$0.27 per MMBtu from last month's *Outlook*.
- EIA projects average household expenditures for space-heating fuels will total \$965 this winter, about the same as last year. EIA projects higher expenditures for heating oil and propane, but lower expenditures for natural gas and electricity. This forecast reflects higher prices for all the fuels, but milder

weather than last winter in the South and Midwest contribute to lower fuel consumption in those areas.

- EIA projects U.S. carbon dioxide (CO₂) emissions from fossil fuels, which declined by 7.0 percent in 2009, will increase by 3.5 percent in 2010. In 2011, projected CO₂ emissions increase by a further 0.4 percent as the expected milder summer reduces electricity use. However, even with these increases, CO₂ emissions remain below their level in any year from 1999 through 2008.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Growth in global oil consumption remains strong. In the current *Outlook*, the projected growth in world real GDP (weighted by oil consumption) is 3.9 percent in 2010. Continued upward revisions this year's world oil consumption, particularly for Europe and China, have led to an expected world consumption growth of 2.0 million bbl/d for 2010. EIA expects this consumption growth to be met in almost equal parts by a 1.0 million bbl/d increase in production from Organization of the Petroleum Exporting Countries (OPEC) and 1.0 million bbl/d increase in non-OPEC supply. While commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remain high, floating oil storage has been declining. EIA believes that the projected gradual reduction in OECD oil inventories over the forecast period should lend support to firming oil prices.

Global Crude Oil and Liquid Fuels Consumption. EIA has revised world oil consumption growth in 2010 upward in response to stronger-than-expected growth in European oil demand during the second and third quarters of 2010, as well as continued strong growth in China. The non-OECD regions, especially China, the Middle East, and Brazil, represent most of the expected growth in world oil consumption in 2011 ([World Liquid Fuels Consumption Chart](#)). Among the OECD regions, EIA expects North America to show almost all the oil consumption growth in 2011, with a gain of nearly 0.4 million bbl/d. In 2011, EIA expects global oil consumption growth of 1.4 million bbl/d.

Non-OPEC Supply. Most of the 1.0 million bbl/d projected growth of non-OPEC supply in 2010 comes from the United States, Brazil, and the former Soviet Union. However, this growth in world supply is not sustained in the 2011 forecast. Total non-OPEC supply falls by 250,000 bbl/d in 2011, primarily because of declining total North American and North Sea production as well as decreasing supplies from Russia. This would be only the third time in the last 15 years that non-OPEC supplies

fall year-over-year, following non-OPEC production declines in 2005 and 2008, which were primarily the result of supply disruptions in the Gulf of Mexico.

OPEC Supply. OPEC left its production targets unchanged at its October meeting, noting that global oil markets were well supplied. However, EIA projects that OPEC crude oil production will increase by 0.3 and 0.5 million bbl/d in 2010 and 2011, respectively. Projected OPEC non-crude petroleum liquids production, which is not subject to OPEC production quotas, increases by 0.7 million bbl/d in both 2010 and 2011. OPEC surplus capacity should remain near 5 million bbl/d, compared with 4.3 million in 2009 and 1.5 million in 2008 ([OPEC Surplus Crude Oil Production Capacity Chart](#)).

OECD Petroleum Inventories. Commercial oil inventories held by OECD countries stood at an estimated 2.76 billion barrels at the end of the third quarter of 2010, equivalent to about 60 days of forward cover, and roughly 70 million barrels more than the 5-year average for the corresponding time of year ([Days of Supply of OECD Commercial Stocks Chart](#)). OECD oil inventories decline through the forecast period, though days-forward-cover may remain relatively high by historical standards.

Crude Oil Prices. WTI crude oil spot prices averaged almost \$82 per barrel in October, about \$7 per barrel higher than the September average, as expectations of higher oil demand pushed up prices. EIA has raised the average fourth-quarter 2010 WTI spot price forecast to about \$83 per barrel compared with \$79 per barrel in last month's *Outlook*. WTI spot prices rise to \$87 per barrel by the fourth quarter of next year. Projected WTI prices average \$79 per barrel in 2010 and \$85 per barrel in 2011.

Energy price forecasts are uncertain ([Energy Price Volatility and Forecast Uncertainty](#)). WTI futures for January 2011 delivery (for the 5-day period ending November 4) averaged \$85 per barrel, and implied volatility – a measure of price uncertainty - averaged 31 percent. This made the lower and upper limits of the 95-percent confidence interval for January 2011 contracts \$69 per barrel and \$103 per barrel, respectively, for WTI delivered in January 2011. Last year at this time, WTI for January 2010 delivery averaged \$80 per barrel and implied volatility averaged 41 percent, with the limits of the 95-percent confidence interval at \$61 per barrel and \$104 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total U.S. liquid fuels consumption increases by 260,000 bbl/d (1.4 percent) in 2010, which is about 60,000 bbl/d higher than forecast in last month's *Outlook*. A year-over-year decline in total liquid fuels

consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise averaging 520,000 bbl/d in the second and third quarters, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, projected gasoline consumption increases by 0.3 percent and distillate consumption increases by 3.4 percent. Total liquid fuels consumption increases by a further 120,000 bbl/d (0.6 percent) in 2011, as all of the major petroleum products register consumption growth ([U.S. Liquid Fuels Consumption Growth Chart](#)). Gasoline, distillate fuel, and jet fuel consumption each increase by 0.7 percent in 2011.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 410,000 bbl/d in 2009, increases by 140,000 bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)) and then falls by 40,000 bbl/d to 5.4 million bbl/d in 2011. The 2011 forecast includes declines of 50,000 bbl/d and 160,000-bbl/d in Alaska and the Federal Gulf of Mexico (GOM), respectively, and a 170,000-bbl/d increase in lower-48 non-GOM production. Ethanol production, which averaged 710,000 bbl/d in 2009, increases to an average of 850,000 bbl/d in 2010 and 870,000 bbl/d in 2011.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 51 percent in 2009. EIA forecasts that liquid fuel net imports will average about 50 percent of total consumption in 2010 and 2011.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average \$2.35 per gallon in 2009 to an average \$2.77 per gallon in 2010 and \$2.97 per gallon in 2011. On-highway diesel fuel retail prices, which averaged \$2.46 per gallon in 2009, average \$2.97 per gallon in 2010 and \$3.19 in 2011 in the current forecast. Projected refining margins, which have been at their lowest levels since 2003, average about \$2 per barrel higher next year because of growing global product demand and shutdowns of excess global refining capacity.

Natural Gas

U.S. Natural Gas Consumption. This month's *Outlook* forecasts that total natural gas consumption will grow by 4.3 percent to 65.0 billion cubic feet per day (Bcf/d) in 2010, and then rise slightly in 2011 to 65.4 Bcf/d ([Total U.S. Natural Gas Consumption Growth Chart](#)). This growth in 2010 is largely due to increases in industrial and electric power sector consumption of natural gas. Hot weather in the summer and low natural gas prices drove the increased use of natural gas for electric power generation in 2010. Forecast population-weighted cooling degree-days for the United States drop by 16 percent, from 1,460 in 2010 to 1,231 in 2011. As a result, natural gas

consumption for electric power generation falls slightly in 2011, even as natural gas prices drop.

Residential consumption of natural gas, which remains flat from 2009 to 2010, will rise by 1.8 percent in 2011, corresponding to a predicted 2.9-percent increase in heating degree-days. In the first quarter of 2011, residential natural gas consumption will average 25.8 Bcf/d, a decline of about 3 percent from the first quarter of 2010, when cold weather drove residential consumption. Commercial and residential consumption will remain flat in 2010 and rise slightly in 2011.

U.S. Natural Gas Production and Imports. EIA is raising the marketed natural gas production forecast by an average of 0.2 Bcf/d in 2010 and 0.4 Bcf/d in 2011 compared with last month's *Outlook*. Marketed natural gas production in the current forecast increases by 2.5 percent this year, but still falls by 1.2 percent in 2011. The drop in 2011 is a result of a 13.5-percent production decline in GOM production, which is only partially offset by a small increase in lower-48 production. The relatively greater decline in GOM production in 2011 is due to an estimated 90 Bcf less production because of the 2010 drilling moratorium and the projected increase in hurricane-induced production outages of about 30 Bcf in the GOM next year compared with a relatively calm season this year.

The increase in the natural-gas-directed drilling rig count since mid-2009, comprised of a growing share of horizontal drilling rigs in the lower-48 states, contributed to the natural gas production growth in 2010. The number of rigs drilling for natural gas reported by Baker Hughes increased from a low of 665 in July 2009 to 973 in April 2010. Over the last 6 months the natural gas rig count has stayed relatively unchanged, ending October 2010 with 969 active rigs. Drilling activity declines modestly in 2011 because of relatively lower natural gas prices. The large price difference between petroleum liquids and natural gas prices on an energy-equivalent basis contributes to an expected shift towards drilling in shale formations that contain a higher proportion of liquids.

EIA expects gross pipeline imports of 9.1 Bcf/d in 2011, an increase of 1.4 percent compared with 2010 imports. Projected liquefied natural gas (LNG) imports average 1.27 Bcf/d in 2010, a 2.3 percent increase from the 2009 levels. High domestic production and low U.S. prices relative to European and Asian markets have discouraged LNG imports into North America. However, LNG imports grow slightly in 2011 to 1.32 Bcf/d, a 4.5-percent increase from 2010 levels.

U.S. Natural Gas Inventories. On October 29, 2010, working natural gas in storage rose to 3,821 billion cubic feet (Bcf) which exceeds the 3,784 Bcf reached at the end of

October 2009 ([U.S. Working Natural Gas in Storage Chart](#)). Last year, storage injections continued into November, with working gas reaching a record-high 3,837 Bcf on November 27, 2009. This year, however, EIA expects a net 3 Bcf withdrawal during November because of a 20-percent increase in forecast heating degree-days compared with November 2009. At the end of the winter heating season (March 31, 2011), EIA expects 1,776 Bcf of working natural gas will remain in storage, about 114 Bcf higher than the end of March 2010. This is an upward revision of more than 70 Bcf from last month's *Outlook* because of the current higher-than-expected stock level and upward revision in the production forecast.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$3.45 per million Btu (MMBtu) in October, \$0.43 per MMBtu lower than the average spot price in September ([Henry Hub Natural Gas Price Chart](#)). The decline in prices over the past two months was partly the result of high production, mild weather, and the absence of significant hurricane activity in the Gulf of Mexico, all of which contributed to the large inventory build. Projected Henry Hub prices rise to \$4.22 per MMBtu in January 2011 because of the increase in winter space-heating demand. EIA has lowered the average 2011 Henry Hub price forecast from last month's *Outlook* by \$0.27 per MMBtu, to \$4.31 per MMBtu, based on the upward revisions in the domestic production and inventory forecasts.

Uncertainty over future natural gas prices is slightly higher this year compared with last year at this time. Natural gas futures for January 2011 delivery (for the 5-day period ending November 4) averaged \$4.13 per MMBtu, and the average implied volatility over the same period was 41 percent. This produced lower and upper bounds for the 95-percent confidence interval for January 2011 contracts of \$3.06 per MMBtu and \$5.59 per MMBtu, respectively. At this time last year, the natural gas January 2010 futures contract averaged \$5.20 per MMBtu and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.52 per MMBtu and \$7.67 per MMBtu.

Electricity

U.S. Electricity Consumption. The National Oceanic and Atmospheric Administration projects warmer temperatures this winter, with average U.S. heating degree-days down 4 percent and down nearly 17 percent for the South, where a majority of households use electricity as the primary heat source ([U.S. Winter Heating Degree-Days Chart](#)). These warmer temperatures contribute to a projected 3-percent decline in U.S. retail sales of electricity to the residential sector over the winter months. In contrast, improvements in manufacturing output should lead to a 4.6-percent increase in U.S. retail sales of electricity to the industrial sector during the

same time period. Overall EIA expects a 4.7 percent increase in total annual consumption of electricity across all sectors during 2010 and little change during 2011 ([U.S. Total Electricity Consumption Chart](#)).

U.S. Electricity Generation. EIA expects total electric power sector generation to increase by 130 gigawatthours per day (GWh/d) (1.3 percent) during the 2010-2011 winter months compared with the same period last year. In response to the expected lower fuel costs for natural gas relative to coal, electricity generation from natural gas increases by 74 GWh/d (3.7 percent) during the winter months, while generation from coal-fired power plants increases by only 48 GWh/d (0.9 percent) compared with the same period last year.

U.S. Electricity Retail Prices. Average retail residential electricity prices in the U.S. began showing year-over-year declines about one year ago. Beginning this past spring, prices began to increase slightly year-over-year as higher fuel costs incurred by utilities were passed through to retail customers. EIA expects this trend to intensify over the next two quarters before moderating late next year. Annual average prices should grow by 1.7 percent during 2011 ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. EIA forecasts that coal consumption in the electric power sector will grow by 6 percent in 2010, primarily the result of higher electricity consumption. Forecast increases in nuclear- and renewable-based generation combined with a 0.1-percent drop in electricity consumption in 2011 contribute to a decline in coal-fired electricity generation and related coal consumption. EIA expects that 2011 coal consumption in the electric power sector will decline by 0.2 percent ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production for the first 6 months of 2010 fell by 3 percent despite a 5-percent increase in U.S. coal consumption because of drawdowns in stocks held by the electric power sector ([U.S. Electric Power Sector Coal Stocks Chart](#)). Projected coal production increases in the second half of 2010 as the drawdown in stocks slows, contributing to 2010 annual growth of 1 percent. EIA projects coal production in 2011 to remain flat as coal consumption shows little change ([U.S. Annual Coal Production Chart](#)).

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, has resulted in sharp increases in U.S. coal exports in 2010. Metallurgical coal exports have nearly doubled in the first half of this year compared

with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to a projected 73 percent in 2010. EIA expects total coal exports to increase by 30 percent in 2010, but decline in 2011 as other major coal-exporting countries increase their supply to the global coal market.

The strong global demand for coal is also a significant factor in the decline of U.S. coal imports in 2010. Coal imports fell by 16 percent in the first half of this year and EIA expects the annual decline in 2010 to be nearly 17 percent below 2009 imports. Colombia, the largest supplier of U.S. coal imports, began exporting sizable quantities to Asian markets, especially China, in response to a combination of higher prices in Asia and lower freight costs. EIA forecasts coal imports will recover next year, with growth of 37 percent. However, the annual import tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons.

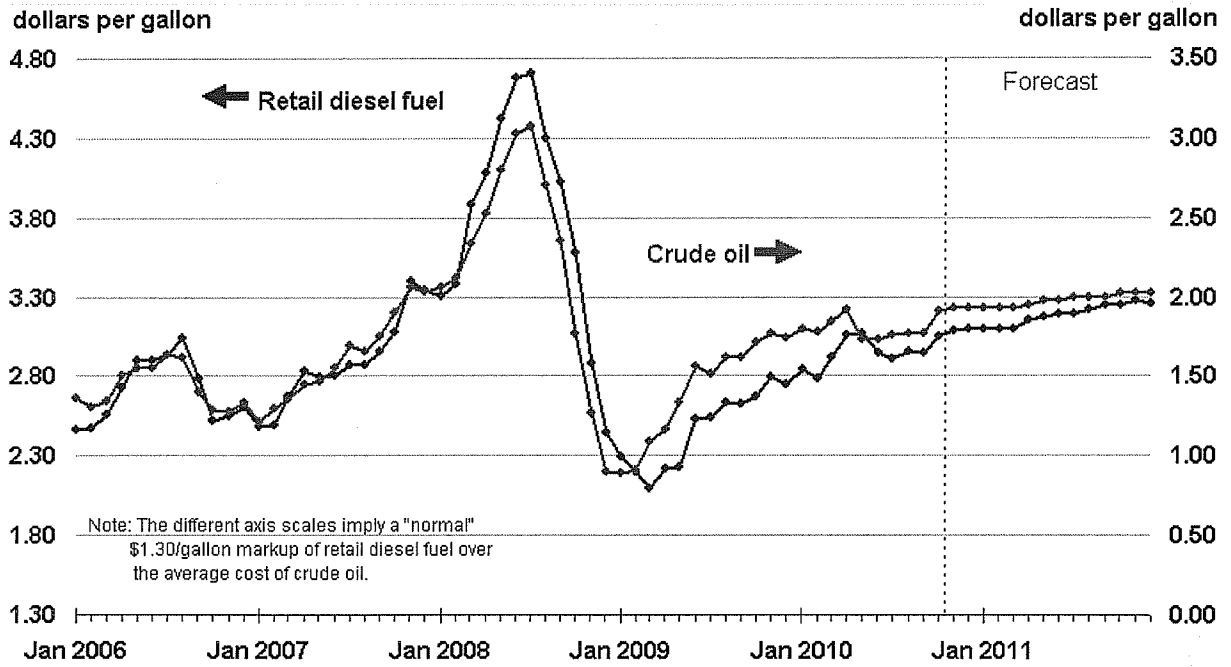
U.S. Coal Prices. The electric power sector coal price rose by 1.3 percent in the first half of 2010 compared with the first half of last year. This higher cost of delivered coal reflects the effect of longer-term power sector coal contracts initiated during a period of high prices, rising transportation costs, increased consumption, and increases in spot coal prices. The projected electric power sector delivered coal price averages \$2.28 per MMBtu in 2010, and then declines slightly to an average of \$2.27 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Expected U.S. real GHP growth of 2.6 percent combined with increased use of coal and natural gas contribute to a 3.5 percent increase in fossil-fuel carbon dioxide (CO₂) emissions in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). The first half of 2010 saw increases of 5.7 percent and 4.3 percent for coal- and natural gas-related CO₂ emissions, respectively. These increases resulted from increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Declines in electric power sector fossil fuel consumption in 2011 offset forecast increased consumption of petroleum in the transportation sector (i.e., motor gasoline, diesel fuel, and jet fuel). Consequently, fossil-fuel CO₂ emissions show a small increase of 0.4 percent in 2011. Projected fossil-fuel CO₂ emissions in 2010 and 2011 also remain below the levels seen in any year from 1999 through 2008.

U.S. Diesel Fuel and Crude Oil Prices



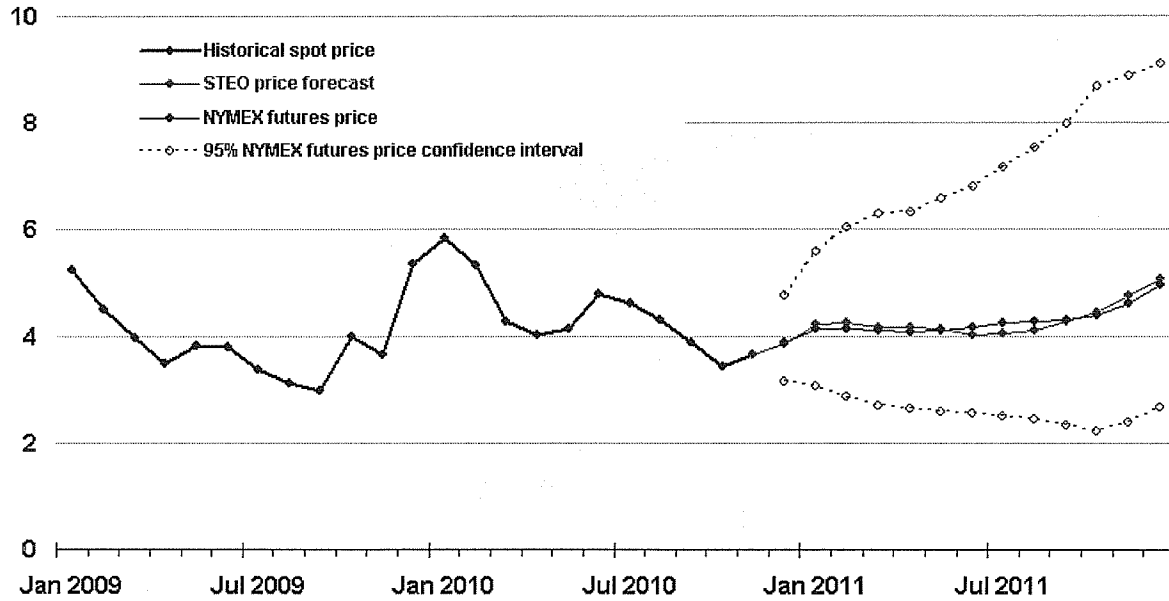
Note: Crude oil price is refiner average acquisition cost. Retail diesel fuel price includes State and Federal taxes.



Source: Short-Term Energy Outlook, November 2010

Henry Hub Natural Gas Price

dollars per million btu

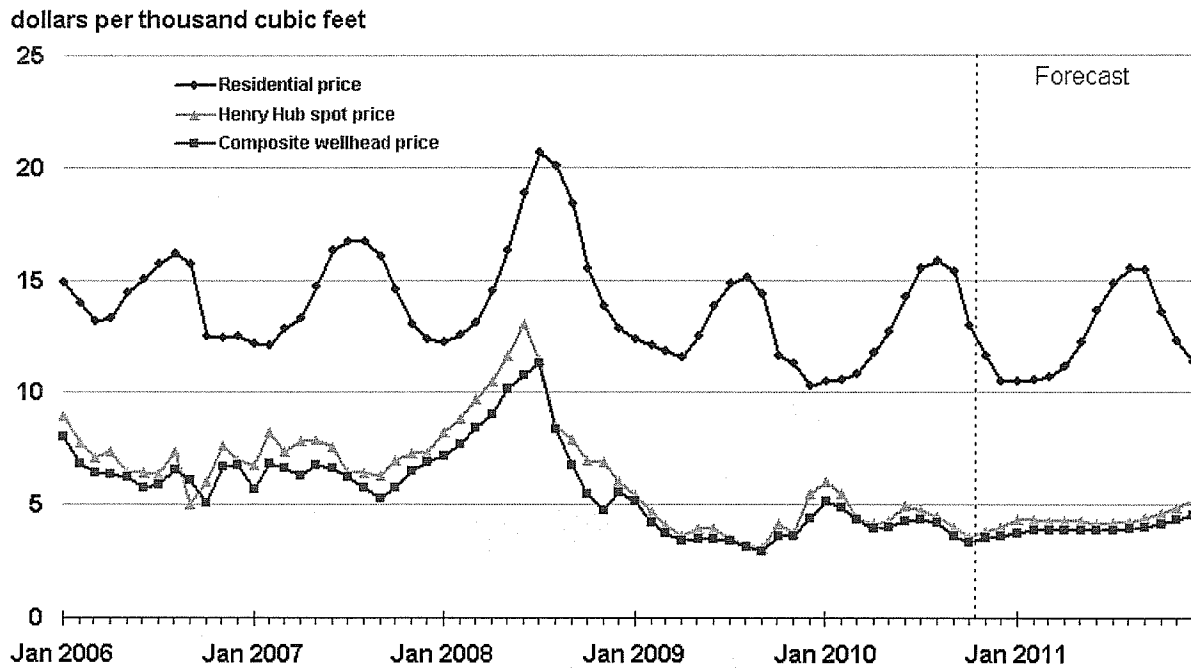


Note: Confidence interval derived from options market information for the 5 trading days ending November 4, 2010
Intervals not calculated for months with sparse trading in "near-the-money" options contracts



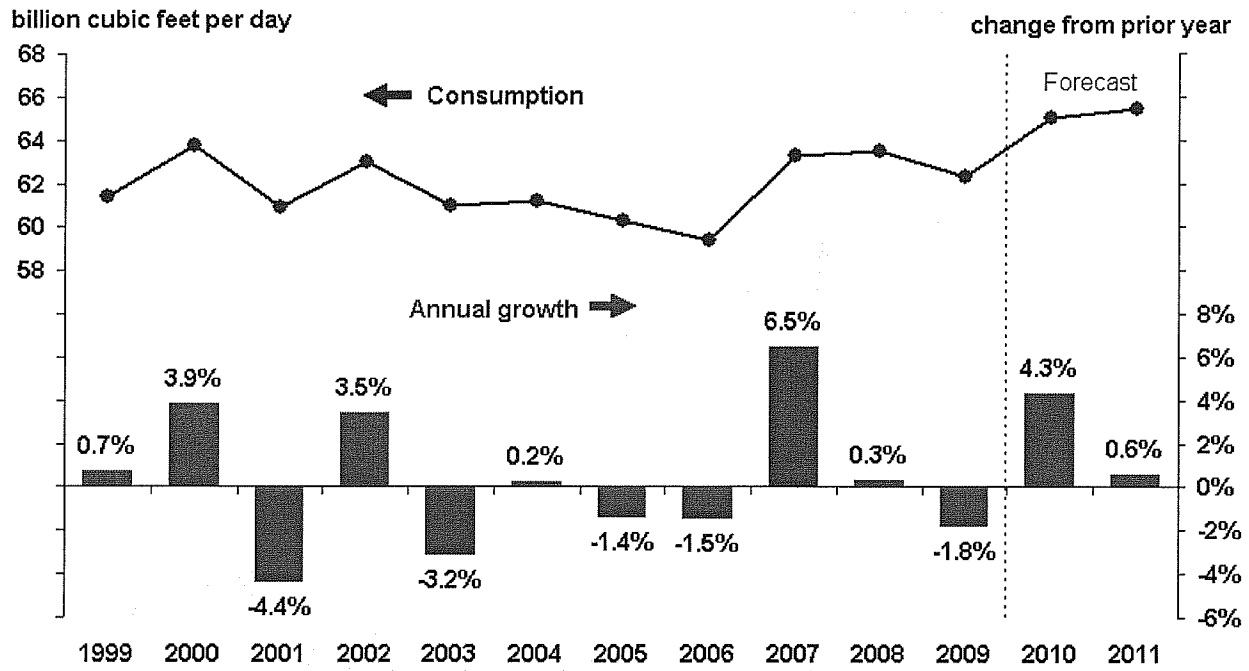
Source: Short-Term Energy Outlook, November 2010; Reuters News Service; and CME Group

Natural Gas Prices



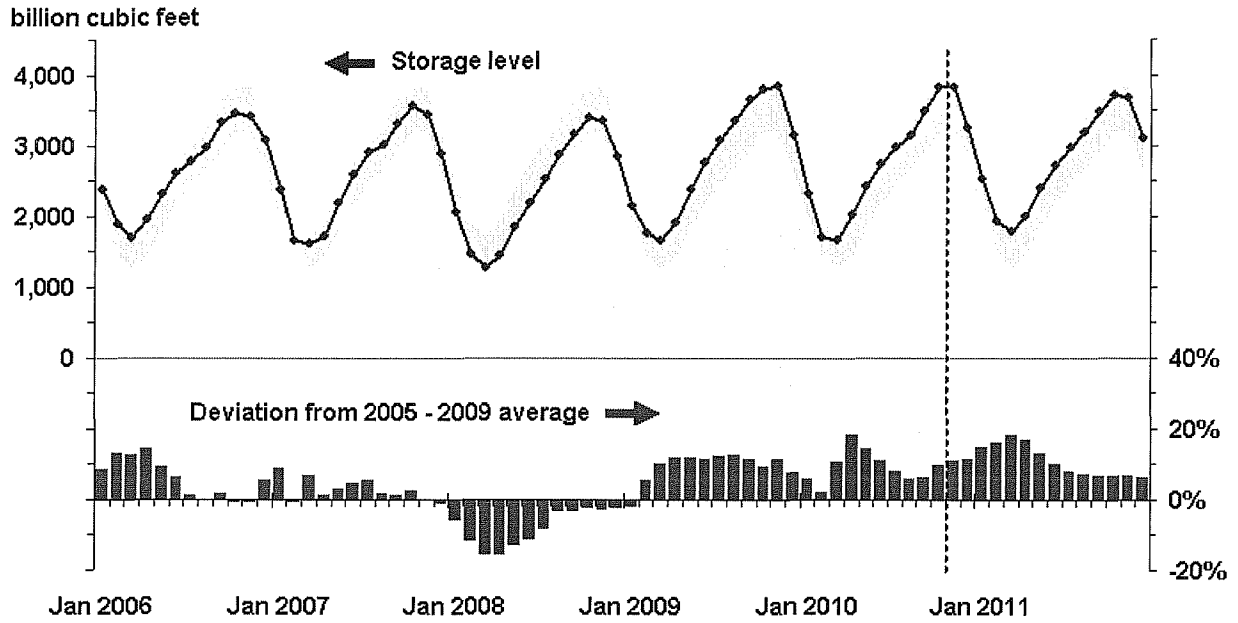
Source: Short-Term Energy Outlook, November 2010; Reuters News Service

U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, November 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, November 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
June	11,277	0	917	12,194	8,311	0.3941	2,356 2/	9,838	152,362
July	20,585	0	982	21,567	6,200	0.3941	2,444	19,123	171,485
August	86,747	0	1,115	87,862	5,953	0.3941	2,347	85,515	257,000
September	92,220	0	1,725	93,945	6,368	0.3941	2,509	91,436	348,436
October	34,666	0	2,373	37,039	8,070	0.3941	3,181	33,858	382,294
Balance @ Oct 31, 2010									<u>\$382,294</u>

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

2/ Reflects 5,750.5 dk @ \$0.2343 and 2,560.2 dk @ \$0.3941.

**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>(\$30,590)</u>
May	\$576	\$0	(\$199)	\$377	10,944	(\$0.7419)	(\$8,120)	\$8,497	(22,093)
June	(8,617)	0	(146)	(8,763)	11,808	(0.1136)	(6,678) 2/	(2,085)	(24,178)
July	(8,501)	0	(169)	(8,670)	10,612	(0.1136)	(1,205)	(7,465)	(31,643)
August	(1,507)	0	(224)	(1,731)	9,466	(0.1136)	(1,075)	(656)	(32,299)
September	422	0	(230)	192	13,953	(0.1136)	(1,585)	1,777	(30,522)
October	4,873	0	(219)	4,654	26,958	(0.1136)	(3,062)	7,716	(22,806)
Balance @ Oct 31, 2010									<u>(\$22,806)</u>

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

2/ Reflects 8,493.0 dk @ (\$0.7419) and 3,315.3 dk @ (\$0.1136).