

May 27, 2011

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

Re: Cost of Gas Adjustment (COG)
June 2011

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 (63rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (63rd Revised Sheet No. 8), showing the June 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.3326 per mcf for residential and firm general service customers and \$0.2481 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for June 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.1523 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 \$0.0642 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of \$0.2165 per mcf for residential and firm general service customers.

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

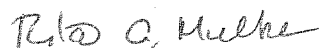
Attachment D shows the calculation of the gas cost reconciliation (GCR) adjustment that will apply during the period of June 1, 2011 through May 31, 2012. The total GCR is \$0.5102 per mcf for residential and general service customers and a negative \$0.0178 per mcf for interruptible customers. The effect of this change is an increase of \$0.1161 for residential and general service customers and an increase of \$0.0958 for interruptible customers.

Great Plains submitted a check for \$600.00 on January 10, 2011 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 Affairs 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

63rd Revised Sheet No. 1.1

Canceling 62nd 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	\$8.9913	\$10.2653 10.0453
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	\$4.1728	\$5.3119 5.0659 4.9139
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$4.1728	\$5.4119
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: May 27, 2011

Effective Date: June 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs 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
63rd Revised Sheet No. 8
Canceling 62nd 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.	4.1750	(1.0953)	0.3941	3.4738	(1.0808)	(0.1136)	(1.1944)
Current Adj.	0.0642	0.1523	0.1161	0.3326	0.1523	0.0958	0.2481
Total Adj.	4.2392	(0.9430)	0.5102	3.8064	(0.9285)	(0.0178)	(0.9463)
Total Rate:	\$4.3050	\$4.1761	\$0.5102	\$8.9913	\$4.1906	(\$0.0178)	\$4.1728

Date Filed: May 27, 2011

Effective Date: June 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

**GREAT PLAINS NATURAL GAS CO.
WHPETON
COST OF GAS ADJUSTMENT
JUNE 2011**

<u>Firm</u>	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per dk</u>
FT-A	7,841	\$3.4671	12	\$326,226	\$0.2325
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	0.0736
FT-A Seasonal	3,000	3.7671	5	56,507	0.0403
TFX Seasonal	3,000	15.1530	5	227,295	0.1620
NOVA - Demand Charge	7,947	17.8286	12	1,700,207	1.2118
Trans Canada - Demand Charge	7,947	24.4629	12	2,332,880	1.6627
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068	17.8286	5	451,777	0.3220
Trans Canada - Seasonal	5,068	24.4629	5	619,890	0.4418
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0174
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0549
LMS Demand 2/					0.0145
Total Demand Charges				\$6,019,758	4.3050
Estimated Weighted Average Commodity Cost	1,403,100	1/ 4.1761		5,859,486	4.1761
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				\$11,879,244	8.9913
Base Cost of Gas					5.1849
Accumulated Adjustment					\$3.8064
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.1761
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					4.1728
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$0.9463)

1/ Three year normalized average Dk sales.

2/ Amount divided by 2008-2010 average interruptible sales volumes plus 2008-2010 average normalized firm sales volumes.

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

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JUNE 2011**

Rates Effective June 1, 2011	<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	17.8286	Per dk/Mo.
Trans Canada Pipeline Demand Charge	24.4629	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.8286	Per dk/Day
Trans Canada - Seasonal	24.4629	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:	4.1761	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	<u>5.1191</u>	Per Mcf
Total Firm Base Cost	\$5.1849	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
Volume No. 1

Part 5.0
Statement of Rates
v. 3.0.0 superseding v. 2.0.0

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

Issued: February 28, 2011
Effective: April 1, 2011

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

Part 5.0
Statement of Rates
v. 3.0.0 superseding v. 2.0.0

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	1.47%
Zone 1-2	\$0.0130	\$0.0019	\$0.0149	1.98%
Zone 2-2	\$0.0130	\$0.0019	\$0.0149	0.51%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0019	\$0.1387	1.47%
Zone 1-2	\$0.1737	\$0.0019	\$0.1756	1.98%
Zone 2-2	\$0.0834	\$0.0019	\$0.0853	0.51%
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: 0.17% for Zone 1-1, 0.22 % for Zone 1-2, and 0.05% 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		\$0.0265	

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

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

Second Revised Sheet No. 50
Superseding
First Revised Sheet No. 50

RATE SCHEDULE TF

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/		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF	Receipt Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
	Market	0.0383	0.0214			0.0175	0.0000	0.0383	0.0214
	Field	0.0383	0.0214	0.0122	0.0040	0.0175	0.0000		
	Market			0.0122	0.0040				
	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. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0005 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
Sixth Revised Volume No. 1

Second Revised Sheet No. 51
Superseding
First Revised Sheet No. 51

RATE SCHEDULES TFX and LFT

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	0.0383	0.0214			0.0175	0.0000	0.0383	0.0214
Field	Market	0.0383	0.0214	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. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0005 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.

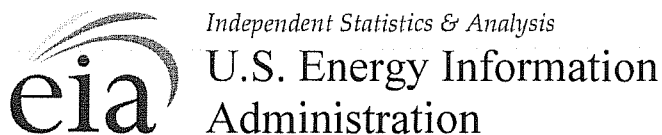
Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
June 2011

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

The threat of shut-in production arising from lower Mississippi River flooding offset by the seasonal decline in space heating load and relative light demand for electric generation contributed to the relative month over month price stability. The year over year price comparison indicates the anticipated June 2011 AECO price will be approximately ten percent higher than the June 2010 index price. The Energy Information Administration (EIA) reported storage levels nationwide as of May 20, 2011 were 1.3 percent below the five-year average and 10.2 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.



May 2011

Short-Term Energy Outlook

May 10, 2011 Release

Highlights

- West Texas Intermediate (WTI) crude oil spot prices averaged \$89 per barrel in February, \$103 per barrel in March, and \$110 per barrel in April. During the first week of May WTI crude oil prices fell by nearly \$17 per barrel to \$97 per barrel, along with a broad set of commodities, and then rebounded by almost \$6 per barrel yesterday. However, EIA still expects oil markets to tighten through 2012 given projected world oil demand growth and slowing growth in supply from countries that are not members of the Organization of the Petroleum Exporting Countries (OPEC). Projected WTI spot prices average \$103 per barrel in 2011 and \$107 per barrel in 2012, reductions of about \$4 and \$6 per barrel respectively from last month's *Outlook*.
- Despite the moderate downward revision to the outlook for oil prices, the rise in crude oil prices from last year continues to imply higher petroleum product prices this year compared with last. EIA forecasts that the annual average regular-grade retail gasoline price will increase from \$2.78 per gallon in 2010 to \$3.63 per gallon 2011 and to \$3.66 per gallon in 2012. The forecast regular-grade motor gasoline retail price averages \$3.81 per gallon during this summer's driving season (from April 1 through September 30), up from \$2.76 per gallon last summer, but 5 cents per gallon lower than last month's *Outlook*. The forecast U.S. monthly average regular gasoline price during the summer peaks in June at \$3.88 per gallon. Prices of futures and options contracts for wholesale gasoline over the 5 days ending May 5 suggest a 41-percent probability that the national monthly average retail price for regular gasoline could exceed \$4.00 per gallon during July 2011.
- Natural gas working inventories ended April 2011 at 1.8 trillion cubic feet (Tcf), about 11 percent, or 230 billion cubic feet (Bcf), below the 2010 end-of-April level. EIA expects that working gas inventories will build strongly during the summer and approach record-high levels in the second half of 2011. The projected Henry Hub natural gas spot price averages \$4.24 per million British thermal units (MMBtu) in 2011, \$0.15 per MMBtu lower than the 2010 average.

EIA expects the natural gas market to begin tightening in 2012, with the Henry Hub spot price increasing to an average of \$4.65 per MMBtu.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA projects that total world oil consumption will grow by 1.4 million barrels per day (bbl/d) in 2011, which is about 0.1 million bbl/d day lower than last month's *Outlook*, and 1.6 million bbl/d in 2012, slightly higher than forecast last month. Supply from non-OPEC countries increases by an average of about 0.6 million bbl/d annually through 2012, which is about 0.2 million bbl/d higher than in last month's *Outlook*. OECD inventory reports for the first quarter 2011 have come in higher than EIA projected in last month's *Outlook*. Consequently, while EIA still expects the market will rely on both a drawdown of inventories and increases in the production of crude oil and non-crude liquids in OPEC member countries to meet projected demand growth, the forecast for OPEC crude oil and liquid fuels production has been lowered from last month's *Outlook* by about 0.14 million bbl/d in 2011 and 0.5 million bbl/d in 2012.

Among the major uncertainties that could push oil prices above or below our current forecast are: continued unrest in producing countries and its potential impact on supply; decisions by key OPEC-member countries regarding their production in response to the global increase in oil demand; the rate of economic growth, both domestically and globally; fiscal issues facing national and sub-national governments; and China's efforts to address concerns regarding its growth and inflation rates.

Global Crude Oil and Liquid Fuels Consumption. World crude oil and liquid fuels consumption grew to 86.7 million bbl/d in 2010, surpassing the previous record of 86.3 million bbl/d set in 2007. EIA expects that world liquid fuels consumption will grow by 1.4 million bbl/d in 2011, followed by 1.6 million bbl/d growth in 2012, resulting in total world consumption of 89.7 million bbl/d in 2012 ([World Liquid Fuels Consumption Chart](#)). Countries outside the Organization for Economic Cooperation and Development (OECD) will make up almost all of the growth in consumption over the next two years, with the largest increases coming from China, Brazil, and the Middle East. EIA expects that, among the OECD nations, only the United States and Canada will show growth in oil consumption over the next two years, offsetting declines in OECD Europe and Japan.

Non-OPEC Supply. EIA projects that non-OPEC crude oil and liquid fuels production will increase by 690,000 bbl/d in 2011 and by 420,000 bbl/d in 2012 ([Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart](#)). The greatest increases in non-OPEC oil production during 2011 occur in Brazil, Canada, China, and countries that were

formerly part of the Soviet Union. EIA expects annual average production growth of 160,000 bbl/d in Brazil, 170,000 bbl/d in Canada, 140,000 bbl/d in China, and 250,000 bbl/d in the former Soviet Union countries in 2011. In 2012, EIA expects Canadian production to grow by 210,000 bbl/d, while production in China and Brazil grow by 140,000 and 110,000 bbl/d, respectively. Production growth in the former Soviet Union countries slows to 30,000 bbl/d in 2012. Other non-OPEC areas are expected to decline, including a decrease in European and North Sea production of 130,000 bbl/d in 2011 and a further decrease of 200,000 bbl/d in 2012.

OPEC Supply. Forecast OPEC crude oil production declines in 2011, falling by about 450,000 bbl/d, followed by an increase of 640,000 bbl/d in 2012. EIA assumes that about one-half of Libya's pre-disruption production will resume by the end of 2012. EIA projects that OPEC surplus capacity will fall from 3.9 million bbl/d at the end of 2010 to 3.6 million bbl/d at the end of 2011, followed by a further decline to 3.1 million bbl/d by the end of 2012 ([OPEC Surplus Crude Oil Production Capacity Chart](#)). Forecast OPEC non-crude liquids production increases by 0.8 million bbl/d in 2011 and by 0.4 million bbl/d in 2012.

OECD Petroleum Inventories. EIA expects that OECD onshore inventories will decline in 2011 following the steep drop in floating storage that has already occurred. Projected onshore OECD stocks fall by about 20 million barrels in 2011, followed by an additional 54 million barrel decline in 2012. Days of supply (total inventories divided by average daily consumption) drops from a relatively high 58.1 days during the fourth quarter of 2010 to 57.0 days in the fourth quarter 2011, and 55.7 days of supply in the fourth quarter 2012 ([Days of Supply of OECD Commercial Stocks Chart](#)).

Crude Oil Prices. EIA expects that WTI spot prices, which averaged \$79 per barrel in 2010, will average \$103 per barrel in 2011 and \$107 per barrel in 2012, reductions averaging about \$4 and \$6 per barrel respectively from last month's *Outlook* ([West Texas Intermediate Crude Oil Price Chart](#)). During the first week of May WTI crude oil prices fell by nearly \$17 per barrel to \$97 per barrel, along with a broad set of commodities, and then rebounded by almost \$6 per barrel yesterday. EIA still expects oil markets to tighten as growing liquid fuels demand in the emerging economies and slowing growth in non-OPEC supply maintain upward pressure on oil prices.

Growing volumes of Canadian crude oil imported into the United States contributed to record-high storage levels at Cushing, Oklahoma, and a price discount for WTI compared with similar quality world crudes such as Brent. Consequently, the projected U.S. refiner average acquisition cost of crude oil, which was about \$2.70 per

barrel below WTI in 2010, is \$1.80 per barrel above WTI in 2011 and \$1.10 per barrel above WTI in 2012.

Energy price forecasts tend to be highly uncertain ([Energy Price Volatility and Forecast Uncertainty](#)). WTI futures for July 2011 delivery over the 5-day period ending May 5 averaged \$110 per barrel and implied volatility averaged 29 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in July of \$91 per barrel and \$133 per barrel, respectively. Last year at this time, WTI for July 2010 delivery averaged \$83 per barrel and implied volatility averaged 33 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$67 per barrel and \$103 per barrel. Based on WTI futures and options prices, the probability that the monthly average price of WTI crude oil will exceed \$120 per barrel in December 2011 is about 31 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below \$90 per barrel is about 21 percent.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of liquid fuels increased by 380,000 bbl/d (2.0 percent) to 19.1 million bbl/d in 2010 ([U.S. Liquid Fuels Consumption Growth Chart](#)). The major sources of this consumption growth were distillate fuel oil (diesel fuel and heating oil), which grew by 160,000 bbl/d (4.5 percent), and motor gasoline, which increased by 40,000 bbl/d (0.4 percent). Projected total U.S. liquid fuels consumption increases by 140,000 bbl/d (0.7 percent) in 2011, and by a further 170,000 bbl/d (0.9 percent), to 19.5 million bbl/d, in 2012, which is still well below the record-high 20.8 million bbl/d in 2005.

In 2011, forecast distillate fuel consumption growth of almost 80,000 bbl/d (2.1 percent) accounts for over half of the forecast increase in liquid fuels consumption, while forecast growth in gasoline and jet fuel grow by just 16,000 bbl/d (0.2 percent) and 13,000 bbl/d (0.9 percent), respectively. In 2012 motor gasoline consumption rises by 75,000 bbl/d (0.8 percent), the highest growth rate since 2006, driven by growing population, rising employment, and rising income. Jet fuel consumption increases 23,000 bbl/d (1.6 percent) in 2012. In contrast, distillate fuel consumption growth moderates slightly to 66,000 bbl/d (1.7 percent) in 2012 as industrial output grows more slowly than in 2011.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 150,000 bbl/d in 2010 to 5.51 million bbl/d, declines by 20,000 bbl/d in 2011 and by a further 60,000 bbl/d in 2012 ([U.S. Crude Oil Production Chart](#)). EIA expects production from the Federal Gulf of Mexico (GOM) to fall by 130,000 bbl/d in

2011 and by a further 190,000 bbl/d in 2012 because of production declines from existing fields and the impact of last year's drilling moratorium and the subsequent delay in issuing new drilling permits. Projected Alaskan crude oil production falls by 80,000 bbl/d in 2011 and then shows no change in 2012. These production declines are offset by projected increases in lower-48 non-GOM production of 200,000 bbl/d in 2011 and 140,000 bbl/d in 2012 because of the increase in oil-directed onshore drilling activity. According to Baker Hughes Inc., the number of active non-GOM oil rigs has increased from 485 at the end of April 2010 to 918 at the end of April 2011.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010, primarily because of the decline in consumption during the recession and rising domestic production. EIA forecasts that liquid fuel net imports will average 9.4 million bbl/d in 2011 and 9.8 million bbl/d in 2012, representing 49 percent and 50 percent of total consumption, respectively.

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade retail gasoline price will increase from \$2.78 per gallon in 2010 to \$3.63 per gallon 2011 and to \$3.66 per gallon in 2012, reductions of 7 cents and 14 cents per gallon respectively from last month's *Outlook*. The sizable jump in retail prices this year reflects not only the higher average cost of crude oil but also an increase in U.S. refinery gasoline margins (the difference between refinery wholesale gasoline prices and the average cost of crude oil) from an average of \$0.34 per gallon in 2010 to \$0.50 per gallon in 2011, near the \$0.53 per gallon and \$0.56 per gallon highs set in 2006 and 2007, respectively. The projected refinery gasoline margin falls back to \$0.44 per gallon in 2012.

Motor gasoline prices vary widely by region. In the Gulf Coast (PADD 3), forecast retail prices average 14 cents per gallon below the national average, while prices on the West Coast (PADD 5) average more than 25 cents per gallon above the national average. The major reasons for that variation are differences in state taxes, the distance from alternative sources of supply, and differences in gasoline quality required by state and federal clean air regulations.

EIA expects that on-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, will average \$3.89 per gallon in 2011 and \$3.93 per gallon in 2012, reductions of 9 cents and 14 cents per gallon respectively from last month's *Outlook*. Projected U.S. refinery diesel fuel margins increase by 22 cents per gallon, from an average \$0.38 per gallon in 2010 to \$0.60 per gallon in 2011, then fall back to \$0.54 per gallon in 2012.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to grow by 0.5 percent to 66.5 billion cubic feet per day (Bcf/d) in 2011 ([U.S. Total Natural Gas Consumption Chart](#)). Forecast industrial consumption rises 1.9 percent to 18.4 Bcf/d in 2011, and electric power consumption rises 0.4 percent to 20.3 Bcf/d.

Projected total consumption increases by 0.7 percent in 2012 to 67.0 Bcf/d. Growth continues in the industrial and electric power sectors at 1.4 percent and 2.6 percent, respectively. Residential and commercial consumption each decline by 1.6 percent in 2012 stemming from forecast 2.2 percent reduction in natural gas-weighted heating degree-days.

U.S. Natural Gas Production and Imports. Marketed natural gas production has been growing steadily since 2005, primarily because of the boom in horizontal drilling in unconventional shale formations. EIA expects total marketed production to average 1.4 Bcf/d (2.3 percent) higher in 2011 compared with last year. Marketed natural gas production fell by 1.1 Bcf/d in February 2011 from the month before, but this drop can largely be attributed to temporary factors including seasonal maintenance in the GOM and colder-than-normal weather in Texas, New Mexico, Oklahoma, and Wyoming which caused freeze-offs (gas flow blockages resulting from water vapor freezing in the gas stream), forcing temporary shut downs to lower-48 onshore production (see [Today in Energy, February 23, 2011](#)). EIA expects production will recover from February levels but begin modest month-to-month declines that could continue through the year because of reductions in the number of active natural gas drilling rigs.

The number of rigs drilling for natural gas, as reported by Baker Hughes Inc., has fallen from 973 in April 2010 to 882 as of April 29, 2011. More rigs are being directed toward oil instead of gas largely because of the large price disparity between the two fuels on an energy-equivalent basis. On April 21, 2011, the number of active oil-directed rigs exceeded the number of gas-directed rigs for the first time since April 28, 1995.

The decline in drilling activity this year and forecast increase in consumption next year contribute to higher natural gas prices next year and a turnabout in drilling activity during 2012. EIA expects total marketed production to increase by 0.6 Bcf/d (0.9 percent) to 63.8 Bcf/d in 2012.

Growing domestic natural gas production continues to reduce reliance on natural gas imports. Because of the earthquake in Japan and subsequent nuclear generation outages, Japan's demand for liquefied natural gas (LNG) as a replacement fuel for

electric power generation is expected to increase, contributing to higher global LNG prices. Japan is already the largest importer of LNG in the world, with daily imports averaging more than 9 Bcf/d in 2010. EIA projects U.S. imports of LNG will average 0.9 Bcf/d in 2011, down 21 percent from 1.2 Bcf/d in 2010.

U.S. Natural Gas Inventories. On April 29, 2011, working natural gas in storage stood at 1,757 Bcf, which is 226 Bcf below last year's level in late April ([U.S. Working Natural Gas in Storage Chart](#)). Cold temperatures and production freeze-offs in January and February contributed to relatively large draws on inventories early in the year. EIA expects that inventories, though lower than last year, will remain robust given higher forecast production throughout the 2011 injection season. Projected inventories near 3.9 Tcf at the end of October 2011 because of high production levels and a mild summer relative to last year.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$4.25 per MMBtu in April, 28 cents higher than the March average and 25 cents higher than forecast in last month's *Outlook* ([Henry Hub Natural Gas Price Chart](#)). EIA expects that the Henry Hub price will average \$4.24 per MMBtu in 2011, a decline of 15 cents from the 2010 average. EIA expects that the forecast decline in production from current levels will contribute to a tightening domestic market next year with the Henry Hub price averaging \$4.65 per MMBtu in 2012.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for July 2011 delivery (for the 5-day period ending May 5) averaged \$4.65 per MMBtu, and the average implied volatility was 34 percent. The lower and upper bounds for the 95-percent confidence interval for July 2011 contracts are \$3.61 per MMBtu and \$5.98 per MMBtu. At this time last year, the natural gas July 2010 futures contract averaged \$4.11 per MMBtu and implied volatility averaged 46 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$2.95 per MMBtu and \$5.70 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA expects little change in total U.S. electricity consumption from 2010 to 2011 ([U.S. Total Electricity Consumption Chart](#)). Forecast cooler temperatures this summer compared with last year's hot summer drive the projected 2.5-percent decline in retail electricity sales to the residential sector. This decline in residential consumption is offset by projected increases in electricity sales to the industrial and commercial sectors of 3.2 percent and 0.7 percent, respectively. During 2012, forecast total U.S. electricity consumption grows by 2.4 percent.

U.S. Electricity Generation. EIA projects that total generation by the electric power sector will fall by 0.2 percent during 2011 ([U.S. Electric Power Sector Generation Growth Chart](#)). This slight decline in generation is offset by increased imports of electricity from Canada and Mexico. Heavy spring precipitation and higher-than-normal snowpack in the Pacific Northwest should drive U.S. hydroelectric generation to its highest level since 2006. In contrast, forecast coal-fired and nuclear generation decline by 2.2 percent and 1.6 percent, respectively, this year. EIA expects a 2.4-percent increase in total electric power sector generation in 2012, fueled primarily by increased coal and natural gas generation.

U.S. Electricity Retail Prices. EIA expects U.S. residential electricity prices to rise by 2.3 percent in 2011 to an average of 11.84 cents per kilowatthour ([U.S. Residential Electricity Prices Chart](#)). The forecast of flat coal and natural gas prices to the electric power sector this year should contribute to very little change in retail electricity prices during 2012.

Coal

U.S. Coal Consumption. Coal consumption in the electric power sector grew by 4.5 percent in 2010, primarily the result of higher electricity demand during the summer. EIA projects that coal consumption in the electric power sector will decrease by 0.7 percent in 2011, as electricity demand remains flat and generation from other energy sources increases. Forecast coal consumption in the electric power sector grows by 3.0 percent in 2012, falling just short of reaching 1 billion short tons. The electric power sector consumed an average of 1 billion short tons annually from 2003 through 2008 ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production in 2010 grew by only 1.0 percent despite the 5-percent increase in total U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase ([U.S. Electric Power Sector Coal Stocks Chart](#)). EIA projects that coal production will increase by 0.6 percent in 2011, followed by a 2.3-percent increase in 2012 ([U.S. Annual Coal Production Chart](#)).

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, resulted in sharp increases in U.S. coal exports in 2010. Metallurgical coal's share of total U.S. coal exports grew from 52 percent in 2008 to 69 percent in 2010. Supply disruptions in several key coal exporting countries have affected the amount of coal available on the world market. Consequently, EIA expects U.S. coal exports to increase in 2011, particularly in the first half of the year, reaching 93 million short tons (mmst). Forecast U.S. coal exports fall back to more typical historical levels (about 80 mmst) in 2012 as supply from other major coal-exporting countries recovers.

The strong global demand for coal outside the United States also contributed to a 14.5 percent decline in U.S. coal imports in 2010 (to 19.4 mmst) despite an increase in consumption. EIA expects the trend of lower U.S. coal imports to continue, with imports below 19 mmst in both 2011 and 2012. U.S. coal imports averaged about 31 mmst annually from 2004 through 2009.

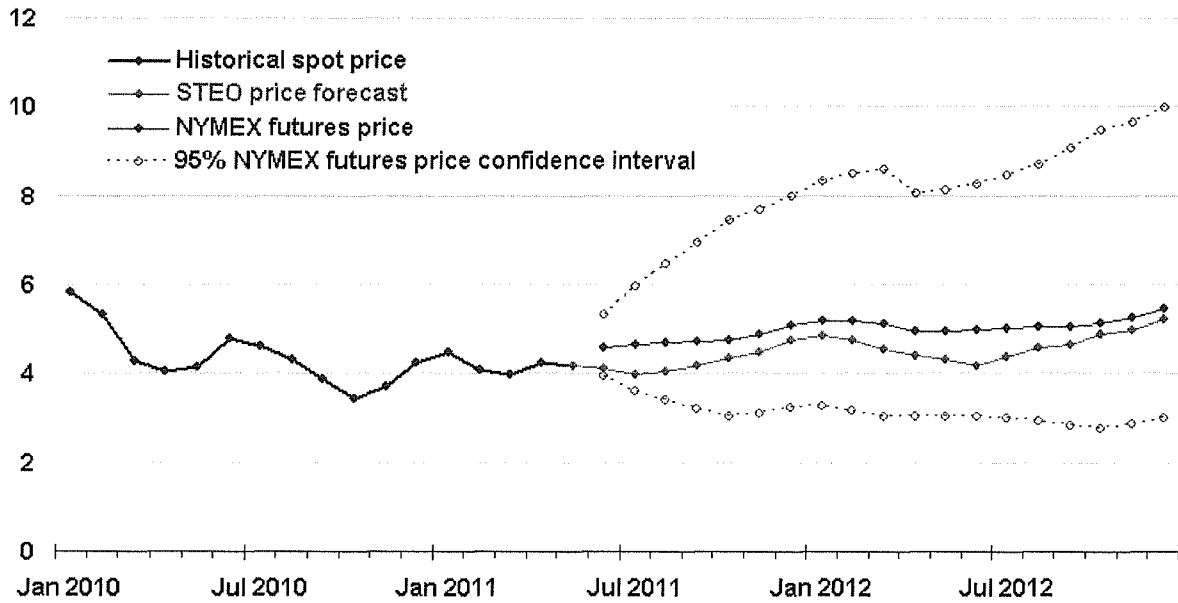
U.S. Coal Prices. Electric power sector delivered coal prices have been rising relatively steadily over the last 10 years, reflecting longer-term coal contracts initiated during a period of high energy prices, rising transportation costs, and increased consumption. However, EIA expects that the power sector coal price will remain stable in 2011 and 2012 as coal competes with natural gas for generation market share. The projected power-sector delivered coal price, which averaged \$2.26 per MMBtu in 2010, averages \$2.30 per MMBtu and \$2.28 per MMBtu in 2011 and 2012, respectively.

U.S. Carbon Dioxide Emissions

EIA estimates that fossil-fuel CO₂ emissions increased by 3.8 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Forecast fossil-fuel CO₂ emissions increase by 0.1 percent in 2011. Projected emission increases from higher petroleum and natural gas consumption are offset by declines in coal consumption. Expected increases in consumption of all fossil fuels in 2012 contribute to a 1.8-percent increase in fossil-fuel CO₂ emissions.

Henry Hub Natural Gas Price

dollars per million btu

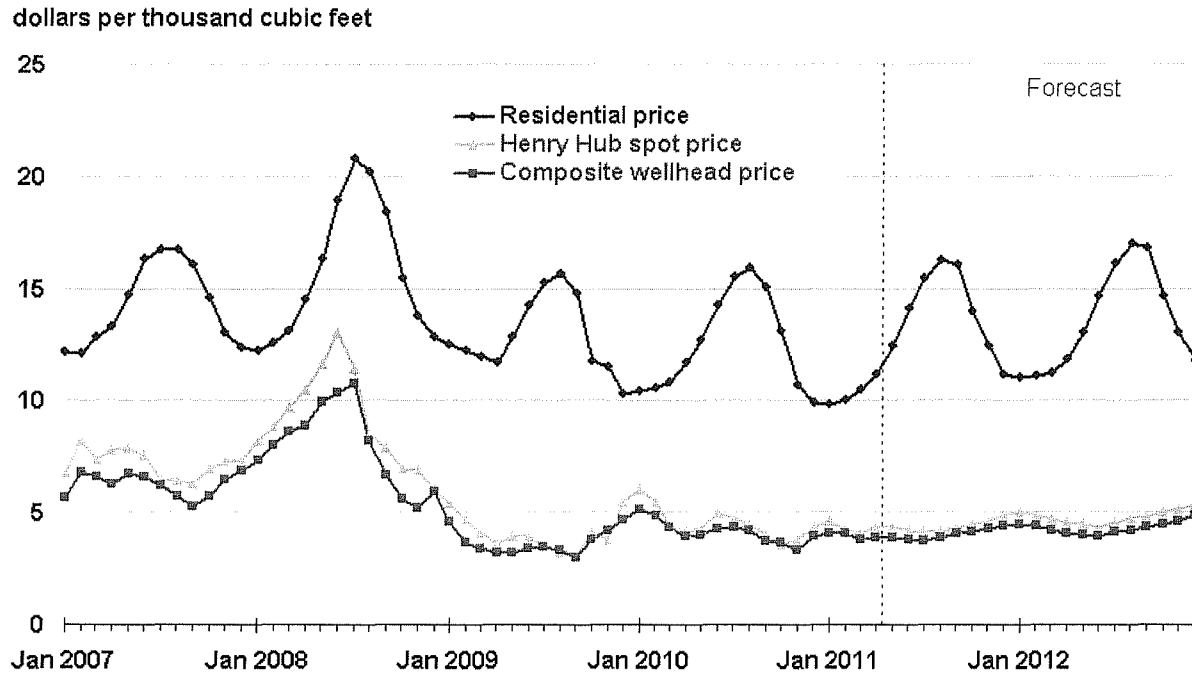


*Note: Confidence interval derived from options market information for 5 trading days ending May 5, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, May 2011



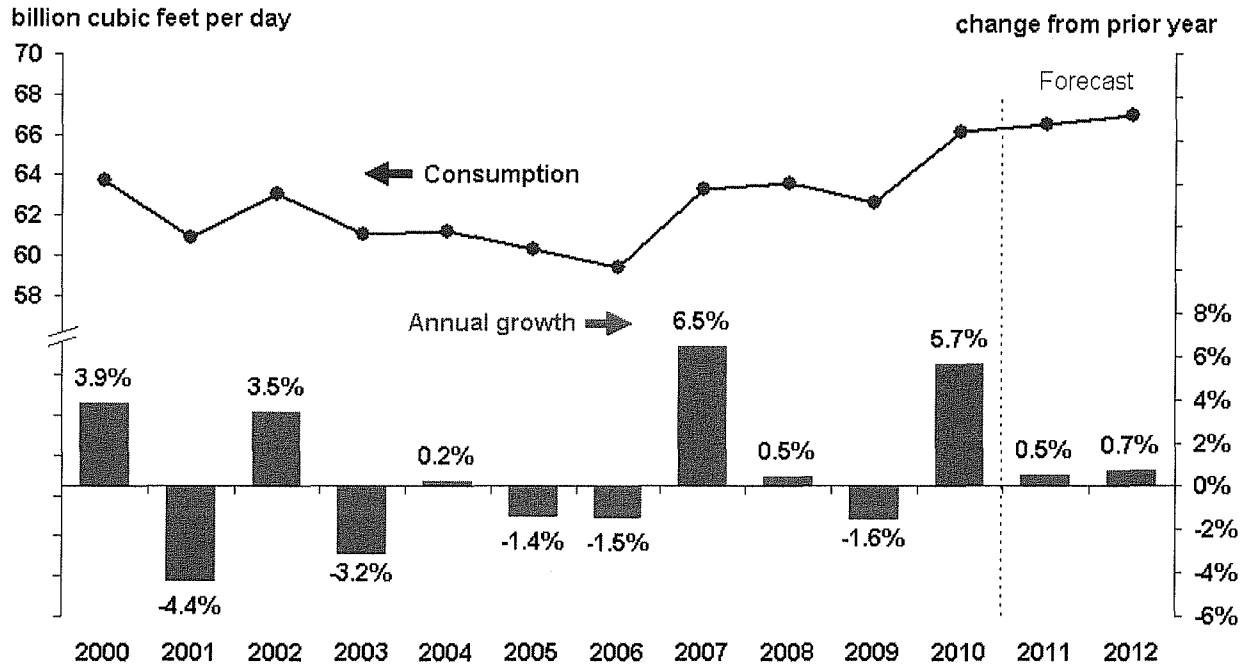
Natural Gas Prices



Source: Short-Term Energy Outlook, May 2011



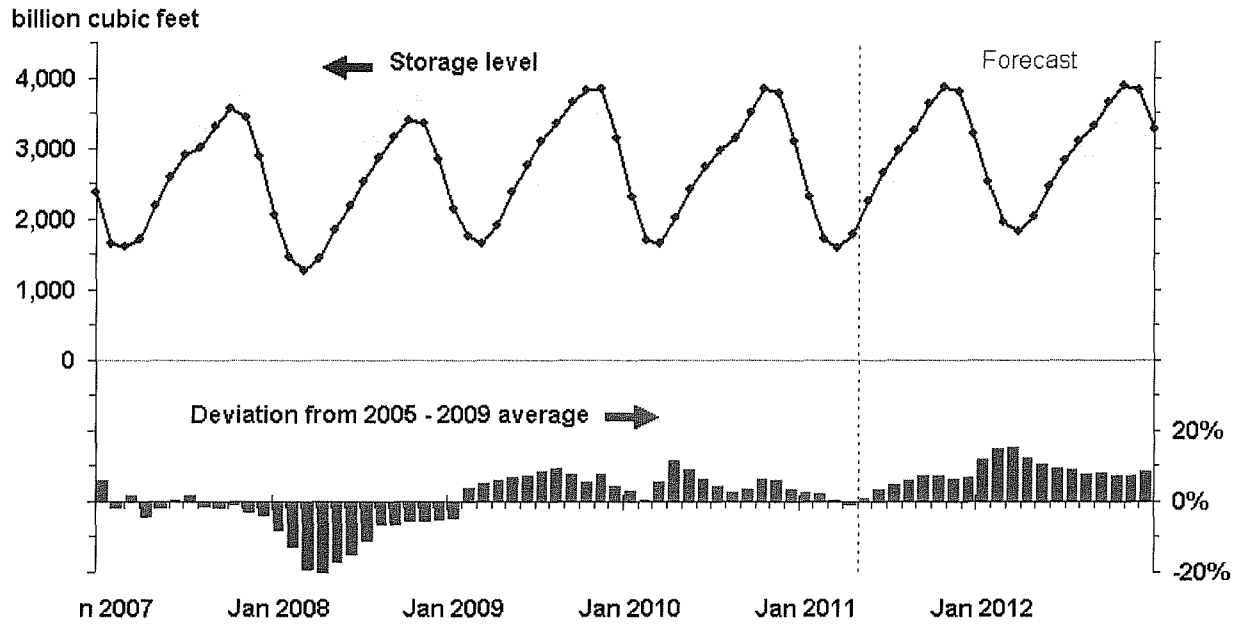
U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, May 2011



U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010

Source: Short-Term Energy Outlook, May 2011



**GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE JUNE 1, 2011 THROUGH MAY 31, 2012**

(Over)/under recovered gas costs @ April 30, 2011: \$148,188

Less projected recovery from rates already established:

	Volume	Rate	Amount
May	10,700	\$0.3941	\$4,217

Additional recovery required \$143,971

Projected sales volumes (mcf)

June 2011	6,400	
July	5,700	
August	6,000	
September	8,900	
October	18,000	
November	31,600	
December	45,500	
January 2012	51,800	
February	42,700	
March	34,800	
April	20,200	
May	10,600	
Total		<u>282,200</u>

Total gas cost reconciliation adjustment
to be effective June 1, 2011 through May 31, 2012 \$0.5102

**GREAT PLAINS NATURAL GAS CO.
GAS COST RECONCILIATION ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE JUNE 1, 2011 THROUGH MAY 31, 2012**

(Over)/under recovered gas costs @ April 30, 2011: (\$5,922)

Less projected recovery from rates already established:

	Volume	Rate	Amount
May	10,900	(\$0.1136)	(\$1,238)

Additional recovery required (\$4,684)

Projected sales volumes (mcf)

June 2011	11,800		
July	10,600		
August	9,500		
September	14,000		
October	27,000		
November	36,000		
December	29,000		
January 2012	17,400		
February	28,700		
March	34,000		
April	34,000		
May	10,900		
Total			<u>262,900</u>

Total gas cost reconciliation adjustment
to be effective June 1, 2011 through May 31, 2012 (\$0.0178)

**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 2/	Cumulative Balance
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 3/	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
November	23,805	0	2,602	26,407	17,808	0.3941	7,019	19,388	401,682
December	(6,120)	0	2,728	(3,392)	38,100	0.3941	15,014	(18,406)	383,276
January 2011	(60,299)	0	2,587	(57,712)	47,283	0.3941	18,633	(76,345)	306,931
February	(63,560)	0	2,033	(61,527)	48,059	0.3941	18,940	(80,467)	226,464
March	(31,931)	0	1,453	(30,478)	42,816	0.3941	16,874	(47,352)	179,112
April	(20,497)	0	1,114	(19,383)	29,284	0.3941	11,541	(30,924)	148,188
	<u>\$116,627</u>	<u>\$0</u>	<u>\$20,352</u>	<u>\$136,979</u>	<u>270,718</u>		<u>\$103,779</u>	<u>\$33,200</u>	
Balance @ April 30, 2011									<u>\$148,188</u>

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

2/ Total net additions less total adjustment amount.

3/ 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**

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change 2/	Cumulative Balance
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) 3/	(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)
November	4,335	0	(170)	4,165	36,122	(0.1136)	(4,104)	8,269	(14,537)
December	6,272	0	(119)	6,153	29,056	(0.1136)	(3,301)	9,454	(5,083)
January 2011	(971)	0	(58)	(1,029)	17,350	(0.1136)	(1,971)	942	(4,141)
February	3,038	0	(56)	2,982	28,670	(0.1136)	(3,257)	6,239	2,098
March	(3,891)	0	(19)	(3,910)	34,060	(0.1136)	(3,870)	(40)	2,058
April	(11,813)	0	(28)	(11,841)	33,991	(0.1136)	(3,861)	(7,980)	(5,922)
	<u>(\$15,784)</u>	<u>\$0</u>	<u>(\$1,637)</u>	<u>(\$17,421)</u>	<u>262,990</u>		<u>(\$42,089)</u>	<u>\$24,668</u>	
Balance @ April 30, 2011									<u>(\$5,922)</u>

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

2/ Total net additions less total adjustment amount.

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

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	1/	2/	3/	Total
<u>May 2010</u>				
Cost of Gas - Actual	\$9.15520	\$9.46680	\$9.15520	
Cost of Gas - Recovered	7.15640	6.97370	6.97370	
(Over) Under recovery per dk	<u>\$1.99880</u>	<u>\$2.49310</u>	<u>\$2.18150</u>	
dk billed	4,923	11,032	(3,489)	12,466
(Over) Under recovery	<u>\$9,840</u>	<u>\$27,505</u>	<u>(\$7,611)</u>	<u>\$29,734</u>
<u>June 2010</u>				
Cost of Gas - Actual	\$10.38120	\$9.15520	\$10.38120	
Cost of Gas - Recovered	7.02140	7.15640	7.15640	
(Over) Under recovery per dk	<u>\$3.35980</u>	<u>\$1.99880</u>	<u>\$3.22480</u>	
dk billed	2,560	12,944	(7,193)	8,311
(Over) Under recovery	<u>\$8,601</u>	<u>\$25,872</u>	<u>(\$23,196)</u>	<u>\$11,277</u>
<u>July 2010</u>				
Cost of Gas - Actual	\$22.38540	\$10.38120	\$22.38540	
Cost of Gas - Recovered	7.62100	7.02140	7.02140	
(Over) Under recovery per dk	<u>\$14.76440</u>	<u>\$3.35980</u>	<u>\$15.36400</u>	
dk billed	2,235	6,109	(2,144)	6,200
(Over) Under recovery	<u>\$32,995</u>	<u>\$20,526</u>	<u>(\$32,936)</u>	<u>\$20,585</u>
<u>August 2010</u>				
Cost of Gas - Actual	\$18.20540	\$22.38540	\$18.20540	
Cost of Gas - Recovered	7.27460	7.62100	7.62100	
(Over) Under recovery per dk	<u>\$10.93080</u>	<u>\$14.76440</u>	<u>\$10.58440</u>	
dk billed	2,322	5,487	(1,856)	5,953
(Over) Under recovery	<u>\$25,382</u>	<u>\$81,009</u>	<u>(\$19,644)</u>	<u>\$86,747</u>
<u>September 2010</u>				
Cost of Gas - Actual	\$12.38970	\$18.20540	\$12.38970	
Cost of Gas - Recovered	6.70570	7.27460	7.27460	
(Over) Under recovery per dk	<u>\$5.68400</u>	<u>\$10.93080</u>	<u>\$5.11510</u>	
dk billed	2,446	4,917	(995)	6,368
(Over) Under recovery	<u>\$13,902</u>	<u>\$83,410</u>	<u>(\$5,092)</u>	<u>\$92,220</u>
<u>October 2010</u>				
Cost of Gas - Actual	\$8.94250	\$12.38970	\$8.94250	
Cost of Gas - Recovered	7.10980	6.70570	6.70570	
(Over) Under recovery per dk	<u>\$1.83270</u>	<u>\$5.68400</u>	<u>\$2.23680</u>	
dk billed	3,047	5,177	(154)	8,070
(Over) Under recovery	<u>\$5,584</u>	<u>\$29,426</u>	<u>(\$344)</u>	<u>\$34,666</u>

**GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>November 2010</u>				
Cost of Gas - Actual	\$7.66940	\$8.94250	\$7.66940	
Cost of Gas - Recovered	6.90340	7.10980	7.10980	
(Over) Under recovery per dk	<u>\$0.76600</u>	<u>\$1.83270</u>	<u>\$0.55960</u>	
dk billed	7,164	9,709	935	17,808
(Over) Under recovery	<u>\$5,488</u>	<u>\$17,794</u>	<u>\$523</u>	<u>\$23,805</u>
<u>December 2010</u>				
Cost of Gas - Actual	\$6.61790	\$7.66940	\$6.61790	
Cost of Gas - Recovered	7.65380	6.90340	6.90340	
(Over) Under recovery per dk	<u>(\$1.03590)</u>	<u>\$0.76600</u>	<u>(\$0.28550)</u>	
dk billed	14,764	15,061	8,275	38,100
(Over) Under recovery	<u>(\$15,294)</u>	<u>\$11,537</u>	<u>(\$2,363)</u>	<u>(\$6,120)</u>
<u>January 2011</u>				
Cost of Gas - Actual	\$6.18610	\$6.61790	\$6.18610	
Cost of Gas - Recovered	7.72660	7.65380	7.65380	
(Over) Under recovery per dk	<u>(\$1.54050)</u>	<u>(\$1.03590)</u>	<u>(\$1.46770)</u>	
dk billed	15,899	23,750	7,634	47,283
(Over) Under recovery	<u>(\$24,492)</u>	<u>(\$24,603)</u>	<u>(\$11,204)</u>	<u>(\$60,299)</u>
<u>February 2011</u>				
Cost of Gas - Actual	\$6.96590	\$6.18610	\$6.96590	
Cost of Gas - Recovered	7.81220	7.72660	7.72660	
(Over) Under recovery per dk	<u>(\$0.84630)</u>	<u>(\$1.54050)</u>	<u>(\$0.76070)</u>	
dk billed	14,572	33,027	460	48,059
(Over) Under recovery	<u>(\$12,332)</u>	<u>(\$50,878)</u>	<u>(\$350)</u>	<u>(\$63,560)</u>
<u>March 2011</u>				
Cost of Gas - Actual	\$6.97640	\$6.96590	\$6.97640	
Cost of Gas - Recovered	7.53970	7.81220	7.81220	
(Over) Under recovery per dk	<u>(\$0.56330)</u>	<u>(\$0.84630)</u>	<u>(\$0.83580)</u>	
dk billed	15,235	28,197	(616)	42,816
(Over) Under recovery	<u>(\$8,582)</u>	<u>(\$23,864)</u>	<u>\$515</u>	<u>(\$31,931)</u>
<u>April 2011</u>				
Cost of Gas - Actual	\$7.70180	\$6.97640	\$7.70180	
Cost of Gas - Recovered	8.23410	7.53970	7.53970	
(Over) Under recovery per dk	<u>(\$0.53230)</u>	<u>(\$0.56330)</u>	<u>\$0.16210</u>	
dk billed	9,076	26,113	(5,905)	29,284
(Over) Under recovery	<u>(\$4,831)</u>	<u>(\$14,709)</u>	<u>(\$957)</u>	<u>(\$20,497)</u>

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.

**GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>May 2010</u>				
Cost of Gas - Actual	\$3.66690	\$4.19460	\$3.66690	
Cost of Gas - Recovered	3.92480	3.87430	3.87430	
(Over) Under recovery per dk	<u>(\$0.25790)</u>	<u>\$0.32030</u>	<u>(\$0.20740)</u>	
dk billed	6,313	5,995	(1,364)	10,944
(Over) Under recovery	<u>(\$1,628)</u>	<u>\$1,921</u>	<u>\$283</u>	<u>\$576</u>
<u>June 2010</u>				
Cost of Gas - Actual	\$1.98810	\$3.66690	\$1.98810	
Cost of Gas - Recovered	3.74290	3.92480	3.92480	
(Over) Under recovery per dk	<u>(\$1.75480)</u>	<u>(\$0.25790)</u>	<u>(\$1.93670)</u>	
dk billed	3,315	8,130	363	11,808
(Over) Under recovery	<u>(\$5,817)</u>	<u>(\$2,097)</u>	<u>(\$703)</u>	<u>(\$8,617)</u>
<u>July 2010</u>				
Cost of Gas - Actual	\$3.91480	\$1.98810	\$3.91480	
Cost of Gas - Recovered	4.05610	3.74290	3.74290	
(Over) Under recovery per dk	<u>(\$0.14130)</u>	<u>(\$1.75480)</u>	<u>\$0.17190</u>	
dk billed	2,921	4,884	2,807	10,612
(Over) Under recovery	<u>(\$413)</u>	<u>(\$8,571)</u>	<u>\$483</u>	<u>(\$8,501)</u>
<u>August 2010</u>				
Cost of Gas - Actual	\$3.62090	\$3.91480	\$3.62090	
Cost of Gas - Recovered	3.70250	4.05610	4.05610	
(Over) Under recovery per dk	<u>(\$0.08160)</u>	<u>(\$0.14130)</u>	<u>(\$0.43520)</u>	
dk billed	2,643	5,708	1,115	9,466
(Over) Under recovery	<u>(\$216)</u>	<u>(\$806)</u>	<u>(\$485)</u>	<u>(\$1,507)</u>
<u>September 2010</u>				
Cost of Gas - Actual	\$2.77310	\$3.62090	\$2.77310	
Cost of Gas - Recovered	3.14680	3.70250	3.70250	
(Over) Under recovery per dk	<u>(\$0.37370)</u>	<u>(\$0.08160)</u>	<u>(\$0.92940)</u>	
dk billed	3,811	5,506	4,636	13,953
(Over) Under recovery	<u>(\$1,424)</u>	<u>\$6,155</u>	<u>(\$4,309)</u>	<u>\$422</u>
<u>October 2010</u>				
Cost of Gas - Actual	\$3.67500	\$2.77310	\$3.67500	
Cost of Gas - Recovered	3.55100	3.14680	3.14680	
(Over) Under recovery per dk	<u>\$0.12400</u>	<u>(\$0.37370)</u>	<u>\$0.52820</u>	
dk billed	9,729	6,024	11,205	26,958
(Over) Under recovery	<u>\$1,206</u>	<u>(\$2,251)</u>	<u>\$5,918</u>	<u>\$4,873</u>

GREAT PLAINS NATURAL GAS CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>November 2010</u>				
Cost of Gas - Actual	\$3.55600	\$3.67500	\$3.55600	
Cost of Gas - Recovered	<u>3.34300</u>	<u>3.55100</u>	<u>3.55100</u>	
(Over) Under recovery per dk	\$0.21300	\$0.12400	\$0.00500	
dk billed	<u>15,068</u>	<u>8,573</u>	<u>12,481</u>	36,122
(Over) Under recovery	<u>\$3,209</u>	<u>\$1,064</u>	<u>\$62</u>	<u>\$4,335</u>
<u>December 2010</u>				
Cost of Gas - Actual	\$3.94580	\$3.55600	\$3.94580	
Cost of Gas - Recovered	<u>3.95480</u>	<u>3.34300</u>	<u>3.34300</u>	
(Over) Under recovery per dk	(\$0.00900)	\$0.21300	\$0.60280	
dk billed	<u>11,731</u>	<u>10,431</u>	<u>6,894</u>	29,056
(Over) Under recovery	<u>(\$106)</u>	<u>\$2,222</u>	<u>\$4,156</u>	<u>\$6,272</u>
<u>January 2011</u>				
Cost of Gas - Actual	\$4.11810	\$3.94580	\$4.11810	
Cost of Gas - Recovered	<u>4.00580</u>	<u>3.95480</u>	<u>3.95480</u>	
(Over) Under recovery per dk	\$0.11230	(\$0.00900)	\$0.16330	
dk billed	<u>3,909</u>	<u>20,922</u>	<u>(7,481)</u>	17,350
(Over) Under recovery	<u>\$439</u>	<u>(\$188)</u>	<u>(\$1,222)</u>	<u>(\$971)</u>
<u>February 2011</u>				
Cost of Gas - Actual	\$4.18520	\$4.11810	\$4.18520	
Cost of Gas - Recovered	<u>4.20970</u>	<u>4.00580</u>	<u>4.00580</u>	
(Over) Under recovery per dk	(\$0.02450)	\$0.11230	\$0.17940	
dk billed	<u>6,597</u>	<u>11,323</u>	<u>10,750</u>	28,670
(Over) Under recovery	<u>(\$162)</u>	<u>\$1,271</u>	<u>\$1,929</u>	<u>\$3,038</u>
<u>March 2011</u>				
Cost of Gas - Actual	\$3.82540	\$4.18520	\$3.82540	
Cost of Gas - Recovered	<u>3.90380</u>	<u>4.20970</u>	<u>4.20970</u>	
(Over) Under recovery per dk	(\$0.07840)	(\$0.02450)	(\$0.38430)	
dk billed	<u>9,863</u>	<u>17,179</u>	<u>7,018</u>	34,060
(Over) Under recovery	<u>(\$773)</u>	<u>(\$421)</u>	<u>(\$2,697)</u>	<u>(\$3,891)</u>
<u>April 2011</u>				
Cost of Gas - Actual	\$3.45160	\$3.82540	\$3.45160	
Cost of Gas - Recovered	<u>4.03830</u>	<u>3.90380</u>	<u>3.90380</u>	
(Over) Under recovery per dk	(\$0.58670)	(\$0.07840)	(\$0.45220)	
dk billed	<u>13,722</u>	<u>14,455</u>	<u>5,814</u>	33,991
(Over) Under recovery	<u>(\$8,051)</u>	<u>(\$1,133)</u>	<u>(\$2,629)</u>	<u>(\$11,813)</u>

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2/ Consumed in prior month.

3/ True-up of prior month volumes.