

August 31, 2011

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

Re: Cost of Gas Adjustment (COG)  
September 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 (66<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (66<sup>th</sup> Revised Sheet No. 8), showing the September 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.1277 per mcf for residential and firm general service customers and \$0.2030 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for September 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.2030 per mcf since the last COG filing due to an decrease in the market price of gas. There has been an increase in pipeline charges of \$0.0753 per mcf due to changes in pipeline rates. The net effect of these changes is an decrease of \$0.1277 per mcf for residential and firm general service customers.

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

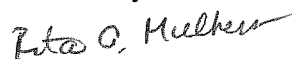
Attachment D shows the calculation of the balancing account since April 30, 2011.

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  
66th Revised Sheet No. 1.1

Canceling 65th 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	\$8.6912	\$9.9652 9.7452
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.8683	\$5.0074 4.7614 4.6094
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.8683	\$5.1074
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

**Date Filed:** August 31, 2011

**Effective Date:** September 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  
66<sup>th</sup> Revised Sheet No. 8  
Canceling 65<sup>th</sup> 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.	4.1683	(1.0445)	0.5102	3.6340	(1.0300)	(0.0178)	(1.0478)
Current Adj.	0.0753	(0.2030)	0.0000	(0.1277)	(0.2030)	0.0000	(0.2030)
Total Adj.	4.2436	(1.2475)	0.5102	3.5063	(1.2330)	(0.0178)	(1.2508)
Total Rate:	\$4.3094	\$3.8716	\$0.5102	\$8.6912	\$3.8861	(\$0.0178)	\$3.8683

**Date Filed:** August 31, 2011

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Regulatory Affairs Manager

**Case No.:**

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

Firm	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
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	17.8070	12	1,698,147	1.2103
Trans Canada - Demand Charge	7,947	24.5375	12	2,339,994	1.6677
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068	17.8070	5	451,229	0.3216
Trans Canada - Seasonal	5,068	24.5375	5	621,780	0.4431
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	0.0145
Total Demand Charges				\$6,026,154	4.3094
Estimated Weighted Average Commodity Cost	1,403,100	1/ 3.8716		5,432,242	3.8716
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				\$11,458,396	8.6912
Base Cost of Gas					5.1849
Accumulated Adjustment					\$3.5063
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.8716
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					3.8683
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.2508)

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.

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

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

<b>Rates Effective September 1, 2011</b>	<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	17.8070	Per dk/Mo.
Trans Canada Pipeline Demand Charge	24.5375	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.8070	Per dk/Day
Trans Canada - Seasonal	24.5375	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:	3.8716	Per dk

<b>Base Rate Effective September 1, 1981</b>		
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	<u>5.1191</u>	Per Mcf
Total Firm Base Cost	\$5.1849	Per Mcf

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

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

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. 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/
<b>Commodity Rates</b>				
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

RATE SCHEDULE TF

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	0.0383	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

- 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.

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages -----
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.85%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.20% 4/ 5/
FDD Storage Fuel	1.21%
	Electric Compression -----
COMMODITY RATES:	1/
Market Area	\$0.0005
Field Area	\$0.0000

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2010.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD & SMS

Rate Schedule FDD

-----		
Maximum Reservation Fee	1.7140	1/
Maximum Capacity Fee	0.3567	1/
Injection Charge - Firm	0.0149	
Withdrawal Charge - Firm	0.0149	
Annual Rollover Fee	0.3567	1/

Rate Schedule PDD

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Maximum Capacity Fee	0.3567	1/
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/

Rate Schedule IDD

-----		
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/

Rate Schedule SMS

-----		
Reservation Fee	2.1800	
Commodity Rate	0.0208	

1/ Minimum Rate is zero.

**Great Plains Natural Gas Co.  
Market Conditions for Wahpeton's Natural Gas  
September 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 September monthly price for the AECO Index is expected to decrease 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).

A combination of cooler weather and increased storage injections, as a result of continued strong production from the domestic shale plays, is expected to result in a slight decrease in the weighted average AECO price. The Energy Information Administration (EIA) reported storage levels nationwide as of August 19, 2011 were 1.9 percent below the five-year average and 4.6 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.



Independent Statistics & Analysis  
U.S. Energy Information  
Administration

August 2011

## Short-Term Energy Outlook

August 9, 2011 Release

### Highlights

- EIA expects the U.S. average refiner acquisition cost of crude oil will rise from \$100 per barrel in 2011 to \$107 per barrel in 2012 as global spare production capacity and inventories continue to decline. This forecast assumes that U.S. real gross domestic product (GDP) grows by 2.4 percent this year and 2.6 percent next year, while world oil-consumption-weighted real GDP grows by 3.4 and 4.1 percent in 2011 and 2012, respectively. These assumptions do not fully reflect recent economic and financial developments that point towards a weaker economic outlook and also contributed to a sharp drop in world crude oil prices during the first week of August. There is a significant downside risk for oil prices if economic and financial market concerns become more widespread or take hold.
- The regular-grade gasoline monthly average retail price fell from \$3.91 per gallon in May to \$3.65 per gallon in July, reflecting the decline in crude oil prices from their April peak and a recovery from unexpected refinery outages. Projected regular-grade gasoline prices average \$3.58 per gallon and \$3.44 per gallon in the third and fourth quarters of 2011, respectively, about 6 cents per gallon below last month's *Outlook*.
- Extremely hot weather settled on much of the Nation last month, with U.S. population-weighted cooling degree-days 27 percent higher than the 30-year normal and 8 percent higher than last year, which contributed to an increase in natural gas consumption for electricity generation compared with July 2010. Nevertheless, the estimated 246 billion cubic feet (Bcf) increase in natural gas working inventories during July 2011 was 21 Bcf higher than during the same month last year. Natural gas working inventories ended July 2011 at 2.8 trillion cubic feet (Tcf), about 7 percent, or 194 Bcf, below the 2010 end-of-July level. EIA expects that working natural gas inventories will build strongly, approaching last year's high levels by the end of this year's inventory build season. 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 \$4.41 per MMBtu.

## Global Crude Oil and Liquid Fuels

***Crude Oil and Liquid Fuels Overview.*** Global oil demand growth, led by China, is expected to outpace the growth in supplies from countries outside of the Organization of the Petroleum Exporting Countries (OPEC), leading markets to rely on both a drawdown of inventories and production increases in OPEC countries to close the gap. However, OPEC countries are not expected to markedly increase production over the next few months.

Among the major upside risks in the crude oil price outlook are additional supply disruptions in producing regions and higher-than-expected demand growth, particularly in the countries that are not members of the Organization for Economic Co-operation and development (OECD). Downside risks for oil prices include the rate of global economic recovery and fiscal issues facing national and sub-national governments.

***Global Crude Oil and Liquid Fuels Consumption.*** World crude oil and liquid fuels consumption grew to a record high 86.8 million barrels per day (bbl/d) in 2010. Despite continued concerns over the pace of the global economic recovery, particularly in OECD countries, EIA expects that world consumption to grow by 1.4 million bbl/d in 2011 and by 1.6 million bbl/d in 2012, outpacing average global demand growth of 1.3 million bbl/d from 1998-2007, prior to the onset of the global economic downturn ([World Liquid Fuels Consumption Chart](#)). Countries outside the OECD make up almost all of the projected growth in consumption over the next two years, with China accounting for almost half of this growth. Chinese oil demand continues to show strong growth despite Chinese measures to cool its economy down, and EIA's projections for Chinese oil demand growth have again been revised upwards.

***Non-OPEC Supply.*** EIA projects that non-OPEC crude oil and liquid fuels production will increase by an average 650 thousand bbl/d in 2011 and 2012 ([Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart](#)). The greatest increases in non-OPEC oil production during 2011 and 2012 occur in Brazil, Canada, China, Columbia, Kazakhstan, and the United States, with annual average growth in each country of over 100 thousand bbl/d. At the same time, EIA expects production declines this year in the North Sea region of 140 thousand bbl/d, particularly in the United Kingdom, as well as declines in Yemen of 140 thousand bbl/d stemming from ongoing strife.

**OPEC Supply.** Forecast OPEC crude oil production is unchanged from last month's *Outlook*. EIA expects OPEC crude oil production will decline by about 250 thousand bbl/d in 2011, in large part due to the supply disruption in Libya. EIA assumes that about one-half of Libya's pre-disruption production will resume by the end of 2012, contributing to an overall increase in OPEC production of 500 thousand bbl/d in 2012. EIA projects that OPEC surplus crude oil production capacity will fall from 4.0 million bbl/d at the end of 2010 to 3.5 million bbl/d at the end of 2011, followed by a further decline to 3.3 million bbl/d by the end of 2012 ([OPEC Surplus Crude Oil Production Capacity Chart](#)). Forecast OPEC non-crude liquids production, which is not subject to production targets, is expected to increase by 520 thousand bbl/d in 2011 and by 410 thousand bbl/d in 2012.

**OECD Petroleum Inventories.** EIA expects that OECD commercial inventories will decline in both 2011 and 2012. Days of supply (total inventories divided by average daily consumption) drop from a relatively high 58 days during the fourth quarter of 2010 to 56 days and 55 days in the fourth quarters of 2011 and 2012, respectively ([Days of Supply of OECD Commercial Stocks Chart](#)).

**Crude Oil Prices.** West Texas Intermediate (WTI) crude oil spot prices fell from an average of \$110 per barrel in April to \$97 per barrel in July. During the first week of August, world crude oil prices fell by about \$10 per barrel reflecting market concerns about world economic and oil demand growth. However, EIA still expects oil markets to tighten as growing liquid fuels demand in emerging economies continues to outpace supply growth with continuing upward pressure on oil prices. EIA expects that WTI spot prices, which averaged \$79 per barrel in 2010, will average \$96 per barrel in 2011 and \$101 per barrel in 2012, while the U.S. refiner average crude oil acquisition cost is projected to average \$100 and \$107 per barrel in 2011 and 2012, respectively ([West Texas Intermediate Crude Oil Price Chart](#)).

Energy price forecasts are highly uncertain ([Market Prices and Uncertainty Report](#)). WTI futures for October 2011 delivery over the 5-day period ending August 4 averaged \$93 per barrel and implied volatility averaged 33 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in October of \$75 per barrel and \$116 per barrel, respectively. Last year at this time, WTI for October 2010 delivery averaged \$82 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$67 per barrel and \$100 per barrel.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** Total consumption of liquid fuels in 2010 grew by 410 thousand bbl/d, or 2.2 percent, the highest rate of growth since 2004 ([U.S. Liquid Fuels Consumption Growth Chart](#)). In contrast, projected total U.S. liquid fuels consumption in 2011 falls by 150 thousand bbl/d (0.8 percent), a reversal of the small 30 thousand bbl/d increase projected in last month's *Outlook*. Motor gasoline and distillate fuel each account for about one-fourth of the change.

EIA expects total liquid fuels consumption to increase by 170 thousand bbl/d (0.9 percent) to 19.2 million bbl/d in 2012, with motor gasoline consumption rising by 50 thousand bbl/d (0.6 percent) and distillate fuel consumption increasing by 70 thousand bbl/d (1.8 percent) as economic growth improves and retail liquid fuels prices show only small increases from this year.

**U.S. Liquid Fuels Supply and Imports.** Domestic crude oil production, which increased 110 thousand bbl/d in 2010 to 5.5 million bbl/d, increases by a further 100 thousand bbl/d in 2011 and 80 thousand bbl/d in 2012 ([U.S. Crude Oil Production Chart](#)), driven by production resulting from increased oil-directed drilling activity in unconventional shale formations.

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 because of rising domestic production and the decline in consumption during the economic downturn. EIA forecasts that liquid fuel net imports' share of total consumption will decline further to 47 percent in 2011 before rising slightly to 48 percent in 2012.

**U.S. Petroleum Product Prices.** EIA forecasts that the annual average regular-grade gasoline retail price will increase from \$2.78 per gallon in 2010 to \$3.53 per gallon in 2011 and to \$3.64 per gallon in 2012 due to increases in oil prices. The increase in retail prices reflects not only the higher cost of crude oil but also changes in average U.S. refinery gasoline margin (the difference between refinery wholesale gasoline prices and the average cost of crude oil) from \$0.34 per gallon in 2010 to \$0.48 per gallon in 2011 and \$0.43 per gallon in 2012.

EIA expects that on-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, will average \$3.83 per gallon in 2011 and \$3.96 per gallon in 2012. Projected U.S. refinery diesel fuel margins increase from an average of \$0.38 per gallon in 2010 to \$0.62 per gallon in 2011, then fall to an average of \$0.55 per gallon in 2012.

**U.S. Inventories.** Commercial crude oil inventory levels ended July at an estimated 354 million barrels, down 3 million barrels from last year but still 21 million barrels

higher than the previous five-year average for that month. Following the release of about 31 million barrels of crude oil from the U.S. Strategic Petroleum Reserve (SPR), commercial crude oil stocks are expected to rise to about 369 million barrels by the end of September 2011, about 40 million barrels higher than the previous five-year average. Crude oil stocks are gradually drawn down to near their five-year averages by the end of 2012.

In contrast, refined product inventories have moved closer to their five-year averages since the beginning of this year and are expected to remain so through next year. Total motor gasoline stocks at the end of July 2011 were an estimated 215 million barrels, down 5 million barrels from last year but 4 million barrels above the previous five-year average for that month. Distillate fuel oil stocks ended July at 153 million barrels, down 14 million barrels from last year but 7 million barrels above the previous five-year average. Projected total motor gasoline and distillate inventories in 2012 average about 4 million barrels and 7 million barrels higher than the previous five-year average, respectively, as higher-than-normal stock levels are maintained to support continuing strong export markets.

## Natural Gas

***U.S. Natural Gas Consumption.*** EIA expects that total natural gas consumption will grow by 1.8 percent to 67.4 billion cubic feet per day (Bcf/d) in 2011 ([U.S. Total Natural Gas Consumption Chart](#)). Forecast industrial and electric power consumption growth make up most of the increase, with expected increases in 2011 to 18.4 Bcf/d (1.7 percent) and 21.0 Bcf/d (3.7 percent), respectively.

Extremely hot weather seen in July throughout most of the country contributed to an increase in consumption of natural gas for electric power generation to meet increased cooling demand. This month's *Outlook* raises the forecast of consumption of natural gas for power generation for the third quarter of 2011 to 28.3 Bcf/d (a 4.2-percent increase from the previous month's forecast of 27.2 Bcf/d) corresponding to an 11-percent increase in projected third quarter cooling degree-days from last month's forecast.

Projected total consumption increases slightly in 2012 to 67.8 Bcf/d. Expected growth in the industrial and electric power sectors offsets projected declines in residential and commercial consumption due to anticipated warmer winter weather.

***U.S. Natural Gas Production and Imports.*** Marketed natural gas production is expected to average 65.5 Bcf/d in 2011, a 3.7 Bcf/d (5.9 percent) increase over 2010. This growth is centered in the onshore production in the Lower 48 States, which more

than offsets projected declines in the Federal Gulf of Mexico. EIA expects production will continue to grow in 2012, but at a slower pace, increasing 0.6 Bcf/d (0.9 percent) to an average of 66.1 Bcf/d.

Growing domestic natural gas production has reduced reliance on natural gas imports and contributed to increased exports. EIA expects that pipeline gross imports of natural gas will fall by 4.3 percent to 8.7 Bcf/d during 2011 and by another 3.7 percent to 8.4 Bcf/d in 2012. Pipeline gross exports to Mexico and Canada are expected to average 4.3 Bcf/d in both 2011 and 2012, compared with just 3.1 Bcf in 2010.

Projected U.S. imports of liquefied natural gas (LNG) fall from 1.2 Bcf/d in 2010 to 1.0 Bcf/d in both 2011 and 2012. Because of the earthquake in Japan and subsequent nuclear generation outages, Japan's demand for LNG as a replacement fuel for electric power generation is expected to increase, contributing to higher global LNG prices.

***U.S. Natural Gas Inventories.*** On July 29, 2011, working natural gas in storage stood at 2,758 Bcf, 186 Bcf below last year's level in late July ([U.S. Working Natural Gas in Storage Chart](#)). EIA expects that inventories, though currently lower than last year, will come close to last year's levels towards the end of the 2011 injection season despite the hot weather. Projected inventories surpass 3.77 Tcf at the end of October 2011 because of current high production rates.

***U.S. Natural Gas Prices.*** The Henry Hub spot price averaged \$4.42 per MMBtu in July 2011, 13 cents lower than the June 2011 average ([Henry Hub Natural Gas Price Chart](#)). EIA expects that the Henry Hub price will average \$4.24 per MMBtu in 2011 and \$4.41 per MMBtu in 2012. Though the 2012 average reflects some tightening in supply as domestic production growth slows, prices have remained relatively low over the past few years as a result of abundant production.

Uncertainty about natural gas prices is lower this year compared with last year at this time ([Market Prices and Uncertainty Report](#)). Natural gas futures for October 2011 delivery (for the 5-day period ending August 4) averaged \$4.11 per MMBtu, and the average implied volatility was 33 percent. The lower and upper bounds for the 95-percent confidence interval for October 2011 contracts are \$3.20 per MMBtu and \$5.28 per MMBtu. At this time last year, the October 2010 natural gas futures contract averaged \$4.74 per MMBtu and implied volatility averaged 51 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.26 per MMBtu and \$6.89 per MMBtu.

## Electricity

**U.S. Electricity Consumption.** According to the National Oceanic and Atmospheric Administration, U.S. population-weighted cooling degree-days during July was the highest recorded monthly value since at least the 1930s. This *Outlook* estimates that retail sales of electricity to the residential sector during July were slightly higher than the record-setting 5.02 billion kilowatthours per day (kwh/d) consumed during July of 2010. EIA expects total consumption of electricity during 2011 to grow by 0.5 percent from last year's level and by 1.1 percent in 2012 ([U.S. Total Electricity Consumption Chart](#)).

**U.S. Electricity Generation.** Hydroelectric generation by the electric power sector averaged 946 million kwh/d during the months of January to May 2011, which is 252 million kwh/d (36 percent) higher than the same period last year. Most of this increase in hydropower occurred in the West Census region, where natural gas was displaced as a generating fuel, falling by 159 million kwh/d year-over-year. In contrast, the low cost of natural gas relative to Appalachian coal drove up the use of natural gas as a generation fuel in the eastern regions of the U.S., increasing by 244 million kwh/d during the first five months of this year compared to the same period in 2010. EIA expects a 3.5-percent increase in U.S. natural gas generation during 2011 and an increase of 3.3 percent next year ([U.S. Total Electricity Generation by Fuels, all Sectors Chart](#)).

**U.S. Electricity Retail Prices.** The regulatory lag in passing through changes in generation costs should lead to a 2.3-percent increase in the average U.S. residential retail electricity price during 2011, in response to the increase in natural gas fuel costs last year. Relatively stable fuel costs this year translate into little growth in retail rates during 2012 ([U.S. Residential Electricity Prices Chart](#)).

## Coal

**U.S. Coal Consumption.** EIA expects that coal consumption in the electric power sector will decline by nearly 3 percent in 2011, as total electricity generation rises by less than 1 percent and generation from natural gas increases by 3.5 percent. Forecast coal consumption in the electric power sector remains relatively unchanged in 2012.

Recently released data for the first quarter of 2011 showed that coal consumption at coke plants rose by more than 20 percent. EIA expects that coal consumption at coke plants will increase to 25 million short tons (mmst) (17 percent) in 2011, and stay close to that level in 2012. EIA forecasts that coal consumed in the other sectors (excluding

electric power and coke plants) will remain at approximately 52 mmst in 2011 and 2012 ([U.S. Coal Consumption Growth Chart](#)).

**U.S. Coal Supply.** EIA forecasts that coal production will fall by 1.7 percent in 2011 despite a significant increase in coal exports. Coal production from the Western region declined in the first six months of 2011 by 2 percent from the same period the year before, while production in the Appalachian and Interior regions increased. EIA projects only a 0.3-percent increase in coal production for 2012 ([U.S. Annual Coal Production Chart](#)).

EIA expects that total coal inventories fall by over 17 mmst in 2011, with secondary inventories declining an additional 4.7 mmst in 2012. Primary inventories are forecast to increase slightly (0.5 mmst) in 2012 ([U.S. Electric Power Sector Coal Stocks Chart](#)).

**U.S. Coal Trade.** U.S. coal exports rose by about 50 percent during the first quarter of 2011 compared with 2010. The first quarter export level of 26.6 mmst was the highest quarterly level since 1992. Despite a slower growth rate, EIA expects U.S. coal exports to remain elevated in 2011, reaching an annual level of 98 mmst. Forecast U.S. coal exports fall back to about 83 mmst in 2012 as supply from other major coal-exporting countries recovers from disruptions. EIA also expects the strong global demand for coal to continue to suppress coal imports, with imports projected below 19 mmst in both 2011 and 2012. U.S. coal imports averaged about 31 mmst annually from 2004 through 2009.

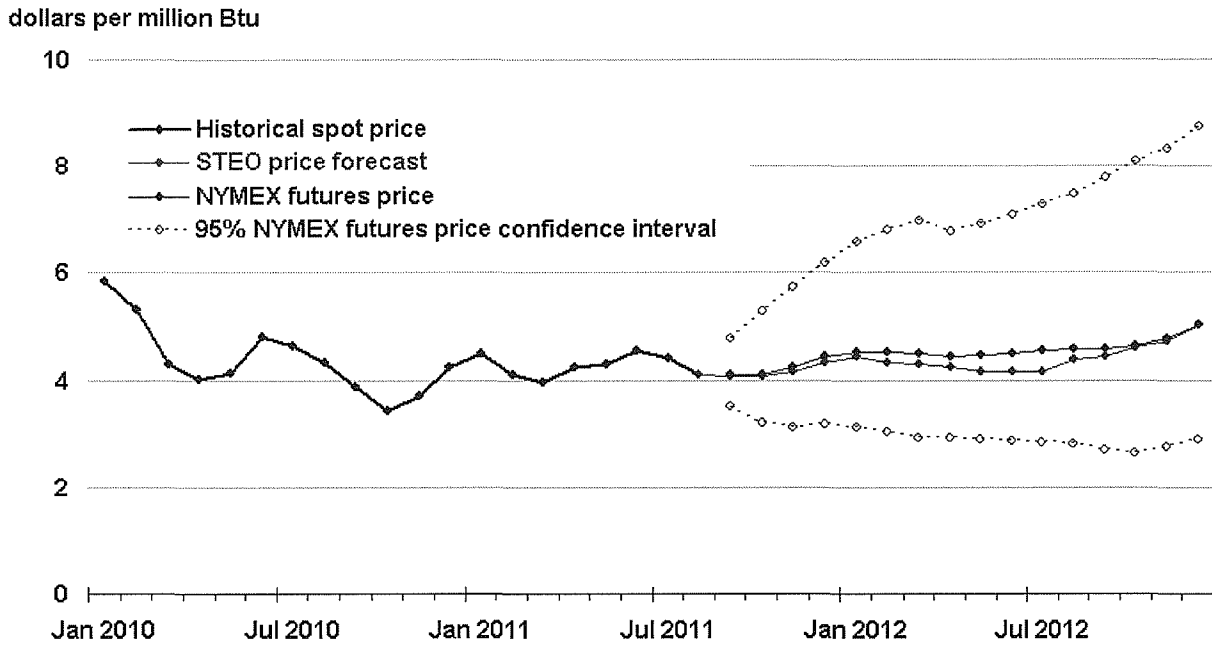
**U.S. Coal Prices.** Average delivered coal prices to the electric power sector have risen steadily over the last 10 years, with an average annual increase of 6.7 percent. EIA expects that this trend will continue in 2011, with a significant portion of the increase attributed to a sharp rise in transportation costs. Nearly all coal transportation is powered by diesel fuel (rail, barge or truck), and wholesale diesel prices are forecast to rise by about 36 percent in 2011. The trend shifts in 2012, with the power sector coal price remaining relatively stable. The projected power-sector delivered coal price, which averaged \$2.26 per MMBtu in 2010, averages about \$2.38 per MMBtu for 2011 and 2012.

## **U.S. Carbon Dioxide Emissions**

EIA estimates that CO<sub>2</sub> emissions from combusting fossil fuels increased by 3.9 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Forecast fossil-fuel CO<sub>2</sub> emissions fall by 0.5 percent in 2011, as emission increases from higher natural gas consumption are offset by declines in coal and petroleum consumption. Increases in hydroelectric generation and other renewable energy sources in 2011 also help to

mitigate emissions growth. Expected increases in total energy consumption next year coupled with a 0.5-percent decline in renewable energy consumption contribute to a 0.4-percent increase in fossil-fuel CO<sub>2</sub> emissions in 2012.

## Henry Hub Natural Gas Price

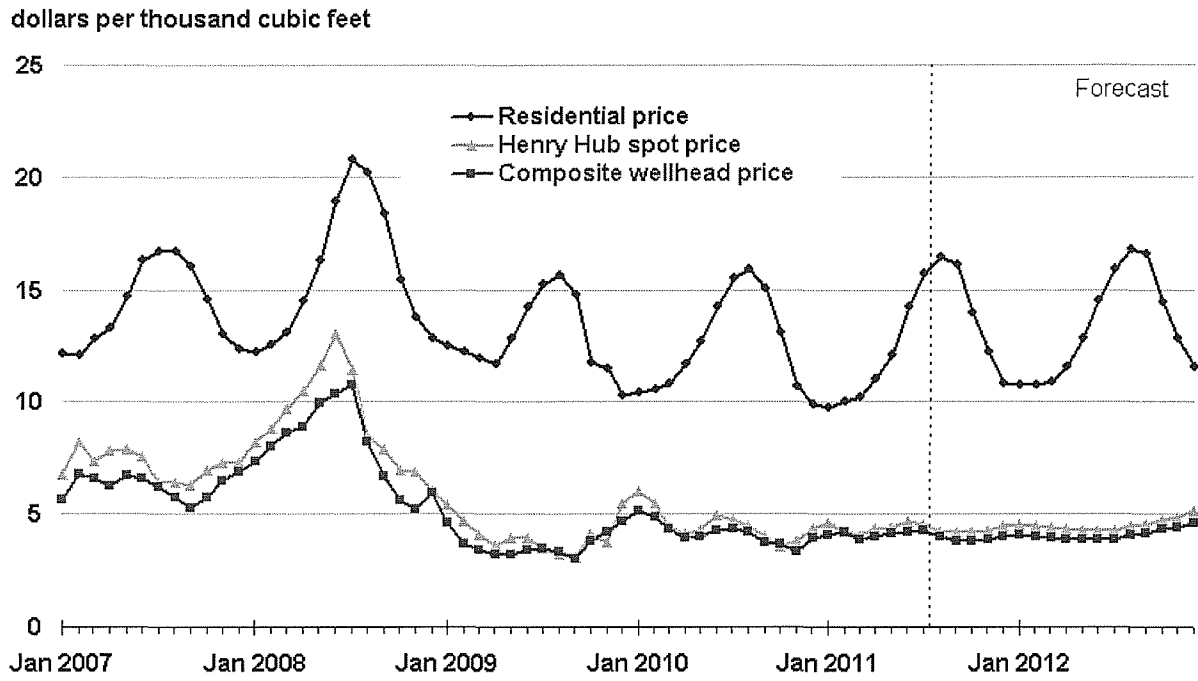


*Note: Confidence interval derived from options market information for 5 trading days ending August 4, 2011  
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, August 2011

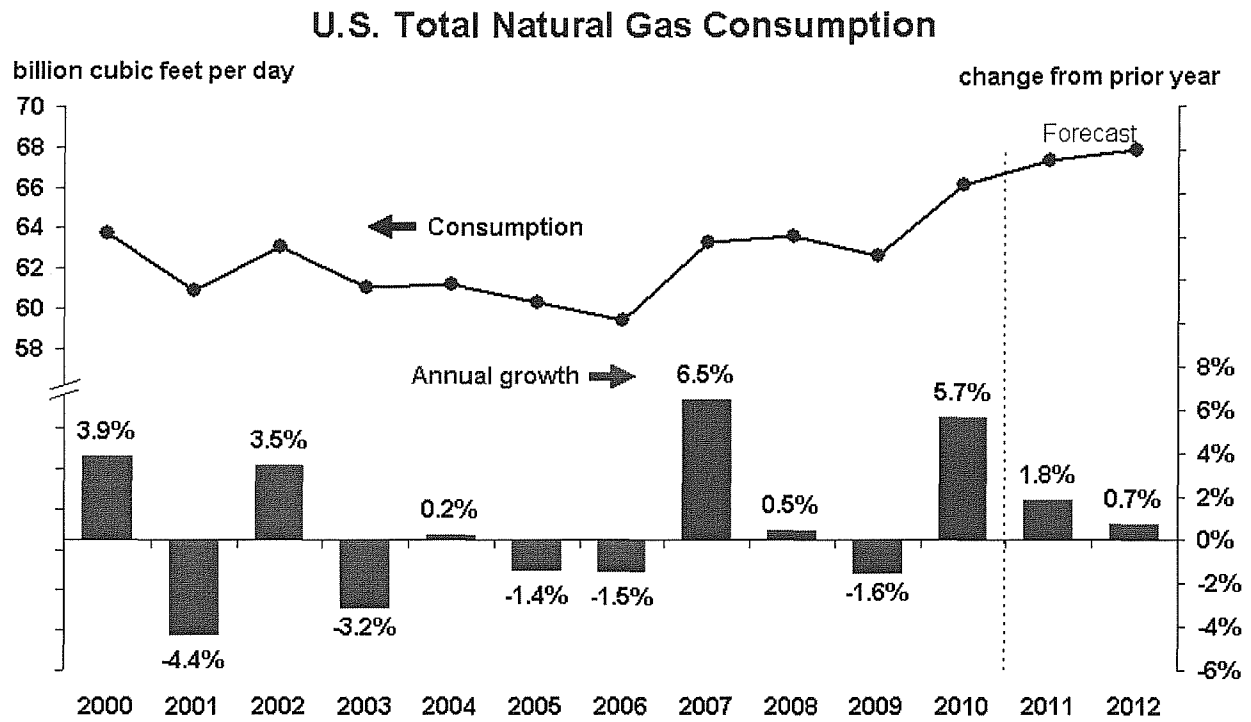


### Natural Gas Prices



Source: Short-Term Energy Outlook, August 2011

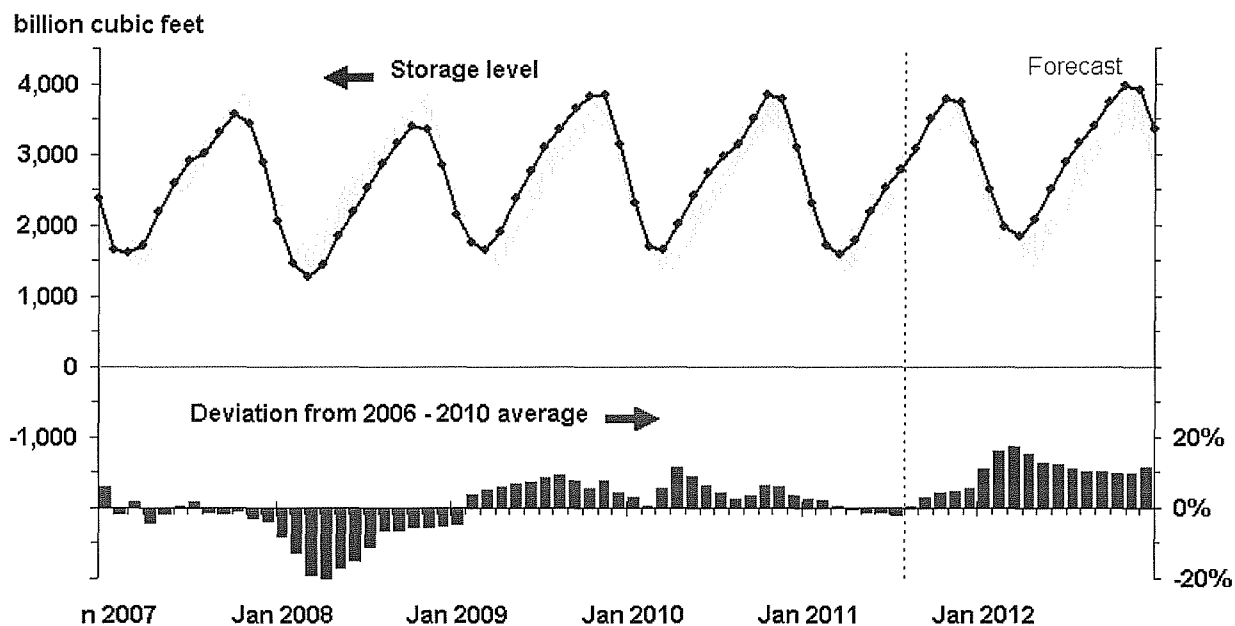




Source: Short-Term Energy Outlook, August 2011



### 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, August 2011



**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 &amp; 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>
<b>Balance @ April 30, 2011</b>									<b><u>\$148,188</u></b>
May	(\$1,396)	\$0	\$892	(\$504)	17,596	\$0.3941	\$6,935	(\$7,439)	140,749
June	33,915	0	837	34,752	9,855	0.5102	4,258 2/	30,494	171,243
July	68,988	0	1,054	70,042	6,564	0.5102	3,349	66,693	237,936
<b>Balance @ July 31, 2011</b>									<b><u>\$237,936</u></b>

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

2/ Reflects 6,634.4 dk @ \$0.3941 and 3,220.6 dk @ \$0.5102.

**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 &amp; 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>
<b>Balance @ April 30, 2011</b>									<b><u>(\$5,922)</u></b>
May	(\$17,358)	\$0	(\$95)	(\$17,453)	22,049	(\$0.1136)	(\$2,505)	(\$14,948)	(20,870)
June	(11,488)	0	(208)	(11,696)	8,011	(0.0178)	(653) 2/	(11,043)	(31,913)
July	(4,652)	0	(288)	(4,940)	9,020	(0.0178)	(161)	(4,779)	(36,692)
<b>Balance @ July 31, 2011</b>									<b><u>(\$36,692)</u></b>

1/ Interest calculated at 13.3%, the authorized rate of return.  
2/ Reflects 5,327.7 dk @ (\$0.1136) and 2,683 dk @ (\$0.0178).