

August 1, 2011

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

Re: Cost of Gas Adjustment (COG)  
August 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 (65<sup>th</sup> Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (65<sup>th</sup> Revised Sheet No. 8), showing the August 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an decrease of \$0.3572 per mcf for residential and firm general service customers and \$0.3248 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for August 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.3248 per mcf since the last COG filing due to an decrease in the market price of gas. There has been a decrease in pipeline charges of \$0.0324 per mcf due to changes in pipeline rates. The net effect of these changes is an decrease of \$0.3572 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

65th Revised Sheet No. 1.1

Canceling 64th Revised Sheet No.1.1

Page 1 of 1

**RATE SUMMARY SHEET**

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$8.8189	\$10.0929 9.8729
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	\$4.0713	\$5.2104 4.9644 4.8124
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$4.0713	\$5.3104
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 1, 2011

**Effective Date:** August 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  
65<sup>th</sup> Revised Sheet No. 8  
Canceling 64<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.	4.2007	(0.7197)	0.5102	3.9912	(0.7052)	(0.0178)	(0.7230)
Current Adj.	(0.0324)	(0.3248)	0.0000	(0.3572)	(0.3248)	0.0000	(0.3248)
Total Adj.	4.1683	(1.0445)	0.5102	3.6340	(1.0300)	(0.0178)	(1.0478)
Total Rate:	\$4.2341	\$4.0746	\$0.5102	\$8.8189	\$4.0891	(\$0.0178)	\$4.0713

**Date Filed:** August 1, 2011

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Regulatory Affairs Manager

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.  
WAHPETON  
COST OF GAS ADJUSTMENT  
AUGUST 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	17.4696	12	1,665,971	1.1874
Trans Canada - Demand Charge	7,947	23.9987	12	2,288,612	1.6311
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068	17.4696	5	442,680	0.3155
Trans Canada - Seasonal	5,068	23.9987	5	608,127	0.4334
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				\$5,920,394	4.2341
Estimated Weighted Average Commodity Cost	1,403,100	1/ 4.0746		5,717,071	4.0746
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				\$11,637,465	8.8189
Base Cost of Gas					5.1849
Accumulated Adjustment					\$3.6340
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.0746
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					4.0713
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$1.0478)

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  
AUGUST 2011**

<b>Rates Effective August 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	17.4696	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.9987	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.4696	Per dk/Day
Trans Canada - Seasonal	23.9987	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:	4.0746	Per dk
<b>Base Rate Effective September 1, 1981</b>		
Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf
<b>Base Rate Calculation</b>		
<u>Firm</u>		
Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf
<u>Interruptible:</u>		
Commodity	\$5.1191	Per Mcf

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

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

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 DEMARCATATION
	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/ 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.

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.

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

Second Revised Sheet No. 54  
Superseding  
First Revised Sheet No. 54

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

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  
August 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 August 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 cool weather during the early half of July and near record high temperatures over much of the lower 48 during the second half is expected to result in the weighted average of the AECO price to decrease slightly. Strong US production and storage levels on the high end of the five year average continue to keep the monthly indexes in a fairly tight trading range. The Energy Information Administration (EIA) reported storage levels nationwide as of July 15, 2011 were 2.2 percent below the five-year average and 7.4 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

July 2011

## Short-Term Energy Outlook

July 12, 2011 Release

### Highlights

- World crude oil prices initially fell following the June 23 announcement by the International Energy Agency (IEA) that its member countries would release up to 60 million barrels from strategic reserves but then rose above the pre-announcement levels in late June and early July. Attributing observed price changes since June 23 to the IEA announcement is difficult because other drivers, including changing expectations of world economic and crude oil consumption growth, uncertainty over oil supply disruptions, estimates of Organization of the Petroleum Exporting Countries (OPEC) spare production capacity, and other physical and financial factors are continually affecting oil prices. Although the IEA release will provide some additional supply, EIA 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 OPEC, the projected U.S. average refiner acquisition cost of crude oil rises from \$102 per barrel in 2011 to \$108 per barrel in 2012, about \$1 per barrel below last month's *Outlook*.
- The regular-grade gasoline monthly average retail price fell from \$3.91 per gallon in May to \$3.68 per gallon in June, reflecting the decline in crude oil prices from their April peak and a recovery from unexpected refinery outages and Mississippi River flooding. EIA expects regular-grade gasoline prices will average \$3.62 per gallon and \$3.51 per gallon over the third and fourth quarters of 2011, respectively.
- Natural gas working inventories ended June 2011 at 2.5 trillion cubic feet (Tcf), about 8 percent, or 214 billion cubic feet (Bcf), below the 2010 end-of-June 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 \$4.27 per million British thermal units (MMBtu) in 2011, \$0.12 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 \$4.54 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 and 1.6 million bbl/d in 2012. EIA still expects that the market will rely on both a drawdown of inventories and production increases in both non-OPEC and OPEC countries to meet projected demand growth. Projected supply from non-OPEC countries increases by an average of about 0.6 million bbl/d annually in 2011 and 2012. OPEC production, including both crude and non-crude liquids, increases by 0.3 and 0.9 million bbl/d in 2011 and 2012, respectively.

EIA expects the release of strategic reserves pursuant to the IEA's June 23 announcement to reduce the expected draw on commercial stocks during the rest of 2011. In last month's *Outlook*, commercial stocks held in Organisation for Economic Cooperation and Development (OECD) member countries, which fell by about 7 million barrels over the first 6 months of 2011, were forecast to fall by 127 million barrels over the last 6 months of this year because of the projected second-half increase in world consumption. In this *Outlook*, the second-half OECD commercial stock draw has been lowered to 71 million barrels.

The crude oil price outlook remains uncertain. Among the major uncertainties that could push oil prices above or below our current forecast are: risk of additional supply disruptions in producing regions, such as possible unrest in Sudan; the willingness and ability of key OPEC-member countries to increase and sustain higher production in response to the global increase in oil demand; the rate of global economic growth; 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 86.7 million bbl/d in 2010. EIA expects that world consumption will continue to grow by 1.4 million bbl/d in 2011 and by 1.6 million bbl/d in 2012, resulting in total world consumption of 89.7 million bbl/d in 2012 ([World Liquid Fuels Consumption Chart](#)). Countries outside the 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. Among OECD countries, EIA expects that consumption will increase in the United States, Canada, Mexico, and South Korea over the next two years, offsetting declines in OECD Europe. Consumption in Japan is forecast to increase slightly in 2011 but then fall in 2012 as power plants recover from the impacts of the earthquake and tsunami.

**Non-OPEC Supply.** EIA projects that non-OPEC crude oil and liquid fuels production will increase by 540 thousand bbl/d in 2011 and by 740 thousand 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 Canada (170 thousand bbl/d), China (140 thousand bbl/d), the United States (140 thousand bbl/d), Brazil (120 thousand bbl/d), and Colombia (120 thousand bbl/d). EIA has lowered the rate of production declines in the North Sea and Europe compared to the last *Outlook*. Increased taxes on production, particularly in the United Kingdom, are now expected to have less of an effect on total production. At the same time, EIA now expects that Azerbaijan's production will be lower compared to the previous *Outlook*, as continued problems with the production in the Azeri-Chirag-Guneshli field last longer than initially anticipated. In Russia, lack of reform of the tax regime likely will dampen any increase in oil production.

**OPEC Supply.** Forecast OPEC crude oil production declines by about 300 thousand bbl/d in 2011, but increases by 560 thousand bbl/d in 2012. EIA assumes that about one-half of Libya's pre-disruption production will resume by the end of 2012. The 12 members of OPEC produced an estimated 29.2 million bbl/d of crude oil in the second quarter of 2011 and EIA expects that their production will increase to an average 29.6 million bbl/d in the third quarter. EIA projects that OPEC surplus 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 3.1 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, increases by 0.6 million bbl/d in 2011 and by 0.4 million bbl/d in 2012.

**OECD Petroleum Inventories.** EIA expects that OECD commercial inventories will decline in both 2011 and 2012. Because of the IEA release of emergency stocks, the projected commercial stock declines are not as large as those in last month's *Outlook*. Projected onshore OECD stocks fall by about 78 million barrels in 2011, compared to 118 million barrels in last month's *Outlook*. Days of supply (total inventories divided by average daily consumption) drop from a relatively high 58.1 days during the fourth quarter of 2010 to 55.7 days in 2011 and 54.6 days of supply in 2012 (Days of Supply of OECD Commercial Stocks Chart).

**Crude Oil Prices.** WTI crude oil spot prices have fallen from an average of \$110 per barrel in April to \$96 per barrel in June. World crude oil prices initially fell following the IEA's June 23 announcement of releases from strategic reserves but then rose above their pre-announcement levels in late June and early July. Attributing observed price changes since June 23 to the IEA announcement is difficult because of other factors which continually affect oil prices, such as changing expectations of

world economic and crude oil demand growth, uncertainty over oil supply disruptions, estimates of OPEC spare production capacity, and other physical and financial market factors (see EIA's [What Drives Crude Oil Prices](#)).

EIA still expects oil markets to tighten as growing liquid fuels demand in emerging economies and slowing growth in non-OPEC supply maintain upward pressure on oil prices. EIA expects that WTI spot prices, which averaged \$79 per barrel in 2010, will average \$98 per barrel in 2011 and \$103 per barrel in 2012, while the U.S. composite refiner acquisition cost of crude oil is projected to average \$102 and \$108 per barrel for 2011 and 2012, respectively ([West Texas Intermediate Crude Oil Price Chart](#)).

Growing volumes of Canadian crude oil imported into the United States have contributed to high [storage levels at Cushing, Oklahoma](#), and a price discount for WTI compared with similar-quality world crudes such as Brent. The price discount for WTI is expected to persist until transportation bottlenecks restricting the movement of mid-continent crude oil to the Gulf Coast are relieved. Consequently, the projected U.S. refiner average acquisition cost of crude oil, which averaged almost \$2.70 per barrel below WTI in 2010, is about \$4 per barrel above WTI in 2011 and \$5 per barrel above WTI in 2012.

Energy price forecasts are highly uncertain ([Market Prices and Uncertainty Report](#)). WTI futures for September 2011 delivery over the 5-day period ending July 7 averaged \$96.93 per barrel and implied volatility averaged 28 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 \$81 per barrel and \$116 per barrel, respectively. Last year at this time, WTI for September 2010 delivery averaged \$77 per barrel and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$60 per barrel and \$98 per barrel.

## **U.S. Crude Oil and Liquid Fuels**

***U.S. Liquid Fuels Consumption.*** Total consumption of liquid fuels in 2010 grew by 380 thousand bbl/d, or 2.0 percent, the fastest rate of growth since 2004 ([U.S. Liquid Fuels Consumption Growth Chart](#)). Distillate fuel oil accounted for over 40 percent of that increase, growing by 4.5 percent.

In contrast to 2010, projected total U.S. liquid fuels consumption in 2011 grows by just 30 thousand bbl/d (0.2 percent), down sharply from the 150 thousand bbl/d projected in the previous *Outlook*. At the beginning of this year, domestic liquid fuels markets remained strong. In the first quarter, total consumption increased by 270 thousand

bbl/d (1.4 percent) over the same period last year, led by distillate fuel oil (160 thousand bbl/d) and liquefied petroleum gas (70 thousand bbl/d), despite a fall in motor gasoline consumption (50 thousand bbl/d). Available data for the second quarter, however, point to a broad-based decline in liquids consumption brought about by moderation in economic growth and high prices, with total consumption and motor gasoline consumption down by 200 thousand bbl/d (1.0 percent) and 210 thousand bbl/d (2.3 percent) respectively relative to the year-ago quarter. Distillate fuel oil consumption, having grown strongly in the first quarter, remained flat in the second quarter. Forecast total liquids consumption in the third quarter are 60 thousand bbl/d (0.3 percent) below their level in the year-ago quarter, but by the fourth quarter liquid fuels are projected to resume their growth, increasing by 110 thousand bbl/d (0.6 percent) over the same period last year.

In 2012, total liquid fuels consumption is forecast to increase by 140 thousand bbl/d (0.7 percent) to 19.3 million bbl/d with motor gasoline consumption rising by 60 thousand bbl/d (0.7 percent) and distillate fuel consumption increasing by 70 thousand bbl/d (1.7 percent) as manufacturing activity continues to register strong growth.

***U.S. Liquid Fuels Supply and Imports.*** Domestic crude oil production, which increased by 150 thousand bbl/d in 2010 to 5.5 million bbl/d, increases by a further 50 thousand bbl/d in both 2011 and 2012 ([U.S. Crude Oil Production Chart](#)). Lower-48 production grows by 260 thousand bbl/d in 2011 and 170 thousand bbl/d in 2012 as a result of increased oil-directed drilling activity.

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 9.2 million bbl/d in 2011 and 9.4 million bbl/d in 2012, representing 48 percent and 49 percent of total consumption, respectively.

***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 \$3.56 per gallon in 2011 and to \$3.65 per gallon in 2012, both slight reductions from last month's *Outlook*. The sizable jump in retail prices this year reflects not only the higher average cost of crude oil compared to previous years, but also an increase in U.S. refining margins on gasoline (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 \$0.45 per gallon in 2011 and \$0.42 per gallon in 2012.

EIA expects that on-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, will average \$3.86 per gallon in 2011 and \$3.95 per gallon in 2012, relatively unchanged from the previous *Outlook*. Projected U.S. refining margins on diesel fuel increase from an average \$0.38 per gallon in 2010 to \$0.62 per gallon in 2011, then fall to \$0.55 per gallon in 2012.

## Natural Gas

***U.S. Natural Gas Consumption.*** EIA expects that total natural gas consumption will grow by 2.0 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 are expected to rise in 2011 by 3.3 percent to 18.7 Bcf/d and 2.1 percent to 20.6 Bcf/d, respectively.

Projected total consumption drops slightly in 2012 to 67.3 Bcf/d, reflecting expected continued growth in the industrial and electric power sectors with a decline in residential and commercial consumption due to a forecast decline in heating degree-days in the Midwest and West.

***U.S. Natural Gas Production and Imports.*** Marketed natural gas production is expected to average 65.4 Bcf/d in 2011, a 3.6 Bcf/d (5.8 percent) increase over 2010. Much of this growth is expected to occur during the first three quarters of the year, with a more moderate increase in the fourth quarter. Production growth is forecast to continue at a much slower pace in 2012, increasing 0.6 Bcf/d (0.9 percent) to average 66.0 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 3.9 percent to 8.7 Bcf/d during 2011 and by 4.0 percent to 8.4 Bcf/d in 2012. Pipeline gross exports to Mexico and Canada are expected to average 4.2 Bcf/d in 2011 and 4.3 Bcf/d in 2012, compared to just 3.1 Bcf in 2010.

EIA projects that U.S. imports of liquefied natural gas (LNG) will fall from an average 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 1, 2011, working natural gas in storage stood at 2,527 Bcf, 214 Bcf below last year's level in late June ([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. Projected inventories surpass 3.8 Tcf at the end of October 2011 because of current high production rates and a milder summer relative to last year.

**U.S. Natural Gas Prices.** The Henry Hub spot price averaged \$4.54 per MMBtu in June, 23 cents higher than the May average and 34 cents higher than forecast in last month's *Outlook* ([Henry Hub Natural Gas Price Chart](#)). EIA expects that the Henry Hub price will average \$4.26 per MMBtu over the second half of 2011, as the inventory deficit relative to last year narrows. EIA projects that the Henry Hub price will average \$4.54 per MMBtu in 2012, as slowing growth in production contributes to tighter domestic natural gas markets.

Uncertainty about natural gas prices is lower this year compared to last year at this time ([Market Prices and Uncertainty Report](#)). Natural gas futures for September 2011 delivery (for the 5-day period ending July 7) averaged \$4.28 per MMBtu, and the average implied volatility was 33 percent. The lower and upper bounds for the 95-percent confidence interval for September 2011 contracts are \$3.34 per MMBtu and \$5.48 per MMBtu. At this time last year, the September 2010 natural gas futures contract averaged \$4.66 per MMBtu and implied volatility averaged 33 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.22 per MMBtu and \$6.20 per MMBtu.

## Electricity

**U.S. Electricity Consumption.** Retail sales of electricity to the residential sector during the first three months of 2011 were down 2.6 percent from the first quarter of 2010. According to the National Oceanic and Atmospheric Administration, cooling degree-days during the summer months of June, July, and August will likely be about 14 percent lower than the same period last year. Reduced cooling needs should lead to a 5.3-percent decline in residential electricity consumption during these 3 months compared with the same period last year. With increased electricity sales to the industrial and commercial sectors, EIA expects total consumption of electricity to show very little growth this year ([U.S. Total Electricity Consumption Chart](#)).

**U.S. Electricity Generation.** Year-over-year changes in fuel shares during the first quarter of 2011 varied widely between different areas of the country. Record levels of hydroelectric generation pushed the share of natural gas-fueled generation in the West Census Region down from 29 percent during the first three months of 2010 to 19 percent this year, which is the smallest first-quarter natural gas fuel share since 2000. In contrast, low marginal costs of natural gas relative to rising coal prices in the eastern United States have pushed up first-quarter natural gas generation in the

Northeast Census Region by nearly 6 percent. EIA expects the natural gas share of generation in the West will gradually rise later this year as the level of hydropower comes down. In addition, generators in the eastern United States will likely continue the trend of substituting natural gas for coal. U.S. electric power sector generation fueled by natural gas should increase by 1.6 percent during 2011 and by 1.2 percent next year ([U.S. Electric Power Sector Generation Growth Chart](#)).

**U.S. Electricity Retail Prices.** EIA expects the average U.S. residential electricity price to rise from 11.6 cents per kilowatthour in 2010 to 11.9 cents per kilowatthour this year, an increase of 2.9 percent ([U.S. Residential Electricity Prices Chart](#)).

## Coal

**U.S. Coal Consumption.** EIA projects that coal consumption in the electric power sector will fall by 2.5 percent in 2011, as electricity demand remains flat and generation from natural gas and renewable energy sources increases. Forecast coal consumption in the electric power sector grows only 1.6 percent in 2012 ([U.S. Coal Consumption Growth Chart](#)).

**U.S. Coal Supply.** EIA expects that coal production will fall by 1.2 percent in 2011 despite a significant increase in coal exports. Combined primary and secondary coal inventories fall by almost 13 million short tons (mmst) in 2011 ([U.S. Electric Power Sector Coal Stocks Chart](#)). EIA projects a 1.8-percent increase in coal production for 2012 ([U.S. Annual Coal Production Chart](#)).

**U.S. Coal Trade.** U.S. coal exports rose by about 50 percent during the first quarter of 2011 compared to 2010. The first quarter export level of 26.6 mmst was the highest quarterly level since 1992. Despite signs of a slowing growth rate, with April 2011 exports 20 percent higher than in April 2010, EIA expects U.S. coal exports, while moderating, to remain elevated in 2011, reaching an annual level of 96 mmst. Forecast U.S. coal exports fall back to recent historical levels (about 83 mmst) in 2012 as supply from other major coal-exporting countries recovers from weather-related 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.** 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. EIA expects that this trend will continue in 2011, but the trend shifts in 2012, with the power sector coal price remaining relatively stable. The projected

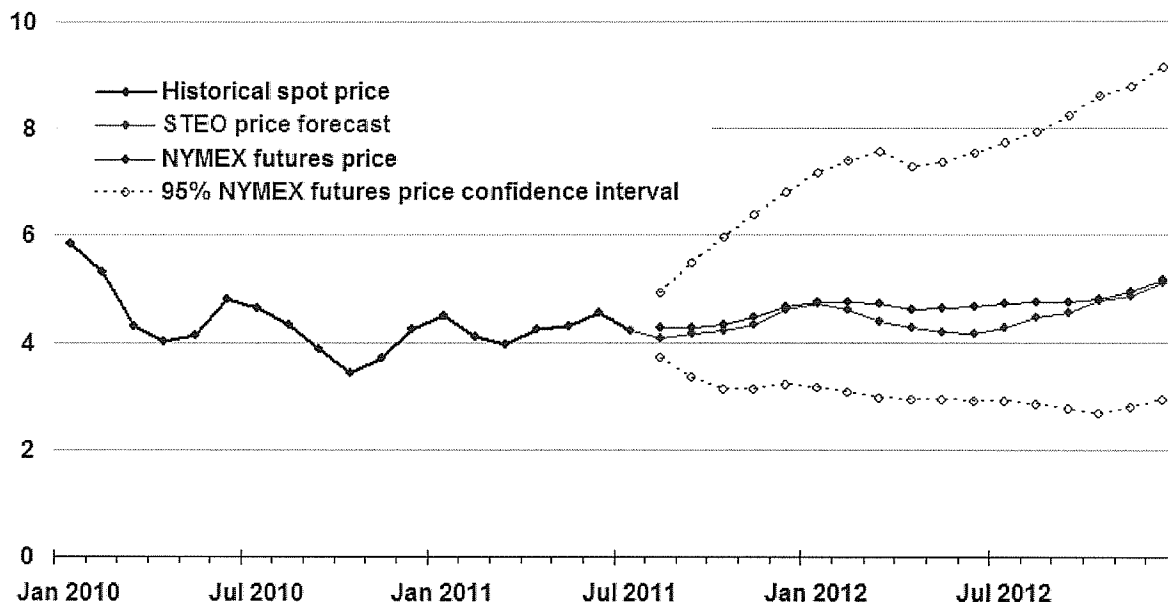
power-sector delivered coal price, which averaged \$2.26 per MMBtu in 2010, averages \$2.32 per MMBtu in both 2011 and 2012.

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

EIA estimates that fossil-fuel CO<sub>2</sub> emissions increased by 3.8 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Forecast fossil-fuel CO<sub>2</sub> emissions remain flat in 2011, as emission increases from higher petroleum and natural gas consumption are offset by declines in coal consumption. Increases in hydroelectric generation and other renewable energy forms in 2011 also help to mitigate emissions growth. Expected increases in consumption in 2012 contribute to a 0.9-percent increase in fossil-fuel CO<sub>2</sub> emissions.

## Henry Hub Natural Gas Price

dollars per million Btu

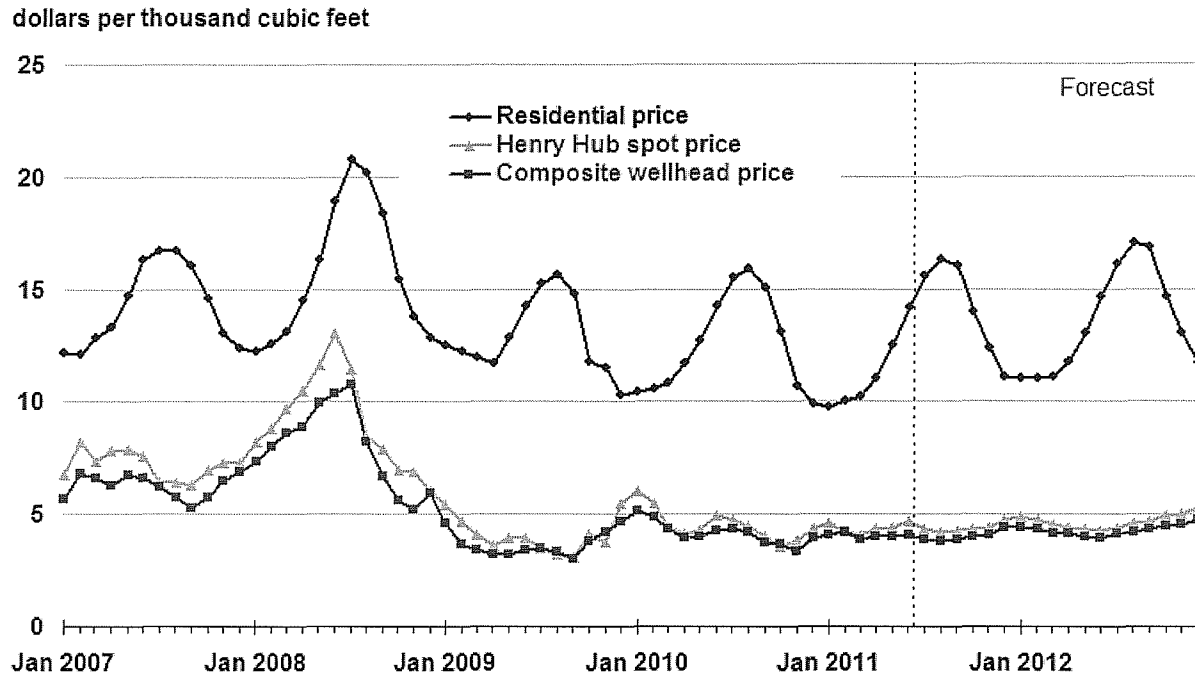


*Note: Confidence interval derived from options market information for 5 trading days ending July 7, 2011  
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, July 2011

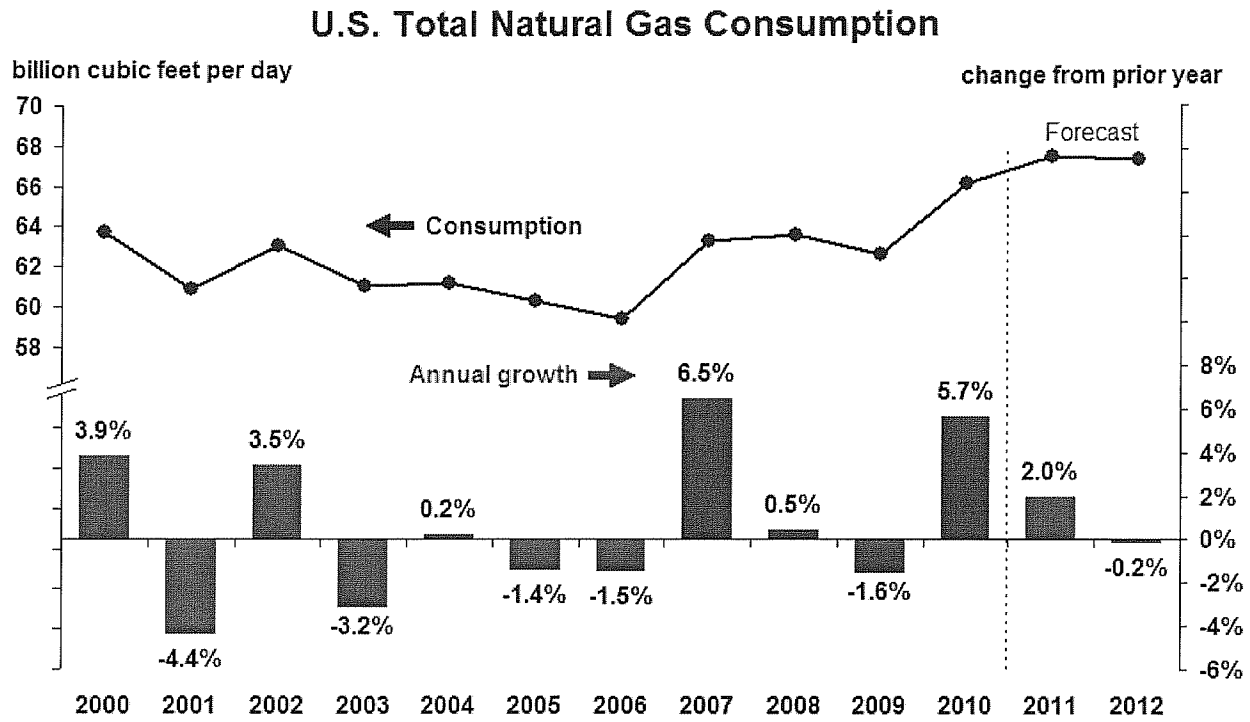


### Natural Gas Prices



Source: Short-Term Energy Outlook, July 2011

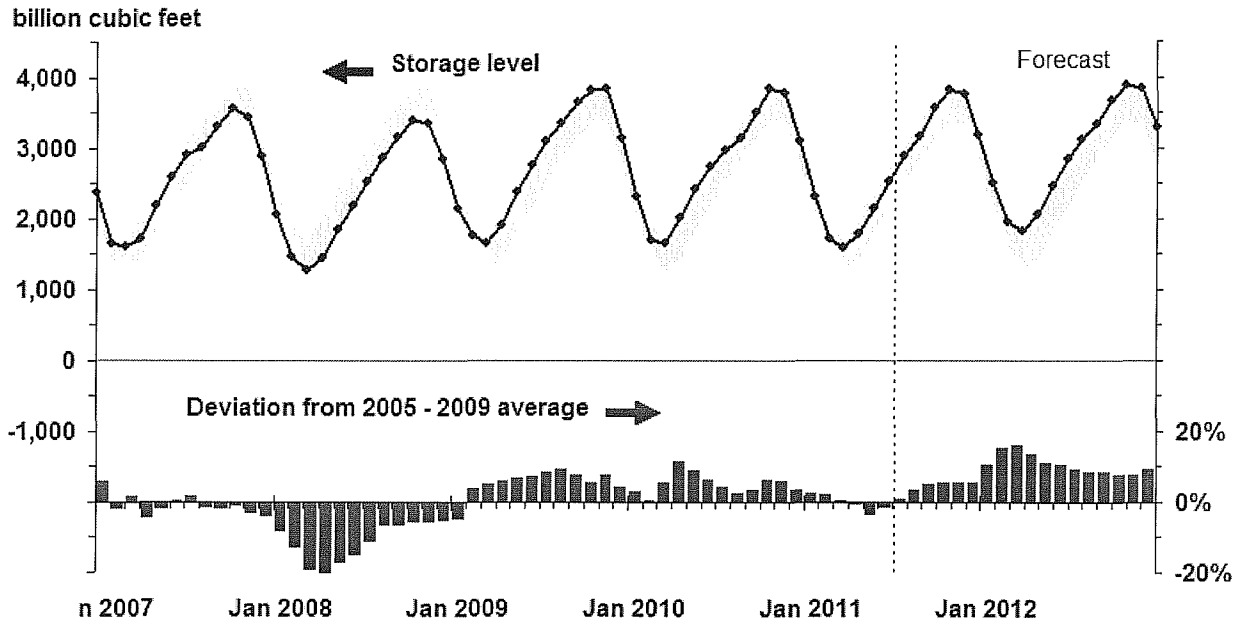




Source: Short-Term Energy Outlook, July 2011



### 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, July 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><u>\$148,188</u></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
<b>Balance @ June 30, 2011</b>									<b><u><u>\$171,243</u></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><u>(\$5,922)</u></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)
<b>Balance @ June 30, 2011</b>									<b><u><u>(\$31,913)</u></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).