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

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October 3, 2011

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

Re: Cost of Gas Adjustment (COG)
October 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 (67th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (67th Revised Sheet No. 8), showing the October 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.1027 per mcf for residential and firm general service customers and a decrease of $0.0001 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for October 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.0001 since the last COG filing. There has been a decrease in pipeline charges of $0.1026 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of $0.1027 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

Rita A. Mulkern
Regulatory Affairs Manager

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
67th Revised Sheet No. 1.1
Canceling 66th Revised Sheet No.1.1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/MCF
Firm Gas Service - General	2	$3.50 per month	First 10 MCF	$1.2740	$8.5885	$9.8625
			Over 10 MCF	1.0540		9.6425
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.8682	$5.0073
			Next 2,600 MCF	0.8931		4.7613
			Over 3,000 MCF	0.7411		4.6093
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.8682	$5.1073
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: October 3, 2011

Effective Date: October 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
67th Revised Sheet No. 8
Canceling 66th 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.	4.2436	(1.2475)	0.5102	3.5063	(1.2330)	(0.0178)	(1.2508)
Current Adj.	(0.1026)	(0.0001)	0.0000	(0.1027)	(0.0001)	0.0000	(0.0001)
Total Adj.	4.1410	(1.2476)	0.5102	3.4036	(1.2331)	(0.0178)	(1.2509)
Total Rate:	$4.2068	$3.8715	$0.5102	$8.5885	$3.8860	($0.0178)	$3.8682

Date Filed: October 3, 2011 **Effective Date:** October 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
OCTOBER 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		17.3010	12	1,649,893	1.1759
Trans Canada - Demand Charge	7,947		23.8500	12	2,274,431	1.6210
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068		17.3010	5	438,407	0.3125
Trans Canada - Seasonal	5,068		23.8500	5	604,359	0.4307
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					$5,882,094	4.2068
Estimated Weighted Average Commodity Cost	1,403,100	1/	3.8715		5,432,102	3.8715
Gas Cost Reconciliation Adjustment						0.5102
Total Current Firm Gas Cost					$11,314,196	8.5885
Base Cost of Gas						5.1849
Accumulated Adjustment						$3.4036

Interruptible	
Estimated Weighted Average Commodity Cost	$3.8715
Gas Cost Reconciliation Adjustment	(0.0178)
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	3.8682
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.2509)

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
OCTOBER 2011

Rates Effective October 1, 2011	$/Dk	
FT-A - Zone 1-1	$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	17.3010	Per dk/Mo.
Trans Canada Pipeline Demand Charge	23.8500	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.3010	Per dk/Day
Trans Canada - Seasonal	23.8500	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

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

Base Rate Calculation		
Firm		
Demand 1/	$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

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

STATEMENT OF RATES
(Rates Per Dekatherm)

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.7671
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.8871
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.1400
Zone 2-2 Minimum Rate	$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.6171
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.7371
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.9900
Zone 2-2 Minimum Rate	$0.0000
Category 3 (Contract Term of 5 or more Years)	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$3.4671
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.5871
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8400
Zone 2-2 Minimum Rate	$0.0000

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

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	$0.0018	$0.0148	1.47%
Zone 1-2	$0.0130	$0.0018	$0.0148	1.98%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.51%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	1.47%
Zone 1-2	$0.1737	$0.0018	$0.1755	1.98%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.51%
Minimum Rate	$0.0130	$0.0018	$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0018 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

Third Revised Sheet No. 50
Superseding
Second Revised Sheet No. 50

RATE SCHEDULE TF

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

COMMODITY RATES 2/ TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

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 $0.0018 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 Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$5.683	$15.153	$5.473	$9.853

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	0.0213			0.0175	0.0000	0.0382	0.0213
Field	Market	0.0382	0.0213	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

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 $0.0018 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 $0.0018.

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
October 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 October monthly price for the AECO Index is expected to remain in the same range as 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).

With light heating and cooling demand typical of this time of the year, storage levels continuing to stay in the mid range of the five year average and continued strong production from the domestic shale plays, the AECO index price is experiencing little change from the previous month. The Energy Information Administration (EIA) reported storage levels nationwide as of September 23, 2011 were 0.2 percent above the five-year average and 2.7 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

September 2011

Short-Term Energy Outlook

September 7, 2011 Release

Highlights

- EIA's economic growth assumptions have been lowered substantially compared with last month's *Outlook*. This forecast assumes that U.S. real gross domestic product (GDP) grows by 1.5 percent this year and 1.9 percent next year compared with 2.4 percent and 2.6 percent, respectively, in the previous *Outlook*. World oil-consumption-weighted real GDP grows by 3.1 percent and 3.8 percent in 2011 and 2012, respectively, compared with 3.4 percent and 4.1 percent in the last *Outlook*. With weaker economic growth and lower petroleum consumption growth, EIA expects the U.S. average refiner acquisition cost of crude oil to rise from an average of $100 per barrel in 2011 to $103 per barrel in 2012, compared with an increase to $107 per barrel in 2012 in last month's *Outlook*.

- Regular-grade gasoline retail prices fell by 40 cents per gallon from their peak this year of $3.97 per gallon on May 9 to $3.57 per gallon on June 27 following a decline in crude oil prices. Gasoline retail prices stabilized in July and August with weekly retail prices averaging between $3.58 per gallon and $3.71 per gallon, but are projected to fall to an average $3.47 per gallon in the fourth quarter 2011 after refiners switch production from summer-grade gasoline to lower-cost winter-grade gasoline.

- Natural gas working inventories ended August 2011 at 3.0 trillion cubic feet (Tcf), about 5 percent, or 144 billion cubic feet (Bcf), below the 2010 end-of-August level. EIA expects that working natural gas inventories will approach last year's high levels by the end of this year's injection season. The projected Henry Hub natural gas spot price averages $4.20 per million British thermal units (MMBtu) in 2011, $0.18 per MMBtu lower than the 2010 average. EIA expects the natural gas market to tighten moderately in 2012, with the Henry Hub spot price increasing to an average of $4.30 per MMBtu.

- Global coal supply disruptions, particularly in Australia, and growing demand in China have helped boost U.S. coal exports for the first half of 2011 to a 29-

year high of 54 million short tons (MMst), an increase of 35 percent compared to the same period in 2010 and double 2009 levels. EIA expects coal exports to begin to weaken, totaling 45 MMst over the second half of 2011 and 87 MMst in 2012.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. The projected pace of global oil demand growth is lower in this month's *Outlook* due to less optimistic assumptions about global economic growth. The downward revision to oil demand growth relieves some of the potential oil market tightness that had been implied by previous forecast balances. Nonetheless, without a significant change in the outlook for supply, EIA expects markets to draw upon inventories to meet at least some of the growth in consumption over the fourth quarter of 2011 and beyond. In 2012, oil demand growth from countries outside of the Organization for Economic Cooperation and Development (OECD) is projected to outpace the growth in supply from producers that are not members of the Organization of the Petroleum Exporting Countries (OPEC), implying a need for OPEC producers to increase their output to balance the market.

The inherent uncertainty of the revised price forecast is evidenced by the various shocks to oil supply, demand, and prices that have occurred this year. Upside risks to the crude oil price outlook remain, particularly due to ongoing unrest in oil-producing regions and the possibility that non-OECD demand will be more resilient than expected. Yet downside risks arguably predominate, as fears persist about the rate of global economic recovery, contagion effects of the debt crisis in the European Union, and other fiscal issues facing national and sub-national governments. On the supply side, the possibility remains that Libya may be able to ramp up oil production and exports sooner than anticipated.

Global Crude Oil and Liquid Fuels Consumption. EIA expects world crude oil and liquid fuels consumption will continue growing from its record-high levels in 2010, albeit less robustly than in the previous *Outlook,* due to a reduction of approximately 0.3 percentage points in the global oil-consumption-weighted economic growth forecast for both 2011 and 2012. EIA expects world consumption to grow by about 1.4 million barrels per day (bbl/d) in both 2011 and 2012 to 89.6 million bbl/d in 2012 – a downward revision of over 200 thousand bbl/d from last month's *Outlook* (World Liquid Fuels Consumption Chart). The demand forecast is also a divergent tale of two regions: consumption in OECD member countries is projected to decline in both 2011 and 2012, while China and other emerging economies account for all of the projected growth in oil consumption through 2012.

Non-OPEC Supply. EIA projects that non-OPEC crude oil and liquid fuels production will grow by 500 thousand bbl/d in 2011 and 770 thousand bbl/d in 2012, to a 2012 average of 53.1 million bbl/d (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). The largest sources of expected growth in non-OPEC oil production over the forecast period are Brazil, Canada, China, Colombia, Kazakhstan, and the United States, with average annual growth in each country of over 100 thousand bbl/d. In contrast, Russian oil production is expected to decline by roughly 120 thousand bbl/d next year, while North Sea production declines by 130 thousand bbl/d in 2011 and 110 thousand bbl/d in 2012. EIA assumes that Yemen will recover most of its pre-disruption levels of production (240 thousand bbl/d) early next year, but heightened turmoil in Syria and the potential for more sanctions on the country's energy sector introduce yet another source of political risk to the non-OPEC outlook.

OPEC Supply. EIA expects OPEC crude oil production to decline by about 360 thousand bbl/d in 2011, in large part due to the supply disruption in Libya. Though the situation in Libya is dynamic and circumstances have changed considerably since last month's *Outlook*, EIA is continuing to maintain its assumption – with only a slightly accelerated timetable – that about one-half of Libya's pre-disruption production will resume by the end of 2012. The restoration of at least some Libyan production is expected to contribute to an overall increase in OPEC output of 510 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 (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 490 thousand bbl/d in 2011 and by 440 thousand bbl/d in 2012.

OECD Petroleum Inventories. EIA expects that OECD commercial inventories will decline slightly in both 2011 and 2012. Days of supply (total inventories divided by average daily consumption) fall slightly but remain relatively high at 58 days during the fourth quarter of 2010, 57 days during the fourth quarter 2011, and 56 days during the fourth quarter 2012 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. West Texas Intermediate (WTI) crude oil spot prices fell from an average of $97 per barrel in July to $86 per barrel in August (West Texas Intermediate Crude Oil Price Chart). EIA has revised the projected oil price paths downward from last month's *Outlook*. EIA expects that the U.S. refiner average crude oil acquisition cost will average $100 per barrel in 2011 and $103 per barrel in 2012 compared with $100 per barrel and $107 per barrel for 2011 and 2012, respectively, in the previous *Outlook*.

The current price discount for WTI relative to other U.S. and world crude oils is expected to continue until transportation bottlenecks restricting the movement of crude oil out of the mid-continent region are relieved. Consequently, the projected average U.S. refiner acquisition cost of crude oil, which averaged almost $2.70 per barrel below WTI in 2010, averages about $6 per barrel above WTI in 2011 and $8 per barrel above WTI in 2012.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for November 2011 delivery over the 5-day period ending September 1 averaged $88 per barrel and implied volatility averaged 40 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in November of $67 per barrel and $116 per barrel, respectively. Implied volatility, or the expectation of future price volatility, is up from the 33 percent implied volatility reported in last month's *Outlook* for the October 2011 contract. Last year at this time, WTI for November 2010 delivery averaged $75 per barrel and implied volatility averaged 32 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $61 per barrel and $94 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of liquid fuels in 2010 grew 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 170 thousand bbl/d (0.9 percent). Motor gasoline consumption accounts for almost all the projected decline for the year.

EIA expects total liquid fuels consumption to increase by 80 thousand bbl/d (0.4 percent) to 19.1 million bbl/d in 2012, down from the 170 thousand bbl/d increase projected in the previous *Outlook* because of the downward revisions to the U.S. economic growth forecast. Projected motor gasoline consumption rises by 40 thousand bbl/d (0.5 percent) as highway travel increases modestly, and distillate fuel consumption increases by 30 thousand bbl/d (0.9 percent) as growth in industrial activity and non-petroleum imports continues to slow as a result of continuing weak economic growth in 2012.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 110 thousand bbl/d in 2010 to 5.5 million bbl/d, increases by a further 140 thousand bbl/d in 2011 and by 60 thousand bbl/d in 2012 (U.S. Crude Oil Production Chart), driven by increased oil-directed drilling activity, particularly 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 both 2011 and 2012.

U.S. Inventories. Commercial crude oil inventory levels ended August 2011 at an estimated 359 million barrels, the same level as last year but 29 million barrels higher than the previous 5-year average for that month. Following the completion of 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 364 million barrels by the end of September 2011, 34 million barrels higher than the previous 5-year average. Commercial crude oil stocks are gradually drawn down to near their 5-year averages by the end of 2012.

EIA expects refined product inventories to remain close to their 5-year averages despite the recent SPR release. Total motor gasoline stocks at the end of August 2011 were an estimated 208 million barrels, down 13 million barrels from last year but 2 million barrels above the previous 5-year average for that month. Distillate fuel oil stocks ended August 2011 at an estimated 157 million barrels, down 13 million barrels from the same time last year but 7 million barrels above the previous 5-year average. Projected total motor gasoline and distillate inventories average about 1 million barrels and 7 million barrels higher, respectively, than their previous 5-year averages at the end of 2011.

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade gasoline retail price, which averaged $2.78 per gallon in 2010, will increase to $3.56 per gallon in 2011, and average $3.54 per gallon in 2012. The increase in retail prices in 2011 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 $0.50 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 $3.85 per gallon in 2011 and $3.87 per gallon in 2012. Projected U.S. refinery diesel fuel margins increase from an average of $0.38 per gallon in 2010 to $0.65 per gallon in 2011, then fall to an average of $0.58 per gallon in 2012.

Natural Gas

U.S. Natural Gas Consumption. Projected natural gas consumption for electric power generation fell from 29.7 Bcf/d in July to 29.2 Bcf/d in August, as the extreme

temperatures (411 cooling degree-days in July) receded somewhat (to 350 cooling degree-days in August). Hurricane Irene, later downgraded to Tropical Storm Irene as it moved up the East Coast, brought wind, rain, and power outages near the end of the month.

EIA expects that total natural gas consumption will grow by 1.8 percent to 67.3 billion cubic feet per day (Bcf/d) in 2011 (U.S. Total Natural Gas Consumption Chart). Growth in the industrial and electric power sectors accounts for most of the growth in total consumption, with expected increases in 2011 to 18.5 Bcf/d (2.1 percent) and 20.7 Bcf/d (2.4 percent), respectively. Projected total natural gas consumption increases 0.6 percent in 2012 to 67.7 Bcf/d.

U.S. Natural Gas Production and Imports. Marketed natural gas production is expected to average 65.8 Bcf/d in 2011, a 4.0 Bcf/d (6.4 percent) increase over 2010. The majority of this growth is centered in the onshore production in the Lower 48 States, which will more than offset steep projected declines in the Federal Gulf of Mexico (GOM). Forecast GOM production falls 0.9 Bcf/d (13.9 percent) in 2011. EIA expects that overall production will continue to grow in 2012, but at a slower pace, increasing 1.1 Bcf/d (1.7 percent) to an average of 66.9 Bcf/d.

Drilling activity has been resilient despite lower natural gas spot and futures prices. According to Baker Hughes, the August 26 rig count had rebounded to 898 active drilling rigs targeting natural gas, up from 866 on May 20. If drilling continues to increase, production could grow more than expected in 2012.

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 4.1 percent to 8.7 Bcf/d during 2011 and by another 3.8 percent to 8.4 Bcf/d in 2012. 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. Pipeline gross exports to Mexico and Canada are expected to average 4.1 Bcf/d in 2011 and 4.2 Bcf/d in 2012, compared with 3.1 Bcf/d in 2010.

U.S. Natural Gas Inventories. On August 26, 2011, working natural gas in storage stood at 2,961 Bcf, 137 Bcf below last year's level in late August (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, reaching 3.74 Tcf at the end of October 2011.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.05 per MMBtu in August 2011, 37 cents lower than the July 2011 average (Henry Hub Natural Gas Price Chart). This month's *Outlook* lowers the 2011 forecast by 4 cents to $4.20 per MMBtu

and lowers the 2012 forecast by 11 cents to $4.30 per MMBtu. The increase in price from 2011 to 2012 reflects some tightening in supply as production growth slows in 2012.

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 November 2011 delivery (for the 5-day period ending September 1, 2011) averaged $4.07 per MMBtu, and the average implied volatility was 34 percent. The lower and upper bounds for the 95-percent confidence interval for November 2011 contracts are $3.16 per MMBtu and $5.26 per MMBtu. At this time last year, the November 2010 natural gas futures contract averaged $4.07 per MMBtu and implied volatility averaged 48 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $2.84 per MMBtu and $5.83 per MMBtu.

Electricity

U.S. Electricity Consumption. Although cumulative cooling degree-days for 2011 through August for the entire United States were just 2.8 percent higher than the same period in 2010, some regions experienced extreme weather during the past few months. Record heat in Texas has led to record-setting power demand while Hurricane Irene recently caused widespread power outages in the Northeast. Overall, EIA expects relatively flat growth this year for U.S. retail sales of electricity to the residential sector.

Electricity sales to the industrial sector were 3.0 percent higher during the first half of 2011 compared with the same period last year. However, a projected slower recovery in manufacturing for the remainder of this year should translate to lower year-over-year growth in industrial electricity sales of 0.6 percent during the second half. EIA expects total consumption of electricity during 2011 to grow by 0.6 percent from last year's level and by 0.2 percent in 2012 (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. A large number of unplanned nuclear plant outages during the spring of 2011 led to the lowest second-quarter level of nuclear generation since 1999. EIA expects that total nuclear generation for 2011 will be 3.4 percent lower than last year's level. In contrast, the share of generation fueled by natural gas continues to increase, spurred by relatively low fuel costs compared with coal and continued warm summer temperatures. EIA expects the fuel share for natural gas to rise from 23.8 percent in 2010 to 24.2 percent this year and 24.9 percent in 2012 (U.S. Electricity Generation by Fuel, all Sectors Chart).

U.S. Electricity Retail Prices. Retail prices of electricity to the residential sector during the first six months of this year were generally higher than the same period in 2010. Growth in residential electricity prices should moderate during the second half. EIA expects average U.S. residential electricity prices to increase by 2.3 percent in 2011 and by 0.6 percent in 2012 (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. EIA expects that coal consumption for electricity generation will decline by 21 million short tons (MMst) (2.1 percent) in 2011, as total electricity generation rises by 0.4 percent and generation from natural gas increases by almost 2 percent. Forecast coal consumption in the electric power sector declines an additional 22 MMst (2.3 percent) in 2012.

U.S. Coal Supply. EIA forecasts that coal production will fall by 2.2 percent in 2011 despite a significant increase in coal exports. Coal production in the Western region declined in the first half of 2011 by 2.0 percent compared to the same period the year before, while production in the Appalachian and Interior regions increased by 1.6 percent and 5.6 percent, respectively. EIA expects coal production will remain flat in 2012 (U.S. Annual Coal Production Chart).

EIA expects total coal inventories to fall by 12 percent (27 MMst) in 2011, and decline by an additional 2.5 percent (4.9 MMst) in 2012 (U.S. Electric Power Sector Coal Stocks Chart).

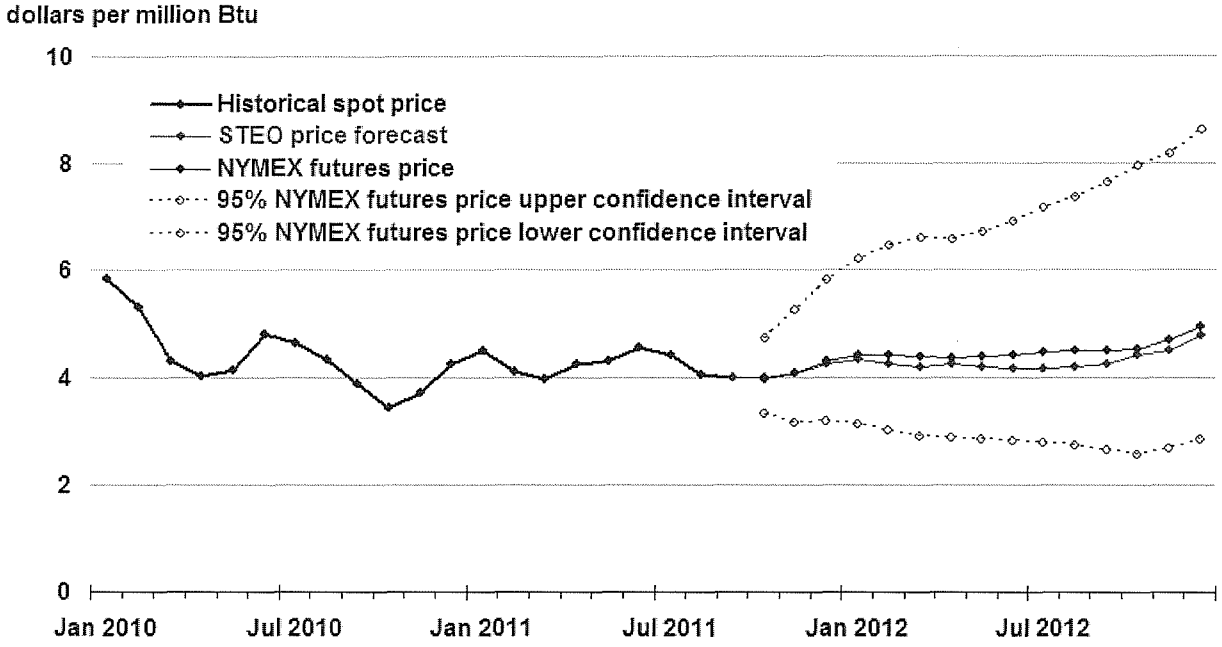
U.S. Coal Trade. U.S. coal exports rose by about 35 percent during the first half of 2011 compared with 2010. The first half exports of 54 MMst were the highest since 1982, when exports were 57 MMst. EIA expects U.S. coal exports to remain elevated over the second half of 2011, reaching an annual total of 99 MMst. Forecast U.S. coal exports fall back to about 87 MMst in 2012 as supply from other major coal-exporting countries recovers from disruptions. EIA also expects strong global demand for coal to continue to suppress coal imports.

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. The projected average delivered coal price to the electric power sector, which averaged $2.26 per MMBtu in 2010, averages $2.37 per MMBtu for 2011 and $2.36 per MMBtu for 2012.

U.S. Carbon Dioxide Emissions

EIA estimates that CO_2 emissions from combusting fossil fuels increased by 3.9 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Forecast fossil-fuel CO_2 emissions fall by 0.7 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. Fossil-fuel CO_2 emissions in 2012 remain stable as expected declines in coal emissions are nearly equaled by the increases in emissions from petroleum and natural gas.

Henry Hub Natural Gas Price



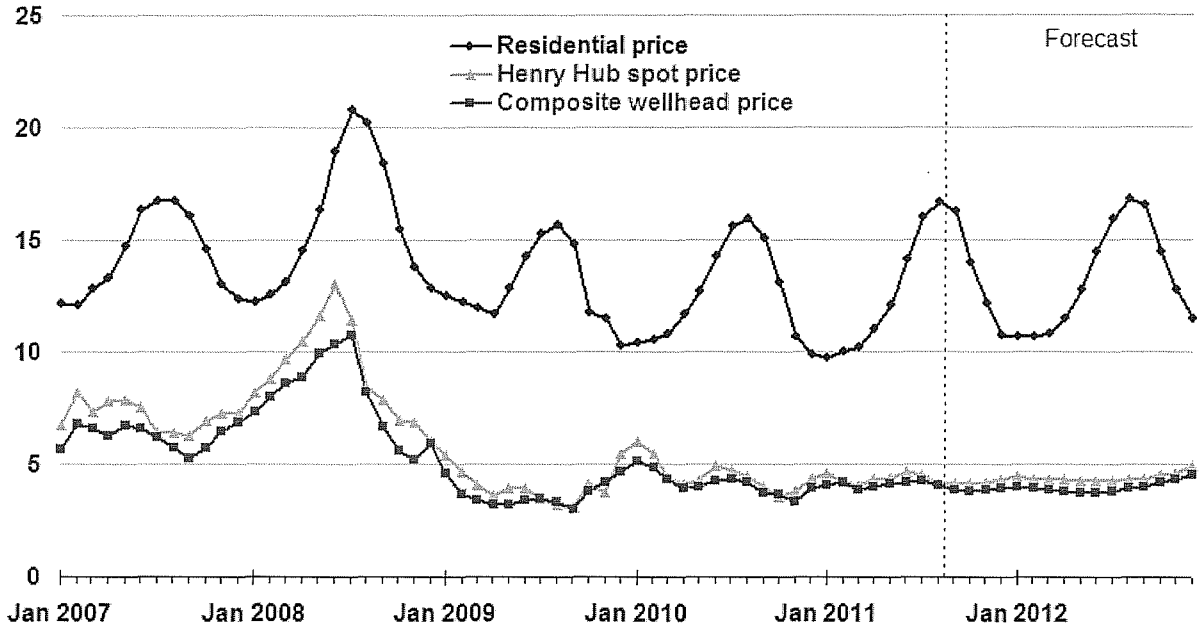
Note: Confidence interval derived from options market information for 5 trading days ending September 1, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, September 2011

eia

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, September 2011

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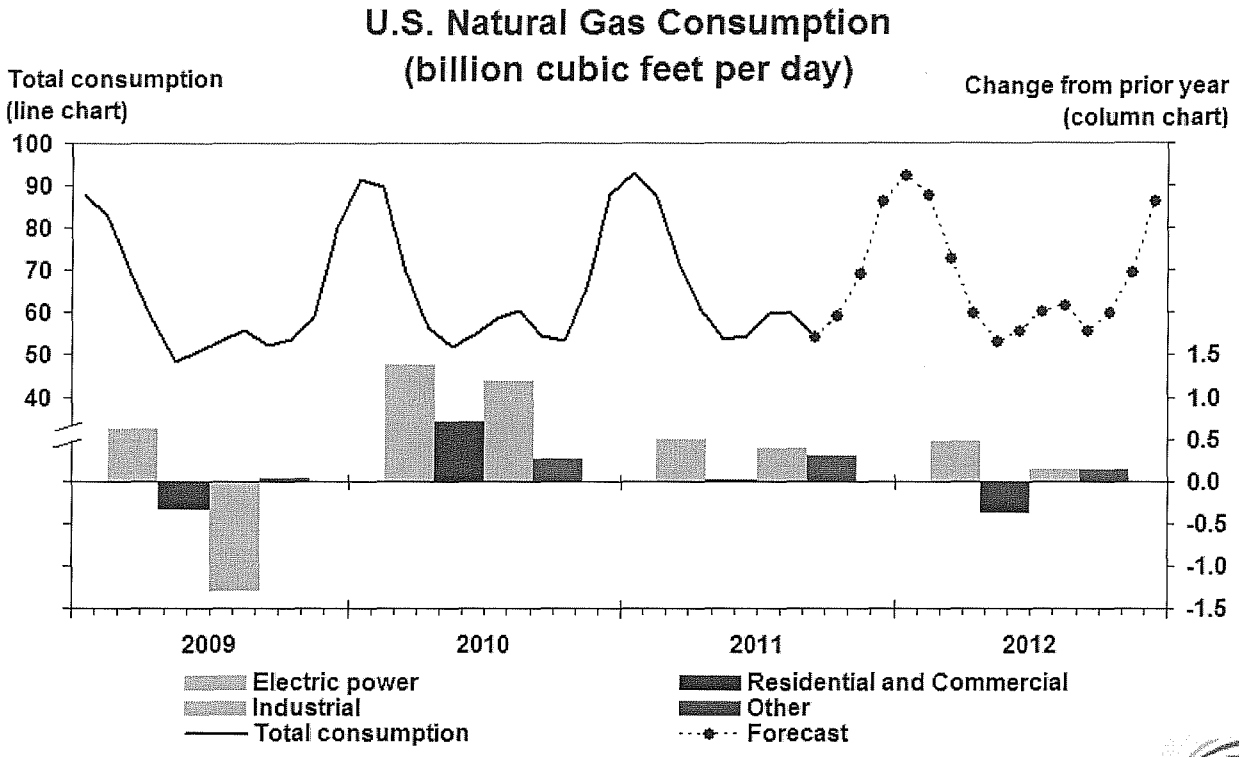
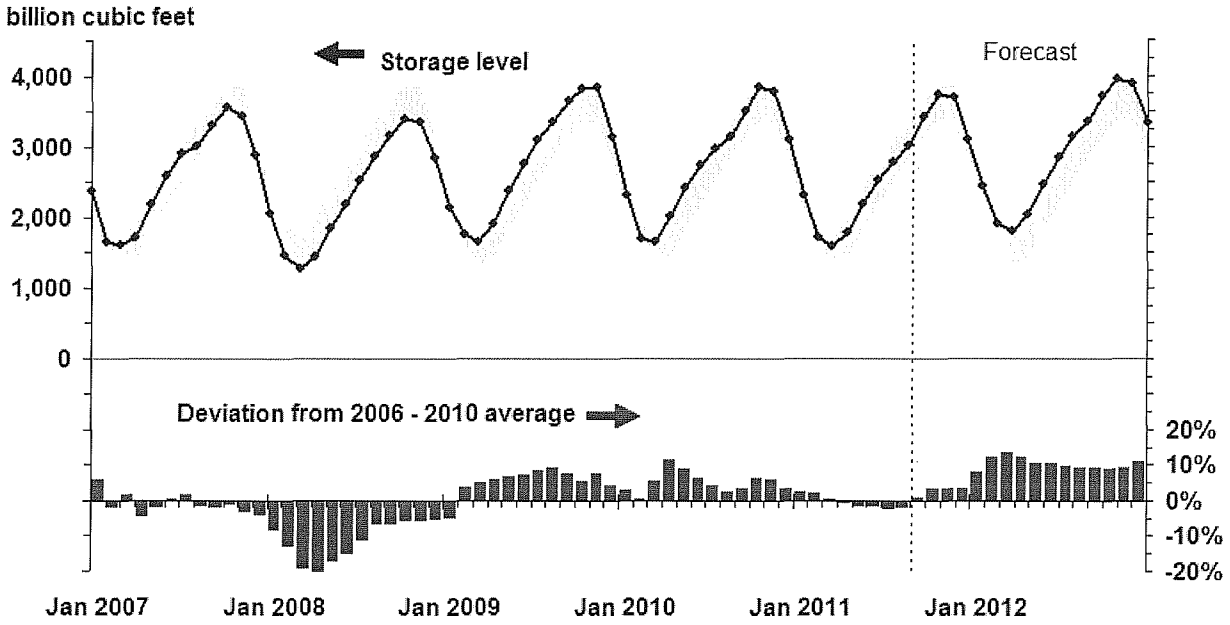


Source: Short-Term Energy Outlook, September 2011

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, September 2011

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2011										**$148,188**
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
August	76,995	0	1,530	78,525	5,973	0.5102	3,047		75,478	313,414
Balance @ August 31, 2011										**$313,414**

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2011									**($5,922)**
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)
August	(3,906)	0	(320)	(4,226)	9,676	(0.0178)	(172)	(4,054)	(40,746)
Balance @ August 31, 2011									**($40,746)**

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).