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

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June 30, 2011

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

Re: Cost of Gas Adjustment (COG)
July 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 (64th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (64th Revised Sheet No. 8), showing the July 2011 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.1848 per mcf for residential and firm general service customers and $0.2233 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for July 2011, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.2233 per mcf since the last COG filing due to an increase in the market price of gas. There has been a decrease in pipeline charges of $0.0385 per mcf due to changes in pipeline rates. The net effect of these changes is an increase of $0.1848 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
64th Revised Sheet No. 1.1
Canceling 63rd 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	$9.1761	$10.4501
			Over 10 MCF	1.0540		10.2301
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$4.3961	$5.5352
			Next 2,600 MCF	0.8931		5.2892
			Over 3,000 MCF	0.7411		5.1372
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$4.3961	$5.6352
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: June 30, 2011

Effective Date: July 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
64th Revised Sheet No. 8
Canceling 63rd 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.	4.2392	(0.9430)	0.5102	3.8064	(0.9285)	(0.0178)	(0.9463)
Current Adj.	(0.0385)	0.2233	0.0000	0.1848	0.2233	0.0000	0.2233
Total Adj.	4.2007	(0.7197)	0.5102	3.9912	(0.7052)	(0.0178)	(0.7230)
Total Rate:	$4.2665	$4.3994	$0.5102	$9.1761	$4.4139	($0.0178)	$4.3961

Date Filed: June 30, 2011 **Effective Date:** July 1, 2011

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JULY 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		17.6296	12	1,681,229	1.1982
Trans Canada - Demand Charge	7,947		24.2162	12	2,309,354	1.6459
BP Canada - Demand Charge	7,947		0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068		17.6296	5	446,734	0.3184
Trans Canada - Seasonal	5,068		24.2162	5	613,639	0.4373
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					$5,965,960	4.2665
Estimated Weighted Average Commodity Cost	1,403,100	1/	4.3994		6,172,798	4.3994
Gas Cost Reconciliation Adjustment						0.5102
Total Current Firm Gas Cost					$12,138,758	9.1761
Base Cost of Gas						5.1849
Accumulated Adjustment						$3.9912

Interruptible	
Estimated Weighted Average Commodity Cost	$4.3994
Gas Cost Reconciliation Adjustment	(0.0178)
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	4.3961
Base Cost of Gas	5.1191
Accumulated Adjustment	($0.7230)

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
JULY 2011

Rates Effective July 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	17.6296	Per dk/Mo.
Trans Canada Pipeline Demand Charge	24.2162	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	17.6296	Per dk/Day
Trans Canada - Seasonal	24.2162	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:	4.3994	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

Rate Schedule	Base Tariff Rate	Adjustment Under Section 19 1/	Rate After Current Adjustment	Fuel and Loss Retention Percentages 2/
Commodity Rates				
FT-A – Maximum Rates				
Zone 1-1	$0.0130	$0.0019	$0.0149	1.47%
Zone 1-2	$0.0130	$0.0019	$0.0149	1.98%
Zone 2-2	$0.0130	$0.0019	$0.0149	0.51%
Minimum Rate	$0.0130	$0.0019	$0.0149	
IT and AOT				
Zone 1-1	$0.1368	$0.0019	$0.1387	1.47%
Zone 1-2	$0.1737	$0.0019	$0.1756	1.98%
Zone 2-2	$0.0834	$0.0019	$0.0853	0.51%
Minimum Rate	$0.0130	$0.0019	$0.0149	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0019 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: 0.17% for Zone 1-1, 0.22 % for Zone 1-2, and 0.05% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
LMS – Load Management Cost Reconciliation Adjustment		$0.0265	

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

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

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	MARKET-TO-MARKET TF12 Variable	MARKET-TO-MARKET 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	0.0383	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.

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	0.0383	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/ 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	0.0019	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		
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
July 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 July monthly price for the AECO Index is expected to increase slightly from the previous month index. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

Natural gas prices for July will be higher due to projected demand from heat requirements and electric generation needs. The year over year price comparison indicates the anticipated July 2011 AECO price will be approximately eight percent higher than the July 2010 index price. The Energy Information Administration (EIA) reported storage levels nationwide as of June 17, 2011 were 2.6 percent below the five-year average and 9.9 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

June 2011

Short-Term Energy Outlook

June 7, 2011 Release

Highlights

- World benchmark crude oil prices reached their highest level of this year at the end of April, fell by about 10 percent by May 9 and have changed very little since then. EIA still expects oil markets to tighten through 2012 given projected world oil demand growth and slowing growth in supply from countries that are not members of the Organization of the Petroleum Exporting Countries (OPEC). The projected U.S. refiner crude oil average acquisition cost rises from $104 per barrel in 2011 to $108 per barrel in 2012, about the same as last month's *Outlook*.

- Based on the outlook from the National Oceanic and Atmospheric Administration (NOAA) for the current Atlantic hurricane season, EIA estimates median (mean) outcomes for total shut-in production in the Federal Gulf of Mexico (GOM) during the upcoming hurricane season (June through November) of about 19 (27) million barrels of crude oil and 53 (78) billion cubic feet (Bcf) of natural gas (see *2011 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). Actual shut-ins are likely to differ significantly from this estimate depending on the number, track, and strength of hurricanes as the season progresses.

- Regular-grade retail gasoline price averaged about $3.96 per gallon during the first half of May as unexpected refinery outages and disruptions in distribution caused by the flooding of the Mississippi River and its tributaries temporarily counterbalanced the impact of lower crude oil prices. In recent weeks, gasoline prices have been falling, however, as the refinery situation has begun to recover. EIA expects the May average price of $3.91 per gallon will be the peak monthly average price this driving season. Still, EIA forecasts that the regular-grade motor gasoline retail price will average $3.75 per gallon during this summer's driving season (from April 1 through September 30), up from $2.76 per gallon last summer, but 6 cents per gallon lower than last month's *Outlook*.

- Natural gas working inventories ended May 2011 at 2.2 trillion cubic feet (Tcf), about 10 percent, or 245 billion cubic feet (Bcf), below the 2010 end-of-May 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 $4.25 per million British thermal units (MMBtu) in 2011, $0.13 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 $4.58 per MMBtu.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA projects that total world oil consumption will grow by 1.7 million barrels per day (bbl/d) in 2011, which is about 0.3 million bbl/d higher than last month's *Outlook*, primarily because of higher forecasts of consumption for electricity generation in China, Japan, and the Middle East. Projected world consumption increases by 1.6 million bbl/d in 2012, unchanged from last month's *Outlook*. Projected supply from non-OPEC countries increases by an average of about 0.6 million bbl/d in 2011 and 0.5 million bbl/d in 2012.

EIA expects that the market will rely on both a drawdown of inventories and increases in production from both OPEC and non-OPEC countries to meet projected demand growth. While OPEC crude oil production declines 0.4 million bbl/d in 2011 because of the disruption forecast to Libyan production, OPEC non-crude liquids production grows by 0.6 million bbl/d. EIA expects the world crude oil market will continue to tighten in 2012, with forecast OPEC crude oil production increasing by 0.7 million bbl/d and OPEC non-crude production growing by 0.4 million bbl/d.

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

Global Crude Oil and Liquid Fuels Consumption. EIA expects that world liquid fuels consumption, which reached a record level of 86.7 million barrels per day in 2010, will grow by 1.7 million bbl/d in 2011 and by an additional 1.6 million bbl/d in 2012, resulting in total world consumption of 90.0 million bbl/d in 2012. Countries outside the Organization for Economic Cooperation and Development (OECD) will make up almost all of the growth in consumption over the next two years, with the largest increases coming from China, Brazil, and the Middle East. Forecasts of 2011

consumption in China, Japan, and the Middle East were raised by 120 thousand bbl/d, 80 thousand bbl/d, and 110 thousand bbl/d, respectively, from last month's *Outlook* because of higher expected demand for petroleum-fueled electric power generation. EIA now expects consumption in China to increase by 700 thousand bbl/d in 2011.

Non-OPEC Supply. EIA projects that non-OPEC crude oil and liquid fuels production will increase by 590 thousand bbl/d in 2011 and by 490 thousand bbl/d in 2012. The greatest increases in non-OPEC oil production during 2011 occur in Brazil (130 thousand bbl/d), Canada (170 thousand bbl/d), China (140 thousand bbl/d), Colombia (110 thousand bbl/d) and countries that were formerly part of the Soviet Union (210 thousand bbl/d). In 2012, EIA expects production growth to remain strong in Canada, China, Brazil, and Colombia, but forecast production growth in the former Soviet Union countries slows to 80 thousand bbl/d. Other non-OPEC areas are expected to decline, including a decrease in North Sea production of 110 thousand bbl/d in 2011 and a further decrease of 200 thousand bbl/d in 2012.

OPEC Supply. Forecast OPEC crude oil production declines by 370 thousand bbl/d in 2011, followed by an increase of 660 thousand bbl/d in 2012. EIA assumes that about one-half of Libya's pre-disruption production will resume by the end of 2012. Estimated OPEC crude oil production during the first quarter of 2011 averaged almost 30 million bbl/d. EIA projects that OPEC surplus capacity will fall from 4.0 million bbl/d at the end of 2010 to 3.6 million bbl/d at the end of 2011, followed by a further decline to 3.1 million bbl/d by the end of 2012. Estimated OPEC production of non-crude liquids totals 6.0 and 6.4 million bbl/d in 2011 and 2012, respectively.

OECD Petroleum Inventories. EIA expects that OECD inventories will decline in 2011 following the steep drop in floating storage that has already occurred. Projected onshore OECD stocks fall by about 120 million barrels in 2011, followed by an additional 110 million-barrel decline in 2012. Days of supply (total inventories divided by average daily consumption) drops from a relatively high 57.9 days during the fourth quarter of 2010 to 54.6 days in the fourth quarter of 2011, and 52.4 days of supply in the fourth quarter of 2012.

Crude Oil Prices. WTI crude oil spot prices averaged $103 per barrel in March, $110 per barrel in April, and $101 per barrel in May. The WTI crude oil price was $113 per barrel at the beginning of May but fell to $97 per barrel by the end of the first week of the month. For the remainder of May, WTI prices fluctuated within a relatively narrow range of between $96 and $103 per barrel. EIA still expects oil markets to tighten as growing liquid fuels demand in the emerging economies and slowing growth in non-OPEC supply maintain upward pressure on oil prices. EIA expects that WTI spot prices, which averaged $79 per barrel in 2010, will average $102 per

barrel in 2011 and $107 per barrel in 2012, about the same as expected in last month's *Outlook* (West Texas Intermediate Crude Oil Price Chart).

Growing volumes of Canadian crude oil imported into the United States contributed to record-high storage levels at Cushing, Oklahoma of over 41 million barrels at the end of March 2011 (86 percent of working capacity at Cushing), and a price discount for WTI compared with similar-quality world crudes such as Brent. A discount for WTI is expected to persist until transportation bottlenecks impacting 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 was about $2.70 per barrel below WTI in 2010, is $1.60 per barrel above WTI in 2011 and $1.10 per barrel above WTI in 2012.

Energy price forecasts are highly uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for August 2011 delivery over the 5-day period ending June 2 averaged $101.49 per barrel and implied volatility averaged 29 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in July of $83 per barrel and $124 per barrel, respectively. Last year at this time, WTI for August 2010 delivery averaged $75 per barrel and implied volatility averaged 39 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $58 per barrel and $97 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of liquid fuels increased by 270 thousand bbl/d (1.4 percent) during the first quarter 2011 over the same period the year before (U.S. Liquid Fuels Consumption Growth Chart). Consumption growth during the first quarter was led by distillate fuel oil (160 thousand bbl/d) and liquefied petroleum gas (70 thousand bbl/d). Motor gasoline consumption fell by 50 thousand bbl/d. Consumption growth is expected to slow over the forecast. Projected total U.S. liquid fuels consumption increases by an average 150 thousand bbl/d (0.8 percent) in 2011, and by a further 130 thousand bbl/d (0.7 percent), to 19.4 million bbl/d in 2012, which is still well below the record-high 20.8 million bbl/d in 2005. Distillate fuel, buoyed by continued increases in industrial production, accounts for two thirds of the projected increase in liquid fuels consumption in 2011. Motor gasoline is the fastest growing consumption category in 2012, reflecting growing population, rising employment and income, and a predicted end to the recent steep run-up in retail gasoline prices.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 150 thousand bbl/d in 2010 to 5.51 million bbl/d, remains at that level in 2011 before declining by 80 thousand bbl/d in 2012 (U.S. Crude Oil Production Chart). EIA expects that production declines from the GOM and Alaska to be offset by projected increases in lower-48 non-GOM production of 230 thousand bbl/d in 2011 and 110 thousand bbl/d in 2012 because of an increase in oil-directed onshore drilling activity.

Based on the outlook from NOAA for the current Atlantic hurricane season, EIA estimates the median outcome for total shut-in crude oil production in the GOM during the upcoming hurricane season (June through November) of 19 million barrels (an average 105 thousand bbl/d over the 6 months). There is a wide range of uncertainty around this forecast (see the *2011 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). The bulk of outages are expected during the late summer and early fall months of August, September, and October.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010, primarily because of the decline in consumption during the recession and rising domestic production. EIA forecasts that liquid fuel net imports will average 9.4 million bbl/d in 2011 and 9.7 million bbl/d in 2012, representing 49 percent and 50 percent of total consumption, respectively.

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade gasoline retail price will increase from $2.78 per gallon in 2010 to $3.60 per gallon in 2011 and to $3.67 per gallon in 2012. The sizable jump in retail prices this year reflects not only the higher average cost of crude oil, but also an increase in U.S. refinery 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 $0.47 per gallon in 2011, still 6 to 9 cents per gallon below the record margins set in 2006 and 2007. Unexpected shutdowns of U.S. refining capacity in March and April with a large drop in gasoline stocks on the East Coast, along with flooding of the Mississippi river in May, contributed to the increase in margins this year. The projected refinery gasoline margin declines to $0.44 per gallon in 2012.

EIA expects that on-highway diesel fuel retail prices, which averaged $2.99 per gallon in 2010, will average $3.87 per gallon in 2011 and $3.95 per gallon in 2012. Projected U.S. refinery diesel fuel margins increase by 21 cents per gallon, from an average $0.38 per gallon in 2010 to $0.59 per gallon in 2011, then fall to $0.53 per gallon in 2012.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will grow by 1.4 percent to 67.1 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 3.1 percent to 18.7 Bcf/d in 2011 and 0.4 percent to 20.3 Bcf/d, respectively. Growth in the electric power sector in 2011 is somewhat moderated by expected declines in cooling demand, with forecasted cooling degree-days falling 14.2 percent compared with last year.

Projected total consumption rises slightly in 2012 to 67.2 Bcf/d. Growth continues in the industrial sector at 1.6 percent, as the natural-gas-weighted industrial production index rises 2.7 percent. Consumption also increases in the electric power sector (2.1 percent). Residential and commercial consumption, however, decline by 2.8 percent and 2.2 percent, respectively, stemming from the forecast decline in heating demand for natural gas.

U.S. Natural Gas Production and Imports. The 2011 production forecast has been revised upward significantly due in part to unexpectedly strong March production reported in the latest EIA *Natural Gas Monthly*. Total U.S. marketed natural gas production is expected to increase by 4.5 percent (to 64.6 Bcf/d) in 2011, up from 2.3 percent (to 63.2 Bcf/d) forecast in last month's *Outlook*.

Production continues to grow at a strong pace despite a significant decline in gas-directed drilling activity. According to Baker Hughes, total working natural gas rigs now number 881, down 11 percent from the August 2010 level. However, growth in oil-directed drilling activity could lead to significant increases in associated natural gas production. EIA expects rising natural gas prices in 2012 to contribute to an increase in drilling activity.

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 4.2 percent to 8.7 Bcf/d during 2011 and by 3.7 percent to 8.4 Bcf/d in 2012. Increased pipeline gross exports to Mexico and Canada during the first part of 2011 have led to an upward revision for both 2011 and 2012. Pipeline gross exports are expected to average 4.1 Bcf/d in 2011 and 3.9 Bcf/d in 2012, compared to just 3.1 Bcf in 2010.

EIA projects 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 2011 and 0.95 Bcf/d in 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 May 27, 2011, working natural gas in storage stood at 2,107 Bcf, which is 237 Bcf below last year's level in late May (U.S. Working Natural Gas in Storage Chart). EIA expects that inventories, though lower than last year, will remain robust given higher forecast production throughout the 2011 injection season. Projected inventories surpass 3.8 Tcf at the end of October 2011 as a result of high production levels and a mild summer relative to last year.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.31 per MMBtu in May, 6 cents higher than the April average and 11 cents higher than forecast in last month's *Outlook* (Henry Hub Natural Gas Price Chart). EIA expects that the Henry Hub price will average $4.25 per MMBtu in 2011, a decline of 13 cents from the 2010 average. EIA expects that the slowing growth in production will contribute to a tightening domestic market next year with the Henry Hub price averaging $4.58 per MMBtu in 2012.

Uncertainty over natural gas prices is lower this year compared to last year at this time (Energy Price Volatility and Forecast Uncertainty). Natural gas futures for August 2011 delivery (for the 5-day period ending June 2) averaged $4.66 per MMBtu, and the average implied volatility was 33 percent. The lower and upper bounds for the 95-percent confidence interval for August 2011 contracts are $3.91 per MMBtu and $5.47 per MMBtu. At this time last year, the natural gas August 2010 futures contract averaged $4.47 per MMBtu and implied volatility averaged 47 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. EIA expects little change in total U.S. electricity consumption between 2010 and 2011 (U.S. Total Electricity Consumption Chart). Cooling degree-days during 2011 are assumed to be 14 percent lower than last year, which drives the projected 2.5-percent decline in retail electricity sales to the residential sector. Improved economic conditions should lead to a 3.6-percent increase in sales to the industrial sector, while commercial-sector electricity sales show little change in 2011. During 2012, total U.S. electricity consumption grows by 2.0 percent.

U.S. Electricity Generation. EIA projects that total generation by the electric power sector during 2011 will remain close to last year's level (U.S. Electric Power Sector

Generation Growth Chart). Weather events have significantly affected generation dispatching patterns this spring. Preliminary data indicate that hydroelectric generation during March reached its highest level since 1999 as a result of heavy precipitation in the Northwest, while strong thunderstorms and tornados caused a number of unplanned nuclear plant outages during April. The increase in hydroelectric generation this year contributes to a decline in the share of total generation fueled by coal and flat natural gas generation during 2011. EIA expects a 2.0-percent increase in total electric power sector generation in 2012, fueled primarily by increases in coal- and natural gas-fired generation.

U.S. Electricity Retail Prices. EIA expects the average U.S. residential electricity price to rise from 11.58 cents per kilowatthour in 2010 to 11.83 cents per kilowatthour this year, an increase of 2.2 percent (U.S. Residential Electricity Prices Chart). The cost of coal and natural gas to the electric power sector this year is expected to stay flat, which should flatten retail electricity prices next year because of regulatory lags in the pass-through of generation costs to retail prices.

Coal

U.S. Coal Consumption. Coal consumption in the electric power sector grew by 4.5 percent in 2010, primarily the result of higher electricity demand during the summer. EIA projects that coal consumption in the electric power sector will decrease by 1.5 percent in 2011, as electricity demand remains flat and generation from other energy sources increases. Forecast coal consumption in the electric power sector grows by 2.9 percent in 2012 (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Coal production in 2010 grew by only 1.0 percent despite the 5-percent increase in total U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase (U.S. Electric Power Sector Coal Stocks Chart). EIA projects that coal production will remain flat in 2011, followed by a 2.5-percent increase in 2012 (U.S. Annual Coal Production Chart).

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, resulted in sharp increases in U.S. coal exports in 2010. U.S. coal exports rose about 50% during the first quarter of 2011 compared to 2010, reaching 26.6 million short tons (mmst), the highest level since 1992. While coking coal remains the primary export, exports of steam coal led recent growth, rising 160% over the same period. EIA expects U.S. coal exports to remain elevated in 2011, particularly in the first half of the year, reaching an annual level of 98 mmst. Forecast U.S. coal exports fall back to more typical historical levels (approximately 80 mmst) in 2012 as supply from other major coal-exporting countries recovers.

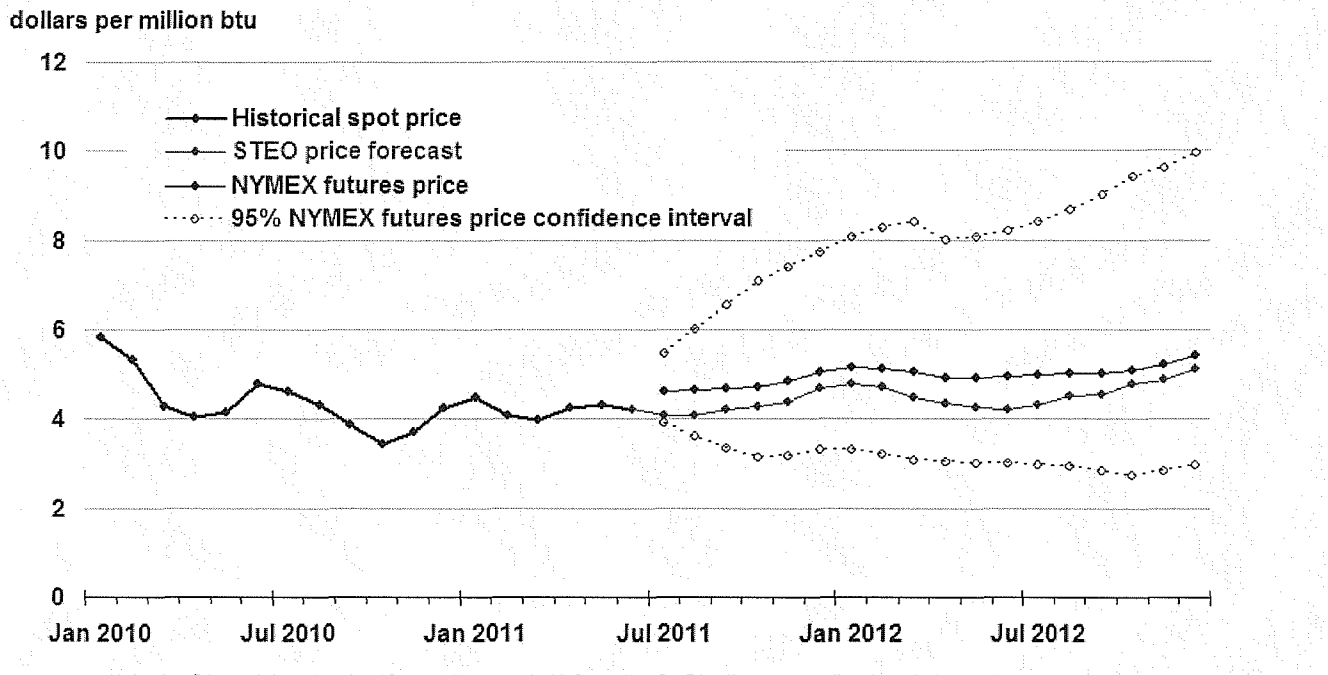
EIA also expects the strong global demand for coal to continue to suppress coal imports, with imports at levels below 19 mmst in both 2011 and 2012. U.S. coal imports averaged about 31 mmst annually from 2004 through 2009.

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

U.S. Carbon Dioxide Emissions

EIA estimates that fossil-fuel CO_2 emissions increased by 3.8 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Forecast fossil-fuel CO_2 emissions remain flat in 2011 as emission increases from higher petroleum and natural gas consumption are offset by declines in coal consumption. Expected increases in consumption of all fossil fuels in 2012 contribute to a 1.6-percent increase in fossil-fuel CO_2 emissions.

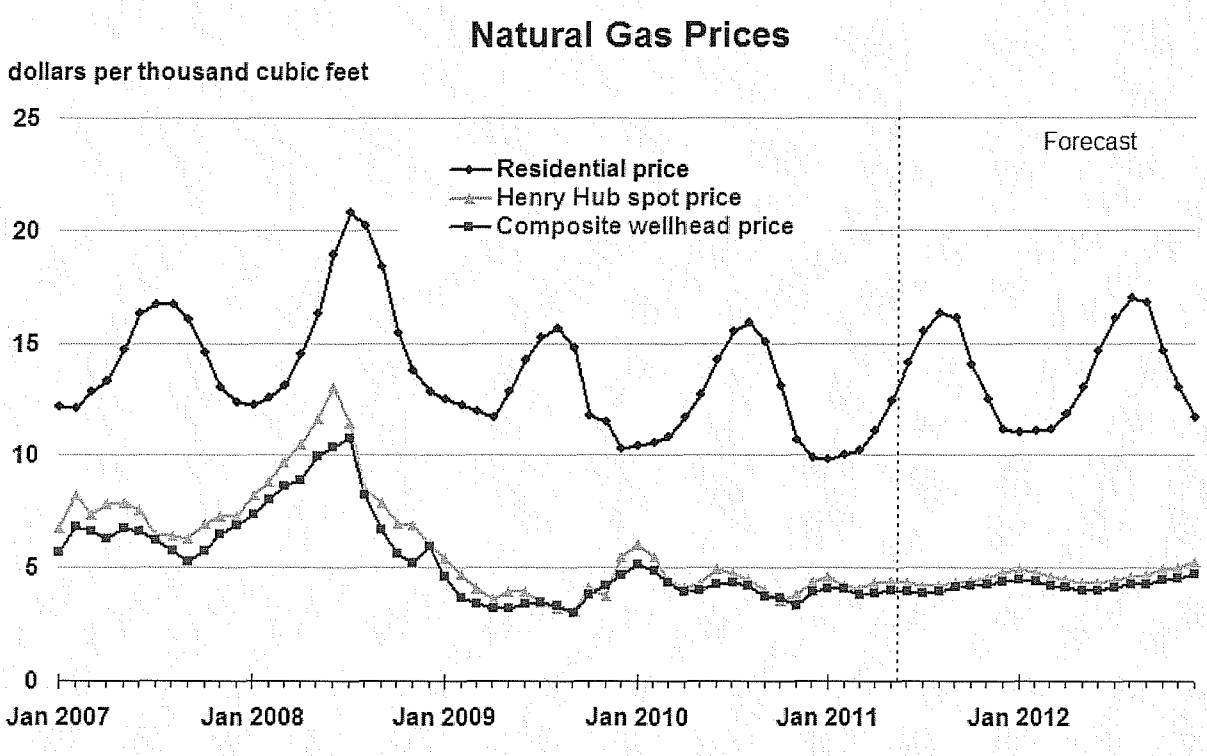
Henry Hub Natural Gas Price



Note: Confidence interval derived from options market information for 5 trading days ending June 2, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, June 2011

eia



Source: Short-Term Energy Outlook, June 2011

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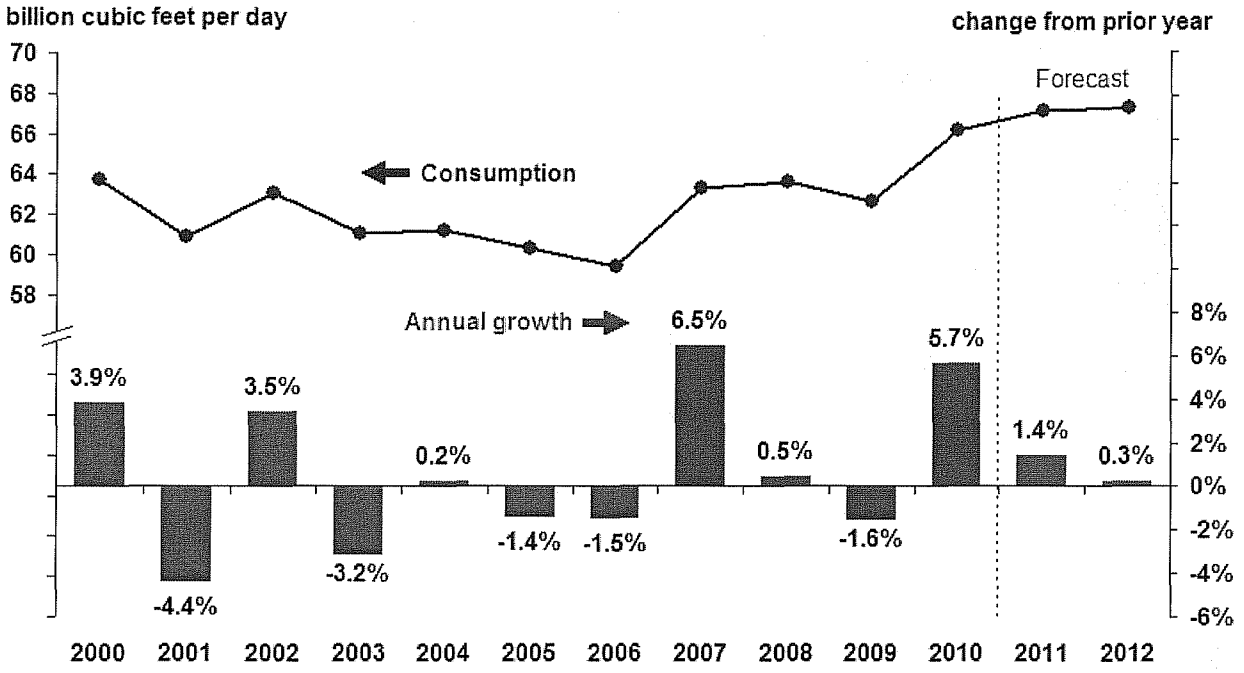
U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, June 2011

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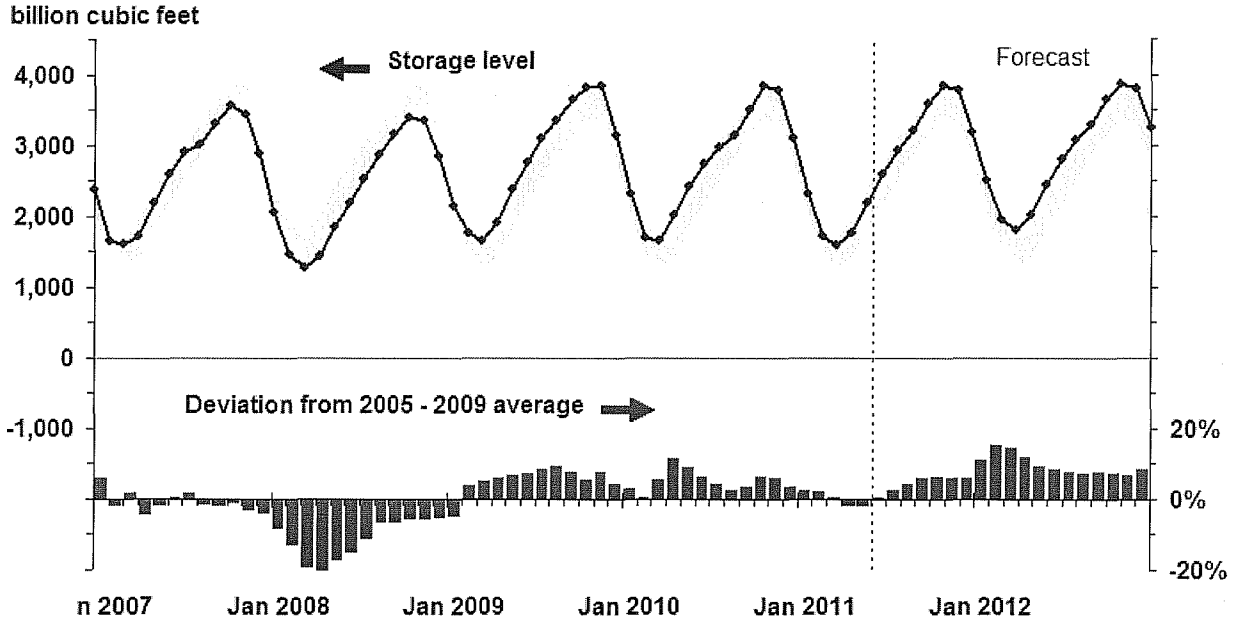
U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, June 2011

eia

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
Balance @ May 31, 2011									**$140,749**

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

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)
Balance @ May 31, 2011									**($20,870)**

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