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January 4, 2012

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

Re: Cost of Gas Adjustment (COG)
January 2012

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 (70th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (70th Revised Sheet No. 8), showing the January 2012 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of \$0.0595 per mcf for residential and firm general service customers and a decrease of \$0.0061 per dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for January 2012, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased \$0.0061 since the last COG filing. There has been a decrease in pipeline charges of \$0.0534 per mcf due to changes in pipeline rates. The net effect of these changes is a decrease of \$0.0595 per mcf for residential and firm general service customers.

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

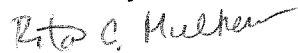
Attachment D shows the calculation of the balancing account since April 30, 2011.

Montana-Dakota also submits herewith its check for \$600.00 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment will cover the filing fee associated with the monthly COG filings.

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

70th Revised Sheet No. 1.1

Canceling 69th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$7.5881	\$8.8621 8.6421
Firm Gas Service - General Highway 13	2.5	\$3.50 per month	First 10 MCF \$2.1740 Over 10 MCF 1.9540	\$7.5881	\$9.7621 9.5421
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$3.1069	\$4.2460 4.0000 3.8480
Interruptible Gas Service - Highway 13	3.5	\$3.50 per month	First 400 MCF \$2.0391 Next 2,600 MCF 1.7931 Over 3,000 MCF 1.6411	\$3.1069	\$5.1460 4.9000 4.7480
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$3.1069	\$4.3460
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: January 4, 2012

Effective Date: Service rendered on and after January 4, 2012

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
 70th Revised Sheet No. 8
 Canceling 69th 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.	3.9553	(2.0028)	0.5102	2.4627	(1.9883)	(0.0178)	(2.0061)
Current Adj.	(0.0534)	(0.0061)	0.0000	(0.0595)	(0.0061)	0.0000	(0.0061)
Total Adj.	3.9019	(2.0089)	0.5102	2.4032	(1.9944)	(0.0178)	(2.0122)
Total Rate:	\$3.9677	\$3.1102	\$0.5102	\$7.5881	\$3.1247	(\$0.0178)	\$3.1069

Date Filed: January 4, 2012 **Effective Date:** Service rendered on and after January 4, 2012

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager **Case No.:**

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2012**

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	2,000	3.7671	5	37,671	0.0268
TFX Seasonal	2,000	15.1530	5	151,530	0.1080
NOVA - Demand Charge	7,947	16.3050	12	1,554,910	1.1082
Trans Canada - Demand Charge	7,947	22.8507	12	2,179,134	1.5531
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0653
NOVA - Seasonal	5,068	16.3050	5	413,169	0.2945
Trans Canada - Seasonal	5,068	22.8507	5	579,037	0.4127
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				\$5,546,653	3.9677
Estimated Weighted Average Commodity Cost	1,403,100	1/ 3.1102		4,363,922	3.1102
Gas Cost Reconciliation Adjustment					0.5102
Total Current Firm Gas Cost				\$9,910,575	7.5881
Base Cost of Gas					5.1849
Accumulated Adjustment					\$2.4032
 <u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$3.1102
Gas Cost Reconciliation Adjustment					(0.0178)
LMS Demand 2/					0.0145
Total Current Interruptible Gas Cost					3.1069
Base Cost of Gas					5.1191
Accumulated Adjustment					(\$2.0122)

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
JANUARY 2012**

Rates Effective January 1, 2012	<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	16.3050	Per dk/Mo.
Trans Canada Pipeline Demand Charge	22.8507	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.3050	Per dk/Day
Trans Canada - Seasonal	22.8507	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:	3.1102	Per dk

Base Rate Effective September 1, 1981

Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation

Firm

Demand 1/	\$0.0658	Per Mcf
Commodity	<u>5.1191</u>	Per Mcf
Total Firm Base Cost	\$5.1849	Per Mcf

Interruptible:

Commodity	\$5.1191	Per Mcf
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1/ Demand base rate calculation: $4,768 \times 12 \times \$0.8100 / 707,222$

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

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	\$0.0017	\$0.0147	1.47%
Zone 1-2	\$0.0130	\$0.0017	\$0.0147	1.98%
Zone 2-2	\$0.0130	\$0.0017	\$0.0147	0.51%
Minimum Rate	\$0.0130	\$0.0017	\$0.0147	
IT and AOT				
Zone 1-1	\$0.1368	\$0.0017	\$0.1385	1.47%
Zone 1-2	\$0.1737	\$0.0017	\$0.1754	1.98%
Zone 2-2	\$0.0834	\$0.0017	\$0.0851	0.51%
Minimum Rate	\$0.0130	\$0.0017	\$0.0147	

- 1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0017 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 Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	\$0.1737	\$0.0000
RPL Service:		
Daily Reservation Rate	\$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			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/	
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.

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

Third Revised Sheet No. 51
Superseding
Second Revised Sheet No. 51

RATE SCHEDULES TFX and LFT

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

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0382	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/		Commodity 6/		Out-of-Balance 6/	
	Maximum	Minimum	Maximum	Minimum	Maximum	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.

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

Third Revised Sheet No. 54
Superseding
Second 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)	1.12%
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.

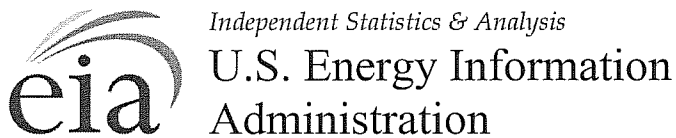
**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
January 2012**

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 January 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).

The continuation of mild weather at the beginning of the heating season, record levels of natural gas in storage and strong domestic supply likely contributed to the index price remaining in the same range as the previous month. The Energy Information Administration (EIA) reported storage levels nationwide as of December 23, 2011 were 13.7 percent above the five-year average and 9.1 percent above 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 15.



December 2011

Short-Term Energy Outlook

December 6, 2011 Release

Highlights

- EIA expects the U.S. average refiner acquisition cost (RAC) of crude oil to increase slightly over the next year, averaging about \$101 per barrel in 2011 and \$102 in 2012. West Texas Intermediate (WTI) crude oil has been trading at a discount to RAC for most of 2011, contrary to the traditional relationship. The forecast WTI price discount relative to the RAC narrows from an average \$11 per barrel in the third quarter of 2011 to \$3 per barrel by the fourth quarter of 2012, supported by the recently announced reversal of the Seaway pipeline in 2012 (see *This Week in Petroleum*, Nov. 30, 2011).
- The warm start to this heating season has lowered the forecast of average household heating expenditures for heating fuels by about 3 percent from last month's *Outlook*. Average household heating oil and propane expenditures are now expected increase by 8 percent and 5 percent, respectively, this winter (October 1 to March 31) compared with last winter. In contrast, natural gas expenditures are projected to decline by 3 percent while electricity expenditures are 2 percent lower than last year's levels.
- Monthly average regular-grade gasoline retail prices in November 2011 averaged \$3.38 per gallon, 52 cents per gallon below their 2011 peak monthly average in May. EIA expects that gasoline pump prices will remain at or below current levels until early spring 2012, when prices begin their normal seasonal rise. Projected regular gasoline retail prices average \$3.45 per gallon in 2012.
- Natural gas working inventories ended November 2011 at a record high for that date, about 1 percent above the same time last year. The projected Henry Hub natural gas spot price averages \$4.02 per million British thermal units (MMBtu) in 2011, \$0.37 per MMBtu lower than the 2010 average. EIA expects that Henry Hub spot prices will continue to decline in 2012, averaging \$3.70 per MMBtu, \$0.43 per MMBtu lower than in last month's *Outlook*.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Tension in the oil-producing regions of the Middle East and Africa continues to exert upward pressure on oil prices. However, this pressure has been offset by the restoration of Libyan oil output, which has thus far exceeded our prior expectations. At the same time, downside demand risks persist, stemming from fears about weakening global economic growth and the contagion effects of the European Union's debt crisis.

Given expected rates of global oil consumption growth driven by emerging markets outside of the Organization for Economic Cooperation and Development (OECD), a combination of increased oil output from members of the Organization of the Petroleum Exporting Countries (OPEC) or inventory withdrawals of about 200 thousand bbl/d will be needed in 2012 to supplement non-OPEC supply growth in order for the oil market to balance at the prices projected in this *Outlook*.

Global Crude Oil and Liquid Fuels Consumption. This forecast assumes non-OECD oil-weighted real GDP increases by 4.9 percent and 5.2 percent in 2011 and 2012, respectively. Forecast OECD oil-weighted GDP growth slows from 1.7 percent in 2011 to 1.5 percent in 2012. EIA expects that world crude oil and liquid fuels consumption will grow from 87.1 million barrels per day (bbl/d) in 2010 to 88.1 million bbl/d in 2011 and 89.5 million bbl/d in 2012 (World Liquid Fuels Consumption Chart). China and other emerging economies account for most of the projected crude oil and liquid fuels consumption growth through 2012. OECD consumption is projected to decline by 0.4 million bbl/d in 2011, and to remain relatively flat in 2012.

Non-OPEC Supply. EIA projects that non-OPEC liquid fuels production will grow by 0.4 million bbl/d in 2011 and 1.2 million bbl/d in 2012 to an average of 53.3 million bbl/d next year (Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart). The largest source of expected growth in non-OPEC liquids production over the forecast is the United States, where production is projected to grow by 340 thousand bbl/d in 2011 and 240 thousand bbl/d in 2012 because of strong growth in on-shore tight oil production. Canada, China, Colombia, and Kazakhstan are each expected to increase production at an average annual rate of 100 thousand bbl/d or more. Brazilian total liquids production remains relatively flat in 2011, as decreased ethanol output offsets modest crude oil production gains. However, expanded Brazilian crude oil offshore production drives an expected increase of nearly 190 thousand bbl/d in 2012.

In contrast, EIA projects that Russian and Mexican annual average production will decrease by 170 thousand bbl/d and 60 thousand bbl/d, respectively, between 2011

and 2012. Regional turmoil, particularly in Syria, Yemen, and Sudan introduces additional uncertainty into the non-OPEC production outlook.

OPEC Supply. While forecast OPEC non-crude liquids production, which is not subject to production targets, is expected to increase by 0.4 million bbl/d in both 2011 and 2012, EIA expects OPEC crude oil production to remain largely unchanged in both years after having grown by 0.7 million bbl/d in 2010. Libyan crude oil production, which began to recover in September, increased from an average of 350 thousand bbl/d in October to an estimated 550 thousand bbl/d in November. Given recent developments in Libya's oil sector, EIA now expects Libyan crude oil production to rise to an average of 900 thousand bbl/d during the first quarter of 2012 and to 1.2 million bbl/d by the fourth quarter of 2012, compared with pre-disruption output of 1.65 million bbl/d.

OPEC surplus crude oil production capacity falls from 3.4 million bbl/d in the fourth quarter of 2010 to a projected 3.0 million bbl/d in the fourth quarter of 2011, but then increases to 4.1 million bbl/d by the first quarter of 2012, as Libyan production capacity comes back on line (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA expects that OECD commercial inventories will decline in 2011 and 2012. However, because of declining consumption, days of supply (total inventories divided by average daily consumption) increases slightly, from 56.9 days in the fourth quarter of 2011 to 57.3 days in the fourth quarter of 2012 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. EIA has revised the projected oil price paths upward from last month's *Outlook*, particularly for WTI. EIA expects that the average refiner acquisition cost for crude oil (RAC) will average \$102 per barrel in 2012, slightly higher than the projection of \$100 per barrel in last month's *Outlook*. EIA expects that the WTI price will average \$98 per barrel in 2012, well above the \$91 per barrel forecast in the previous *Outlook* (West Texas Intermediate Crude Oil Price Chart).

For most of the last 30 years, WTI traded at a premium over the average RAC price. However, the recent growth in crude oil supply, particularly from Canada and North Dakota, to the midcontinent region where WTI is traded, has not yet been matched by increases in transportation capacity out of the midcontinent. This transportation bottleneck contributed to the large price discount this year for WTI relative to other U.S. and world crude oils, which reached a record price discount in the third quarter of 2011. The recent announcement of the planned reversal of the Seaway pipeline, which will begin shipping crude oil from Cushing, Oklahoma to the Gulf Coast in 2012 supports a reduced WTI price discount relative to the RAC. WTI crude oil spot

prices increased from an average \$86 per barrel in October 2011 to \$97 per barrel in November 2011, an \$11 per barrel increase, while the estimated average RAC increased from \$98 per barrel to \$104 per barrel, an increase of \$6 per barrel. EIA expects that the WTI discount will continue to narrow to \$3 per barrel below RAC by the fourth quarter of 2012.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for February 2012 delivery during the 5-day period ending December 1, 2011 averaged \$99 per barrel. Implied volatility averaged 39 percent, establishing the lower and upper limits of a 95-percent confidence interval for the market's expectations of monthly average WTI prices in February 2012 of \$76 per barrel and \$129 per barrel, respectively. Last year at this time, WTI for February 2011 delivery averaged \$86 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$70 per barrel and \$106 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total U.S. liquid fuels consumption in 2011 falls by 260 thousand bbl/d (1.4 percent) from 2010 (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounts for most of the projected decline for the year, shrinking by 230 thousand bbl/d (2.6 percent). EIA expects total liquid fuels consumption to increase by 120 thousand bbl/d (0.6 percent) to 19.0 million bbl/d in 2012.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by 110 thousand bbl/d in 2010 to 5.5 million bbl/d. Projected production increases by roughly 200 thousand bbl/d in 2011 and by a similar amount in 2012 (U.S. Crude Oil and Liquid Fuels Production Chart). This rising trend in production is driven by increased oil-directed drilling activity, particularly in on-shore shale formations. The number of on-shore oil-directed drilling rigs reported by Baker Hughes increased from 768 at the beginning of 2011 to 1,113 on December 2, 2011.

EIA expects that the United States will be a net exporter of petroleum products in 2011 for the first time since 1949 with gross product exports averaging 0.3 million bbl/d more than gross product imports (product exports averaged as much as 2.5 million barrels per day less than gross imports in 2005). EIA expects that the United States will remain a net product exporter of about 0.2 million barrels per day in 2012.

The share of total U.S. consumption met by liquid fuel net imports (including both crude oil and refined products), which has been falling since 2005, is expected to be 45 percent in 2011 and 46 percent in 2012. The 220 thousand bbl/d drawdown in

commercial and government stocks in 2011, which contributed to lower imports, is reversed in 2012 with stocks rising by an average 40 thousand bbl/d.

U.S. Crude Oil and Petroleum Product Inventories. Distillate fuel oil stocks fell by 24 million barrels between Sep. 30, 2011 and Nov. 18, 2011. Distillate fuel inventory at the end of November 2011 was an estimated 139 million barrels, 23 million barrels lower than at the same time last year and 10 million barrels below the average for that month between 2006 and 2010. Total motor gasoline stocks at the end of November 2011 were an estimated 211 million barrels, down 2 million barrels from last year but 2 million barrels higher than the previous 5-year average for that month. Projected total distillate and motor gasoline inventories at the end of 2012 are expected to average about 2 million barrels lower and 3 million barrels higher, respectively, than their previous 5-year averages (U.S. Gasoline and Distillate Inventories Chart).

Commercial crude oil inventory levels ended November 2011 at an estimated 334 million barrels, 18 million barrels below last year but 5 million barrels above the previous 5-year average for that month. Projected commercial crude oil stocks end 2012 at 320 million barrels, about 4 million barrels above the previous 5-year average (U.S. Crude Oil Stocks Chart).

U.S. Petroleum Product Prices. EIA forecasts that the annual average regular-grade gasoline retail price, which was \$2.78 per gallon in 2010, will be \$3.53 per gallon in 2011 and \$3.45 per gallon in 2012 (U.S. Gasoline and Crude Oil Prices Chart). The higher retail price in 2011 reflects not only the higher cost of crude oil but also changes in the average U.S. refinery gasoline margin (the difference between refinery wholesale gasoline prices and the average cost of crude oil), which increases from \$0.34 per gallon in 2010 to \$0.47 per gallon in 2011, then declines to \$0.35 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 both 2011 and 2012 (U.S. Diesel Fuel and Crude Oil Prices Chart).

Between 1990 and 2004 annual average wholesale gasoline prices ranged from 5 cents per gallon to 11 cents per gallon above wholesale diesel prices. Beginning in 2005, wholesale gasoline prices fell below wholesale diesel fuel prices in all years except 2009 as world demand growth for diesel fuel, primarily in the emerging economies, outpaced gasoline demand growth. In 2010 gasoline prices fell below wholesale diesel prices again as world demand growth for diesel fuel picked up. EIA expects the gasoline wholesale price to weaken further relative to diesel prices, averaging 17 cents per gallon below diesel in 2011 and 22 cents per gallon below diesel in 2012.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that total natural gas consumption will average 67.2 billion cubic feet per day (Bcf/d) in 2011 (U.S. Total Natural Gas Consumption Chart). The increasing use of natural gas in the industrial and electric power sectors accounts for most of the increase in total consumption this year, with projected growth rates of 2.3 percent and 2.2 percent, respectively. Projected total natural gas consumption increases by 1.7 percent in 2012 to 68.4 Bcf/d.

U.S. Natural Gas Production and Imports. EIA expects U.S. marketed natural gas production to average 65.9 Bcf/d in 2011, a 4.1-Bcf/d (6.6 percent) increase over 2010. All of this growth comes from higher onshore production in the lower 48 States, which more than offsets a year-over-year decline of 1.2 Bcf/d (20 percent) in the Federal Gulf of Mexico. EIA expects that total marketed production will continue to grow in 2012, but at a slower pace, increasing by 1.8 Bcf/d (2.8 percent) (U.S. Total Natural Gas Production and Imports Chart).

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 6.5 percent to 8.5 Bcf/d during 2011 and by another 3.6 percent to 8.2 Bcf/d in 2012. Projected U.S. imports of liquefied natural gas will fall from 1.2 Bcf/d in 2010 to 0.9 Bcf/d in 2011 and to 0.7 Bcf/d in 2012. Pipeline gross exports to Mexico and Canada are expected to average 4.3 Bcf/d in 2011 and 4.4 Bcf/d in 2012, compared with 3.1 Bcf/d in 2010.

U.S. Natural Gas Inventories. Working natural gas inventories increased by about 390 Bcf during October 2011, a record for that month, and reached 3,851 Bcf on November 25 (U.S. Working Natural Gas in Storage Chart), also a new record high for that week. This winter began with fairly mild weather. Heating degree-days are estimated to be down by 8 percent in October and by 12 percent in November from the 30-year (1970-2000) normal levels. The warm weather combined with the strong production growth this year has enabled stocks to reach such high levels. EIA expects that working natural gas inventories will total about 1.8 Tcf at the end of March 2012. This represents a withdrawal of 2.0 Tcf over the current heating season compared with a withdrawal of 2.3 Tcf last season.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$3.24 per MMBtu in November 2011, 32 cents lower than the October 2011 average and 66 cents lower than the September 2011 average (Henry Hub Natural Gas Price Chart). November marks the fifth consecutive month in which Henry Hub prices have fallen. This month's *Outlook* lowers the 2011 forecast by 7 cents to \$4.02 per MMBtu and lowers the 2012

forecast by 43 cents to \$3.70 per MMBtu. Strength in domestic production and abundant storage supplies have led to relatively low prices this year and EIA expects supply growth to continue.

Natural gas futures prices for February 2012 delivery (for the 5-day period ending December 1, 2011) averaged \$3.63 per MMBtu, and the average implied volatility was 35 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for February 2012 contracts are \$2.79 per MMBtu and \$4.73 per MMBtu. At this time last year, the February 2011 natural gas futures contract averaged \$4.29 per MMBtu and implied volatility averaged 45 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.06 per MMBtu and \$6.03 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption for electricity generation will decline by 19 million short tons (MMst) (2.0 percent) in 2011, as the slight growth in total electricity generation is more than satisfied by increases in generation from natural gas, hydropower, and wind. Projected increases in generation from natural gas and nuclear, combined with lower electricity consumption, contribute to an additional 4.9 percent decline in electric power sector coal consumption in 2012.

U.S. Coal Supply. EIA forecasts that coal production will remain at nearly the same level for a second consecutive year in 2011 (U.S. Annual Coal Production Chart). The significant increase in coal exports in 2011 was balanced by lower domestic consumption and a drawdown in inventories. Coal production in the Western region, which is primarily used for power generation, is projected to decline in by 1.4 percent in 2011 while production in the Appalachian and Interior regions increases by 1.7 percent. EIA expects coal production to decline by 4.1 percent in 2012 as domestic consumption and exports fall. A reduction of coal inventories at electric power plants (EIA expects that nearly 24 MMst will be withdrawn in 2011) is forecast to continue at a slower rate in 2012 (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. U.S. coal exports were 80 MMst for the first 3 quarters of 2011, nearly equaling the 82 MMst exported for the entire year in 2010. EIA expects U.S. coal exports to remain elevated for the remainder of 2011, reaching an annual total of 106 MMst. Forecast U.S. coal exports decline to 97 MMst in 2012, as supply from other major coal-exporting countries recovers from disruptions.

U.S. Coal Prices. Delivered coal prices to the electric power sector have increased steadily over the last 10 years by an average of 6.7 percent each year. EIA expects that

this trend will continue in 2011, largely because of a rise in transportation costs. The projected average delivered coal price to the electric power sector, which was \$2.26 per MMBtu in 2010, rises to \$2.41 per MMBtu in 2011 and \$2.42 per MMBtu in 2012.

Electricity

U.S. Electricity Consumption. Total U.S. consumption of electricity across all sectors is forecast to fall by 0.5 percent during 2012 after having grown by an estimated 0.3 percent this year (U.S. Total Electricity Consumption Chart). Differences in weather patterns are a significant driver of changes in electricity consumption in the residential and commercial sectors. Based on projections from the National Oceanic and Atmospheric Administration that overall temperatures should be closer to normal during 2012 after the hot summer of 2011, EIA expects retail sales of electricity to the residential and commercial sectors to fall by 2.0 percent and 0.4 percent, respectively. Slower growth in manufacturing production next year leads to relatively slow growth in retail sales of electricity to the industrial sector of 0.7 percent during 2012.

U.S. Electricity Generation. Power plant emissions regulations such as the Cross-State Air Pollution Rule (CSAPR) and Maximum Achievable Control Technology (MACT) standards are expected to take effect between 2012 and 2015. The short-term impact of these regulations on the electricity generation fuel mix remains uncertain. The requirement to install pollution control equipment could result in a number of large power plants being taken offline for a significant period of time. Yet the exact level and timing of retrofit outages, or possible retirements, remains unknown. EIA expects coal to fuel about 41.9 percent of total generation during 2012, down from a share of 43.5 percent this year and 44.8 percent in 2010. In contrast, the share of generation fueled by natural gas is forecast to rise from 24.2 percent this year to 25.5 percent in 2012 (U.S. Electric Power Sector Generation Chart). Much of this switching reflects the impact of lower natural gas prices on dispatch decisions.

U.S. Electricity Retail Prices. EIA expects average U.S. residential electricity prices to increase by 1.8 percent in 2011 and by 0.6 percent in 2012 (U.S. Residential Electricity Prices Chart).

Renewables and Carbon Dioxide Emissions

U.S. Renewables. Led by a 23-percent increase in conventional hydropower, the total supply of renewables is projected to grow by about 11 percent from 2010 to 2011. EIA expects total renewable energy supply to decline by 1.4 percent in 2012 as a 12-percent decline in hydropower offsets growth in other renewable energy supplies.

U.S. hydropower generation during 2011 is expected to reach the highest level since 1999, primarily because of high levels of precipitation in the Pacific Northwest. EIA assumes a return to normal snow and rainfall levels in 2012, with hydropower generation falling by 0.37 quadrillion Btu (12 percent).

Wood and wood waste is second only to hydropower in terms of the total energy supplied by renewable sources. A decline of 3.2 percent is projected between 2010 and 2011. Wood supply increases in 2012, growing by 2.6 percent.

Wind energy is projected to grow by 22 percent from 2010 to 2011, but in 2012 growth is projected to slow to 13 percent with the expiration of the production tax credits.

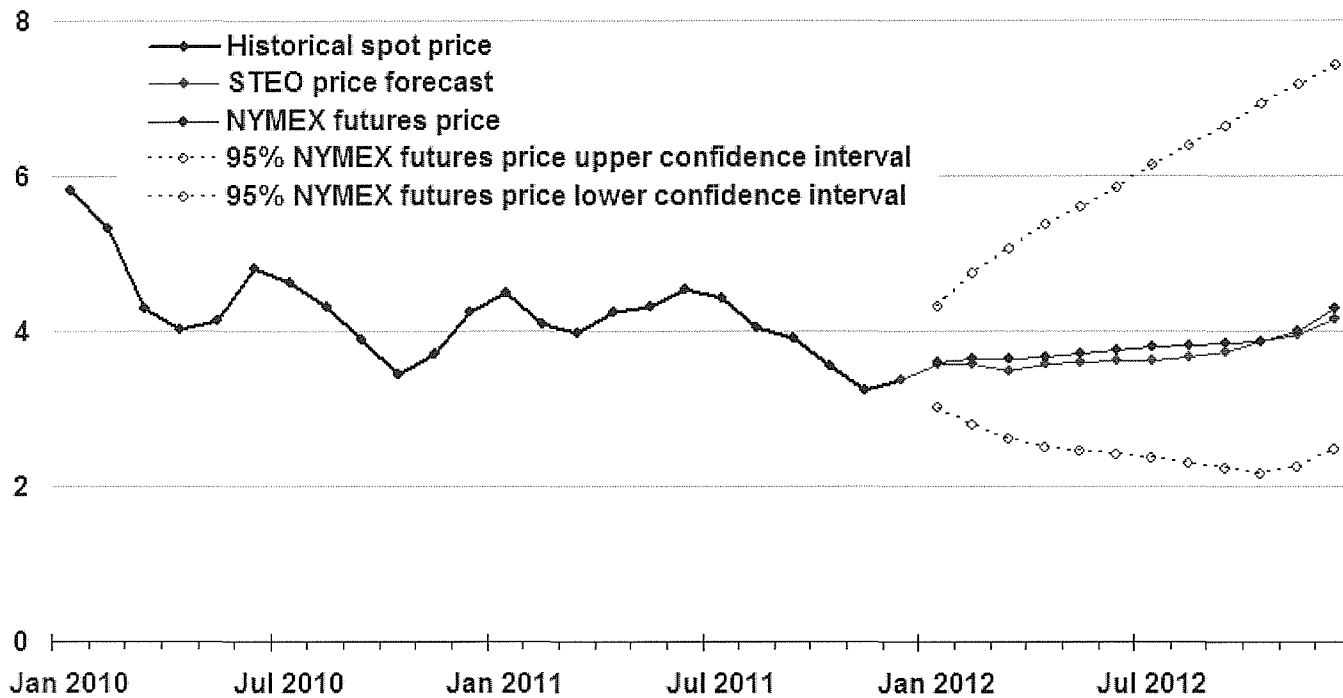
Ethanol production growth, which averaged 120 thousand bbl/d each year between 2005 and 2010, is expected to slow to 40 thousand bbl/d in 2011 and 10 thousand bbl/d in 2012, reaching an average of 920 thousand bbl/d in 2012. Ethanol production nameplate capacity on January 1, 2011 was 888 thousand bbl/d and the estimated maximum sustainable capacity was 929 thousand bbl/d (see EIA [U.S. Fuel Ethanol Plant Production Capacity](#)). Ethanol exports reduce the volume of ethanol blended into gasoline. Assuming ethanol net exports average about 40 thousand bbl/d next year, EIA expects that 880 thousand bbl/d of ethanol will be blended into gasoline in 2012. The expiration of the Federal motor fuels excise tax credit for ethanol blending is expected to have little effect on blending levels, as ethanol producers do not currently appear to be capturing much of the value of the credit.

EIA estimates that biodiesel production in 2011 averaged about 56 thousand bbl/d (860 million gallons total annual production). This volume surpasses the 2011 Renewable Fuel Standard (RFS) Biomass-Based Diesel mandate of 800 million gallons. RFS credits generated above the current mandate can be banked and used for compliance in the following year for up to 20 percent of the requirement. The \$1 per gallon biodiesel tax credit expires at the end of 2011. In 2012, biodiesel production is forecast to grow slightly higher to 62 thousand bbl/d (940 million gallons annually), just reaching the proposed 2012 RFS mandate of 1.0 billion gallons after accounting for 60 million gallons of 2011 credits.

U.S. CO₂ Emissions. EIA estimates that CO₂ emissions from fossil fuels were 5.62 billion metric tons in 2010, a 3.9 percent increase from the prior year (U.S. Carbon Dioxide Emissions Growth Chart). Forecast fossil fuel CO₂ emissions fall by an average 0.7 percent in 2011 and 2012, as increasing emissions from higher natural gas consumption in both years are offset by declines in coal emissions. Petroleum emissions decline in 2011, but increase slightly in 2012.

Henry Hub Natural Gas Price

dollars per million Btu



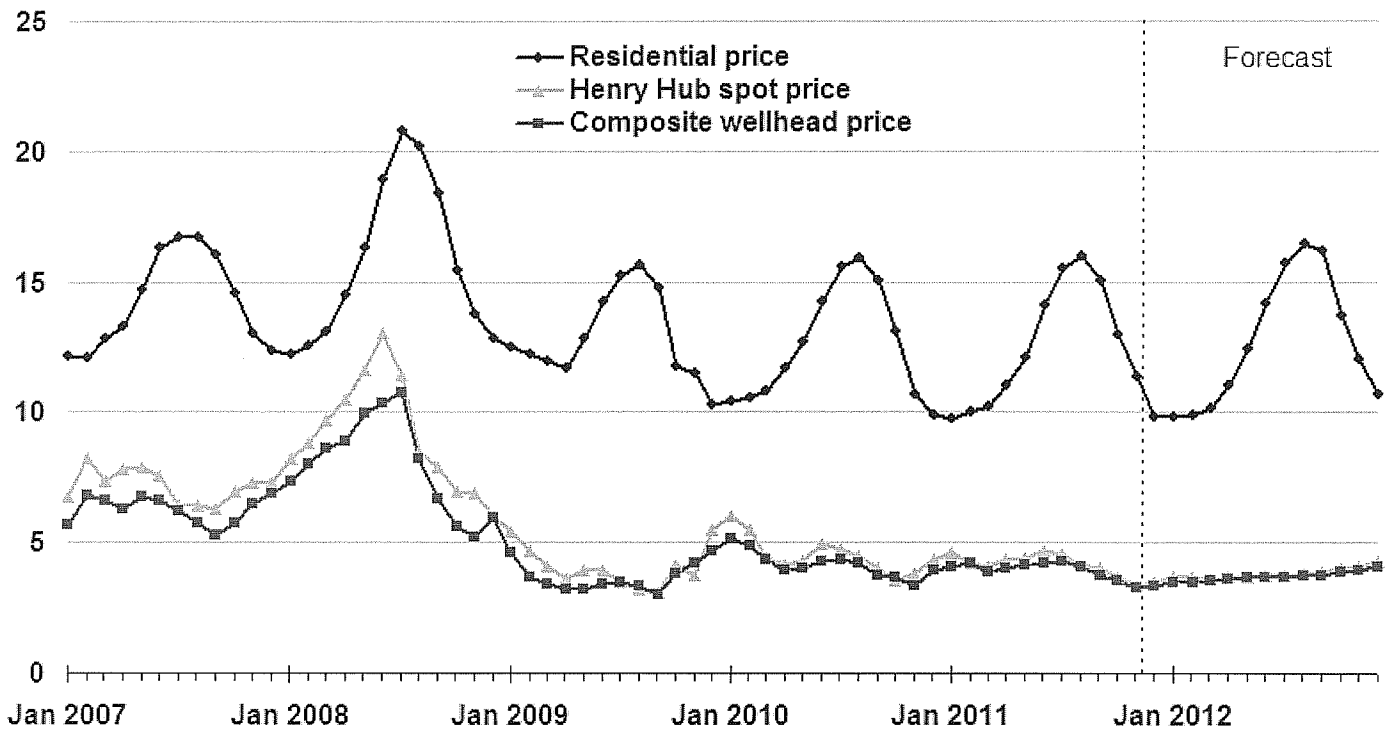
Note: Confidence interval derived from options market information for the 5 trading days ending December 1, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, December 2011



U.S. Natural Gas Prices

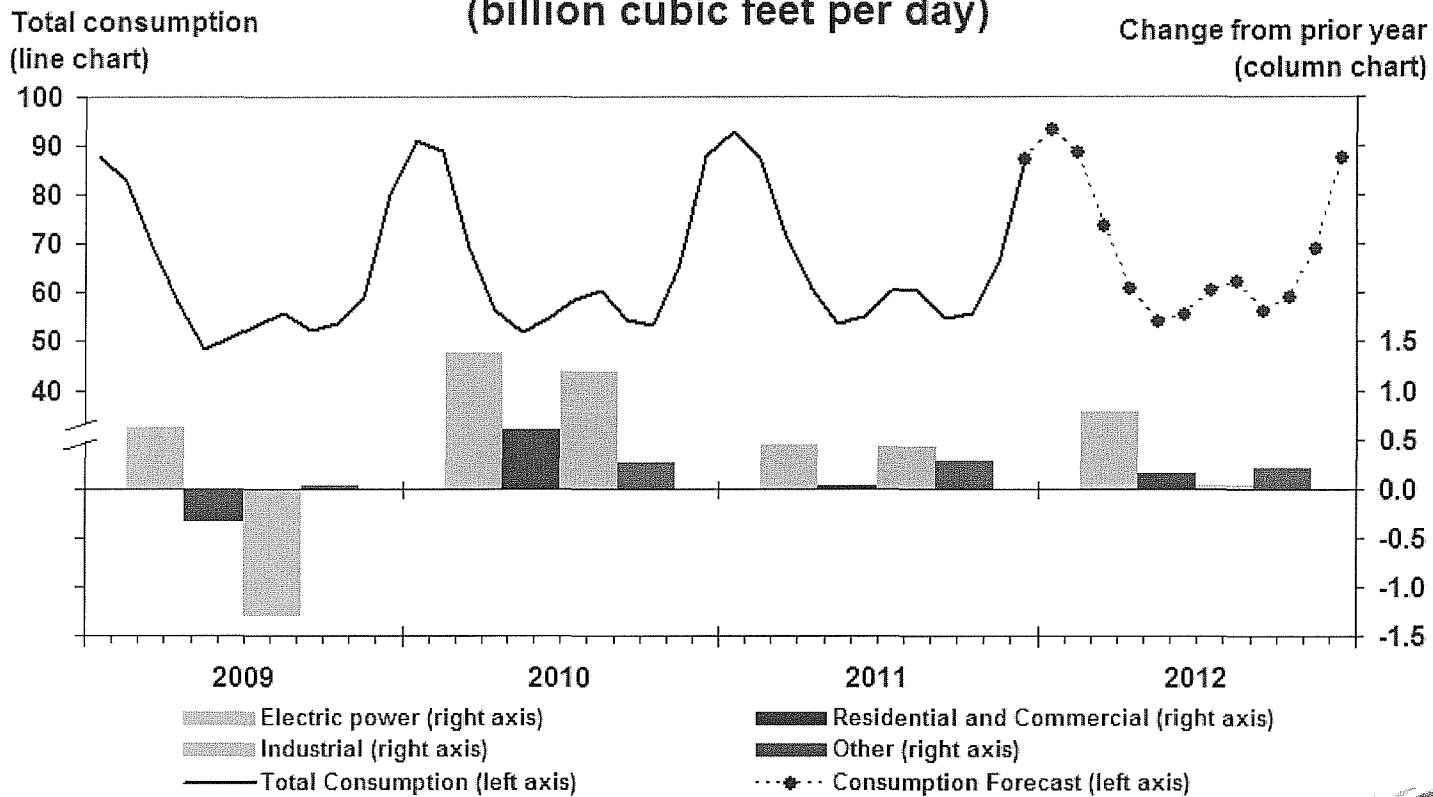
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, December 2011



U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, December 2011

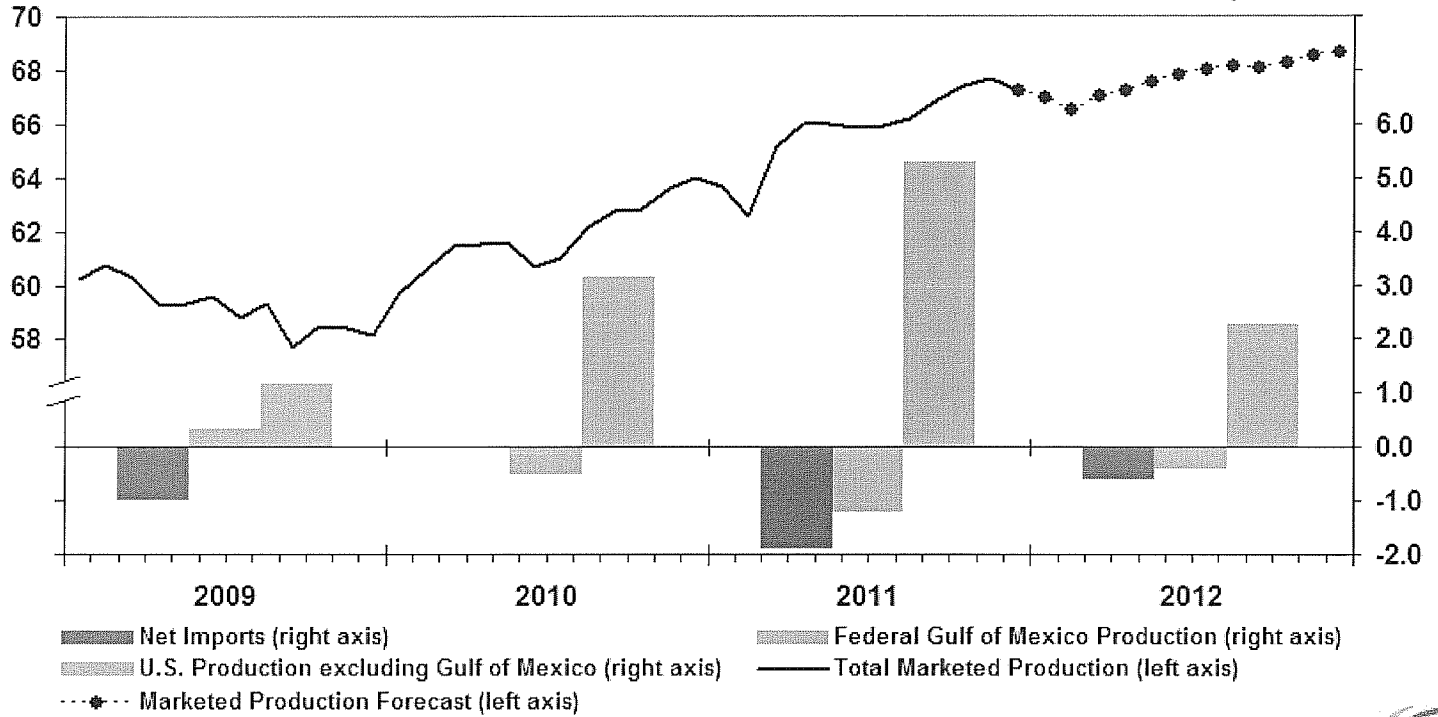


U.S. Natural Gas Production and Imports

(billion cubic feet per day)

Total marketed production
(line chart)

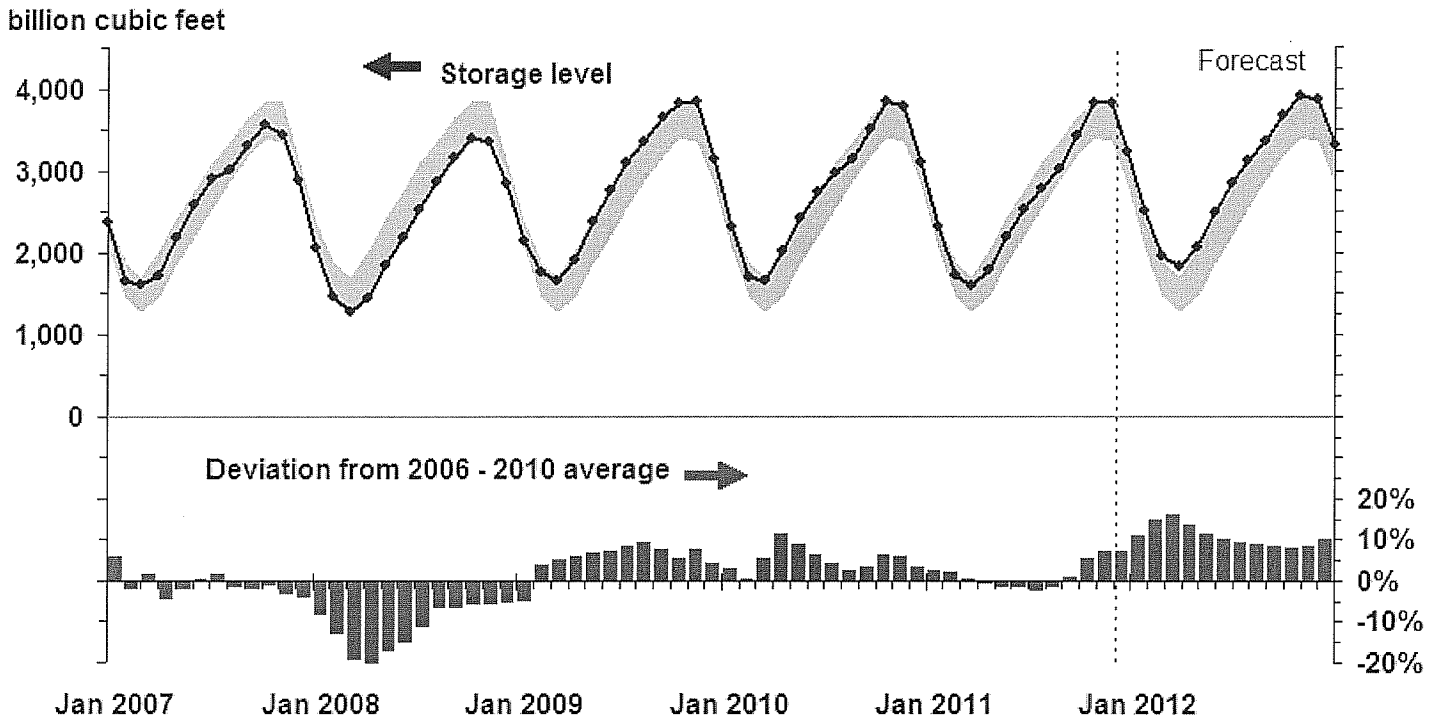
Change from prior year
(column chart)



Source: Short-Term Energy Outlook, December 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, December 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 & 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>
Balance @ April 30, 2011									<u>\$148,188</u>
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
September	25,141	0	2,066	27,207	6,611	0.5102	3,373	23,834	337,248
October	54,572	0	2,227	56,799	8,236	0.5102	4,202	52,597	389,845
November	18,005	0	2,594	20,599	17,707	0.5102	9,034	11,565	401,410
Balance @ November 30, 2011									<u>\$401,410</u>

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 & 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>
Balance @ April 30, 2011									<u><u>(\$5,922)</u></u>
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)
September	(25,158)	0	(348)	(25,506)	10,802	(0.0178)	(192)	(25,314)	(66,060)
October	(1,098)	0	(529)	(1,627)	13,245	(0.0178)	(236)	(1,391)	(67,451)
November	(4,349)	0	(535)	(4,884)	24,583	(0.0178)	(438)	(4,446)	(71,897)
Balance @ November 30, 2011									<u><u>(\$71,897)</u></u>

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).