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

ORIGINAL

705 West Fir Ave.
PO Box 176
Fergus Falls, MN 56538-0176
(218) 736-6935

January 29, 2010

RECEIVED

FEB 01 2010

PUBLIC SERVICE COMMISSION

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

Re: Cost of Gas Adjustment (COG)
February 2010

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 (47th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (47th Revised Sheet No. 8), showing the February 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $.0159 per mcf for residential and firm general service customers and no change for interruptible customers.

Attachment B shows the calculations supporting the gas costs for February 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has not changed since the last COG filing. There has been an increase in pipeline charges of $0.0159 per mcf due to changes in pipeline charges. The net effect of these changes is an increase of $0.0159 per mcf for residential and firm general service customers.

Attachment C discusses the market conditions of the gas commondity.

Attachment D shows the calculation of the balancing account since April 30, 2009.

Great Plains submitted a check for $600.00 on January 19, 2010 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 Analysis Manager

Attachments

# GREAT PLAINS NATURAL GAS CO.

*A Division of MDU Resources Group, Inc.*

## State of North Dakota
## Gas Rate Schedule

NDPSC Volume 2
47th Revised Sheet No. 1.1
Canceling 46th 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 | $8.8479 | $10.1219 |
| | | | Over 10 MCF | 1.0540 | | 9.9019 |
| Interruptible Gas Service - General | 3 | $3.50 per month | First 400 MCF | $1.1391 | $4.7133 | $5.8524 |
| | | | Next 2,600 MCF | 0.8931 | | 5.6064 |
| | | | Over 3,000 MCF | 0.7411 | | 5.4544 |
| Interruptible Gas Service - Grain Processing | 4 | $3.50 per month | All MCF | $1.2391 | $4.7133 | $5.9524 |
| 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:** January 29, 2010 **Effective Date:** February 1, 2010

**Issued By:** Donald R. Ball
Vice President - Regulatory Affairs

**Case No.:**

# GREAT PLAINS NATURAL GAS CO.

*A Division of MDU Resources Group, Inc.*

## State of North Dakota
## Gas Rate Schedule

NDPSC Volume 2
47th Revised Sheet No. 8
Canceling 46th 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. | 3.0767 | 0.3361 | 0.2343 | 3.6471 | 0.3361 | (0.7419) | (0.4058) |
| Current Adj. | 0.0159 | 0.0000 | 0.0000 | 0.0159 | 0.0000 | 0.0000 | 0.0000 |
| Total Adj. | 3.0926 | 0.3361 | 0.2343 | 3.6630 | 0.3361 | (0.7419) | (0.4058) |
| Total Rate: | $3.1584 | $5.4552 | $0.2343 | $8.8479 | $5.4552 | ($0.7419) | $4.7133 |

**Date Filed:** January 29, 2010 **Effective Date:** February 1, 2010

**Issued By:** Donald R. Ball
Vice President – Regulatory Affairs

**Case No.:**

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**FEBRUARY 2010**

| Firm | Billing Determinants | | Rate | Demand Months | Amount | Amount Per dk |
|---|---|---|---|---|---|---|
| FT-A | 7,841 | | $3.4671 | 12 | $326,226 | $0.2084 |
| FT-A - Zone 1-1 | 500 | | 3.4671 | 5 | 8,668 | 0.0055 |
| FT-A - Zone 1-2 | 4,500 | | 4.5871 | 5 | 103,210 | 0.0659 |
| FT-A Seasonal | 3,000 | | 3.7671 | 5 | 56,507 | 0.0361 |
| TFX Seasonal | 3,000 | | 15.1530 | 5 | 227,295 | 0.1452 |
| NOVA - Demand Charge | 7,947 | | 16.6690 | 12 | 1,589,623 | 1.0154 |
| Trans Canada - Demand Charge | 7,947 | | 16.4667 | 12 | 1,570,330 | 1.0030 |
| BP Canada - Demand Charge | 7,947 | | 0.9612 | 12 | 91,664 | 0.0586 |
| NOVA - Seasonal | 5,068 | | 16.6690 | 5 | 422,392 | 0.2698 |
| Trans Canada - Seasonal | 5,068 | | 16.4667 | 5 | 417,266 | 0.2665 |
| BP Canada - Seasonal | 5,068 | | 0.9612 | 5 | 24,357 | 0.0156 |
| BP Canada Winter Surcharge | 5,068 | | 3.0417 | 5 | 77,077 | 0.0492 |
| LMS Demand | 2,500 | | 1.0000 | 12 | 30,000 | 0.0192 |
| Total Demand Charges | | | | | $4,944,615 | 3.1584 |
| Estimated Weighted Average Commodity Cost | 1,565,565 | 1/ | 5.4552 | | 8,540,470 | 5.4552 |
| Gas Cost Reconciliation Adjustment | | | | | | 0.2343 |
| Total Current Firm Gas Cost | | | | | $13,485,085 | 8.8479 |
| Base Cost of Gas | | | | | | 5.1849 |
| Accumulated Adjustment | | | | | | $3.6630 |
| | | | | | | |
| Interruptible | | | | | | |
| Estimated Weighted Average Commodity Cost | | | | | | $5.4552 |
| Gas Cost Reconciliation Adjustment | | | | | | (0.7419) |
| Total Current Interruptible Gas Cost | | | | | | 4.7133 |
| Base Cost of Gas | | | | | | 5.1191 |
| Accumulated Adjustment | | | | | | ($0.4058) |

1/ Authorized in MN Docket No. G004/GR-04-1487 plus Wahpeton volumes.

**GREAT PLAINS NATURAL GAS CO.**
**WAHPETON**
**COST OF GAS ADJUSTMENT**
**FEBRUARY 2010**

| **Rates Effective February 1, 2010** | $/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 | 16.6690 | Per dk/Mo. |
| Trans Canada Pipeline Demand Charge | 16.4667 | Per dk/Mo. |
| BP Canada - Demand Charge | 0.9612 | Per dk/Mo. |
| NOVA - Seasonal | 16.6690 | Per dk/Day |
| Trans Canada - Seasonal | 16.4667 | 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: | 5.4552 | 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

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Twelfth Revised Sheet No. 5
Superseding
Eleventh Revised Sheet No. 5

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 |

Issued by: Raymond D. Neppl, Vice President
Issued on: November 29, 2005 Effective on: January 1, 2006
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP02-132-002, issued November 8, 2002, 01 FERC ¶ 61,170

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Twenty-Seventh Revised Sheet No. 5B
Superseding
Twenty-Sixth Revised Sheet No. 5B

STATEMENT OF RATES
(Rates Per Dekatherm)

| 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 | 0.74% |
| Zone 1 - 2 | $0.0130 | $0.0019 | $0.0149 | 0.87% |
| Zone 2 - 2 | $0.0130 | $0.0019 | $0.0149 | 0.13% |
| Minimum Rate | $0.0130 | $0.0019 | $0.0149 | |
| IT and AOT | | | | |
| Zone 1 - 1 | $0.1368 | $0.0019 | $0.1387 | 0.74% |
| Zone 1 - 2 | $0.1737 | $0.0019 | $0.1756 | 0.87% |
| Zone 2 - 2 | $0.0834 | $0.0019 | $0.0853 | 0.13% |
| 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: .05% for Zone 1-1, .06% for Zone 1-2, and .01% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

Issued by: Ron Mucci, Vice President of Regulatory
Issued on: September 23, 2009
Effective on: November 1, 2009

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Fourteenth Revised Sheet No. 5C
Superseding
Thirteenth Revised Sheet No. 5C

STATEMENT OF RATES
(Rates Per Dekatherm)

| 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 | | $0.0080 | |

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.

Issued by: J. Phill May, Vice President Commercial
Issued on: February 20, 2009
Effective on: April 1, 2009

# 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 | 0.0381 | 0.0212 | | | 0.0175 | 0.0000 | 0.0381 | 0.0212 |
| Field | Market | 0.0381 | 0.0212 | 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.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0003 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
Fifth Revised Volume No. 1

79 Revised Sheet No. 51
Superseding
78 Revised Sheet No. 51

# 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 | 0.0381 | 0.0212 | | | 0.0175 | 0.0000 | 0.0381 | 0.0212 |
| Field | Market | 0.0381 | 0.0212 | 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.
3/ Maximum and Minimum rates include ACA of $0.0019 and the Market Area Electric Compression charge of $0.0003 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.

**Great Plains Natural Gas Co.**
**Market Conditions for Wahpeton's Natural Gas**
**February 2010**

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 estimated price for the February monthly price for the AECO Index is expected to remain the same 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 temperatures varying from well below normal to above normal across much of the U.S during the month of January, the storage balances as of January 22 remained above the level of five year average. The storage levels combined with record daily imports of Liquefied Natural Gas during a portion of the month were likely factors resulting in little change in the index price estimate from last month. The Energy Information Administration (EIA) reported storage levels nationwide as of January 22, 2010 were 3.6 percent above the five-year average and 5.0 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 12.

U.S. Energy Information Administration

**January 2010**

# Short-Term Energy Outlook

January 12, 2010 Release

## Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include monthly forecasts through December 2011.

- EIA expects that the price of West Texas Intermediate (WTI) crude oil, which averaged $62 per barrel in 2009, will average about $80 and $84 per barrel in 2010 and 2011, respectively. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 2.0 percent in 2010 and by 2.7 percent in 2011, while world oil-consumption-weighted real GDP grows by 2.5 percent and 3.7 percent in 2010 and 2011, respectively.

- Escalating crude oil prices drive the annual average regular-grade gasoline retail price from $2.35 per gallon in 2009 to $2.84 in 2010 and $2.96 in 2011. Pump prices are likely to pass $3 per gallon at some point during the upcoming spring and summer. Projected annual average diesel fuel retail prices are $2.98 and $3.14 per gallon, respectively, in 2010 and 2011.

- EIA expects the annual average natural gas Henry Hub spot price for 2010 to be $5.36 per thousand cubic feet (Mcf), a $1.30-per-Mcf increase over the 2009 average of $4.06 per Mcf. The price will continue to increase in 2011, averaging $6.12 per Mcf for the year.

- The annual average residential electricity price changes slightly over the forecast period, falling from 11.6 cents per kilowatthour (kWh) in 2009 to 11.5 cents in 2010, and then rising to 11.7 cents per kWh in 2011.

- Projected carbon dioxide ($CO_2$) emissions from fossil fuels, which declined by 6.1 percent in 2009, increase by 1.5 percent and 1.7 percent in 2010 and 2011, respectively, as economic recovery contributes to an increase in energy consumption.

## Global Crude Oil and Liquid Fuels

*Global Crude Oil and Liquid Fuels Overview.* The world oil market should gradually tighten in 2010 and 2011, provided the global economic recovery continues as projected. While countries outside of the Organization for Economic Cooperation and Development (OECD) will lead 2010 demand recovery, OECD countries should begin to show significant oil demand growth in 2011 in response to improving economic conditions. Projected economic growth in the OECD more than doubles from 1.2 percent in 2010 to 2.7 percent in 2011.

Although compliance with cuts announced by the Organization of the Petroleum Exporting Countries (OPEC) has weakened and global oil inventories and spare production capacity remain very high by historical standards, expectations of a continued global economic turnaround have continued to buttress oil markets. EIA expects that WTI prices, which have been trending upward since February 2009, will continue to increase in 2010 and 2011.

*Global Crude Oil and Liquid Fuels Consumption.* Global oil demand declined in 2009 for the second consecutive year, the first time since 1983 that this had occurred. The decline bottomed out in the middle of 2009, as the world economy began to recover in the last half of the year (World Liquid Fuels Consumption Chart). EIA expects this recovery to continue in 2010 and 2011, contributing to global oil demand growth of 1.1 million barrels per day (bbl/d) in 2010 and 1.5 million bbl/d in 2011. Non-OECD countries are likely to account for most of this growth in 2010, although projected demand in the United States increase slightly by 0.2 million bbl/d after a very weak 2009. China continues to lead world consumption growth with projected increases of more than 0.4 million bbl/d in both 2010 and 2011.

*Non-OPEC Supply.* Non-OPEC oil supply increased by more than 0.6 million bbl/d in 2009, the largest annual increase since 2004. Higher production in the United States, Brazil, and the Former Soviet Union (FSU) were the largest contributors to this growth. However, very little net increase in non-OPEC supply is expected over the forecast period. Projected non-OPEC supply increases by 0.4 million bbl/d in 2010 but then falls slightly by more than 0.1 million bbl/d in 2011. The largest source of growth over this period is Brazil (0.4 million bbl/d), the result of rising offshore and biofuels production. The United States and the FSU each contribute an additional 0.2 million bbl/d of growth. However, large declines in production from the North Sea (0.7 million bbl/d) and Mexico (0.4 million bbl/d) are responsible for offsetting these sources of growth, underlying the low overall growth during the forecast period (see *STEO Supplement: Outlook for non-OPEC Oil Supply in 2010-2011*).

*OPEC Supply.* As many market observers had expected, at its 155th meeting in December 2009 OPEC decided for the time being to keep its current oil production levels unchanged. Although OPEC faces a global oil market that has firmed in response to its production cuts since last January, the strength and durability of the global economic recovery is still uncertain. EIA expects that annual average OPEC crude oil production, which declined by almost 2.2 million bbl/d on average in 2009, will increase by an average of about 0.5 million bbl/d per year through 2011 as global oil demand recovers. In addition, EIA expects OPEC non-crude petroleum liquids, which are not subject to OPEC production targets, to grow by 0.6 million bbl/d in 2010 and by 0.7 million bbl/d in 2011.

OPEC surplus crude oil production capacity, which averaged 2.8 million bbl/d during the 1998-2008 period (OPEC Surplus Crude Oil Production Capacity Chart), will continue to remain high, with surplus capacity reaching almost 6 million bbl/d by the end of the forecast period. As a result of the low growth in non-OPEC supply, OPEC market share could increase to 42 percent in 2011, from 40 percent in 2009. The combination of higher market share and the relatively high level of surplus production capacity would give the group greater influence over the world oil market in the coming years. OPEC is scheduled to meet in Vienna on March 16, 2010, to reassess the market.

*OECD Petroleum Inventories.* EIA estimates OECD commercial oil inventories were 2.69 billion barrels at the end of 2009, equivalent to about 58 days of forward cover, and about 80 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories remain at the upper end of the historical range over the forecast period.

*Crude Oil Prices.* WTI crude oil spot prices averaged $74.50 per barrel in December 2009, about $3.50 per barrel lower than the prior month's average. This decline reflected price weakness during the first 2 weeks of December as the WTI spot price fell from $78 to $70. However, colder-than-normal weather and U.S. crude oil and product inventory draws that exceeded the December 5-year averages helped push the WTI spot price back up to $79 per barrel by the end of the month. EIA forecasts that WTI spot prices will weaken over the next few months, averaging $76 per barrel in March, before rising to about $82 per barrel in the late spring and to $85 by late next year (West Texas Intermediate Crude Oil Price Chart).

Expected WTI price volatility continued to edge lower going into the new year. Crude oil futures market participants were pricing March 2010 options at an implied volatility slightly below 40 percent per annum at the beginning of December 2009, and the level dropped to an average of 34 percent over the 5 days ending on January 7,

2010. March 2010 WTI futures averaged $82 per barrel over that same 5-day window. Thus, the lower and upper limits of the 95-percent confidence interval for the March 2010 futures price were $66 per barrel and $102 per barrel, respectively (see Energy Price Volatility and Forecast Uncertainty).

During the same period last year, market participants were pricing March-delivered WTI into Cushing, Oklahoma, at $50 per barrel. However, the implied volatility of 87 percent was more than twice the current level, resulting in lower and upper limits of $29 and $87 per barrel, respectively, for the 95-percent confidence interval. Global oil markets still were adjusting to highly uncertain conditions following a price collapse from all-time highs for WTI futures in mid-2008.

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

***U.S. Liquid Fuels Consumption.*** Liquid fuels consumption declined by 810,000 bbl/d, or 4.2 percent, in 2009, the second consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). Motor gasoline was the only major petroleum product whose consumption did not decline, having increased by a scant 0.1 percent. Despite the cold weather that gripped much of the Nation in late December, average annual distillate fuel consumption declined by 330,000 bbl/d, or 8.3 percent, in 2009, led by a precipitous decline in transportation usage. EIA projects total petroleum products consumption will rise by 210,000 bbl/d in 2010, or 1.1 percent, due to a moderate economic recovery that began late in 2009. All major products contribute to that increase. Consumption of motor gasoline rises by 50,000 bbl/d, or 0.6 percent, and distillate fuel consumption increases by 80,000 bbl/d, or 2.1 percent. The projected continuing economic recovery in 2011 boosts total petroleum products consumption by 220,000 bbl/d. Both motor gasoline and distillate consumption rise by about 70,000 bbl/d in 2011.

***U.S. Crude Oil and Liquid Fuels Supply.*** Domestic crude oil production averaged 5.31 million bbl/d in 2009, up 360,000 bbl/d from 2008 (U.S. Crude Oil Production Chart). The forecast growth in domestic output slows in 2010 with an increase of 130,000 bbl/d and then declines slightly by 20,000 bbl/d in 2011. Ethanol production continues to grow to meet the volume requirements of the Renewable Fuel Standard. Projected ethanol production, which averaged 690,000 bbl/d in 2009, increases to an average of 790,000 bbl/d in 2010 and 840,000 bbl/d in 2011.

***U.S. Petroleum Product Prices.*** Monthly average regular-grade gasoline prices increased from $1.79 per gallon in January 2009 to $2.61 per gallon in December 2009. EIA expects these prices to average $2.84 per gallon in 2010 and $2.96 per gallon in 2011. Pump prices are likely to pass $3 per gallon at some point during the upcoming

spring and summer. Because of growth in motor gasoline consumption, the difference between the average gasoline retail price and the average cost of crude oil widens in 2010 before starting to level out in 2011.

On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.98 per gallon in 2010 and $3.14 in 2011. As with motor gasoline, the expected recovery in the consumption of diesel fuel in the United States, as well as growth in distillate fuel usage outside the United States, strengthens refining margins for distillate throughout the forecast period.

**Natural Gas**

***U.S. Natural Gas Consumption.*** EIA estimates that total natural gas consumption fell by 1.5 percent in 2009, primarily because of the economic downturn (Total U.S. Natural Gas Consumption Growth Chart). Despite low natural gas prices throughout most of 2009, which contributed to a significant increase in natural gas-fired electric power generation, declines in industrial, residential, and commercial sector consumption drove the year-over-year decline in total consumption.

Total annual natural gas consumption is forecast to remain relatively unchanged in 2010. Higher natural gas prices in 2010 are expected to cause a 2.8-percent decline in natural gas consumption in the electric power sector in 2010, which will offset growth in the residential, commercial, and industrial sectors. Forecast total natural gas consumption increases by 0.4 percent in 2011, led by a 2.5 percent increase in consumption in the industrial sector.

***U.S. Natural Gas Production and Imports.*** EIA estimates that total marketed natural gas production increased by 3.7 percent in 2009, despite a 59-percent decline in the working natural gas rig count from September 2008 to July 2009. Working natural gas rigs have since turned around from the mid-July 2009 low of 665, increasing to 759 as of December 31, 2009. While production growth in 2009 was supported by the enhanced productivity of new wells being drilled, steep declines from initial production at these newly drilled wells and the lagged effect of reduced drilling activity are expected to contribute to a 3-percent decline in 2010 production. EIA expects marketed production to increase by 1.3 percent in 2011 with growth in production from lower-48 non-Gulf of Mexico (GOM) fields offsetting a decline in GOM production.

U.S. pipeline imports declined by almost 0.9 billion cubic feet per day (Bcf/d) in 2009, or 8.8 percent, as Canadian drilling activity and production fell because of lower prices. EIA expects continued low Canadian production to cause U.S. pipeline

imports to fall this year as well, by more than 1 Bcf/d. Meanwhile, EIA forecasts that recent additions to global liquefied natural gas (LNG) supply in Russia, Yemen, Qatar, and Indonesia will cause U.S. LNG imports to increase by almost 0.5 Bcf/d in 2010 to 1.76 Bcf/d. EIA expects U.S. LNG imports to increase slightly in 2011, as growing global demand for LNG absorbs the new supply growth.

***U.S. Natural Gas Inventories.*** On January 1, 2010, working natural gas in storage was 3,123 Bcf (U.S. Working Natural Gas in Storage Chart), 316 Bcf above the previous 5-year average (2005–2009) and 286 Bcf above the level during the corresponding week last year. Colder-than-normal temperatures in December 2009 contributed to an estimated storage withdrawal of 665 billion cubic feet, 32 percent above the previous 5-year average December drawdown. The weekly withdrawal of 207 Bcf during the week ending December 11, 2009, was the largest weekly December drawdown since the week ending December 29, 2000, when 208 Bcf was withdrawn. Despite the large December draw and a projected first-quarter 2010 inventory withdrawal about 6 percent greater than the previous 5-year average, the expected end-of-March 2010 storage level of 1,734 Bcf will be about 16 percent (237 Bcf) greater than the previous 5-year average for that period.

***U.S. Natural Gas Prices.*** The Henry Hub spot price averaged $5.50 per Mcf in December 2009, $1.73 per Mcf higher than the average spot price in November (Henry Hub Natural Gas Price Chart). Prices were affected by the colder-than-normal weather in December, which contributed to an increase of 2.2 Bcf/d in total consumption during December compared with the forecast in last month's *Outlook*. The Henry Hub spot price averaged $4.06 per Mcf in 2009, and the forecast price averages $5.36 per Mcf in 2010 and $6.12 per Mcf in 2011. Continued high storage levels combined with enhanced domestic production capabilities and slow consumption growth are expected to keep prices from rising dramatically through the forecast.

While natural gas inventories remain ample, implied volatility for the futures market in natural gas options moved slightly higher at the start of the new year. Natural gas for delivery in March 2010 at Henry Hub, Louisiana, was priced at $5.73 per million Btu (MMBtu) ($5.90 per Mcf) during the 5 days ending January 7, 2010. Implied volatility for options settling against March 2010 natural gas futures averaged just below 57 percent. Futures market participants, therefore, were pricing a 95-percent confidence interval with a lower limit of $3.88 and an upper limit of $8.47 per MMBtu for the March 2010 contract (see Energy Price Volatility and Forecast Uncertainty).

Last year at this time the picture looked very similar. Futures contracts on natural gas delivered to the Henry Hub during March 2009 traded at $5.90 per MMBtu. Implied

volatility on the March 2009 natural gas options was at 59 percent; thus the lower and upper limits of the 95-percent confidence interval for natural gas prices were $3.94 and $8.84 per MMBtu, respectively.

**Electricity**

***U.S. Electricity Consumption.*** EIA expects total electricity consumption to grow by 1.9 percent in 2010 (U.S. Total Electricity Consumption Chart). This growth is driven by projected increase in residential and commercial sector electricity sales as assumed summer air conditioning use this year returns to normal after the mild summer in 2009. Improving economic conditions will help drive growth in electricity sales to the industrial sector over the next two years, with projected consumption of electricity in this sector growing by 0.9 percent in 2010 and 2.0 percent 2011.

***U.S. Electricity Generation.*** Total expected electricity generation in 2010 reaches an average of about 11 billion kWh per day, 0.22 billion kWh more than the average level of generation in 2009, and increases to 11.2 in 2011. This growth will be primarily supplied by increases from wind, nuclear, and coal-fired generation sources.

***U.S. Electricity Retail Prices.*** Many utilities have made downward fuel cost adjustments recently as a result of lower fuel costs in 2009. These adjustments have been offset somewhat by the need to increase revenues to cover the capital costs of expanding renewable energy generation (U.S. Residential Electricity Prices Chart). Overall, forecast residential electricity prices fall by 0.9 percent in 2010 and increase by 1.4 percent in 2011.

**Coal**

***U.S. Coal Consumption.*** Estimated coal consumption by the electric power sector fell by nearly 10 percent in 2009. Lower total electricity generation combined with increases in generation from natural gas (5 percent) and hydropower (5 percent) were the major factors leading to the decline in coal consumption. Anticipated increases in electricity demand and higher natural gas prices will contribute to growth in coal-fired generation in 2010 and 2011. Forecast coal consumption in the electric power sector increases by almost 4 percent in 2010 but remains below 1 billion short tons for the second consecutive year. A projected 2.5-percent increase in electric-power-sector coal consumption puts it at the 1-billion-short-ton level in 2011. Estimated coal consumption for coke production declined by 30 percent in 2009. Consumption of coal at coke plants rises over the forecast period as economic conditions improve, with an increase of 4 million short tons (28 percent) in 2010 and an additional 3-percent increase in 2011. EIA projects growth in 2010 and 2011 for coal consumption in the

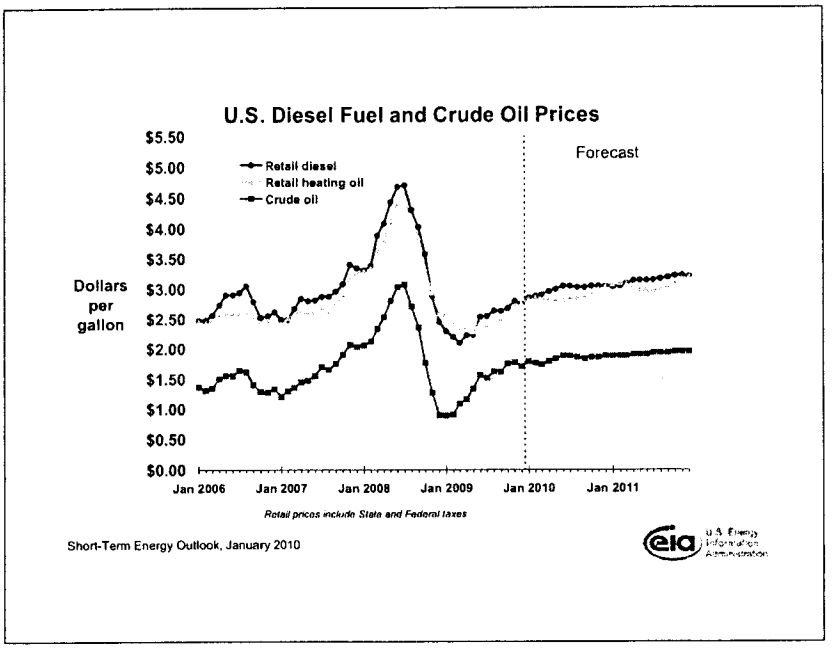
retail and general industry sectors, following a 17-percent decline in 2009 (U.S. Coal Consumption Growth Chart).

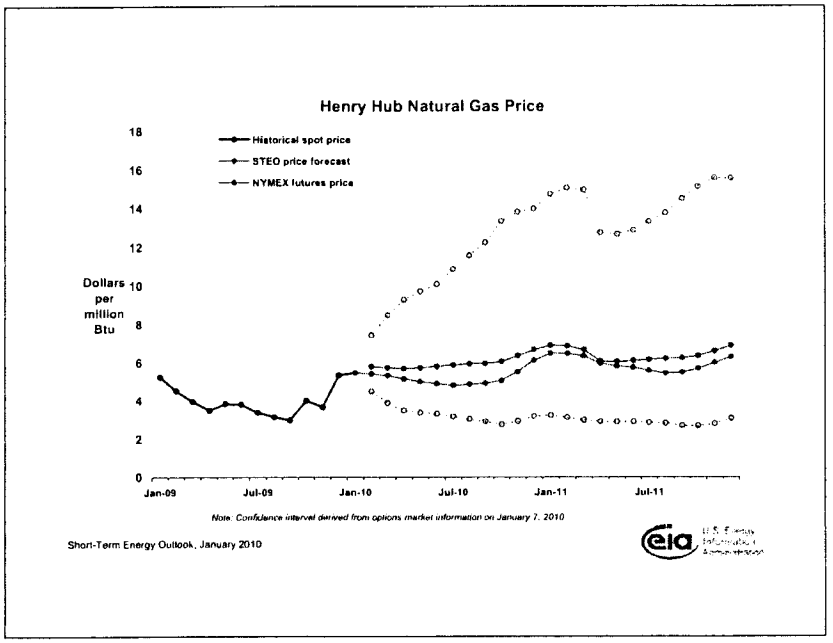
*U.S. Coal Supply.* EIA estimates that 2009 coal production fell more 7 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 4.6 percent in the 2010 forecast despite increases in domestic consumption and exports. The balance between supply and demand is maintained through a reduction in coal inventories and slightly higher imports. Continued growth in coal consumption and exports in 2011 will lead to a projected 6.5-percent increase in coal production (U.S. Annual Coal Production Chart).

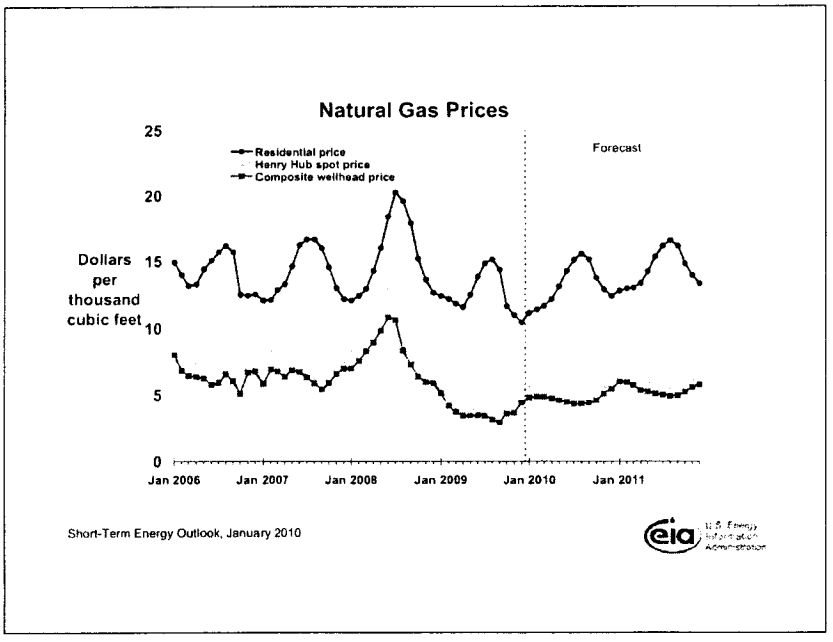
*U.S. Coal Prices.* EIA estimates that the delivered electric-power-sector coal price averaged $2.22 per MMBtu in 2009, a 7-percent increase compared with the 2008 average price, despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in demand for coal for electricity generation. This higher cost of delivered coal is due to the significant portion of longer-term power-sector coal contracts that were initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price falls by 7 percent to average $2.06 per MMBtu in 2010, and declines by an additional 2 percent in 2011.

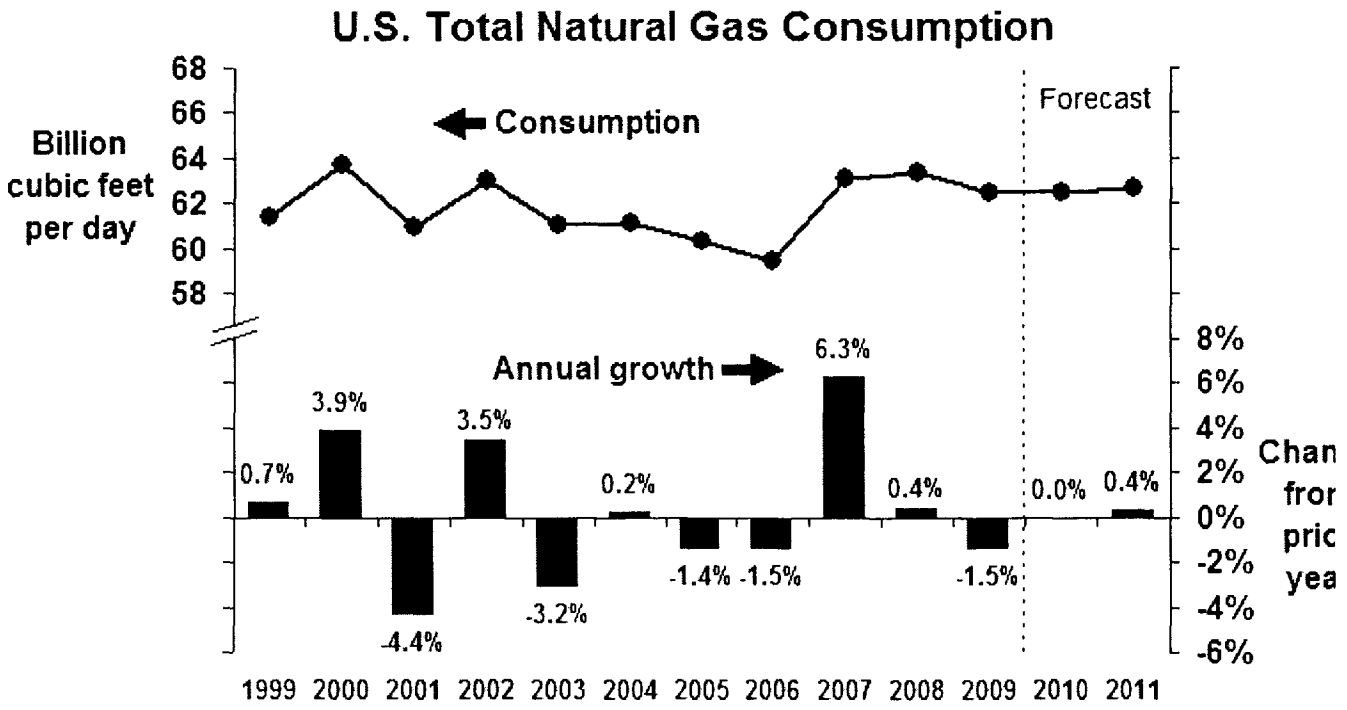
**U.S. Carbon Dioxide Emissions**

$CO_2$ emissions from fossil fuels fell by an estimated 6.1 percent in 2009. Emissions from coal led the drop in 2009 $CO_2$ emissions, falling by nearly 11 percent. Declines in energy consumption in the industrial sector, a result of the weak economy, and changes in electricity generation sources are the primary reasons for the decline in $CO_2$ emissions (U.S. Carbon Dioxide Emissions Growth Chart). Looking forward, projected improvements in the economy contribute to an expected 1.5-percent increase in $CO_2$ emissions in 2010. Increased use of coal in the electric-power sector and continued economic growth, along with the expansion of travel-related petroleum consumption, lead to a 1.7-percent increase in $CO_2$ emissions in 2011. However, even with increases in 2010 and 2011, projected $CO_2$ emissions in 2011 are still expected to be lower than annual emissions from 1999 through 2008.


U.S. Diesel Fuel and Crude Oil Prices
Forecast
Retail diesel
Retail heating oil
Crude oil
Dollars per gallon
$5.50
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
Jan 2006
Jan 2007
Jan 2008
Jan 2009
Jan 2010
Jan 2011
Retail prices include State and Federal taxes
Short-Term Energy Outlook, January 2010

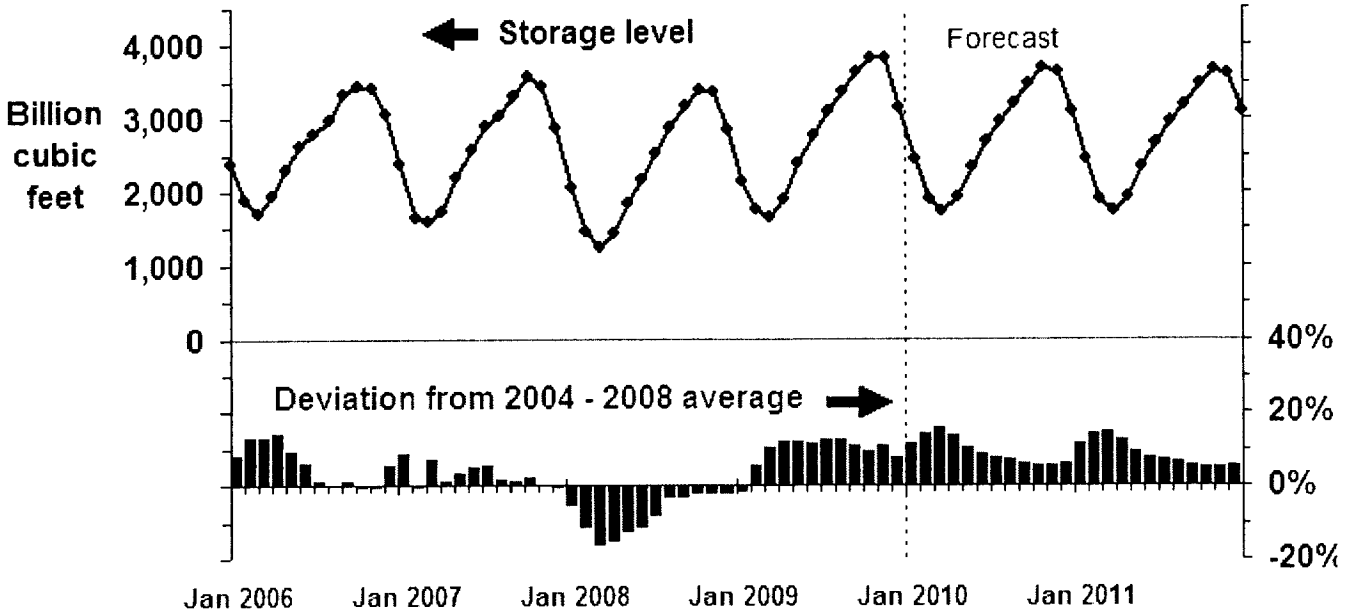

Henry Hub Natural Gas Price
Historical spot price
STEO price forecast
NYMEX futures price
Dollars per million Btu
18
16
14
12
10
8
6
4
2
0
Jan-09
Jul-09
Jan-10
Jul-10
Jan-11
Jul-11
Note: Confidence interval derived from options market information on January 7, 2010
Short-Term Energy Outlook, January 2010


Natural Gas Prices
Forecast
Residential price
Henry Hub spot price
Composite wellhead price
Dollars per thousand cubic feet
25
20
15
10
5
0
Jan 2006
Jan 2007
Jan 2008
Jan 2009
Jan 2010
Jan 2011
Short-Term Energy Outlook, January 2010




Short-Term Energy Outlook, January 2010

# U.S. Working Natural Gas in Storage




*NOTE: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009*

Short-Term Energy Outlook, January 2010

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**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, 2009** | | | | | | | | | **$65,941** |
| May | ($2,105) | $0 | $671 | ($1,434) | 16,822 | ($0.1857) | ($3,124) | $1,690 | 67,631 |
| June | 24,415 | 0 | 690 | 25,105 | 9,107 | 0.2343 | (427) 2/ | 25,532 | 93,163 |
| July | 39,344 | 0 | 629 | 39,973 | 6,447 | 0.2343 | 1,511 | 38,462 | 131,625 |
| August | 39,771 | 0 | 902 | 40,673 | 5,943 | 0.2343 | 1,392 | 39,281 | 170,906 |
| September | (2,165) | 0 | 1,179 | (986) | 5,775 | 0.2343 | 1,353 | (2,339) | 168,567 |
| October | 35,022 | 0 | 1,154 | 36,176 | 11,535 | 0.2343 | 2,703 | 33,473 | 202,040 |
| November | (980) | 0 | 1,387 | 407 | 19,033 | 0.2343 | 4,459 | (4,052) | 197,988 |
| December | 25,639 | 0 | 1,349 | 26,988 | 32,413 | 0.2343 | 7,595 | 19,393 | 217,381 |
| **Balance @ December 31, 2009.** | | | | | | | | | **$217,381** |

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 6,097.5 dk @ ($0.1857) and 3,009.9 dk @ $0.2343.

**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, 2009** | | | | | | | | | **($110,191)** |
| May | ($5,411) | $0 | ($1,024) | ($6,435) | 15,426 | ($0.7309) | ($11,275) | $4,840 | (105,351) |
| June | (2,099) | 0 | (967) | (3,066) | 10,879 | (0.7419) | (7,985) 2/ | 4,919 | (100,432) |
| July | (3,038) | 0 | (592) | (3,630) | 7,435 | (0.7419) | (5,516) | 1,886 | (98,546) |
| August | (4,584) | 0 | (581) | (5,165) | 9,775 | (0.7419) | (7,252) | 2,087 | (96,459) |
| September | (14,605) | 0 | (571) | (15,176) | 9,230 | (0.7419) | (6,848) | (8,328) | (104,787) |
| October | (9,999) | 0 | (634) | (10,633) | 16,552 | (0.7419) | (12,280) | 1,647 | (103,140) |
| November | (15,225) | 0 | (633) | (15,858) | 18,004 | (0.7419) | (13,357) | (2,501) | (105,641) |
| December | (354) | 0 | (663) | (1,017) | 22,135 | (0.7419) | (16,422) | 15,405 | (90,236) |
| **Balance @ December 31, 2009.** | | | | | | | | | **($90,236)** |

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 7,849.5 dk @ ($0.7309) and 3,029.9 dk @ ($0.7419).