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August 29, 2014

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

Re: Cost of Gas Adjustment (COG)
September 2014

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (102nd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (102nd Revised Sheet No. 8), showing the September 2014 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$0.1773 per Dk for residential and firm general service customers and an increase of \$0.1773 per Dk for interruptible customers.

Attachment B shows the calculations supporting the gas costs for September 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.1773 per Dk for all customers since the last COG filing due to an increase in the market price of gas.

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, 2014.

Great Plains submitted a check for \$600.00 on January 2, 2014 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,

A handwritten signature in black ink that reads "Tamie A. Aberle". The signature is written in a cursive style with a large, prominent initial "T".

Tamie A. Aberle
Director of Regulatory Affairs

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

102nd Revised Sheet No. 1.1

Canceling 101st Revised Sheet No.1.1

Page 1 of 1

RATE SUMMARY SHEET

| Rate Schedule | Sheet No. | Basic Service Charge | Distribution Delivery Charge | COG Items | Total Rate/dk |
|--|-----------|----------------------|--|------------------------------|--|
| Firm Gas Service - General | 2 | \$3.50 per month | First 10 dk Over 10 dk | \$1.2869 1.0646 | \$6.9481 \$8.2350 8.0127 |
| Interruptible Gas Service - General | 3 | \$3.50 per month | First 400 dk Next 2,600 dk Over 3,000 dk | \$1.1506 0.9021 0.7486 | \$5.0748 \$6.2254 5.9769 5.8234 |
| Interruptible Gas Service - Grain Processing | 4 | \$3.50 per month | All dk | \$1.2516 | \$5.0748 \$6.3264 |
| Transportation Service | 5 | \$3.50 per month | First 400 dk Next 2,600 dk Over 3,000 dk | \$1.1506 0.9021 0.7486 | \$1.1506 0.9021 0.7486 |

Date Filed: August 29, 2014

Effective Date: Service rendered on and after September 1, 2014

Issued By: Tamie A. Aberle
 Director - 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
102nd Revised Sheet No. 8
Canceling 101st Revised Sheet No. 8

COST OF GAS

Page 1 of 1

| Summary: | Firm | | | Interruptible | | | |
|------------------|------------------------------|----------------------|-------------|----------------------------|----------------------|-------------|---------------|
| | Est. Wtd. Demand Costs | Average Commodity | GCR Adj. | Est. Wtd. Total Firm | Average Commodity | GCR Adj. | Total Int. |
| Base Rate | \$0.0662 | \$5.1708 | \$0.0000 | \$5.2370 | \$5.1708 | \$0.0000 | \$5.1708 |
| Accumulated Adj. | 1.4450 | (1.2574) | 1.3462 | 1.5338 | (1.2429) | 0.9696 | (0.2733) |
| Current Adj. | 0.0000 | 0.1773 | 0.0000 | 0.1773 | 0.1773 | 0.0000 | 0.1773 |
| Total Adj. | 1.4450 | (1.0801) | 1.3462 | 1.7111 | (1.0656) | 0.9696 | (0.0960) |
| Total Rate | \$1.5112 | \$4.0907 | \$1.3462 | \$6.9481 | \$4.1052 | \$0.9696 | \$5.0748 |

Date Filed: August 29, 2014

Effective Date: Service rendered on and
after September 1, 2014

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 2014

| <u>Firm</u> | <u>Billing Determinants</u> | <u>Rate</u> | <u>Demand Months</u> | <u>Amount</u> | <u>Amount Per dk</u> |
|---|---------------------------------|-------------|--------------------------|---------------|--------------------------|
| FT-A - Zone 1-1 | 8,000 | \$3.3978 | 12 | \$326,189 | \$0.2315 |
| FT-A - Zone 1-1 | 5,000 | 3.6918 | 5 | 92,295 | 0.0655 |
| FT-A Seasonal | 2,000 | 3.6918 | 5 | 36,918 | 0.0262 |
| TFX Seasonal | 2,000 | 15.1530 | 5 | 151,530 | 0.1075 |
| TFX - Winter | 13,000 | 15.1530 | 5 | 984,945 | 0.6990 |
| TFX - Summer | 13,000 | 5.6830 | 7 | 517,153 | 0.3670 |
| LMS Demand 2/ | | | | | 0.0145 |
| Total Demand Charges | | | | \$2,109,030 | 1.5112 |
| Estimated Weighted Average Commodity Cost | 1,409,081 | 1/ 4.0907 | | 5,764,128 | 4.0907 |
| Gas Cost Reconciliation Adjustment | | | | | 1.3462 |
| Total Current Firm Gas Cost | | | | \$7,873,158 | 6.9481 |
| Base Cost of Gas | | | | | 5.2370 |
| Accumulated Adjustment | | | | | \$1.7111 |
| | | | | | |
| <u>Interruptible</u> | | | | | |
| Estimated Weighted Average Commodity Cost | | | | | \$4.0907 |
| Gas Cost Reconciliation Adjustment | | | | | 0.9696 |
| LMS Demand 2/ | | | | | 0.0145 |
| Total Current Interruptible Gas Cost | | | | | 5.0748 |
| Base Cost of Gas | | | | | 5.1708 |
| Accumulated Adjustment | | | | | (\$0.0960) |

1/ Three year normalized average Dk sales

2/ Amount divided by 2011-2013 average normalized interruptible sales volumes plus 2011-2013 average normalized firm sales volumes.

| | <u>Billing Determinants</u> | <u>Rate</u> | <u>Demand Months</u> | <u>Amount</u> | <u>Amount Per dk</u> |
|------------|---------------------------------|-------------|--------------------------|---------------|--------------------------|
| LMS Demand | 2,500 | \$0.9800 | 12 | \$29,400 | \$0.0145 |

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 2014

| Rates Effective August 29, 2014 | \$/Dk | |
|--|----------|------------|
| FT-A - Zone 1-1 (Category 1) | \$3.6918 | Per Dk/Mo. |
| FT-A - Zone 1-1 (Category 3) | 3.3978 | Per Dk/Mo. |
| FT-A - Seasonal | 3.6918 | Per Dk/Mo. |
| TFX | 15.1530 | Per Dk/Mo. |
| TFX Seasonal | 15.1530 | Per Dk/Mo. |
| LMS Demand | 0.9800 | Per Dk/Mo. |
| Estimated Weighted Average Commodity Cost: | 4.0907 | Per Dk |

| Base Rate Effective September 1, 1981 1/ | | |
|--|----------|-------------|
| Demand Charge | \$0.8100 | Per MCF/Mo. |
| Commodity Charge | 5.1191 | Per MCF |

Base Rate Calculation

Firm

| | | |
|----------------------|----------|--------|
| Demand 2/ | \$0.0662 | Per Dk |
| Commodity | 5.1708 | Per Dk |
| Total Firm Base Cost | \$5.2370 | Per Dk |

Interruptible:

| | | |
|-----------|----------|--------|
| Commodity | \$5.1708 | Per Dk |
|-----------|----------|--------|

1/ The Firm Gas Base Cost is based on the FERC Gas Tariff, Third Revised
Volume No. 1 of Midwestern Gas Transmission Company, effective July 1, 1981.

2/ Demand base rate calculation:

| | | | |
|-------------------|---|-----------|--------------|
| Demand Charge | | 0.81 | Per MCF/Mo. |
| Convert mcf to dk | x | 0.99 | Therm Factor |
| | | 0.82 | Per Dk/Mo. |
| Capacity | x | 4,768 | |
| Months | x | 12 | |
| | | 46,814.13 | |
| Volumes | / | 707,222 | |
| | | 0.0662 | Per Dk |

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 | \$3.6918 |
| Zone 1-1 Minimum Rate | \$0.0000 |
| Zone 1-2 Maximum Rate | \$4.7894 |
| Zone 1-2 Minimum Rate | \$0.0000 |
| Zone 2-2 Maximum Rate | \$2.0972 |
| 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 | \$3.5448 |
| Zone 1-1 Minimum Rate | \$0.0000 |
| Zone 1-2 Maximum Rate | \$4.6424 |
| Zone 1-2 Minimum Rate | \$0.0000 |
| Zone 2-2 Maximum Rate | \$1.9502 |
| 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 | \$3.3978 |
| Zone 1-1 Minimum Rate | \$0.0000 |
| Zone 1-2 Maximum Rate | \$4.4954 |
| Zone 1-2 Minimum Rate | \$0.0000 |
| Zone 2-2 Maximum Rate | \$1.8032 |
| Zone 2-2 Minimum Rate | \$0.0000 |

| Rate Schedule | Base Tariff Rate | Fuel and Loss Retention Percentages 2/ |
|----------------------|------------------------|--|
| Commodity Rates 1/ | | |
| FT-A – Maximum Rates | | |
| Zone 1-1 | \$0.0127 | 0.08% |
| Zone 1-2 | \$0.0127 | 0.10% |
| Zone 2-2 | \$0.0127 | 0.02% |
| Minimum Rate | \$0.0127 | |
| IT and AOT | | |
| Zone 1-1 | \$0.1341 | 0.08% |
| Zone 1-2 | \$0.1702 | 0.10% |
| Zone 2-2 | \$0.0816 | 0.02% |
| Minimum Rate | \$0.0127 | |

- 1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at <http://www.ferc.gov>.
- 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: 0.01% for Zone 1-1, 0.01% for Zone 1-2, and 0.00% 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 | \$0.9800 | | \$0.9800 |
| LMS – Daily Ovrerrun Rate | \$0.1702 | | \$0.1702 |
| LMS – Load Management Cost Reconciliation Adjustment | | \$0.0116 | |

- 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 | \$0.1702 | \$0.0000 |
| RPL Service: | | |
| Daily Reservation Rate | \$0.1702 | \$0.0000 |

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

Seventh Revised Sheet No. 50
Superseding
Sixth Revised Sheet No. 50

RATE SCHEDULE TF

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

| COMMODITY RATES 2/ | | Market Area 3/ | | Field Mileage 5/ Rate per 100 miles | | Carlton Surcharge 4/ | | Out-of Balance 3/ | |
|--------------------|----------------------|----------------|---------|--|---------|-------------------------|---------|-------------------|---------|
| TF12 Base | TF12 Var., TFS & TFF | Maximum | Minimum | Maximum | Minimum | Maximum | Minimum | Maximum | Minimum |
| Market | Market | 0.0364 | 0.0195 | | | 0.0175 | 0.0000 | 0.0364 | 0.0195 |
| Field | Market | 0.0364 | 0.0195 | 0.0122 | 0.0040 | 0.0175 | 0.0000 | | |
| Market | Field | | | 0.0122 | 0.0040 | | | | |
| Field | Field | | | 0.0122 | 0.0040 | | | 0.0276 | 0.0090 |

- 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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of \$0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 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, the Field Area Electric Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.

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

Seventh Revised Sheet No. 51
Superseding
Sixth 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/ | | <u>\$5.683</u> | <u>\$15.153</u> | <u>\$5.473</u> | <u>\$9.853</u> | | |

| 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 | 0.0364 | 0.0195 | | | 0.0175 | 0.0000 | 0.0364 | 0.0195 |
| Field | Market | 0.0364 | 0.0195 | 0.0122 | 0.0040 | 0.0175 | 0.0000 | | |
| Market | Field | | | 0.0122 | 0.0040 | | | | |
| Field | Field | | | 0.0122 | 0.0040 | | | 0.0276 | 0.0090 |

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

- 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 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/ The Maximum and Minimum rates include the Market Area Electric Compression charge of \$0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 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, the Field Area Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.
- 6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.

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

Eighth Revised Sheet No. 54
Superseding
Seventh Revised Sheet No. 54

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

| | <u>Percentages</u> |
|---|-----------------------------|
| FUEL PERCENTAGES: | 1/ |
| Market Area (including Out-of-Balance) | 0.97% |
| Field Area | 2/ 3/ 5/ 6/ |
| UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance) | 0.09% 4/ 5/ |
| FDD Storage Fuel | 1.76% |
| | <u>Electric Compression</u> |
| 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, 2013.

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
September 2014**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The September monthly price for the NNG-Ventura Index is expected to increase slightly from the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

Warmer weather throughout heavily populated areas of the south, midcontinent and east resulted in increased electric generation for a portion of August, along with national storage levels that are 15 to 20 percent below last year and the five year average likely all contributed to the increase in the first of the month index price of natural gas. The EIA reported storage levels nationwide as of August 22, 2014 were 16.5 percent below the five-year average and 15.7 percent below last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: <http://www.eia.doe.gov>.

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 17.



Independent Statistics & Analysis

U.S. Energy Information
Administration

August 2014

Short-Term Energy Outlook (STEO)

Highlights

- The market's perception of reduced risk to Iraqi oil exports and news regarding increasing Libyan oil exports contributed to a drop in the Brent crude oil spot price to an average of \$107 per barrel (bbl) in July, \$5/bbl lower than the June average. EIA projects Brent crude oil prices to average \$107/bbl over the second half of 2014 and \$105/bbl in 2015. West Texas Intermediate (WTI) crude oil prices fell from an average of \$106/bbl in June to \$104/bbl in July, despite record levels of U.S. demand for crude oil. The WTI discount to Brent, which averaged \$11/bbl in 2013, is expected to average \$8/bbl and \$9/bbl in 2014 and 2015, respectively, both \$1/bbl lower than projected in last month's STEO.
- Regular gasoline retail prices fell to an average of \$3.61 per gallon (gal) in July, 8 cents/gal below the June average. Regular gasoline retail prices are projected to continue to decline to an average of \$3.30/gal in December. EIA expects regular gasoline retail prices to average \$3.50/gal in 2014 and \$3.46/gal in 2015, compared with \$3.51/gal in 2013.
- U.S. total crude oil production averaged an estimated 8.5 million barrels per day (bbl/d) in July, the highest monthly level of production since April 1987. U.S. total crude oil production, which averaged 7.5 million bbl/d in 2013, is expected to average 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The 2015 forecast represents the highest annual average level of oil production since 1972. Natural gas plant liquids production increases from an average of 2.6 million bbl/d in 2013 to 3.1 million bbl/d in 2015. The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. petroleum and other liquids consumption met by net imports fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 22% in 2015, which would be the lowest level since 1970.
- Natural gas spot prices fell from \$4.47/million British thermal units (MMBtu) at the beginning of July to \$3.78/MMBtu at the end of the month as natural gas stock builds continued to outpace historical norms. Natural gas working inventories on August 1 totaled 2.39 trillion cubic feet (Tcf), 0.54 Tcf (18%) below the level at the same time a year ago and 0.61 Tcf (20%) below the previous five-year average (2009-13). Projected natural gas working inventories reach 3.46 Tcf at the end of October, 0.35 Tcf below the level at the same time last year. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73 per MMBtu in 2013, will average \$4.46/MMBtu in 2014 and \$4.00/MMBtu in 2015, \$0.31/MMBtu and \$0.51/MMBtu lower than in last month's STEO, respectively.

Global Petroleum and Other Liquids

EIA's world oil balance is virtually unchanged from last month's STEO. EIA still expects the balance to remain relatively tight, with surplus crude oil production capacity averaging 2.1 million bbl/d in 2014 and 2.7 million bbl/d in 2015. Global unplanned supply disruptions remain at an elevated level and averaged 3.2 million bbl/d in July, of which Libya accounted for more than one-third. Libya's outages declined slightly in July, but Libya continues to experience swings in its production. Most of Iraq's northern production (outside of the Kurdistan area) remains offline, while Iraq's southern production and export volumes continue to be unaffected despite the ongoing unrest in northern and western Iraq.

EIA projects world petroleum and other liquids supply to increase by 1.5 million bbl/d in 2014 and by another 1.3 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). Forecast non-OPEC supply grows by 1.8 million bbl/d in 2014 and 1.1 million bbl/d in 2015. The United States and Canada account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.1 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.3 million bbl/d (1.4%) in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow by 1.1 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.6% in 2013, grows by 2.7% and 3.4% in 2014 and 2015, respectively.

Non-OECD countries account for nearly all of the expected consumption growth in 2014 and 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 0.37 million bbl/d (3.5%) in 2014 and 0.43 million bbl/d in 2015. Oil consumption growth in 2013 was revised downward to 0.33 million bbl/d to better reflect the slowdown in China's economic expansion. China's real GDP growth rate was 7.5% in the second quarter of 2014, compared with an annual real GDP growth rate exceeding 9% from 2009 through 2011.

EIA expects a 0.18-million-bbl/d decline in OECD petroleum and other liquids consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 0.13 million bbl/d in 2014 and 0.16 million bbl/d in 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in 2015. EIA projects that OECD Europe's consumption, which fell by 0.12 million bbl/d in 2013, will decline by 0.12 million bbl/d in 2014 and by a further 0.03 million bbl/d in 2015. The 2015 OECD Europe consumption forecast represents a downward revision from the 0.06-million-bbl/d increase in last month's

STEO. U.S. petroleum and other liquids consumption, which increased by 0.40 million bbl/d in 2013, is expected to be flat in 2014 and then increase by 0.09 million bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.3 million bbl/d in 2013, averaging 54.0 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.8 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.6 million bbl/d in 2014 and 1.1 million bbl/d in 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.05 million bbl/d in 2014, led by Russia. However, production in the region declines by 0.09 million bbl/d in 2015. This forecast assumes the current economic sanctions on Russia do not affect Russian oil production in the short term.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in July, slightly higher than the estimated June level. South Sudan, Syria, and Yemen accounted for 79% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.3 million bbl/d in 2014 and by less than 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in July 2014, slightly lower than the previous month because of decreased outages in Libya. Libya continues to experience swings in its production, contributing to changes in the OPEC disruption estimate.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.1 million bbl/d in 2014 and 2.7 million bbl/d in 2015. These estimates do not include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.57 billion barrels at the end of 2014.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$107/bbl in July, a decrease of \$5/bbl from June. July was the 13th consecutive month in which average Brent crude oil spot prices fell within a relatively narrow range of \$107/bbl to \$112/bbl. The forecast Brent crude oil price averages \$108/bbl in 2014, \$1/bbl lower than in last month's STEO, and \$105/bbl in 2015, which is unchanged from last month's STEO.

The WTI crude oil spot price increased from an average of \$102/bbl in May to \$106/bbl in June, before falling to \$104/bbl in July. Driven in part by the relocation of crude oil to refining centers along the Gulf Coast through new pipelines, crude oil inventory levels at the Cushing, Oklahoma, storage hub, the futures market's delivery point for WTI, have fallen by more than half since early this year, from nearly 42 million barrels on January 24 to below 18 million barrels on July 25, the lowest level since October 2008. The discount of WTI crude oil to Brent crude oil averaged more than \$13/bbl from November 2013 through January 2014. Record high refinery runs contributed to the WTI discount falling to \$3/bbl in July, which was the same level seen during July 2013 when refinery runs were similarly at their seasonal peak for the year. EIA now expects the discount of WTI to Brent crude oil to average \$7/bbl in the second half of 2014 and \$9/bbl in 2015, reductions of \$2/bbl and \$1/bbl, respectively, from last month's STEO.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels (*Market Prices and Uncertainty Report*). WTI futures contracts for November 2014 delivery, traded during the five-day period ending August 7, averaged \$96/bbl. Implied volatility averaged 16%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in November 2014 at \$84/bbl and \$111/bbl, respectively. Last year at this time, WTI for November 2013 delivery averaged \$103/bbl and implied volatility averaged 21%. The corresponding lower and upper limits of the 95% confidence interval were \$85/bbl and \$125/bbl.

U.S. Petroleum and Other Liquids

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by 400,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain in 2013, increasing by 150,000 bbl/d (6.4%). Total consumption is expected to be flat in 2014, with declines in the consumption of hydrocarbon gas liquids, residual fuel oil, and unfinished oils offsetting increases in distillate fuel, gasoline, and jet fuel. Total consumption grows by 90,000 bbl/d in 2015, with HGL consumption increasing by 100,000 bbl/d.

Motor gasoline consumption grew by 90,000 bbl/d (1.1%) in 2013, the largest annual increase since 2006. Motor gasoline consumption grows by 40,000 bbl/d in 2014 and then falls by 10,000 bbl/d in 2015 as improving fuel economy in new vehicles increasingly offsets highway travel growth. Distillate fuel consumption increased by 90,000 bbl/d (2.5%) last year, reflecting colder weather and economic growth. Consumption of that fuel rises by 140,000 bbl/d and 70,000 bbl/d in 2014 and 2015, respectively.

In 2013, consumption of HGL increased by 150,000 bbl/d, led by a 90,000-bbl/d increase in propane consumption. Propane demand was unusually high last year because of strong petrochemical demand in the first half of the year, followed by high crop-drying demand and cold weather late in the year. EIA projects a 60,000-bbl/d decline in HGL consumption in 2014, with propane consumption returning to 2012 levels as higher propane prices reduce the use of

propane as a petrochemical feedstock. HGL consumption increases by 100,000 bbl/d in 2015, with propane forecast to increase by 60,000 bbl/d as new propane dehydrogenation units, which produce propylene, are expected to come online in the second half of the year.

Liquid Fuels Supply. The forecast for total U.S. crude oil production increases from an estimated 7.5 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.3 million bbl/d in 2015. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Oil production from the Gulf of Mexico is expected to increase from 1.25 million bbl/d in 2013 to 1.44 million bbl/d in 2014, with 11 projects starting this year. Six projects began production in the first half of 2014: Na Kika Phase 3, Mars B, Dalmatian, Entrada, Atlantis Phase 2, and Tubular Bells. Additional wells are expected to come online in the fourth quarter of 2014 from the Cardamom Deep, South Deimos/West Boreas, Hadrian South, Jack/St. Malo, and Lucius projects.

HGL production at natural gas liquids plants is projected to increase from 2.6 million bbl/d in 2013 to 3.1 million bbl/d in 2015. About half of this growth is expected to come from ethane production to meet growing demand associated with expanding domestic ethylene production and export capacity.

The growth in domestic production has contributed to a significant decline in petroleum imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an average of 33% in 2013. EIA expects the net import share to decline to 22% in 2015, which would be the lowest level since 1970.

Petroleum Product Prices. EIA expects that the monthly average regular gasoline retail price will fall from the recent peak of \$3.69/gal in June to \$3.50/gal in September, before falling to \$3.30/gal in December. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.50/gal and \$3.46/gal in 2014 and 2015, respectively. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.89/gal in 2014, 4 cents lower than projected in last month's STEO, and \$3.87/gal in 2015.

Natural Gas

This month's STEO raises the outlook for total marketed natural gas production in 2014 by 0.8 billion cubic feet per day (Bcf/d) to 73.9 Bcf/d. The EIA 914 production survey has indicated strong growth in the Lower 48 states through May, while additional preliminary data sources indicate continued gains in production in June and July. Increases come largely from the Marcellus states and Texas. Strength in production over the summer, in addition to mild weather, contributed to multiple weekly storage injections of 100 Bcf or greater, and storage is on track for a record overall injection. This month's STEO slightly raises the projected end-of-October working gas inventory to 3,460 Bcf. Natural gas spot prices fell from \$4.47/MMBtu at

the beginning of July to \$3.78/MMBtu at the end of the month, reflecting the current strength in supply growth and stock builds.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.6 Bcf/d in 2014, an increase of 1.7% from 2013, led by the industrial sector. In 2015, total natural gas consumption increases by 0.4 Bcf/d as continued industrial sector growth offsets lower residential and commercial consumption. Higher natural gas prices this year contribute to a 2.2% decline in natural gas consumption in the power sector to 21.8 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.7 Bcf/d in 2015 with lower natural gas prices and the retirement of some coal plants.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an annual rate of 5.3% in 2014 and 2.1% in 2015. STEO projects that strong increases in the Lower 48 states will offset Gulf of Mexico declines. As of May 2014, the most recent month for which EIA data are available, marketed production was more than 4 Bcf/d greater than it was in May 2013. Rapid natural gas production growth in the Marcellus formation has contributed to low natural gas forward prices in the Northeast, and as a result new infrastructure has been proposed to take gas to other market regions. In June, the eastward-flowing Rockies Express Pipeline (REX) began service on its Seneca Lateral, which will take Marcellus gas westward to the Midwest. REX's parent company, Tallgrass Energy, plans to add bidirectional capability on a significant portion of REX's easternmost segment.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada, and increase exports to Mexico. As a result, EIA projects net imports to decline to 3.3 Bcf/d in 2014 and to 2.6 Bcf/d in 2015. Liquefied natural gas (LNG) imports have fallen over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. Cheniere Energy's Sabine Pass facility is expected to be the first to liquefy natural gas produced in the Lower 48 states for export. It is scheduled to come online in stages beginning in late 2015.

Natural Gas Inventories. Natural gas working inventories totaled 2,389 Bcf as of August 1, which was 538 Bcf lower than the same time last year and 608 Bcf lower than the previous five-year (2009-13) average. The injection season began somewhat slowly in April, but has continued at a strong pace, with injections averaging above the five-year average throughout most of the injection season. EIA expects working gas stocks will reach 3,463 Bcf at the end of October, 353 Bcf lower than at the same time last year.

Natural Gas Prices. Natural gas spot prices fell from \$4.47/million British thermal units (MMBtu) at the beginning of July to \$3.78/MMBtu at the end of the month as natural gas stock builds continued to outpace the historical norms. EIA expects spot prices will remain below \$4/MMBtu through October, before rising with winter heating demand. Projected Henry Hub natural gas prices average \$4.46/MMBtu in 2014 and \$4.00/MMBtu in 2015.

Natural gas futures prices for November 2014 delivery (for the five-day period ending August 7) averaged \$3.96/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for November 2014 contracts at \$3.03/MMBtu and \$5.16/MMBtu, respectively. At this time last year, the natural gas futures contract for November 2013 averaged \$3.58/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.68/MMBtu and \$4.79/MMBtu.

Coal

Electric power sector coal inventories fell to 118 million short tons (MMst) in March, the lowest level since 2006, because of the increase in coal-fired generation as natural gas prices rose, cold weather boosting electricity demand, and rail congestion over the winter slowing coal deliveries. Stocks increased to 136 MMst at the end of May, but were still 40 MMst lower compared with the same time last year. Midwestern coal inventories are down approximately 10 MMst from last year, and this deficit has become an issue for some regional power producers. Electric generators in Wisconsin and Minnesota are citing continuing problems with coal deliveries to power plants. Although generation has yet to be affected, ongoing coal delivery problems have the potential to hinder or even lead to the curtailment of some power production. Year-to-date rail coal shipments are up by nearly 1%, but they have fallen over the past three consecutive weeks.

Coal Supply. EIA estimates that coal production for the first six months of this year (487 MMst) was nearly identical to production over the same period last year. EIA expects that U.S. coal production will grow 2.5% to 1,009 MMst in 2014, driven by higher consumption and a need to replenish consumer inventories, particularly at power producers. In 2015, forecast U.S. coal production falls slightly by 0.2% to 1,007 MMst.

Coal Consumption. EIA projects total coal consumption growth of 2.5% to 949 MMst in 2014 because of higher electricity demand and power sector natural gas prices 22% above their 2013 level. Total coal consumption is projected to fall by 2.7% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, electricity sales growth slows to 0.4%, and natural gas prices fall relative to coal prices.

Coal Exports. In May, coal exports were 26.3% (2.8 MMst) lower compared with last year, with nearly equal tonnage declines for steam and metallurgical coal. Coal exports are projected to total 99 MMst in 2014, primarily because of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. Coal exports remain flat in 2015.

Coal Prices. Annual average coal prices to the electric power industry fell over the past two years, from \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA expects average delivered coal

prices to increase over the forecast period, with prices of \$2.38/MMBtu in 2014 and \$2.39/MMBtu in 2015.

Electricity

During the first quarter of this year natural gas fuel costs increased rapidly, leading the power industry to cut back on the amount of natural gas used for electricity generation, even though the total level of generation was higher than the previous year. The average U.S. share of generation fueled by natural gas fell to 23.5% in the first quarter compared with 25.6% during the same quarter last year. The share of generation from coal picked up much of this decline, rising from 40.0% during the first quarter of 2013 to 42.5% during the first quarter of this year. Natural gas prices have moderated since then, with the natural gas and coal generation shares during the second quarter close to the same levels as last year.

Electricity Consumption. For the entire year, EIA expects that residential sales of electricity in 2014 will average 2.1% more than 2013. A large increase in residential consumption during the first quarter is offset by little growth during the summer and an expected 1.0% decline in residential sales during the fourth quarter of 2014. EIA expects U.S. retail sales of electricity to the industrial sector to remain relatively flat this year. Robust growth of industrial consumption in some areas of the country, especially the West South Central states, is offset by an expected 7.1% decline in industrial sales in the East South Central Census division. Sales of electricity to the commercial sector grow by 1.2% in 2014, led by businesses in the West South Central area.

Electricity Generation. EIA projects that total U.S. electricity generation in 2014 will grow by 1.1% from last year to an average of about 11,200 gigawatthours per day. The share of total generation fueled by natural gas has stabilized in recent months as natural gas prices have moderated from high levels earlier in the year. EIA expects that power sector natural gas prices will hover around \$4.60/MMBtu for the next few months. However, these prices are still higher than last year, leading to a slight decline in the natural gas share of generation to 28.0% during the second half of 2014 from 28.7% during the same period last year. The share of generation fueled by coal during the second half rises from 39.2% in 2013 to 40.6% this year in response to declines in natural gas generation and nuclear generation.

Electricity Retail Prices. EIA expects the U.S. residential electricity price to average 12.5 cents per kilowatthour during 2014, an increase of 2.8% from last year. Electricity prices increase in all regions of the country except for the Pacific states, where prices in 2014 are expected to average 2.7% lower than last year. Residential customers in New England experience the highest average price increase (8.5%).

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects that total renewables use for electricity and heat generation will grow by 2.1% in 2014. Conventional hydropower generation is projected to fall by 2.8%, while nonhydropower renewables rise by 4.8%. Nonhydropower renewables generation surpass hydropower on an annual basis for the first time in 2014. In 2015, total renewables consumption for electric power and heat generation increases by 4.2%, as a result of a 3.2% increase in hydropower and a 4.7% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 7.8% in 2014 and 15.3% in 2015. Electricity generation from wind is projected to contribute 4.6% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.6% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA expects that utility-scale solar capacity will increase by 96% between the end of 2013 and the end of 2015; about two-thirds of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to EIA's Annual Energy Outlook 2014.

Liquid Biofuels. Ethanol production increased from an average of 907,000 bbl/d in March to average about 940,000 bbl/d over the last 3 months, which are among the highest monthly levels ever recorded, and included the highest weekly level ever recorded at 972,000 bbl/d for the week ending June 13. Ethanol production is forecast to average 930,000 bbl/d in 2014 and 935,000 bbl/d in 2015. Biodiesel production averaged 87,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.4% in 2013 from the previous year. Emissions are forecast to rise by 1.4% in 2014, and then to decline by 0.6% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 2.7%, respectively. The price of natural gas to electric power generators rose on average by \$0.91/MMBtu in 2013 and is projected to rise by \$0.95/MMBtu in 2014, contributing to an increase coal use. Coal emissions are projected to decline by 2.6% in 2015.

U.S. Economic Assumptions

Recent Economic Indicators. Economic growth slowed in the first quarter of 2014 but improved substantially in the second. The U.S. Bureau of Economic Analysis (BEA) reported that second quarter real gross domestic product (GDP) grew at an annualized rate of 4% from the first quarter. Second-quarter growth was associated with increases in private inventory investment

and exports, along with greater state and local government spending and higher nonresidential fixed investment.

Recent employment indicators remained positive; the U.S. Bureau of Labor Statistics (BLS) reported that the four-week moving average of initial unemployment insurance claims for the week ending August 2 was the lowest since February 2006, at 293,500. According to BLS, the U.S. economy added 209,000 jobs in July, and the unemployment rate rose to 6.2%. New orders for durable goods rose 0.7% in June according to the U.S. Census Bureau, compared with the 1.0% decrease reported in May. Orders rose 0.8% excluding transportation, and rose 0.7% excluding defense. Census also reported that sales of new single-family homes fell 8.1% from May to June to a level 11.5% below the June 2013 estimate.

EIA used the July 2014 version of the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The July 2014 simulation did not include the advanced estimate for second quarter real U.S. GDP growth or its revision for the first quarter of 2014.

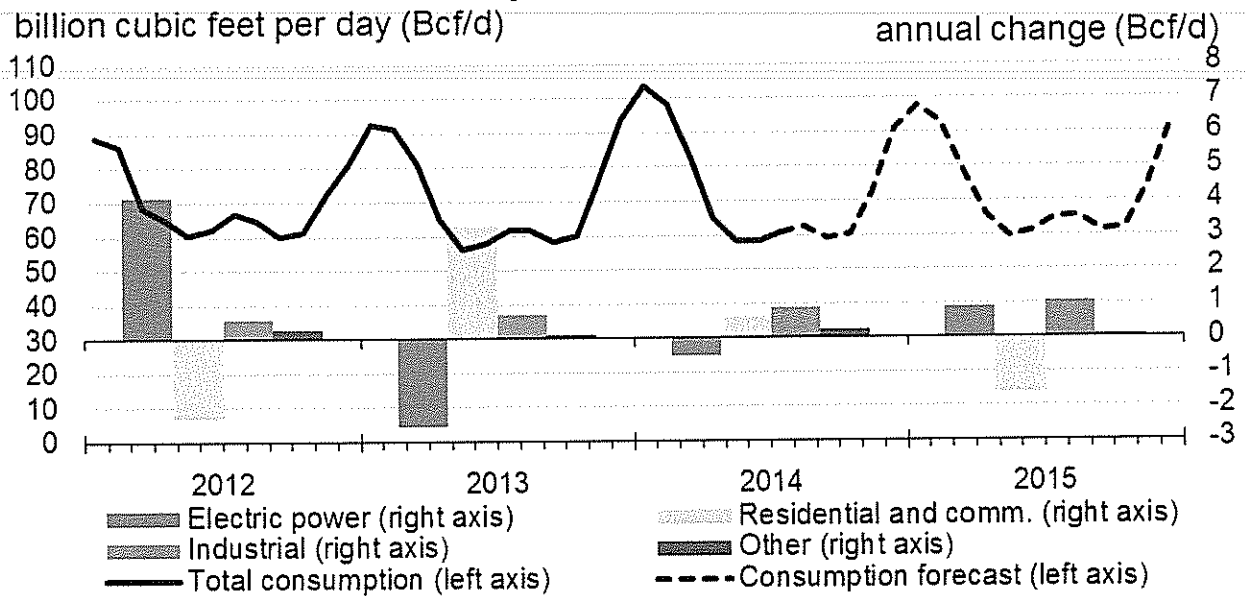
Production and Income. Forecast real GDP growth reaches 1.7% in 2014 and accelerates to 2.8% in 2015, below the 2.2% and 2.9% forecast last month. The decrease reflects the downward revision to real GDP growth in the first quarter of 2014, and less optimism about fixed investment in 2015. Consumption in 2015 is forecast to be slightly lower as well because real disposable income grows by 2.8%, down from the 3.1% forecast last month. Real disposable income grows 1.9% in 2014, and total industrial production grows at 4.0% in 2014 and 2.9% in 2015. Growth in industrial production in the manufacturing sector is lower than total industrial production in 2014, at 3.6%, but jumps higher in 2015 to 3.4%.

Expenditures. Private real fixed investment growth averages 4.3% and 8.2% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.1%, but fall below the real GDP growth rate in 2015 at 2.6%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.5% and 5.5% over the same two years, while import growth is 3.2% in 2014 and 5.1% in 2015. Total government expenditures fall by 0.9% in 2014, but increase by 0.3% in 2015.

Employment, Housing, and Prices. Projected annual growth in nonfarm employment averages 1.8% in 2014 and 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.9% at the end of 2015. The employment growth in 2014 and 2015 is faster than projected last month and the declines in the unemployment rate are about the same. Housing starts grow an average of 10.0% and 26.2% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.

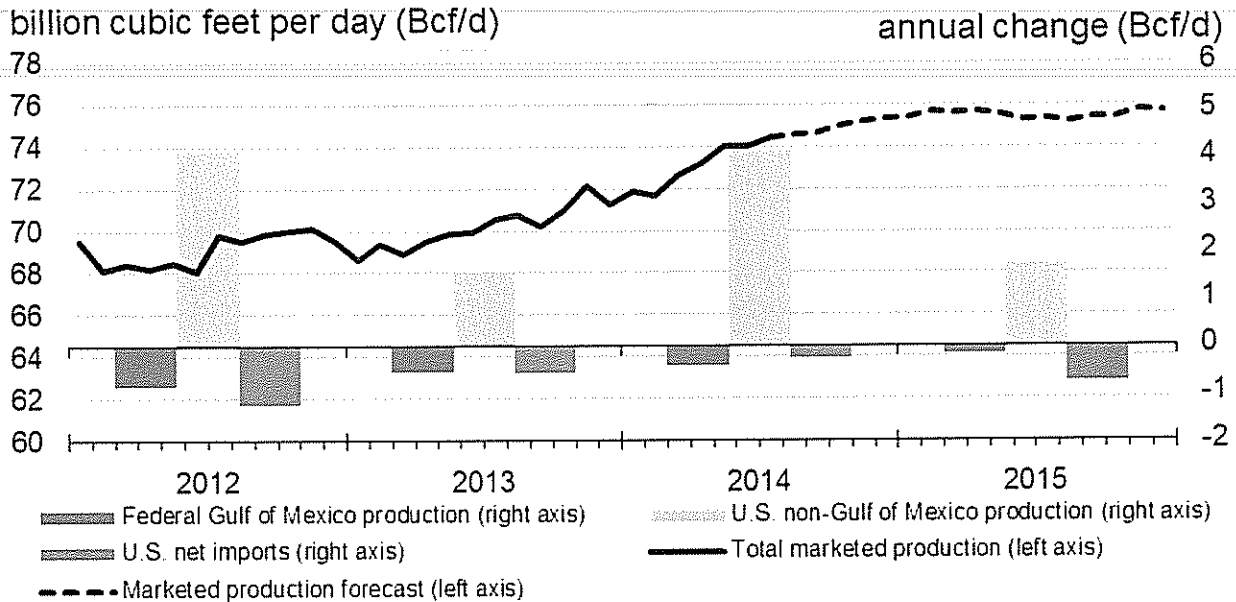
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

U.S. Natural Gas Consumption



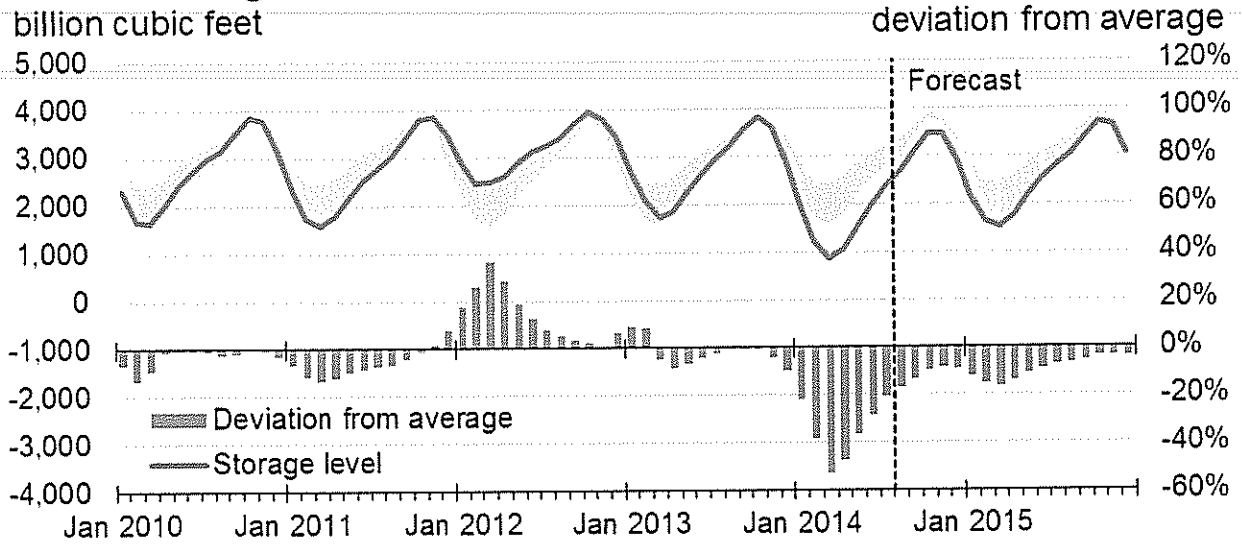
Source: Short-Term Energy Outlook, August 2014.

U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, August 2014.

U.S. Working Natural Gas in Storage



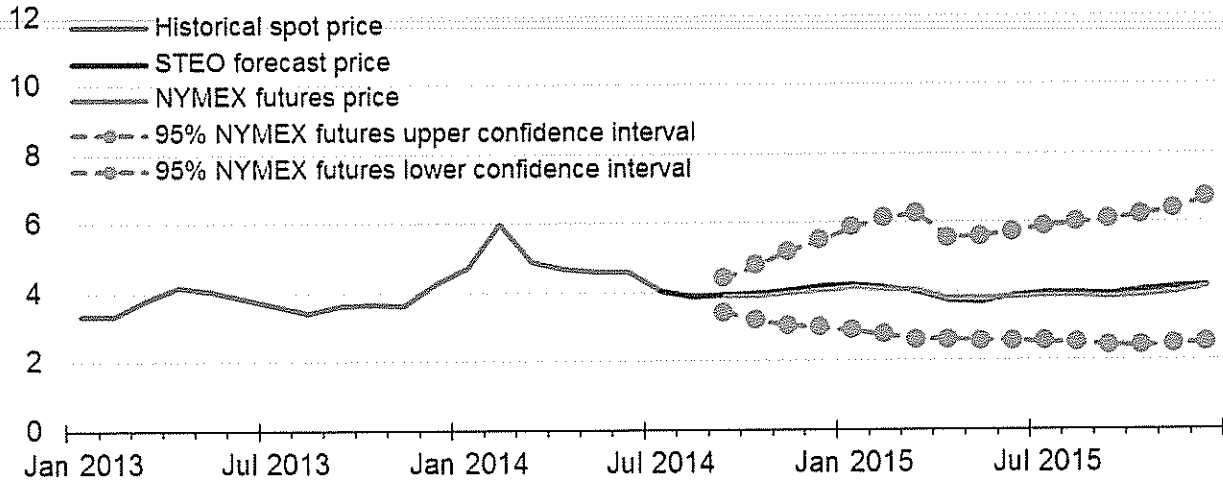
Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, August 2014.



Henry Hub Natural Gas Price

dollars per million Btu



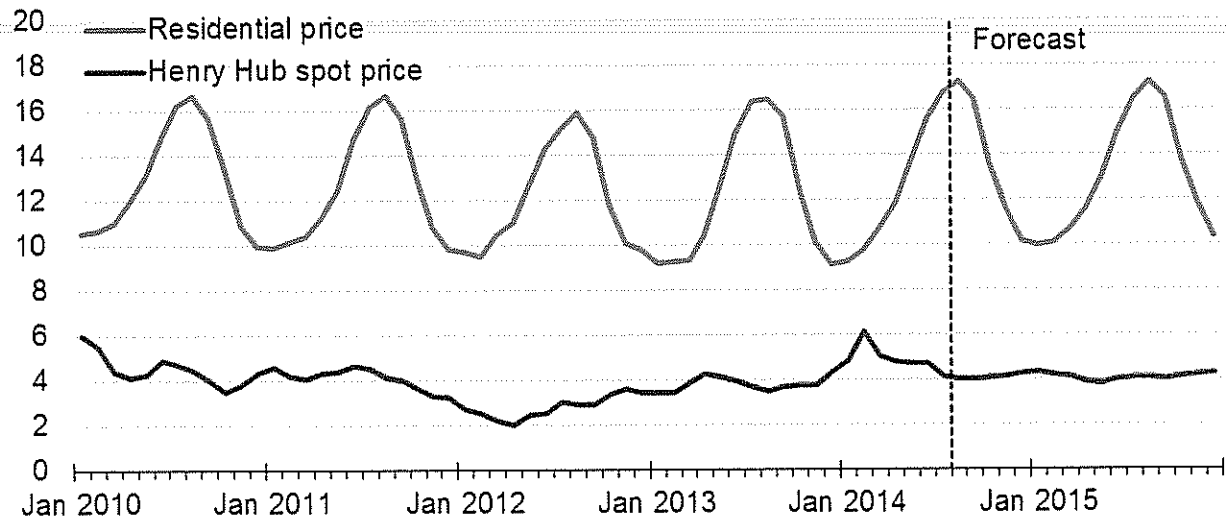
Note: Confidence interval derived from options market information for the 5 trading days ending Aug. 7, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, August 2014.

U.S. Natural Gas Prices



dollars per thousand cubic feet



Source: Short-Term Energy Outlook, August 2014.

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, 2014 | | | | | | | | | \$404,569 |
| May 2014 | (\$15,520) | 0 | \$2,700 | (\$12,820) | 18,641 | \$0.9614 | \$17,921 | (\$30,741) | 373,828 |
| June | (\$1,551) | 0 | \$2,475 | 924 | 9,300 | 1.3462 | \$10,015 | (9,092) | 364,736 |
| July | \$13,177 | 0 | \$2,399 | 15,576 | 6,189 | 1.3462 | \$8,331 | 7,245 | 371,981 |
| Total | (\$3,894) | 0 | \$7,574 | \$3,680 | 34,130 | | \$36,267 | (\$32,588) | \$371,981 |

Balance @ July 31, 2014

- 1/ Interest calculated at 13.3%, the authorized rate of return.
- 2/ Reflects 6,507.2 dk at \$0.9614 and 2,792.4 dk at \$1.3462.

**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/ 2/ | Total Net Additions | Actual Mcf Sales | Adjustment Per Mcf | Total Adjustment Amount | Net Change- Additions less Adjustment | Cumulative Balance |
|---------------------------------|--------------------------|--------------------|-------------------|------------------------|---------------------|-----------------------|-------------------------------|---|-----------------------|
| Balance @ April 30, 2014 | | | | | | | | | \$388,932 |
| May 2014 | (\$22,536) | 0 | \$2,691 | (\$19,845) | 42,002 | \$0.0274 | \$1,151 | (\$20,996) | 367,936 |
| June | (\$17,420) | 0 | \$2,515 | (14,905) | 19,772 | 0.9696 | \$5,999 2/ | (\$20,903) | 347,033 |
| July | (\$3,815) | 0 | \$2,344 | (1,471) | 11,279 | 0.9696 | 10,936 | (12,407) | 334,626 |
| Total | (\$43,771) | 0 | \$7,550 | (\$36,221) | 73,053 | | \$18,086 | (\$54,306) | \$334,626 |

Balance @ July 31, 2014

- 1/ Interest calculated at 13.3%, the authorized rate of return.
- 2/ Reflects 13,980.6 dk at \$0.0274 and 5,791.7 dk at \$0.9696.