

October 8, 2014

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

Re: Cost of Gas Adjustment  
(COG) Rate 88  
Case No. PU-14-008

In accordance with North Dakota Century Code Section 49-05-05, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and two (2) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (130<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered November 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.069 per dk since the last filing due to a decrease in the overall commodity price of gas. Attachment B explains the reasons for the decrease in the market price of gas. In addition, Montana-Dakota has increased its firm transportation capacity to meet increasing capacity requirements, resulting in a system wide change in demand allocation and a decrease of approximately \$0.039 per dk in North Dakota.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and the market based pricing differential provision that will apply during the month of November 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.108 per dk for residential and firm general customers, a decrease of \$0.075 per dk for small and large interruptible customers and a decrease of \$0.074 per dk for Air Force customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of November 2014. The average cost of

gas for firm customers, adjusted for losses, is \$5.512.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid demand and commodity balances using the calculation procedure set forth in Rate 88. The overall rate of return of 7.881% was authorized by the Commission in Case No. PU-13-803.

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has increased since the last COG filing due to an increase in the market price of propane. Attachment B page 2 explains the reasons for the increase in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of November 2014. The average cost of propane for all customers, adjusted for losses, is \$11.197 per dk.

Exhibit D shows the calculation of the current cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of November 2014 and is an increase of \$0.219 per dk. The market based pricing differential credit increased by \$0.005 per dk resulting in a net increase of \$0.214 per dk for all propane customers from the currently effective rates.

Exhibit E shows the computation of the (over)/under recovered gas cost account balances.

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$214,900 for natural gas customers during the month of November 2014. All of Montana-Dakota's retail natural customers in North Dakota may be affected by this proposal. There were 102,690 natural gas customers and 342 propane customers in North Dakota as of September 30, 2014.

Please refer all inquiries regarding this filing to:

Ms. Tamie A. Aberle  
Director - Regulatory Affairs  
Montana-Dakota Utilities Co.  
400 North Fourth Street  
Bismarck, ND 58501

Also, please send copies of all written inquiries, correspondence and pleadings to:

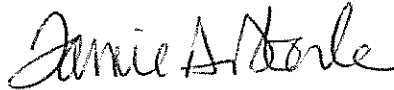
Mr. Daniel S. Kuntz  
Associate General Counsel  
MDU Resources Group, Inc.  
P. O. Box 5650  
Bismarck, ND 58506-5650

Montana-Dakota mailed a check on February 5, 2014 to the North Dakota Public Service Commission for \$500 pursuant to the requirements of North Dakota Century Code Section 49-05-05. This payment will cover the filing fee associated with the monthly COG filings for March 2014 through January 2015.

Montana-Dakota respectfully requests that 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,



Tamie A. Aberle  
Director of Regulatory Affairs

Attachment

**Rate Summary Sheet  
(Proposed)**



# Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.

400 N 4th Street

Bismarck, ND 58501

## State of North Dakota Gas Rate Schedule

NDPSC Volume 7

130<sup>th</sup> Revised Sheet No. 3

Canceling 129<sup>th</sup> Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.4935 per day	\$0.326	\$5.703	\$6.029
Air Force Rate 64	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$5.703	\$6.032
Interruptible Service - PAR			\$0.260	\$4.704	\$4.964
Interruptible Service - MAFB			\$0.260	\$4.670	\$4.930
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$5.703	\$6.433
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$4.704	(Maximum) \$5.633
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$5.808	\$6.538
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.019	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.019	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$4.704	(Maximum) \$5.422
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$12.373	\$12.699
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$12.373	\$13.103

Date Filed: October 8, 2014

Effective Date: November 1, 2014

Issued By: Tamie A. Aberle  
Director - Regulatory Affairs

Case No.: PU-14-008

**Montana-Dakota Utilities Co.  
Market Conditions for Regional Natural Gas**

**November 2014**

The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by willing sellers and buyers of quantities of gas in that region. That price is reflective of natural gas prices in the Rocky Mountain region and indicative of the supplies Montana-Dakota purchases for its requirements.

The seasonal transition from summer to fall, the decreased use of natural gas for electric generation and the relatively small demand for space heating throughout the nation, likely leads to the decrease in the CIG index. While the national storage level remains lower than both last year's balance and the five year average, increased flowing supply appears to have offset the fears associated with the lower storage balance. The EIA reported the national storage level as of September 26, 2014, was 11.4 percent below the five-year average and 10.7 percent below last year's storage balance.

The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.gov>.

The October Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 20. The November Outlook will be published November 12, 2014.

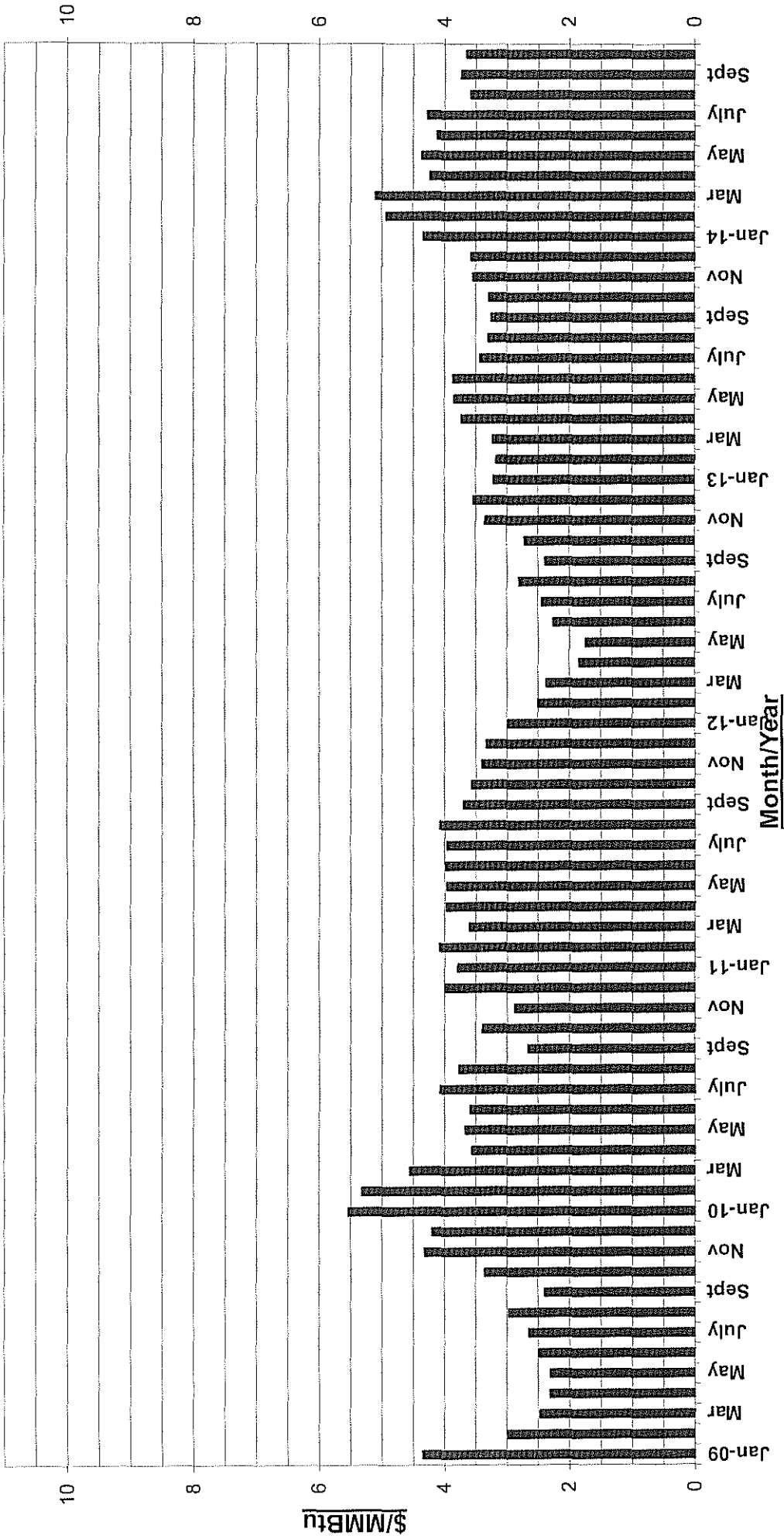
**Montana-Dakota Utilities Co.  
Market Conditions for Regional Propane  
November 2014**

Montana-Dakota uses two regional bulk wholesale propane suppliers for obtaining the lowest prices for Hettinger customers. Each time Montana-Dakota purchases propane, it requests a price quote from each supplier for a specific delivery date and quantity in truckloads, delivering 8,000 to 12,000 gallons. Montana-Dakota selects the lowest price, all other things being equal.

The November prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, and demand and inventory levels. Seasonal usage increases have resulted in an increase in the price of propane.

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

# CIG Rocky Mountains Index Monthly Gas Prices 2009-2014YTD



From Inside F.E.R.C.'s Gas Market Report  
Annual Averages: - 2012-\$2.58; 2013-\$3.45; 2014YTD-\$4.24



## Short-Term Energy and Winter Fuels Outlook (STEO)

### Highlights

- EIA projects average U.S. household expenditures for natural gas, heating oil, electricity, and propane will decrease this winter heating season (October 1 through March 31) compared with last winter, which was 11% colder than the previous 10-year average nationally. Projected average household expenditures for propane and heating oil are 27% and 15% lower, respectively, because of lower heating demand and prices. Lower heating demand and higher prices contribute to natural gas and electricity expenditures that are 5% and 2% lower than last winter (see EIA [Short-Term Energy Outlook and Winter Fuels Outlook slideshow](#)).
- Driven in large part by falling crude oil prices, U.S. regular gasoline retail prices fell to an average of \$3.41/gallon (gal) in September, 29 cents below the June average. U.S. regular gasoline retail prices are projected to continue to decline to an average of \$3.14/gal in December. EIA expects U.S. regular gasoline retail prices, which averaged \$3.51/gal in 2013, to average \$3.45/gal in 2014 and \$3.38/gal in 2015.
- Weakening global demand helped North Sea Brent crude oil spot prices fall to an average of \$97 per barrel (bbl) in September, the first month Brent prices have averaged below \$100/bbl in more than two years. EIA projects that Brent crude oil prices will average \$98/bbl in fourth-quarter 2014 and \$102/bbl in 2015. The WTI discount to Brent, which averaged \$11/bbl in 2013, is expected to average \$7/bbl in both 2014 and 2015.
- Total U.S. crude oil production averaged an estimated 8.7 million barrels per day (bbl/d) in September, the highest monthly production since July 1986. Total crude oil production, which averaged 7.4 million bbl/d in 2013, is expected to average 9.5 million bbl/d in 2015. If realized, the 2015 forecast would be the highest annual average crude oil production since 1970. Natural gas plant liquids production is expected to increase from an average of 2.6 million bbl/d in 2013 to 3.2 million bbl/d in 2015.
- Natural gas working inventories on September 26 totaled 3.10 trillion cubic feet (Tcf), 0.37 Tcf (11%) below the level at the same time a year ago and 0.40 Tcf (11%) below the previous five-year average (2009-13). Projected natural gas working inventories reach 3.53 Tcf at the end of October, 0.28 Tcf below the level at the same time last year. Despite the lower stocks at the start of this winter's heating season, EIA expects the Henry Hub natural gas

spot price to \$4.00/million British thermal units (MMBtu) this winter compared with \$4.53/MMBtu last winter. This price forecast reflects both lower expected heating demand and significantly higher natural gas production this winter.

### Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this STEO provide a broad guide to changes compared with last winter. However, fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings (see [Winter Fuels Outlook table](#)). Forecast temperatures based on the latest forecasts from the National Oceanic and Atmospheric Administration (NOAA) are much warmer than last winter east of the Rocky Mountains, with the Midwest 16% warmer, the South 12% warmer, the Northeast 11% warmer. However, last winter provides a reminder that weather can be unpredictable, and the Winter Fuels Outlook includes forecasts for scenarios where heating degree days (HDD) in all regions may be 10% higher (colder) or 10% lower (warmer) than forecast.

**Natural Gas.** About half of all U.S. households heat with natural gas, and the average household may expect a 5% decrease in winter natural gas expenditures. EIA projects a 10% decline in residential natural gas consumption this year as temperatures are expected to return to closer-to-normal levels. The savings from lower consumption are partially offset by higher residential prices. Although EIA forecasts lower Henry Hub prices this winter, current spot prices do not directly translate into lower delivered residential prices. Utilities began buying gas in April for the upcoming heating season, and prices in 2014 have averaged higher than last year. Plus, the rates that utilities charge can be set by state utility commissions a year or more in advance.

Under a 10%-colder scenario, EIA projects consumption will be 3% less than last year and expenditures will be 6% greater than last year. Under a 10%-warmer scenario, EIA expects a decline of 17% in consumption and 12% in expenditures compared with last year.

Last winter, [gas-fired power plants in the Northeast](#) had to compete for an increasingly limited amount of available natural gas pipeline capacity from a system that was already constrained, particularly in New England and New York. This caused natural gas spot prices and consequently day-ahead power prices to spike. Pipeline constraints still exist in the area, and day-to-day price volatility is likely. The region has two important marginal sources of supply for times of very high demand: liquefied natural gas (LNG) imports and pipeline imports from Canada. Although LNG imports have declined dramatically in the past several years, GDF Suez still receives cargoes from Trinidad under long-term contracts at its LNG terminal near Boston. One of the terminal's customers is the adjacent Mystic Power Plant. LNG received at the Canaport LNG terminal in New Brunswick, Nova Scotia, also comes to the United States via the Brunswick Pipeline.

Strong production growth this year contributed to a record inventory build. EIA projects working natural gas inventories of 3,532 billion cubic feet (Bcf) at the end of October. EIA

expects working gas inventories to be drawn down to 1,534 Bcf at the end of March 2015. Even in the event of another cold winter, EIA does not expect stocks to fall below 1,000 Bcf by the end of this heating season.

**Heating Oil.** EIA expects households heating primarily with heating oil to spend an average of \$362 (15%) less this winter than last winter, reflecting prices that are \$0.25/gal (6%) lower and consumption that is 10% lower. Heating oil prices are expected to be lower in large part because of lower crude oil prices, with Brent crude oil prices forecast to average \$9/bbl (\$0.22/gal) lower this winter than last. In the 10%-colder-weather scenario, projected expenditures are \$124 lower than last winter, with prices that are \$0.16/gal lower than last winter.

A number of factors contribute to uncertainty in this winter's heating oil market, including weather and oil price volatility, the adequacy of inventories, and changes in fuel specifications. Distillate stocks in the Northeast totaled 29.3 million barrels on September 26, 0.2 million barrels below the same time last year and the lowest level for this time of year since 2000. However, unless severe weather in the Northeast coincides with severe weather in Europe, demand should be readily met via supplies from the Atlantic Basin market.

Reliance on heating oil is highest in the Northeast, where about 23% of households depend on heating oil for space heating. Nationwide, only 5% of households use heating oil. The state of New York, which accounts for about one-third of the region's heating oil market, has required the use of ultra-low sulfur heating oil since July 2012. Five states (Connecticut, Massachusetts, New Jersey, Rhode Island, and Vermont) lowered their heating oil maximum sulfur specification on July 1 from 2,000 parts per million (ppm) (and higher) to 500 ppm. No major impact is expected as suppliers will either blend high-sulfur distillate with ultra-low sulfur diesel (ULSD) or deliver ULSD, which is a readily available fuel.

In January 2015, new regulations will limit marine vessel fuel sulfur levels in certain coastal waters to 1,000 ppm. Some vessels are expected to switch from using residual fuel oil to distillate because of its lower sulfur content. However, the effect on the Northeast heating oil market should be limited because marine fuel demand in this region is relatively small.

**Propane.** About 5% of all U.S. households heat with propane. EIA expects households heating primarily with propane to spend less this winter, but the projected decrease varies across regions. EIA expects that households heating with propane in the Midwest will spend an average of \$767 (34%) less this winter than last winter, reflecting prices that are about 24% lower and consumption that is 13% lower than last winter. Households in the Northeast are expected to spend an average of \$340 (13%) less this winter, with average prices that are about 5% lower and consumption that is 9% lower than last winter.

Heading into the winter months, primary propane stocks in the Gulf Coast (PADD 3) and the Midwest (PADD 2) at the end of September were 6.6 million barrels (18%) and 3.7 million

barrels (15%) higher, respectively, than at the same time last year. Propane spot prices at the Mont Belvieu, Texas and Conway, Kansas delivery points in early October were close to prices at the same time last year. The outlook for propane demand is uncertain given volatility in winter temperatures and another expected record corn crop, which could draw down propane stocks for crop drying. The Cochin Pipeline, which previously delivered propane from Canada to the Midwest, was reversed in early 2014. While this reversal will limit the ability to deliver propane into the region, higher propane production from gas plants in the Midwest and new and expanded rail terminals should help to supply propane to the region this winter.

**Electricity.** Households heating primarily with electricity can expect to spend an average of \$17 (2%) less this winter, with 3% higher prices but 5% less consumption than last winter. About 39% of all U.S. households rely on electricity as their primary heating source, ranging regionally from 15% in the Northeast to 63% in the South.

Under a 10% colder scenario, EIA estimates that U.S. residential electricity consumption this winter would be 1.8% higher than during the winter of 2013-14. Residential electricity prices would not rise immediately, but the effect of colder temperatures would pass through to retail electricity rates over the succeeding months of 2015. For a 10% colder scenario, the average U.S. residential price would rise by 2.7% in 2015 in contrast to the baseline forecast of 1.7% growth. The effect would be greatest in New England where residential prices would rise by 6.0% next year if there's a cold winter, in contrast to the baseline forecast of a 3.6% increase.

Wholesale electricity prices in the Northeast region spiked last winter because of a winter freeze and constraints on supplying natural gas to power generators. As a result, retail electricity customers in that area have experienced increases averaging up to 12% so far this year. The natural gas pipeline constraints in New England still exist and deliveries into the region are near capacity. If colder-than-expected temperatures occur this winter, there is the possibility that wholesale electricity prices could rise again. Electricity traders are already factoring in this uncertainty through higher forward market prices for wholesale electricity in the Northeast Independent System Operators.

**Wood.** The use of cord wood and wood pellets as the primary residential space heating fuel has increased by 38% since 2004, to about 2.5 million households in 2013. About 8% of households use wood as a secondary source of heat, making wood second only to electricity as a supplemental heating fuel. About 20% of New England homes (1.1 million) used wood for space heating, water heating, or cooking in 2009 (EIA, Residential Energy Consumption Survey, 2009), which is nearly twice the national rate. Almost half of all rural households in New England used wood, compared with only 12% of the area's urban households.

## Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.6 million bbl/d in 2014 and by 0.9 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 1.9 million bbl/d in 2014 and 1.2 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 1.0 million bbl/d in 2014 and 1.2 million bbl/d in 2015.

Global disruptions to near-term supply have abated since June, when Libya's production and exports were at a minimal level, and violence in northern Iraq escalated, causing northern production (outside of Iraqi Kurdistan) to come nearly to halt. Iraq's southern crude oil exports still remain unaffected by the unrest in northern Iraq. In Libya, production averaged 0.8 million bbl/d in September, its highest level in more than 1 year. However, the security situation in Libya is still precarious, with a significant possibility of intermittent disruptions.

**Global Petroleum and Other Liquids Consumption.** EIA estimates that global consumption grew by 1.3 million bbl/d (1.5%) in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in 2014 and 1.2 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.7% in 2013, grows by 2.7% and 3.3% in 2014 and 2015, respectively.

Consumption outside of the Organization for Economic Cooperation and Development (OECD) is projected to grow by 1.2 million bbl/d in 2014 and 1.1 million bbl/d in 2015, accounting for nearly all forecast global consumption growth during that period. China is the leading contributor to projected global consumption growth, with consumption increasing by 0.37 million bbl/d in both 2014 and 2015.

EIA expects a 0.20-million-bbl/d decline in OECD consumption in 2014. Japan and Europe are expected to account for much of the projected OECD consumption declines. EIA expects Japan's consumption, which fell by 0.16 million bbl/d in 2013, to continue to decline by an annual average of 0.13 million bbl/d in 2014 and 0.14 million bbl/d in 2015. Japan's oil consumption is expected to fall as the country continues to reduce its share of oil used in the electricity sector, replacing it with natural gas, coal, and nuclear power as the country returns some nuclear power plants to service in 2015. EIA projects that OECD Europe's consumption, which fell by 0.15 million bbl/d in 2013, will decline by 0.13 million bbl/d in 2014 and by a further 0.02 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to decline by 0.04 million bbl/d in 2014 and then increase by 0.17 million bbl/d in 2015.

**Non-OPEC Petroleum and Other Liquids Supply.** EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, averaging 54.1 million bbl/d for the year. EIA expects non-OPEC production to grow by 1.9 million bbl/d in 2014 and 1.2 million bbl/d in 2015. The United States is the leading contributor to forecast non-OPEC supply growth, increasing by 1.48 million bbl/d in 2014 and 1.23 million bbl/d in 2015. EIA estimates that Eurasia's production will rise by an annual average of 0.08 million bbl/d in 2014 and 0.02 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 nearly 0.6 million bbl/d in September, down slightly from the previous month. South Sudan, Syria, and Yemen accounted for more than 90% 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 Petroleum and Other Liquids Supply.** EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2013, a decline of 0.99 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 0.2 million bbl/d in 2014 and by more than 0.4 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.2 million bbl/d in September 2014, 0.2 million bbl/d lower than the previous month because of decreased outages in Libya. Libya's production increased to 0.8 million bbl/d in September, 0.3 million bbl/d higher than the previous month, but still well below the 1.4 million bbl/d the country produced before the major blockades started in mid-2013. Libya still faces a considerable challenge in ramping up production to its full capacity or even sustaining it at the current level. Despite the recent production increase, the security situation has deteriorated in parts of the country, and the evacuation of foreign workers is inhibiting production levels from reaching capacity at some fields. As a result, EIA does not expect Libya's oil production to recover to its pre-blockade level over the forecast period.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to average 2.2 million bbl/d in 2014 and 3.0 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 2.62 billion barrels at the end of 2014.

**Crude Oil Prices.** North Sea Brent crude oil spot prices averaged \$97/bbl in September, a decrease of \$5/bbl from August and the first month Brent crude oil prices have averaged below \$100/bbl since June 2012. Brent crude oil prices were driven downward in large part because of weakening global oil demand and higher Libyan oil exports (EIA, *This Week in Petroleum*, September 24, 2014). The forecast Brent crude oil price averages \$104/bbl in 2014 and \$102/bbl in 2015, \$2/bbl lower and \$1/bbl lower than projected in last month's STEO, respectively.

The monthly average WTI crude oil spot price fell from an average of \$97/bbl in August to \$93/bbl in September. High refinery runs contributed to the discount of WTI crude oil to Brent

crude oil falling from an average of \$8/bbl during the first half of this year to an average of \$4/bbl in the third quarter. EIA now expects WTI crude oil prices to average \$91/bbl in the fourth quarter of 2014 and \$95/bbl in 2015. The discount of WTI to Brent crude oil is forecast to widen from current levels, averaging \$7/bbl in the fourth quarter of 2014 and in 2015.

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 January 2015 delivery, traded during the five-day period ending October 2, averaged \$91/bbl. Implied volatility averaged 19%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in January 2015 at \$76/bbl and \$107/bbl, respectively. Last year at this time, WTI for January 2014 delivery averaged \$102/bbl and implied volatility averaged 20%. The corresponding lower and upper limits of the 95% confidence interval were \$85/bbl and \$121/bbl.

## U.S. Petroleum and Other Liquids

**Liquid Fuels Consumption.** Total U.S. liquid fuels consumption rose by 470,000 bbl/d (2.5%) in 2013, the largest increase since 2004. Consumption of all the major liquid fuels rose, except residual fuel oil. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain, increasing by 190,000 bbl/d (8.5%). In 2014, total liquid fuels consumption is expected to fall by 40,000 bbl/d (0.2%), with declines in the consumption of motor gasoline, HGL, residual fuel oil, and other oils offsetting increases in distillate fuel and unfinished oils consumption. Total consumption grows by 170,000 bbl/d in 2015, with HGL consumption accounting for three-fourths of the increase.

Motor gasoline consumption grew by 160,000 bbl/d (1.9%) in 2013, the largest increase since 2004. But consumption of that fuel falls by 20,000 bbl/d (0.2%) in 2014 and by a further 20,000 bbl/d in 2015 as improving fuel economy in new vehicles offsets highway travel growth. Distillate fuel consumption increases by 150,000 bbl/d (3.9%) in 2014, reflecting colder-than-average first-quarter weather and economic growth. Consumption of that fuel rises by a more moderate 70,000 bbl/d (1.9%) in 2015 under assumptions of normal winter weather.

**Liquid Fuels Supply.** The forecast for total U.S. crude oil production increases from 7.4 million bbl/d in 2013 to 8.5 million bbl/d in 2014 and 9.5 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 1.3 million bbl/d in 2013 to 1.6 million bbl/d in 2015, 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 3.2 million bbl/d in 2015. Most of this growth is expected to come from additional ethane and propane production that will meet growing demand associated with expanding domestic ethylene and propylene 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 20% in 2015, which would be the lowest level since 1968.

**Petroleum Product Prices.** Monthly average regular gasoline retail prices fell from \$3.69/gal in June to \$3.41/gal in September. EIA expects average regular gasoline retail prices to continue falling to \$3.14/gal in December. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.45/gal in 2014 and \$3.38/gal in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.85/gal in 2014 and \$3.80/gal in 2015. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by \$0.30/gal or more.

## Natural Gas

**Natural Gas Consumption.** EIA expects that total natural gas consumption to average 72.5 Bcf/d in 2014, an increase of 1.6% from 2013, with the industrial sector leading the growth. In 2015, total natural gas consumption will increase 0.3%, as continued industrial sector growth and higher electric power sector consumption offset lower residential and commercial consumption. Higher natural gas prices this year contribute to a 2.3% 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 22.6 Bcf/d in 2015.

**Natural Gas Production and Trade.** EIA expects natural gas marketed production to grow by an annual rate of 5.4% in 2014 and 2.0% in 2015. STEO projects that the strong increases already seen in the Lower 48 states this year will continue, offsetting declines in the Gulf of Mexico. As of July, the most recent month for which EIA data are available, marketed production was 4.2 Bcf/d greater than it was in July 2013.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada and spur exports to Mexico. Exports to Mexico, particularly from the Eagle Ford Shale in South Texas, are expected to increase because of growing demand from Mexico's electric power sector and flat Mexican production.

LNG imports have fallen over the past four years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. LNG exports are

still a very small part of the total picture, however, and overall the United States will remain a net importer of natural gas because of pipeline imports from Canada.

**Natural Gas Inventories.** Natural gas working inventories totaled 3,100 Bcf as of September 26, which was 373 Bcf lower than at the same time last year and 399 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 above the five-year (2009-13) average throughout most of the injection season. EIA expects working gas stocks will reach 3,532 Bcf at the end of October, 283 Bcf lower than at the same time last year. Heading into next summer, EIA projects end-of-March 2015 inventories will be 122 Bcf below the five-year (2010-14) average.

**Natural Gas Prices.** The Henry Hub natural gas spot price averaged \$3.92/MMBtu in September, a slight increase from August. EIA expects spot prices to remain below \$4.00/MMBtu through November, before rising with winter heating demand. Projected Henry Hub natural gas prices average \$4.45/MMBtu in 2014 and \$3.84/MMBtu in 2015.

Natural gas futures prices for January 2015 delivery (for the five-day period ending October 2) averaged \$4.19/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for December 2014 contracts at \$2.96/MMBtu and \$5.94/MMBtu, respectively. At this time last year, the natural gas futures contract for January 2014 averaged \$3.83/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.91/MMBtu and \$5.04/MMBtu.

## Coal

According to data compiled by [the Association of American Railroads \(AAR\)](#), [year-to-date rail coal shipments](#) were down by 0.1% as of September 27. AAR data show that total U.S. rail traffic is up 4.4% year-to-date and shipments of petroleum and grain are up by 12.5% and 17.7%, respectively.

Two railways that serve Powder River Basin (PRB) producers, Union Pacific and BNSF, provided the [U.S. Surface Transportation Board \(STB\)](#) with their assessments of their ability to provide rail service for the remainder of the year (fall peak period) and the upcoming winter season. The STB annually requests the assessments from all [Class I railroads](#). Union Pacific stated that it has responded by activating surge resources, which included acquiring more locomotives, hiring more employees, and increasing coal train sizes where possible. [BNSF](#) also plans to expand its locomotive fleet and increase coal train sizes, but they emphasized that their priority will be to transport coal that is currently contracted.

**Coal Supply.** EIA estimates that coal production for the first three quarters of this year, 742 million short tons (MMst), was slightly lower (3 MMst, or 0.4%) than production over the same period last year. Year-to-date production in the West, which includes the PRB, is down by nearly

2 MMst, and has been hindered by rail transportation problems. EIA expects that U.S. coal production will accelerate in the fourth quarter and annual production will grow 1.4% to 998 MMst in 2014. In 2015, forecast U.S. coal production increases by 0.4% to 1,002 MMst.

Electric power sector coal inventories fell to 125 MMst at the end of July, 7 MMst lower than the previous month. This stock drawdown was 4 MMst less than the same time last year. Coal inventory reductions in the Midwest and South, two regions that rely heavily on coal-fired generation, were down 1 MMst and 2 MMst, respectively, when compared with last year.

**Coal Consumption.** Higher electricity demand and higher power sector natural gas prices that are more than 21% above their 2013 level contributed to a 3.0% increase in electric power sector coal consumption for the first seven months of this year from the same period last year. EIA projects total coal consumption of 941 MMst in 2014, an increase of 1.7% from last year. Total coal consumption is projected to fall by 2.0% 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 0.6%, and natural gas prices fall relative to coal prices.

**Coal Trade.** EIA estimates that coal exports for the first seven months of this year were 15.5% (10.9 MMst) lower compared with last year, with tonnage declines for steam coal exports more than 4 times those for metallurgical coal. Exports of coal are projected to decline to 96 MMst in 2014 from 118 MMst in 2013, primarily because of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. EIA projects coal exports to remain nearly flat in 2015.

Coal imports for the first seven months of this year increased by 36.5% (1.8 MMst) compared with last year. EIA expects coal imports, which account for about 1% of U.S. coal consumption, to total 11.4 MMst in 2014 and fall slightly to 10.7 MMst in 2015.

**Coal Prices.** Annual average coal prices to the electric power industry fell from \$2.39/MMBtu in 2011 to \$2.35/MMBtu in 2013. EIA expects the average delivered coal prices to be \$2.36/MMBtu in 2014 and remain at that level in 2015.

## Electricity

**Electricity Consumption.** Forecast U.S. sales of electricity to the residential sector are 1.7% higher in 2014 compared with last year, driven in large part by the cold weather experienced early in the year. Residential electricity sales fall by 0.3% in 2015. U.S. commercial sector electricity sales are expected to average 0.9% higher in 2014 than sales last year and then grow by 0.4% in 2015. EIA expects U.S. industrial sector electricity sales to remain flat during 2014 and grow by 2.1% in 2015.

**Electricity Generation.** EIA projects that average daily U.S. electricity generation in 2014 will grow by 105 gigawatthours per day (0.9%) from last year. Relative fuel costs have favored coal-

fired generation over natural gas this year, leading to an expected increase in coal's share of total generation from 39.1% in 2013 to 39.8% this year, while the share supplied by natural gas falls from 27.4% to 26.8%. In 2015, EIA expects that natural gas' fuel share will rise to 27.6% and coal's fuel share will decline to 38.7%.

**Electricity Retail Prices.** EIA expects the U.S. residential price to average 12.5 cents per kilowatthour in 2014, which is 3.0% higher than the average last year. Prices increase in all regions of the country except along the Pacific Coast. Average U.S. residential electricity prices grow at a slower rate of 1.7% in 2015.

## Renewables and Carbon Dioxide Emissions

**Electricity and Heat Generation from Renewables.** EIA projects that total renewables used for electricity and heat generation will grow by 2.2% in 2014. Conventional hydropower generation is projected to fall by 4.2%, while nonhydropower renewables rise by 5.6%. [Nonhydropower renewables generation surpasses hydropower](#) on an annual basis for the first time in 2014. In 2015, total renewables consumption for electric power and heat generation increases by 4.6%, as a result of a 4.3% increase in hydropower and a 4.7% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 8.8% in 2014 and 16.2% in 2015. Electricity generation from wind is projected to contribute 4.7% 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 slightly more than doubled in 2013. EIA expects that utility-scale solar capacity will about double again 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 in June matched the monthly average production record of 959,000 bbl/d set in December 2011, and then fell back to an average of 909,000 bbl/d in September. EIA expects ethanol production to average 927,000 bbl/d in 2014 and 933,000 bbl/d in 2015. Biodiesel production averaged 89,000 bbl/d in 2013 and is forecast to average 81,000 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 2.5% in 2013 from the previous year. Emissions are forecast to rise by 1.1% in 2014, and then to decline by 0.4% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 1.8%, respectively. The price of natural gas to electric power generators was \$0.91/MMBtu above its 2012 level in 2013 and is

expected to rise by \$0.91/MMBtu in 2014, contributing to an increase in coal use. Coal emissions are projected to decline by 1.9% in 2015.

## U.S. Economic Assumptions

**Recent Economic Indicators.** Economic growth improved substantially in the second quarter of 2014. The U.S. Bureau of Economic Analysis (BEA) reported that second quarter real gross domestic product (GDP) grew at an annualized rate of 4.6% from the first quarter of 2014, which reflects an upward revision of 0.4% from its previous estimate. Recent housing data have been mixed. The Census Bureau reported that new home sales in August rose 18% over July levels, and 33% over levels in August 2013. Existing home sales in August, however, fell by 1.8% from July according to the National Association of Realtors. Census also reported that new orders for durable goods fell 18.2% from July to August, but rose 0.7% excluding transportation.

EIA used the September 2014 version of the IHS macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

**Production and Income.** Real GDP growth reaches 2.2% in 2014 and accelerates to 2.9% in 2015, similar to the forecast last month. Exports are expected to pick up in the latter half of 2014 relative to imports, but a strong dollar will slow these gains in 2015. Housing starts more than make up for this in 2015. Real disposable income grows by 2.5% in 2014, the same as last month, and total industrial production grows by 4.1% in 2014, up from 3.9% forecast last month. In 2015, these variables grow at 2.5% and 3.7%, respectively.

**Expenditures.** Private real fixed investment growth averages 5.5% and 7.4% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and a broad array of equipment categories in 2015. Real consumption expenditures grow at the same rate as real GDP in 2014 at 2.2%, 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 2.8% and 4.9% over the same two years, while import growth is 3.2% in 2014 and 4.2% in 2015. Total government expenditures fall by 0.4% in 2014, but increase by 0.5% in 2015.

**U.S. Employment, Housing, and Prices.** Projected growth in nonfarm employment averages 1.8% in 2014 and 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.7% at the end of 2015. The employment growth in 2015 is slower than projected last month and the declines in the unemployment rate are the same. Housing starts grow an average of 8.9% and 25.4% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.

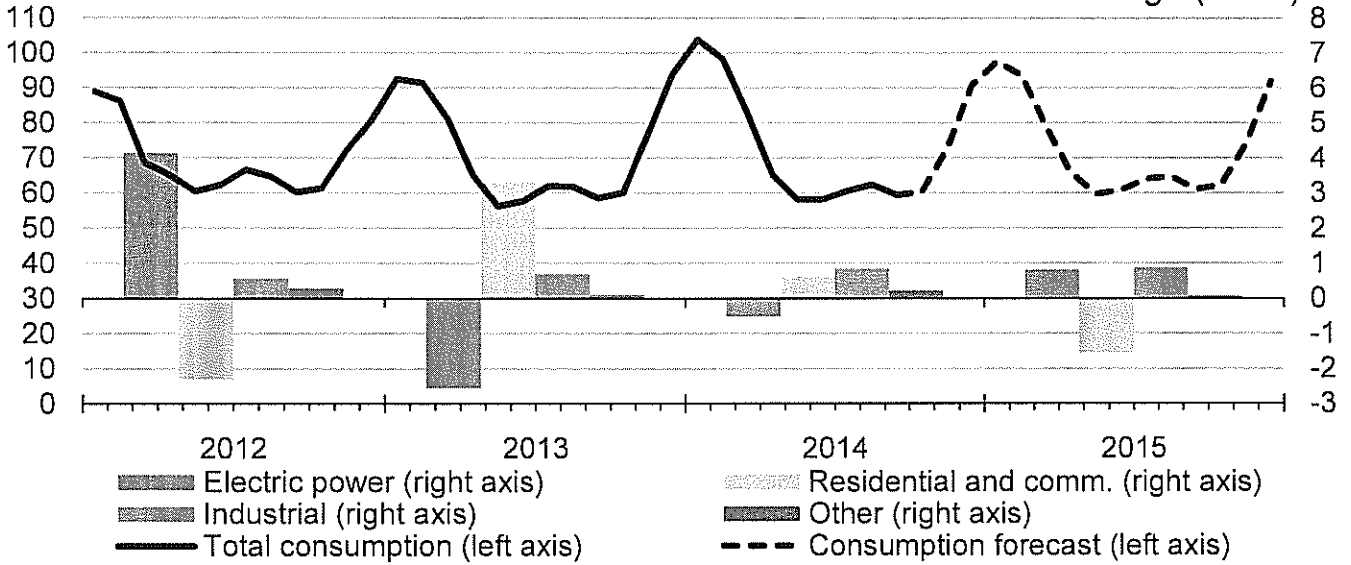
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views 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



billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



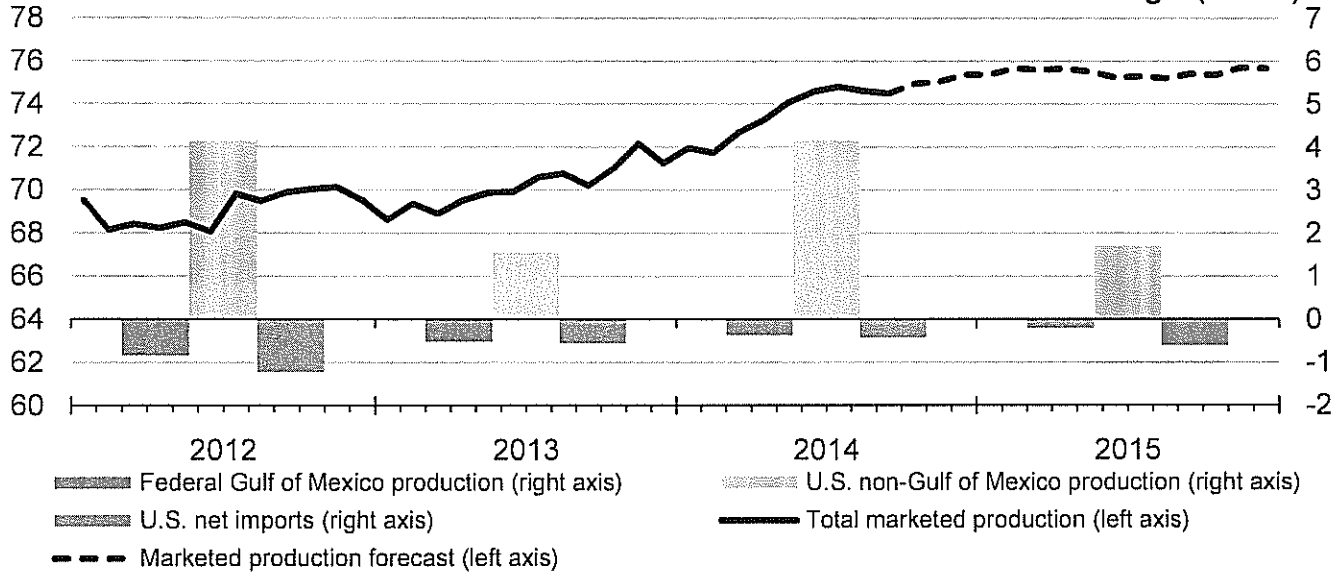
Source: Short-Term Energy Outlook, October 2014.

## U.S. Natural Gas Production and Imports



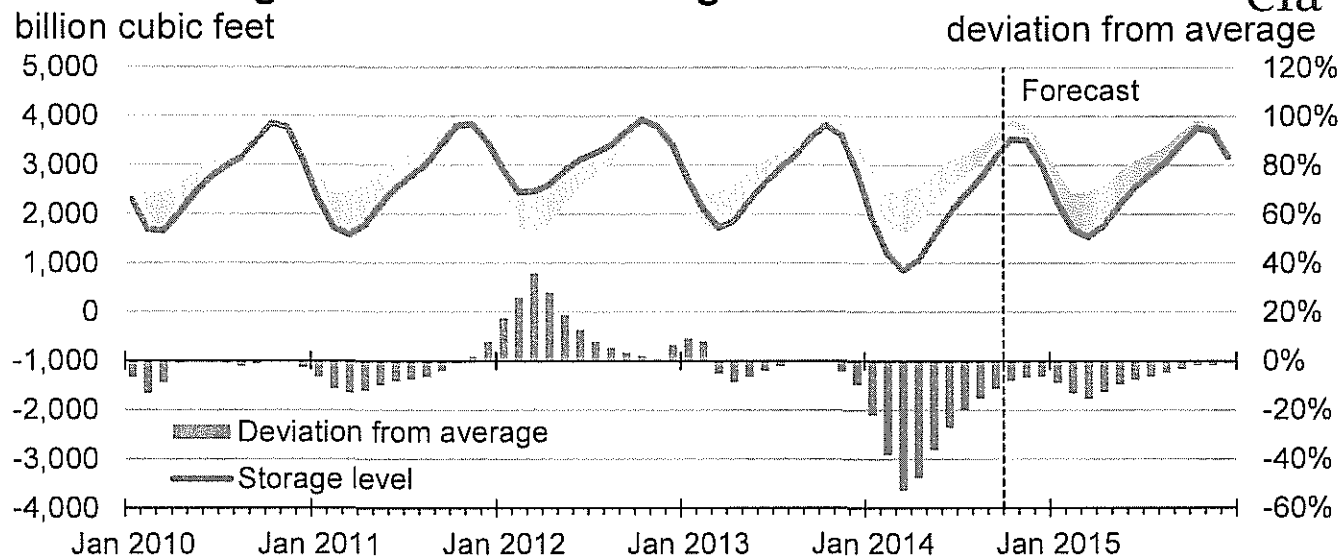
billion cubic feet per day (Bcf/d)

annual change (Bcf/d)



Source: Short-Term Energy Outlook, October 2014.

## U.S. Working Natural Gas in Storage

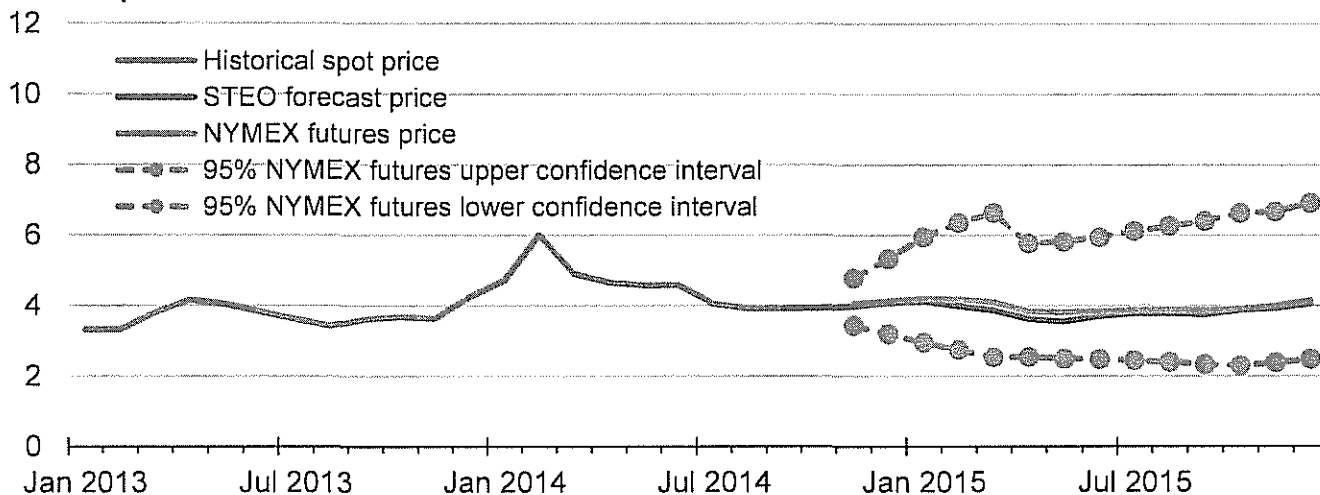


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, October 2014.

## Henry Hub Natural Gas Price

dollars per million Btu



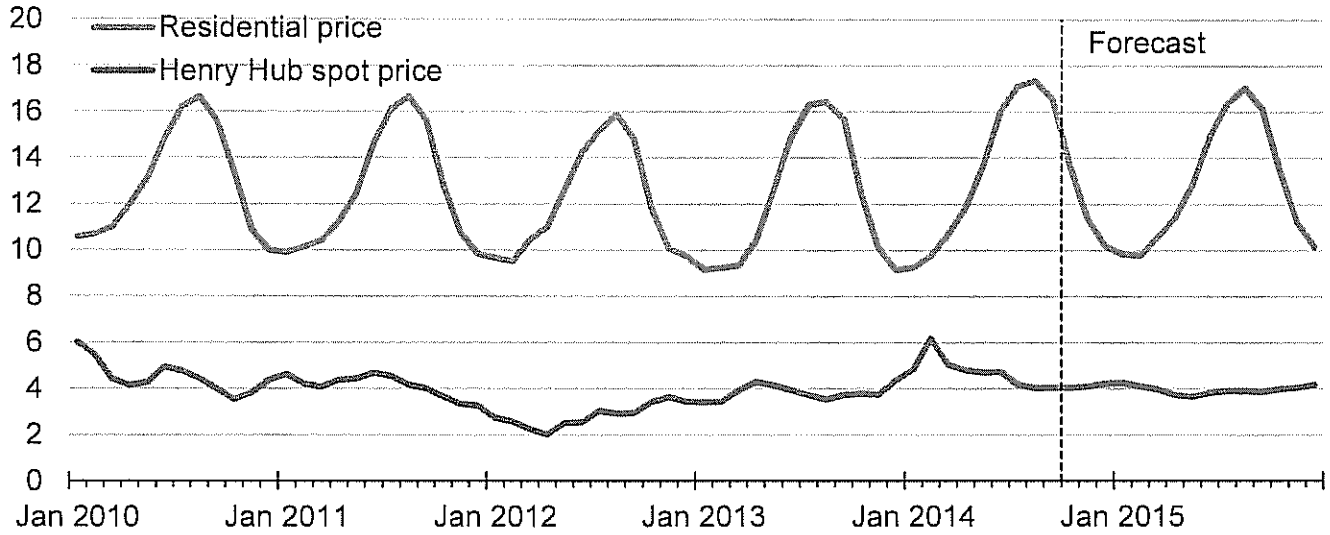
Note: Confidence interval derived from options market information for the 5 trading days ending Oct. 2, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, October 2014.



## U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, October 2014.

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS TARIFF SHEET  
NORTH DAKOTA GAS  
EFFECTIVE NOVEMBER 2014

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$5.512	\$5.617	\$4.324	\$4.305
Prior Gas Cost	5.620	5.736	4.399	4.379
Current Gas Cost Adjustment	(\$0.108)	(\$0.119)	(\$0.075)	(\$0.074)
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
Gas Cost Level	\$5.512	\$5.617	\$4.324	\$4.305
Plus: Surcharge	0.209	0.209	0.380	0.365
<b>Total Gas Cost Level in Tariff Rates</b>	<b><u>\$5.721</u></b>	<b><u>\$5.826</u></b>	<b><u>\$4.704</u></b>	<b><u>\$4.670</u></b>
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment	(\$0.017)	(\$0.017)	\$0.000	\$0.000
Prior Adjustment	(0.017)	(0.017)	0.000	0.000
Change in Market Based Pricing	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Grain Drying Margin Sharing</u></b>				
Current Adjustment	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Prior Adjustment	(0.001)	(0.001)	0.000	0.000
Change in Grain Drying Margin Sharing	\$0.000	\$0.000	\$0.000	\$0.000
<b>Total Cost of Gas Items</b>	<b><u>\$5.703</u></b>	<b><u>\$5.808</u></b>	<b><u>\$4.704</u></b>	<b><u>\$4.670</u></b>
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>(\$0.108)</u></b>	<b><u>(\$0.119)</u></b>	<b><u>(\$0.075)</u></b>	<b><u>(\$0.074)</u></b>

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE TARIFF SHEET  
NORTH DAKOTA PROPANE  
EFFECTIVE NOVEMBER 2014

**Cost of Gas - Propane**

Current Propane Cost (Exhibit D)	\$11.197
Prior Propane Cost	<u>10.978</u>
Current Propane Cost Adjustment	<u>\$0.219</u>

**Surcharge Adjustment**

Current Adjustment	\$1.193
Prior Adjustment	<u>1.193</u>
Change in Surcharge Adjustment	\$0.000

**Market Based Pricing Differential**

Current Adjustment	(\$0.017)
Prior Adjustment	<u>(0.012)</u>
Change in Margin Sharing Provision	(\$0.005)

**Net Increase (Decrease) in Gas Costs** \$0.214

Propane Cost Level	\$11.197
Plus: Surcharge	<u>1.193</u>
Total Propane Cost Level in Rates	<u><u>\$12.390</u></u>

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
RESIDENTIAL AND GENERAL SERVICE  
EFFECTIVE NOVEMBER 2014**

	Amount
Total Gas Costs 1/	\$82,206,841
Residential and General Service dk Requirements 2/	14,983,356
Average Cost of Gas per dk	\$5.487
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.512
Less: Gas Cost Level in Rates 3/	5.620
<b>Current Gas Cost Adjustment</b>	<b>(\$0.108)</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Normalized dk sales for the twelve months ended July 31, 2014, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective October 1, 2014:

Cost of Purchased Gas	\$5.595
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.620

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
OPTIONAL SEASONAL - RATE 72  
EFFECTIVE NOVEMBER 2014**

Total Gas Costs 1/	\$82,206,841
Less: Annual MDDQ Costs	<u>17,711,968</u>
Total Gas Costs excluding MDDQ	\$64,494,873
Firm Service Requirements 1/	14,983,356
Other Gas Costs per Dk (excluding MDDQ)	\$4.304
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$17,711,968
Winter Firm Service Requirements	13,749,069
MDDQ Costs per Winter Dk	\$1.288
Add: Other Gas Costs per Dk	<u>4.304</u>
Winter Seasonal Rate	\$5.592
Winter Seasonal Rate, adjusted for losses 2/	\$5.617
Less: Gas Cost Level in Rates 3/	<u>5.736</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>(\$0.119)</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective October 1, 2014:

	<u>Winter</u>
Cost of Purchased Gas	\$5.710
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.736

**MONTANA-DAKOTA UTILITIES CO.  
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA  
INTERRUPTIBLE  
EFFECTIVE NOVEMBER 2014**

	Amount
Total Gas Costs 1/	\$30,109,988
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$4.305
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.324
Less: Gas Cost Level in Rates 2/	4.399
<b>Current Gas Cost Adjustment</b>	<b>(\$0.075)</b>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective October 1, 2014:

Cost of Purchased Gas	\$4.379
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.399



**Montana-Dakota Utilities Co.  
Schedule of Applicable Effective Pipeline Rates  
November 2014 PGA**

WBI Energy Transmission, Inc. - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company - Exhibit B, page 9 for Schedule T-1.

Foothills Pipe Lines, Ltd. - Billed on a cost of service basis so there are no tariff sheets.

NOVA Gas Transmission - Exhibit B, pages 10-11 for Schedule FT-D.

NorthWestern Energy - Exhibit B, page 12 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline - Exhibit B, page 13 for Rate 1.

SourceGas Distribution LLC - Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----					
RATE SCHEDULE FT-1					
-----					
RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	921.000	N.A.	N.A.	921.000
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	32.112	N.A.	N.A.	32.112
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	30.279	N.A.	N.A.	30.279
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	0.000

- 
- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 3.867%, CONSISTING OF 3.582% FOR THE CURRENT PERCENTAGE AND 0.285% FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
  - B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 1.138 CENTS, CONSISTING OF 0.818 CENTS FOR THE CURRENT RATE AND 0.320 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.
  - C/ SHIPPER MUST REIMBURSE TRANSPORTER FOR THE ACA SURCHARGE. SUCH SURCHARGE SHALL BE THE ACA UNIT CHARGE SPECIFIED IN THE ANNUAL NOTICE ISSUED BY THE FERC ENTITLED "FY [YEAR] GAS ANNUAL CHARGES CORRECTION FOR ANNUAL CHARGES UNIT CHARGE."

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----					
RATE SCHEDULE FTN-1					
-----					
RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	24.274	N.A.	N.A.	24.274
MINIMUM	RATE PER EQV. DKT PER MO.	1.263	N.A.	N.A.	1.263
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	0.798	N.A.	N.A.	0.798
MINIMUM	RATE PER DKT	0.042	N.A.	N.A.	0.042

NOTICE OF CURRENTLY EFFECTIVE RATES

(ALL RATES ARE STATED IN CENTS PER DEKATHERM OR EQUIVALENT DEKATHERM AS INDICATED)

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1					
CAPACITY RESERVATION CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	1.757	N.A.	N.A.	1.757
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY CHARGE					
MAXIMUM	RATE PER EQV. DKT PER MO.	201.507	N.A.	N.A.	201.507
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
INJECTION CHARGE					
MAXIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
WITHDRAWAL CHARGE					
MAXIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
SCHEDULED OVERRUN CHARGE					
INJECTION					
MAXIMUM A/B/	RATE PER DKT	18.683	N.A.	N.A.	18.683
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221
WITHDRAWAL					
MAXIMUM A/B/	RATE PER DKT	18.683	N.A.	N.A.	18.683
MINIMUM A/B/	RATE PER DKT	1.221	N.A.	N.A.	1.221

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.132%, CONSISTING OF 2.174% FOR THE CURRENT PERCENTAGE AND (0.042%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.
- B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.661 CENTS, CONSISTING OF 0.801 CENTS FOR THE CURRENT RATE AND (0.140) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

Issued On: August 29, 2014  
 Docket Number: RP14-1219-000  
 FERC Order Date: September 23, 2014

Effective On: October 1, 2014

Northern Border Pipeline Company  
FERC Gas Tariff  
Second Revised Volume No. 1

PART 4.1  
4.1 - Statement of Rates  
T-1 and T-1B - Long Term Base Tariff Rates  
v.2.0.0 Superseding v.1.0.0

STATEMENT OF RATES  
2/ 3/

Rate Schedule	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	\$0.0286
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0307
Minimum	\$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	\$0.0004
Minimum	\$0.0004

- 1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.
- 2/ The Settlement Rates, pursuant to Articles II and VII of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al., remain in effect until such rates are superseded by new rates placed into effect consistent with the provisions of the Stipulation.
- 3/ Rates in this section are subject to the revenue retrieval provision pursuant to Article V.A of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al.

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$ 216.98/10 <sup>3</sup> m <sup>3</sup>		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D <sup>1</sup>	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point Average FT-D Demand Rate for Group 1 Delivery Points \$ 5.23/GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.19/GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.02/GJ		
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P <sup>1</sup>	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	1-5 years	11.29	
	6-10 years	9.44	
	15 years	8.46	
	20 years	7.51	
8. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 <sup>3</sup> m <sup>3</sup>	
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D <sup>1</sup>	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
11. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
12. Rate Schedule PT	<u>Schedule No.</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
13. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2014612719	\$ 2.00	/ month
	2014612718	\$ 2.00	/ month
	2014612720	\$ 2,174.00	/ month
	2014612725	\$ 20.00	/ month
	2014612724	\$ 129.00	/ month
	2014612723	\$ 71.00	/ month
	2014612722	\$ 15.00	/ month
	2014612721	\$ 283.00	/ month
	2014612717	\$ 212.00	/ month
	2011475772	\$ 9,250.00	/ month
	2014613454	\$ 650.00	/ month
	2003004522	Applicable IT-R and IT-D Rate	
	2011476052 / 2011476054	\$ 0.1376 \$ 717,000.00	/ GJ subject to Minimum Annual Charge
	2011475056 / 2011476092 / 2011476049 / 2011476050	\$ 0.095 \$ 1,000.00	/ GJ and / month
14. Rate Schedule CO <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	528.30	
	2	418.06	
	3	272.20	

1. Service under rate Schedule FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedule OS No. 2011476092 and No. 2011476049, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)
2000	ALBERTA-B.C. BORDER	5.18	0.1874
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.19	0.1514
31110	ALLIANCE EDSON INTERCONNECT APN	4.19	0.1514
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.19	0.1514
3002	BOUNDARY LAKE BORDER	4.19	0.1514
1958	EMPRESS BORDER	5.35	0.1935
3886	GORDONDALE BORDER	4.19	0.1514
6404	MCNEILL BORDER	5.35	0.1935

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" (\$/GJ)	IT-D Rate per Day (\$/GJ)	Subject to ATCO Pipelines Franchise Fees <sup>1</sup>
31000	A.T. PLASTICS SALES APN	4.19	0.1514	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.19	0.1514	Yes
3880	AECO INTERCONNECTION	4.19	0.1514	
31003	AGRIUM CARSELAND SALES APS	4.19	0.1514	
31002	AGRIUM FT. SASK SALES APN	4.19	0.1514	Yes
31004	AGRIUM REDWATER SALES APN	4.19	0.1514	
31005	AINSWORTH SALES APGP	4.19	0.1514	
31006	AIR LIQUIDE SALES APN	4.19	0.1514	
3214	AKUINU RIVER WEST SALES	4.19	0.1514	
31007	ALBERTA ENVIROFUELS SALES APN	4.19	0.1514	Yes <sup>2</sup>
31008	ALBERTA HOSPITAL SALES APN	4.19	0.1514	Yes
3868	ALBERTA-MONTANA BORDER	4.19	0.1514	
3059	ALLISON CREEK SALES	4.19	0.1514	
31009	ALTASTEEL SALES APN	4.19	0.1514	Yes <sup>2</sup>
3562	AMOCO SALES (BP SALES TAP)	4.19	0.1514	
31012	APL JASPER SALES APN	4.19	0.1514	Yes
3488	ARDLEY SALES	4.19	0.1514	
3237	ASPEN SALES	4.19	0.1514	
3216	AURORA NO 2 SALES	4.19	0.1514	
3135	AURORA SALES	4.19	0.1514	
3423	BASHAW WEST SALES	4.19	0.1514	
31013	BAYMAG SALES APS	4.19	0.1514	
31014	BEAR CREEK COGEN SALES APGP	4.19	0.1514	
3068	BEAVER HILLS SALES	4.19	0.1514	
3268	BENBOW SOUTH SALES	4.19	0.1514	
3933	BIG EDDY INTERCONNECTION	4.19	0.1514	
3067	BIGSTONE SALES	4.19	0.1514	
3468	BLEAK LAKE SALES	4.19	0.1514	
3225	BOTHA SALES	4.19	0.1514	
3259	BOULDER CREEK SALES	4.19	0.1514	
3164	BRAINARD LAKE SALES	4.19	0.1514	
3918	BUFFALO CREEK INTERCONNECTION	4.19	0.1514	
31015	BURDETT COGEN SALES APS	4.19	0.1514	
3265	BURNT TIMBER SALES	4.19	0.1514	
3204	CABIN SALES	4.19	0.1514	
3109	CALDWELL SALES	4.19	0.1514	
31016	CALGARY ENERGY CENTRE SALES APS	4.19	0.1514	Yes
3634	CANOE LAKE SALES	4.19	0.1514	
3165	CANOE LAKE SALES NO 2	4.19	0.1514	
3866	CARBON INTERCONNECTION	4.19	0.1514	
3484	CARIBOU LAKE SALES	4.19	0.1514	
3157	CARIBOU LAKE SOUTH SALES	4.19	0.1514	
3106	CARMON CREEK SALES	4.19	0.1514	
3101	CAROLINE SALES	4.19	0.1514	
31017	CARSELAND COGEN SALES APS	4.19	0.1514	
3275	CARSON CREEK SALES	4.19	0.1514	
3495	CAVALIER SALES	4.19	0.1514	
31018	CHAIN LAKES COOP SALES APS	4.19	0.1514	
3907	CHANCELLOR INTERCONNECTION	4.19	0.1514	
3151	CHEECHAM WEST NO 2 SALES	4.19	0.1514	
3622	CHEECHAM WEST SALES	4.19	0.1514	
6014	CHEVRON AURORA SALES	4.19	0.1514	
31019	CHEVRON FT. SASK SALES APN	4.19	0.1514	Yes
3097	CHICKADEE CREEK SALES	4.19	0.1514	
3305	CHIGWELL NORTH SALES	4.19	0.1514	
3496	CHIPEWYAN RIVER SALES	4.19	0.1514	
3163	CHRISTINA LAKE NORTH SALES	4.19	0.1514	
31020	CLOVERBAR FIBERGLASS SALES APN	4.19	0.1514	Yes

NATURAL GAS TARIFF

**NorthWestern**  
Energy

Canceling  $\frac{36^{th}}{35^{th}}$  Revised Revised Sheet No. 80.1  
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT  
FIRM TRANSPORTATION NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for firm transportation service on the Utility Transmission System under the terms of a Firm Gas Transportation Service Agreement (Agreement) between the Utility Transportation Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	\$ 120.40
10,001 to 30,000	\$ 173.05
>30,000	\$ 384.05

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for  
Maximum Daily Delivery Quantity (MDDQ) \$ 0.9840814

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0074572
Minimum	\$ 0.0017935
GTAC Amortization	\$ (0.0009972) (I)
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm Or 150% of Market Price

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: June 17, 2014  
Docket No.: D2013.5.34, Interim Order No. 7282b  
Tariff Letter No. 243-G

Effective for bills rendered on or after  
July 1, 2014

PUBLIC SERVICE COMMISSION  
*Alvina Salem* Secretary

**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**  
1415 N. Airport Rd  
Pierre, SD 57501

SD P.U.C. Section No. 3  
Original Sheet No. 1

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

Issued By: Lisa A. Murphy, Vice President-Chief Financial Officer

**STATE OF SOUTH DAKOTA  
GAS RATE SCHEDULE**

NG-00-001

**South Dakota Intrastate Pipeline Company**

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5  
Seventh Revised Sheet No. 12  
Cancels Sixth Revised Sheet No. 12

Statement of Firm and Interruptible Transportation Service Rates  
Applicable to Shippers Not Receiving  
Choice Gas Service  
Rate Schedule TC 1/  
Casper Division

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Demand Charge 6/	Minimum Demand Charge 6/	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$9.50	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	1.153%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	3.579%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	1.153%
Administrative Fee 5/			\$325.00					

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per therm.

3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

6/ Per Dth of MDTQ per month.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect  
MLE Mainline System End-user  
DSE Distribution System End-user

MDTQ Maximum Daily Transportation Quantity

Date Issued: February 28, 2014  
By: Michael Noone

Date Effective: June 1, 2014  
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.  
RETURN ON CYCLE STORAGE BALANCES  
AND PREPAID DEMAND AND COMMODITY BALANCES  
NORTH DAKOTA GAS  
EFFECTIVE NOVEMBER 2014**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2014	\$11,683,245	\$1,125,570	\$4,237,630
November	9,918,339	1,030,941	3,374,415
December	5,653,534	769,865	1,598,973
January 2015	548,005	486,210	(440,867)
February	(2,873,873)	296,097	(1,873,073)
March	(3,474,289)	262,738	(2,811,033)
April	(3,447,796)	264,782	(2,588,967)
May	(1,082,692)	447,331	(1,499,062)
June	2,150,873	696,910	(42,836)
July	5,341,980	943,213	1,393,307
August	8,637,580	1,197,581	2,833,825
September	11,340,969	1,406,239	4,022,088
October	11,693,630	1,433,460	4,239,246
13 month average	<u>\$4,314,577</u>	<u>\$796,995</u>	<u>\$957,204</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$340,032	\$62,811	\$75,437
Return Requirement	<u>\$474,647</u>	<u>\$87,677</u>	<u>\$105,302</u>

1/ Monthly balance from SENDOUT Model, allocated to North Dakota on ratio of storage capacity MDDQ.

2/ Monthly balance allocated to North Dakota on sales volumes.

MONTANA-DAKOTA UTILITIES CO.  
COST OF GAS - PROPANE  
NORTH DAKOTA  
EFFECTIVE NOVEMBER 2014

Cost of Purchased Propane	\$47,934
Gallons Purchased	46,994
Projected dk Sales	4,300
Propane Cost per Dk	\$11.147
Average Cost of Propane as Adjusted for Losses @ 99.55%	11.197
Less: Propane Cost Level in Rates 1/	<u>10.978</u>
Current Propane Cost Adjustment	<u><u>\$0.219</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-14-008, effective September 1, 2014.

**MONTANA-DAKOTA UTILITIES CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
APPLICABLE TO NORTH DAKOTA  
FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u><u>\$3,163,455</u></u></b>
August	\$226,615	\$0	\$49	\$226,664	277,347	\$0.024	\$6,656	\$220,008	3,383,463
<b>Balance @ August 31, 2014</b>									<b><u><u>\$3,383,463</u></u></b>

1/ Interest calculated at the 90 day Treasury Note rate.

MONTANA-DAKOTA UTILITIES CO.  
 COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
 APPLICABLE TO NORTH DAKOTA  
 INTERRUPTIBLE

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u><u>\$553,358</u></u></b>
August	\$27,773	\$0	\$9	\$27,782	37,258	\$0.116	\$4,323	\$23,459	576,817
<b>Balance @ August 31, 2014</b>									<b><u><u>\$576,817</u></u></b>

1/ Interest calculated at the 90 day Treasury Note rate.

MONTANA-DAKOTA UTILITIES CO.  
 COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE  
 APPLICABLE TO NORTH DAKOTA  
 AIR FORCE

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2014</b>									<b><u><u>\$185,080</u></u></b>
August	\$16,626	\$0	\$3	\$16,629	4,035	\$0.181	\$731	\$15,898	200,978
<b>Balance @ August 31, 2014</b>									<b><u><u>\$200,978</u></u></b>

1/ Interest calculated at the 90 day Treasury Note rate.