



MONTANA-DAKOTA

UTILITIES CO.

A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

March 7, 2014

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

Re: Cost of Gas Adjustment
(COG) Rate 88 and Rate 99
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 (123rd Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered April 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.668 per dk since the last filing due to an increase in the overall commodity price of gas. Attachment B explains the reasons for the increase in the market price of gas. In addition, Montana-Dakota has also seen a change in the pipeline rates, as shown on Attachment C, decreasing the cost of gas \$0.016 per dk.

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 April 2014.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.652 per dk for residential and firm general customers, an increase of \$0.702 per dk for small and large interruptible customers and an increase of \$0.699 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 April 2014. The average cost of gas for firm customers, adjusted for losses, is \$6.749.

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 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane. Attachment B page 2 explains the reasons for the decrease 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 April 2014. The net effect of this filing is a decrease of \$8.234 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of April 2014. The average cost of propane for all customers, adjusted for losses, is \$17.016 per dk.

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

These proposed adjustments, calculated in accordance with Rate 88 and Rate 99, will amount to an increase of approximately \$820,400 for natural gas customers and a decrease of approximately \$43,600 for propane customers during the month of April 2014. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 101,912 natural gas and 343 propane customers in North Dakota as of February 28, 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
123rd Revised Sheet No. 3
Canceling 122nd 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 ¹	4	\$0.30 per day	\$0.812	\$6.761	\$7.573
Air Force Rate 64 ¹	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$6.761	\$6.899
Interruptible Service - PAR			\$0.120	\$5.890	\$6.010
Interruptible Service - MAFB			\$0.120	\$5.929	\$6.049
Firm General Service Rate 70 ¹	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$6.761	\$7.358
Small Interruptible Gas Rate 71 ²	14	\$100.00 per month	(Maximum) \$0.871	\$5.890	(Maximum) \$6.761
Optional Seasonal Gas ¹					
Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$6.850	\$7.447
Transportation Service ¹	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.026	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.026	
Large Interruptible Gas Rate 85 ³	27	\$675.00 per month	(Maximum) \$0.719	\$5.890	(Maximum) \$6.609
Residential Propane Rate 90 ¹	32	\$0.30 per day	\$0.812	\$16.227	\$17.039
Firm General Propane Rate 92 ¹	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$16.227	\$16.824

1/ Interim increase of 15.678% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

2/ Interim increase of 8.671% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

3/ Interim increase of 9.382% applicable to amounts billed under Basic Service Charge and Distribution Delivery Charge.

Date Filed: March 7, 2014

Effective Date:

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

April 2014

The established monthly price for the Rocky Mountain CIG Index has increased 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 extreme cold weather across much of the U.S. continued during most of the month of February. The associated higher than normal demand of natural gas has drawn storage levels to the lowest level in the last ten years and it is projected that the working gas in storage at the end of March will be below the 1 tcf mark. The EIA reported storage levels nationwide indicate the five year average as of February 28, 2014, was 38.3 percent below the five-year average and 43.2 percent below last year’s storage balance. In addition, the freeze off of producing natural gas wells is another factor contributing to the increase in the index price of gas for the upcoming month.

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

The February Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 18. The March Outlook will be published March 11, 2014.

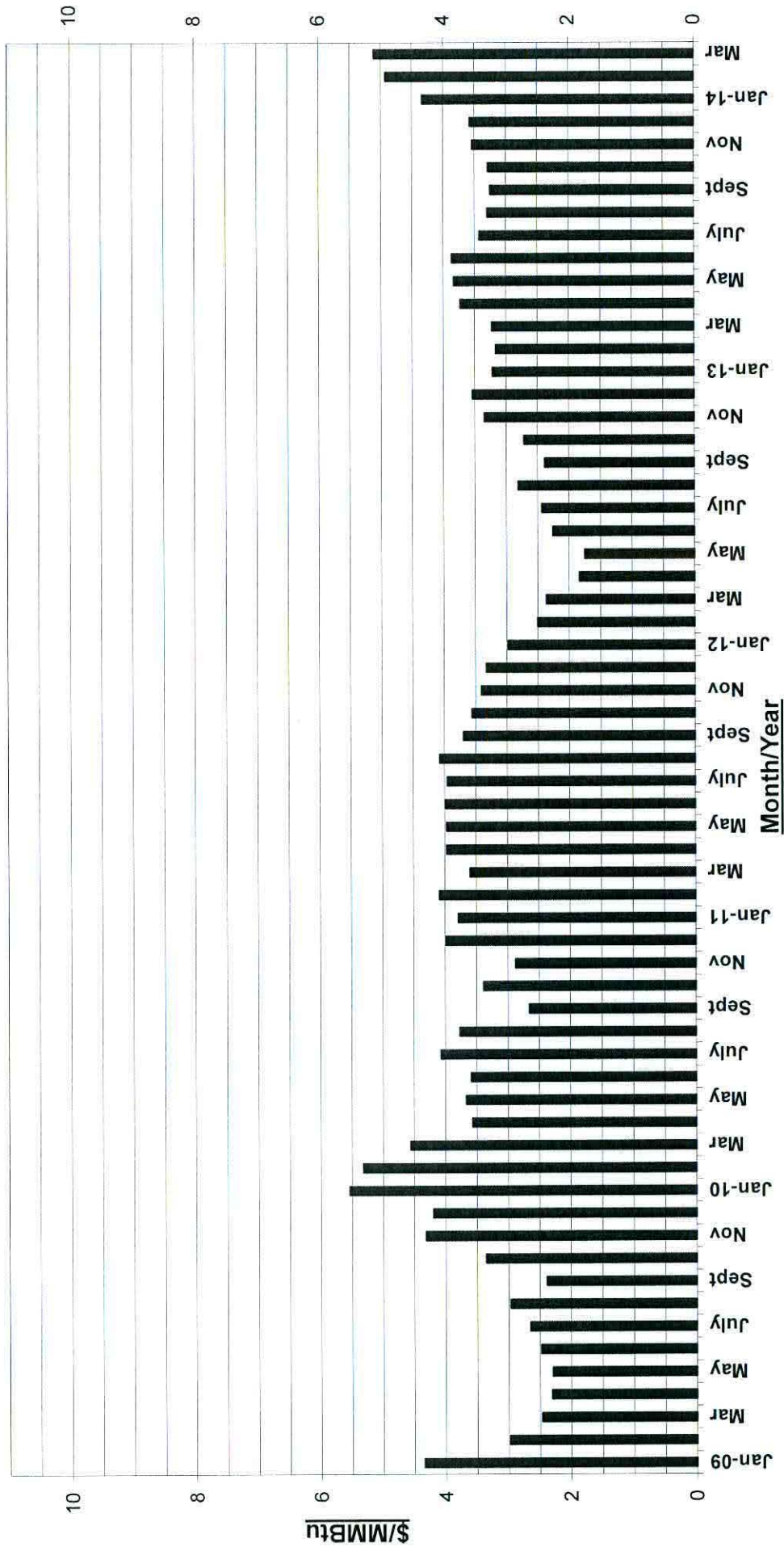
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
April 2014**

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 April prices for propane have decreased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage decreases has resulted in a decrease 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-\$4.79

*Independent Statistics & Analysis*U.S. Energy Information
Administration

February 2014

Short-Term Energy Outlook (STEO)

Highlights

- Temperatures east of the Rocky Mountains have been significantly colder this winter (October – January) compared with the same period both last winter and the previous 10-year average, putting upward pressure on consumption and prices of fuels used for space heating. U.S. average heating degree days were 12% higher than last winter (indicating colder weather) and 8% above the previous 10-year average. The Northeast was 11% colder than last winter, the Midwest 17% colder, and the South 20% colder, while the West was 3% warmer.
- The cold weather has had the greatest effect on propane prices, particularly for consumers in the Midwest. Cold temperatures have tightened supplies in the East and Midwest regions that were already low heading into the winter heating season. Residential propane prices in the Midwest rose from an average of \$2.08 per gallon (gal) on December 2, 2013, to \$4.20/gal on January 27; prices fell back to \$3.83/gal on February 3. EIA now expects that propane prices in the Midwest will average \$2.41/gal over the winter (39% higher than last winter) while those in the Northeast will average \$3.43/gal (14% higher than last winter).
- While the North Sea Brent crude oil monthly average spot price fell by almost \$3 per barrel (bbl) from December to January, cold temperatures have tightened heating oil supplies and helped drive up retail prices. Weekly U.S. residential heating oil prices increased by \$0.14/gal between the end of December and end of January. Despite the recent increases, EIA expects that U.S. heating oil prices will average \$3.82/gal this winter, \$0.05/gal (1%) lower than during last year's winter heating season.
- Cold weather also contributed to a [new record-high withdrawal of natural gas from storage](#) and a surge in natural gas spot prices. Natural gas working inventories on January 31 totaled 1.92 trillion cubic feet (Tcf), 0.78 Tcf below the level at the same time a year ago and 0.56 Tcf below the previous five-year average (2009-13). Henry Hub natural gas spot prices increased from \$4.32 per million British thermal units (MMBtu) on January 2 to \$5.66/MMBtu on January 27, before falling back to \$5.04/MMBtu on January 31. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73/MMBtu in 2013, will average \$4.17/MMBtu in 2014, an increase of \$0.27/MMBtu from last month's STEO. Residential natural gas prices are expected to average \$10.16 per thousand cubic feet (Mcf) this winter, an increase of \$0.41/Mcf (4%) from last winter.

Global Petroleum and Other Liquids

Projected world petroleum and other liquids supply increases by 1.7 million barrels per day (bbl/d) in 2014 and 1.4 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). [The Americas](#), in particular the United States, Canada, and Brazil, will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.3 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. Non-OPEC supply growth contributes to an increase in global surplus crude oil production capacity from an average of 2.2 million bbl/d in 2013 to 3.8 million bbl/d in 2015.

Global unplanned supply disruptions reached nearly 3.2 million bbl/d by the end of 2013, but fell to 3.0 million bbl/d in January as some of Libya's oil production restarted. OPEC members continue to account for most of the global supply disruptions, averaging 2.3 million bbl/d in January. [Supply disruptions present considerable uncertainty](#) over the forecast period because the issues underpinning the disruptions in most countries remain unresolved.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, exceeding 91 million bbl/d by the second half of the year. EIA expects global consumption to grow at a similar pace of nearly 1.3 million bbl/d in 2014 and 1.4 million bbl/d in 2015, exceeding 93 million bbl/d by the second half of 2015.

Non-OECD countries account for almost all consumption growth over the forecast period. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth have moderated compared with levels before 2012, when GDP growth exceeded 9% and annual oil consumption growth averaged 790,000 bbl/d from 2009 through 2011.

On the other hand, EIA expects OECD consumption to remain relatively flat over the next two years. Projected consumption declines in the OECD are led by Japan and Europe. EIA expects Japan's oil consumption to decrease annually by about 120,000 bbl/d in both 2014 and 2015, as the country continues to increase natural gas consumption in the electricity sector and returns some nuclear power plants to service. EIA projects that OECD Europe's consumption continues to decline by 100,000 bbl/d in 2014 and another 50,000 bbl/d in 2015, albeit at a slower pace compared with previous years. U.S. oil consumption growth, which was 380,000 bbl/d in 2013, is expected to slow to 30,000 bbl/d in 2014 and 60,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC production grew by 1.4 million bbl/d in 2013, exceeding 55 million bbl/d by the end of the year. EIA expects non-OPEC liquids production to grow annually by 1.9 million bbl/d in 2014 and 1.5 million bbl/d in 2015, reaching more than 58 million bbl/d by the end of 2015.

EIA forecasts production from the United States and Canada to grow by a combined annual average of 1.2 million bbl/d in both 2014 and 2015. Brazil's production is expected to increase by an annual average of 0.15 million bbl/d over the next two years, attributed to new deepwater fields. EIA expects Kazakhstan's production to grow by 0.09 million bbl/d in 2014 and by 0.13 million bbl/d in 2015 as output ramps up at the Kashagan oil field. EIA estimates that Asia and Oceania's production will rise by an annual average of 0.17 million bbl/d over the forecast period, led by China.

Unplanned supply disruptions among non-OPEC producers averaged 0.8 million bbl/d in 2013, a slight decline from 0.9 million bbl/d in 2012 but still considerably above the 2011 level of 0.5 million bbl/d. In January 2014, non-OPEC supply disruptions were less than 0.7 million bbl/d. South Sudan, Syria, and Yemen continue to account for more than 80% of total non-OPEC supply disruptions.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 30.0 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, primarily resulting from increased outages in Libya, Nigeria, and Iraq. EIA expects OPEC crude oil production to fall by 0.4 million bbl/d and 0.3 million bbl/d in 2014 and 2015, respectively, as some OPEC countries, led by Saudi Arabia, reduce production to accommodate the non-OPEC supply growth in 2014. Projected OPEC non-crude oil liquids, which averaged an estimated 5.9 million barrels per day in 2013, increases to an average of 6.3 million bbl/d in 2015.

Unplanned crude oil supply disruptions among OPEC producers averaged 1.8 million bbl/d in 2013, nearly double the amount from the previous year. OPEC disruptions increased in the second half of 2013, reaching 2.6 million bbl/d by the end of the year because of increased outages in Libya. In January 2014, crude oil output in Libya partially recovered as the El Sharara field resumed production. OPEC supply disruptions fell to 2.3 million bbl/d in January 2014.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.2 million bbl/d in the first quarter of 2014, reflecting the upward movement that began in the second half of 2013. Projected surplus crude oil production capacity increases over the forecast period, averaging 2.5 million bbl/d in 2014 and 3.8 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from other OPEC members and non-OPEC producers. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2013 totaled 2.61 billion barrels, equivalent to roughly 56 days of supply. Projected OECD oil inventories rise to 2.63 billion barrels by the end of 2014 and continue increasing to 2.64 billion barrels by the end of 2015.

Crude Oil Prices. Brent crude oil spot prices averaged between \$108/bbl and \$112/bbl for the seventh consecutive month in January. EIA expects the Brent crude oil price to weaken as non-

OPEC supply growth exceeds growth in world consumption. The Brent crude oil price is projected to average \$105/bbl and \$101/bbl in 2014 and 2015, respectively.

The forecast WTI crude oil spot price, which increased from a monthly average of \$94/bbl in November to \$98/bbl in December because of strong U.S. refinery crude oil runs, fell back to \$95/bbl in January 2014. EIA expects that WTI crude oil prices will average \$93/bbl in 2014 and \$90/bbl during 2015. The discount of WTI crude oil to Brent crude oil, which averaged \$18/bbl in 2012 and then fell below \$4/bbl in July 2013, averaged \$14/bbl in January 2014. EIA expects the discount of WTI crude oil to Brent crude oil to average \$11/bbl over the forecast, reflecting the economics of transporting and processing the growing production of light sweet crude oil in U.S. and Canadian refineries.

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 May 2014 delivery, traded during the five-day period ending February 6, 2014, averaged \$96/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 May 2014 at \$81/bbl and \$113/bbl, respectively. Last year at this time, WTI for May 2013 delivery averaged \$98/bbl and implied volatility averaged 21%. The corresponding lower and upper limits of the 95% confidence interval were \$82/bbl and \$117/bbl.

U.S. Petroleum and Other Liquids

Despite relatively stable crude oil prices over the winter months, consistently cold temperatures east of the Rocky Mountains have tightened fuel supplies for both propane and heating. Propane stocks began the winter heating season at low levels because of heavy demand for drying an unusually wet fall corn crop harvest and have since fallen further. PADD 2 (Midwest) propane stocks started the winter heating season (end of September) at 24.4 million barrels, 3.5 million barrels lower than the same time the previous year and 2.5 million barrels lower than the previous 5-year average. The region's propane stocks were 8.8 million barrels the week ending January 24, which was 8.4 million barrels lower than the same week last year and the lowest recorded by EIA for January. By January 31 Midwest stocks had increased to 9.6 million barrels. These low propane inventories combined with consistently cold temperatures contributed to significant price increases for many consumers in the region. As of January 27, residential propane prices in PADD 2 increased to an average of \$4.20/gal, which was an increase of 65% in just one week's time and the highest nominal price ever recorded for the region. By February 3, regional prices had fallen to an average of \$3.83/gal.

Less-severe, but still considerable, tightness in Northeast heating oil supplies has similarly driven up heating oil prices in recent weeks as a result of cold winter temperatures and high residential heating demand. Distillate inventories in the Northeast (PADDs 1A and 1B) declined by 7.0 million barrels between January 3 through January 31, which is significantly greater than the

average stock draw of 2.6 million barrels during the four weeks of January over the previous five years. Distillate stocks in the Northeast ended January at 18.2 million barrels, more than 10 million barrels lower than the same time last year. Residential heating oil prices in New England, which began 2014 at an average of \$4.01/gal, increased to \$4.17/gal on February 3.

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 380,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids registered the largest gain, increasing by 140,000 bbl/d (6.2%). Motor gasoline consumption grew by 100,000 bbl/d (1.1%), the largest increase since 2004. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased 80,000 bbl/d (2.0%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption increases 30,000 bbl/d (0.2%) in 2014. Motor gasoline consumption remains unchanged as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 60,000 bbl/d (1.5%). Growing distillate demands from the transportation and industrial sectors as well as increased heating oil use in the current quarter contribute to that growth. Ethane consumption increases by an average of 50,000 bbl/d (5.4%), as ethylene plant capacity expansions contribute to an increase in ethane cracking capacity. In 2015, total liquid fuels consumption increases by 60,000 bbl/d (0.3%), driven primarily by increasing transportation demand for distillate fuel oil and industrial demand for hydrocarbon gas liquids.

U.S. Liquid Fuels Supply. EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015. Forecast production increases from an estimated 7.4 million bbl/d in 2013 to 8.4 million bbl/d in 2014 and 9.2 million bbl/d in 2015. The U.S. crude oil production forecast for both 2014 and 2015 was revised downward by 0.1 million bbl/d from last month's STEO because of indications that severe weather this winter has caused temporary slowdowns in completing new wells. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Crude oil production from the Bakken formation in North Dakota and Montana averaged 0.88 million bbl/d in 2013, and surpassed 1 million bbl/d in December 2013. Production in the Eagle Ford formation in South Texas surpassed 1 million bbl/d in May 2013, reaching an estimated 1.22 million bbl/d in December 2013.

U.S. Federal Gulf of Mexico (GOM) crude oil production averaged 1.25 million bbl/d in 2013, down slightly from 2012. EIA forecasts 1.38 million bbl/d of GOM crude oil production in 2014 and 1.59 million bbl/d in 2015. Production growth in 2014 comes from eight projects expected to come online: Jack, St. Malo, Entrada, Big Foot, Tubular Bells, Atlantis Phase 2, Hadrian South, and Lucius. Further production growth in 2015 comes from an additional 10 projects: Axe, Cardamom Deep, Dalmatian, Deimos South, Kodiak, Pony, Samurai, West Boreas, Winter, and Mars B.

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 peaked at more than 60% in 2005 and fell to an average of 33% in 2013. EIA expects the net import share to decline to 25% in 2015, which would be the lowest level since 1971.

U.S. Petroleum Product Prices. Led by falling crude oil prices, the projected U.S. annual average regular gasoline retail price, which fell from \$3.63/gal in 2012 to an average of \$3.51/gal in 2013, will continue to fall to \$3.44/gal in 2014 and \$3.37 in 2015. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to average \$3.83/gal in 2014 and \$3.73/gal in 2015.

Natural Gas

Very cold temperatures in early January led to [new record-high withdrawals of natural gas from storage](#) in a season already characterized by larger-than-normal storage withdrawals. [Several more days of brutal cold](#) came in the following weeks of January with working natural gas storage withdrawals exceeding 200 billion cubic feet (Bcf) for three of the weeks during the month. For the second month in a row, the forecast end-of-March 2014 working inventory has been revised downward to reflect recent very high withdrawals. EIA now projects inventories will end this heating season at 1,331 Bcf, the lowest end-of-season level since 2008.

The natural gas February futures contract expired at \$5.56/MMBtu, which was a four-year high. [Pipeline constraints in the Northeast](#) often lead to price increases during times of high winter demand. Last month, spot market prices in the Northeast were routinely in the double digits, with New York prices settling in the \$90/MMBtu range on several days in January. The effect of spot market fluctuations on end-use prices depends on several factors. Utilities begin buying natural gas in the spring, and policies for price-setting vary by state. Additionally, per-unit prices are lower in the winter and during times of high consumption, as a utility's high fixed costs are distributed over larger volumes. Residential natural gas prices are expected to average \$10.16 per thousand cubic feet (Mcf) this winter, an increase of \$0.41/Mcf (4.2%) from last winter. Last winter, natural gas consumers spent an average of \$603 on their heating bills. This season, consumers can expect to spend \$649 on natural gas heating for the winter months, a 7.7% increase.

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will average 70.2 Bcf/d in 2014. This represents an upward revision of 0.6 Bcf/d from last month's STEO and is largely attributable to an increase in January consumption. The projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 24.9 Bcf/d in 2012 to 22.3 Bcf/d in 2013 and 22.0 Bcf/d in 2014. In 2015, total natural gas consumption increases by 0.8 Bcf/d with growth in use by the industrial and electric power sectors. EIA expects natural gas consumption in the power sector to increase to 22.6 Bcf/d in 2015 with the retirement of some coal plants.

U.S. Natural Gas Production and Trade. EIA expects natural gas marketed production will grow at an average rate of 2.2% in 2014 and 1.2% in 2015. Rapid Marcellus production growth is causing natural gas forward prices in the Northeast to fall even with or below Henry Hub prices outside of peak-demand winter months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price. EIA projects Gulf of Mexico production will increase by 1.7% in 2014 before falling 2.3% in 2015.

Liquefied natural gas (LNG) imports have declined 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. The first of the new facilities to liquefy gas produced in the Lower-48 states for export is expected to come online in the fourth quarter of 2015.

Growing domestic production over the past several years has replaced pipeline imports from Canada, while exports to Mexico have increased. EIA expects these trends will continue through 2015. EIA projects net imports of 3.5 Bcf/d in 2014 and 2.6 Bcf/d in 2015, which would be the lowest level since 1987. Over the longer term, the EIA Annual Energy Outlook 2014 projects the United States will be a net exporter of natural gas beginning in 2018.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 262 Bcf to 1,923 Bcf during the week ending January 31, 2014. Colder-than-normal temperatures during the month resulted in increased heating demand, prompting larger-than-normal withdrawals, and a new record high monthly withdrawal (surpassing the previous record set in December 2013). Stocks are now 778 Bcf less than last year at this time and 556 Bcf less than the five-year (2009-13) average for this time of year.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$4.71/MMBtu at the Henry Hub in January, up \$0.47/MMBtu from December, the result of bitterly cold weather during the month. EIA expects the price increases of the past few months will reverse at the end of winter. Projected Henry Hub natural gas prices average \$4.17/MMBtu in 2014 and \$4.11/MMBtu in 2015.

Natural gas futures prices for May 2014 delivery (for the five-day period ending February 6, 2014) averaged \$4.48/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for May 2014 contracts at \$3.28/MMBtu and \$6.13/MMBtu, respectively. At this time last year, the natural gas futures contract for May 2013 averaged \$3.46/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.61/MMBtu and \$4.58/MMBtu.

Coal

Coal production for 2013 totaled an estimated 996 million short tons (MMst), 21 MMst (2%) lower than in 2012. It is the first time in 20 years that annual coal production was below 1 billion short tons. Coal production has fallen by nearly 100 MMst since 2011, with nearly identical declines in the Appalachian and Western coal regions. Coal production in the Interior region, which includes the Illinois Basin, increased by about 14 MMst over the same time.

U.S. Coal Supply. EIA projects coal production will grow 3.9% to 1,035 MMst in 2014 as inventories stabilize and consumption increases. Coal production is projected to fall 1.5% in 2015 to 1,019 MMst.

U.S. Coal Consumption. EIA estimates total coal consumption for 2013 to be 920 MMst, a 3.5% increase over 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Projected consumption grows 4.1% to 958 MMst in 2014 as electricity demand grows and natural gas prices continue to rise. Total coal consumption is projected to decline by 2.1% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#).

U.S. Coal Exports. EIA estimates that exports for 2013 totaled 118 MMst, about 8 MMst lower than 2012. Exports are projected to total 106 MMst in 2014 and 105 MMst in 2015. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports. However, a supply disruption in Colombia could provide a temporary boost to U.S. exports. Columbian steam coal exports are expected to drop by about a third after a new law, which took effect on January 1, only allows coal exporters to load ships using enclosed conveyor belts and prohibits the use of cranes and barges. Upgraded loading facilities are currently slated for completion in March.

U.S. Coal Prices. Nominal annual average coal prices to the electric power industry fell for the second consecutive year, from \$2.38/MMBtu in 2012 to \$2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of \$2.36/MMBtu in 2014 and \$2.37/MMBtu in 2015.

Electricity

The cold weather experienced east of the Rocky Mountains last month led to an increase in electricity demand. The colder temperatures contrast with the mild weather experienced last January in much of the United States. EIA estimates residential electricity sales in the Midwest during January 2014 were about 10% higher than last January and residential sales in the Northeast are estimated to have been 6% higher.

Electricity supply in the Northeast was particularly affected by the colder weather. In recent years, power generators in this region have become increasingly reliant on natural gas, which is also used by many households for space heating. Periods of cold weather can temporarily raise natural gas prices, which can lead to spikes in wholesale electricity prices. During the early January freeze in New England, day-ahead on-peak power prices at the Massachusetts hub rose above \$235 per megawatthour.

U.S. Electricity Consumption. EIA has raised its forecast for electricity demand during the first quarter as a result of the colder weather that occurred in January. U.S. residential electricity sales during the first quarter of 2014 are expected to increase 2.1% compared with the same period last year. The East South Central area of the country, where a large number of homes heat with electricity, shows the strongest year-over-year growth of 4.8% during the first quarter. U.S. sales of electricity to the commercial and industrial sectors grow by 1.2% and 1.4%, respectively, during the first quarter of 2014.

U.S. Electricity Generation. EIA projects total U.S. electricity generation will average 11.2 terawatthours per day in 2014, an increase of 1.0% from last year. Natural-gas-fired generation accounts for a 27.0% share of total generation during 2014, down from 27.5% in 2013 as a result of rising natural gas prices. In contrast, the share of generation fueled by coal increases from 39.0% in 2013 to 40.3% in 2014. Renewable energy sources, including hydropower, account for 12.9% of total generation this year, the same as in 2013.

U.S. Electricity Retail Prices. The rising cost of generation fuels, particularly natural gas, contributes to a projected increase in the residential price of electricity. EIA expects the U.S. residential price of electricity to average 12.4 cents per kilowatthour during 2014, an increase of 2.2% from 2013. Residential electricity prices increase 1.9% during 2015.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewables used for electricity and heat generation will grow by about 0.7% in 2014. Hydropower is projected to decrease by 2.0%, while nonhydropower renewables rise by 2.2%. In 2015, renewables consumption for electric power and heat generation is projected to increase by a rate of 5.8% from 2014, as a 5.0% increase in hydropower is combined with a 6.2% increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 8.7% in 2014 to about 66 gigawatts (GW) by the end of the year and will increase 15.1% to total more than 75 GW at the end of 2015. Electricity generation from wind is projected to remain flat in 2014 but increase by 11.8% in 2015, contributing 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 0.4% by 2015.

While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity grew by 96% in 2013. EIA currently projects that utility-scale solar capacity will increase by approximately 47% between year-end 2013 and year-end 2015. However, customer-sited photovoltaic (PV) capacity growth, which the STEO does not forecast, is still projected to exceed utility-scale solar growth between 2013 and 2015 according to [EIA's Annual Energy Outlook 2014](#).

U.S. Liquid Biofuels. Ethanol and biodiesel production have recovered from last year's drought. Ethanol production increased from an average of 825,000 bbl/d in December 2012 to an estimated 925,000 bbl/d during December 2013 and is forecast to average 908,000 bbl/d during 2014. Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, rose to a record-high level of 101,000 bbl/d (132 million gallons) in October 2013 [and fell slightly to 128 million gallons in November 2013](#). Biodiesel production averaged about 87,000 bbl/d in 2013 and is forecast to average 84,000 bbl/d in both 2014 and 2015.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 1.9% in 2013 from the previous year. Emissions are forecast to rise 1.2% in 2014, followed possibly by a small decline in 2015. The increase in emissions in 2013 and 2014 primarily reflected growth in coal use for electricity generation in response to higher natural gas prices relative to coal. Coal emissions are projected to decline by 2.1% in 2015 as the power sector responds to increasing coal plant retirements.

U.S. Economic Assumptions

Reported economic indicators showed mixed signals for first quarter 2014 growth. The [U.S. Bureau of Economic Analysis](#) reported that real gross domestic product (GDP) increased at an annual rate of 3.2% during the fourth quarter of 2013, and 1.9% for 2013 as a whole. The [U.S. Department of Labor](#) reported that initial weekly unemployment insurance claims were 331,000 in the week ending February 1, an decrease of 20,000 from the previous week's revised figure, and the four-week moving average rose slightly to 334,000. The [U.S. Census Bureau](#) reported that new orders for manufactured durable goods fell 4.3% in December, following a 2.6% increase in November. [The Federal Reserve Board](#) reported that U.S. industrial production rose in December by 0.3%, following a 1.0% gain in November. The [ISM purchasing manager's index](#) fell to 51.3 in January 2014, from December's 56.5, where a measure above 50 indicates expansion in the manufacturing sector.

EIA uses the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

U.S. Production and Income. Forecast U.S. real GDP grows by 2.6% in 2014 and 3.2% in 2015. Even though forecast real GDP growth accelerates over the next two years, it is only in 2015 that GDP growth exceeds the economy's average annual growth of 3% from 1990 through 2007.

Forecast real disposable income increases 3.1% in 2014 and 3.5% in 2015. Total industrial production grows at 3.0% in 2014, and is projected to grow 3.5% in 2015, reflecting the acceleration in growth of real fixed investment spending.

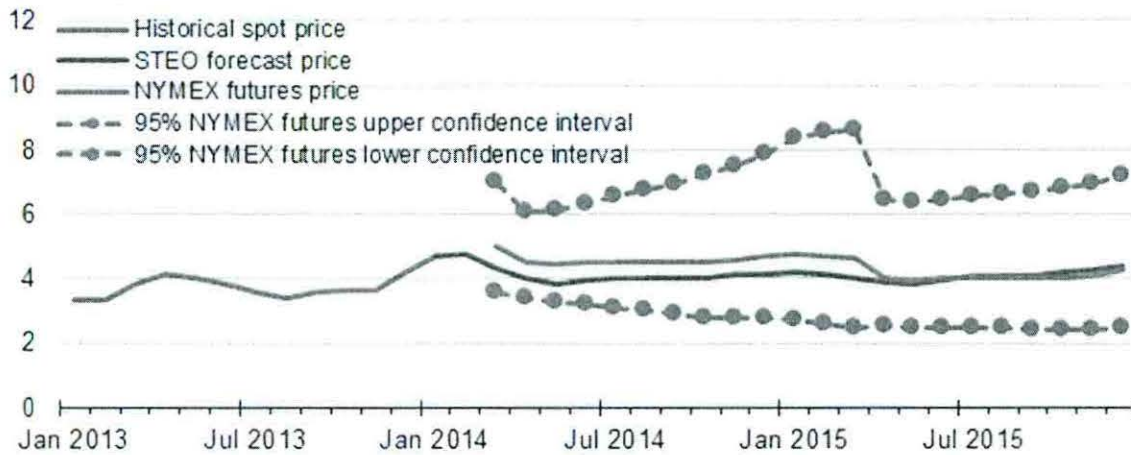
U.S. Expenditures. Private real fixed investment growth averages 6.8% and 8.5% over 2014 and 2015, respectively, with equipment spending accounting for most of investment's growth. Real consumption expenditures grow faster than real GDP in 2014, at 2.7%, but are below the rate of real GDP growth in 2015, at 3.0%. Export growth is 4.6% and 5.1% over the same two years. Government expenditures fall 0.2% in 2014, but increase by 0.4% in 2015.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 6.4% over 2014, and gradually falls to 5.5% at the end of 2015. This is accompanied by nonfarm employment growth averaging 1.7% in 2014 and 1.9% in 2015. Housing starts grow an average of 23.5% and 27.4% 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.

Henry Hub Natural Gas Price

dollars per million Btu

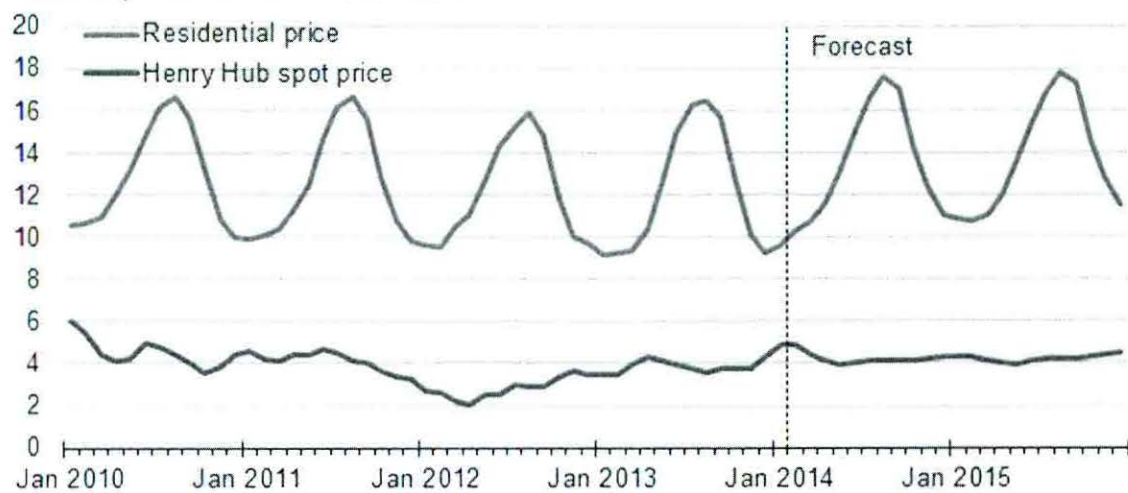


Note: Confidence interval derived from options market information for the 5 trading days ending Feb. 6, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

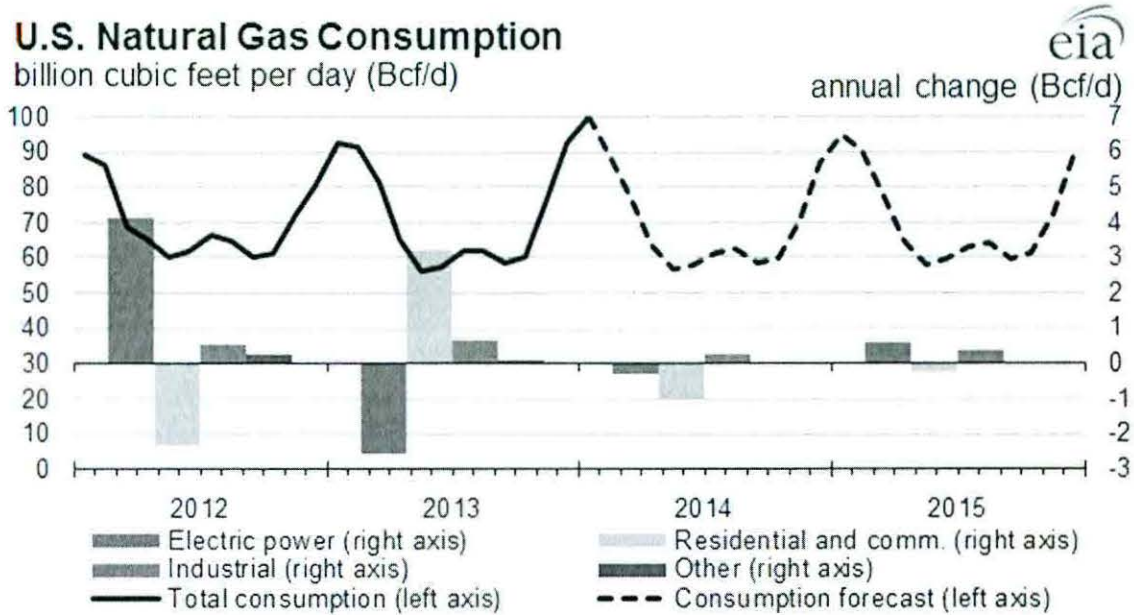
Source: Short-Term Energy Outlook, February 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet

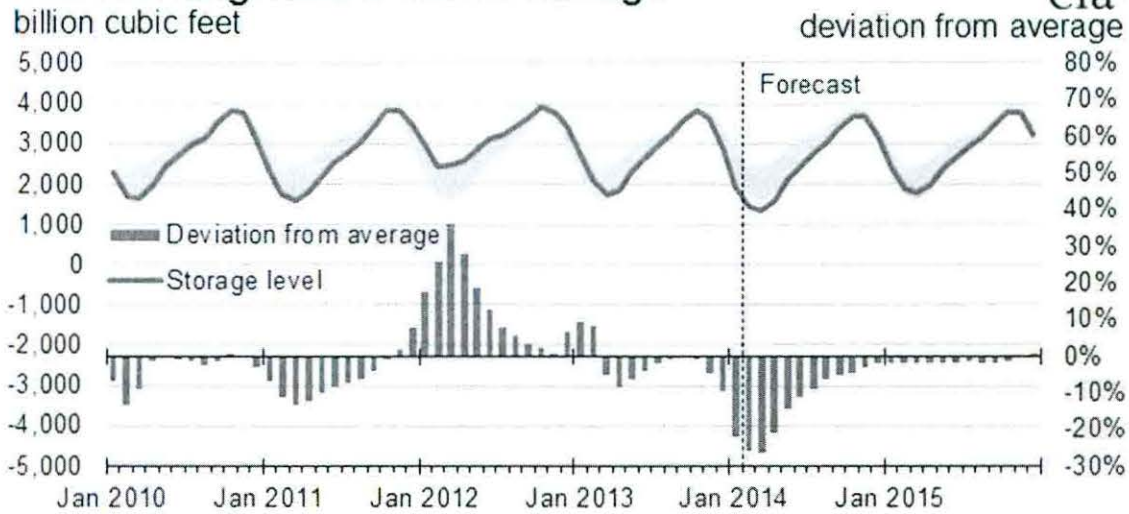


Source: Short-Term Energy Outlook, February 2014.



Source: Short-Term Energy Outlook, February 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, February 2014.

**Montana-Dakota Utilities Co.
Pipeline Rate Changes Since Last COG
North Dakota**

WBI Energy Transmission, Inc. Docket No. RP14-554-000

On February 28, 2014, WBI Energy Transmission, Inc. (WBI Energy) filed its semi-annual fuel and electric power reimbursement adjustments with the FERC in Docket No. RP14-554-000, reflecting revisions to the fuel and electric power components of WBI Energy's storage and transportation rates effective April 1, 2014.

Approximate impact on Montana-Dakota's cost of gas: (1.6) cents per dk

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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$6.749	\$6.838	\$5.774	\$5.748
Prior Gas Cost	6.097	6.188	5.072	5.049
Current Gas Cost Adjustment	\$0.652	\$0.650	\$0.702	\$0.699
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.024	\$0.024	\$0.116	\$0.181
Prior Adjustment	0.024	0.024	0.116	0.181
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.012)	(\$0.012)	\$0.000	\$0.000
Prior Adjustment	(0.012)	(0.012)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	<u>\$0.652</u>	<u>\$0.650</u>	<u>\$0.702</u>	<u>\$0.699</u>
Gas Cost Level	\$6.749	\$6.838	\$5.774	\$5.748
Plus: Surcharge	0.024	0.024	0.116	0.181
Total Gas Cost Level in Tariff Rates	<u>\$6.773</u>	<u>\$6.862</u>	<u>\$5.890</u>	<u>\$5.929</u>

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

Cost of Gas - Propane

Current Propane Cost (Exhibit A)	\$17.016
Prior Propane Cost	<u>25.250</u>
Current Propane Cost Adjustment	<u><u>(\$8.234)</u></u>

Surcharge Adjustment

Current Adjustment	(\$0.777)
Prior Adjustment	<u>(0.777)</u>
Change in Surcharge Adjustment	\$0.000

Market Based Pricing Differential

Current Adjustment	(\$0.012)
Prior Adjustment	<u>(0.012)</u>
Change in Margin Sharing Provision	\$0.000

Net Increase (Decrease) in Gas Costs

(\$8.234)

Propane Cost Level	\$17.016
Plus: Surcharge	<u>(0.777)</u>
Total Propane Cost Level in Rates	<u><u>\$16.239</u></u>

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

	Amount
Total Gas Costs 1/	\$102,450,317
Residential and General Service dk Requirements 2/	15,246,927
Average Cost of Gas per dk	\$6.719
Average Cost of Gas as Adjusted for Losses @ 99.55%	6.749
Less: Gas Cost Level in Rates 3/	6.097
Current Gas Cost Adjustment	\$0.652

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 January 31, 2014, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$6.070
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$6.097

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

Total Gas Costs 1/	\$102,450,317
Less: Annual MDDQ Costs 1/	<u>14,055,342</u>
Total Gas Costs excluding MDDQ	\$88,394,975
Firm Service Requirements 1/	15,246,927
Other Gas Costs per Dk (excluding MDDQ)	\$5.798
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$14,055,342
Winter Firm Service Requirements	13,923,661
MDDQ Costs per Winter Dk	\$1.009
Add: Other Gas Costs per Dk	<u>5.798</u>
Winter Seasonal Rate	\$6.807
Winter Seasonal Rate, adjusted for losses 2/	\$6.838
Less: Gas Cost Level in Rates 3/	<u>6.188</u>
Current Gas Cost Adjustment	<u><u>\$0.650</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$4.523	\$6.160
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$4.543	\$6.188

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

	Amount
Total Gas Costs 1/	\$20,134,562
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$5.748
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.774
Less: Gas Cost Level in Rates 2/	5.072
Current Gas Cost Adjustment	\$0.702

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 March 1, 2014:

Cost of Purchased Gas	\$5.049
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.072

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE APRIL 2014**

	<u>Amount</u>
Total Gas Costs 1/	<u>\$5,058,427</u>
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$5.748
Less: Gas Cost Level in Rates 2/	<u>5.049</u>
Current Gas Cost Adjustment	<u><u>\$0.699</u></u>

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, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective March 1, 2014:
Cost of Purchased Gas \$5.049

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
April 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.	737.928	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
MINIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	30.884	N.A.	N.A.	30.884
MINIMUM A/B/C/	RATE PER DKT	3.120	N.A.	N.A.	3.120
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	24.261
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 2.560%, CONSISTING OF 2.275% 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 1.727 CENTS, CONSISTING OF 1.407 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."

Issued On: February 28, 2014
 Docket Number:
 FERC Order Date:

Effective On: April 1, 2014

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.	47.491	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	0.052

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.	2.102	N.A.	N.A.	2.102
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.	190.602	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	0.000
INJECTION CHARGE					
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
WITHDRAWAL CHARGE					
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE					
INJECTION					
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888
WITHDRAWAL					
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	0.888

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.642%, CONSISTING OF 0.684% 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 (0.140) CENTS, CONSISTING OF 0.000 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: February 28, 2014
 Docket Number:
 FERC Order Date:

Effective On: April 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 ³ m ³		
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 ¹	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 ¹	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/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 ³ m ³		
9. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
10. Rate Schedule IT-D ¹	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 ³ m ³ /d
13. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2013568692	\$ 14.00	/ month
	2013568691	\$ 2.00	/ month
	2013568690	\$ 2.00	/ month
	2013568689	\$ 2,125.00	/ month
	2013568688	\$ 51.00	/ month
	2013568687	\$ 138.00	/ month
	2013568686	\$ 88.00	/ month
	2013568682	\$ 20.00	/ month
	2013568681	\$ 194.00	/ month
	2013568680	\$ 210.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011475772	\$ 9,250.00	/ month
	2011476052 / 2011476054	\$ 0.1376 \$ 717,000.00	/ GJ subject to Minimum Annual Charge
	2011475056 / 2011476092 / 2011494569 / 2011476049 / 2011476050	\$ 0.095 \$ 1,000.00	/ GJ and / month
14. Rate Schedule CO ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</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 APG	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 ¹
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	AQUINU RIVER WEST SALES	4.19	0.1514	
31007	ALBERTA ENVIROFUELS SALES APN	4.19	0.1514	Yes ²
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 ²
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	
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	
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	
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	
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	

NATURAL GAS TARIFF

**NorthWestern
Energy**

Canceled $\frac{35^{th}}{34^{th}}$ 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	(1)
10,001 to 30,000	\$ 173.05	(1)
>30,000	\$ 384.05	(1)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 0.9840814 (1)

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum \$ 0.0074572 (1)

Minimum \$ 0.0017935

GTAC Amortization \$ (0.0013032)

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)

Docket No. D2013.12.83
Tariff Letter No. 237-G
By Operation of Law

Effective for service rendered on or after
January 1, 2014

PUBLIC SERVICE COMMISSION
Aleisha 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

NG-60-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

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
Sixth Revised Sheet No. 12
Cancels Fifth 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	0.526%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.1040	\$0.0010	0.526%
	MLI	DSE	\$225.00	\$0.00	\$0.00	\$0.1978	\$0.0020	2.684%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.00	\$0.00	\$0.0844	\$0.0010	0.526%
	MLI	MLE	\$145.00	\$0.00	\$0.00	\$0.0844	\$0.0010	0.526%
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: March 1, 2013
By: William N. Cantrell

Date Effective: June 1, 2013
Title: President and CEO

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

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2013	\$11,873,285	\$524,021	\$3,373,058
November	10,083,032	468,480	2,743,332
December	2,713,665	282,335	1,290,628
January 2014	1,718,601	140,548	(516,571)
February	(8,606,952)	(17,524)	(1,680,015)
March	(10,562,641)	(68,093)	(2,431,238)
April	(9,712,343)	(32,060)	(2,219,394)
May	(6,943,438)	92,400	(1,285,250)
June	(2,330,090)	300,725	(45,891)
July	2,264,596	508,207	1,172,786
August	7,005,421	721,273	2,395,209
September	11,024,198	901,786	3,405,384
October	12,309,507	959,519	3,599,027
13 month average	<u>\$1,602,834</u>	<u>\$367,817</u>	<u>\$753,928</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$140,905	\$32,335	\$66,278
Return Requirement	<u>\$191,282</u>	<u>\$43,896</u>	<u>\$89,974</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 APRIL 2014

Cost of Purchased Propane	\$89,779
Gallons Purchased	57,922
Projected dk Sales	5,300
Propane Cost per Dk	\$16.939
Average Cost of Propane as Adjusted for Losses @ 99.55%	17.016
Less: Propane Cost Level in Rates 1/	<u>25.250</u>
Current Propane Cost Adjustment	<u><u>(\$8.234)</u></u>

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

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

	<u>(Over) Under</u>	<u>Refunds &</u>	<u>Interest 1/</u>	<u>Total Net</u>	<u>Actual Dk</u>	<u>Adjustment</u>	<u>Total</u>	<u>Net Change-</u>	<u>Cumulative</u>
	<u>Recovery</u>	<u>Other</u>		<u>Additions</u>	<u>Sales</u>	<u>Per Dk</u>	<u>Adjustment</u>	<u>Additions less</u>	<u>Balance</u>
							<u>Amount</u>	<u>Adjustment</u>	
Balance @ July 31, 2013									<u>\$268,918</u>
August	(\$171,535)	\$0	\$6	(\$171,529)	283,161	(\$0.113)	(\$31,997)	(\$139,532)	129,386
September	(10,802)	387,468 2/	2	376,668	259,134	(0.113)	(29,282)	405,949	535,335
October	91,702	0	15	91,717	509,627	0.024	(28,445) 3/	120,162	655,497
November	(43,397)	46,049 4/	27	2,679	1,155,975	0.024	27,743	(25,064)	630,433
December	448,098	0	25	448,123	2,259,276	0.024	54,223	393,900	1,024,333
January 2014	218,746	0	22	218,768	3,260,430	0.024	78,250	140,518	1,164,851
Balance @ January 31, 2014									<u>\$1,164,851</u>

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

2/ Adjustment to correct gas costs for the period December 2010 - August 2013 due to a billing error.

3/ Reflects 296,905.6 Dk @ (\$0.113) and 212,721.2 Dk @ \$0.024.

4/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

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

	<u>(Over) Under</u> <u>Recovery</u>	<u>Refunds &</u> <u>Other</u>	<u>Interest 1/</u>	<u>Total Net</u> <u>Additions</u>	<u>Actual Dk</u> <u>Sales</u>	<u>Adjustment</u> <u>Per Dk</u>	<u>Total</u> <u>Adjustment</u> <u>Amount</u>	<u>Net Change-</u> <u>Additions less</u> <u>Adjustment</u>	<u>Cumulative</u> <u>Balance</u>
Balance @ July 31, 2013									<u>\$162,872</u>
August	(\$8,729)	\$0	\$4	(\$8,725)	32,348	(\$0.115)	(\$3,719)	(\$5,006)	157,866
September	(2,593)	0	1	(2,592)	33,833	(0.115)	(3,891)	1,299	159,165
October	9,049	0	4	9,053	55,674	0.116	(4,732) 2/	13,785	172,950
November	19,660	6,105 3/	7	25,772	126,614	0.116	14,687	11,085	184,035
December	67,199	0	7	67,206	203,609	0.116	23,618	43,588	227,623
January 2014	86,756	0	5	86,761	165,685	0.116	19,220	67,541	295,164
Balance @ January 31, 2014									<u>\$295,164</u>

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

2/ Reflects 48,442.5 Dk @ (\$0.115) and 7,230.6 Dk @ \$0.116.

3/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.

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 & 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>
Balance @ July 31, 2013									<u><u>\$86,961</u></u>
August	(\$1,327)	\$0	\$2	(\$1,325)	4,039	(\$0.377)	(\$1,522)	\$197	87,158
September	(5,633)	0	1	(5,632)	4,641	(0.377)	(1,750)	(3,882)	83,276
October	1,205	0	2	1,207	6,585	0.181	(2,484) 2/	3,691	86,967
November	3,672	1,691 3/	3	5,366	29,839	0.181	5,401	(35)	86,932
December	4,326	0	4	4,330	52,750	0.181	9,547	(5,217)	81,715
January 2014	63,099	0	2	63,101	88,671	0.181	16,050	47,051	128,766
Balance @ January 31, 2014									<u><u>\$128,766</u></u>

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

2/ Reflects 6,585.1 Dk @ (\$0.377).

3/ Adjustment to correct gas costs for the period February 2013 - October 2013 for revisions to volume calculations.