

September 9, 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-

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 (129th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered October 1, 2014.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.150 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. There has also been a change in pipeline rates as shown on Attachment C, increasing the cost of gas by \$0.097 per dk. In addition, this filing reflects the annual change in the surcharge adjustment, which is an increase of \$0.185 per dk for residential and firm general service customers. The market based pricing differential credit increased by \$0.005 per dk and the grain drying margin sharing provision established in Case No. PU-13-803 results in an additional credit of \$0.001.

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

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.411 per dk for residential customers and firm general customers, an increase of \$0.503 per dk for small and large interruptible customers and an increase of \$0.422 per dk for Air Force interruptible 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 October 2014. The average cost of gas for firm customers, adjusted for losses, is \$5.620.

firm customers, adjusted for losses, is \$5.620.

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.

Exhibit D shows the calculation of the surcharge adjustment that will apply during the period October 1, 2014 through September 30, 2015. The total surcharge is \$0.209 per dk residential and general service customers, \$0.380 per dk for small and large interruptible customers and \$0.365 per dk for the Air Force, or an increase of \$0.185 per dk for residential and general service customers, an increase of \$0.264 per dk for small and large interruptible customers and an increase of \$0.184 per dk for the Air Force from the adjustment effective October 1, 2013.

Exhibit E shows the calculation of the interruptible market based pricing differential pursuant to the terms of Rate 88. Fifty percent of the non-gas commodity revenues received from small and large interruptible sales in excess of the authorized level are credited to residential and firm general service customers through the COG. A credit of \$0.017 per dk will be applicable to all residential and general service customers due to the market based pricing differential for the period October 1, 2014 through September 30, 2015.

Exhibit F shows the grain drying margin sharing provision pursuant to the terms of Rate 88. Ninety percent of the margin revenues collected from grain drying customers served under interruptible service rates will be credited to residential and firm general service customers through the COG. A credit of \$0.001 per dk will be applicable to all residential and general service customers due to the grain drying margin sharing provision for the period October 1, 2014 through September 30, 2015.

Montana-Dakota purchases propane supplies from various wholesale suppliers. There is no change in the cost of propane established in the October COG filing.

These proposed adjustments, calculated in accordance with Rate 88 and Rate 99, will amount to an increase of approximately \$155,700 for natural gas customers during the month of October 2014. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 102,017 natural gas customers in North Dakota as of August 31, 2014.

Please refer all inquiries regarding this filing to:

Ms. Tamie A. Aberle
Director of 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:

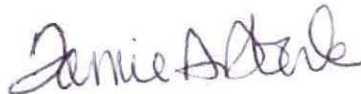
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

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
129th Revised Sheet No. 3
Canceling 128th 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	\$5.811	\$6.137
Air Force Rate 64	7	\$2,000.00 per month \$175.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.329	\$5.811	\$6.140
Interruptible Service - PAR			\$0.260	\$4.779	\$5.039
Interruptible Service - MAFB			\$0.260	\$4.744	\$5.004
Firm General Service Rate 70	13	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet			\$0.730	\$5.811	\$6.541
Meters rated > 500 cubic feet					
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$4.779	(Maximum) \$5.708
Optional Seasonal Gas Service Rate 72	15	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet			\$0.730	\$5.927	\$6.657
Meters rated > 500 cubic feet					
Transportation Service	24	\$175.00 per month \$1,000.00 per month			
Small Interruptible Rate 81					
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.020	
Large Interruptible Rate 82					
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.020	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$4.779	(Maximum) \$5.497
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$12.159	\$12.485
Firm General Propane Rate 92	34	\$0.67 per day \$1.90 per day			
Meters rated < 500 cubic feet			\$0.730	\$12.159	\$12.889
Meters rated > 500 cubic feet					

Date Filed: September 9, 2014

Effective Date: October 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**

October 2014

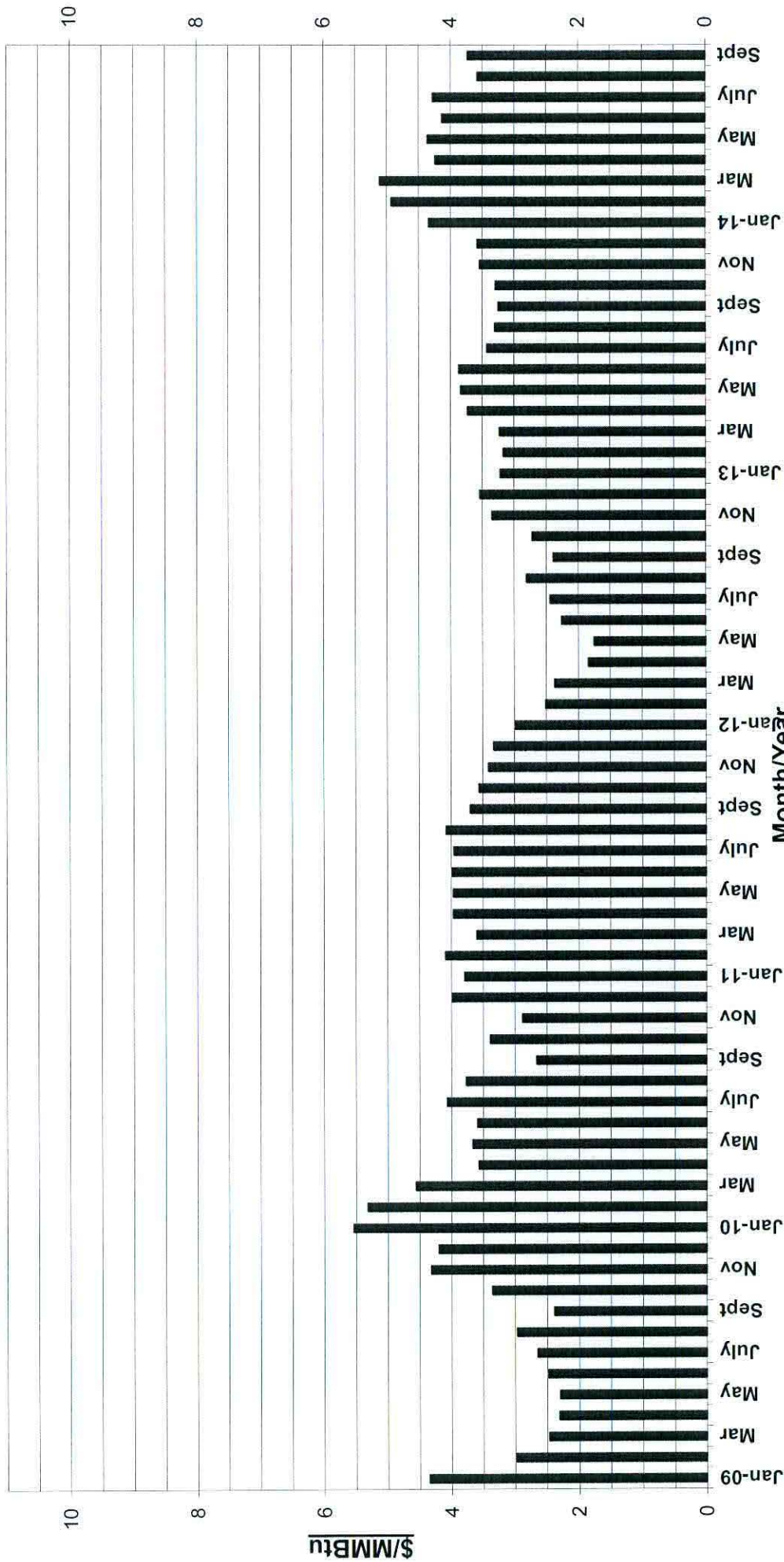
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including “Inside FERC Gas Market” report and “Gas Daily” by McGraw-Hill Companies, of prices paid 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.

Warmer weather throughout heavily populated areas of the south, midcontinent and east, resulting in increased electric generation for a portion of August and the still lagging national storage balance when compared to the previous and five year averages, likely contributed to the increase in the monthly index price of natural gas. The EIA reported the national storage level as of August 29, 2014, was 15.4 percent below the five-year average and 14.8 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 September Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 18. The October Outlook will be published on October 7, 2014.

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-\$4.30



Independent Statistics & Analysis

U.S. Energy Information
Administration

September 2014

Short-Term Energy Outlook (STEO)

Highlights

- Driven in large part by falling crude oil prices, U.S. regular gasoline retail prices fell to an average of \$3.49/per gallon (gal) in August, 12 cents below the July average and 21 cents below the average in June. U.S. regular gasoline retail prices are projected to continue to decline to an average of \$3.18/gal in December, 12 cents lower than projected in last month's STEO. EIA expects U.S. regular gasoline retail prices, which averaged \$3.51/gal in 2013, to average \$3.46/gal in 2014 and \$3.41/gal in 2015, 4 cents lower and 6 cents lower than last month's STEO, respectively.
- Weakening global demand and increased Libyan oil exports contributed to a drop in the North Sea Brent crude oil spot price to an average of \$102 per barrel (bbl) in August, \$5/bbl lower than the July average and \$10/bbl below the average in June. For the first time in 14 months, average [Brent spot prices fell outside the relatively narrow \\$5/bbl range between \\$107/bbl and \\$112/bbl](#). EIA projects that Brent crude oil prices will average \$103/bbl in fourth-quarter 2014 and \$103/bbl in 2015, \$5/bbl and \$2/bbl lower than forecast in last month's STEO, respectively. The WTI discount to Brent, which averaged \$11/bbl in 2013, is expected to average \$8/bbl in both 2014 and 2015.
- Total U.S. crude oil production averaged an estimated 8.6 million barrels per day (bbl/d) in August, the highest monthly production since July 1986. Total crude oil production, which averaged 7.5 million bbl/d in 2013, is expected to average 9.5 million bbl/d in 2015, 0.2 million bbl/d higher than projected in last month's STEO. If achieved, the 2015 forecast would be the highest annual average crude oil production since 1970. Natural gas plant liquids production increases from an average of 2.6 million bbl/d in 2013 to 3.1 million bbl/d in 2015. The growth in domestic liquids production has contributed to a significant decline in petroleum imports. The share of total U.S. petroleum and other liquids consumption met by net imports fell from 60% in 2005 to an average of 32% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1968.
- Natural gas spot prices fell 15% from an average of \$4.59/million British thermal units (MMBtu) in June to \$3.91/MMBtu in August even as natural gas stock builds continued to outpace historical norms. Natural gas working inventories on August 29 totaled 2.71 trillion cubic feet (Tcf), 0.47 Tcf (15%) below the level at the same time a year ago and 0.50 Tcf (15%) below the previous five-year average (2009-13). Projected natural gas working

inventories reach 3.48 Tcf at the end of October, 0.34 Tcf below the level at the same time last year. EIA expects that the Henry Hub natural gas spot price, which averaged \$3.73 per MMBtu in 2013, will average \$4.46/MMBtu in 2014 and \$3.87/MMBtu in 2015.

Global Petroleum and Other Liquids

EIA estimates that global oil inventories grew by 0.5 million bbl/d in August. The recent inventory builds are somewhat atypical for this time of year and signal a relatively loose global crude oil market compared with conditions over the past three years. Weaker oil demand and lower refinery runs in European and Asian countries within the Organization for Economic Cooperation and Development (OECD) this year have reduced market tightness. Nevertheless, these conditions may be temporary and the risk for tighter markets in the future remains elevated due to persistently high supply disruptions and relatively low surplus crude oil production capacity.

Geopolitical risks 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 to a near-halt. Iraq's southern crude oil exports still remain unaffected by the unrest in northern Iraq. In Libya, crude oil exports restarted in August at the country's two major eastern ports, Es Sidra and Ras Lanuf, after being blocked by protestors for about a year. However, the situation in Libya is still very precarious as the security situation remains volatile, with a significant possibility of intermittent disruptions.

EIA projects world petroleum and other liquids supply to increase by 1.6 million bbl/d in 2014 and by 1.3 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). Forecast non-OPEC supply grows by 1.8 million bbl/d in 2014 and 1.2 million bbl/d in 2015. The United States accounts for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.0 million bbl/d in 2014 and 1.3 million bbl/d in 2015. Non-OECD countries, notably China, drive expected consumption growth.

Global Petroleum and Other Liquids Consumption. Global consumption grew by 1.3 million bbl/d (1.5%) in 2013, averaging 90.5 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in 2014 and 1.3 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased 2.7% in 2013, grows by 2.7% and 3.3% in 2014 and 2015, respectively.

Non-OECD consumption is projected to grow by 1.3 million bbl/d in 2014 and 1.2 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 (3.5%) in 2014 and 0.43 million bbl/d in 2015.

EIA expects a 0.21-million-bbl/d decline in OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. Japan's consumption, which fell by 0.16 million bbl/d in 2013, is projected to continue to decline by an annual average of 0.13 million bbl/d in 2014 and 0.16 million bbl/d in 2015. The projected decline reflects Japan's effort to reduce its share of oil 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. OECD Europe's consumption, which fell by 0.12 million bbl/d in 2013, is projected to decline by a further 0.12 million bbl/d in 2014 and by 0.03 million bbl/d in 2015. U.S. consumption, which increased by 0.47 million bbl/d in 2013, is expected to be mostly flat in 2014 and then increase by 0.15 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 1.8 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 1.4 million bbl/d in 2014 and 1.2 million bbl/d in 2015. EIA estimates that Eurasia's production will increase by less than 0.1 million bbl/d in 2014, with increased production from Russia and Kazakhstan offsetting declines in other countries, and stay relatively flat 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 August, slightly lower than the estimated July level. South Sudan, Syria, and Yemen accounted for more than 85% 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 1.0 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.3 million bbl/d in 2014 and by 0.1 million bbl/d in 2015 to accommodate growing production in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.4 million bbl/d in August 2014, 0.1 million bbl/d lower than the previous month mainly because of decreased outages in Libya. Libya's production increased to 0.5 million bbl/d in August, 0.3 million bbl/d higher than the second quarter 2014 average, but still well below the 1.4 million bbl/d the country produced before the major blockades started in mid-2013. Almost all of Libya's export terminals are able to export crude as protestors agreed to stop the blockades, and production has restarted in some of Libya's largest eastern oil fields. However, some of the major issues that incited the widespread protests over the past year remain unresolved. As a result, EIA does not expect Libya's oil production to recover to its preblockade 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 2.7 million bbl/d in 2015. These estimates do not

include additional capacity that may be available in Iran but is offline because of the effects of U.S. and European Union sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.55 billion barrels at the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.58 billion barrels at the end of 2014.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$102/bbl in August, a decrease of \$5/bbl, or 4.7%, from July. Brent crude oil prices were driven downward in large part because of weakening global oil demand as well as growing Libyan oil exports. August was the first in 13 consecutive months in which average Brent crude oil spot prices fell outside the relatively narrow range of \$107/bbl to \$112/bbl. The forecast Brent crude oil price averages \$106/bbl in 2014, \$2/bbl lower than in last month's STEO, and \$103/bbl in 2015, \$2/bbl lower than in last month's STEO.

The monthly average WTI crude oil spot price fell from a high of \$106/bbl in June to \$97/bbl in August. Driven in part by [new pipelines delivering crude oil to refining centers along the Gulf Coast](#), crude oil inventory levels at the Cushing, Oklahoma, storage hub, the futures market's delivery point for WTI, fell below 18 million barrels on July 25, the lowest level since October 2008. Crude oil inventories then built for four consecutive weeks to reach 20.7 million barrels on August 22. After falling to an annual low of \$3/bbl in July, the discount of WTI crude oil to Brent crude oil increased to \$5/bbl in August. While record high refinery runs contributed to the WTI discount falling to \$3/bbl in July, the discount widened in August while refinery runs remained elevated. EIA now expects WTI crude oil prices to average \$93/bbl in the fourth quarter of 2014, \$5/bbl lower than in last month's STEO, and \$95/bbl in 2015. The discount of WTI to Brent crude oil is forecast to widen from current levels, averaging \$10/bbl in the fourth quarter of 2014 and \$8/bbl 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 December 2014 delivery, traded during the five-day period ending September 4, averaged \$93/bbl. Implied volatility averaged 16%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in December 2014 at \$81/bbl and \$107/bbl, respectively. Last year at this time, WTI for December 2013 delivery averaged \$106/bbl and implied volatility averaged 25%. The corresponding lower and upper limits of the 95% confidence interval were \$86/bbl and \$131/bbl.

U.S. Petroleum and Other Liquids

After reaching a summer peak of \$3.70/gal in late June, U.S. average regular gasoline retail prices fell to \$3.45/gal on August 25, [the lowest price on the Monday before Labor Day since 2010](#). Gasoline prices have fallen from their summer peak in late June primarily because of

lower crude oil prices, which in addition to reduced geopolitical risk premiums to Iraqi and Libyan oil exports, have been driven downward because of weakening global oil demand indicators in combination with growing international oil supplies. EIA expects that U.S. regular gasoline retail prices will continue to fall through the end of the year, reaching \$3.18/gal in December, which would mark the lowest monthly average since January 2011.

Liquid Fuels Consumption. EIA has revised total 2013 U.S. petroleum and other liquids consumption upwards by 74,000 bbl/d to 18.96 million bbl/d. Upward revisions in motor gasoline (69,000 bbl/d), special naphthas (66,000 bbl/d), and hydrocarbon gas liquids (HGL) (47,000 bbl/d) were offset by a 113,000 bbl/d reduction in unfinished oils consumption. Total U.S. petroleum and other liquids consumption rose by 470,000 bbl/d (2.5%) in 2013, the largest annual increase since 2004. Motor gasoline consumption rose by 160,000 bbl/d (1.9%). High petrochemical demand and a very wet corn crop late in the year contributed to a 100,000 bbl/d (8.5%) increase in propane consumption last year.

Total consumption is expected to fall slightly, by 0.2%, in 2014. A year-over-year increase in total consumption of 170,000 bbl/d during the first quarter is expected to be more than offset by an average 150,000 bbl/d decline during the second half of the year. Propane consumption retreats from last year's growth, falling by an average of 110,000 bbl/d this year. Distillate fuel consumption is projected to increase by an average of 160,000 bbl/d (4.2%) in 2014.

Total consumption grows by 150,000 bbl/d in 2015 to average 19.08 million bbl/d, an increase of 100,000 bbl/d from last month's STEO. HGL consumption, primarily ethane and propane, increases by 120,000 bbl/d next year, while distillate consumption is 70,000 bbl/d higher.

Liquid Fuels Supply. The forecast for total U.S. crude oil production increases from an estimated 7.45 million bbl/d in 2013 to 8.53 million bbl/d in 2014 and 9.53 million bbl/d in 2015. The 2014 and 2015 forecasts are 0.07 million bbl/d and 0.25 million bbl/d higher than in last month's STEO, respectively. The highest previous annual average U.S. production level was 9.6 million bbl/d in 1970. Oil production from the Gulf of Mexico is expected to increase from 1.25 million bbl/d in 2013 to 1.67 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 3.1 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 32% in 2013. EIA expects the net import share to decline to 21% in 2015, which would be the lowest level since 1968.

Petroleum Product Prices. EIA expects that the monthly average regular gasoline retail price will fall from the recent peak of \$3.69/gal in June to \$3.41/gal in September, before falling to \$3.18/gal in December. The U.S. annual average regular gasoline retail price, which averaged \$3.51/gal in 2013, is projected to average \$3.46/gal in 2014 and \$3.41/gal in 2015, 4 cents and 6 cents lower than in last month's STEO, respectively. Diesel fuel prices, which averaged \$3.92/gal in 2013, are projected to fall to an average of \$3.86/gal in 2014 and \$3.82/gal in 2015, 2 cents and 5 cents lower than projected in last month's STEO, respectively. 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 30 cents/gal or more.

Natural Gas

[Industrial natural gas consumption](#) has grown steadily since 2009, as relatively low prices have been attractive to consumers who use natural gas as a feedstock for chemical production. [Ammonia-based fertilizer and methanol plants](#) that use natural gas as a feedstock are among the most natural gas-intensive industrial end users. Low gas prices and proximity to shale resources have led to proposals for several methanol and ammonia plants. Two methanol plants are currently under construction and set to begin service this year— a small facility in Pampa, Texas and one in Geismar, Louisiana. Two large facilities coming online in 2015, a methanol plant in Clear Lake, Texas, and a fertilizer/urea plant in Wever, Iowa, will support continued growth in industrial demand. Many large plants use more than 0.1 billion cubic feet per day (Bcf/d) of natural gas. EIA projects growth in industrial demand will continue through 2015, with consumption averaging 21.3 Bcf/d in 2014 and 22.1 Bcf/d in 2015.

Natural Gas Consumption. EIA expects total natural gas consumption will average 72.6 Bcf/d in 2014, an increase of 1.8% from 2013 led by the industrial sector. In 2015, total natural gas consumption increases 0.2% as continued industrial sector growth offsets lower residential and commercial consumption. Higher natural gas prices this year contribute to a 2.0% decline in natural gas consumption in the power sector to 21.9 Bcf/d in 2014. EIA expects natural gas consumption in the power sector to increase to 22.8 Bcf/d in 2015.

Natural Gas Production and Trade. EIA expects natural gas marketed production to grow by an annual rate of 5.3% in 2014 and 2.1% in 2015. STEO projects that strong increases already seen in the Lower 48 states this year will continue, offsetting declines in the Gulf of Mexico. As of June, the most recent month for which EIA data are available, marketed production was 4.6 Bcf/d greater than it was in June 2013. Rapid natural gas production growth in the Marcellus formation has contributed to [low natural gas forward prices in the Northeast](#), and as a result new infrastructure has been proposed to flow gas to other market regions. In June, the eastward-flowing Rockies Express Pipeline (REX) began service on its [Seneca Lateral](#), which flows

Marcellus gas westward to the Midwest. REX's parent company, Tallgrass Energy, plans to add bi-directional capability on a significant portion of REX's easternmost segment.

Growing domestic production is expected to continue to put downward pressure on natural gas imports from Canada, and spur exports to Mexico. Exports to Mexico have been increasing in recent months because of growing demand from Mexico's electric power sector and flat Mexican production. Mexico has been an outlet for U.S. production, particularly from the Eagle Ford Shale in South Texas.

Liquefied natural gas (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. This month's STEO revises the forecast for 2015 LNG net imports to reflect Cheniere Energy's Sabine Pass export terminal beginning service in 2015. EIA now expects the United States will be a net exporter of LNG in 2015. 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 2,709 Bcf as of August 29, which was 471 Bcf lower than the same time last year and 495 Bcf lower than the previous five-year (2009-13) average. The injection season began somewhat slowly in April, but has continued at a strong pace, with injections averaging above the five-year average throughout most of the injection season. EIA expects working gas stocks will reach 3,477 Bcf at the end of October, 339 Bcf lower than at the same time last year.

Natural Gas Prices. Natural gas prices fell from \$4.05/MMBtu in July to \$3.91/MMBtu in August as storage injections continue to outpace historical norms. EIA expects spot prices will remain below \$4/MMBtu through October, before rising with winter heating demand. Projected Henry Hub natural gas prices average \$4.46/MMBtu in 2014 and \$3.87/MMBtu in 2015.

Natural gas futures prices for December 2014 delivery (for the five-day period ending September 4) averaged \$4.07/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 \$3.09/MMBtu and \$5.35/MMBtu, respectively. At this time last year, the natural gas futures contract for December 2013 averaged \$3.87/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$2.98/MMBtu and \$5.04/MMBtu.

Coal

Electric power sector coal inventories fell to 133 million short tons (MMst) at the end of June, 38 MMst lower compared with the same time last year. Coal inventories in the Midwest and South, two regions that rely heavily on coal-fired generation, are down 19% and 29%, respectively, when compared with last year. Midwestern electric generators have recently cited

continuing problems with rail coal deliveries to power plants. One utility in [Wisconsin](#) is concerned that it may have to cease or curtail operations at a coal plant and in [Minnesota](#) one utility states that it has begun curtailing output at a large coal-fired plant to conserve fuel. Coal car loadings have fallen in 8 of the past 9 weeks, and although year-to-date [rail coal shipments](#) are up by 0.1%, this has been insufficient to maintain stocks. Some Southern generators are reportedly turning to shipments of imported coal to meet their needs.

Coal Supply. EIA estimates that coal production for the first eight months of this year (658 MMst) was slightly lower (5 MMst) than production over the same period last year. EIA expects that U.S. coal production will grow 1.4% to 998 MMst in 2014, driven by higher consumption and a need to replenish consumer inventories, particularly at power producers. In 2015, forecast U.S. coal production increases slightly by 0.5% to 1,002 MMst.

Coal Consumption. EIA projects total coal consumption growth of 2.0% to 943 MMst in 2014 because of higher electricity demand and power sector natural gas prices more than 20% above their 2013 level. Total coal consumption is projected to fall by 2.6% in 2015, as retirements of coal power plants rise in response to the implementation of the [Mercury and Air Toxics Standards](#), electricity sales growth slows to 0.4%, and natural gas prices fall relative to coal prices.

Coal Trade. EIA estimates that coal exports for the first six months of this year were 17.2% (10.5 MMst) lower compared with last year, with tonnage declines for steam coal exports more than double those of metallurgical coal. Coal exports 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.

[Coal imports](#) for the first six months of this year increased by 43% (1.8 MMst) compared with last year. Rail congestion, coupled with falling global coal prices, has made imports an attractive alternative to domestic coal, especially to [power plants in the East](#). EIA expects coal imports to total 12.8 MMst in 2014 and fall slightly to 10.8 MMst in 2015.

Coal Prices. Annual average coal prices to the electric power industry fell over the past few years, 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

Preliminary data indicate that [power generators added](#) 4.35 gigawatts (GW) of new capacity during the first half of 2014. This rate of new capacity builds is 40% below the rate of capacity additions during the same period last year. Power plants fueled by natural gas accounted for more than half of the new capacity coming online so far this year, with the remainder primarily composed of renewable generating capacity. No coal-fired generating capacity was completed

during the first half of 2014, compared with 1.51 GW in 2013. Two coal plants with a total capacity of 0.58 GW are scheduled to begin operations this year. Preliminary data indicate that at least 0.95 GW of coal-fired capacity has been retired so far this year. A much larger number of coal plants are expected to retire during 2015.

Electricity Consumption. After cold weather during the first quarter of this year and relatively close to normal summer temperatures, EIA projects growth of 1.9% in U.S. retail sales of electricity to the residential sector in 2014. As forecast temperatures return to normal in 2015, EIA expects residential electricity sales will decline by 0.7% next year. Relatively modest economic growth compared with last year has led to slower growth in the electricity sales to the commercial sector. U.S. commercial 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 electricity sales to remain flat during 2014 and grow by 2.2% in 2015 after two years of declines.

Electricity Generation. EIA projects that average daily U.S. electricity generation in 2014 will grow by 100 gigawatthours per day (0.9%) from last year. Changes in relative fuel costs have altered the mix of plants used to generate electricity. Power sector natural gas prices this year are expected to be more than 20% higher than prices last year, while the prices of coal delivered to the power sector are expected remain flat. Rising natural gas costs lead to a reduction in the fuel's share of total generation from 27.4% in 2013 to 26.7% this year. In contrast, coal's share of total generation rises from 39.1% in 2013 to 40.1% this year. In 2015, EIA expects the power sector's price of natural gas will fall by 12%. This lower price, combined with the scheduled retirements of coal capacity, should push up natural gas's fuel share next year to 27.6% and reduce coal's fuel share to 38.8%.

Electricity Retail Prices. Residential [electricity prices have risen](#) in most states so far this year, compared with the same period in 2013. EIA expects the U.S. residential price to average 12.5 cents per kilowatthour in 2014, which is 3.1% higher than the average last year. The increase in average prices will be highest in the New England states, at 7.8%. Average U.S. residential electricity prices grow at a slower rate of 1.7% in 2015.

Renewables and Carbon Dioxide Emissions

Almost 50% of the new utility-scale [power generation capacity added during the first half of 2014](#) uses renewable energy sources. Solar-powered capacity grew about 1,150 megawatts (MW) during the first six months of 2014 compared with 690 MW added during the same period last year. The electricity industry has added 675 MW of wind capacity this year, which is more than double the amount added during the first half of 2013.

Electricity and Heat Generation from Renewables. EIA projects that total renewables use for electricity and heat generation will grow by 2.1% in 2014. Conventional hydropower generation is projected to fall by 4.2%, while nonhydropower renewables rise by 5.5%. In 2014, [nonhydropower renewables generation in the electric power sector surpasses hydropower on](#)

an annual basis for the first time. In 2015, total renewables consumption for electric power and heat generation increases by 4.4%, as a result of a 4.5% increase in hydropower and a 4.4% increase in nonhydropower renewables.

EIA projects that wind power capacity will increase by 9.2% in 2014 and 16.2% in 2015. Electricity generation from wind is projected to contribute 4.6% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.6% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA expects that utility-scale solar capacity will increase by 104% between the end of 2013 and the end of 2015, with about two-thirds of this new capacity built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to [EIA's Annual Energy Outlook 2014](#).

Liquid Biofuels. Ethanol production increased from an average of 907,000 bbl/d in March to average about 940,000 bbl/d over the past 3 months, which are among the highest monthly levels ever recorded, and included the highest weekly level ever recorded at 972,000 bbl/d for the week ending June 13. Ethanol production is forecast to average 929,000 bbl/d in 2014 and 934,000 bbl/d in 2015. Biodiesel production averaged 87,000 bbl/d in 2013 and is forecast to average 80,000 bbl/d in 2014 and 84,000 bbl/d in 2015.

Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.4% in 2013 from the previous year. Emissions are forecast to rise by 1.3% in 2014, and then to decline by 0.6% in 2015. The increase in total emissions in 2013 and 2014 reflects increases in emissions from coal of 4.2% and 2.1%, respectively. The price of natural gas to electric power generators rose on average by \$0.91/MMBtu in 2013 and is projected to rise by \$0.93/MMBtu in 2014, contributing to an increase in coal use. Coal emissions are projected to decline by 2.5% 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 4.2% from the first quarter of 2014, which reflects an upward revision of 0.2% from its previous estimate. Second quarter growth was associated with increases in private inventory investment and exports, along with greater state and local government spending and higher nonresidential fixed investment.

The [U.S. Bureau of Labor Statistics](#) (BLS) reported that the four-week moving average of initial unemployment insurance claims for the week ending August 30 was 302,750, an increase of 3,000 from the previous week's moving average.

EIA used the August 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. Forecast real GDP growth in 2014 was revised upwards from an average 1.7% in last month's STEO to 2.1%. For 2014, the increase reflects the upward revision in real GDP growth in the second quarter of 2014. Real disposable income grows by 2.5% in 2014, down from the 3.1% forecast last month. In 2015, both real GDP and disposable income increase by 2.8%. Total industrial production grows at 3.9% in 2014 and 3.4% in 2015. Growth in industrial production in the manufacturing sector averages 3.5% in both 2014 and 2015.

Expenditures. Private real fixed investment growth averages 4.8% and 7.3% in 2014 and 2015, respectively, led by industrial and transportation equipment in 2014 and by a broad array of equipment categories in 2015. Real consumption expenditures grow faster than real GDP in 2014 at 2.3%, but fall below the real GDP growth rate in 2015 at 2.7%. Durable goods expenditures drive consumption spending in both years. Export growth is 2.7% and 5.4% over the same two years, while import growth is 3.5% in 2014 and 4.9% in 2015. Total government expenditures fall 0.4% in 2014, but increase by 0.3% in 2015.

U.S. Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.8% in 2014 and 1.9% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 5.7% at the end of 2015. Housing starts grow an average of 11.4% and 26.8% in 2014 and 2015, respectively. Both consumer and producer price indexes increase at a moderate pace, and wages continue to show modest gains.

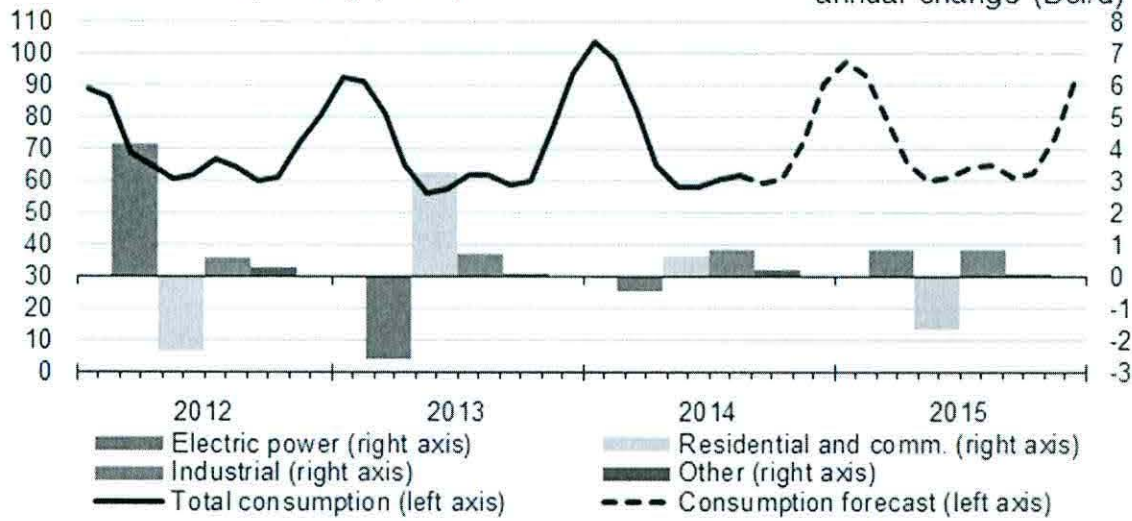
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views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

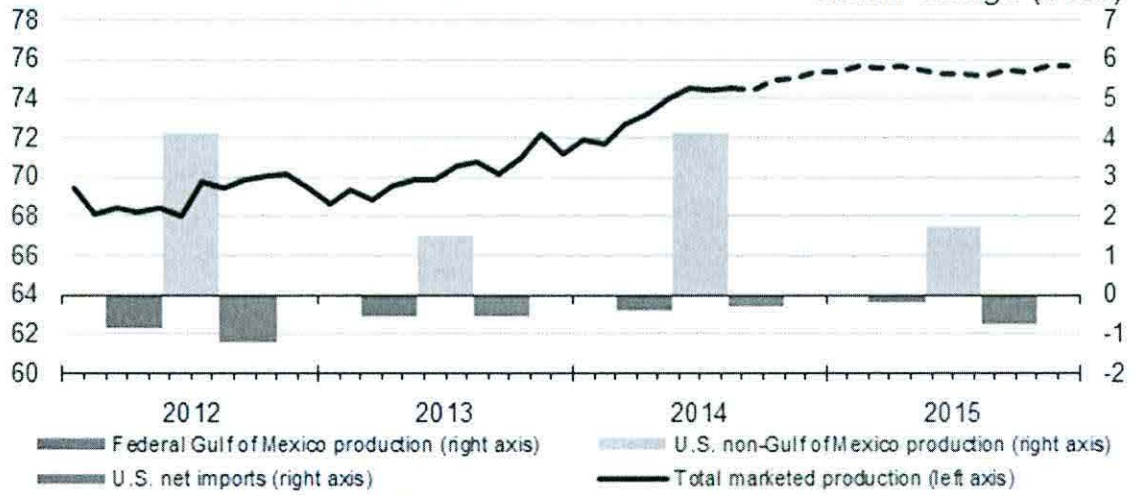


Source: Short-Term Energy Outlook, September 2014.

U.S. Natural Gas Production and Imports

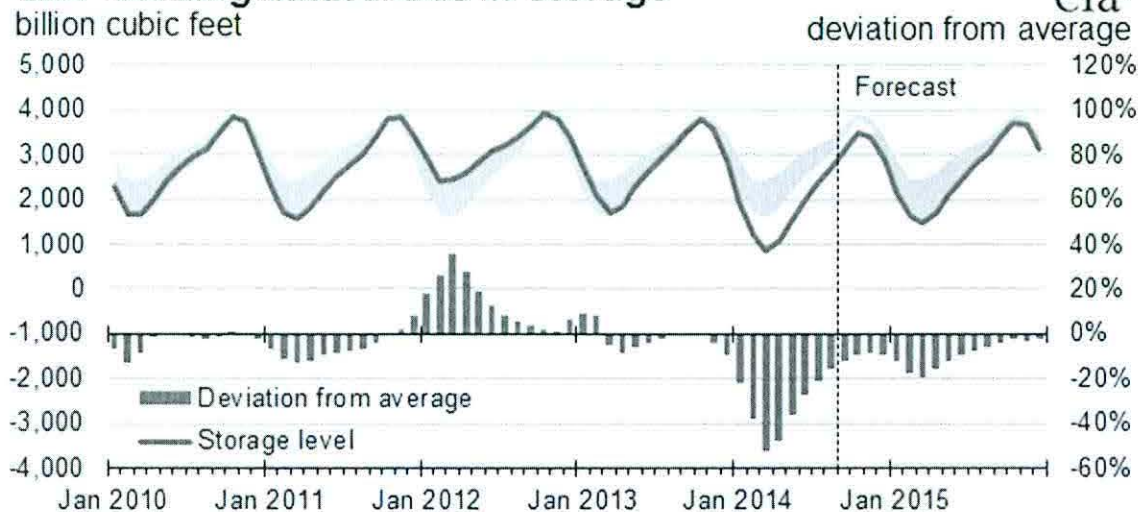
billion cubic feet per day (Bcf/d)

eia
annual change (Bcf/d)



Source: Short-Term Energy Outlook, September 2014.

U.S. Working Natural Gas in Storage

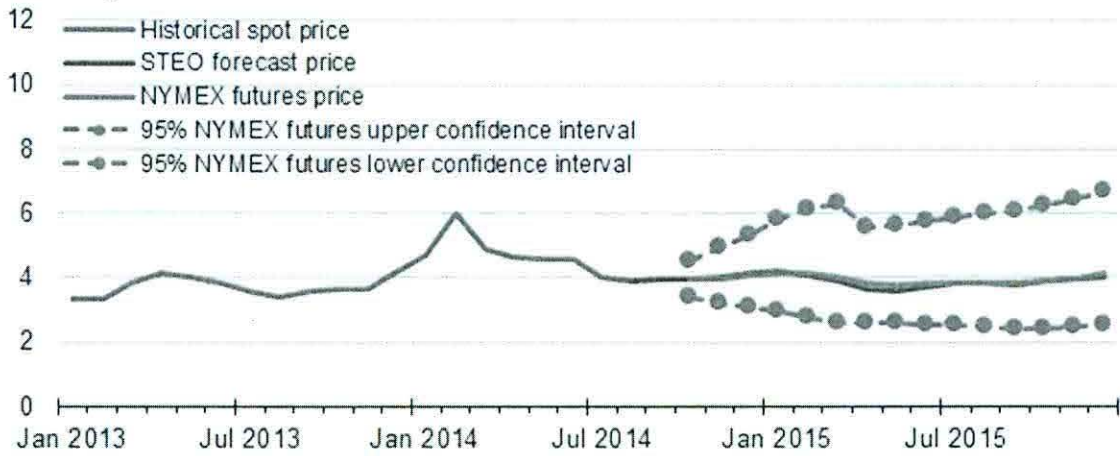


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.

Source: Short-Term Energy Outlook, September 2014.

Henry Hub Natural Gas Price

dollars per million Btu

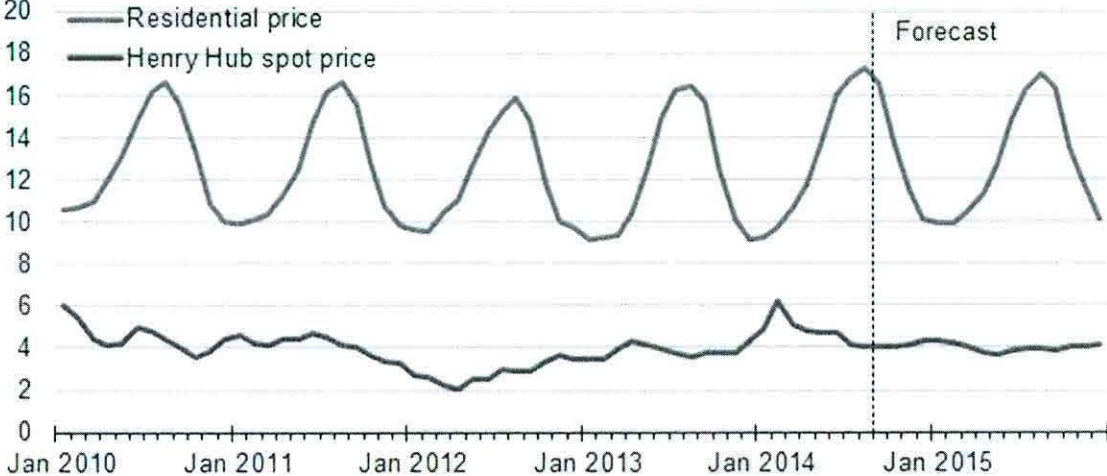


Note: Confidence interval derived from options market information for the 5 trading days ending Sep. 4, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, September 2014.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, September 2014.

**Montana-Dakota Utilities Co.
Pipeline Rate Changes Since Last Annual COG
North Dakota
October 2014 COG**

NorthWestern Energy Docket No. D2012.9.94

On September 28, 2012, NorthWestern Energy filed an application to increase natural gas rates in Montana with the Montana Public Service Commission. On March 20, 2013, the Montana Public Service Commission issued an interim order authorizing NorthWestern to implement an interim increase effective April 1, 2013.

On May 7, 2013, the Montana PSC issued its Final Order authorizing NorthWestern to increase its rates effective June 1, 2013. NorthWestern refunded to customers the difference between the current level of interim rates that had been in effect since April 1, 2013 and the final rates approved in its Final Order for service rendered on or after June 1, 2013 through a Natural Gas Delivery Services Rebate.

On September 16, 2013, NorthWestern filed to expire the Natural Gas Delivery Services Rebate and filed new adjusted final natural gas rates to be effective September 20, 2013.

Approximate impact on Montana-Dakota's cost of gas: 0.0 cents per dk

Foothills Pipe Lines Ltd.

On October 31, 2013, TransCanada filed new rates for the Foothills Pipe Lines Ltd. System with the National Energy Board (NEB) to be effective January 1, 2014.

Approximate impact on Montana-Dakota's cost of gas: 0.3 cents per dk

NOVA Gas Transmission Ltd.

On October 31, 2013, TransCanada filed new interim rates for the Alberta System with the National Energy Board (NEB) to be effective January 1, 2014. On November 14, 2013, the NEB approved the proposed interim 2014 rates, pending an order.

Approximate impact on Montana-Dakota's cost of gas: (0.1) cents per dk

NorthWestern Energy

On December 11, 2013, NorthWestern Energy filed its 2014 Electric and Natural Gas Tax Tracker filing in Docket No. D2013.12.83 with the Montana Public Service Commission to be effective January 1, 2014. On December 17, 2013, NorthWestern Energy filed revised rates to be effective January 1, 2014, on an interim basis.

Approximate impact on Montana-Dakota's cost of gas: 0.0 cents per dk

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

WBI Energy Transmission, Inc. Docket No. RP14-118-000

On October 31, 2013, WBI Energy Transmission, Inc. (WBI Energy) filed revised tariff records reflecting a general rate increase with the FERC in Docket No. RP14-118-000, reflecting revisions to its rates in FERC Gas Tariff, Third Revised Volume No. 1. The rates were proposed to be effective on December 1, 2013 on an interim basis or alternatively on May 1, 2014, following the suspension period.

On May 8, 2014, WBI Energy Transmission, Inc. (WBI Energy) filed interim settlement rates to place into effect on May 1, 2014, in Docket No. RP14-118-003, reflecting revisions to its rates in FERC Gas Tariff, Third Revised Volume No. 1. The Federal Energy Regulatory Commission approved these rates in its Final Order dated June 10, 2014.

Approximate impact on Montana-Dakota's cost of gas: 21.0 cents per dk

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

On August 29, 2014, WBI Energy filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP-14-____-000, reflecting revisions to the fuel and electric power components of WBI Energy's transportation and storage rates effective October 1, 2014.

Approximate impact on Montana-Dakota's cost of gas: 9.6 cents per dk.

Federal Energy Regulatory Commission Annual Charges Unit Charge

On June 20, 2014 the Federal Energy Regulatory Commission filed its annual charges unit charge (ACA) to be applied to its fiscal year 2015 for recovery of FY 2014 Current year and 2013 True-Up as \$0.0014 per Dekatherm. The new ACA surcharge will become effective October 1, 2014.

Approximate impact on Montana-Dakota's cost of gas: 0.0 cents per dk.

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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$5.620	\$5.736	\$4.399	\$4.379
Prior Gas Cost	5.388	4.159	4.160	4.141
Current Gas Cost Adjustment	\$0.232	\$1.577	\$0.239	\$0.238
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.024	0.024	0.116	0.181
Change in Surcharge Adjustment	\$0.185	\$0.185	\$0.264	\$0.184
Gas Cost Level	\$5.620	\$5.736	\$4.399	\$4.379
Plus: Surcharge	0.209	0.209	0.380	0.365
Total Gas Cost Level in Tariff Rates	\$5.829	\$5.945	\$4.779	\$4.744
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.017)	(\$0.017)	\$0.000	\$0.000
Prior Adjustment	(0.012)	(0.012)	0.000	0.000
Change in Market Based Pricing	(\$0.005)	(\$0.005)	\$0.000	\$0.000
<u>Grain Drying Margin Sharing</u>				
Current Adjustment	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Prior Adjustment	0.000	0.000	0.000	0.000
Change in Grain Drying Margin Sharing	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Total Cost of Gas Items	\$5.811	\$5.927	\$4.779	\$4.744
Net Increase (Decrease) in Gas Costs	\$0.411	\$1.756	\$0.503	\$0.422

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

	Amount
Total Gas Costs 1/	\$83,389,621
Residential and General Service dk Requirements 2/	14,905,071
Average Cost of Gas per dk	\$5.595
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.620
Less: Gas Cost Level in Rates 3/	5.388
Current Gas Cost Adjustment	\$0.232

- 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 June 30, 2014, adjusted for losses at .45%.
- 3/ Gas Cost Level in Current Tariff Rates Case No. PU-14-008 effective September 1, 2014:
- | | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$5.364 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$5.388 |

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

Total Gas Costs 1/	\$83,389,621
Less: Annual MDDQ Costs	<u>18,087,631</u>
Total Gas Costs excluding MDDQ	\$65,301,990
Firm Service Requirements 1/	14,905,071
Other Gas Costs per Dk (excluding MDDQ)	\$4.381
<u>Winter - October - May</u> Annual MDDQ Costs 1/	\$18,087,631
Winter Firm Service Requirements	13,611,475
MDDQ Costs per Winter Dk	\$1.329
Add: Other Gas Costs per Dk	<u>4.381</u>
Winter Seasonal Rate	\$5.710
Winter Seasonal Rate, adjusted for losses 2/	\$5.736
Less: Gas Cost Level in Rates 3/	<u>4.159</u>
Current Gas Cost Adjustment	<u><u>\$1.577</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 September 1, 2014:

	<u>Summer</u>
Cost of Purchased Gas	\$4.140
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.159

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

	Amount
Total Gas Costs 1/	\$30,628,591
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$4.379
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.399
Less: Gas Cost Level in Rates 2/	4.160
Current Gas Cost Adjustment	\$0.239

- 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 September 1, 2014:
- | | |
|-------------------------------------|---------|
| Cost of Purchased Gas | \$4.141 |
| Adjustment for Distribution Losses | 0.9955 |
| Gas Cost Level in Base Tariff Rates | \$4.160 |

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
October 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."

Issued On: August 29, 2014
 Docket Number:
 FERC Order Date:

Effective On: October 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.	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.

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 FERC Order Date:

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 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>	
	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 /	\$ 0.1376	/ GJ subject to
	2011476054	\$ 717,000.00	Minimum Annual Charge
	2011475056 / 2011476092 /	\$ 0.095	/ GJ and
	2011476049 / 2011476050	\$ 1,000.00	/ 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 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 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	
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 36th Revised Sheet No. 80.1
35th Revised 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
Aleisbra 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-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Demand Charge 6/</u>	<u>Minimum Demand Charge 6/</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
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 OCTOBER 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	(7,802,409)	0	(1,585,437)
March	(8,760,334)	17,312	(2,249,296)
April	(8,193,736)	55,269	(2,031,162)
May	(5,576,042)	204,090	(1,264,517)
June	(1,937,654)	387,617	(45,040)
July	2,452,763	593,881	725,509
August	7,071,098	914,874	2,201,419
September	11,011,583	1,207,691	3,420,942
October	11,943,110	1,276,327	3,654,129
13 month average	<u>\$2,045,920</u>	<u>\$467,111</u>	<u>\$747,461</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$161,239	\$36,813	\$58,907
Return Requirement	<u>\$225,072</u>	<u>\$51,387</u>	<u>\$82,228</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.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
FIRM
TO BE EFFECTIVE OCTOBER 1, 2014 THROUGH SEPTEMBER 30, 2015**

(Over)/under recovered gas costs @ July 31, 2014 \$3,163,455

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	259,000	\$0.024	6,216
September	429,000	0.024	10,296
	688,000		16,512

Additional recovery required \$3,146,943

Projected sales volumes (dk)

October 2014	1,083,000		
November	1,848,000		
December	2,475,000		
January 2015	2,659,000		
February	2,241,000		
March	1,901,000		
April	1,103,000		
May	506,000		
June	254,000		
July	267,000		
August	264,000		
September	437,000		
Total			<u>15,038,000</u>

Total (over)/under recovered gas cost adjustment
to be effective October 1, 2014 through September 30, 2015 \$0.209

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE
TO BE EFFECTIVE OCTOBER 1, 2014 THROUGH SEPTEMBER 30, 2015**

(Over)/under recovered gas costs @ July 31, 2014 \$553,358

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	87,000	\$0.116	10,092
September	97,000	0.116	11,252
	184,000		21,344

Additional recovery required \$532,014

Projected sales volumes (dk)

October 2014	125,000		
November	145,000		
December	150,000		
January 2015	151,000		
February	142,000		
March	128,000		
April	114,000		
May	96,000		
June	77,000		
July	88,000		
August	87,000		
September	97,000		
Total			<u>1,400,000</u>

Total (over)/under recovered gas cost adjustment
to be effective October 1, 2014 through September 30, 2015 \$0.380

**MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
TO BE EFFECTIVE OCTOBER 1, 2014 THROUGH SEPTEMBER 30, 2015**

(Over)/under recovered gas costs @ July 31, 2014 \$185,080

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	9,000	\$0.181	1,629
September	14,000	0.181	2,534
	23,000		4,163

Additional recovery required \$180,917

Projected sales volumes (dk)

October 2014	35,000	
November	60,000	
December	82,000	
January 2015	88,000	
February	73,000	
March	63,000	
April	36,000	
May	17,000	
June	9,000	
July	9,000	
August	9,000	
September	14,000	
Total		<u>495,000</u>

Total (over)/under recovered gas cost adjustment
to be effective October 1, 2014 through September 30, 2015 \$0.365

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 & 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>\$268,918</u></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
February	(243,381)	(98,337) 5/	30	(341,688)	2,668,333	0.024	64,040	(405,728)	759,123
March	2,821,004	0	20	2,821,024	2,727,677	0.024	65,465	2,755,559	3,514,682
April	(316,839)	0	55	(316,784)	1,876,237	0.024	45,030	(361,814)	3,152,868
May	(777,340)	0	49	(777,291)	1,120,204	0.024	26,885	(804,176)	2,348,692
June	319,741	0	48	319,789	551,428	0.024	13,233	306,556	2,655,248
July	516,353	0	41	516,394	341,095	0.024	8,187	508,207	3,163,455
	<u>\$2,852,350</u>	<u>\$335,180</u>	<u>\$340</u>	<u>\$3,187,870</u>	<u>17,012,577</u>		<u>\$293,332</u>	<u>\$2,894,537</u>	<u><u>\$3,163,455</u></u>
Balance @ July 31, 2014									

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

2/ Adjustment resulting from an incorrect billing system configuration for a large rate 70 customer from 2010-2013.

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

4/ Correction of "farm tap" report volumes incorrectly adjusted for pressure and a failed WBIP border station meter from June 2009 through October 2012.

5/ Correction of an error in the allocation of December 2013 costs. Total costs were correct; however, the allocation overstated North Dakota firm's share of the cost.

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 & 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>\$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	67,198	0	7	67,205	203,609	0.116	23,619	43,586	227,621
January 2014	86,756	0	5	86,761	165,685	0.116	19,219	67,542	295,163
February	8,193	4,502 4/	8	12,703	157,100	0.116	18,224	(5,521)	289,642
March	239,148	0	8	239,156	149,744	0.116	17,370	221,786	511,428
April	56,003	0	8	56,011	119,450	0.116	13,856	42,155	553,583
May	(48,683)	0	9	(48,674)	89,162	0.116	10,344	(59,018)	494,565
June	23,527	0	10	23,537	50,737	0.116	5,885	17,652	512,217
July	46,155	0	8	46,163	43,297	0.116	5,022	41,141	553,358
	<u>\$495,684</u>	<u>\$10,607</u>	<u>\$79</u>	<u>\$506,370</u>	<u>1,227,253</u>		<u>\$115,884</u>	<u>\$390,486</u>	<u>\$553,358</u>
Balance @ July 31, 2014									

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/ Correction of "farm tap" report volumes incorrectly adjusted for pressure and a failed WBIP border station meter from June 2009 through October 2012.

4/ Correction of an error in the allocation of December 2013 costs. Total costs were correct; however, the allocation understated North Dakota interruptible's share of the cost.

**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>\$86,961</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
February	(50,998)	2,212 4/	3	(48,783)	86,357	0.181	15,631	(64,414)	64,352
March	133,077	0	2	133,079	73,450	0.181	13,295	119,784	184,136
April	30,408	0	3	30,411	60,313	0.181	10,917	19,494	203,630
May	(30,439)	0	3	(30,436)	38,279	0.181	6,929	(37,365)	166,265
June	14,106	0	3	14,109	17,955	0.181	3,249	10,860	177,125
July	9,141	0	3	9,144	6,571	0.181	1,189	7,955	185,080
	<u>\$170,637</u>	<u>\$3,903</u>	<u>\$31</u>	<u>\$174,571</u>	<u>469,450</u>		<u>\$76,452</u>	<u>\$98,119</u>	<u>\$185,080</u>
Balance @ July 31, 2014									

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

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

3/ Correction of "farm tap" report volumes incorrectly adjusted for pressure and a failed WBIP border station meter from June 2009 through October 2012.

4/ Correction of an error in the allocation of December 2013 costs. Total costs were correct; however, the allocation understated North Dakota air force's share of the cost.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

	Residential and Firm General				Seasonal	Total
	1/	2/	3/	Total		
<u>August 2013</u>						
Cost of Gas - Actual	\$4.12221	\$4.71427	\$4.12221		\$3.81312	
Cost of Gas - Recovered	4.75500	5.26700	5.26700		4.35500	
(Over) Under recovery per dk	(\$0.63279)	(\$0.55273)	(\$1.14479)		(\$0.54188)	
dk billed	94,158	172,226	12,716	279,100	4,061	283,161
(Over) Under recovery	(\$59,582)	(\$95,196)	(\$14,557)	(\$169,335)	(\$2,200)	(\$171,535)
<u>September 2013</u>						
Cost of Gas - Actual	\$5.25182	\$4.12221	\$5.25182		\$3.84472	
Cost of Gas - Recovered	4.62000	4.75500	4.75500		3.85300	
(Over) Under recovery per dk	\$0.63182	(\$0.63279)	\$0.49682		(\$0.00828)	
dk billed	78,870	132,286	46,469	257,625	1,509	259,134
(Over) Under recovery	\$49,832	(\$83,709)	\$23,087	(\$10,790)	(\$12)	(\$10,802)
<u>October 2013</u>						
Cost of Gas - Actual	\$4.55300	\$5.25182	\$4.55300		\$3.80370	
Cost of Gas - Recovered	4.64100	4.62000	4.62000		3.72200	
(Over) Under recovery per dk	(\$0.08800)	\$0.63182	(\$0.06700)		\$0.08170	
dk billed	212,721	186,363	110,003	509,087	540	509,627
(Over) Under recovery	(\$18,719)	\$117,747	(\$7,370)	\$91,658	\$44	\$91,702
<u>November 2013</u>						
Cost of Gas - Actual	\$4.69411	\$4.55300	\$4.69411		\$4.87645	
Cost of Gas - Recovered	4.64100	4.64100	4.64100		4.72600	
(Over) Under recovery per dk	\$0.05311	(\$0.08800)	\$0.05311		\$0.15045	
dk billed	0 4/	742,976	412,481	1,155,457	518	1,155,975
(Over) Under recovery	\$0	(\$65,382)	\$21,907	(\$43,475)	\$78	(\$43,397)
<u>December 2013</u>						
Cost of Gas - Actual	\$5.26048	\$4.69411	\$5.26048		\$5.53894	
Cost of Gas - Recovered	4.83000	4.64100	4.64100		4.72600	
(Over) Under recovery per dk	\$0.43048	\$0.05311	\$0.61948		\$0.81294	
dk billed	732,337	1,435,847	90,282	2,258,466	810	2,259,276
(Over) Under recovery	\$315,256	\$76,258	\$55,926	\$447,440	\$658	\$448,098
<u>January 2014</u>						
Cost of Gas - Actual	\$4.12480	\$5.26048	\$4.12480		\$4.31164	
Cost of Gas - Recovered	4.83000	4.83000	4.83000		4.91700	
(Over) Under recovery per dk	(\$0.70520)	\$0.43048	(\$0.70520)		(\$0.60536)	
dk billed	0 4/	2,217,086	1,042,328	3,259,414	1,016	3,260,430
(Over) Under recovery	\$0	\$954,411	(\$735,050)	\$219,361	(\$615)	\$218,746

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
FIRM

Exhibit D
Page 8 of 12

	Residential and Firm General				Seasonal	Total
	1/	2/	3/	Total		
<u>February 2014</u>						
Cost of Gas - Actual	\$6.88561	\$4.12480	\$6.88561		\$7.29771	
Cost of Gas - Recovered	5.50300	4.83000	4.83000		4.91700	
(Over) Under recovery per dk	<u>\$1.38261</u>	<u>(\$0.70520)</u>	<u>\$2.05561</u>		<u>\$2.38071</u>	
dk billed	810,650	1,877,392	(20,496)	2,667,546	787	2,668,333
(Over) Under recovery	<u>\$1,120,813</u>	<u>(\$1,323,937)</u>	<u>(\$42,131)</u>	<u>(\$245,255)</u>	<u>\$1,874</u>	<u>(\$243,381)</u>
<u>March 2014</u>						
Cost of Gas - Actual	\$6.26209	\$6.88561	\$6.26209		\$6.62120	
Cost of Gas - Recovered	6.09700	5.50300	5.50300		5.59500	
(Over) Under recovery per dk	<u>\$0.16509</u>	<u>\$1.38261</u>	<u>\$0.75909</u>		<u>\$1.02620</u>	
dk billed	841,920	2,005,225	(120,422)	2,726,723	954	2,727,677
(Over) Under recovery	<u>\$138,993</u>	<u>\$2,772,444</u>	<u>(\$91,411)</u>	<u>\$2,820,026</u>	<u>\$978</u>	<u>\$2,821,004</u>
<u>April 2014</u>						
Cost of Gas - Actual	\$5.67001	\$6.26209	\$5.67001		\$6.02738	
Cost of Gas - Recovered	6.74900	6.09700	6.09700		6.18800	
(Over) Under recovery per dk	<u>(\$1.07899)</u>	<u>\$0.16509</u>	<u>(\$0.42699)</u>		<u>(\$0.16062)</u>	
dk billed	535,007	1,406,796	(66,260)	1,875,543	694	1,876,237
(Over) Under recovery	<u>(\$577,267)</u>	<u>\$232,248</u>	<u>\$28,292</u>	<u>(\$316,727)</u>	<u>(\$112)</u>	<u>(\$316,839)</u>
<u>May 2014</u>						
Cost of Gas - Actual	\$6.82089	\$5.67001	\$6.82089		\$6.24055	
Cost of Gas - Recovered	6.41400	6.74900	6.74900		6.83800	
(Over) Under recovery per dk	<u>\$0.40689</u>	<u>(\$1.07899)</u>	<u>\$0.07189</u>		<u>(\$0.59745)</u>	
dk billed	312,888	836,141	(29,409)	1,119,620	584	1,120,204
(Over) Under recovery	<u>\$127,311</u>	<u>(\$902,188)</u>	<u>(\$2,114)</u>	<u>(\$776,991)</u>	<u>(\$349)</u>	<u>(\$777,340)</u>
<u>June 2014</u>						
Cost of Gas - Actual	\$7.22812	\$6.82089	\$7.22812		\$6.63561	
Cost of Gas - Recovered	6.20200	6.41400	6.41400		6.55400	
(Over) Under recovery per dk	<u>\$1.02612</u>	<u>\$0.40689</u>	<u>\$0.81412</u>		<u>\$0.08161</u>	
dk billed	123,608	378,103	47,782	549,493	1,935	551,428
(Over) Under recovery	<u>\$126,837</u>	<u>\$153,846</u>	<u>\$38,900</u>	<u>\$319,583</u>	<u>\$158</u>	<u>\$319,741</u>
<u>July 2014</u>						
Cost of Gas - Actual	\$8.11072	\$7.22812	\$8.11072		\$5.79996	
Cost of Gas - Recovered	5.93500	6.20200	6.20200		5.05900	
(Over) Under recovery per dk	<u>\$2.17572</u>	<u>\$1.02612</u>	<u>\$1.90872</u>		<u>\$0.74096</u>	
dk billed	110,685	179,872	45,829	336,386	4,709	341,095
(Over) Under recovery	<u>\$240,820</u>	<u>\$184,570</u>	<u>\$87,474</u>	<u>\$512,864</u>	<u>\$3,489</u>	<u>\$516,353</u>

1/ Consumed in current month.

2/ Consumed in prior month.

3/ True-up of prior month volumes.

4/ No change in the PGA. Current month volumes are included in the true-up.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>August 2013</u>				
Cost of Gas - Actual	\$3.63715	\$4.11776	\$3.63715	
Cost of Gas - Recovered	3.78400	4.27800	4.27800	
(Over) Under recovery per dk	(\$0.14685)	(\$0.16024)	(\$0.64085)	
dk billed	4,475	20,370	7,503	32,348
(Over) Under recovery	(\$657)	(\$3,264)	(\$4,808)	(\$8,729)
<u>September 2013</u>				
Cost of Gas - Actual	\$3.83739	\$3.63715	\$3.83739	
Cost of Gas - Recovered	3.65300	3.78400	3.78400	
(Over) Under recovery per dk	\$0.18439	(\$0.14685)	\$0.05339	
dk billed	3,438	24,222	6,173	33,833
(Over) Under recovery	\$634	(\$3,557)	\$330	(\$2,593)
<u>October 2013</u>				
Cost of Gas - Actual	\$3.80041	\$3.83739	\$3.80041	
Cost of Gas - Recovered	3.67700	3.65300	3.65300	
(Over) Under recovery per dk	\$0.12341	\$0.18439	\$0.14741	
dk billed	7,231	27,452	20,991	55,674
(Over) Under recovery	\$892	\$5,063	\$3,094	\$9,049
<u>November 2013</u>				
Cost of Gas - Actual	\$3.89046	\$3.80041	\$3.89046	
Cost of Gas - Recovered	3.67700	3.67700	3.67700	
(Over) Under recovery per dk	\$0.21346	\$0.12341	\$0.21346	
dk billed	0 4/	81,800	44,814	126,614
(Over) Under recovery	\$0	\$10,094	\$9,566	\$19,660
<u>December 2013</u>				
Cost of Gas - Actual	\$4.54203	\$3.89046	\$4.54203	
Cost of Gas - Recovered	3.84700	3.67700	3.67700	
(Over) Under recovery per dk	\$0.69503	\$0.21346	\$0.86503	
dk billed	6,884	165,385	31,340	203,609
(Over) Under recovery	\$4,785	\$35,303	\$27,110	\$67,198
<u>January 2014</u>				
Cost of Gas - Actual	\$3.29789	\$4.54203	\$3.29789	
Cost of Gas - Recovered	3.84700	3.84700	3.84700	
(Over) Under recovery per dk	(\$0.54911)	\$0.69503	(\$0.54911)	
dk billed	0 4/	142,858	22,827	165,685
(Over) Under recovery	\$0	\$99,291	(\$12,535)	\$86,756

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE

	<u>1/</u>	<u>2/</u>	<u>3/</u>	<u>Total</u>
<u>February 2014</u>				
Cost of Gas - Actual	\$6.27801	\$3.29789	\$6.27801	
Cost of Gas - Recovered	4.47000	3.84700	3.84700	
(Over) Under recovery per dk	\$1.80801	(\$0.54911)	\$2.43101	
dk billed	7,314	123,875	25,911	157,100
(Over) Under recovery	<u>\$13,224</u>	<u>(\$68,021)</u>	<u>\$62,990</u>	\$8,193
<u>March 2014</u>				
Cost of Gas - Actual	\$5.56391	\$6.27801	\$5.56391	
Cost of Gas - Recovered	5.07200	4.47000	4.47000	
(Over) Under recovery per dk	\$0.49191	\$1.80801	\$1.09391	
dk billed	12,193	115,786	21,765	149,744
(Over) Under recovery	<u>\$5,998</u>	<u>\$209,341</u>	<u>\$23,809</u>	\$239,148
<u>April 2014</u>				
Cost of Gas - Actual	\$5.02341	\$5.56391	\$5.02341	
Cost of Gas - Recovered	5.77400	5.07200	5.07200	
(Over) Under recovery per dk	(\$0.75059)	\$0.49191	(\$0.04859)	
dk billed	7,193	123,693	(11,436)	119,450
(Over) Under recovery	<u>(\$5,399)</u>	<u>\$60,846</u>	<u>\$556</u>	\$56,003
<u>May 2014</u>				
Cost of Gas - Actual	\$5.44769	\$5.02341	\$5.44769	
Cost of Gas - Recovered	5.02400	5.77400	5.77400	
(Over) Under recovery per dk	\$0.42369	(\$0.75059)	(\$0.32631)	
dk billed	8,698	61,546	18,918	89,162
(Over) Under recovery	<u>\$3,685</u>	<u>(\$46,195)</u>	<u>(\$6,173)</u>	(\$48,683)
<u>June 2014</u>				
Cost of Gas - Actual	\$5.71569	\$5.44769	\$5.71569	
Cost of Gas - Recovered	5.07800	5.02400	5.02400	
(Over) Under recovery per dk	\$0.63769	\$0.42369	\$0.69169	
dk billed	5,468	42,059	3,210	50,737
(Over) Under recovery	<u>\$3,487</u>	<u>\$17,820</u>	<u>\$2,220</u>	\$23,527
<u>July 2014</u>				
Cost of Gas - Actual	\$6.42507	\$5.71569	\$6.42507	
Cost of Gas - Recovered	4.75300	5.07800	5.07800	
(Over) Under recovery per dk	\$1.67207	\$0.63769	\$1.34707	
dk billed	7,791	20,724	14,782	43,297
(Over) Under recovery	<u>\$13,028</u>	<u>\$13,215</u>	<u>\$19,912</u>	\$46,155

1/ Consumed in current month.

2/ Consumed in prior month.

3/ True-up of prior month volumes.

4/ No change in the PGA. Current month volumes are included in the true-up.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
AIR FORCE

	<u>1/</u>	<u>2/</u>	<u>Total</u>
<u>August 2013</u>			
Cost of Gas - Actual	\$3.69463	\$2.57024	
Cost of Gas - Recovered	4.25900	4.25900	
(Over) Under recovery per dk	(\$0.56437)	(\$1.68876)	
dk billed	4,885	(846)	\$4,039
(Over) Under recovery	(\$2,756)	\$1,429	(\$1,327)
<u>September 2013</u>			
Cost of Gas - Actual	\$2.57024	\$3.82024	
Cost of Gas - Recovered	3.76700	3.76700	
(Over) Under recovery per dk	(\$1.19676)	\$0.05324	
dk billed	4,704	(63)	4,641
(Over) Under recovery	(\$5,630)	(\$3)	(\$5,633)
<u>October 2013</u>			
Cost of Gas - Actual	\$3.82024	\$3.78262	
Cost of Gas - Recovered	3.63700	3.63700	
(Over) Under recovery per dk	\$0.18324	\$0.14562	
dk billed	6,555	30	6,585
(Over) Under recovery	\$1,201	\$4	\$1,205
<u>November 2013</u>			
Cost of Gas - Actual	\$3.78262	\$3.75606	
Cost of Gas - Recovered	3.66000	3.66000	
(Over) Under recovery per dk	\$0.12262	\$0.09606	
dk billed	30,354	(515)	29,839
(Over) Under recovery	\$3,721	(\$49)	\$3,672
<u>December 2013</u>			
Cost of Gas - Actual	\$3.75606	\$4.51980	
Cost of Gas - Recovered	3.66000	3.66000	
(Over) Under recovery per dk	\$0.09606	\$0.85980	
dk billed	53,716	(966)	52,750
(Over) Under recovery	\$5,159	(\$833)	\$4,326
<u>January 2014</u>			
Cost of Gas - Actual	\$4.51980	\$3.28219	
Cost of Gas - Recovered	3.83000	3.83000	
(Over) Under recovery per dk	\$0.68980	(\$0.54781)	
dk billed	90,233	(1,562)	88,671
(Over) Under recovery	\$62,243	\$856	\$63,099

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
AIR FORCE

Exhibit D
Page 12 of 12

	<u>1/</u>	<u>2/</u>	<u>Total</u>
<u>February 2014</u>			
Cost of Gas - Actual	\$3.28219	\$6.24893	
Cost of Gas - Recovered	3.83000	3.83000	
(Over) Under recovery per dk	(\$0.54781)	\$2.41893	
dk billed	87,601	(1,244)	86,357
(Over) Under recovery	<u>(\$47,989)</u>	<u>(\$3,009)</u>	(\$50,998)
<u>March 2014</u>			
Cost of Gas - Actual	\$6.24893	\$5.53810	
Cost of Gas - Recovered	4.45000	4.45000	
(Over) Under recovery per dk	\$1.79893	\$1.08810	
dk billed	74,779	(1,329)	73,450
(Over) Under recovery	<u>\$134,523</u>	<u>(\$1,446)</u>	\$133,077
<u>April 2014</u>			
Cost of Gas - Actual	\$5.53810	\$4.97270	
Cost of Gas - Recovered	5.04900	5.04900	
(Over) Under recovery per dk	\$0.48910	(\$0.07630)	
dk billed	61,921	(1,608)	60,313
(Over) Under recovery	<u>\$30,285</u>	<u>\$123</u>	\$30,408
<u>May 2014</u>			
Cost of Gas - Actual	\$4.97270	\$5.81284	
Cost of Gas - Recovered	5.74800	5.74800	
(Over) Under recovery per dk	(\$0.77530)	\$0.06484	
dk billed	39,185	(906)	38,279
(Over) Under recovery	<u>(\$30,380)</u>	<u>(\$59)</u>	(\$30,439)
<u>June 2014</u>			
Cost of Gas - Actual	\$5.81284	\$6.55647	
Cost of Gas - Recovered	5.00100	5.00100	
(Over) Under recovery per dk	\$0.81184	\$1.55547	
dk billed	18,587	(632)	17,955
(Over) Under recovery	<u>\$15,090</u>	<u>(\$984)</u>	\$14,106
<u>July 2014</u>			
Cost of Gas - Actual	\$6.55647	\$8.64612	
Cost of Gas - Recovered	5.05500	5.05500	
(Over) Under recovery per dk	\$1.50147	\$3.59112	
dk billed	6,918	(347)	6,571
(Over) Under recovery	<u>\$10,387</u>	<u>(\$1,246)</u>	\$9,141

1/ Consumed in prior month.
2/ True-up of prior month volumes.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
INTERRUPTIBLE MARKET BASED PRICING DIFFERENTIAL
EFFECTIVE OCTOBER 1, 2014 THROUGH SEPTEMBER 30, 2015**

Balance of Accumulated Revenues 1/	\$249,525
Projected Residential & General Service Sales Volumes	<u>15,038,000</u>
Market Based Pricing Differential Provision	<u><u>\$0.017</u></u>

1/ Represents 50% of margin above the approved margin from all interruptible sales, calculated on Exhibit E, page 2.

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
INTERRUPTIBLE MARKET BASED PRICING DIFFERENTIAL
EFFECTIVE OCTOBER 1, 2014 THROUGH SEPTEMBER 30, 2015**

Rates 71 & 85 Credit - Balance @ 7/31/13		\$191,948	
Additional Credits 1/		268,081	
Reduction to Credit Balance		<u>(202,248)</u>	
Balance @ 7/31/13		<u><u>\$257,781</u></u>	
Less: Projected recovery from current amortization			
	<u>dk</u>	<u>Rate</u>	
August	259,000	(\$0.012)	(\$3,108)
September	429,000	(0.012)	<u>(5,148)</u>
			(\$8,256)
Balance @ 9/30/13		<u><u>\$249,525</u></u>	
Firm Volumes October 2013 - September 2014		15,038,000	
Market Based Pricing Differential Provision		<u><u>\$0.017</u></u>	

1/ Interruptible gas sales margin sharing amount (50% of additional margin).

**MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA GAS
GRAIN DRYING MARGIN SHARING PROVISION
EFFECTIVE OCTOBER 1, 2014 THROUGH SEPTEMBER 30, 2015**

Rate 71 Grain Drying Credit - Initial Balance 1/	\$0
Additional Credits 2/	<u>\$21,744</u>
Balance @ 7/31/14	\$21,744
Projected Residential & General Service Sales Volumes	15,038,000
Grain Drying Margin Sharing Provision	<u><u>\$0.001</u></u>

1/ Established in Case No. PU-13-803

2/ Represents 90% of margin above the approved margin from all Grain Drying sales.