

February 6, 2015

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-15-008

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

Attachment A is the Rate Summary Sheet (134th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered March 1, 2015.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.385 per dk since the last filing due to a decrease in the overall commodity price of gas. Attachment B explains the reasons for the decrease in the market price of gas.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and the market based pricing differential provision that will apply during the month of March 2015.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.385 per dk for residential and firm general customers, a decrease of \$0.351 per dk for small and large interruptible customers and a decrease of \$0.350 per dk for Air Force customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of March 2015. The average cost of gas for firm customers, adjusted for losses, is \$4.652.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid

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

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane from that established in the December 2014 PGA filing.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of March 2015. The average cost of propane for all customers, adjusted for losses, is \$10.210 per dk.

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

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$793,500 for natural gas customers during the month of March 2015. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 104,863 natural gas customers and 344 propane customers in North Dakota as of January 31, 2015.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota submitted a check on December 8, 2014 to the North Dakota Public Service Commission for \$650 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.

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,

A handwritten signature in red ink that reads "Tamie A. Aberle". The signature is written in a cursive style.

Tamie A. Aberle
Director of Regulatory Affairs

Attachment

Attachment A

**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
 134th Revised Sheet No. 3
 Canceling 133rd 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	\$4.843	\$5.169
Air Force Rate 64	7				
Minot Air Force Base		\$2,000.00 per month			
PAR Site		\$175.00 per month			
Firm Service			\$0.329	\$4.843	\$5.172
Interruptible Service - PAR			\$0.260	\$3.899	\$4.159
Interruptible Service - MAFB			\$0.260	\$3.868	\$4.128
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$4.843	\$5.573
Small Interruptible Gas Rate 71	14	\$175.00 per month	(Maximum) \$0.929	\$3.899	(Maximum) \$4.828
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$4.945	\$5.675
Transportation Service	24				
Small Interruptible Rate 81		\$175.00 per month			
Maximum			\$0.485		
Minimum			\$0.102		
Fuel Charge				\$0.016	
Large Interruptible Rate 82		\$1,000.00 per month			
Maximum			\$0.297		
Minimum			\$0.061		
Fuel Charge				\$0.016	
Large Interruptible Gas Rate 85	27	\$1,000.00 per month	(Maximum) \$0.718	\$3.899	(Maximum) \$4.617
Residential Propane Rate 90	32	\$0.4935 per day	\$0.326	\$11.386	\$11.712
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.67 per day			
Meters rated > 500 cubic feet		\$1.90 per day	\$0.730	\$11.386	\$12.116

Date Filed: February 6, 2015

Effective Date: March 1, 2015

Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Case No.: PU-15-008

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

March 2015

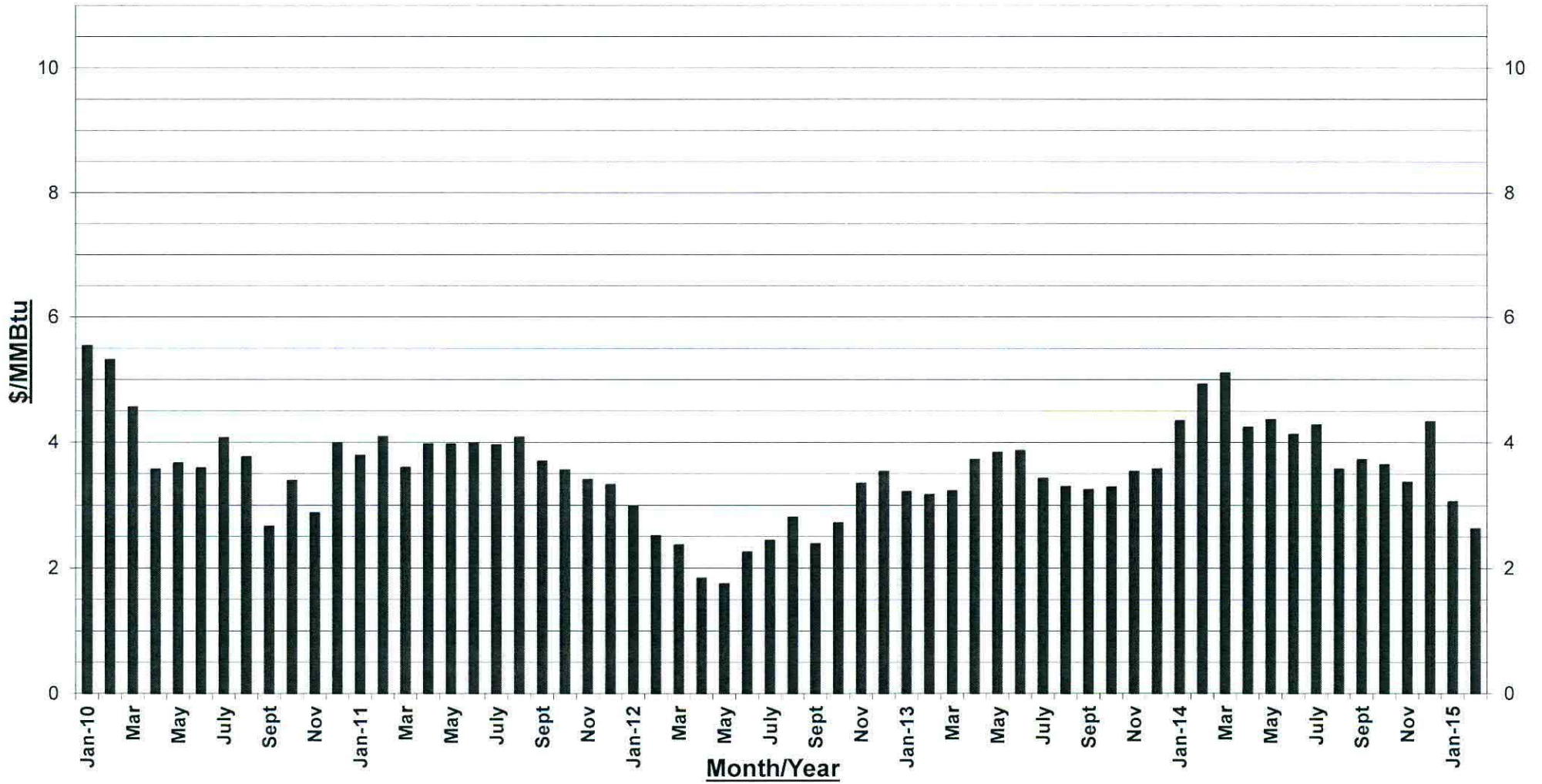
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including “Inside FERC Gas Market” report and “Gas Daily” by McGraw-Hill Companies, of prices paid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

Domestic production levels reaching record highs during the month of January and the national storage level continuing to rebound from the large deficits after the last heating season, where contributing factors to the decrease in first of the month index price of natural gas. The EIA reported the national storage level as of January 30, 2015, was 1.2 percent below the five-year average and 23.9 percent above 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 January Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 19. The February Outlook will be published February 10, 2015.

CIG Rocky Mountains Index Monthly Gas Prices 2010-2015YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2013-\$3.45; 2014-\$4.17; 2015YTD-\$2.85



Independent Statistics & Analysis

U.S. Energy Information
Administration

January 2015

Short-Term Energy Outlook (STEO)

Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2016.
- December was the sixth consecutive month in which monthly average Brent prices decreased, falling \$17/barrel (bbl) from November to a monthly average of \$62/bbl, the lowest since May 2009. The December price decline reflects continued growth in U.S. tight oil production, strong global supply, and weakening outlooks for the global economy and oil demand growth.
- EIA forecasts that Brent crude oil prices will average \$58/bbl in 2015 and \$75/bbl in 2016, with annual average West Texas Intermediate (WTI) prices expected to be \$3/bbl to \$4/bbl below Brent. The current values of futures and options contracts suggest very high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for April 2015 delivery, traded during the five-day period ending January 8, averaged \$51/bbl, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2015 at \$34/bbl and \$76/bbl, respectively. The 95% confidence interval for market expectations widens considerably over time, with lower and upper limits of \$28/bbl and \$112/bbl for prices in December 2015.
- Total U.S. crude oil production averaged an estimated 9.2 million barrels per day (bbl/d) in December. Forecast total crude oil production averages 9.3 million bbl/d in 2015. Under EIA's price forecast, projected crude oil production averages 9.5 million bbl/d in 2016, which would be the second-highest annual average level of production in U.S. history; the highest was 9.6 million bbl/d in 1970.
- Driven largely by falling crude oil prices, U.S. weekly regular gasoline retail prices averaged \$2.14/gallon (gal) on January 12, the lowest since May 4, 2009. U.S. regular gasoline retail prices are projected to average \$2.16/gal in the first quarter of 2015. EIA expects U.S. regular gasoline retail prices, which averaged \$3.36/gal in 2014, to average \$2.33/gal in 2015. The average household is now expected to spend about \$750 less for gasoline in 2015 compared with last year because of lower prices. The projected regular gasoline retail price increases to an average of \$2.72/gal in 2016.

- Natural gas working inventories on January 2 totaled 3.09 trillion cubic feet (Tcf), 0.25 Tcf (9%) above the level at the same time a year ago and 0.07 Tcf (2%) below the previous five-year average (2010-14). EIA expects the Henry Hub natural gas spot price to average \$3.52/million British thermal units (MMBtu) this winter compared with \$4.51/MMBtu last winter, reflecting both lower-than-expected space heating demand and higher natural gas production this winter. Turning to annual measures, EIA expects the Henry Hub natural gas spot price to average \$3.44/MMBtu in 2015 and \$3.86/MMBtu in 2016, compared with \$4.39/MMBtu in 2014.

Global Petroleum and Other Liquids

EIA estimates that global oil inventories increased by almost 0.8 million bbl/d in 2014, the largest build since 2008, when falling demand for oil caused prices to drop sharply during the second half of the year. However, unlike in 2008, the current market imbalance has been predominantly supply-driven, as production from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) grew by a record high of 2.0 million bbl/d in 2014. Global oil inventories are expected to continue to grow by 0.9 million bbl/d during the first half of 2015, but to taper off by the end of the year as non-OPEC supply growth, particularly from the United States, weakens because of lower oil prices.

EIA estimates that commercial oil inventories held by countries in the Organization for Economic Cooperation and Development (OECD) grew by a record 158 million barrels in 2014, after ending 2013 at the lowest end-of-year level since 2003. EIA expects OECD commercial inventories to grow by 68 million barrels in 2015 and to stay relatively flat in 2016. Throughout 2015 and 2016, OECD commercial inventories are expected to be above the previous five-year (2010-14) range.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 0.9 million bbl/d in 2014, averaging 91.4 million bbl/d for the year. EIA expects global consumption to grow by 1.0 million bbl/d in both 2015 and 2016. Projected global oil-consumption-weighted real gross domestic product (GDP), which increased by an estimated 2.7% in 2014, is projected to grow by 2.9% in 2015 and by 3.2% in 2016.

Non-OECD consumption, which grew by 1.2 million bbl/d in 2014, is projected to grow by 0.9 million bbl/d in 2015 and 1.1 million bbl/d in 2016. The biggest reduction in forecast non-OECD consumption growth in 2015 comes from a 0.2-million-bbl/d decline in Russia's consumption because of its economic downturn. Russia's consumption is expected to decline by a similar amount in 2016. China is the leading contributor to projected global consumption growth, with consumption expected to increase by an annual average of 0.3 million bbl/d over the next two years.

OECD consumption, which fell by 0.3 million bbl/d in 2014, is expected to grow by 0.1 million bbl/d in 2015 and remain relatively flat in 2016. Japan and Europe accounted for almost the

entire decline in 2014 and are expected to continue to decline over the next two years, albeit at a lesser rate than in 2014. The United States is the leading contributor to projected OECD consumption growth, with U.S. consumption increasing by 0.3 million bbl/d in 2015 and 0.1 million bbl/d in 2016.

Non-OPEC Petroleum and Other Liquids Supply. EIA estimates that non-OPEC production grew by 2.0 million bbl/d in 2014, averaging 56.2 million bbl/d for the year. Non-OPEC supply growth is expected to slow over the next two years mostly because of lower projected oil prices. Non-OPEC production grows by 0.7 million bbl/d in 2015 and 0.5 million bbl/d in 2016, with the United States as the leading contributor. The slower growth in total non-OPEC supply is largely attributable to slower production growth in the United States, Canada, and Central and South America. Additionally, production in Europe and Eurasia is projected to decline.

Unplanned supply disruptions among non-OPEC producers averaged slightly less than 0.6 million bbl/d in December 2014, unchanged from the previous month. EIA estimates that unplanned non-OPEC supply disruptions averaged slightly more than 0.6 million bbl/d in 2014, 0.2 million bbl/d less than the previous year. South Sudan, Syria, and Yemen accounted for more than 80% of total non-OPEC supply disruptions in 2014.

OPEC Petroleum and Other Liquids Supply. EIA estimates that OPEC crude oil production averaged 29.9 million bbl/d in 2014, a slight decline from the previous year. Crude oil production declines in Libya, Angola, Algeria, and Kuwait more than offset production growth in Iraq and Iran. EIA expects OPEC crude oil production to remain flat in 2015 and fall by 0.3 million bbl/d in 2016. Iraq is OPEC's largest contributor of growth over the next two years, but its growth is expected to be offset by production declines from other Persian Gulf producers. However, the threat of the Islamic State of Iraq and the Levant (ISIL) on northern Iraqi production and exports still looms, and as a result, Iraq is a major wild card in the world oil production forecast.

EIA estimates that OPEC produced 6.1 million bbl/d of noncrude oil liquids in 2014, close to production in 2013. OPEC noncrude liquids production is expected to increase by almost 0.1 million bbl/d in 2015 and 0.3 million bbl/d in 2016, led by Iran and Qatar.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.8 million bbl/d in December 2014, an increase of 0.1 million bbl/d compared with the previous month because of new production outages in Libya. Unplanned OPEC crude supply disruptions averaged 2.5 million bbl/d in 2014, 0.6 million bbl/d higher than the previous year. Libya and Iraq accounted for almost all of the growth in OPEC disruptions. The high level of OPEC disruptions contributed to higher crude oil prices during the first half of 2014. However, with continuous growth in non-OPEC production, continued strong production in Saudi Arabia, and relatively flat world demand growth, the current volume of supply disruptions has become less significant. Unplanned supply disruptions could still affect crude oil prices, but the threshold that the market can bear has risen in light of robust global production.

EIA expects OPEC surplus crude oil production capacity, which is concentrated in Saudi Arabia, to increase to 2.3 million bbl/d in 2015 and 2.7 million bbl/d in 2016, after averaging about 2.1 million bbl/d in 2014. Surplus capacity is typically an indication of market conditions, and surplus capacity below 2.5 million bbl/d is an indicator of a relatively tight market. However, the current and forecast levels of global inventory builds make the projected low surplus capacity level in 2015 less significant.

OECD Commercial Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.71 billion barrels at the end of 2014, equivalent to roughly 57 days of consumption, and the highest end-of-year level on record. Projected OECD oil inventories rise to 2.78 billion barrels at the end of 2015 and 2.79 billion barrels at the end of 2016.

Crude Oil Prices. North Sea Brent crude oil spot prices averaged \$62/bbl in December, the lowest monthly average Brent price since May 2009, down \$17/bbl from the November average. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices (EIA, *This Week in Petroleum*, November 13, 2014).

EIA expects global oil inventories to continue to build in 2015, keeping downward pressure on oil prices. The forecast Brent crude oil price averages \$58/bbl in 2015, \$11/bbl lower than projected in last month's STEO. Based on current market balances, EIA expects downward price pressures to be concentrated in the first half of 2015 when global inventory builds are expected to be particularly strong. EIA projects that Brent prices will reach a 2015 monthly average low of \$49/bbl in January and February, and then increase through the remainder of the year to average \$67/bbl during the fourth quarter.

The monthly average WTI crude oil spot price fell from an average of \$76/bbl in November to \$59/bbl in December. Like Brent crude oil prices, WTI prices have decreased considerably, with monthly average prices falling by more than 44% as of December after reaching their 2014 peak of \$106/bbl in June. EIA now expects WTI crude oil prices to average \$55/bbl in 2015, \$8/bbl lower than in last month's STEO, and \$71/bbl in 2016. The discount of WTI to Brent crude oil is forecast to widen slightly from current levels later in the forecast, averaging \$3/bbl in 2015 and \$4/bbl in 2016.

However, the current values of futures and options contracts suggest high uncertainty in the price outlook (*Market Prices and Uncertainty Report*). WTI futures contracts for April 2015 delivery, traded during the five-day period ending January 8, averaged \$51/bbl. Implied volatility averaged 48%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2015 at \$34/bbl and \$76/bbl, respectively. The 95% confidence interval for market expectations widens considerably over time, with lower and upper limits of \$28/bbl and \$112/bbl for prices in December 2015. Last year at this time, WTI for April 2014 delivery averaged \$98/bbl, and implied volatility

averaged 16%. The corresponding lower and upper limits of the 95% confidence interval were \$86/bbl and \$113/bbl.

The recent declines in oil prices and associated increase in oil price volatility continue to contribute to a particularly uncertain forecasting environment, and several factors could cause oil prices to deviate significantly from current projections. Among these factors is the responsiveness of supply to lower prices. Despite OPEC's recent decision to leave its crude oil production target at 30 million bbl/d, key producers could decide to reduce output, tightening market balances. The level of unplanned production outages could also vary from forecast levels for a wide range of producers, including OPEC members Libya, Iraq, Iran, Nigeria, and Venezuela. The degree to which non-OPEC supply growth is affected by lower oil prices will also affect market balances and prices.

Several OPEC and non-OPEC oil producers rely heavily on oil revenues to finance their fiscal budgets. Some producers have already started adjusting their upcoming budgets to reflect the crude oil price decline. If crude oil prices continue to fall or are sustained at a lower level, then oil-dependent producers will have to make tough policy decisions. These decisions could potentially lead to austerity programs and fuel subsidy cuts that could spark social unrest, leaving some countries vulnerable to supply disruptions if protesters target oil infrastructure. Potential new supply disruptions are a real possibility in a lower-than-expected price climate and present a major uncertainty in the world oil supply forecast.

U.S. Petroleum and Other Liquids

U.S. weekly regular gasoline retail prices averaged \$2.14/gal on January 12, a decrease of \$0.64/gal since the beginning of December and the lowest weekly price since May 4, 2009. Regional gasoline retail prices ranged from a low of \$1.91/gal in Petroleum Administration for Defense District (PADD) 3 to a high of \$2.49/gal in PADD 5. U.S. average regular gasoline retail prices are now down more than 40% from their summer peak in late June. Falling Brent crude oil prices have been largely responsible for falling retail gasoline prices. EIA expects retail gasoline prices to average \$2.16/gal during the first quarter of 2015 and \$2.33/gal for the full year.

Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 100,000 bbl/d (0.5%) in 2014. Motor gasoline consumption increased by 100,000 bbl/d (1.1%) because of increases in highway travel. Distillate consumption grew by 170,000 bbl/d (4.6%), as a result of colder-than-average weather in the first quarter as well as increases in industrial production during the year. Jet fuel usage increased by 30,000 bbl/d (2.3%). Hydrocarbon gas liquids (HGL) and residual fuel oil consumption fell by an estimated 100,000 bbl/d (4.0%) and 70,000 bbl/d (22%), respectively, in 2014.

In 2015, total liquid fuels consumption is forecast to grow by 260,000 bbl/d (1.4%). Lower pump prices result in a slight increase in motor gasoline consumption in 2015, but a decline in sales is

expected with higher prices in the following year. HGL consumption is expected to reverse 2014's decline and increase by 110,000 bbl/d (4.7%) in 2015.

Distillate consumption is projected to increase by 60,000 bbl/d (1.5%) in 2015 based on forecast assumptions of continuing economic growth. Some of the growth in distillate fuel consumption comes from Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI), which is an international agreement that generally requires the use of fuels below 1,000 parts per million sulfur by marine vessels in most U.S. waters, unless alternative devices, procedures, or compliance methods are used to achieve equivalent emissions reductions. This increase in marine distillate use because of MARPOL regulations will displace the use of residual fuel oil.

In 2016, EIA projects more moderate growth in liquid fuels consumption of 110,000 bbl/d (0.5%). HGL growth accounts for most of the overall growth, with HGL consumption projected to grow by 100,000 bbl/d (3.9%). EIA projects that distillate fuel consumption increases by 60,000 bbl/d (1.5%) in 2016, while residual fuel oil consumption stabilizes near the 2015 level.

Liquid Fuels Supply. Forecast U.S. crude oil production increases from an average of 8.7 million bbl/d in 2014 to 9.3 million bbl/d in 2015 and 9.5 million b/d in 2016. With WTI crude oil prices expected to average \$49/bbl in the first half of 2015, EIA expects 2015 drilling activity to decline because of unattractive economic returns in some areas of both emerging and mature oil production regions. Many companies have begun redirecting investment away from marginal exploration and research drilling and focusing on core areas of major tight oil plays. Oil prices remain high enough to support some development drilling activity in 2015 in the Bakken, Eagle Ford, Niobrara, and Permian Basin, albeit lower than previously forecast. Companies that have lower drilling and debt costs and have acreage in the sweet spots of these regions will continue to drill highly productive wells in 2015. Nevertheless, EIA expects 2015 production to reach 9.4 million bbl/d in the second quarter, then decline by 190,000 bbl/d in the third quarter. With projected WTI crude oil prices starting to rise in the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for both leasing acreage and drilling services, causing production to resume rising at a relatively low WTI crude oil price. However, this forecast remains particularly sensitive to actual prices available at the wellhead and drilling economics that vary across regions and operators. Projected production for the Federal offshore region and Alaska, which rise and fall respectively, are less sensitive to short-term price movements than Lower 48 onshore production.

HGL production at natural gas liquids plants, which reached a record high of 3.1 million bbl/d in October, is projected to increase to 3.3 million bbl/d by the end of 2015. Ethane and propane are expected to contribute most to the projected growth, with most of the production supplying domestic petrochemical use or exports. EIA expects higher rates of ethane recoveries as a result of planned increases in petrochemical facility feedstock demand, while export terminal expansions will allow higher quantities of domestically produced propane and butanes to reach the international market.

The growth in domestic production has contributed to a significant decline in crude oil and other liquids imports. The share of total U.S. liquid fuels consumption met by net imports fell from 60% in 2005 to an estimated 27% in 2014. EIA expects the net import share to decline to 20% in 2016, which would be the lowest level since 1968.

Petroleum Product Prices. U.S. average regular gasoline retail prices fell from a monthly average of \$3.69/gal in June to \$2.54/gal in December, the lowest monthly average since July 2009. EIA expects that U.S. regular gasoline retail prices will fall to an average of \$2.13/gal in January 2015. The U.S. regular gasoline retail price, which averaged \$3.36/gal in 2014, is projected to average \$2.33/gal in 2015, \$0.26/gal lower than in last month's STEO, and \$2.72/gal in 2016. Diesel fuel retail pump prices, which averaged \$3.83/gal in 2014, are projected to fall to an average of \$2.85/gal in 2015 but rise to \$3.25/gal in 2016.

The April 2015 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged \$1.63/gal for the five trading days ending January 8, 2015. An RBOB futures contract price of \$1.63/gal is consistent with a monthly average regular-grade gasoline retail price less than \$2.35/gal in April 2015. The current values of futures and options contracts suggest there is a 2% probability that the RBOB futures contract price at expiration may exceed \$2.35/gal, consistent with a retail price of \$3.00/gal or higher, and a 17% probability that the RBOB futures price may fall below \$1.35/gal, consistent with a retail price of \$2.00/gal or lower. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas falling above or below the national average price by \$0.30/gal or more.

Lower projected crude oil prices also contribute to a reduction in the forecast residential heating oil price and average household heating oil expenditures this winter compared with last winter. The average household that uses heating oil as its primary space heating fuel is expected to pay an average of \$2.90/gal this winter, \$0.98/gal lower than last winter. The average household is now expected to spend \$1,586 for heating oil this winter, \$767 lower than last winter. Propane prices are expected to be 17% lower in the Northeast and 27% lower in the Midwest, resulting in households spending 24% and 35% less on propane in those regions, respectively.

Natural Gas

Natural gas futures prices have fallen more than \$1/MMBtu since mid-November, and on December 31, the February 2015 futures contract settled at \$2.89/MMBtu, the lowest settlement price for a front-month contract since September 2012. Prices remain at relatively low levels, reflecting abundant supplies. December 2014 was warmer than normal, which along with robust production contributed to lower-than-average storage withdrawals. The deficit of natural gas inventories to the previous five-year average narrowed to 67 Bcf at the end of December, from a 959-Bcf deficit at the end of March 2014.

Natural Gas Consumption. EIA projects that U.S. total natural gas consumption will increase to an average of 73.8 Bcf/d in 2015 and 74.8 Bcf/d in 2016, compared with an estimated 73.6 Bcf/d in 2014. Growth is largely driven by the industrial and electric power sectors, while residential and commercial consumption is projected to decline in 2015, then remain flat in 2016. Natural gas consumption in the power sector is expected to average 23.0 Bcf/d in 2015, a 3.2% increase compared with 2014, and it is expected to grow by 1.8% to 23.4 Bcf/d in 2016. Industrial sector consumption increases by 4.5% and 2.1% in 2015 and 2016, respectively, as new industrial projects come online, particularly in the fertilizer and chemicals sectors.

Natural Gas Production and Trade. EIA expects that growth in marketed natural gas production will continue through 2015 and 2016. This increase is the result of continuing strong growth in the Lower 48 states, which more than offsets the long-term trend of declining production in the Gulf of Mexico. As of October, the most recent month for which EIA data are available, dry natural gas production was 4.6 Bcf/d greater than it was in October 2013. Although natural gas prices have declined, and this month's STEO lowers the Henry Hub spot price forecast, EIA expects that increases in drilling efficiency and growth in oil production (although at a slower rate) will continue to support growing natural gas production in the coming years. Additionally, with most growth coming from the Marcellus Shale, a backlog of drilled but uncompleted wells will continue to support production growth as new pipeline infrastructure comes online in the Northeast.

Growing domestic natural gas production is expected to reduce demand for imports from Canada and spur exports to Mexico. EIA expects exports to Mexico, particularly from the Eagle Ford Shale in South Texas, to increase because of growing demand from Mexico's electric power sector coupled with flat Mexican natural gas production.

Liquefied natural gas (LNG) imports have fallen over the past five years because higher prices in Europe and Asia are more attractive to LNG exporters than the relatively low prices in the United States. EIA projects that gross LNG exports will average 0.8 Bcf/d in 2016.

Natural Gas Inventories. Natural gas working inventories totaled 3,089 Bcf as of January 2, which is 250 Bcf greater than at the same time in 2014 and 67 Bcf lower than the previous five-year (2010-14) average. Following last year's extremely cold winter, inventories fell 1,000 Bcf below the five-year average in mid-April. After a strong injection season, inventories were 237 Bcf below the five-year average on November 7. EIA projects that end-of-March 2015 inventories will total 1,665 Bcf, which is 9 Bcf greater than the five-year (2010-14) average.

Natural Gas Prices. The Henry Hub natural gas spot price averaged \$3.48/MMBtu in December, a decline of \$0.64/MMBtu from November. EIA expects monthly average spot prices to remain less than \$4/MMBtu until the fourth quarter of 2016. The projected Henry Hub natural gas price averages \$3.44/MMBtu in 2015 and \$3.86/MMBtu in 2016.

Natural gas futures prices for April 2015 delivery (for the five-day period ending January 8) averaged \$2.88/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for April 2015 contracts at \$1.90/MMBtu and \$4.36/MMBtu, respectively. At this time last year, the natural gas futures contract for April 2014 averaged \$4.19/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were \$3.21/MMBtu and \$5.46/MMBtu.

Coal

Despite railroad transportation problems and increased rail traffic for other commodities encountered in 2014, year-to-date coal railcar loadings through December 27 were 1% higher than the same period in 2013. Weekly carloads peaked at 120,914 during the week ending December 20, 2014.

Total electric power sector coal stocks increased by just over 12 million short tons (MMst) in October 2014 compared with the previous month, which was the largest stock build since a 12.5-MMst build in October 2011. The increase in coal inventories followed the typical seasonal pattern where coal plants build stocks during the autumn months in preparation for increased coal consumption during the winter. Despite the increase, end-of-October 2014 stocks of 136.3 MMst were 17 MMst (11%) lower than the previous year and 19% lower than the previous four-year average for the month. The large year-over-year decrease in stocks reflects high levels of coal-fired electricity generation during the winter of 2013-14 across a large portion of the country and subsequent decrease in coal deliveries because of rail transportation issues.

Coal Supply. EIA estimates that coal production for 2014 was 994 MMst, 1% (10 MMst) higher than in 2013. EIA expects that annual production will decline in both 2015 and 2016, to 984 MMst and 977 MMst, respectively.

Regional shifts in production are more significant. Appalachian coal production, which averaged 272 MMst in 2014, is projected to decline by 3.6% in 2015 and by nearly 2.9% in 2016 as a result of higher mining costs, weak demand from export markets, and a shift to higher-sulfur, lower-cost Interior region coal. Interior region coal production, which averaged 187 MMst in 2014, is projected to grow by 1.0% in 2015 and 1.3% in 2016. Many power generators have recently installed sulfur dioxide scrubbers in response to environmental regulations, allowing them to switch from Appalachian and Western region coal to Interior region coal.

Western region coal production, which averaged 535 MMst in 2014, is projected to remain largely unchanged in both 2015 and 2016.

Coal Consumption. Electric power sector coal consumption was largely unchanged in 2014. Power sector coal consumption is projected to increase by 0.3% in 2015, despite a 0.8% increase in electricity demand, as comparative natural gas prices decline and retirements of coal power

plants rise in response to the implementation of the Mercury and Air Toxics Standards. The full effect of the coal plant retirements is felt in 2016, as projected electric power sector coal consumption declines by 1.4%.

Coal Trade. Coal exports in 2014 were estimated at 98 MMst in 2014, a 17.1% decline from 118 MMst in 2013. The decline was primarily a result of slowing world coal demand growth, lower international coal prices, and increasing coal output in other coal-exporting countries. EIA expects that there will be no improvement in global market conditions in 2015, and coal exports will fall to 83 MMst, which would be the lowest since 2010. In 2016, EIA projects a slight improvement in international markets (for steam coal), and exports are expected to increase by 1 MMst (1.6%).

Coal Prices. The annual average coal price to the electric power industry fell from a record-high \$2.39/MMBtu in 2011 to an estimated \$2.35/MMBtu in 2014. EIA expects the average delivered coal price to fall to \$2.33/MMBtu in 2015 and to increase back to \$2.35/MMBtu in 2016.

Electricity

The U.S. residential retail price averaged 12.54 cents per kilowatt-hour (kWh) between January and October 2014, which was 3.1% higher than the same period in 2013. Electricity rates rose the fastest in the New England states (10.9%) over this period, while residential prices in the West North Central region rose by 1.6%. Growth in residential electricity prices for the Pacific states in 2014 was relatively flat compared with 2013, as growth in regional rates was offset by credits to the electricity bills of some California residential customers. Retail electricity prices to the commercial and industrial sectors also increased over 2013 levels: by 4.4% and 3.4%, respectively.

Electricity Consumption. Heating degree days (HDD) during the first quarter of 2015 are projected to be about 12% lower than last year. Milder forecast temperatures during the early part of 2015 should translate to lower household usage of electricity, especially for those households that use heat pumps for space heating. This contributes to EIA's forecast of a 0.3% decline in retail sales of electricity to the residential sector for the full year of 2015. Residential electricity sales grow by 0.6% in 2016.

Electricity Generation. EIA forecasts that U.S. electricity generation will grow by 1.1% in 2015 and then by 0.9% in 2016. The mix of energy sources used to produce this generation shifts over the next two years. The share of total generation fueled by coal falls from 39.0% in 2014 to 37.6% in 2016, as declining natural gas prices make that fuel more attractive for power generators and as coal-fueled plants retire in 2015. This decline in coal is balanced by an increase in natural gas generation, which rises from 27.3% of total generation in 2014 to 28.1% in 2016, and by an increase in renewable electricity (other than hydropower), which rises from 6.7% to 7.9%.

Electricity Retail Prices. EIA expects continued growth in average residential electricity prices over the forecast period, albeit at a slower pace than in 2014. The U.S. retail residential price is projected to increase by 1.1% in 2015 and by 1.8% in 2016. Most areas of the country should experience rising prices, with the exception of the West South Central states where residential prices fall by 3.2% this year. Projected price increases in 2015 are again highest in the New England states (3.8%).

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA projects that total renewables used for electricity and heat generation will grow by 3.3% in 2015. Conventional hydropower generation increases by 2.1%, while nonhydropower renewables generation increases by 3.9%. In 2016, total renewables consumption for electric power and heat generation increases by 4.8% as a result of a 1.1% increase in hydropower and a 6.6% increase in nonhydropower renewables.

In 2013, the electricity generation shares were 6.6% and 6.2% from hydropower and nonhydropower renewables, respectively. In 2014, 6.4% of generation came from hydropower and 6.7% from nonhydropower renewables. This trend is expected to continue, with the electricity generation share from nonhydropower renewables rising to 7.9% by 2016, and the hydropower share remaining at 6.4%. Wind is the largest source of nonhydropower renewable generation, and it is projected to contribute 5.3% of total electricity generation in 2016.

EIA expects continued growth in utility-scale solar power generation, which is projected to average almost 80 gigawatthours per day in 2016. Despite the growth, solar power remains just 0.7% of total U.S. utility-scale generation in 2016. Although solar growth has historically been concentrated in customer-sited distributed generation installations, EIA expects that utility-scale solar capacity will increase more than 60% between the end of 2014 and the end of 2016, with about half of this new capacity being built in California. Wind capacity, which grew by 10% between 2012 and 2014, is forecast to increase by about 23% between 2014 and 2016. Because wind is starting from a much larger base than solar, even though the growth rate is lower, the absolute amount of the increase in capacity is more than twice that of solar: 15 gigawatts of wind versus 6 gigawatts of utility-scale solar.

Liquid Biofuels. Ethanol production in December 2014 reached an estimated monthly average record of 979,000 bbl/d, exceeding the previous record of 968,000 bbl/d set the previous month. Ethanol production is estimated to have averaged 935,000 bbl/d in 2014, and EIA expects that ethanol production will average 936,000 bbl/d in 2015 and 937,000 bbl/d in 2016. Biodiesel production averaged an estimated 81,000 bbl/d in 2014 and is forecast to average 84,000 bbl/d in both 2015 and 2016.

Energy-Related Carbon Dioxide Emissions. EIA estimates that emissions grew 0.9% in 2014. Emissions are forecast to increase by 0.9% in 2015 and 0.3% in 2016. These forecasts are sensitive to both weather and economic assumptions.

U.S. Economic Assumptions

Recent Economic Indicators. The Bureau of Economic Analysis (BEA) reported that real gross domestic product (GDP) grew at an annual rate of 5.0% in the third quarter of 2014. This rate was an upward revision from its earlier estimate of 3.9% growth because personal consumption expenditures and nonresidential fixed investment increased more than previously estimated.

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

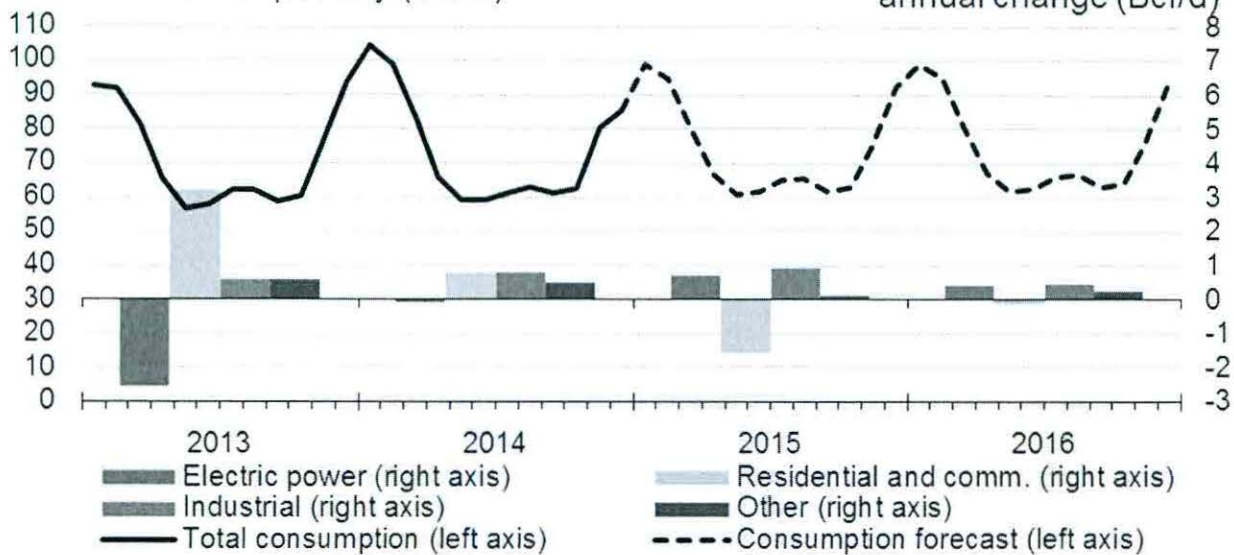
Production, Income, and Employment. Forecast real GDP growth reaches 2.5% in 2015 and declines slightly to 2.4% in 2016. Growth is expected to rise in 2015 because of greater business investment spending, increases in consumer purchases, and recent declines in gasoline prices. However, a stronger dollar and lower demand from slower-growing economies are expected to reduce export growth and raise import growth. Real disposable income grows by 2.8% in 2015, above the 2.4% forecast last month, and by 2.7% in 2016. Total industrial production grows at 2.3% in 2015 and 3.3% in 2016. Projected growth in nonfarm employment averages 1.8% in 2015 and 1.3% in 2016.

Expenditures. Forecast private real fixed investment growth averages 4.8% and 5.8% in 2015 and 2016, respectively, led by equipment in 2015 and 2016 and by equipment and structures in 2016. Real consumption expenditures grow faster than real GDP in 2015 and 2016, at 2.8% and 2.7%, respectively. Durable goods expenditures drive consumption spending in both years. Export growth is 3.1% and 4.0% over the same two years, while import growth is 3.6% in 2015 and 6.1% in 2016. Total government expenditures rise 0.5% in both years.

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.

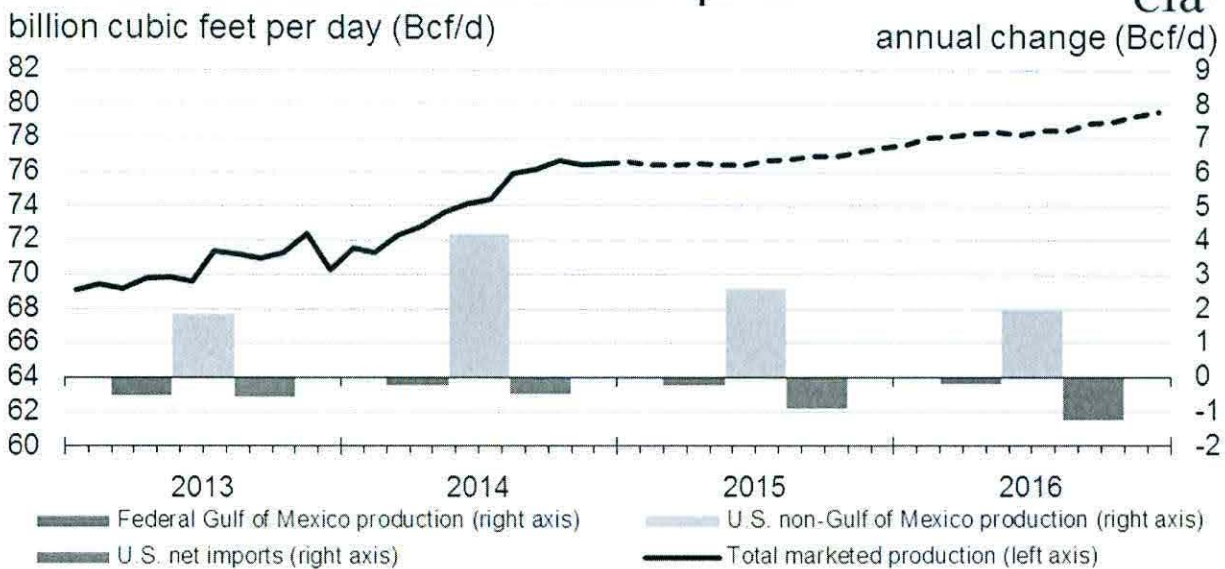
U.S. Natural Gas Consumption

billion cubic feet per day (Bcf/d)



Source: Short-Term Energy Outlook, January 2015.

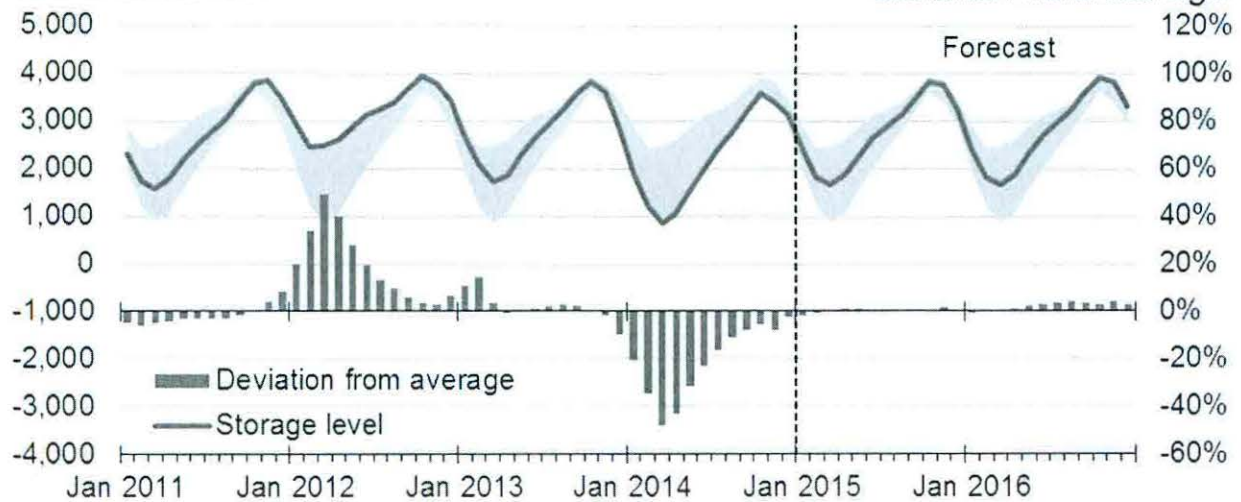
U.S. Natural Gas Production and Imports



Source: Short-Term Energy Outlook, January 2015.

U.S. Working Natural Gas in Storage

billion cubic feet

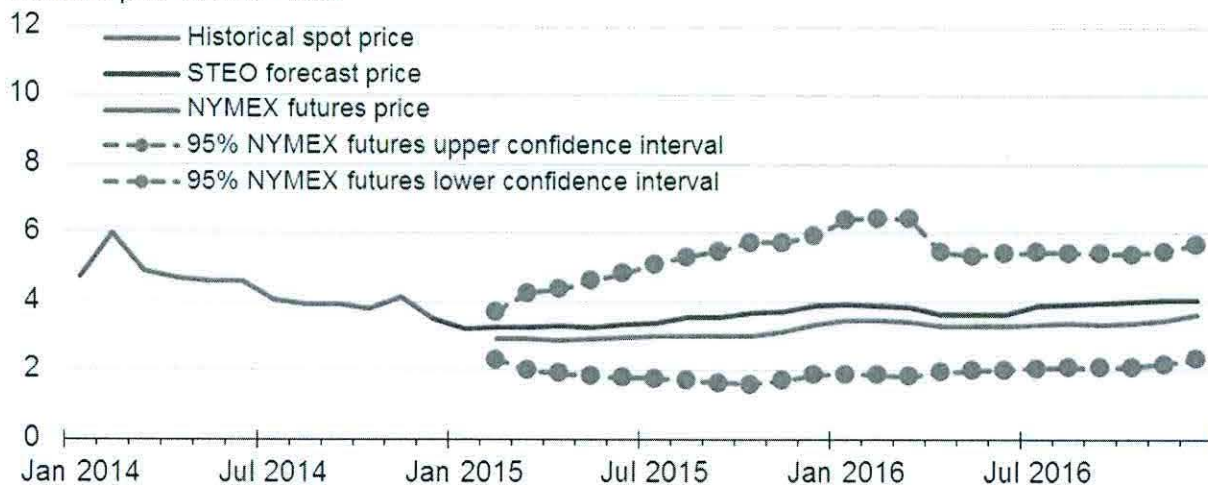


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.

Source: Short-Term Energy Outlook, January 2015.

Henry Hub Natural Gas Price

dollars per million Btu

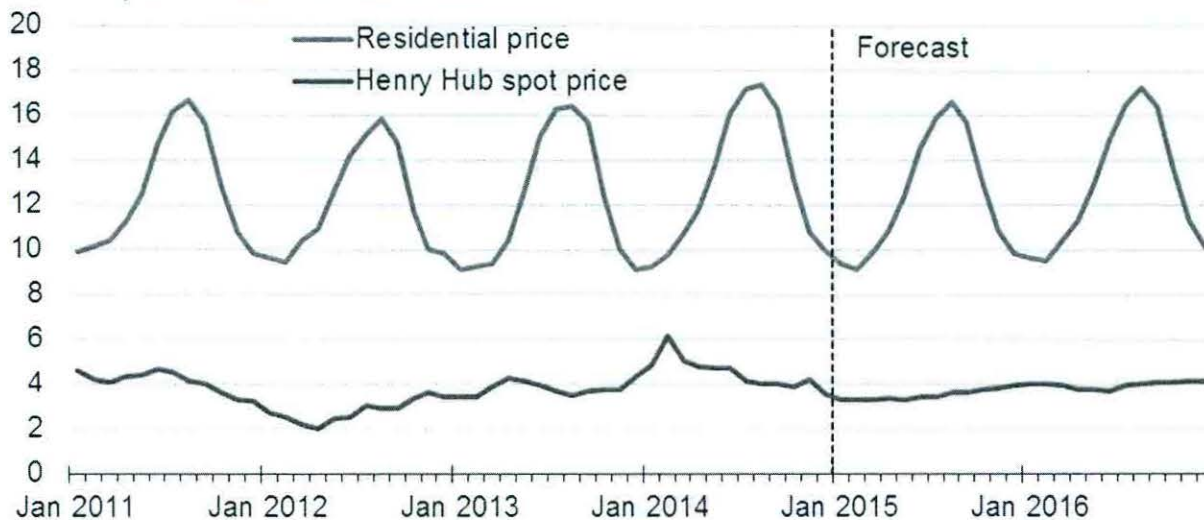


Note: Confidence interval derived from options market information for the 5 trading days ending Jan. 8, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, January 2015.

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, January 2015.

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE MARCH 2015

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.652	\$4.754	\$3.519	\$3.503
Prior Gas Cost	5.037	5.143	3.870	3.853
Current Gas Cost Adjustment	(\$0.385)	(\$0.389)	(\$0.351)	(\$0.350)
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.209	\$0.209	\$0.380	\$0.365
Prior Adjustment	0.209	0.209	0.380	0.365
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
Gas Cost Level	\$4.652	\$4.754	\$3.519	\$3.503
Plus: Surcharge	0.209	0.209	0.380	0.365
Total Gas Cost Level in Tariff Rates	\$4.861	\$4.963	\$3.899	\$3.868
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.017)	(\$0.017)	\$0.000	\$0.000
Prior Adjustment	(0.017)	(0.017)	0.000	0.000
Change in Market Based Pricing	\$0.000	\$0.000	\$0.000	\$0.000
<u>Grain Drying Margin Sharing</u>				
Current Adjustment	(\$0.001)	(\$0.001)	\$0.000	\$0.000
Prior Adjustment	(0.001)	(0.001)	0.000	0.000
Change in Grain Drying Margin Sharing	\$0.000	\$0.000	\$0.000	\$0.000
Total Cost of Gas Items	\$4.843	\$4.945	\$3.899	\$3.868
Net Increase (Decrease) in Gas Costs	(\$0.385)	(\$0.389)	(\$0.351)	(\$0.350)

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE MARCH 2015

Cost of Gas - Propane

Current Propane Cost (Exhibit D)	\$10.210
Prior Propane Cost	<u>13.284</u>
Current Propane Cost Adjustment	<u><u>(\$3.074)</u></u>

Surcharge Adjustment

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

Market Based Pricing Differential

Current Adjustment	(\$0.017)
Prior Adjustment	<u>(0.017)</u>
Change in Margin Sharing Provision	\$0.000

Net Increase (Decrease) in Gas Costs (\$3.074)

Propane Cost Level	\$10.210
Plus: Surcharge	<u>1.193</u>
Total Propane Cost Level in Rates	<u><u>\$11.403</u></u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE MARCH 2015**

	Amount
Total Gas Costs 1/	\$71,924,044
Residential and General Service dk Requirements 2/	15,532,466
Average Cost of Gas per dk	\$4.631
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.652
Less: Gas Cost Level in Rates 3/	5.037
Current Gas Cost Adjustment	(\$0.385)

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

3/ Gas Cost Level in Current Tariff Rates Case No. PU-15-008 effective February 1, 2015:

Cost of Purchased Gas	\$5.014
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.037

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE MARCH 2015**

Total Gas Costs 1/	\$71,924,044 ✓
Less: Annual MDDQ Costs	<u>17,724,248 ✓</u>
Total Gas Costs excluding MDDQ	\$54,199,796 ✓
Firm Service Requirements 1/	15,532,466 ✓
Other Gas Costs per Dk (excluding MDDQ)	\$3.489 ✓
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$17,724,248 ✓
Winter Firm Service Requirements	14,252,945 ✓
MDDQ Costs per Winter Dk	\$1.244 ✓
Add: Other Gas Costs per Dk	<u>3.489 ✓</u>
Winter Seasonal Rate	\$4.733 ✓
Winter Seasonal Rate, adjusted for losses 2/	\$4.754 ✓
Less: Gas Cost Level in Rates 3/	<u>5.143 ✓</u>
Current Gas Cost Adjustment	<u><u>(\$0.389) ✓</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-15-008 effective February 1, 2015:

	<u>Winter</u>
Cost of Purchased Gas	\$5.120 ✓
Adjustment for Distribution Losses	0.9955 ✓
Gas Cost Level in Base Tariff Rates	\$5.143 ✓

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE MARCH 2015**

	Amount
Total Gas Costs 1/	\$24,497,645
Interruptible Service dk Requirements	6,993,666
Average Cost of Gas per dk	\$3.503
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.519
Less: Gas Cost Level in Rates 2/	3.870
Current Gas Cost Adjustment	(\$0.351)

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-15-008 effective February 1, 2015:

Cost of Purchased Gas	\$3.853
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.870

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
March 2015 PGA**

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

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

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

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

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

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

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

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FT-1					

RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	921.000	N.A.	N.A.	921.000
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	0.000
COMMODITY CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
SCHEDULED OVERRUN CHARGE					
MAXIMUM A/B/C/	RATE PER DKT	32.112	N.A.	N.A.	32.112
MINIMUM A/B/C/	RATE PER DKT	2.842	N.A.	N.A.	2.842
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	30.279	N.A.	N.A.	30.279
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	0.000

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

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES

RATE SCHEDULE FTN-1					

RESERVATION CHARGE					
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)					
MAXIMUM	RATE PER EQV. DKT PER MO.	24.274	N.A.	N.A.	24.274
MINIMUM	RATE PER EQV. DKT PER MO.	1.263	N.A.	N.A.	1.263
VOLUMETRIC CAPACITY RELEASE CHARGE					
MAXIMUM	RATE PER DKT	0.798	N.A.	N.A.	0.798
MINIMUM	RATE PER DKT	0.042	N.A.	N.A.	0.042

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

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

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) \$ 225.73 /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 \$ 5.32 /GJ FT-D Demand Rate for Group 2 Delivery Points \$ 4.55 /GJ FT-D Demand Rate for Group 3 Delivery Points \$ 5.46 /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	11.52
	20 years	7.66
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 /	\$ 0.1496 / 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 CO2	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>
	1	542.06
	2	428.98
	3	279.71
15. Monthly Abandonment Surcharge ²	\$12.45/10 ³ m ³ /month	\$0.33/GJ/month
16. Daily Abandonment Surcharge ³	\$ 0.41/10 ³ m ³ /day	\$0.0108/GJ/day

1. Service under rate Schedules FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedules 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.

2. Monthly Abandonment Surcharge applicable to Rate Schedules FT-R, FT-D, FT-P, FT-RN, FT-DW, STFT, and LRS-3.

3. Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, LRS, the following Rate Schedules OS: 2011476052, 2011476054, 2011475056, 2011476092, 2011476049, 2011476050, 2003004522, and if applicable Over-Run Gas.

Effective Date: January 1, 2015

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	5.01	0.1811
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.55	0.1646
31110	ALLIANCE EDSON INTERCONNECT APN	4.55	0.1646
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.55	0.1646
3002	BOUNDARY LAKE BORDER	4.55	0.1646
1958	EMPRESS BORDER	5.62	0.2034
3886	GORDONDALE BORDER	4.55	0.1646
6404	MCNEILL BORDER	5.62	0.2034

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	4.55	0.1646	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.55	0.1646	Yes
3880	AECO INTERCONNECTION	4.55	0.1646	
31003	AGRIUM CARSELAND SALES APS	4.55	0.1646	
31002	AGRIUM FT. SASK SALES APN	4.55	0.1646	Yes
31004	AGRIUM REDWATER SALES APN	4.55	0.1646	
31005	AINSWORTH SALES APGP	4.55	0.1646	
31006	AIR LIQUIDE SALES APN	4.55	0.1646	
3214	AKUINU RIVER WEST SALES	4.55	0.1646	
31007	ALBERTA ENVIROFUELS SALES APN	4.55	0.1646	Yes ²
31008	ALBERTA HOSPITAL SALES APN	4.55	0.1646	Yes
3868	ALBERTA-MONTANA BORDER	4.55	0.1646	
3059	ALLISON CREEK SALES	4.55	0.1646	
31009	ALTASTEEL SALES APN	4.55	0.1646	Yes ²
3562	AMOCO SALES (BP SALES TAP)	4.55	0.1646	
31012	APL JASPER SALES APN	4.55	0.1646	Yes
3488	ARDLEY SALES	4.55	0.1646	
3237	ASPEN SALES	4.55	0.1646	
3216	AURORA NO 2 SALES	4.55	0.1646	
3135	AURORA SALES	4.55	0.1646	
3423	BASHAW WEST SALES	4.55	0.1646	
31013	BAYMAG SALES APS	4.55	0.1646	
31014	BEAR CREEK COGEN SALES APGP	4.55	0.1646	
3068	BEAVER HILLS SALES	4.55	0.1646	
3268	BENBOW SOUTH SALES	4.55	0.1646	
3933	BIG EDDY INTERCONNECTION	4.55	0.1646	
3067	BIGSTONE SALES	4.55	0.1646	
3285	BILBO SALES	4.55	0.1646	
3468	BLEAK LAKE SALES	4.55	0.1646	
3225	BOTHA SALES	4.55	0.1646	
3259	BOULDER CREEK SALES	4.55	0.1646	
3164	BRAINARD LAKE SALES	4.55	0.1646	
3918	BUFFALO CREEK INTERCONNECTION	4.55	0.1646	
31015	BURDETT COGEN SALES APS	4.55	0.1646	
3265	BURNT TIMBER SALES	4.55	0.1646	
3204	CABIN SALES	4.55	0.1646	
3109	CALDWELL SALES	4.55	0.1646	
31016	CALGARY ENERGY CENTRE SALES APS	4.55	0.1646	Yes
3634	CANOE LAKE SALES	4.55	0.1646	
3165	CANOE LAKE SALES NO 2	4.55	0.1646	
3866	CARBON INTERCONNECTION	4.55	0.1646	
3484	CARIBOU LAKE SALES	4.55	0.1646	
3157	CARIBOU LAKE SOUTH SALES	4.55	0.1646	
3106	CARMON CREEK SALES	4.55	0.1646	
3248	CARMON CREEK EAST SALES	4.55	0.1646	
3101	CAROLINE SALES	4.55	0.1646	
31017	CARSELAND COGEN SALES APS	4.55	0.1646	
3275	CARSON CREEK SALES	4.55	0.1646	
3495	CAVALIER SALES	4.55	0.1646	
31018	CHAIN LAKES COOP SALES APS	4.55	0.1646	
3907	CHANCELLOR INTERCONNECTION	4.55	0.1646	
3151	CHEECHAM WEST NO 2 SALES	4.55	0.1646	
3622	CHEECHAM WEST SALES	4.55	0.1646	
6014	CHEVRON AURORA SALES	4.55	0.1646	
31019	CHEVRON FT. SASK SALES APN	4.55	0.1646	Yes
3097	CHICKADEE CREEK SALES	4.55	0.1646	
3305	CHIGWELL NORTH SALES	4.55	0.1646	
3496	CHIPEWYAN RIVER SALES	4.55	0.1646	
3163	CHRISTINA LAKE NORTH SALES	4.55	0.1646	
31020	CLOVERBAR FIBERGLASS SALES APN	4.55	0.1646	Yes

NATURAL GAS TARIFF



Canceling	<u>37th</u>	Revised	Sheet No.	<u>80.1</u>
	<u>36th</u>	Revised	Sheet No.	<u>80.1</u>

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	\$ 119.95	(R)
10,001 to 30,000	\$ 172.45	(R)
>30,000	\$ 382.65	(R)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.9805387	(R)
--	--------------	-----

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0074304	(R)
Minimum	\$ 0.0017935	
GTAC Amortization	\$ (0.0009972)	
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)

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

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

<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 MARCH 2015**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2014	\$13,138,114	\$1,130,570	\$4,252,066
November	9,055,168	929,233	3,379,652
December	5,147,252	724,553	1,610,827
January 2015	1,563,156	505,590	(417,244)
February	(1,812,842)	307,454	(1,837,596)
March	(2,308,886)	278,343	(2,753,670)
April	(2,244,427)	283,886	(2,543,378)
May	(8,267)	465,080	(1,473,946)
June	2,942,394	703,911	(41,036)
July	5,889,326	942,488	1,376,041
August	8,904,857	1,186,817	2,788,778
September	11,433,860	1,391,683	3,980,123
October	11,513,137	1,398,090	4,100,689
13 month average	<u>\$4,862,526</u>	<u>\$788,284</u>	<u>\$955,485</u>
Rate of Return	7.881%	7.881%	7.881%
Return	\$383,216	\$62,125	\$75,302
Return Requirement	<u>\$534,927</u>	<u>\$86,720</u>	<u>\$105,113</u>

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

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

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE MARCH 2015

Cost of Purchased Propane	\$64,031
Gallons Purchased	68,851
Projected dk Sales	6,300
Propane Cost per Dk	\$10.164
Average Cost of Propane as Adjusted for Losses @ 99.55%	10.210
Less: Propane Cost Level in Rates 1/	<u>13.284</u>
Current Propane Cost Adjustment	<u><u>(\$3.074)</u></u>

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & 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, 2014									<u>\$3,163,455</u>
August	\$226,615	\$0	\$49	\$226,664	277,347	\$0.024	\$6,656	\$220,008	3,383,463
September	(85,563)	0	35	(85,528)	328,455	0.024	7,883	(93,411)	3,290,052
October	9,216	0	34	9,250	599,658	0.209	56,897 2/	(47,647)	3,242,405
November	(234,355)	0	33	(234,322)	918,828	0.209	192,034	(426,356)	2,816,049
December	(703,392)	(1,696) 3/	44	(705,044)	2,483,155	0.209	518,979	(1,224,023)	1,592,026
Balance @ December 31, 2014									<u>\$1,592,026</u>

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

2/ Reflects 369,900 dk @ \$0.024 and 229,758 dk @ \$0.209.

3/ Record immaterial under or over refunded portions of the 1998 and 2005 WBI Energy Transmission, Inc. refunds.

**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, 2014									<u><u>\$553,358</u></u>
August	\$27,773	\$0	\$9	\$27,782	37,258	\$0.116	\$4,323	\$23,459	576,817
September	(4,907)	0	6	(4,901)	40,083	0.116	4,649	(9,550)	567,267
October	13,995	0	6	14,001	81,768	0.380	14,393 2/	(392)	566,875
November	(11,543)	0	6	(11,537)	101,794	0.380	38,681	(50,218)	516,657
December	13,622	0	8	13,630	154,400	0.380	58,672	(45,042)	471,615
Balance @ December 31, 2014									<u><u>\$471,615</u></u>

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

2/ Reflects 63,180 dk @ \$0.116 and 18,588 dk @ \$0.380.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2014									<u>\$185,080</u>
August	\$16,626	\$0	\$3	\$16,629	4,035	\$0.181	\$731	\$15,898	200,978
September	(888)	0	2	(886)	3,604	0.181	652	(1,538)	199,440
October	2,549	0	2	2,551	9,112	0.365	1,649 2/	902	200,342
November	(4,099)	0	2	(4,097)	26,445	0.365	9,652	(13,749)	186,593
December	(8,282)	0	3	(8,279)	61,559	0.365	22,468	(30,747)	155,846
Balance @ December 31, 2014									<u>\$155,846</u>

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

2/ Reflects 9,112 dk @ \$0.181 and 0 dk @ \$0.365.