



UTILITIES CO.

A Division of MDU Resources Group, Inc.

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

March 10, 2011

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-11-____

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 seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (95th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered April 1, 2011.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.304 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, decreasing the cost of gas \$0.010 per dk.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of April 2011.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.314 per dk for residential and firm general service customers, a decrease of \$0.300 per dk for small and large interruptible customers and a decrease of \$0.299 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 April 2011. The average cost of gas for firm customers, adjusted for losses, is \$5.151.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid demand and commodity balances using the calculation procedure set forth in Rate 88.

The overall rate of return of 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota will not seek a Cost of Gas – Propane (COG) adjustment change for the month of April 2011. The Purchased Propane Cost Adjustment tariff (Rate 99), Section 2(b) provides that "Montana-Dakota shall file an adjustment to reflect changes in its average cost of propane supply only when the amount of such adjustment is at least 10 (ten) cents per dk." The COG adjustment for the month of April 2011 results in a change of less than 10 cents per dk, and therefore, in accordance with the authorized tariff, Montana-Dakota will not seek a purchased propane cost adjustment change.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to a decrease of approximately \$346,500 for natural gas customers during the month of April 2011. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 94,152 natural gas customers in North Dakota as of February 28, 2011.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern
Regulatory Affairs Manager
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

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

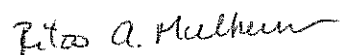
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of \$600 in accordance with North Dakota Century Code Section 49-05-05 on December 9, 2010. This payment will cover the filing fee associated with this monthly COG.

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,



Rita A. Mulkern
Regulatory Affairs Manager

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
 95th Revised Sheet No. 3
 Canceling 94th 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	\$0.30 per day	\$0.812	\$5.120	\$5.932
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$5.120	\$5.258
Interruptible Service - PAR			\$0.120	\$4.194	\$4.314
Interruptible Service - MAFB			\$0.120	\$4.216	\$4.336
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$5.120	\$5.717
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$4.194	(Maximum) \$5.065
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day			
Winter Gas Usage			\$0.597	\$5.216	\$5.813
Summer Gas Usage			\$0.597	\$4.256	\$4.853
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.019	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.019	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$4.194	(Maximum) \$4.913
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$15.245	\$16.057
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$15.245	\$15.842

Date Filed: March 10, 2011

Effective Date:

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:

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

April 2011

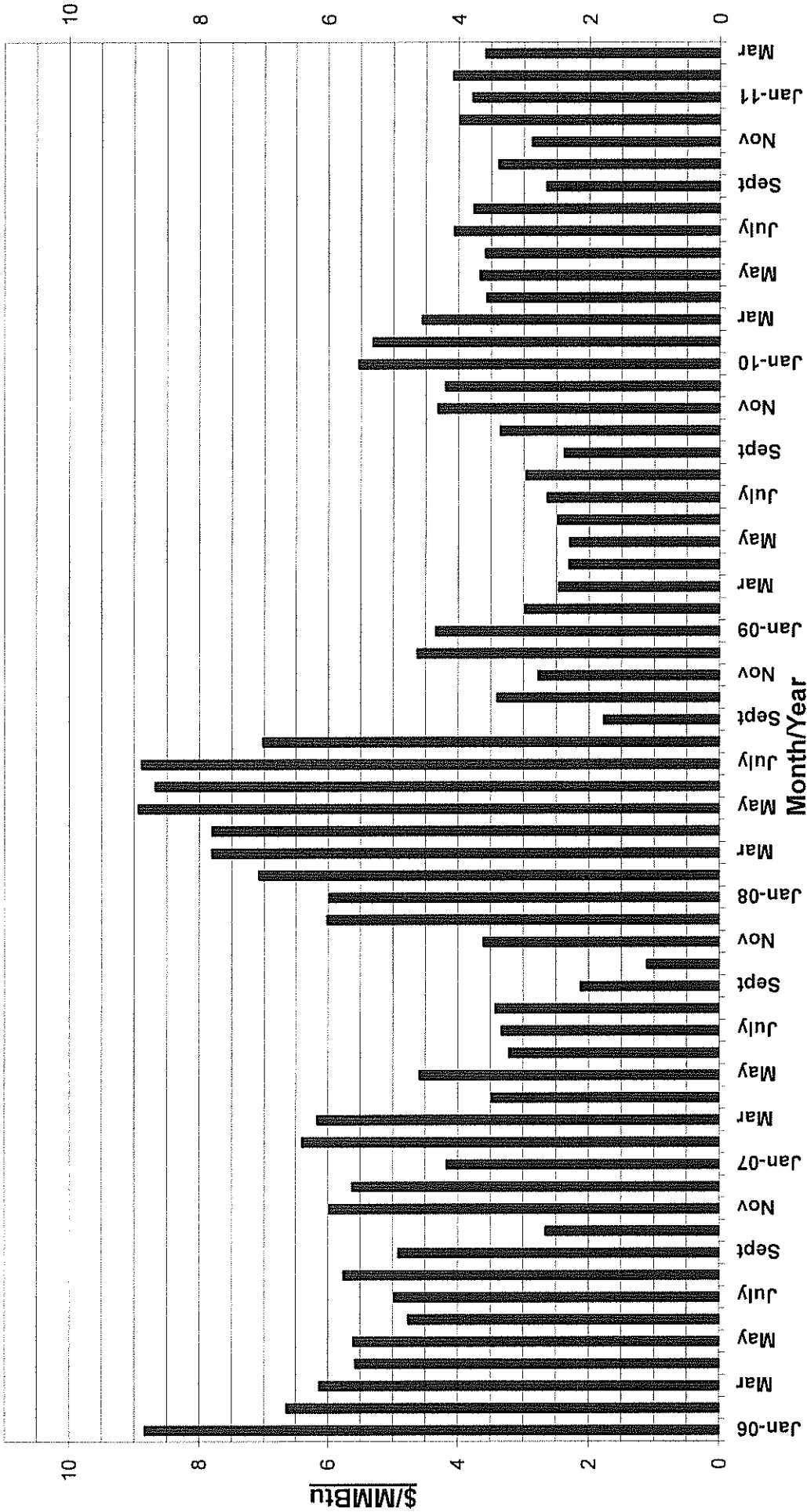
The established monthly price for the Rocky Mountain CIG Index decreased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by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

Cold temperatures and production freeze-offs in February contributed to a larger than expected draw on storage inventories. However, the ending of winter heating season affects the market, which has resulted in lower prices in the near term. The year over year comparison shows the March 2011 CIG index price is approximately 21 percent less than the previous year. The Energy Information Administration (EIA) reported storage levels nationwide as of February 25, 2011 were 0.9 percent above the five-year average and 0.5 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.doe.gov>.

The February Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 15.

CIG Rocky Mountains Index Monthly Gas Prices 2006-2011YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2009-\$3.07; 2010-\$3.92; 2011YTD - \$3.83



Independent Statistics & Analysis

**U.S. Energy Information
Administration**

Short-Term Energy Outlook

March 2011

March 8, 2011 Release

Highlights

- West Texas Intermediate (WTI) and other crude oil spot prices have risen about \$15 per barrel since mid-February partly in response to the disruption of crude oil exports from Libya. Continuing unrest in Libya as well as other North African and Middle Eastern countries has led to the highest crude oil prices since 2008. As a result, EIA has raised its forecast for the average cost of crude oil to refiners to \$105 per barrel in 2011, \$14 higher than in the previous *Outlook*. However, EIA has raised its 2011 forecast for WTI by only \$9 per barrel to \$102 per barrel because of the projected continued price discount for this type of crude compared with other crudes. EIA projects a further small increase in crude oil prices in 2012, with the refiner acquisition cost for crude oil averaging \$106 per barrel and WTI averaging \$105 per barrel. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 3.3 percent in 2011 and 2.8 percent in 2012, while world real GDP (weighted by oil consumption) grows by 3.8 percent and 3.7 percent in 2011 and 2012, respectively.
- The recent rapid increase in spot crude and gasoline prices has led to a significant rise in retail product prices. Motorists currently experiencing a jump in pump prices will likely see further increases from now through the spring since the recent increase in crude oil prices has not yet been fully passed through to gasoline prices. EIA expects the retail price of regular-grade motor gasoline to average \$3.56 per gallon in 2011, 77 cents per gallon higher than the 2010 average and about 40 cents above the projected price in the previous *Outlook*. EIA projects gasoline prices to average about \$3.70 per gallon during the peak driving season (April through September) with considerable regional and local variation. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting a 25-percent probability that the national monthly average retail price for regular gasoline could exceed \$4.00 per gallon during summer 2011. Rising crude oil prices are the primary reason for higher retail prices, but higher refining margins are also expected to be a contributing factor.

- EIA estimates that natural gas working inventories ended February 2011 at 1.7 trillion cubic feet (Tcf), slightly below the 2010 end-of-February level. Inventories are expected to remain relatively high through 2011. The projected Henry Hub natural gas spot price averages \$4.10 per million Btu (MMBtu) in 2011, \$0.29 per MMBtu lower than the 2010 average. EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average of \$4.58 per MMBtu.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects continued tightening of world oil markets over the next two years, particularly in light of the recent events in North Africa and the Middle East, the world's largest oil producing region. The current situation in Libya increases oil market uncertainty because, according to various reports, much of the country's 1.8-million bbl/d total liquids production has been shut in and it is unclear how long this situation will continue. The market remains concerned that the unrest in the region could continue to spread.

The forecast for total world oil consumption grows by an annual average of 1.6 million bbl/d through 2012. Supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries grows about 0.2 million bbl/d this year, then falls slightly in 2012. Consequently, EIA expects that the market will rely on both inventories and significant increases in the production of crude oil and non-crude liquids in OPEC member countries to meet projected world demand growth. Onshore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high in 2010, but floating oil storage fell sharply. EIA expects that OECD oil inventories will decline to the lower bound of the previous 5-year range by the end of 2012.

There are many reasons for market uncertainty that could push oil prices higher or lower than current expectations. Among the uncertainties are: the continued unrest in producing countries and its potential impact on supply; decisions by key OPEC member countries regarding their production response to the global recovery in oil demand and recent supply losses; the rate of economic recovery, both domestically and globally; fiscal issues facing national and sub-national governments; and China's efforts to address concerns regarding its growth and inflation rates.

Global Crude Oil and Liquid Fuels Consumption. World crude oil and liquid fuels consumption grew by an estimated 2.4 million bbl/d in 2010 to 86.7 million bbl/d, the second largest annual increase in at least 30 years. This growth more than offset the reductions in demand during the prior two years and surpassed the 2007

consumption level of 86.3 million bbl/d. EIA expects that world liquid fuels consumption will grow by 1.5 million bbl/d in 2011 and by an additional 1.7 million bbl/d in 2012. Non-OECD countries will make up almost all of the growth in consumption over the next 2 years, with the largest demand increases coming from China, Brazil, and the Middle East. EIA expects that, among the OECD regions, only North America will show growth in oil consumption over the next two years, offsetting declines in OECD Europe and Asia.

Non-OPEC Supply. EIA projects that non-OPEC crude oil and liquid fuels production will increase by 170,000 bbl/d in 2011, then decline slightly in 2012. Increases in non-OPEC oil production during 2011 will be concentrated in a few countries, particularly China and Brazil, where EIA expects annual average production growth of 140,000 and 170,000 bbl/d, respectively. In 2012, EIA expects Canadian production growth to average 170,000 bbl/d while China and Brazil grow by 140,000 and 110,000 bbl/d, respectively. Other non-OPEC production is expected to decline. EIA expects that Mexico's production will fall by about 220,000 bbl/d in 2011, followed by a further decline of 80,000 bbl/d in 2012. Similarly, production from the North Sea will fall by 210,000 bbl/d and 170,000 bbl/d in 2011 and 2012, respectively. EIA expects the former Soviet Union republics to increase production by 320,000 bbl/d in 2011, followed by a production decrease of 180,000 bbl/d in 2012 mainly driven by decreases in Russia, whose West Siberian fields are expected to decline significantly. Projected U.S. crude oil and liquid fuels production declines by 100,000 bbl/d in 2011 and by a further 160,000 bbl/d in 2012.

OPEC Supply. EIA expects that lost crude oil production from Libya will be made up for by both drawdown of inventories and increases in production from other OPEC countries. Forecast OPEC crude oil and non-crude liquids production increase by 0.1 million bbl/d and by 0.7 million bbl/d in 2011, respectively. Continuing growth in global demand for oil and limited growth in supplies originating from non-OPEC countries contribute to an increase in OPEC crude oil production of 1.9 million bbl/d in 2012. EIA expects growth in OPEC non-crude liquids production to slow to 0.3 million bbl/d in 2012. EIA has revised its projected OPEC surplus capacity downward, compared with the last *Outlook*, as assumptions underlying these projections changed in light of the unrest in Libya. As a result, EIA projects that OPEC surplus capacity will fall from an average 4.4 million bbl/d in 2010 to 4.1 million bbl/d in 2011, followed by a further decline to 3.1 million bbl/d in 2012.

OECD Petroleum Inventories. Onshore commercial oil inventories in the OECD countries remained high in 2010, but reports indicate that floating oil storage fell sharply. EIA expects that OECD onshore inventories will decline over the forecast period. Projected OECD stocks fall by about 111 million barrels in 2011, followed by

an additional 38 million barrel decline in 2012. Days of supply (total inventories divided by average daily consumption) drops from a relatively high 57 days at the end of 2010 to 55 days by the end of 2011, which is close to the middle of the previous 5-year range.

Crude Oil Prices. WTI crude oil spot prices averaged \$88.58 per barrel in February, slightly lower than the January average, while over the same time period the estimated average cost of all crude oil to U.S. refineries increased by about \$4.50 per barrel to \$92.50. Growing volumes of Canadian crude oil imported into the United States contributed to record-high storage levels at Cushing, Oklahoma, and a price discount for WTI compared with similar quality world crudes such as Brent crude oil. Projected WTI spot prices rise to an average of \$105 per barrel in December 2011 and remain at about that level through 2012.

Energy price forecasts are particularly uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for May 2011 delivery over the 5-day period ending March 3 averaged \$101 per barrel and implied volatility averaged 36 percent. This makes the lower and upper limits of the 95-percent confidence interval \$79 per barrel and \$129 per barrel, respectively. Last year at this time, WTI for May 2010 delivery averaged \$80 per barrel with the limits of the 95-percent confidence interval at \$65 per barrel and \$99 per barrel. Based on WTI futures and options prices, the probability that the monthly average price of WTI crude oil will exceed \$110 per barrel in December 2011 is about 36 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below \$90 per barrel is about 34 percent.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of petroleum and non-petroleum liquid fuels increased by 380,000 bbl/d (2.0 percent) to 19.1 million bbl/d in 2010 (U.S. Liquid Fuels Consumption Growth Chart). The major sources of this consumption growth were distillate fuel oil (diesel fuel and heating oil), which grew by 160,000 bbl/d (4.5 percent), and motor gasoline, which increased by 40,000 bbl/d (0.4 percent). Projected total U.S. liquid fuels consumption increases by 130,000 bbl/d (0.7 percent) in 2011, and by a further 190,000 bbl/d (1.0 percent), to 19.5 million bbl/d, in 2012. As in 2010, motor gasoline and distillate fuel account for much of the growth in consumption.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 150,000 bbl/d in 2010 to 5.51 million bbl/d, declines by 110,000 bbl/d in 2011 and by a further 130,000 bbl/d in 2012 (U.S. Crude Oil Production Chart). The 2011 forecast includes production declines in Alaska of 60,000 bbl/d in 2011 and an

additional decline of 10,000 bbl/d in 2012 because of maturing Alaskan oil fields. EIA expects production from the Federal Gulf of Mexico (GOM) to fall by 240,000 bbl/d in 2011 and by a further 200,000 bbl/d in 2012. These production declines in Alaska and the GOM are partially offset by projected increases in lower-48 non-GOM production of 190,000 bbl/d and 70,000 bbl/d in 2011 and 2012, respectively.

Liquid fuel net imports, including both crude oil and refined products, fell from 57 percent of total U.S. consumption in 2008 to 49 percent in 2010, primarily because of the decline in consumption during the recession and rising domestic production. EIA forecasts that liquid fuel net imports will average 9.7 million bbl/d in 2011 and 10.0 million bbl/d in 2012, comprising 50 percent and 52 percent of total consumption, respectively.

EIA expects slow growth in fuel ethanol production over the next 2 years. Ethanol production increases by a projected 40,000 bbl/d, to 900,000 bbl/d in 2011, followed by an additional 10,000 bbl/d increase in 2012.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from a national average of \$2.78 per gallon in 2010 to \$3.56 per gallon in 2011 and \$3.57 per gallon in 2012, although there is considerable variation within and between regions. The forecast for on-highway diesel fuel retail prices, which averaged \$2.99 per gallon in 2010, averages \$3.81 per gallon and \$3.82 per gallon in 2011 and 2012, respectively.

The projected monthly average regular gasoline price peaks this year at \$3.75 per gallon in June. New York Harbor RBOB (reformulated gasoline blendstock for oxygenate blending) futures contracts for July 2011 delivery over the 5-day period ending March 3 averaged \$2.97 per gallon and implied volatility averaged 33 percent. The probability the RBOB futures price will exceed \$3.30 per gallon (consistent with a U.S. average regular gasoline retail price above \$4 per gallon) in July 2011 is about 25 percent.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that total 2011 natural gas consumption will remain close to 2010 levels. Forecast residential and commercial consumption in 2011 should be lower than reported 2010 levels by 1.2 percent and 2.7 percent, respectively, reflecting changes to EIA's methodology for collecting and reporting natural gas consumption data (see [*Changes in Natural Gas Monthly Consumption Data Collection and the Short-Term Energy Outlook*](#)) that were implemented in the middle of 2010 to provide more accurate data on seasonal patterns of natural gas use. Industrial

consumption rises from 18.1 billion cubic feet per day (Bcf/d) in 2010 to 18.8 Bcf/d in 2011 as the natural-gas-weighted industrial production index increases 4.0 percent year-over-year.

Total consumption grows 1.0 percent in 2012, from 66.6 Bcf/d to 67.2 Bcf/d. Increases in natural gas consumption in the electric power sector and the industrial sector are partially offset by slight declines in residential and commercial consumption. EIA expects electric power sector and industrial sector consumption in 2012 to grow by 2.8 percent and 1.5 percent, respectively.

U.S. Natural Gas Production and Imports. Total marketed natural gas production grew strongly throughout 2010 (4.4 percent), increasing from 59.7 Bcf/d in January to an estimated 63.8 Bcf/d in December. Year-over-year growth in 2011 slows considerably to just 0.8 percent as an increase of 1.0 Bcf/d in the lower-48 States is partially offset by a decline of 0.5 Bcf/d in the GOM.

The latest EIA data for monthly natural gas production in the *Natural Gas Monthly* show an increase in production in the lower-48 States in December 2010, continuing an increase from the previous month. However, modest declines are expected through 2011 because of a falling gas-directed drilling rig count in response to lower prices. The number of rigs drilling for natural gas, as reported by Baker Hughes Inc., increased from a low of 665 in July 2009 to 973 in April 2010. The natural gas rig count stayed relatively unchanged from April through October 2010. However, since October 2010 the rig count has fallen, dropping to 906 rigs as of February 25. The large price difference between petroleum liquids and natural gas on an energy-equivalent basis contributes to an expected shift towards drilling for liquids rather than for dry gas.

Increasing consumption in 2012, led by strong growth in the electric power sector, contributes to higher prices and to an economic incentive for producers to resume drilling. Total domestic natural gas production increases by 0.9 percent in 2012. Lower-48 production is expected to increase throughout 2012 from 55.0 Bcf/d in January to 57.4 Bcf/d in December. Federal GOM production remains flat in 2012.

EIA expects gross pipeline imports of 8.4 Bcf/d in 2011 and 8.2 Bcf/d in 2012, year-over-year decreases of 5.6 and 2.3 percent, respectively. Projected imports of liquefied natural gas (LNG) average 1.2 Bcf/d in 2011, a 3-percent decrease from 2010 levels. LNG imports in 2012 remain relatively flat. High domestic production combined with high inventories and low U.S. prices relative to European and Asian markets should continue to discourage LNG imports.

U.S. Natural Gas Inventories. On February 25, 2011, working natural gas in storage stood at 1,745 Bcf, slightly below last year's level at this time ([U.S. Working Natural Gas in Storage Chart](#)). At the end of the winter heating season (March 31, 2011), EIA expects that about 1,549 Bcf of working natural gas will remain in storage, a downward revision of about 102 Bcf from last month's *Outlook*. Cold temperatures and production freeze-offs in February contributed to a larger-than-expected draw on inventories. EIA expects that inventories, though somewhat below their 2010 levels for the first half of the year, still will remain relatively robust. Slower growth in production and greater consumption contribute to lower inventories in the second half of 2012.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$4.09 per MMBtu in February 2011, \$0.40 per MMBtu less than the average spot price in January 2011 ([Henry Hub Natural Gas Price Chart](#)). EIA expects that the Henry Hub spot price will average \$4.10 per MMBtu in 2011, a drop of \$0.29 per MMBtu from the 2010 average. EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average of \$4.58 per MMBtu.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for May 2011 delivery (for the 5-day period ending March 3) averaged \$3.98 per MMBtu, and the average implied volatility over the same period was 33 percent. This produced lower and upper bounds for the 95-percent confidence interval for May 2011 contracts of \$3.09 per MMBtu and \$5.11 per MMBtu, respectively. At this time last year, the natural gas May 2010 futures contract averaged \$4.77 per MMBtu and implied volatility averaged 39 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.57 per MMBtu and \$6.39 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA expects an increase of 0.5 percent in total U.S. consumption of electricity during 2011 ([U.S. Total Electricity Consumption Chart](#)). Retail sales of electricity to the residential sector this year will fall 1.7 percent in response to the assumed 16-percent decline in cooling degree-days compared to the hot summer of 2010. During 2012, total U.S. electricity consumption should grow by 2.0 percent. EIA projects that retail sales of electricity to the residential sector will grow by 1.8 percent in 2012, while electricity sales to the commercial and industrial sectors grow by 2.3 and 2.0 percent, respectively.

U.S. Electricity Generation. EIA projects that total generation by the electric power sector will increase slightly during 2011, rising by 24 gigawatthours per day (0.2

percent) ([U.S. Electric Power Sector Generation Growth Chart](#)). Preliminary estimates by EIA indicate that wind power capacity grew by at least 3,657 megawatts during 2010, which is the lowest capacity addition since 2006. Capacity is expected to grow at a similar pace this year, boosting wind generation by 43 gigawatthours per day (16 percent) during 2011. During 2012, EIA expects a 2.1-percent increase in total electric power sector generation, fueled primarily by increased coal and natural gas generation.

U.S. Electricity Retail Prices. During 2010, retail prices for electricity distributed to the residential sector averaged 11.58 cents per kilowatthour, about the same level as in 2009. EIA expects residential prices to rise by 1.0 percent in 2011, followed by an increase of 0.5 percent in 2012 ([U.S. Residential Electricity Prices Chart](#)). The effect of lower generation fuel costs in 2011 should be more evident in retail prices for electricity distributed to the industrial sector, which EIA projects will fall 1.6 percent during 2011 and then rise 0.2 percent next year.

Coal

U.S. Coal Consumption. EIA estimates that coal consumption in the electric power sector grew by nearly 5 percent in 2010, primarily the result of higher electricity consumption during the hot summer. EIA projects that coal consumption in the electric power sector will increase only slightly in 2011, as slow growth in power demand and increases in generation from hydropower and wind power reduce the need for coal-fired generation. In 2012, coal consumption in the electric power sector grows by 2.6 percent ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production in 2010 grew by only 1 percent despite the nearly 5-percent increase in total U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase ([U.S. Electric Power Sector Coal Stocks Chart](#)). EIA projects that coal production in 2011 will increase just slightly as total coal consumption shows little change ([U.S. Annual Coal Production Chart](#)). The projected increase in coal consumption in 2012 leads to a forecast 3.3-percent increase in coal production.

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, resulted in sharp increases in U.S. coal exports in 2010. Metallurgical coal exports nearly doubled in the first three-quarters of 2010 compared with the same period of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to 69 percent in 2010. Supply disruptions in several key coal exporting countries (Australia, Colombia, Indonesia, and South Africa) have greatly affected the amount of coal available on the world market. Consequently, EIA expects U.S. coal

exports to increase by 7.7 percent in 2011. In 2012, U.S. coal exports are forecast to fall back to more recent levels (about 80 million short tons) as supply from other major coal-exporting countries recovers.

U.S. Coal Prices. Coal prices have been rising relatively steadily over the last 10 years, reflecting longer-term power sector coal contracts initiated during a period of high energy prices, rising transportation costs, and increased consumption. However, EIA expects that the power sector coal price will decline slightly in 2011 and 2012 as coal competes with natural gas for market share. The projected power sector delivered coal price, which averaged \$2.26 per MMBtu in 2010, averages \$2.23 per MMBtu and \$2.21 per MMBtu in 2011 and 2012, respectively.

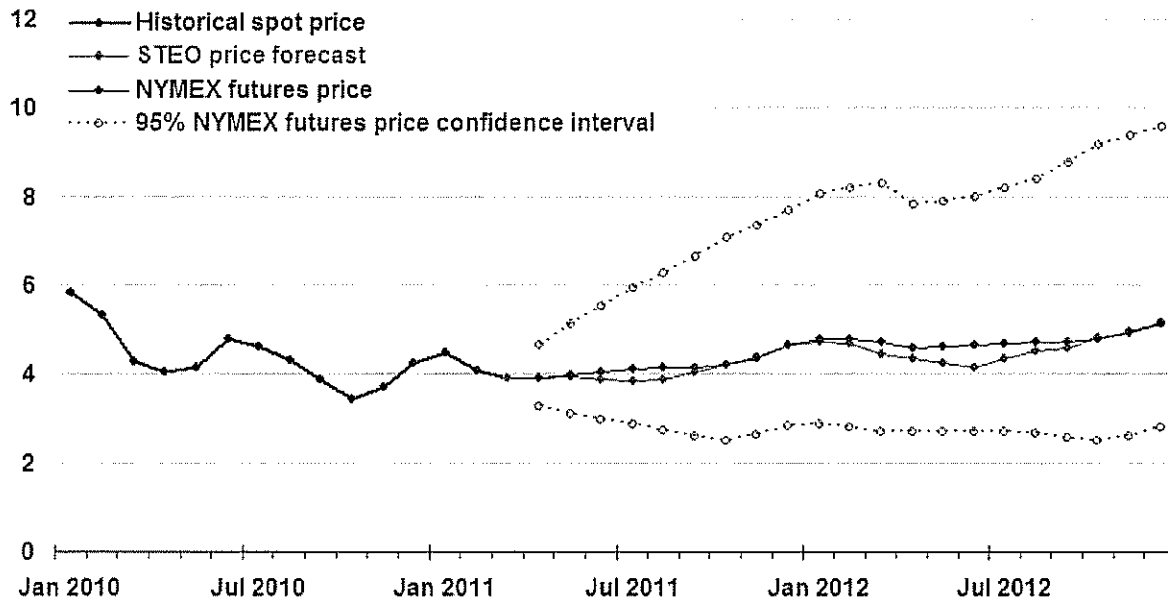
U.S. Carbon Dioxide Emissions

EIA estimates that fossil-fuel CO₂ emissions increased by 3.7 percent in 2010 ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Coal- and natural gas-related CO₂ emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Forecast fossil-fuel CO₂ emissions remain relatively flat in 2011, as projected increases in consumption of petroleum, primarily in the transportation sector, and natural gas, primarily in the industrial sector, offset declines in natural gas consumption in both the residential and commercial sectors in 2011. The expected resumption of growth in electricity generation and the improvement in economic growth in 2012 contribute to a 1.8-percent increase in fossil-fuel CO₂ emissions.

Henry Hub Natural Gas Price

dollars per million btu

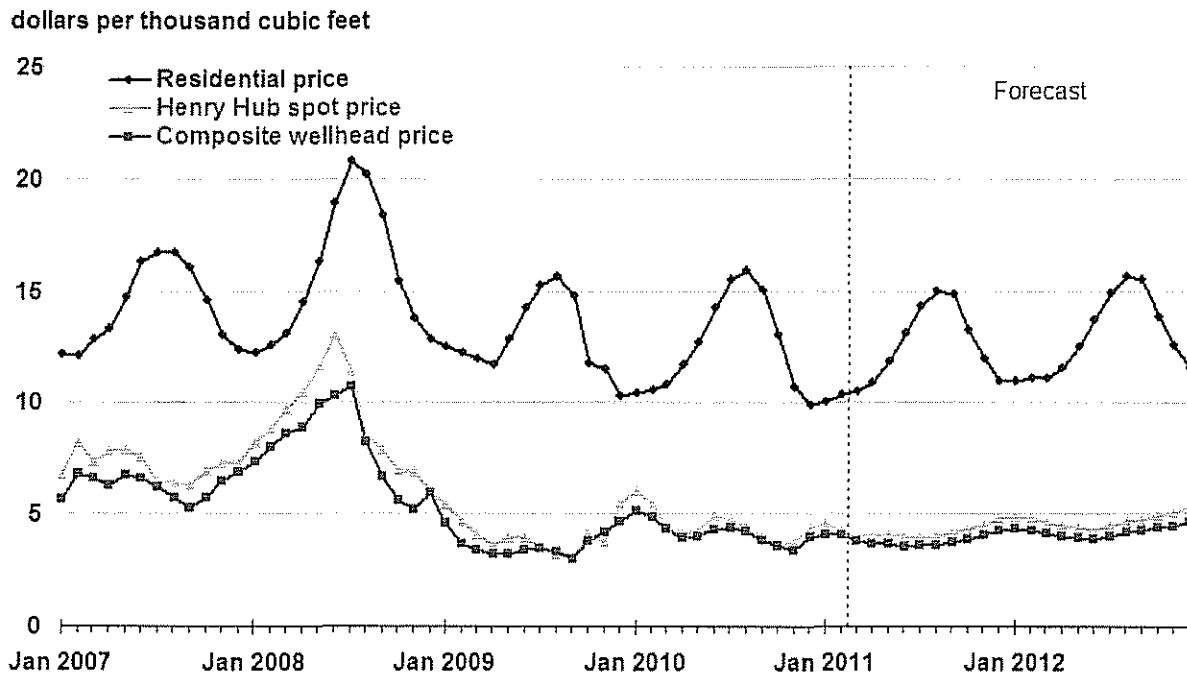


*Note: Confidence interval derived from options market information for 5 trading days ending March 3, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, March 2011



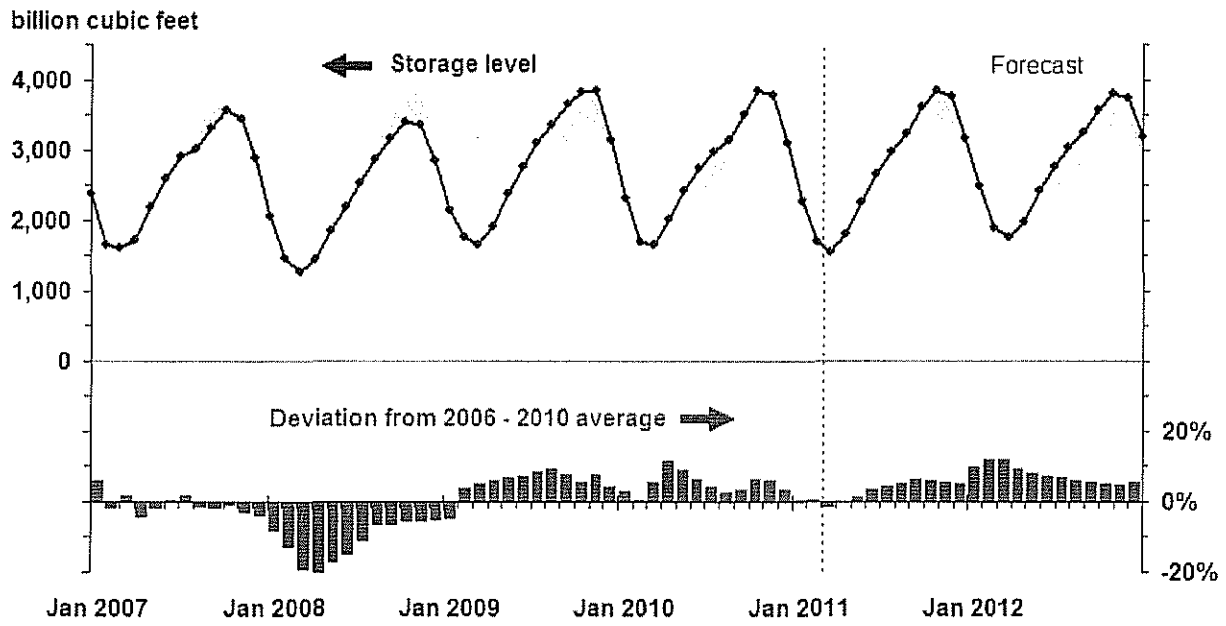
Natural Gas Prices



Source: Short-Term Energy Outlook, March 2011



U.S. Working Natural Gas in Storage

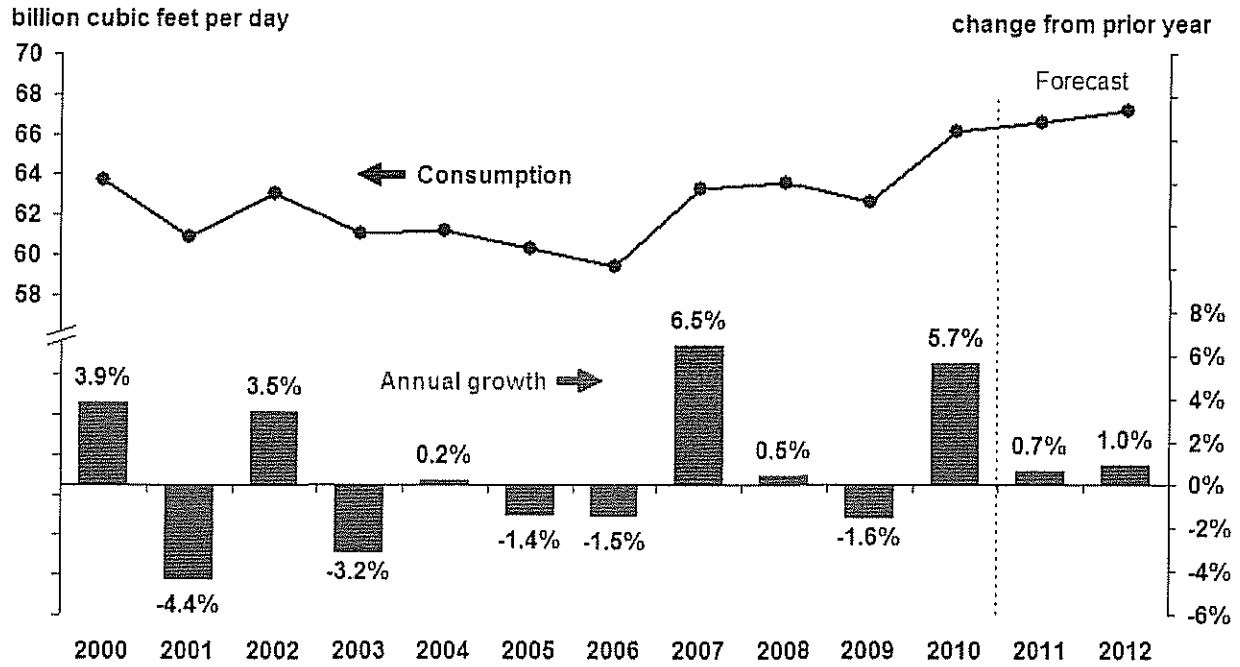


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010

Source: Short-Term Energy Outlook, March 2011



U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, March 2011



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

Williston Basin Interstate Pipeline Company Docket No. RP10- 1829-000

On March 1, 2011, Williston Basin filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP10-1829-000, reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective April 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – (1.0) cents per dk

SourceGas Distribution LLC Docket No. 30022-148-GR-10

On February 26, 2010, SourceGas filed an application with the Wyoming Public Service Commission requesting authority to increase its retail natural gas service rates in Docket No. 30022-148-GR-10. The Commission approved a change in rates to be effective with service rendered on or after January 1, 2011.

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 APRIL 2011

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$5.151	\$5.247	\$4.204	\$4.185
Prior Gas Cost	5.465	5.561	4.504	4.484
Current Gas Cost Adjustment	(\$0.314)	(\$0.314)	(\$0.300)	(\$0.299)
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.023)	(\$0.023)	(\$0.010)	\$0.031
Prior Adjustment	(0.023)	(0.023)	(0.010)	0.031
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.008)	(\$0.008)	\$0.000	\$0.000
Prior Adjustment	(0.008)	(0.008)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	<u>(\$0.314)</u>	<u>(\$0.314)</u>	<u>(\$0.300)</u>	<u>(\$0.299)</u>
Gas Cost Level	\$5.151	\$5.247	\$4.204	\$4.185
Plus: Surcharge	(0.023)	(0.023)	(0.010)	0.031
Total Gas Cost Level in Tariff Rates	<u>\$5.128</u>	<u>\$5.224</u>	<u>\$4.194</u>	<u>\$4.216</u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE APRIL 2011**

	Amount
Total Gas Costs 1/	\$69,651,843
Residential and General Service dk Requirements 2/	13,581,434
Average Cost of Gas per dk	\$5.128
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.151
Less: Gas Cost Level in Rates 3/	5.465
Current Gas Cost Adjustment	(\$0.314)

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -15 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.

2/ Normalized dk sales for the twelve months ended January 31, 2011, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8:

Cost of Purchased Gas	\$5.440
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$5.465

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE APRIL 2011**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$69,651,843
Less: Annual MDDQ Costs 1/	<u>11,685,993</u>
Total Gas Costs excluding MDDQ	\$57,965,850
Firm Service Requirements 1/	13,581,434
Other Gas Costs per Dk (excluding MDDQ)	\$4.268
Summer Seasonal Rate, adjusted for losses 2/	4.287
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,685,993
Winter Firm Service Requirements	12,235,037
MDDQ Costs per Winter Dk	\$0.955
Add: Other Gas Costs per Dk	<u>4.268</u>
Winter Seasonal Rate	\$5.223
Winter Seasonal Rate, adjusted for losses 2/	\$5.247
Less: Gas Cost Level in Rates 3/	<u>5.561</u>
Current Gas Cost Adjustment	<u><u>(\$0.314)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$4.575	\$5.536
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$4.596	\$5.561

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE APRIL 2011**

	Amount
Total Gas Costs 1/	\$14,657,565
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$4.185
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.204
Less: Gas Cost Level in Rates 2/	4.504
Current Gas Cost Adjustment	(\$0.300)

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -15 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-11-8:

Cost of Purchased Gas	\$4.484
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.504

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE APRIL 2011**

	<u>Amount</u>
Total Gas Costs 1/	\$3,682,440
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$4.185
Less: Gas Cost Level in Rates 2/	<u>4.484</u>
Current Gas Cost Adjustment	<u><u>(\$0.299)</u></u>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -15 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8:
Cost of Purchased Gas \$4.484

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
April 2011 PGA**

Williston Basin Interstate Pipeline Company - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company – Exhibit B, pages 9-10 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 11-12 for Schedule FT-D.

NorthWestern Energy – Exhibit B, page 13 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline – Exhibit B, page 14 for Rate 1.

SourceGas Distribution LLC – Exhibit B, Page 15 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	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FT-1						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.170%, CONSISTING OF 2.359% FOR THE CURRENT PERCENTAGE AND (0.189%) 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 0.632 CENTS, CONSISTING OF 0.496 CENTS FOR THE CURRENT RATE AND 0.136 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.

Issued On: March 1, 2011
 Docket Number:
 FERC Order Date:

Effective On: April 1, 2011

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

RATE SCHEDULE FTN-1						

RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	N.A.	0.052

Issued On: September 30, 2010
 Docket Number: RP10-1378-000
 FERC Order Date: November 1, 2010

Effective On: September 30, 2010

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1						
CAPACITY RESERVATION						
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY						
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
INJECTION						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE						
INJECTION						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.095%, CONSISTING OF 0.361% FOR THE CURRENT PERCENTAGE AND (0.266%) 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 (0.182) CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND (0.182) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

Issued On: March 1, 2011
 Docket Number:
 FERC Order Date:

Effective On: April 1, 2011

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

PART 4.1
Statement of Rates
T-1 and T-1B - Long Term Base Tariff Rates
v.0.0.0

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	\$0.0321
Minimum	\$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	\$0.0345
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 Base Rates, pursuant to the Stipulation at Docket No. RP06-72-000, et al., remain in effect until such rates are superseded by new base 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 X of the Stipulation at Docket No. RP06-72-000, et al.

Issued: July 28, 2010
Effective: July 28, 2010

Docket No. RP10-1004-000
Accepted: September 22, 2010

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

PART 4.7
Statement of Rates
ACA and Compressor Usage Surcharge
v.0.0.0

STATEMENT OF RATES

	Commodity Rate -----
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	\$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	\$0.0020

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 6.16 of the General Terms and Conditions herein, the ACA is effectively charged at a rate of \$0.0002 per 100 Dekatherm-miles.

2/ Rate is charged in accordance with Section 6.44 of the General Terms and Conditions.

Issued: July 28, 2010
Effective: July 28, 2010

Docket No. RP10-1004-000
Accepted: September 22, 2010

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges
Page 1 of 1

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)	\$ 191.49/10 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	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	\$ 5.97/GJ	
	FT-D Demand Rate for Group 2 Delivery Points ¹	\$ 1.74/GJ	
	FT-D Demand Rate for Group 3 Delivery Points ²	N/A	
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	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	10.64	
	6-10 years	8.89	
	15 years	7.97	
	20 years	7.08	
8. Rate Schedule LRS-2	LRS-2 Rate per month	\$ 50,000	
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month	\$ 129.55/10 ³ m ³	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
13. Rate Schedule PT	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9006-01000-0	\$ 60.50/d	1.0 10 ³ m ³ /d
	9009-01001-1	\$ 660.00/d	50.0 10 ³ m ³ /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2011462247	\$ 27.00 / month	
	2011462241	\$ 7.00 / month	
	2011462238	\$ 20.00 / month	
	2011462242	\$ 3.00 / month	
	2011462243	\$ 1.00 / month	
	2011462244	\$ 32.00 / month	
	2011462240	\$ 1.00 / month	
	2011462245	\$ 1,985.00 / month	
	2011462252	\$ 3.00 / month	
	2011462239	\$ 56.00 / month	
	2011462248	\$ 135.00 / month	
	2011462249	\$ 75.00 / month	
	2011462246	\$ 11.00 / month	
	2011462250	\$ 207.00 / month	
	2011462251	\$ 204.00 / month	
	2011463220	\$ 392.00 / month	
	2003004522	\$ 83,333.00 / month	
15. Rate Schedule CO ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	505.25	
	2	399.89	
	3	261.29	

1. Rate for all Group 2 Delivery Points with the exception of Alberta-Montana, Cold Lake and Unity.
2. FT-D Service at Group 3 Delivery Points not available until the Integration Effective Date.

NOVA Gas Transmission Ltd.

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	5.95	0.2150
3002	BOUNDARY LAKE BORDER	4.37	0.1581
1958	EMPRESS BORDER	6.03	0.2181
3886	GORDONDALE BORDER	4.37	0.1581
6404	MCNEILL BORDER	6.03	0.2181

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)
3880	AECO INTERCONNECTION	1.74	0.0628
3868	ALBERTA-MONTANA	4.37	0.1581
3059	ALLISON CREEK SALES	1.74	0.0628
3562	AMOCO SALES (BP SALES TAP)	1.74	0.0628
3488	ARDLEY SALES	1.74	0.0628
3943	ATUSIS CREEK INTERCONNECTION	1.74	0.0628
3135	AURORA SALES	1.74	0.0628
3423	BASHAW WEST SALES	1.74	0.0628
3068	BEAVER HILLS SALES	1.74	0.0628
3933	BIG EDDY INTERCONNECTION	1.74	0.0628
3067	BIGSTONE SALES	1.74	0.0628
3887	BITTERN LAKE INTERCONNECTION	1.74	0.0628
3468	BLEAK LAKE SALES	1.74	0.0628
3471	BLUE RIDGE EAST SALES	1.74	0.0628
3164	BRAINARD LAKE SALES	1.74	0.0628
2364	BROWNVALE SALES	1.74	0.0628
3918	BUFFALO CREEK INTERCONNECTION	1.74	0.0628
3109	CALDWELL SALES	1.74	0.0628
3634	CANOE LAKE SALES	1.74	0.0628
3165	CANOE LK SLS #2	1.74	0.0628
3866	CARBON INTERCONNECTION	1.74	0.0628
3484	CARIBOU LAKE SALES	1.74	0.0628
3157	CARIBOU LK SOUTH SL	1.74	0.0628
3106	CARMON CREEK SALES	1.74	0.0628
3101	CAROLINE SALES	1.74	0.0628
3893	CARROT CREEK INTERCONNECTION	1.74	0.0628
3495	CAVALIER SALES	1.74	0.0628
3907	CHANCELLOR INTERCONNECTION	1.74	0.0628
3151	CHEECHAM W. #2 SALES	1.74	0.0628
3622	CHEECHAM WEST SALES	1.74	0.0628
6014	CHEVRON AURORA SALES	1.74	0.0628
3097	CHICKADEE CREEK SALES	1.74	0.0628
3305	CHIGWELL NORTH SALES	1.74	0.0628
3496	CHIPEWYAN RIVER SALES	1.74	0.0628
3163	CHRISTINA LAKE NORTH SALES	1.74	0.0628
3158	CLYDE N SALES	1.74	0.0628
1417	COLD LAKE BDR	4.37	0.1581
3052	COLEMAN SALES	1.74	0.0628
3168	COLLICUTT SALES	1.74	0.0628
3904	CONKLIN WEST INTERCONNECTION	1.74	0.0628
3416	COUSINS A SALES	1.74	0.0628
1963	COUSINS B & C SALES	1.74	0.0628
3483	CRAMMOND SALES	1.74	0.0628
3105	CRANBERRY LAKE SALES	1.74	0.0628

NATURAL GAS TARIFF

NorthWestern
Energy

Canceling 22nd Revised
21st Revised

Sheet No. 80.1
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 101.80	(I)
10,001 to 30,000	\$ 146.35	(I)
>30,000	\$ 324.70	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 8.321131 (I)

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum \$ 0.063056 (I)

Minimum \$ 0.017935

GTAC Amortization \$ 0.000962

Balancing Penalty Rate Higher of \$25.00 / Dkt. 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.

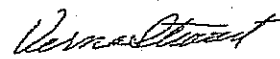
MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: December 29, 2010
Docket No.: D2010.12.116, Interim Order No. 7131
Tariff Letter No. 182-G

Effective for service rendered on or after
January 1, 2011

PUBLIC SERVICE COMMISSION

 Secretary

GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company
1415 N. Airport Rd
Pierre, SD 57501
e Filed: January 24, 2001

SD P.U.C. Section 1
Original Sheet No. 1
Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

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

**STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE**

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
Second Revised Sheet No. 12
Cancels First 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 Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantiv Percentage 3/</u>
TC (Casper) Firm Transportation	MLI	MLI	\$0.00	\$0.1040	\$0.0010	0.781%
	MLI	MLE	\$145.00 \$0.	1040 \$0	.0010	0.781%
	MLI	DSE	\$225.00 \$0.	1978 \$0	.0020	3.425%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.781%
	MLI	MLE	\$145.00 \$0.	0844 \$0	.0010	0.781%
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.
- 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.

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

MLI M ainline System Interconnect
MLE M ainline System End-user
DSE D istribution System End-user

Date Issued: November 19, 2010
By: William N. Cantrell

Date Effective: January 1, 2011
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE APRIL 2011**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2010	\$13,431,294	\$653,606	\$3,048,451
November	11,876,668	567,703	2,461,969
December	8,556,380	397,067	1,152,656
January 2011	3,966,541	182,321	(456,011)
February	306,599	12,852	(1,380,617)
March	(1,218,268)	(70,050)	(1,960,834)
April	(1,032,073)	(80,282)	(1,777,995)
May	406,617	(37,897)	(1,050,438)
June	2,692,001	41,432	(53,899)
July	5,261,526	128,466	984,848
August	8,219,519	232,148	2,004,193
September	11,324,717	575,004	2,806,698
October	12,792,581	618,253	3,052,265
13 month average	<u>\$5,891,085</u>	<u>\$247,740</u>	<u>\$679,330</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$517,885	\$21,779	\$59,720
Return Requirement	<u>\$712,821</u>	<u>\$29,977</u>	<u>\$82,199</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 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, 2010									<u>(\$695,379)</u>
August	(\$305,149)	\$0	(\$94)	(\$305,243)	253,885	(\$0.515)	(\$130,750)	(\$174,493)	(869,872)
September	(418,566)	29,770 2/	(108)	(388,904)	283,887	(0.515)	(146,202)	(242,702)	(1,112,574)
October	(107,579)	0	(121)	(107,700)	428,232	(0.023)	(146,040) 3/	38,340	(1,074,234)
November	369,998	0	(126)	369,872	828,788	(0.023)	(19,062)	388,934	(685,300)
December	(144,841)	0	(80)	(144,921)	2,130,965	(0.023)	(49,012)	(95,909)	(781,209)
January 2011	813,114	0	(98)	813,016	2,578,993	(0.023)	(59,316)	872,332	91,123
Balance @ January 31, 2011									<u>\$91,123</u>

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

2/ True-up related to August gas costs.

3/ Reflects 276,812.1 Dk @ (\$0.515) and 151,420 Dk @ (\$0.023).

**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, 2010									<u>(\$18,649)</u>
August	\$9,163	\$0	(\$3)	\$9,160	29,023	(\$0.152)	(\$4,411)	\$13,571	(5,078)
September	(15,678)	(11,373) 2/	(1)	(27,052)	37,408	(0.152)	(5,686)	(21,366)	(26,444)
October	(34,715)	0	(3)	(34,718)	37,752	(0.010)	(5,698) 3/	(29,020)	(55,464)
November	30,228	0	(6)	30,222	50,009	(0.010)	(500)	30,722	(24,742)
December	(30,216)	0	(3)	(30,219)	87,608	(0.010)	(876)	(29,343)	(54,085)
January 2011	55,493	0	(7)	55,486	108,571	(0.010)	(1,086)	56,572	2,487
Balance @ January 31, 2011									<u>\$2,487</u>

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

2/ True-up related to August gas costs.

3/ Reflects 37,464.9 Dk @ (\$0.152) and 287.3 Dk @ (\$0.010).

**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, 2010									<u>\$14,139</u>
August	(\$14,595)	\$0	\$2	(\$14,593)	3,296	\$0.024	\$79	(\$14,672)	(533)
September	(16,382)	2,449 2/	0	(13,933)	5,317	0.024	128	(14,061)	(14,594)
October	(12,118)	0	(2)	(12,120)	12,771	0.031	306 3/	(12,426)	(27,020)
November	10,050	0	(3)	10,047	27,693	0.031	859	9,188	(17,832)
December	(18,781)	0	(2)	(18,783)	56,480	0.031	1,751	(20,534)	(38,366)
January 2011	41,278	0	(5)	41,273	80,326	0.031	2,490	38,783	417
Balance @ January 31, 2011									<u>\$417</u>

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

2/ True-up related to August gas costs.

3/ Reflects 12,770.8 Dk @ \$0.024.