

February 9, 2012

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-12-008

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 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 (101st Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered March 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.518 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 \$0.001 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 March 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.519 per dk for residential and firm general service customers, a decrease of \$0.511 per dk for small and large interruptible customers and a decrease of \$0.509 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 March 2012. The average cost of gas for firm customers, adjusted for losses, is \$3.939.

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.

These proposed adjustments, calculated in accordance with Rate 88, will amount to a decrease of approximately \$995,600 for natural gas customers during the month of March 2012. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 94,503 natural gas customers in North Dakota as of January 31, 2012.

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

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of March 2012. The net effect of this filing is a decrease of \$1.098 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of March 2012. The average cost of propane for all customers, adjusted for losses, is \$17.016 per dk.

This proposed adjustment, calculated in accordance with Rate 99, will amount to a decrease of approximately \$7,600 for propane customers during the month of March, 2012. All of the Montana-Dakota's propane customers in North Dakota may be affected by this proposal. There were 336 propane customers in North Dakota as of January 31, 2012.

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 also submits herewith its check for \$500 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment will cover the filing fee associated with the monthly COG filings for March through December 2012.

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
 101st Revised Sheet No. 3
 Canceling 100th 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	\$3.898	\$4.710
Air Force Rate 64	7	\$1,000.00 per month \$135.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.138	\$3.898	\$4.036
Interruptible Service - PAR			\$0.120	\$3.069	\$3.189
Interruptible Service - MAFB			\$0.120	\$3.032	\$3.152
Firm General Service Rate 70	13	\$0.52 per day \$1.75 per day	\$0.597	\$3.898	\$4.495
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet					
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.069	(Maximum) \$3.940
Optional Seasonal Gas Service Rate 72	15	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet					
Winter Gas Usage			\$0.597	\$3.986	\$4.583
Summer Gas Usage			\$0.597	\$3.050	\$3.647
Transportation Service	24	\$150.00 per month			
Small Interruptible Rate 81					
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.014	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.014	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.069	(Maximum) \$3.788
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$17.518	\$18.330
Firm General Propane Rate 92	34	\$0.52 per day \$1.75 per day	\$0.597	\$17.518	\$18.115
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet					

Date Filed: February 9, 2012

Effective Date:

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:

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

March 2012

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.

Continued mild weather across much of the US, record levels of gas in storage and strong domestic supply likely contributed to the decrease in the commodity price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of January 27, 2012 were 25.4 percent above the five-year average and 19.8 percent above last year’s record 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 4 through 16.

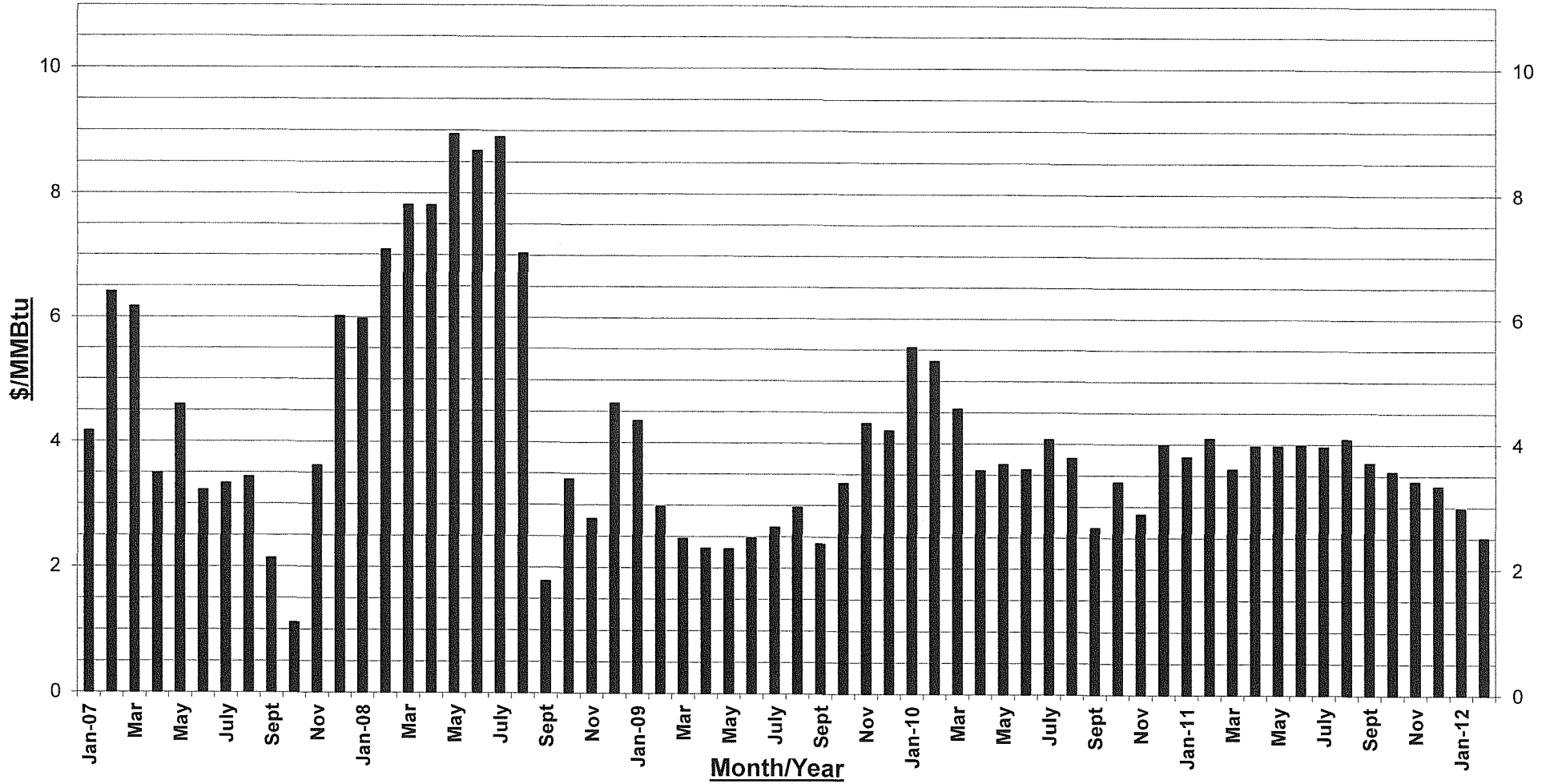
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
March 2012**

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

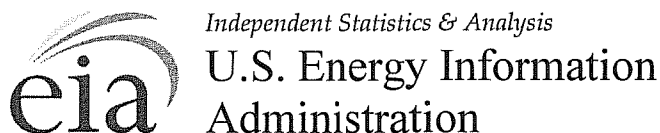
The February prices for propane have decreased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage decreases, this has resulted in a decrease in the price of propane.

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

CIG Rocky Mountains Index Monthly Gas Prices 2007-2012YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2010-\$3.92; 2011-\$3.79; 2012YTD - \$2.75



February 2012

Short-Term Energy Outlook

February 7, 2012 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$100 per barrel in 2012, almost \$6 per barrel higher than the average price last year. Based on recent futures and options data, the market believes there is about a one-in-fifteen chance that the average WTI price in June 2012 will exceed \$125 per barrel, and about a one-in-fifty chance that it would exceed \$140 per barrel. For 2013, EIA expects WTI prices to continue to rise, reaching \$106 per barrel in the fourth quarter of next year. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 2.0 percent in 2012 and 2.4 percent in 2013, while world real GDP (weighted by oil consumption) grows by 2.9 percent and 3.7 percent in 2012 and 2013, respectively.
- This is the third consecutive monthly *Outlook* in which the forecast of average household expenditures for heating fuels has been lowered because of the continuing unusually warm weather for most of the Nation. Average household heating oil expenditures are now expected to increase by only 1 percent this winter heating season (October 1 to March 31) compared with last winter. Natural gas and propane expenditures are projected to decline by 11 percent and 5 percent, respectively, and electricity expenditures are 4 percent lower than last winter's levels.
- EIA expects regular-grade motor gasoline retail prices to average \$3.55 per gallon in 2012, compared with \$3.53 cents per gallon last year, and then average \$3.59 per gallon in 2013. During the April through September peak driving season each year, prices are forecast to average about 7 cents per gallon higher than the annual average. Recent options and futures price data imply that the market believes that there is about a one-in-four chance that the U.S. average pump price of regular gasoline could exceed \$4 in June of this year.

- Natural gas working inventories continue to set new record seasonal highs and ended January 2012 at an estimated 2.86 trillion cubic feet (Tcf), about 24 percent above the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is \$3.35 per million British thermal units (MMBtu), a decline of about \$0.65 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$4.07 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Absent a significant oil supply disruption, EIA expects world markets to continue to gradually tighten in 2012 and 2013, as increases in global consumption outpace production growth in countries outside of the Organization of the Petroleum Exporting Countries (OPEC). World liquid fuels consumption grows by an annual average of 1.3 million barrels per day (bbl/d) in 2012 and 1.5 million bbl/d in 2013. Supply from non-OPEC countries increases by 0.8 million bbl/d in 2012 and 0.9 million bbl/d in 2013. EIA expects that the market will rely on both inventories and increases in production of crude oil and non-crude liquids from OPEC members to meet world demand growth.

There are many significant uncertainties that could push oil prices higher or lower than projected. Should a significant oil supply disruption occur, and OPEC members do not increase production, or projected non-OPEC projects come online more slowly than expected, oil prices could be significantly higher than projected in this *Outlook*. If the pace of global economic growth fails to accelerate in Organization for Economic Cooperation and Development (OECD) countries, or if economic growth slows in non-OECD countries, reduced demand could result in lower prices.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 0.8 million bbl/d to 87.9 million bbl/d in 2011. EIA expects that this growth will accelerate over the next two years, with consumption reaching 89.3 million bbl/d in 2012 and 90.7 million bbl/d in 2013. OECD consumption fell by 490 thousand bbl/d in 2011 and is expected to decline again in 2012 as very modest consumption growth in the United States and Japan will be more than offset by a decline in consumption in Europe. Non-OECD countries are expected to account for most of the world's consumption growth over the next two years, with the largest contributions coming from China and the Middle East (World Liquid Fuels Consumption Chart). EIA expects that non-OECD consumption growth will increase from 1.3 million bbl/d in 2011 to 1.5 million bbl/d in 2012, and then slow to 1.3 million bbl/d in 2013.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 770 thousand bbl/d in 2012 and by a further 850 thousand bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 350 thousand bbl/d and 260 thousand bbl/d in 2012 and 2013, respectively, resulting from continuing growth in production from U.S. onshore shale formations and Canadian oil sands. Other major growth areas include Brazil, where production increases annually by an average of 170 thousand bbl/d over the next two years with increased output from its offshore, pre-salt oil fields, and Kazakhstan, which will commence commercial production in the Kashagan field in 2013, increasing its production annually by an average of 140 thousand bbl/d. Production also increases in Colombia, Norway, and China. Production declines in Russia, Mexico, and the United Kingdom.

The most notable revision in this month's *Outlook* occurs in Sudan, where an unresolved dispute between the Khartoum government and newly independent South Sudan over transit fees and other issues has caused the latter to shut in production. EIA now projects that total Sudan and South Sudan production, which averaged about 425 thousand bbl/d in 2011, will average 210 thousand bbl/d in 2012 and recover to 340 thousand bbl/d in 2013.

OPEC Supply. EIA expects that OPEC members' crude oil production will continue to rise over the next two years to accommodate increasing world oil consumption. Projected OPEC crude oil production increases by about 250 thousand bbl/d and 520 thousand bbl/d in 2012 and 2013, respectively. OPEC non-crude petroleum liquids (condensates, natural gas liquids, and gas-to-liquids), which are not subject to production targets, increase by 640 thousand bbl/d in 2012 and by 80 thousand bbl/d in 2013. EIA expects that OPEC surplus production capacity will increase from about 2.2 million bbl/d in December 2011 to 3.9 million bbl/d at the end of 2013, as the assumed recovery of Libyan production to pre-disruption levels allows other OPEC producers to scale back production (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the OECD ended 2011 at 2.64 billion barrels, equivalent to about 56.8 days of forward-cover (days-of-supply). Although the December 2011 inventory is slightly lower than the 2.66 billion barrel level at the end of December 2010, the days of forward-cover is the highest end-of-year level since 1994 because of a decline in OECD consumption last year. Projected OECD oil inventories decline slightly over the forecast, with OECD inventories falling to 2.59 billion barrels, or 55.5 days of forward cover, at the end of 2013 (Days of Supply of OECD Commercial Stocks Chart).

Crude Oil Prices. EIA's forecast of the WTI spot price is unchanged from last month's *Outlook*, averaging about \$100 per barrel in 2012 and \$104 per barrel in 2013 (West Texas Intermediate Crude Oil Price Chart). The projected WTI price discount to other U.S. and world crude oils narrows over the forecast. The projected average refiner acquisition cost (RAC) of crude oil averages \$105 per barrel and \$106 per barrel in 2012 and 2013, respectively.

Energy price forecasts are highly uncertain (Market Prices and Uncertainty Report). WTI futures for April 2012 delivery during the 5-day period ending February 2, 2012 averaged \$98.52 per barrel. Implied volatility averaged 30 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in April 2012 at \$81 per barrel and \$120 per barrel, respectively. Last year at this time, WTI for April 2011 delivery averaged \$93 per barrel and implied volatility averaged 30 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$76 per barrel and \$114 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. In 2011, total U.S. liquid fuels consumption fell by 340 thousand bbl/d (1.8 percent) from 2010 (U.S. Liquid Fuels Consumption Chart). Motor gasoline consumption accounted for much of that decline, shrinking by 250 thousand bbl/d (2.8 percent). In contrast, distillate fuel oil consumption rose by 60 thousand bbl/d (1.5 percent), brought about by recovery in industrial output and freight transport.

Despite the prospects for continued economic recovery and projections of slight increases in petroleum product prices, the next two years are expected to see only small increases in total liquid fuels consumption, with growth of about 30 thousand bbl/d (0.1 percent) in 2012 and 90 thousand bbl/d (0.5 percent) in 2013. Motor gasoline consumption, constrained by slowing driving-age population growth and the improving fuel economy of new vehicles, is forecast to fall slightly in both 2012 and 2013. Distillate fuel consumption, however, continues to rise by an annual average of 60 thousand bbl/d through 2013.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 110 thousand bbl/d to 5.59 million bbl/d in 2011. A 380-thousand bbl/d increase in lower-48 onshore production in 2011 was partly offset by a 40-thousand bbl/d decline in Alaska and a 230-thousand bbl/d decline in output in the Federal Gulf of Mexico (GOM).

Forecast total crude oil production increases by 240 thousand bbl/d in 2012 and by a further 90 thousand bbl/d in 2013. Continued increases in lower-48 onshore crude oil production of 340 thousand bbl/d in 2012 and 110 thousand bbl/d in 2013 overshadow declines averaging about 20 thousand bbl/d in Alaskan output each year and a 90 thousand bbl/d decrease in 2012 GOM production (U.S. Crude Oil and Liquid Fuels Production Chart). The rise in production is driven by increased oil-directed drilling activity, particularly in onshore shale formations. The number of onshore oil-directed drilling rigs reported by Baker Hughes increased from 777 at the beginning of 2011 to 1,245 on February 3, 2012.

For the first time since 1949, the United States was a net exporter of refined petroleum products in 2011, with gross product exports averaging 420 thousand bbl/d more than gross product imports (product exports averaged almost 2.5 million barrels per day less than gross product imports in 2005). EIA expects that the United States will continue to be a net product exporter, with net product exports averaging 350 thousand bbl/d in 2012 and 320 thousand bbl/d in 2013.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and refined products), which has been falling since 2005, averaged 45 percent in 2011, down substantially from 49 percent in 2010. EIA expects that the total net import share of consumption will remain near 2011 levels in 2012 and 2013, as continued growth in domestic crude oil output exceeds the growth in liquid fuels consumption and total inventory levels stabilize.

U.S. Petroleum Product Prices. Regular-grade gasoline retail prices averaged \$3.53 per gallon in 2011, which was \$0.74 per gallon (27 percent) higher than the 2010 average. Higher crude oil costs (\$0.60 per gallon) and refinery gasoline margins (\$0.11 per gallon) accounted for most of that increase. EIA expects the regular-grade gasoline retail price to average \$3.55 per gallon in 2012 as higher crude oil prices are offset by lower refinery gasoline margins (U.S. Gasoline and Crude Oil Prices Chart). Forecast regular-grade gasoline prices increase to an average \$3.59 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.91 per gallon in 2012 and \$3.99 per gallon in 2013 (U.S. Diesel Fuel and Crude Oil Prices Chart).

Between 1990 and 2004, annual average wholesale gasoline prices ranged from 5 cents per gallon to 11 cents per gallon above wholesale diesel prices. Beginning in 2005, wholesale gasoline prices fell below wholesale diesel fuel prices in all years except 2009, as world demand growth for diesel fuel, primarily in the emerging economies, outpaced gasoline demand growth. EIA expects the gasoline wholesale price to

remain lower than diesel wholesale prices, with gasoline prices averaging 18 cents per gallon below diesel in 2012 and 22 cents per gallon lower in 2013.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 68.5 billion cubic feet per day (Bcf/d) in 2012, an increase of 1.6 Bcf/d (2.4 percent) from 2011. Consumption increases in all sectors, with the largest volume increase (1.2 Bcf/d) coming from the electric power sector. Natural gas consumption growth continues into 2013, with projected total consumption averaging 69.7 Bcf/d (U.S. Natural Gas Consumption Chart). Increases in the consumption of natural gas for power generation are likely to continue as domestic production continues to grow and natural gas remains a relatively inexpensive option for generators.

U.S. Natural Gas Production and Imports. Total marketed production grew by an estimated 4.8 Bcf/d (7.8 percent) in 2011, the largest year-over-year volumetric increase in history. This strong growth was driven in large part by increases in shale gas production. While EIA expects production growth to continue in 2012 and 2013, the projected increases occur at a much lower rate than in 2011 as low prices reduce new drilling plans. According to Baker Hughes, the natural gas rig count has fallen to 745 as of February 3, 2012, from a 2011 high of 936 in mid-October. Declines in production have not accompanied declines in the rig count, partly reflecting improving drilling efficiency. That fact, combined with high initial production rates from new wells, associated natural gas production from oil drilling, and a backlog of uncompleted or unconnected wells contribute to EIA's forecast of further production increases in 2012 and 2013.

Pipeline gross imports are expected to fall by 0.5 Bcf/d (5.5 percent) in 2012 as domestic production grows and displaces Canadian sources. This follows a 0.6 Bcf/d (6.4 percent) decline in pipeline gross imports in 2011. Pipeline gross exports grew by 1.0 Bcf/d in 2011, largely the result of increased exports to Mexico. Pipeline gross exports are expected to continue to grow, though at a slower rate, in 2012 and 2013.

Liquefied natural gas (LNG) imports are expected to decline by 0.3 Bcf/d (28 percent) in 2012. EIA predicts an average of about 0.7 Bcf/d will arrive at terminals in the United States in both 2012 and 2013, either to take advantage of temporarily high local prices due to cold snaps and disruptions or to fulfill long-term contract obligations.

U.S. Natural Gas Inventories. Working natural gas inventories continue to set new seasonal record highs as the unusually warm winter has contributed to much lower-than-normal inventory draws. As of January 27, 2012, according to EIA's *Weekly*

Natural Gas Storage Report, working inventories totaled 2,966 Bcf, 586 Bcf greater than last year's level. EIA expects the winter heating season will end March 31 with inventories over 2,000 Bcf, and inventory levels at the end of October 2012 and 2013 are expected to set new record highs as well (U.S. Working Natural Gas in Storage Chart).

U.S. Natural Gas Prices. Natural gas spot prices averaged \$2.67 per MMBtu at the Henry Hub in January 2012, down \$0.50 per MMBtu from the December 2011 average and the lowest average monthly price since 2002. Abundant storage levels, as well as ample supply, have contributed to the recent low prices. EIA expects the Henry Hub spot price will begin to recover after this winter's inventory draw season ends and will average \$3.35 per MMBtu in 2012 and \$4.07 per MMBtu in 2013, down \$0.18 per MMBtu and \$0.07 per MMBtu from last month's *Outlook*, respectively (U.S. Natural Gas Prices Chart).

Natural gas futures prices for April 2012 delivery (for the 5-day period ending February 2, 2012) averaged \$2.71 per MMBtu, and the average implied volatility was 52 percent (Market Prices and Uncertainty Report). The lower and upper bounds for the 95-percent confidence interval for April 2012 contracts are \$1.84 per MMBtu and \$4.01 per MMBtu. At this time last year, the April 2011 natural gas futures contract averaged \$4.39 per MMBtu and implied volatility averaged 34 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.40 per MMBtu and \$5.66 per MMBtu.

Coal

U.S. Coal Consumption. Coal consumption for electricity generation fell by 40 million short tons (MMst) (4 percent) in 2011 (U.S. Coal Consumption Chart). Electric power sector coal consumption is forecast to decline by an additional 2 percent in 2012 as generation from natural gas, nuclear, and wind increases and electricity consumption grows by less than 1 percent. EIA expects electric power sector coal consumption to continue declining in 2013 as increased output from other generation sources meets growing demand for electricity.

U.S. Coal Supply. U.S. coal production remained nearly flat in 2011 as production growth in the Interior and Appalachian regions offset a decline in the Western region (U.S. Coal Production Chart). The significant increase in coal exports in 2011 was balanced by lower domestic consumption and a drawdown in inventories. EIA expects coal production to decline by about 2 percent in 2012 as domestic consumption and exports fall. EIA forecasts that the decline in production will

continue in 2013 as consumption falls slightly and inventory withdrawals continue (U.S. Electric Power Sector Coal Stocks Chart).

U.S. Coal Trade. U.S. coal exports of 107 MMst in 2011 were the highest since 1991. In anticipation of continued strong exports, several North American ports have announced plans to expand facilities to export coal. Facilities have been upgraded in the Hampton Roads, VA, area, and significant terminal upgrades to Gulf Coast coal-handling facilities are currently underway. Canada's Pacific coal terminals are undergoing expansion to meet Asian demand for coal and to help facilitate increasing exports from the U.S. Western Region. Several potential sites for new coal export facilities have been identified in the Pacific Northwest (Oregon and Washington), but no final decisions have been made.

U.S. Coal Prices. Delivered coal prices to the electric power sector have increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per MMBtu (5.8 percent increase from 2010). Looking forward, several factors are exerting downward pressure on the average delivered coal price, including lower demand for coal to generate electricity due to lower natural gas prices and concerns about the effects of the implementation of pending environmental requirements. EIA forecasts the average delivered coal price to be slightly lower than the 2011 level in 2012 and 2013.

Electricity

U.S. Electricity Consumption. EIA expects that total U.S. consumption of electricity will rise slightly during 2012 and then grow by 1.8 percent during 2013 (U.S. Total Electricity Consumption Chart). Much of the growth in consumption during 2012 will come from the commercial and industrial sectors. In contrast, moderate weather this year leads to reduced consumption in the residential sector. Temperatures during January were much warmer than normal, particularly in the Southeast, where a large proportion of homes heat with electricity. This lower winter consumption of electricity combined with projected lower summer temperatures is expected to push electricity sales to the residential sector down 1.2 percent in 2012. The total number of U.S. households is expected to grow 1.3 percent during 2013, which would be the highest growth rate since 1998. The increased number of households is projected to lead to a relatively strong 2.1 percent increase in residential electricity consumption in 2013.

U.S. Electricity Generation. EIA projects that total U.S. generation by all sectors will average 11.3 terawatt-hours per day during 2012. Coal is expected to fuel about 41.7 percent of this generation, down 0.8 percentage point from last year. During 2013,

EIA expects coal's share of generation to fall to 41.2 percent. In contrast, the share of generation fueled by natural gas is forecast to rise quite rapidly this year, growing from 24.6 percent in 2011 to 26.1 percent in 2012, primarily as a result of lower hydroelectric generation in the West and low natural gas fuel costs. The natural gas share of generation rises slightly in 2013 to 26.2 percent (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. Average U.S. residential electricity prices are forecast rise by 0.5 percent in 2012 before falling by a similar amount in 2013 (U.S. Residential Electricity Prices Chart). Regional price changes during 2012 vary from a decline of 2.5 percent in the Mountain region to an increase of 2.2 percent in New England.

Renewables and Carbon Dioxide Emissions

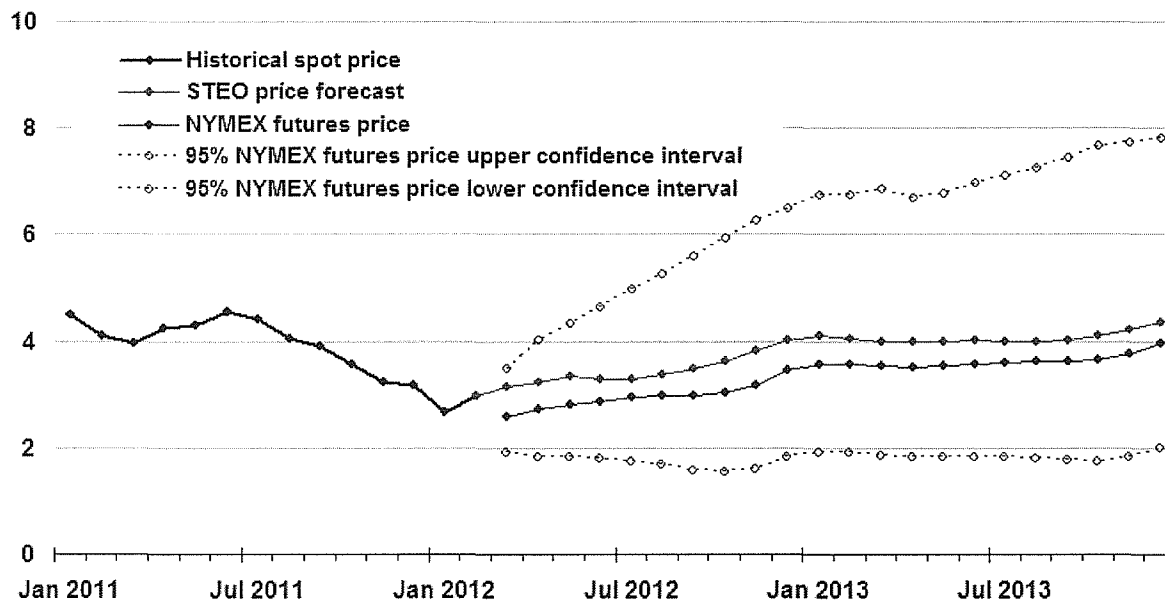
U.S. Renewables. After growing 13 percent in 2011, EIA expects the total renewable energy supply to decline by 3.6 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of a return to long-term average hydropower resource levels with hydropower supply falling by 0.5 quadrillion Btu (16 percent). The decline in hydropower from the 2011 level offsets growth in other renewable energy supplies. In 2013, renewables supply increases 2.1 percent, as non-hydropower renewables continue to increase.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to grow from an average of 909 thousand bbl/d in 2011 to 933 thousand bbl/d in 2012, and 938 thousand bbl/d in 2013. EIA estimates that biodiesel production in 2011 averaged about 58 thousand bbl/d (885 million gallons of total annual production). Forecast biodiesel production remains at 58 thousand bbl/d in 2012, then grows to 67 thousand bbl/d in 2013.

U.S. CO₂ Emissions. After declining by 1.2 percent in 2011, fossil fuel emissions are projected to increase by 0.2 percent in 2012 and remain flat in 2013. This modest change is the result of increasing emissions from natural gas while petroleum and coal emissions are either flat or declining over these projection years. (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

dollars per million Btu



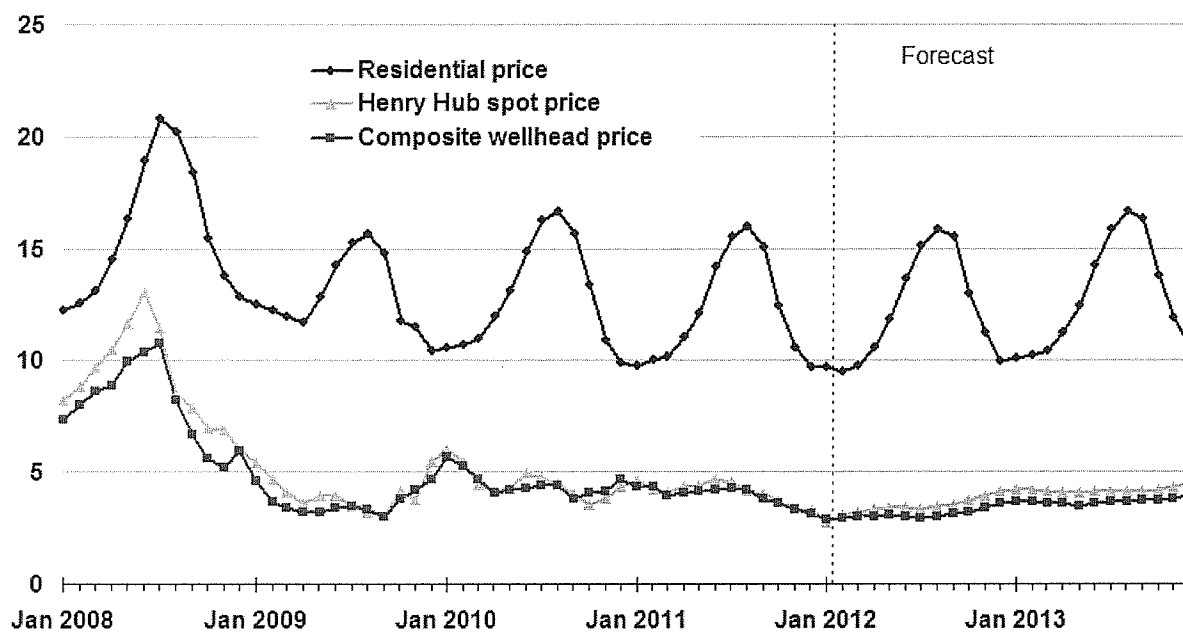
*Note: Confidence interval derived from options market information for the 5 trading days ending February 2, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts*

Source: Short-Term Energy Outlook, February 2012



U.S. Natural Gas Prices

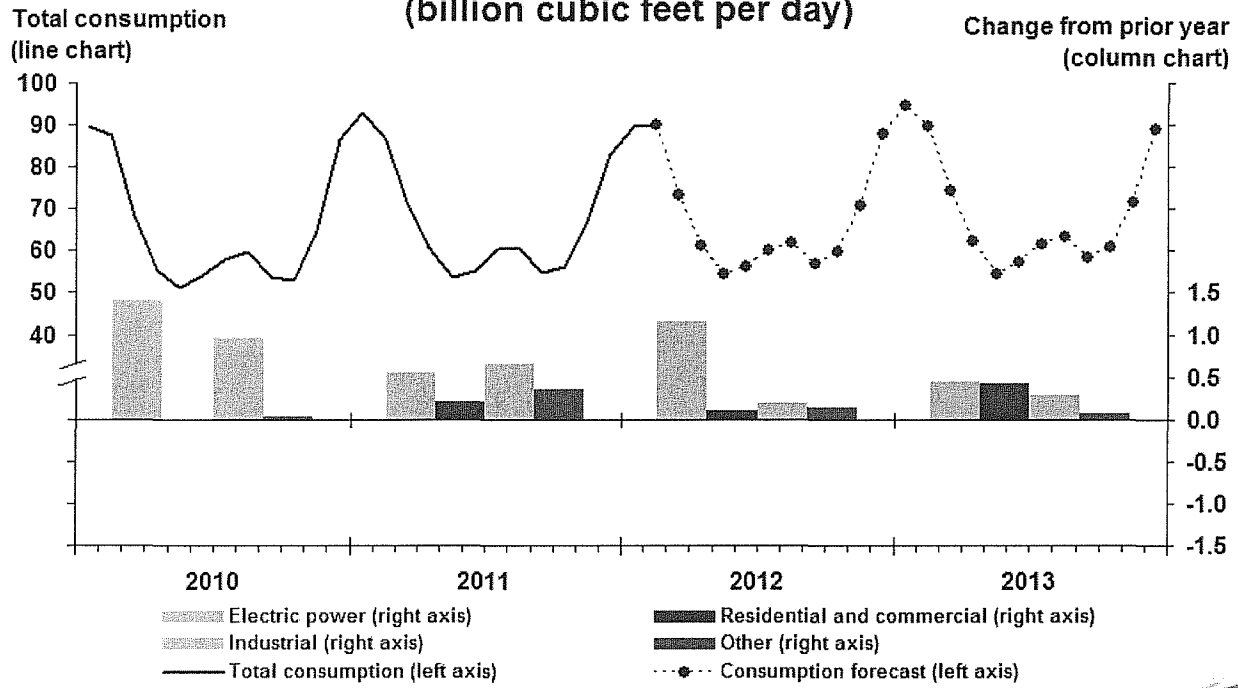
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, February 2012



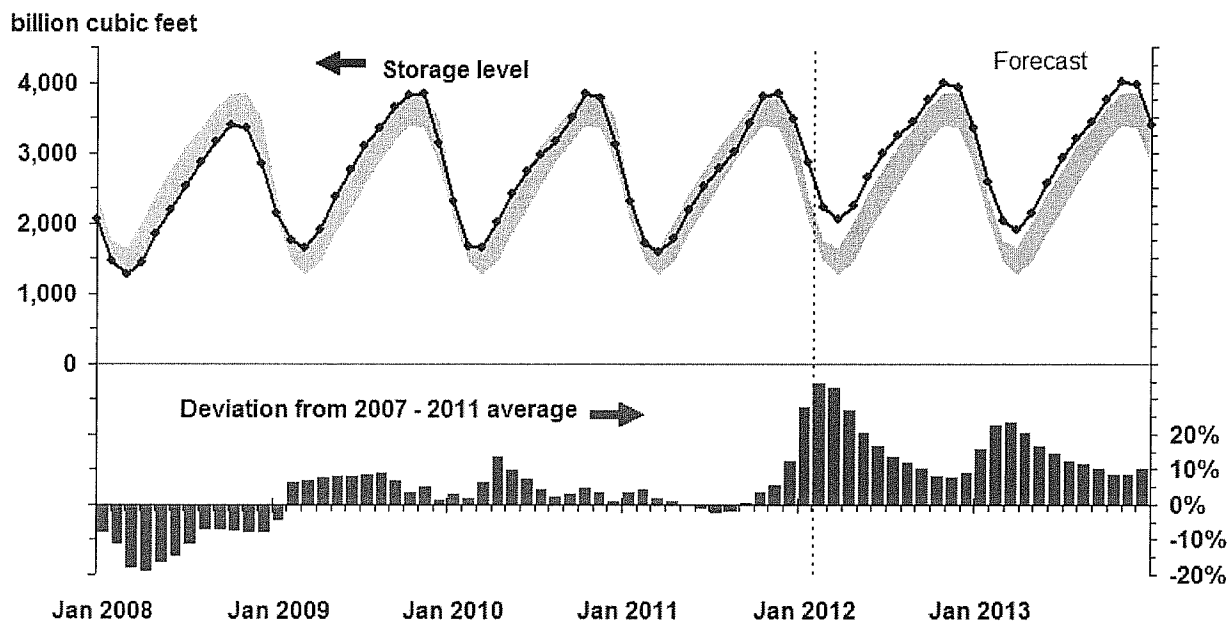
U.S. Natural Gas Consumption (billion cubic feet per day)



Source: Short-Term Energy Outlook, February 2012



U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, February 2012



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

NorthWestern Energy

On December 8, 2011, NorthWestern Energy filed its 2012 Electric and Natural Gas State and Local Tax and Fee tracking filing in Docket No. D2011.12.97. On January 17, 2012, the Montana Public Service Commission issued an order approving these rates effective January 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: (0.001) cents per dk

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE MARCH 2012

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$3.939	\$4.027	\$3.005	\$2.991
Prior Gas Cost	4.458	4.546	3.516	3.500
Current Gas Cost Adjustment	(\$0.519)	(\$0.519)	(\$0.511)	(\$0.509)
<u>Surcharge Adjustment:</u>				
Current Adjustment	(\$0.032)	(\$0.032)	\$0.064	\$0.041
Prior Adjustment	(0.032)	(0.032)	0.064	0.041
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.009)	(\$0.009)	\$0.000	\$0.000
Prior Adjustment	(0.009)	(0.009)	0.000	0.000
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	(\$0.519)	(\$0.519)	(\$0.511)	(\$0.509)
Gas Cost Level	\$3.939	\$4.027	\$3.005	\$2.991
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	\$3.907	\$3.995	\$3.069	\$3.032

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE MARCH 2012

Cost of Gas - Propane

Current Propane Cost (Exhibit D)	\$17.016
Prior Propane Cost	<u>18.114</u>
Current Propane Cost Adjustment	<u><u>(\$1.098)</u></u>

Surcharge Adjustment

Current Adjustment	\$0.511
Prior Adjustment	<u>0.511</u>
Change in Surcharge Adjustment	\$0.000

Market Based Pricing Differential

Current Adjustment	(\$0.009)
Prior Adjustment	<u>(0.009)</u>
Change in Margin Sharing Provision	\$0.000

Net Increase (Decrease) in Gas Costs (\$1.098)

Propane Cost Level	\$17.016
Plus: Surcharge	<u>0.511</u>
Total Propane Cost Level in Rates	<u><u>\$17.527</u></u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE MARCH 2012**

	Amount
Total Gas Costs 1/	\$54,894,961
Residential and General Service dk Requirements 2/	13,998,738
Average Cost of Gas per dk	\$3.921
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.939
Less: Gas Cost Level in Rates 3/	4.458
Current Gas Cost Adjustment	(\$0.519)

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, 2011, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective February 1, 2012:

Cost of Purchased Gas	\$4.438
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.458

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE MARCH 2012**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$54,894,961
Less: Annual MDDQ Costs 1/	<u>11,821,667</u>
Total Gas Costs excluding MDDQ	\$43,073,294
Firm Service Requirements 1/	13,998,738
Other Gas Costs per Dk (excluding MDDQ)	\$3.077
Summer Seasonal Rate, adjusted for losses 2/	3.091
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,821,667
Winter Firm Service Requirements	12,681,002
MDDQ Costs per Winter Dk	\$0.932
Add: Other Gas Costs per Dk	<u>3.077</u>
Winter Seasonal Rate	\$4.009
Winter Seasonal Rate, adjusted for losses 2/	\$4.027
Less: Gas Cost Level in Rates 3/	<u>4.546</u>
Current Gas Cost Adjustment	<u><u>(\$0.519)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective February 1, 2012:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.586	\$4.526
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.602	\$4.546

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE MARCH 2012**

	Amount
Total Gas Costs 1/	\$10,476,710
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$2.991
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.005
Less: Gas Cost Level in Rates 2/	3.516
Current Gas Cost Adjustment	(\$0.511)

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-12-008 effective February 1, 2012:

Cost of Purchased Gas	\$3.500
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.516

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE MARCH 2012

	<u>Amount</u>
Total Gas Costs 1/	<u>\$2,632,078</u>
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$2.991
Less: Gas Cost Level in Rates 2/	<u>3.500</u>
Current Gas Cost Adjustment	<u><u>(\$0.509)</u></u>

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective February 1, 2012:
Cost of Purchased Gas \$3.500

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
March 2012 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, 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	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	0.180	N.A.	N.A.	3.300
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.180	N.A.	N.A.	31.064
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
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 3.261%, CONSISTING OF 3.450% 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 1.098 CENTS, CONSISTING OF 0.962 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: September 1, 2011
 Docket Number: RP11-2476-001
 FERC Order Date: September 28, 2011

Effective On: October 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 CHARGE						
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 CHARGE						
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 CHARGE						
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 CHARGE						
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 0.998%, CONSISTING OF 1.264% 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 0.491 CENTS, CONSISTING OF 0.673 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: August 31, 2011
 Docket Number: RP11-2477-000
 FERC Order Date: September 23, 2011

Effective On: October 1, 2011

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.1.0.0 Superseding 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: December 13, 2010
Effective: July 28, 2010

Docket No. RP10-1004-001
Accepted: August 16, 2011

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges
Page 1 of 2

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)	\$ 179.94/10 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 ³	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	\$ 5.44/GJ	
	FT-D Demand Rate for Group 2 Delivery Points ¹	\$ 2.39/GJ	
	FT-D Demand Rate for Group 3 Delivery Points ²	\$ 2.87/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 ³	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	10.85	
	6-10 years	9.07	
	15 years	8.13	
	20 years	7.22	
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 ³	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>
	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
	2011466606	\$ 204.00	/ month
	2011463220	\$ 392.00	/ month
	2003004522	\$ 83,333.00	/ month
	2011476052 / 2011476054	\$ 0.0783	/ GJ subject to
		\$ 717,000.00	Minimum Annual Charge
	2011475772	\$ 9,250.00	/ month
	2011475056	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011476092	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month
	2011494569	\$ 0.095	/ GJ and
		\$ 1,000.00	/ month

NOVA Gas Transmission Ltd.

Attachment 2
Table of Rates, Tolls and Charges
Page 1 of 5

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	5.51	0.1986
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	2.39	0.0861
31110	ALLIANCE EDSON INTERCONNECT APN	2.39	0.0861
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	2.39	0.0861
3002	BOUNDARY LAKE BORDER	3.44	0.1242
1958	EMPRESS BORDER	5.30	0.1911
3886	GORDONDALE BORDER	3.44	0.1242
6404	MCNEILL BORDER	5.30	0.1911

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	3.39	0.1226	Yes
31001	ADM AGRI INDUSTRIES SALES APN	3.39	0.1226	Yes
3880	AECO INTERCONNECTION	2.39	0.0861	
31003	AGRIUM CARSELAND SALES APS	2.39	0.0861	
31002	AGRIUM FT. SASK SALES APN	2.39	0.0861	Yes
31004	AGRIUM REDWATER SALES APN	2.39	0.0861	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes ²
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA	3.44	0.1242	
3059	ALLISON CREEK SALES	2.39	0.0861	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes ²
3562	AMOCO SALES (BP SALES TAP)	2.39	0.0861	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	2.39	0.0861	
3135	AURORA SALES	2.39	0.0861	
3423	BASHAW WEST SALES	2.39	0.0861	
31013	BAYMAG SALES APS	2.39	0.0861	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	2.39	0.0861	
3933	BIG EDDY INTERCONNECTION	2.39	0.0861	
3067	BIGSTONE SALES	2.39	0.0861	
3468	BLEAK LAKE SALES	2.39	0.0861	
3164	BRAINARD LAKE SALES	2.39	0.0861	
3918	BUFFALO CREEK INTERCONNECTION	2.39	0.0861	
31015	BURDETT COGEN SALES APS	2.39	0.0861	
3204	CABIN SALES	2.39	0.0861	
3109	CALDWELL SALES	2.39	0.0861	
31016	CALGARY ENERGY CENTRE SALES APS	2.39	0.0861	Yes
3634	CANOE LAKE SALES	2.39	0.0861	
3165	CANOE LK SLS #2	2.39	0.0861	
3866	CARBON INTERCONNECTION	2.39	0.0861	
3484	CARIBOU LAKE SALES	2.39	0.0861	
3157	CARIBOU LK SOUTH SL	2.39	0.0861	
3106	CARMON CREEK SALES	2.39	0.0861	
3101	CAROLINE SALES	2.39	0.0861	
31017	CARSELAND COGEN SALES APS	2.39	0.0861	
3495	CAVALIER SALES	2.39	0.0861	
31018	CHAIN LAKES COOP SALES APS	2.39	0.0861	
3907	CHANCELLOR INTERCONNECTION	2.39	0.0861	
3151	CHEECHAM W. #2 SALES	2.39	0.0861	
3622	CHEECHAM WEST SALES	2.39	0.0861	
6014	CHEVRON AURORA SALES	2.39	0.0861	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes

NATURAL GAS TARIFF

**NorthWestern
Energy**

Canceling	<u>27th</u>	Revised	Sheet No.	<u>80.1</u>
	<u>26th</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	\$ 100.20	(R)
10,001 to 30,000	\$ 144.10	(R)
>30,000	\$ 319.75	(R)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	\$ 0.8193411	(R)
--	--------------	-----

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0062088	(R)
Minimum	\$ 0.0017935	
GTAC Amortization	\$ (0.0011145)	
Balancing Penalty Rate	Higher of \$25.00/ Dekatherm Or 150% of Market Price	

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

Staff Approved: December 28, 2011
Docket No.: D2011.12.97, Interim Order No. 7191
Tariff Letter No. 203-G

Effective for service rendered on or after
January 1, 2012

PUBLIC SERVICE COMMISSION
Aleisha Salim Secretary

GAS RATE SCHEDULE

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

SD P.U.C. Section No. 3
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

NG-00-001

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
Third Revised Sheet No. 12
Cancels Second 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 Quantity Percentage 3/</u>
TC (Casper)						
Firm						
Transportation	MLI	MLI	\$0.00	\$0.1040	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.1040	\$0.0010	0.885%
	MLI	DSE	\$225.00	\$0.1978	\$0.0020	2.425%
Interruptible						
Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.0844	\$0.0010	0.885%

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.

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

Date Issued: March 1, 2011
By: William N. Cantrell

Date Effective: June 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 MARCH 2012**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2011	\$14,843,510	\$727,522	\$3,066,232
November	12,931,691	618,119	2,523,623
December	9,767,572	426,234	1,229,961
January 2012	8,203,570	284,558	(366,933)
February	5,749,736	119,512	(1,382,030)
March	4,245,765	12,753	(1,971,229)
April	4,143,290	(5,501)	(1,787,711)
May	4,288,882	(1,564)	(1,054,028)
June	5,092,717	51,085	(50,343)
July	6,667,952	157,282	1,003,778
August	8,441,701	277,056	2,038,667
September	10,190,656	629,549	2,854,083
October	10,864,752	666,988	3,115,161
13 month average	<u>\$8,110,138</u>	<u>\$304,892</u>	<u>\$709,172</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$712,962	\$26,803	\$62,343
Return Requirement	<u>\$972,243</u>	<u>\$36,550</u>	<u>\$85,015</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 2012

Cost of Purchased Propane	\$116,882
Gallons Purchased	75,408
Projected dk Sales	6,900
Propane Cost per Dk	\$16.939
Average Cost of Propane as Adjusted for Losses @ 99.55%	17.016
Less: Propane Cost Level in Rates 1/	<u>18.114</u>
Current Propane Cost Adjustment	<u><u>(\$1.098)</u></u>

1/ Propane Cost Level in Current Rates - Case No. PU-12-008, effective February 1, 2012.

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, 2011									<u>(\$589,074)</u>
August	\$229,854	\$119,111 2/	(\$5) 3/	\$348,960	257,122	(\$0.023)	(\$5,914)	\$354,874	(234,200)
September	153,237	(52,739) 4/	(70) 5/	100,428	263,383	(0.023)	(6,058)	106,486	(127,714)
October	(21,312)	0	(2)	(21,314)	389,643	(0.032)	(10,319) 6/	(10,995)	(138,709)
November	(43,536)	0	(1)	(43,537)	881,908	(0.032)	(28,221)	(15,316)	(154,025)
December	6,351	0	(1)	6,350	1,811,727	(0.032)	(57,975)	64,325	(89,700)
Balance @ December 31, 2011									<u>(\$89,700)</u>

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

2/ Reflects correction to restate June gas costs to include correct dk volumes.

3/ Includes interest associated with June gas cost adjustment.

4/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

5/ Includes interest associated with the September gas cost adjustments.

6/ Reflects 238,784.1 Dk @ (\$0.023) and 150,875.5 Dk @ (\$0.032).

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, 2011									<u><u>\$48,803</u></u>
August	\$10,522	\$0	\$1	\$10,523	30,906	(\$0.010)	(\$309)	\$10,832	59,635
September	14,424	20,058 2/	32 3/	34,514	33,439	(0.010)	(334)	34,848	94,483
October	(12,066)	0	1	(12,065)	54,461	0.064	(510) 4/	(11,555)	82,928
November	(4,161)	0	1	(4,160)	71,035	0.064	4,546	(8,706)	74,222
December	(22,361)	0	1	(22,360)	97,320	0.064	6,229	(28,589)	45,633
Balance @ December 31, 2011									<u><u>\$45,633</u></u>

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

2/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

3/ Includes interest associated with the September gas cost adjustments.

4/ Reflects 53,993.4 Dk @ (\$0.010) and 467.7 Dk @ \$0.064.

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2011									<u><u>\$82,096</u></u>
August	\$7,880	(\$62,107) 2/	\$0	(\$54,227)	4,781	\$0.031	\$148	(\$54,375)	27,721
September	11,054	(72,081) 3/	(7) 4/	(61,034)	4,781	0.031	148	(61,182)	(33,461)
October	(2,569)	0	(1)	(2,570)	11,572	0.041	358 5/	(2,928)	(36,389)
November	(9,963)	0	0	(9,963)	25,050	0.041	1,027	(10,990)	(47,379)
December	(12,123)	0	(1)	(12,124)	52,081	0.041	2,135	(14,259)	(61,638)
Balance @ December 31, 2011									<u><u>(\$61,638)</u></u>

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

2/ Reflects correction to restate June gas costs to include correct dk volumes.

3/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.

4/ Includes interest associated with the September gas cost adjustments.

5/ Reflects 11,571.6 Dk @ \$0.031.