MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

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

February 9, 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 (94th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered March 1, 2011.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.166 per dk since the last filing due to an increase in the overall market price of gas. Attachment B explains the reasons for the increase in the market price of gas.

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

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.166 per dk for residential and firm general service customers, an increase of $0.167 per dk for small and large interruptible customers and an increase of $0.167 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 2011. The average cost of gas for firm customers, adjusted for losses, is $5.465.

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 March 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 March 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 an increase of approximately $305,400 for natural gas customers during the month of March 2011. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 94,054 natural gas customers in North Dakota as of January 31, 2011.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern
Regulatory Analysis 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

Rita A. Mulkern
Regulatory Analysis 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
94th Revised Sheet No. 3
Canceling 93rd Revised Sheet No. 3

RATE SUMMARY SHEET

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	$5.434	$6.246
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$5.434	$5.572
Interruptible Service - PAR			$0.120	$4.494	$4.614
Interruptible Service - MAFB			$0.120	$4.515	$4.635
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	$5.434	$6.031
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$4.494	$5.365
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	$5.530	$6.127
Summer Gas Usage			$0.597	$4.565	$5.162
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.020	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.020	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$4.494	$5.213
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: February 9, 2011 **Effective Date:**

Issued By: Tamie A. Aberle
Pricing & Tariff Manager **Case No.:**

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

March 2011

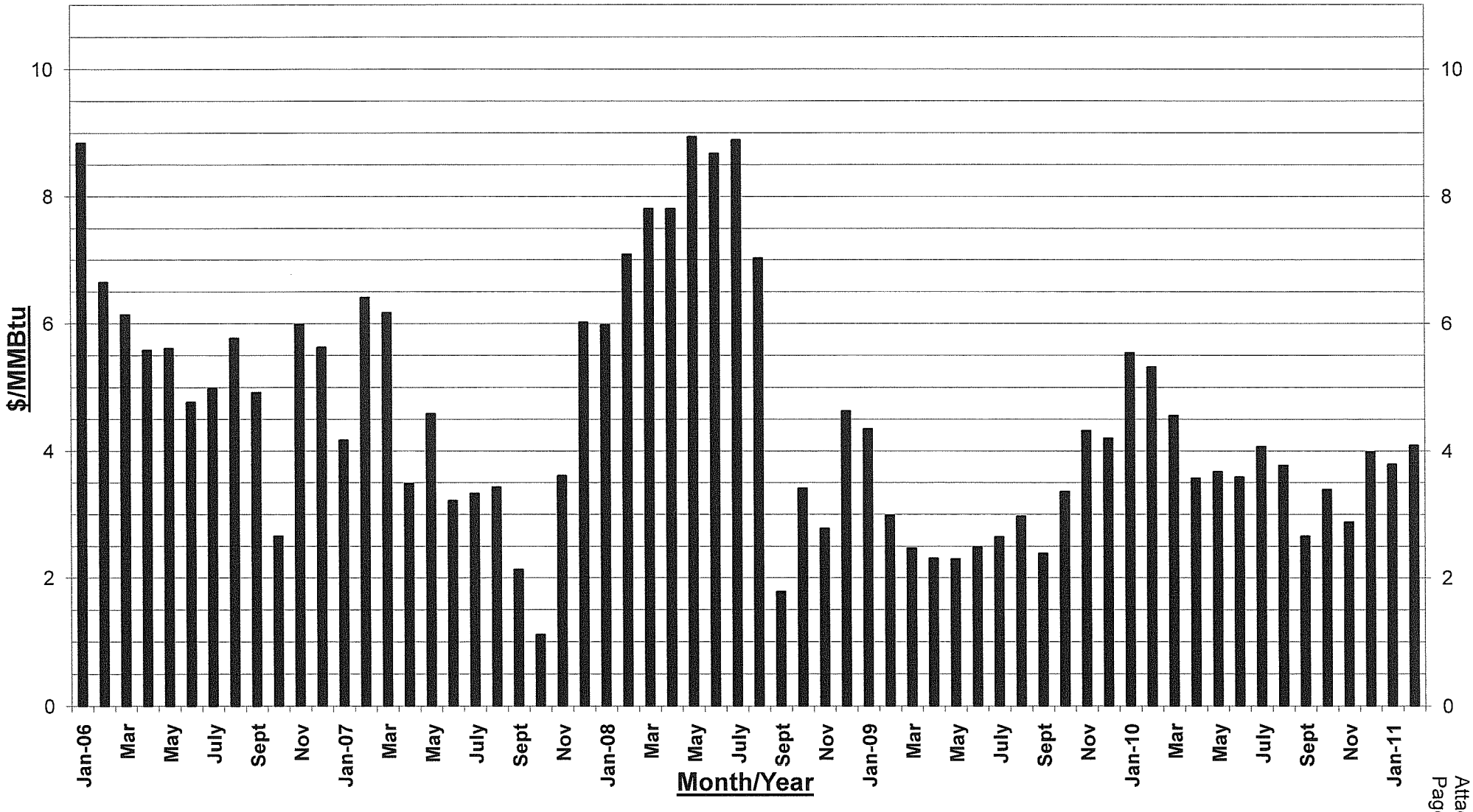
The established monthly price for the Rocky Mountain CIG Index increased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by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

Below normal temperatures over a large portion of the U.S. during the month of January and the corresponding increase in consumption to meet heating demand is the reason for the increase in the index price. The year over year comparison shows the February 2011 CIG index price is approximately 23 percent less than the previous year. The Energy Information Administration (EIA) reported storage levels nationwide as of January 28, 2011 were 0.2 percent above the five-year average and 2.8 percent below last year's storage balance.

The EIA provides various publications on energy issues. The information is available on their website: http://www.eia.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 - $3.94

www.eia.doe.gov
Energy Information Administration

February 2011

Short-Term Energy Outlook

February 8, 2011 Release

Highlights

- EIA expects the price of WTI crude oil to average about $93 per barrel in 2011, $14 higher than the average price last year. For 2012, EIA projects that WTI prices will continue to rise, averaging $98 per barrel. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 3.0 percent in 2011 and 2.8 percent in 2012, while world real GDP (weighted by oil consumption) grows by 3.9 percent and 4.0 percent, respectively, in 2011 and 2012.

- EIA expects regular-grade motor gasoline retail prices to average $3.15 per gallon in 2011, 37 cents per gallon higher than the 2010 average, and $3.30 per gallon in 2012, with prices forecast to average about 5 cents per gallon higher in each year during the peak driving season (April through September). There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the peak driving season. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting a 35 percent probability that the national monthly average retail price for regular gasoline could exceed $3.50 per gallon during summer 2011 and about a 10 percent probability that it could exceed $4.00 per gallon. Rising crude oil prices are the primary reason for higher retail prices, but higher refining margins are also expected to contribute.

- EIA estimates that natural gas working inventories ended January 2011 at 2.3 trillion cubic feet (Tcf), about 30 billion cubic feet (Bcf) or 1 percent below the 2010 end-of-January level. Inventories are expected to remain high through 2011. The projected Henry Hub natural gas spot price averages $4.16 per million Btu (MMBtu) for 2011, $0.22 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.

- EIA forecasts average household expenditures for space-heating fuels to total $991 during this 2010-2011 winter season, $24 higher than last year. EIA projects higher expenditures for heating oil and propane, flat expenditures for electricity, but lower expenditures for natural gas. A forecast of milder weather in the South and the West compared with the 2009-2010 winter leads to lower fuel consumption in those areas.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA expects a continued tightening of world oil markets over the next two years. World oil consumption grows by an annual average of 1.5 million barrels per day (bbl/d) through 2012 while the growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries averages about 0.3 million bbl/d this year and remains flat in 2012. Consequently, EIA expects 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 world demand growth. While on-shore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high last year, floating oil storage fell sharply in 2010, and EIA expects that OECD oil inventories will decline over the forecast period to close to the middle of the previous 5-year range by the end of 2012.

There are many significant uncertainties that could push oil prices higher or lower than current expectations. Among the uncertainties are decisions by key OPEC member countries regarding their production response to the global recovery in oil demand; 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. In addition, even though Egypt is not a major supplier of crude oil or natural gas to world markets, the recent unrest in that country raises the concern that unrest could spread to other countries in the region with a larger role in supplying world energy markets or that key transit routes for energy and other goods could be disrupted.

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 losses of the previous two years and surpassed the 2007 level of 86.3 million bbl/d reached prior to the economic downturn. EIA expects that world liquid fuels consumption will grow by 1.5 million bbl/d in 2011 and by an additional 1.6 million bbl/d in 2012. Non-OECD countries make up almost all of the growth in consumption

over the next 2 years, with the largest contributions coming from China, Brazil, and the Middle East. Among the OECD regions, EIA expects that only North America will show oil consumption growth over the next 2 years, which will be offset by continued declines in OECD Europe and Asia.

Non-OPEC Supply. EIA projects non-OPEC crude oil and liquid fuels production will increase by 310,000 bbl/d in 2011, then decline slightly in 2012. Increases in non-OPEC oil production will be concentrated in a few countries, particularly in China and Brazil, where EIA expects each to show annual average production growth of 170,000 bbl/d in 2011. In 2012, EIA expects Canadian production growth to average 170,000 bbl/d while China and Brazil grow by 130,000 and 110,000 bbl/d, respectively. Other non-OPEC production is expected to decline. EIA expects Mexico's production will fall by about 210,000 bbl/d in 2011, followed by a further decline of 80,000 bbl/d in 2012. Similarly, production from the North Sea falls by 220,000 bbl/d and 160,000 bbl/d in 2011 and 2012, respectively. Projected U.S. crude oil production declines by 50,000 bbl/d in 2011 and by a further 190,000 bbl/d in 2012.

OPEC Supply. Forecast OPEC crude oil production increases by 0.4 million bbl/d in 2011, followed by a further increase of 1.2 million bbl/d in 2012. These production increases are in response to the increase in global demand for oil and limited growth in supplies originating in non-OPEC countries. Non-crude liquids production is expected to increase by 0.7 and 0.4 million bbl/d in 2011 and 2012, respectively. EIA expects that OPEC surplus production capacity will remain above 4 million bbl/d during the next 2 years.

OECD Petroleum Inventories. Onshore commercial oil inventories in the OECD countries remained high last year, but reports indicate floating oil storage fell sharply. Now that floating storage has been reduced, EIA expects that OECD onshore inventories will decline over the forecast period. Projected OECD stocks fall by about 55 million barrels in 2011, followed by an additional 60 million barrel decline in 2012. Days-of-supply (total inventories divided by average daily consumption) drops from 57 days to 55 days between December 2010 and the end of 2012, which is close to the middle of the previous 5-year range.

Crude Oil Prices. WTI crude oil spot prices averaged $89 per barrel in January, about the same as the December average, while over the same time period the estimated average cost of all crude oil to U.S. refineries increased by about $1 per barrel. 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 $95 per barrel in December 2011 and continue to increase to $99 per barrel by the fourth quarter of 2012.

Energy price forecasts are uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for April 2011 delivery over the 5-day period ending February 3 averaged $93 per barrel, and implied volatility averaged 30 percent. This makes the lower and upper limits of the 95-percent confidence interval $76 per barrel and $114 per barrel, respectively, for WTI delivered in April 2011. Last year at this time, WTI for April 2010 delivery averaged $75 per barrel and implied volatility averaged 34 percent, with the limits of the 95-percent confidence interval at $60 per barrel and $94 per barrel. Based on WTI futures and options prices, the probability that the monthly average price of WTI crude oil will exceed $100 per barrel in December 2011 is about 44 percent. Conversely, the probability that the monthly average December 2011 WTI price will fall below $85 per barrel is about 32 percent.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption of petroleum and non-petroleum liquid fuels increased by 360,000 bbl/d (1.9 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 140,000 bbl/d (3.8 percent), and motor gasoline, which increased by 60,000 bbl/d (0.6 percent). Projected total U.S. liquid fuels consumption increases by 140,000 bbl/d (0.8 percent) in 2011 and a further 170,000 bbl/d (0.9 percent), to 19.5 million bbl/d, in 2012. 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 50,000 bbl/d in 2011 and by a further 190,000 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 20,000 bbl/d in 2012 because of the ongoing decline in production from the maturing Alaskan oil fields. EIA expects production from the Federal Gulf of Mexico (GOM) to fall by 250,000 bbl/d each year over the next 2 years. The production declines in Alaska and the GOM are partially offset by projected increases in lower-48 non-GOM production of 250,000-bbl/d in 2011 and 80,000 bbl/d in 2012.

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 9.6 million bbl/d in 2011 and 10.0

million bbl/d in 2012, comprising 50 percent and 51 percent of total consumption, respectively.

EIA expects slow growth in fuel ethanol production over the next 2 years. Ethanol production increases by a projected 50,000 bbl/d to 910,000 bbl/d in 2011 and then grows by an additional 10,000 bbl/d in 2012.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average of $2.78 per gallon in 2010 to $3.15 per gallon in 2011 and $3.30 per gallon in 2012. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average.

On-highway diesel fuel retail prices, which averaged $2.99 per gallon in 2010, will average $3.43 per gallon and $3.51 per gallon, respectively, in 2011 and 2012. Rising crude oil prices are the primary reason for higher retail prices, but higher gasoline and distillate refining margins are also expected to contribute to higher retail prices.

The projected monthly average regular gasoline price peaks this year at $3.24 per gallon in July. New York Harbor RBOB (reformulated gasoline blendstock for oxygenate blending) futures contracts for July 2011 delivery over the 5-day period ending February 3 averaged $2.65 per gallon and implied volatility averaged 30 percent. The probability the RBOB futures price will exceed $2.80 per gallon (and the U.S. average regular gasoline retail price exceed $3.50 per gallon) in July 2011 is about 35 percent. The probability the RBOB futures price will exceed $3.30 per gallon (and the gasoline retail price exceed $4.00 per gallon) in July 2011 is about 10 percent.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that total natural gas consumption will remain flat from 2010 to 2011. Reported residential and commercial consumption are expected to decline by 0.3 percent and 2.4 percent, respectively, primarily because of 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*). Industrial consumption rises from 18.0 billion cubic feet per day (Bcf/d) in 2010 to 18.3 Bcf/d in 2011 as the natural-gas weighted industrial production index increases 2.4 percent year over year.

Total consumption grows 1 percent in 2012, from 66.2 Bcf/d to 66.8 Bcf/d. Increases in natural gas consumption in the electric power sector (2.9 percent) and industrial sector (1.2 percent) are partially offset by slight declines in residential and commercial consumption. EIA expects electric power sector and industrial sector consumption to grow by 2.9 percent and 1.2 percent, respectively, in 2012.

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 63.7 Bcf/d in December. Year-over-year growth in 2011 is expected to slow 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 0.4 Bcf/d in the GOM.

The latest EIA data for monthly natural gas production in the *Natural Gas Monthly*, showed an increase in lower-48 states' production for November 2010, reversing October's decline. Modest declines are expected to resume and continue through 2011, however, because of a falling drilling rig count in response to lower prices. The number of rigs drilling for natural gas reported by Baker Hughes Inc. increased from a low of 665 in July 2009 to 973 in April 2010. Over the following 6 months the natural gas rig count stayed relatively unchanged. However, over the last 3 months the rig count has fallen, dropping to 911 rigs as of February 4. 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, especially in the electric power sector, contributes to higher prices and more economic incentive for producers to resume drilling. Total domestic natural gas production increases 1.1 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, which would be strong growth, but significantly less than during 2010. Federal GOM production declines slightly, by 0.4 percent (0.02 Bcf/d) in 2012.

EIA expects gross pipeline imports of 8.7 Bcf/d in 2011 and 8.2 Bcf/d in 2012, year-over-year decreases of 4.2 and 5.5 percent, respectively. Projected imports of liquefied natural gas (LNG) average 1.1 Bcf/d in 2011, a 4.4-percent decrease from 2010 levels. LNG imports in 2012 grow modestly to 1.2 Bcf/d. High domestic production, 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 January 28, 2011, working natural gas in storage stood at 2,353 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 1,651 Bcf of working natural gas will remain in storage, which is a downward revision of about 120 Bcf from last month's Outlook. Colder-than-normal weather east of the Rocky Mountains in January contributed to a larger-than-expected draw on inventories. EIA expects near-record high inventories to continue through most of 2011. Falling 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 $4.49 per MMBtu in January, 2011, $0.24 per MMBtu greater than the average spot price in December 2010 (Henry Hub Natural Gas Price Chart). EIA expects that the Henry Hub spot price will average $4.16 per MMBtu in 2011, a drop of $0.22 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 April 2011 delivery (for the 5-day period ending February 3) averaged $4.39 per MMBtu, and the average implied volatility over the same period was 34 percent. This produced lower and upper bounds for the 95-percent confidence interval for April 2011 contracts of $3.40 per MMBtu and $5.66 per MMBtu, respectively. At this time last year, the natural gas April 2010 futures contract averaged $5.35 per MMBtu and implied volatility averaged 46 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.80 per MMBtu and $7.50 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA expects total U.S. consumption of electricity in 2011 to remain at about the same level as consumption during 2010. Retail sales of electricity to the residential sector this year will fall 2.0 percent in response to the assumed 16-percent decline in cooling degree-days. Consumption should grow by 2.5 percent during 2012 (U.S. Total Electricity Consumption Chart). During 2012, EIA's assumption of a relatively strong increase in the number of households leads to a 2.3-percent increase in residential electricity sales. Continued robust growth in manufacturing output should drive growth in industrial electricity sales of 1.7 percent during 2011 and 2.3 percent in 2012.

U.S. Electricity Generation. Projected total generation by the electric power sector decreases by 0.2 percent in 2011, which is the same year-over-year decline as projected in last month's *Outlook*. However, EIA has lowered its projections for growth in hydroelectric power this year to 0.9 percent compared to 6.0 percent in the last *Outlook*. This downward revision in hydro generation will be offset by natural gas-fired generation, which is now expected to grow slightly during 2011. During 2012, EIA expects a 2.5-percent increase in total electric power sector generation, which will be fueled primarily by increased generation from coal, natural gas, and non-hydropower renewables (U.S. Electric Power Sector Generation Growth Chart).

U.S. Electricity Retail Prices. EIA expects the U.S. retail price for electricity distributed to the residential sector to rise slightly (0.6 percent) during 2011, after a

small increase of 0.7 percent during 2010. The U.S. residential price increases by about 0.7 percent in 2012. These price increases are relatively small compared with the average annual growth rate of 3.5 percent over the period of 2000-2009 (U.S. Residential Electricity Prices Chart). The effect of lower generation fuel costs should be more evident in retail electricity prices for the industrial sector, which are expected to fall about 2 percent this year after a similar rise last year. Projected industrial electricity prices should rise 0.8 percent in 2012.

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 because of the very warm summer. EIA projects that coal consumption in the electric power sector will decrease by 0.7 percent in 2011, as increases in generation from natural gas, nuclear, and wind back out coal. In 2012, projected electricity generation increases by 2.5 percent and coal consumption in the electric power sector grows by 3.4 percent (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Coal production during the first 6 months of 2010 fell by 2.5 percent from the same period last year despite a 5.4-percent increase in 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). Estimated coal production increases in the second half of 2010 contributed to 2010 annual growth of 1.0 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change (U.S. Annual Coal Production Chart). The projected increase in coal consumption in 2012 leads to a forecast 3.6 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 to an average of 7.3 percent of production. Metallurgical coal exports nearly doubled in the first half of 2010 compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to almost 70 percent in 2010. Flooding in Australia has greatly affected the amount of metallurgical coal available on the world market, and EIA expects U.S. metallurgical coal exports to increase in 2011 by 7.3 percent. In 2012, forecast U.S. coal exports fall back to more recent levels (about 80 million short tons) as other major coal-exporting countries increase their supply to the global coal market.

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

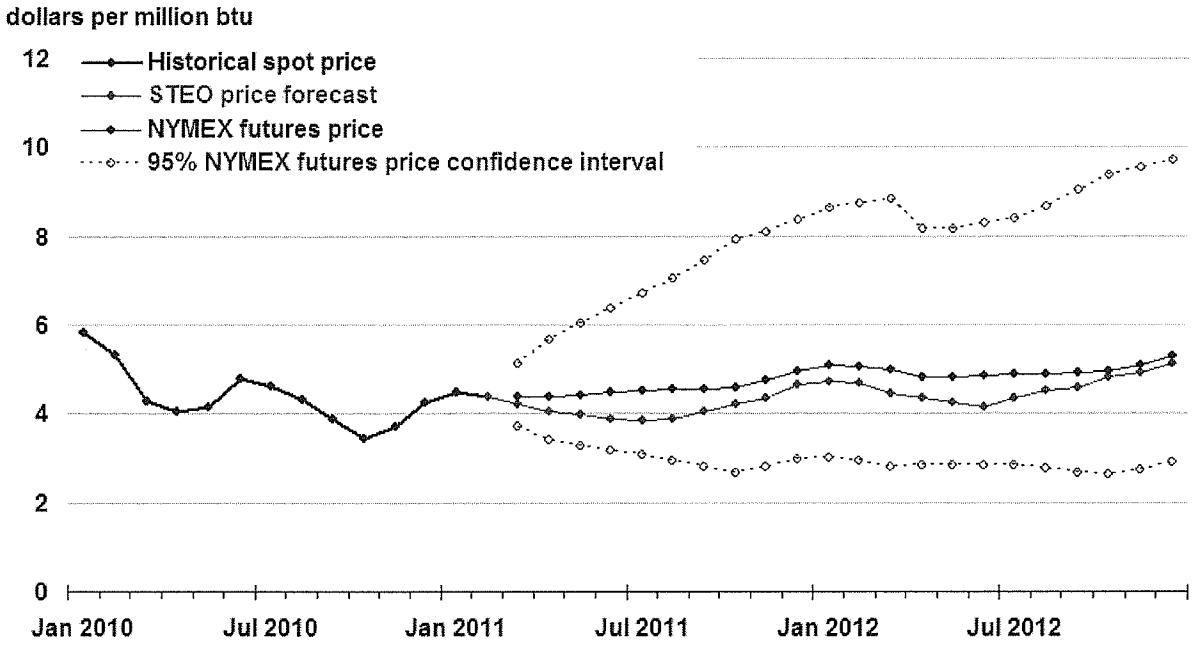
energy prices, rising transportation costs, and increased consumption. However, EIA expects that the power sector coal price will show little change over 2011 and 2012 as coal competes with natural gas for market share in the power sector. The projected power sector-delivered coal price, which averaged $2.26 per MMBtu in 2010, averages $2.23 per MMBtu in both 2011 and 2012.

U.S. Carbon Dioxide Emissions

EIA estimates that fossil-fuel CO_2 emissions increased by 3.6 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Coal- and natural gas-related CO_2 emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Projected increases for consumption of petroleum--primarily in the transportation sector--and natural gas are offset by declines in coal consumption in the electric power sector in 2011. As a result, forecast fossil-fuel CO_2 emissions remain relatively flat in 2011. The forecast resumption of growth in electricity generation and improvement in economic growth in 2012 contribute to a 2.0-percent increase in fossil-fuel CO_2 emissions. Projected fossil-fuel CO_2 emissions in 2012 remain below the levels seen since 1999 and 4.3 percent below 2005 emissions.

Henry Hub Natural Gas Price



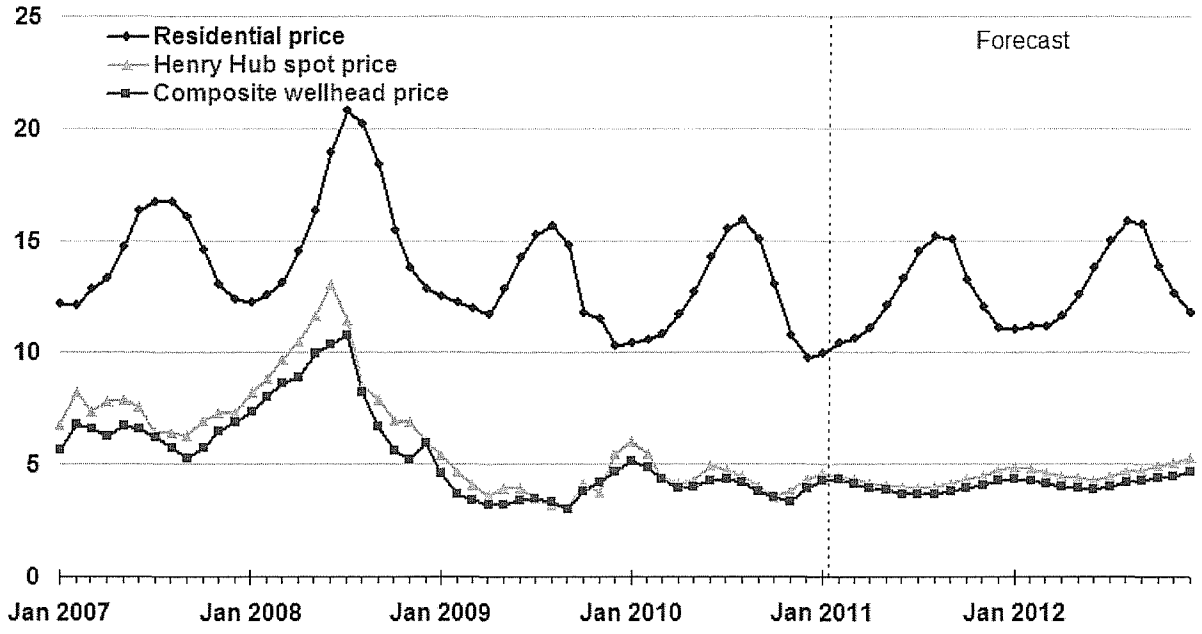
Note: Confidence interval derived from options market information for 5 trading days ending February 3, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

Natural Gas Prices

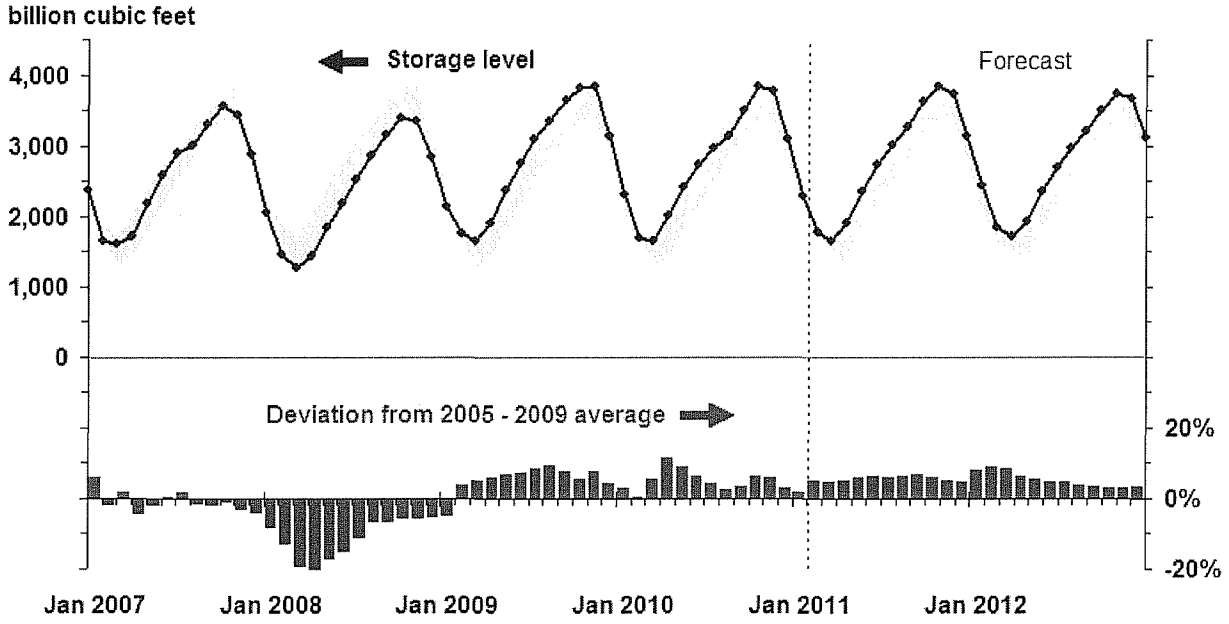
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

U.S. Working Natural Gas in Storage

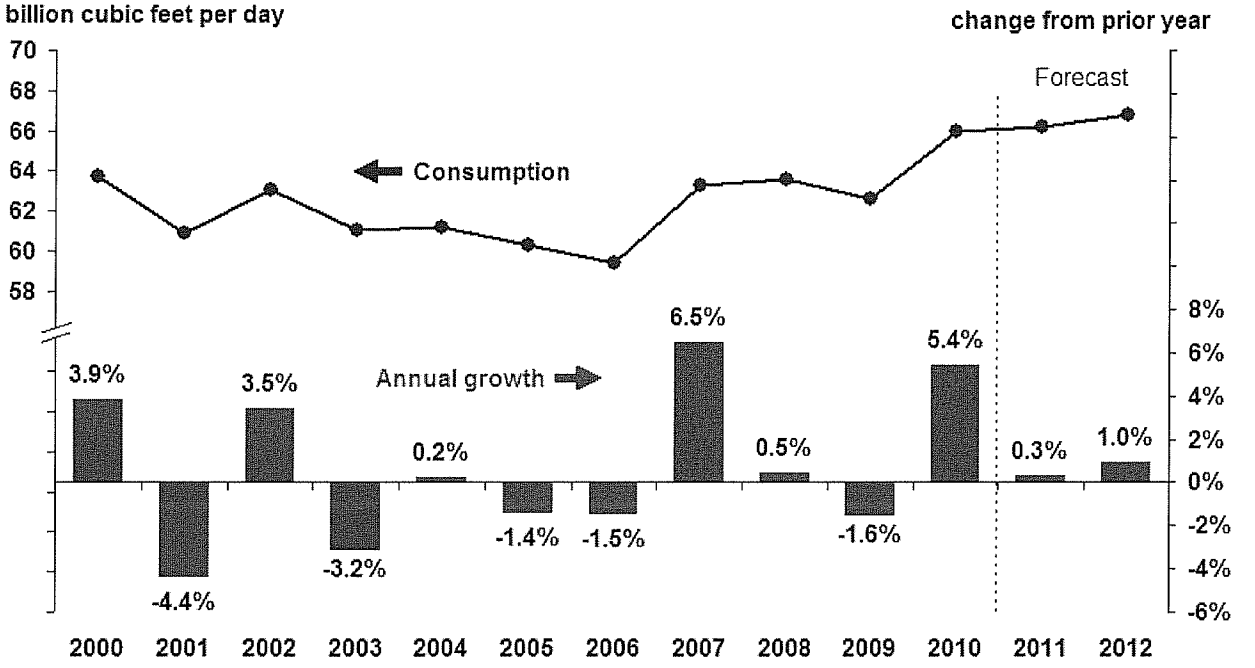


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2006 - Dec. 2010

Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, February 2011

U.S. Energy Information Administration

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE MARCH 2011

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$5.465	$5.561	$4.504	$4.484
Prior Gas Cost	5.299	5.394	4.337	4.317
Current Gas Cost Adjustment	$0.166	$0.167	$0.167	$0.167
Surcharge Adjustment:				
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
Market Based Pricing Differential				
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	**$0.166**	**$0.167**	**$0.167**	**$0.167**
Gas Cost Level	$5.465	$5.561	$4.504	$4.484
Plus: Surcharge	(0.023)	(0.023)	(0.010)	0.031
Total Gas Cost Level in Tariff Rates	$5.442	$5.538	$4.494	$4.515

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

	Amount
Total Gas Costs 1/	$73,452,303
Residential and General Service dk Requirements 2/	13,501,954
Average Cost of Gas per dk	$5.440
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.465
Less: Gas Cost Level in Rates 3/	5.299
Current Gas Cost Adjustment	**$0.166**

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 December 31, 2010, adjusted for losses at .45%

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

Cost of Purchased Gas	$5.275
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$5.299

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

Summer - June - September	
Total Gas Costs 1/	$73,452,303
Less: Annual MDDQ Costs 1/	11,685,993
Total Gas Costs excluding MDDQ	$61,766,310
Firm Service Requirements 1/	13,501,954
Other Gas Costs per Dk (excluding MDDQ)	$4.575
Summer Seasonal Rate, adjusted for losses 2/	4.596
Winter - October - May	
Annual MDDQ Costs 1/	$11,685,993
Winter Firm Service Requirements	12,163,436
MDDQ Costs per Winter Dk	$0.961
Add: Other Gas Costs per Dk	4.575
Winter Seasonal Rate	$5.536
Winter Seasonal Rate, adjusted for losses 2/	$5.561
Less: Gas Cost Level in Rates 3/	5.394
Current Gas Cost Adjustment	**$0.167**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-11-8:

	Summer	Winter
Cost of Purchased Gas	$4.410	$5.370
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$4.430	$5.394

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

	Amount
Total Gas Costs 1/	$15,706,455
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$4.484
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.504
Less: Gas Cost Level in Rates 2/	4.337
Current Gas Cost Adjustment	**$0.167**

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	$4.317
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.337

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

	Amount
Total Gas Costs 1/	$3,945,963
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$4.484
Less: Gas Cost Level in Rates 2/	4.317
Current Gas Cost Adjustment	**$0.167**

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 $4.317

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
March 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 2.153%, CONSISTING OF 2.614% FOR THE CURRENT PERCENTAGE AND (0.461%) 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 0.818 CENTS, CONSISTING OF 0.830 CENTS FOR THE CURRENT RATE AND (0.012) 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.

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

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 0.402%, CONSISTING OF 0.568% FOR THE CURRENT PERCENTAGE AND (0.166%) 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 0.346 CENTS FOR THE CURRENT RATE AND (0.164) 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.

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.

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.

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) $ 191.49/10^3m^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	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 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 $ 129.55/10^3m^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	Schedule No — PT Rate — PT Gas Rate 9006-01000-0 $ 60.50/d 1.0 10^3m^3/d 9009-01001-1 $ 660.00/d 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. — Charge 2010416547 $ 24.00 / month 2010416543 $ 7.00 / month 2010416549 $ 63.00 / month 2010416546 $ 5.00 / month 2010416548 $ 1.00 / month 2010416540 $ 42.00 / month 2010416550 $ 96.00 / month 2010416545 $ 1,688.00 / month 2010418000 $ 151.00 / month 2010416551 $ 46.00 / month 2010417322 $ 153.00 / month 2010416544 $ 79.00 / month 2010433424 $ 36.00 / month 2010416541 $ 209.00 / month 2010418777 $ 209.00 / month 2010418778 $ 350.00 / month 2003004522 $ 83,333.00 / month
15. Rate Schedule CO_2	Tier — CO_2 Rate ($/$10^3m^3$) 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.

Effective Date: Jan 1, 2011

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

22nd Revised Sheet No. 80.1
Canceling 21st Revised Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour			Per Meter Charge	
5,001	to	10,000	$ 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 No
Original Sheet No. 1

Effective Date: January 10, 20

TRANSPORTATION SERVICE Rate 1

Transportation rate is $2.398 per dekatherm.

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

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
First Revised Sheet No. 12
Cancels Original Sheet No. 12

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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	$0.00	$1.0551	$0.0100	0.781%
	MLI	MLE	$163.00	$1.0551	$0.0100	0.781%
	MLI	DSE	$163.00	$2.0988	$0.0200	3.425%
Interruptible Transportation 4/	MLI	MLI	$0.00	$0.8439	$0.0100	0.781%
	MLI	MLE	$163.00	$0.8439	$0.0100	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 Dekatherm.

3/ For fuel, lost and unaccounted for gas, SourceGas shall be entitled to retain the stated percentage of all Dekatherms 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 Mainline System Interconnect
MLE Mainline System End-user
DSE Distribution System End-user

Date Issued: June 8, 2007
By: Bentley W. Breland

Date Effective: June 15, 2007
Title: Senior Vice President

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

	General Service		
	Storage Balance 1/	Prepaid 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	4,520,480	197,295	(428,778)
February	1,580,767	59,715	(1,361,043)
March	1,266,823	19,326	(1,947,837)
April	1,466,191	10,514	(1,769,175)
May	2,574,384	45,980	(1,044,081)
June	4,537,177	122,549	(49,158)
July	6,772,702	207,650	988,947
August	8,977,738	293,815	2,007,647
September	11,663,179	631,428	2,809,469
October	12,792,989	667,725	3,054,256
13 month average	$6,924,367	$298,029	$686,409
Rate of Return	8.791%	8.791%	8.791%
Return	$608,721	$26,200	$60,342
Return Requirement	$837,848	$36,062	$83,055

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

	(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											**($695,379)**
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)
Balance @ December 31, 2010											**($781,209)**

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

	(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									**($18,649)**
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)
Balance @ December 31, 2010									**($54,085)**

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									**$14,139**
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)
Balance @ December 31, 2010									**($38,366)**

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.