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

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

December 9, 2010

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-10-___

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 (92nd Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered January 1, 2011.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.487 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. There has also been a change in pipeline rates, as shown on Attachment C, decreasing the cost of gas $0.005 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 January 2011.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.482 per dk for residential and firm general service customers, an increase of $0.488 per dk for small and large interruptible customers and an increase of $0.486 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 January 2011. The average cost of gas for firm customers, adjusted for losses, is $5.142.

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 January 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 January 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.

The proposed adjustment, calculated in accordance with Rate 88, will amount to an increase of approximately $1,339,600 for natural gas customers during the month of January 2011. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 93,645 natural gas customers in North Dakota as of November 30, 2010.

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 also submits herewith its check for $600.00 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.

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 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
92nd Revised Sheet No. 3
Canceling 91st 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	$5.111	$5.923
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$5.111	$5.249
Interruptible Service - PAR			$0.120	$4.180	$4.300
Interruptible Service - MAFB			$0.120	$4.202	$4.322
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	$5.111	$5.708
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$4.180	$5.051
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	$5.207	$5.804
Summer Gas Usage			$0.597	$4.248	$4.845
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.019	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.019	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$4.180	$4.899
Residential Propane Rate 90	32	$0.30 per day	$0.812	$13.049	$13.861
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	$13.049	$13.646

Date Filed: December 9, 2010 **Effective Date:**

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

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

January 2011

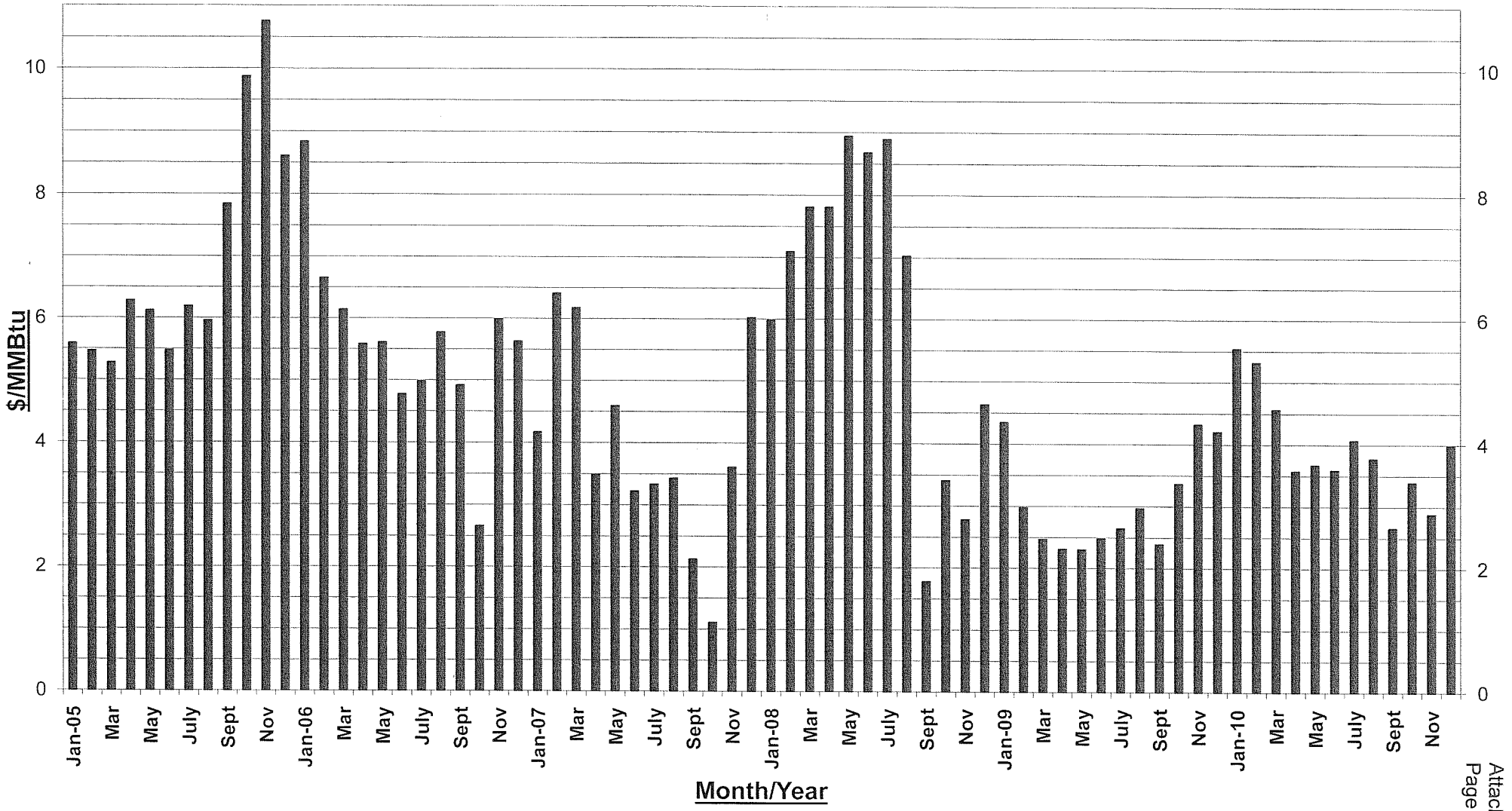
The established monthly price for the Rocky Mountain CIG Index increased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by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

Despite record levels of natural gas in storage, the increase in prices was a result of the seasonal temperatures and increased heating demand for natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of November 26, 2010 were 10.0 percent above the five-year average and 0.6 percent below 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 December Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 14.

CIG Rocky Mountains Index
Monthly Gas Prices 2005-2010



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2008-$6.24; 2009-$3.07; 2010 - $3.92

www.eia.doe.gov
Energy Information Administration

December 2010

Short-Term Energy Outlook

December 7, 2010 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $84 per barrel this winter (October 1 to March 31), more than $6 higher than the average price last winter. Projected WTI prices rise to $89 per barrel by the end of 2011, a $2 per barrel increase from last month's *Outlook*, as U.S. and global economic conditions improve. EIA's forecast assumes U.S. real gross domestic product (GDP) grows 2.7 percent in 2010 and 2.1 percent in 2011, while world real GDP (weighted by oil consumption) grows by 4.0 percent and 3.2 percent, in 2010 and 2011, respectively.

- EIA expects regular-grade motor gasoline retail prices to average $2.88 per gallon this winter, 22 cents per gallon higher than last winter. Projected retail diesel fuel prices average $3.14 per gallon this winter, an increase of 35 cents per gallon over last winter, while residential heating oil prices average $3.17 per gallon this winter. In 2011, higher crude oil prices combined with higher refiner margins push annual average prices for motor gasoline and diesel fuel to $3.00 and $3.23 per gallon, respectively.

- Natural gas working inventories end November 2010 at 3.8 trillion cubic feet (Tcf), slightly less than last year's record-setting end-of-November level. The projected Henry Hub natural gas spot price averages $4.37 per million Btu (MMBtu) for 2010, a $0.42-per-MMBtu increase over the 2009 average. EIA expects the Henry Hub spot price to average $4.33 per MMBtu in 2011.

- EIA expects average household expenditures for space-heating fuels to total $962 this winter, about the same as last year's expenditures. EIA projects higher expenditures for heating oil and propane, but lower expenditures for natural gas and electricity. This forecast reflects higher prices for all the fuels, although electricity prices increase by only 1 percent. However, a forecast of milder weather than last winter in all the regions, except the Northeast, leads to lower fuel consumption in those areas.

- EIA projects that U.S. carbon dioxide (CO_2) emissions from fossil fuels, which fell by 7.0 percent in 2009, will increase by 3.9 percent in 2010. In 2011, projected CO_2 emissions remain relatively flat as the increase in emissions from growth in petroleum consumption is offset by a decline in emissions from natural gas and coal because of reduced summer electricity use based on a projected milder summer.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. Gradual tightening in global oil markets continues to support world oil prices. Projected liquid fuels consumption growth of 2 million barrels per day (bbl/d) in 2010 is almost double the growth in supply from countries outside of the Organization of the Petroleum Exporting Countries (OPEC), which has led to rising demand for OPEC crude oil production and declining global oil inventories. While overall commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remain high, stock levels are unevenly distributed with some regions experiencing tightness in recent months. Both floating and reported on-shore inventories have been declining, and EIA believes that the projected continued reduction in OECD stocks over the forecast period should lend support to firming oil prices.

Global Crude Oil and Liquid Fuels Consumption. Projected world liquid fuels consumption increases by 2 million bbl/d in 2010, following declines in 2008 and 2009. As a result, total global consumption in 2010 should be close to the 2007 level. Global oil consumption growth slows to 1.4 million bbl/d in 2011. Non-OECD regions, especially China, the Middle East, and Brazil, represent most of the expected growth in world oil consumption next year (World Liquid Fuels Consumption Chart). Among the countries of the OECD, only the United States is expected to show any significant growth in consumption volume in 2011 at about 0.2 million bbl/d.

Non-OPEC Supply. EIA projects the total non-OPEC supply of crude oil will grow by just over 1.0 million bbl/d to an average 51.5 million bbl/d in 2010 - the largest year-over-year increase since 2002. The increase in total non-OPEC supply for the year is the result of higher production in the United States, Brazil, China, and Russia. However, non-OPEC supply falls by 280,000 bbl/d in 2011. The decline in non-OPEC supply in 2011 would be only the third time in the last 15 years that non-OPEC supplies fall year-over-year. Previous declines in 2005 and 2008 were primarily the result of supply disruptions in the Gulf of Mexico related to hurricanes.

OPEC Supply. EIA expects that OPEC crude oil production will increase by 0.3 and 0.4 million bbl/d in 2010 and 2011, respectively, similar to last month's *Outlook*, to accommodate increasing world oil consumption. Projected non-crude liquids increase by 0.7 million bbl/d in both 2010 and 2011. OPEC surplus capacity should remain close to 5 million bbl/d, compared with 4.3 million in 2009 and 1.5 million in 2008 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. Commercial oil inventories held by OECD countries at the end of 2010 are an estimated 2.73 billion barrels, equivalent to about 58 days of forward cover and roughly 94 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories decline through the forecast period, though days of forward cover should remain high by historical standards.

Crude Oil Prices. WTI crude oil spot prices averaged over $84 per barrel in November, more than $2 per barrel higher than the October average, as expectations of higher oil demand pushed up prices. EIA has raised the average winter 2010-2011 WTI spot price forecast by $1 per barrel from the last month's *Outlook* to $84 per barrel. WTI spot prices rise to $89 per barrel by the end of next year, $2 per barrel higher than in the last *Outlook*. Projected WTI prices average $79 per barrel in 2010 and $86 per barrel in 2011.

Energy price forecasts are uncertain (Energy Price Volatility and Forecast Uncertainty). WTI futures for February 2011 delivery for the 5-day period ending December 2 averaged $86 per barrel, and implied volatility averaged 30 percent. This made the lower and upper limits of the 95-percent confidence interval $70 per barrel and $106 per barrel, respectively, for WTI delivered in February 2011. Last year at this time, WTI for February 2010 delivery averaged $78 per barrel and implied volatility averaged 40 percent, with the limits of the 95-percent confidence interval at $61 per barrel and $102 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total U.S. liquid fuels consumption increases by 320,000 bbl/d (1.7 percent) to 19.09 million bbl/d in 2010, which is about 60,000 bbl/d higher than forecast in last month's *Outlook*. A year-over-year decline in total liquid fuels consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise averaging 610,000 bbl/d in the second and third quarters, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, projected gasoline consumption increases by 0.4 percent and distillate consumption increases by 4.0 percent. Total liquid fuels consumption

increases by a further 160,000 bbl/d (0.8 percent) in 2011, as all of the major petroleum products register consumption growth (U.S. Liquid Fuels Consumption Growth Chart). Gasoline consumption grows by 0.8 percent, and distillate fuel consumption increases by 1.7 percent in 2011.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 410,000 bbl/d in 2009, increases by 140,000 bbl/d in 2010 (U.S. Crude Oil Production Chart) and then falls by 30,000 bbl/d to 5.47 million bbl/d in 2011. The 2011 forecast includes declines of 50,000 bbl/d and 180,000 bbl/d in Alaska and the Federal Gulf of Mexico (GOM), respectively, and a 190,000-bbl/d increase in lower-48 non-GOM production. Ethanol production, which averaged 710,000 bbl/d in 2009, increases to an average of 860,000 bbl/d in 2010 and 890,000 bbl/d in 2011.

Liquid fuel net imports (including both crude oil and refined products) fell from 57 percent of total U.S. consumption in 2008 to 51 percent in 2009, primarily because of the decline in consumption during the recession. EIA forecasts that liquid fuel net imports will average 9.48 million bbl/d in 2010 and 9.62 million bbl/d in 2011, about 50 percent of total consumption in both years.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average of $2.35 per gallon in 2009 to an average of $2.77 per gallon in 2010 and $3.00 per gallon in 2011. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.98 per gallon in 2010 and $3.23 in 2011 in the current forecast. Refining margins, which had been at their lowest levels since 2003, average about $2 per barrel higher next year because of growing global product demand.

Natural Gas

U.S. Natural Gas Consumption. This month's *Outlook*, for the first time, reflects recent changes in the Form EIA-857 monthly natural gas survey methodology in the forecasts for residential and commercial natural gas consumption (see *Changes in Natural Gas Monthly Consumption Data Collection and the Short-Term Energy Outlook*). The new survey methodology should not significantly change reported total annual consumption volumes. However, EIA expects significant changes in the seasonality of reported residential and commercial sector natural gas consumption from historical reporting norms as the improved reporting on the EIA-857 leads to more accurate monthly reports. For example, first quarter 2011 forecast residential plus commercial consumption is 1.7 billion cubic feet per day (Bcf/d) lower in this forecast compared with last month's *Outlook*, while fourth quarter 2011 consumption is 3.8 Bcf/d higher.

U.S. Natural Gas Production and Imports. Forecast marketed natural gas production increases by 3.5 percent in 2010, up from 2.5 percent in last month's *Outlook*. The revision is largely due to unexpectedly high production during the month of September as reported in the EIA *Natural Gas Monthly*. Natural gas production in 2011 has also been revised upwards, but EIA still predicts a total year-over-year decline of 0.1 percent in 2011. An expected 14.3-percent decline in GOM production is mostly offset by a 1.4 percent increase in the lower 48 non-GOM production.

The increase in the natural-gas-directed drilling rig count since mid-2009, combined with a growing share of horizontal drilling rigs in the lower-48 States, contributed to natural gas production growth in 2010. The number of rigs drilling for natural gas reported by Baker Hughes Incorporated increased from a low of 665 in July 2009 to 973 in April 2010. Over the last 6 months the natural gas rig count has stayed relatively unchanged, but in the last several weeks it has appeared to show the beginning of an expected decline, ending November with 953 rigs. EIA expects drilling activity to decline in 2011 because of relatively lower natural gas prices. The large price difference between petroleum liquids and natural gas prices on an energy-equivalent basis contributes to an expected shift towards drilling in shale formations that contain a higher proportion of liquids.

EIA expects gross pipeline imports of 8.4 Bcf/d in 2011, a decrease of 6.3 percent compared with 2010 pipeline imports. This is a significant revision of last month's forecast of a 1.4-percent increase. EIA expects that Canadian gas will become less competitive as new U.S. pipelines and increased lower-48 production with lower transport costs displace imports. Projected liquefied natural gas (LNG) imports average 1.25 Bcf/d in 2010, a 1.0-percent increase from 2009 levels. Imports in 2011 fall to 1.21 Bcf/d, a decline of 2.9 percent. High domestic production, high inventories, and low U.S. prices relative to European and Asian markets should continue to discourage LNG imports into North America.

U.S. Natural Gas Inventories. On November 26, 2010, working natural gas in storage stood at 3,814 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 1,833 Bcf of working natural gas will remain in storage, about 171 Bcf higher than at the end of March 2010. The forecast higher inventory is primarily the result of both the projected 3.1 Bcf/d increase in natural gas production and 5 percent fewer heating degree-days over the next 4 months compared with the year before.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $3.71 per million Btu (MMBtu) during November, an increase of about 28 cents from October's price of $3.43 per MMBtu (Henry Hub Natural Gas Price Chart). Over the winter heating

season, the projected monthly average spot price peaks at $4.29 per MMBtu in January 2011, before dropping back down to close to $4.00 per MMBtu in June 2011. This month's *Outlook* slightly raises the average 2011 Henry Hub spot price to $4.33 per MMBtu from last month's forecast of $4.31 per MMBtu.

Uncertainty over future natural gas prices is slightly lower this year compared with last year at this time. Natural gas futures for February 2011 delivery (for the 5-day period ending December 2) averaged $4.29 per MMBtu, and the average implied volatility over the same period was 45 percent. This produced lower and upper bounds for the 95-percent confidence interval for February 2011 contracts of $3.06 per MMBtu and $6.03 per MMBtu, respectively. At this time last year, the natural gas February 2010 futures contract averaged $4.84 per MMBtu and implied volatility averaged 57 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.20 per MMBtu and $7.34 per MMBtu.

Electricity

U.S. Electricity Consumption. EIA expects U.S. electricity consumption will rise slightly by 4.7 percent in 2010. Retail sales of electricity to the industrial sector from January through September 2010 were up by nearly 7 percent compared with the same period last year, about the same as the increase in the U.S. manufacturing production index. EIA's assumption of 3.6 percent growth in manufacturing output during 2011 translates to an expected growth in electricity sales to the industrial sector of about 1.7 percent. Improved economic conditions should also spur growth of 1.1 percent in retail electricity sales to the commercial sector. However, EIA expects residential electricity sales to fall by 2.1 percent next year as summer temperatures return to normal levels after the hot summer of 2010. Overall, growth in total U.S. consumption of electricity remains nearly flat during 2011 (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. EIA projects that total electric power sector generation will increase slightly (by 0.2 percent) during 2011. A 0.9-percent increase in nuclear power and a 7.2-percent increase in conventional hydropower generation (due to an assumed return to near-normal precipitation levels) will offset a 1.7-percent reduction in electric power sector generation fired by coal. EIA expects the share of total generation fueled by natural gas will fall slightly next year as cooler summer temperatures reduce the need for the peaking capacity required during the past year (U.S. Electric Power Sector Generation Growth Chart).

U.S. Electricity Retail Prices. The average U.S. retail price for electricity distributed to the residential sector during the first three quarters of 2010 was about the same as

the retail price during the same period last year. However, residential electricity prices during the fourth quarter 2010 are expected to be 1.2 percent higher than last year. EIA expects the U.S. residential price to continue growing by 0.9 percent during 2011 as utilities pass through the higher fuel costs they incurred this past year to their retail customers (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. EIA forecasts that coal consumption in the electric power sector will grow by 5.7 percent in 2010, primarily the result of higher electricity consumption. EIA expects electricity consumption in 2011 to decline by 0.1 percent and generation from non-fossil-fuel-fired sources to increase. Although natural gas-fired generation also declines, EIA expects that lower electric power sector natural gas prices will keep natural gas competitive as a generation source and lessen its decline. EIA projects that 2011 coal consumption in the electric power sector will decline by 0.2 percent (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Coal production for the first 6 months of 2010 fell by 3 percent despite a 5-percent increase in U.S. coal consumption. Drawdowns in stocks, particularly in the electric power sector, met the demand increase (U.S. Electric Power Sector Coal Stocks Chart). Projected coal production increases in the second half of 2010 contribute to 2010 annual growth of 1 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change (U.S. Annual Coal Production Chart).

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, has resulted in sharp increases in U.S. coal exports in 2010. Metallurgical coal exports nearly doubled in the first half of this year compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to a projected 73 percent in 2010. EIA expects total coal exports to increase by 30 percent in 2010 but to decline in 2011 as other major coal-exporting countries increase their supply to the global coal market.

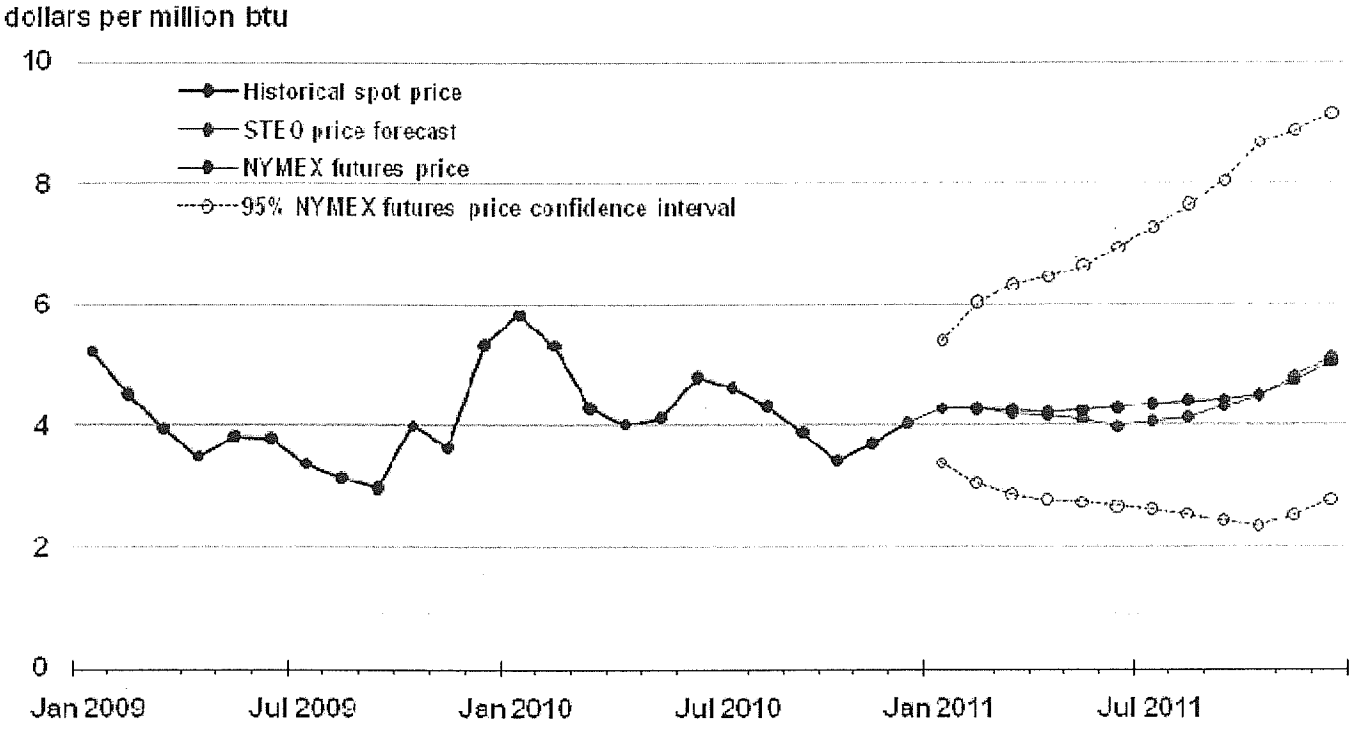
U.S. Coal Prices. The electric power sector coal price rose by 1.3 percent in the first half of 2010 compared with the first half of last year. This higher cost of delivered coal reflects the effect of longer-term power sector coal contracts initiated during a period of high prices, rising transportation costs, increased consumption, and increases in spot coal prices. The projected electric power sector delivered coal price averages $2.27 per MMBtu in 2010, and then declines slightly to an average of $2.26 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

EIA expects fossil-fuel CO_2 emissions to increase by 3.0 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Coal- and natural gas-related CO_2 emissions rise as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector.

Declines in electric power sector fossil fuel consumption in 2011 offset forecast increased consumption of petroleum in the transportation sector (i.e., motor gasoline, diesel fuel, and jet fuel). Consequently, fossil-fuel CO_2 emissions remain virtually unchanged in 2011. Projected fossil-fuel CO_2 emissions in 2010 and 2011 also remain below the levels seen in any year from 1999 through 2008.

Henry Hub Natural Gas Price

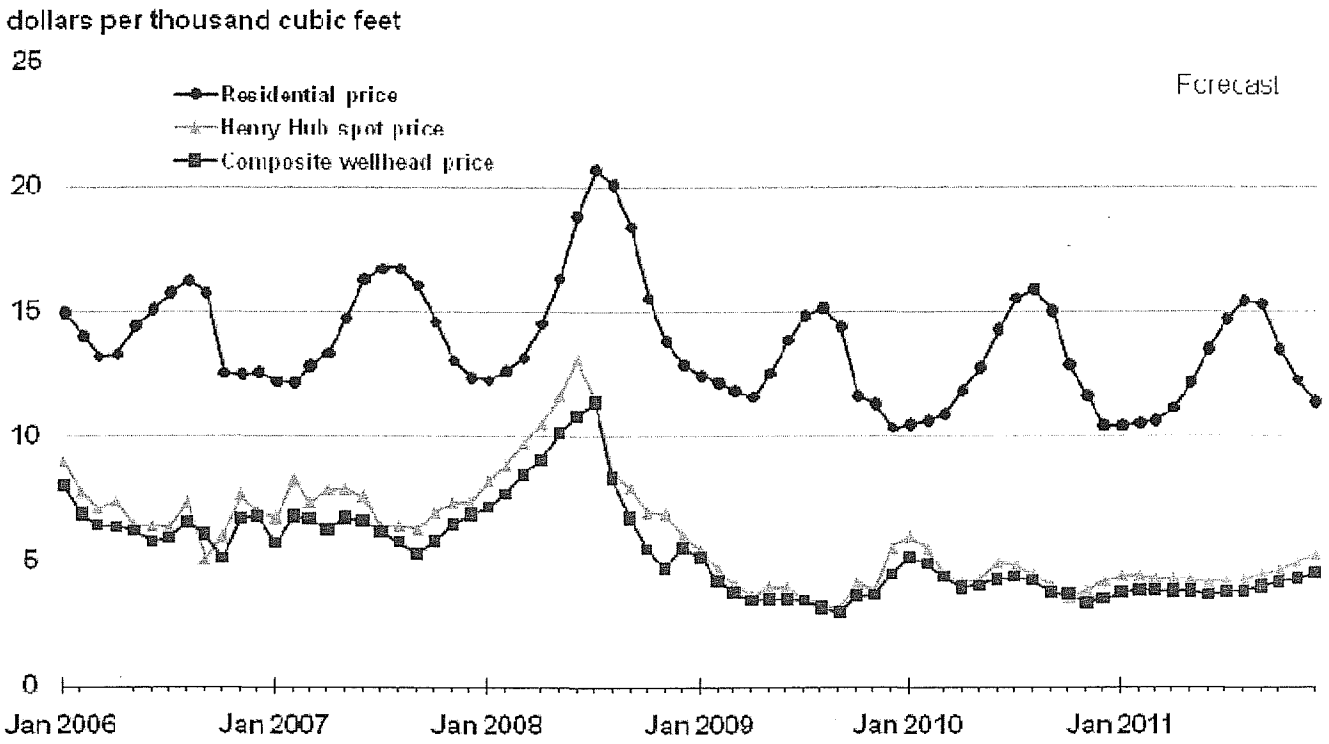


Note: Confidence interval derived from options market information for the 5 trading days ending December 2, 2010.
Intervals not calculated for months with sparse trading in "near-the-money" options contracts.

U.S. Energy Information Administration

Source: Short-Term Energy Outlook, December 2010; Reuters News Service; and CME Group

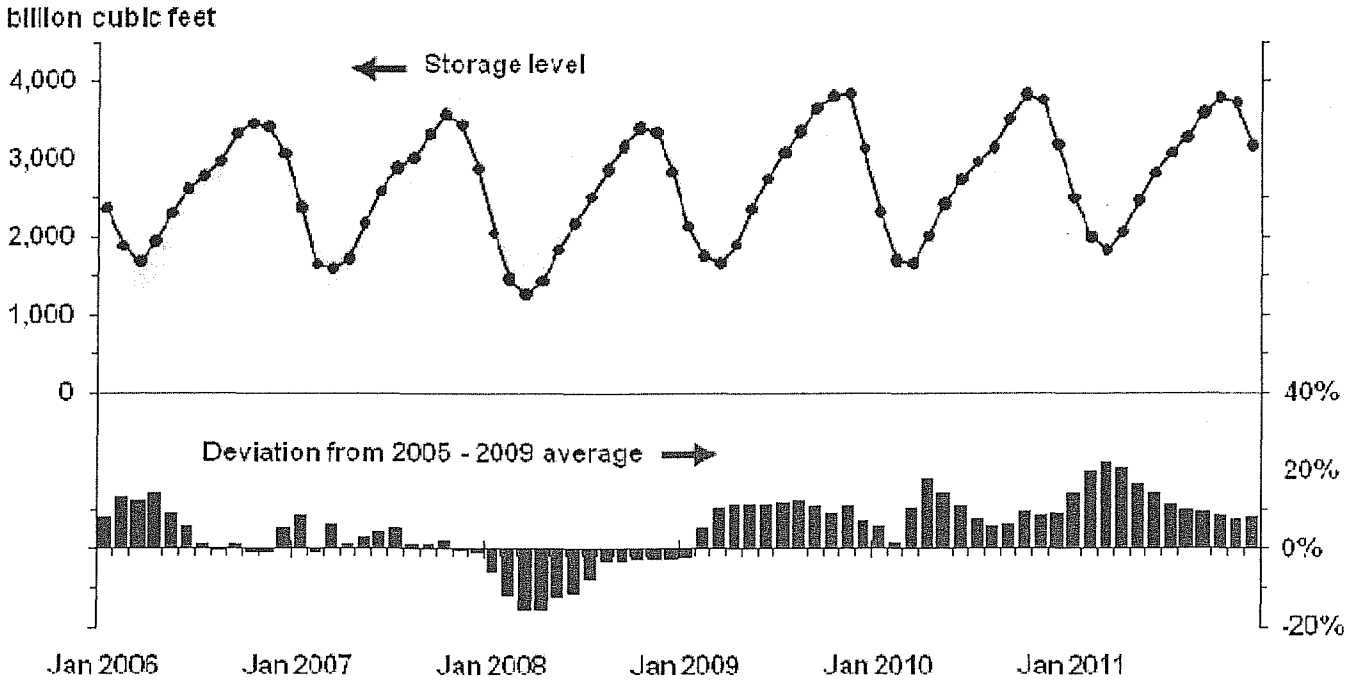
Natural Gas Prices



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, December 2010; Reuters News Service

U.S. Working Natural Gas in Storage

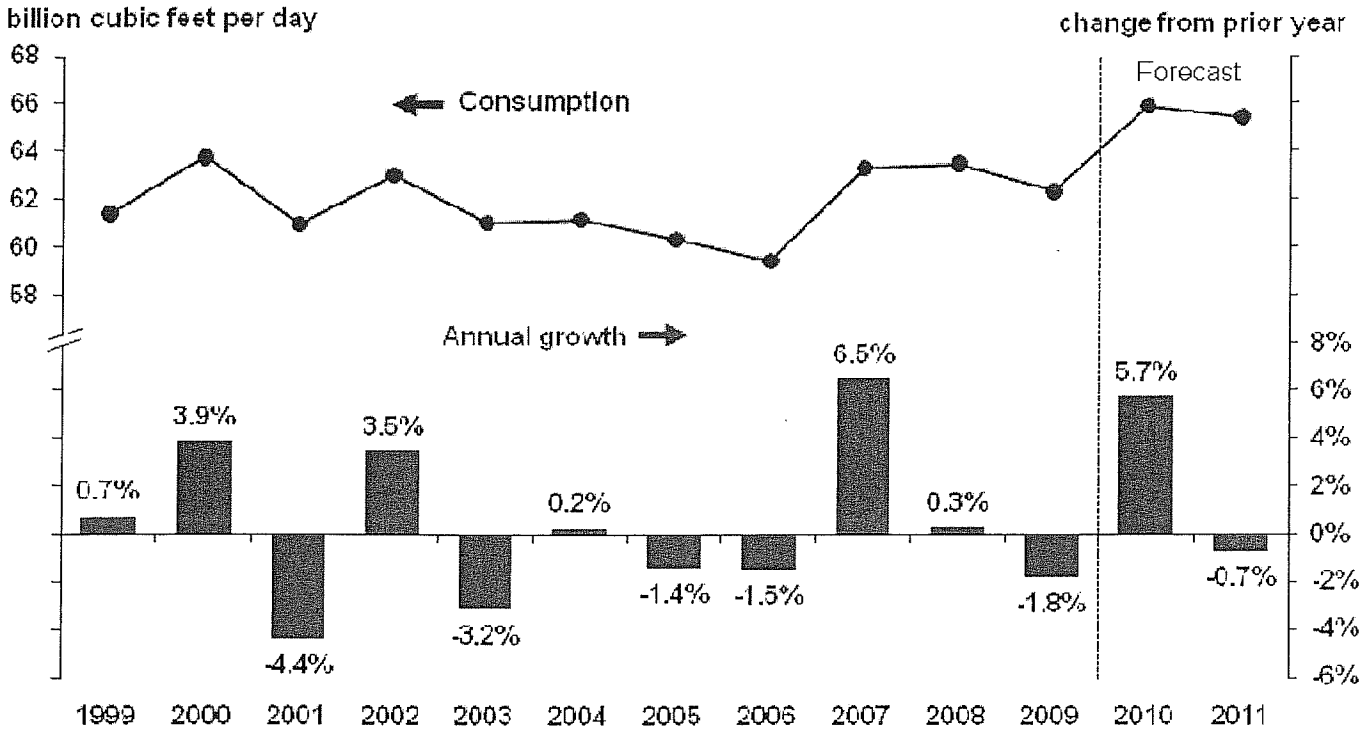


Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2005 - Dec. 2009.

U.S. Energy Information Administration

Source: Short-Term Energy Outlook, December 2010

U.S. Total Natural Gas Consumption



U.S. Energy Information Administration

Source: Short Term Energy Outlook, December 2010

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

Foothills Pipe Lines Ltd.

On December 1, 2010, TransCanada filed new rates for the Foothills Pipe Lines Ltd. System with the National Energy Board to be effective January 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – (0.005) cents per dk

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$5.142	$5.238	$4.190	$4.171
Prior Gas Cost	4.660	4.755	3.702	3.685
Current Gas Cost Adjustment	$0.482	$0.483	$0.488	$0.486
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	**$0.482**	**$0.483**	**$0.488**	**$0.486**
Gas Cost Level	$5.142	$5.238	$4.190	$4.171
Plus: Surcharge	(0.023)	(0.023)	(0.010)	0.031
Total Gas Cost Level in Tariff Rates	$5.119	$5.215	$4.180	$4.202

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

	Amount
Total Gas Costs 1/	$69,652,389
Residential and General Service dk Requirements 2/	13,606,695
Average Cost of Gas per dk	$5.119
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.142
Less: Gas Cost Level in Rates 3/	4.660
Current Gas Cost Adjustment	**$0.482**

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 October 31, 2010, adjusted for losses at .45%
3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

Cost of Purchased Gas	$4.639
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.660

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

Summer - June - September	
Total Gas Costs 1/	$69,652,389
Less: Annual MDDQ Costs 1/	11,689,211
Total Gas Costs excluding MDDQ	$57,963,178
Firm Service Requirements 1/	13,606,695
Other Gas Costs per Dk (excluding MDDQ)	$4.260
Summer Seasonal Rate, adjusted for losses 2/	4.279
Winter - October - May	
Annual MDDQ Costs 1/	$11,689,211
Winter Firm Service Requirements	12,257,794
MDDQ Costs per Winter Dk	$0.954
Add: Other Gas Costs per Dk	4.260
Winter Seasonal Rate	5.214
Winter Seasonal Rate, adjusted for losses 2/	$5.238
Less: Gas Cost Level in Rates 3/	4.755
Current Gas Cost Adjustment	**$0.483**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

	Summer	Winter
Cost of Purchased Gas	$3.778	$4.734
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$3.795	$4.755

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

	Amount
Total Gas Costs 1/	$14,610,149
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$4.171
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.190
Less: Gas Cost Level in Rates 2/	3.702
Current Gas Cost Adjustment	**$0.488**

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-10-8:

Cost of Purchased Gas	$3.685
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.702

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

	Amount
Total Gas Costs 1/	$3,670,535
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$4.171
Less: Gas Cost Level in Rates 2/	3.685
Current Gas Cost Adjustment	**$0.486**

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-10-8:
Cost of Purchased Gas $3.685

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
November 2010 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.

TABLE OF RATES, TOLLS & CHARGES

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) $207.61/10^3m^3$
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 $6.01/GJ FT-D Demand Rate for Group 2 Delivery Points[1] $0.98/GJ FT-D Demand Rate for Group 3 Delivery Points[2] N/A
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point
6. Rate Schedule FT-P	Refer to Attachment "3" for applicable FT-P Demand Rate per month
7. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/10^3m^3$/day) 1-5 years 10.43 6-10 years 8.72 15 years 7.82 20 years 6.94
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 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 ($/10^3m^3$) 1 520.03 2 411.79 3 272.12

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

NOVA Gas Transmission Ltd.

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)
2000	ALBERTA-B.C. BORDER	6.00	0.2170
3002	BOUNDARY LAKE BORDER	5.37	0.1941
1958	EMPRESS BORDER	6.03	0.2179
3886	GORDONDALE BORDER	5.37	0.1941
6404	MCNEILL BORDER	6.03	0.2179

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	0.98	0.0353
3868	ALBERTA-MONTANA	5.37	0.1941
3059	ALLISON CREEK SALES	0.98	0.0353
3562	AMOCO SALES (BP SALES TAP)	0.98	0.0353
3488	ARDLEY SALES	0.98	0.0353
3943	ATUSIS CREEK INTERCONNECTION	0.98	0.0353
3135	AURORA SALES	0.98	0.0353
3423	BASHAW WEST SALES	0.98	0.0353
3068	BEAVER HILLS SALES	0.98	0.0353
3933	BIG EDDY INTERCONNECTION	0.98	0.0353
3067	BIGSTONE SALES	0.98	0.0353
3887	BITTERN LAKE INTERCONNECTION	0.98	0.0353
3468	BLEAK LAKE SALES	0.98	0.0353
3471	BLUE RIDGE EAST SALES	0.98	0.0353
3164	BRAINARD LAKE SALES	0.98	0.0353
2364	BROWNVALE SALES	0.98	0.0353
3918	BUFFALO CREEK INTERCONNECTION	0.98	0.0353
3109	CALDWELL SALES	0.98	0.0353
3634	CANOE LAKE SALES	0.98	0.0353
3165	CANOE LK SLS #2	0.98	0.0353
3866	CARBON INTERCONNECTION	0.98	0.0353
3484	CARIBOU LAKE SALES	0.98	0.0353
3157	CARIBOU LK SOUTH SL	0.98	0.0353
3106	CARMON CREEK SALES	0.98	0.0353
3101	CAROLINE SALES	0.98	0.0353
3893	CARROT CREEK INTERCONNECTION	0.98	0.0353
3495	CAVALIER SALES	0.98	0.0353
3907	CHANCELLOR INTERCONNECTION	0.98	0.0353
3151	CHEECHAM W. #2 SALES	0.98	0.0353
3622	CHEECHAM WEST SALES	0.98	0.0353
6014	CHEVRON AURORA SALES	0.98	0.0353
3097	CHICKADEE CREEK SALES	0.98	0.0353
3305	CHIGWELL NORTH SALES	0.98	0.0353
3496	CHIPEWYAN RIVER SALES	0.98	0.0353
3163	CHRISTINA LAKE NORTH SALES	0.98	0.0353
3158	CLYDE N SALES	0.98	0.0353
1417	COLD LAKE BDR	5.37	0.1941
3052	COLEMAN SALES	0.98	0.0353
3168	COLLICUTT SALES	0.98	0.0353
3904	CONKLIN WEST INTERCONNECTION	0.98	0.0353
3416	COUSINS A SALES	0.98	0.0353
1963	COUSINS B & C SALES	0.98	0.0353
3483	CRAMMOND SALES	0.98	0.0353

NATURAL GAS TARIFF

NorthWestern Energy

	20th	Revised	Sheet No.	80.1
Canceling	19th	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	$ 102.95	(I)
10,001	to	30,000	$ 148.05	(I)
>30,000			$ 328.50	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	$ 8.417686	(I)

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	$ 0.063787	(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)

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 N
Original Sheet No. 1

Effective Date: January 10, 2

TRANSPORTATION SERVICE Rate 1

Transportation rate is $2.398 per dekatherm.

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 JANUARY 2011

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2010	$13,431,294	$653,606	$3,048,451
November	12,163,970	558,373	2,496,440
December	9,643,407	398,831	1,227,799
January 2011	5,414,293	206,497	(376,823)
February	2,753,244	79,854	(1,327,207)
March	1,859,943	19,856	(1,929,422)
April	1,981,758	8,095	(1,760,204)
May	3,176,555	48,225	(1,040,286)
June	5,223,007	126,697	(48,437)
July	7,540,200	216,021	989,264
August	10,294,186	322,802	2,007,568
September	12,227,867	637,534	2,809,076
October	13,195,402	667,193	3,053,763
13 month average	$7,608,087	$303,353	$703,845
Rate of Return	8.791%	8.791%	8.791%
Return	$668,827	$26,668	$61,875
Return Requirement	$920,579	$36,706	$85,165

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)
Balance @ October 31, 2010									**($1,074,234)**

1/ Interest calculated at the current investment 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)
Balance @ October 31, 2010									**($55,464)**

1/ Interest calculated at the current investment 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)
Balance @ October 31, 2010									**($27,020)**

1/ Interest calculated at the current investment rate.
2/ True-up related to August gas costs.
3/ Reflects 12,770.8 Dk @ $0.024.