

April 10, 2009

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-09-____

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 Rate 88.

Attachment A is the Rate Summary Sheet (74th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered May 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.404 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. In addition, firm transportation capacity has been reallocated to reflect changes in system capacity, resulting in a decrease of \$0.003 per dk.

The COG tariff sheet, Exhibit A, 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 May 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.407 per dk for residential and firm general service customers, a decrease of \$0.418 per dk for small and large interruptible customers and a decrease of \$0.417 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 May 2009. The average cost of gas for firm customers, adjusted for losses, is \$4.365.

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.

The proposed adjustment will amount to a decrease of approximately \$244,200 during the month of May 2009. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 91,181 customers in North Dakota as of March 31, 2009.

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 January 9, 2009. This payment will cover the filing fee associated with the monthly COG filings for January through December, 2009.

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,



Donald R. Ball
Vice President – Regulatory Affairs

Attachments

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
 74th Revised Sheet No. 3
 Canceling 73rd Revised Sheet No. 3

RATE SUMMARY SHEET

Page 1 of 2

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	\$0.30 per day	\$0.812	\$5.202	\$6.014
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$5.202	\$5.340
Interruptible Service - PAR			\$0.120	\$3.794	\$3.914
Interruptible Service - MAFB			\$0.120	\$3.596	\$3.716
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	\$5.202	\$5.799
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.794	(Maximum) \$4.665
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	\$5.292	\$5.889
Summer Gas Usage			\$0.597	\$4.343	\$4.940
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.016	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.016	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.794	(Maximum) \$4.513
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$7.350	\$8.162
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	\$7.350	\$7.947

Date Filed: April 10, 2009

Effective Date:

Issued By: Donald R. Ball
 Vice President - Regulatory Affairs

Case No.:

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

May 2009

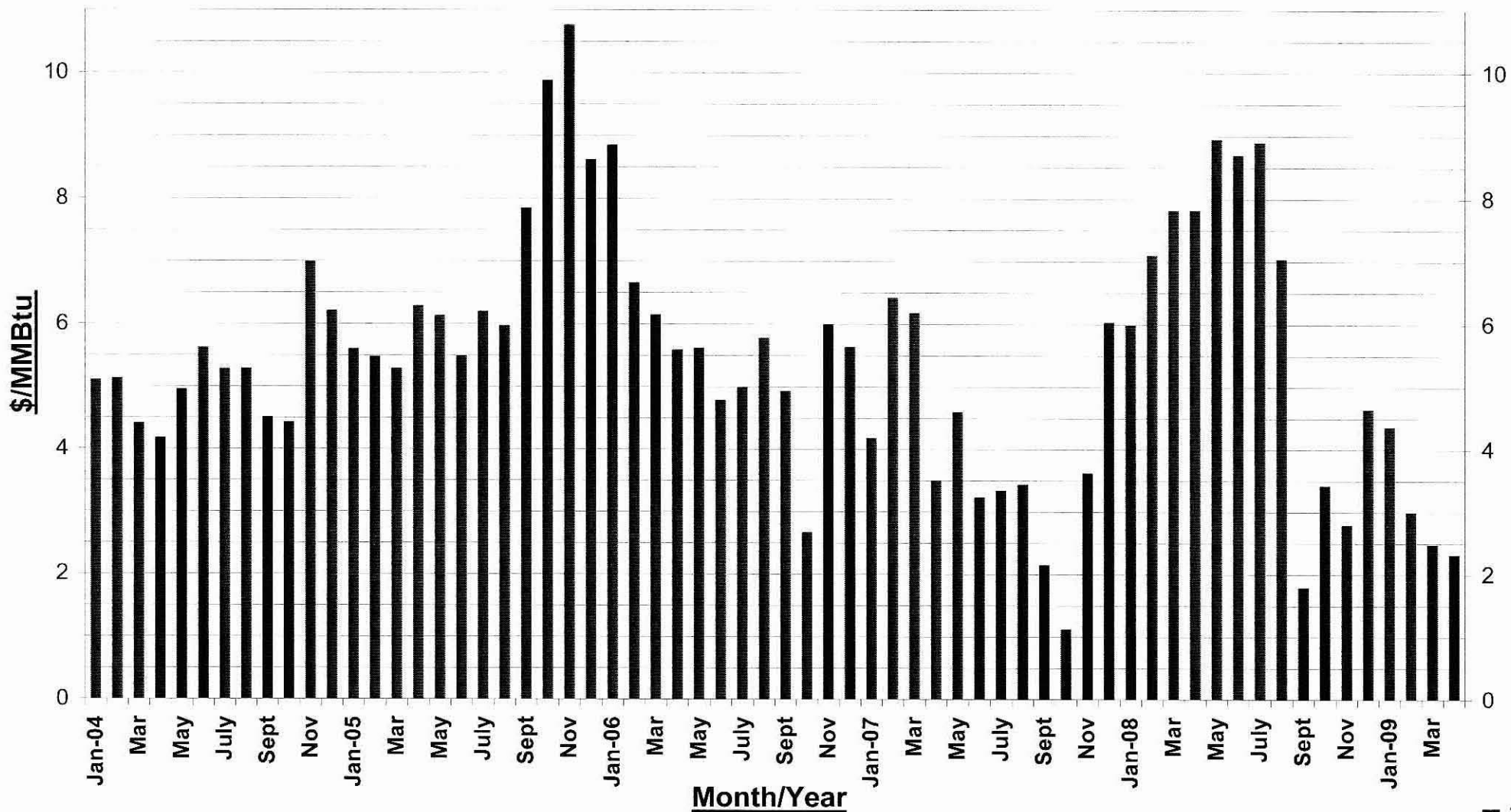
The established April monthly price for the Rocky Mountain CIG Index decreased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

The lower level of industrial demand for natural gas as a result of the ongoing economic downturn, the end of winter and the corresponding reduction in demand related to space heating and the high level of gas in storage likely contributed to the reduction of the natural gas price. The Energy Information Administration (EIA) reported storage levels nationwide as of March 27, 2009 were 22.4 percent above the five-year average and 32.1 percent above last year's balance.

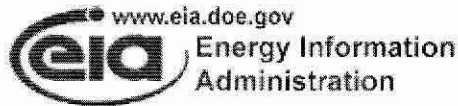
The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The March Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 11. The April Outlook is to be published April 14.

CIG Rocky Mountains Index Monthly Gas Prices 2004-2009 YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2007-\$3.97; 2008-\$6.24; 2009YTD-\$3.03



March 2009

Short-Term Energy Outlook

March 10, 2009 Release

Highlights

- The global economic contraction continues to depress energy demand.
- The annual price of West Texas Intermediate (WTI) crude oil averaged \$100 per barrel in 2008. The global economic slowdown is projected to cut these prices by more than half, to average \$42 per barrel in 2009 and \$53 in 2010--forecasts slightly lower than last month's *Outlook*.
- Gasoline prices have been slowly increasing over the last 2 months while crude oil prices have stabilized and refiner margins have recovered from their recent near-historic lows. After averaging \$1.69 per gallon in December 2008, the lowest monthly average since February 2004, the retail gasoline price in February rose to \$1.92 per gallon. Retail gasoline prices are projected to average \$1.96 per gallon in 2009 and \$2.18 per gallon in 2010.
- The U.S. economic downturn is the principal cause for the decline in domestic natural gas consumption, particularly in the industrial sector--where it is projected to fall by 6 percent in 2009--which in turn has led to lower natural gas prices. The Henry Hub natural gas spot price is projected to decline from an average of \$9.13 per thousand cubic feet (Mcf) in 2008 to about \$4.70 per Mcf in 2009, but then increase in 2010 to an average of almost \$5.90 per Mcf.

Global Crude Oil and Liquid Fuels

Overview. Following the sharp price decline that occurred during the second half of 2008, the global oil market has remained relatively stable since the beginning of the year. This situation is expected to continue through most of 2009, until economic recovery in the United States and elsewhere leads to a rebound in oil demand growth.

The future direction of world oil prices in the short-term will largely depend upon the timing and pace of the recovery of the global economy. Our macroeconomic forecasts

are derived from the IHS Global Insight macroeconomic model. If economic growth in the United States and overseas rebounds sooner than expected, oil demand could experience stronger-than-expected growth and outpace production increases, leading to rising prices. However, any upward movement in oil prices will be muted by the relatively high levels of commercial inventories in the Organization for Economic Cooperation and Development (OECD) and surplus production capacity among members of the Organization of the Petroleum Exporting Countries (OPEC). OPEC is scheduled to meet March 15 to assess the market situation and determine its future oil production targets.

U.S. real gross domestic product (GDP) is expected to decline by 2.8 percent in 2009, leading to a reduction in domestic energy consumption for all major fuels. An economic rebound is projected to begin in 2010, with a 1.9-percent year-over-year growth in U.S. real GDP.

Consumption. Average annual world oil consumption is projected to decline by almost 1.4 million barrels per day (bbl/d) in 2009, with consumption in the OECD falling by 1.6 million bbl/d. This expected decline in global consumption growth is roughly 200,000 bbl/d larger than in last month's *Outlook*, reflecting lower expectations of global economic activity in 2009. World GDP growth (oil-consumption weighted) is assumed to decline by 0.8 percent in 2009 followed by growth of 2.6 percent in 2010, compared with last month's assumption of a 0.1-percent decline and 3-percent growth.

EIA's projection for 2009 global oil consumption is now 3 million bbl/d lower than it was in the September 2008 *Outlook*. World oil consumption is expected to rebound in 2010, growing by 900,000 bbl/d, in response to an economic recovery which is projected to begin at the end of 2009. However, this revised projection for 2010 is 300,000 bbl/d lower than in last month's forecast due to the projected slower pace of recovery in the global economy (World Liquid Fuels Consumption).

Non-OPEC Supply. Non-OPEC supply is expected to remain fairly flat over the next 2 years, following a decline of 300,000 bbl/d in 2008. This contrasts with an average annual growth of 570,000 bbl/d from 2000 through 2007. The largest sources of growth over the forecast period are the United States, Brazil, and Azerbaijan, offset by large declines in production in Mexico, the North Sea, and Russia (Non-OPEC Crude Oil and Liquid Fuels Production Growth). Considerable downside risks remain, as additional project delays, declines in drilling activity, and more rapid decline rates than assumed could result from the financial crisis and the current price environment.

OPEC Supply. Press and industry reports indicate that OPEC countries have trimmed production significantly over the past several months. Estimated OPEC crude oil production fell by 1.1 million bbl/d during the fourth quarter of 2008, reaching 30.6 million bbl/d. OPEC crude oil production is expected to fall by an additional 2 million bbl/d in the first quarter of 2009 to 28.6 million bbl/d, the lowest level for the first quarter since 2003. OPEC crude oil production in 2009 is expected to average 28.9 million bbl/d, then rise to 29.8 million bbl/d in 2010. In addition, EIA expects that OPEC production of non-crude liquids will grow by 410,000 bbl/d in 2009 and by 740,000 bbl/d in 2010. This is lower than last month's forecast due to a re-estimation of the impact of falling crude oil production upon the growth of production in associated non-crude liquids.

The combination of lower oil demand, rising natural gas liquids production, and increases in crude oil production capacity over the next 2 years will result in an OPEC surplus production capacity averaging 4 to 5 million bbl/d over the period. Higher surplus production capacity should mitigate the impacts of actual or perceived supply disruptions and reduce the likelihood of sharp price increases. There remains a risk, however, that financial constraints and prospects of weak demand could lead OPEC members to further delay expansion programs, reducing future surplus capacity and setting the stage for higher prices once the economic recovery is underway.

Inventories. Revised data indicate that OECD commercial inventories stood at 2.7 billion barrels at the end of 2008, equivalent to 52 days of forward cover, which is above recent end-of-year average levels (Days of Supply of OECD Commercial Stocks). Measured as days of forward cover, OECD commercial inventories are projected to remain in the upper end of the historic range through the end of 2010.

U.S. Crude Oil and Liquid Fuels

Consumption. Total consumption of liquid fuels in 2008 declined by almost 1.3 million bbl/d, or 6.1 percent, from that of 2007 (U.S. Liquid Fuels Consumption Growth). The major factors contributing to the fall in consumption were a rapid rise in retail prices to record levels during the first half of 2008 and a deteriorating economy in the second half of the year. Total liquid fuels consumption for 2009 is projected to fall by a further 420,000 bbl/d, or 2.2 percent, because of continued economic weakness. The expected economic recovery in 2010 is projected to boost total liquid fuels consumption by 210,000 bbl/d, or 1.1 percent, with all of the major fuels registering increases in consumption.

Production. Domestic crude oil production in 2009 is projected to increase by about 400,000 bbl/d from 2008 levels to an average of 5.36 million bbl/d (U.S. Crude Oil

Production). This would be the first increase in production since 1991. Output is projected to rise by a further 150,000 bbl/d in 2010. Contributing to the increases in output are the Gulf of Mexico Thunder Horse platform, which is producing now, and the Tahiti platform, which is expected to come on stream later this year.

Prices. Under current economic and world crude oil supply assumptions, WTI prices are expected to average \$42 per barrel in 2009 and \$53 per barrel in 2010 (Crude Oil Prices). A stronger economic recovery, lower non-OPEC production because of the current low oil prices and financial market constraints, or more aggressive action to cut production by OPEC countries could lead to a faster and stronger rise in oil prices.

Regular-grade gasoline prices, which averaged \$3.26 per gallon in 2008, are projected to average \$1.96 per gallon in 2009 and \$2.18 per gallon in 2010. The monthly average price is expected to peak slightly over \$2 per gallon this year, although it remains possible that weekly prices could rise significantly higher at some point this spring or summer. Because of lower motor gasoline consumption, refining margins for gasoline are expected to remain depressed for much of 2009 but are expected to increase slightly in 2010 as consumption begins to recover.

On-highway diesel fuel retail prices are projected to average \$2.19 per gallon in 2009 and \$2.51 in 2010. The expected continuing decline in diesel fuel consumption in the United States this year as well as the growing weakness in distillate fuel usage outside the United States are projected to result in a narrowing of refining margins for distillate throughout the forecast period. Because of the global weakness in industrial output, it is possible that we will see diesel prices fall below gasoline prices this summer.

Natural Gas

Consumption. Total natural gas consumption is projected to decline by 1.3 percent in 2009 and then increase by 0.4 percent in 2010 (Total U.S. Natural Gas Consumption Growth). The outlook for continued economic weakness in 2009 is expected to take its greatest toll on industrial sector natural gas consumption, which is expected to decline by about 6 percent this year, more than offsetting the small projected increases in other end-use sectors. Lower natural gas delivered prices compared with coal in some markets, particularly in the Southeast, are expected to cause some electric power generators to switch some generation from coal to natural gas. Natural gas consumption by the electric power sector is projected to grow by 0.4 percent in 2009.

The pace and extent of economic recovery in 2010 are the primary factors influencing the natural gas consumption forecast next year, particularly for industrial users.

Based on the current economic assumptions for 2010, slight growth in the industrial sector and 2-percent growth in the electric power sector are balanced by declines in the residential and commercial sectors because of projected milder winter temperatures.

Production and Imports. Total U.S. marketed natural gas production is expected to remain flat in 2009 and then fall by 0.8 percent in 2010. Baker-Hughes reports 916 natural gas rigs working in the United States as of March 6, 2009, a decline of 43 percent from August 2008. Consequently, the robust growth in natural gas production in the Lower-48 region (excluding the Gulf of Mexico) over the last few years is expected to end as production reaches about 53 billion cubic feet per day (Bcf/d) in early 2009, then declines during the second half of 2009. The extent of the production decline later this year is highly uncertain and subject to fluctuations in demand and prices over the period. Rig activity is expected to recover in 2010 as the economy improves and prices increase. However, annual average production is still projected to be lower next year because of the decline in new wells drilled this year.

U.S. imports of liquefied natural gas (LNG) are expected to increase slightly in 2009 to 380 Bcf. New LNG supply capacity in Qatar, Indonesia, and Yemen could supply a significantly greater volume of LNG imports this year. However, delays to this new supply capacity as well as uncertainty about the weakness of natural gas demand in other LNG-consuming countries contribute to doubts about much higher LNG imports might be this year. LNG imports in 2010 are projected to be about 460 billion cubic feet (Bcf) as global supply projects ramp up. Pipeline imports are expected to decline by 9.4 percent in 2009 as Canadian drilling activity subsides, fields age, and a growing portion of available supply is dedicated to oil sands development.

Inventories. On February 27, 2009, working natural gas in storage was 1,793 Bcf (U.S. Working Natural Gas in Storage). Current inventories are now 218 Bcf above the 5-year average (2003–2007) and 270 Bcf above the level during the corresponding week last year. Storage inventories at the end of March 2009 are expected at about 1.6 trillion cubic feet (Tcf), roughly 200 Bcf above the previous 5-year average for that time.

Prices. The Henry Hub spot price averaged \$4.65 per Mcf in February, \$0.75 per Mcf below the average spot price in January. Prices continue to reflect demand reductions brought about by the current economic downturn. As the year progresses, it is expected that average spot prices will remain near \$4 per Mcf. If prices fall further than currently forecast, natural gas will become increasingly competitive with coal for base load power generation in some regions. On the supply side, the current drilling pullback could contribute to higher-than-expected prices if the economy begins to

recover earlier than expected and production is slow to react. The Henry Hub spot price is expected to average \$4.67 per Mcf in 2009 and \$5.87 per Mcf in 2010.

Electricity

Consumption. An expected decline of 6.4 percent in industrial electricity sales during 2009 leads to a projected decline in total electricity consumption of 1.7 percent this year (U.S. Total Electricity Consumption). Total electricity consumption is expected to grow by 1.2 percent in 2010 as a slowly improving economic climate contributes to a recovery in the sales of electricity.

Prices. Despite the recent drop in generation fuel costs, some electric utilities have proposed slight rate increases in response to higher costs of securing credit for purchases of fuel and wholesale power, while other retail electricity distributors, especially in the West South Central region, have been able to pass the declining fuel costs on to customers through lower rates. Residential electricity prices are projected to rise at annual rates of about 1.1 percent in 2009 and 1.8 percent in 2010 (U.S. Residential Electricity Prices).

Generation. Below-average snowpack in the Pacific region is expected to contribute to a 4.3-percent decline in U.S. hydropower generation in the electric power sector during 2009. Some of the drop in hydropower and coal-fired generation is expected to be picked up by natural-gas-fired generation, which is expected to increase by 1.2 percent in 2009.

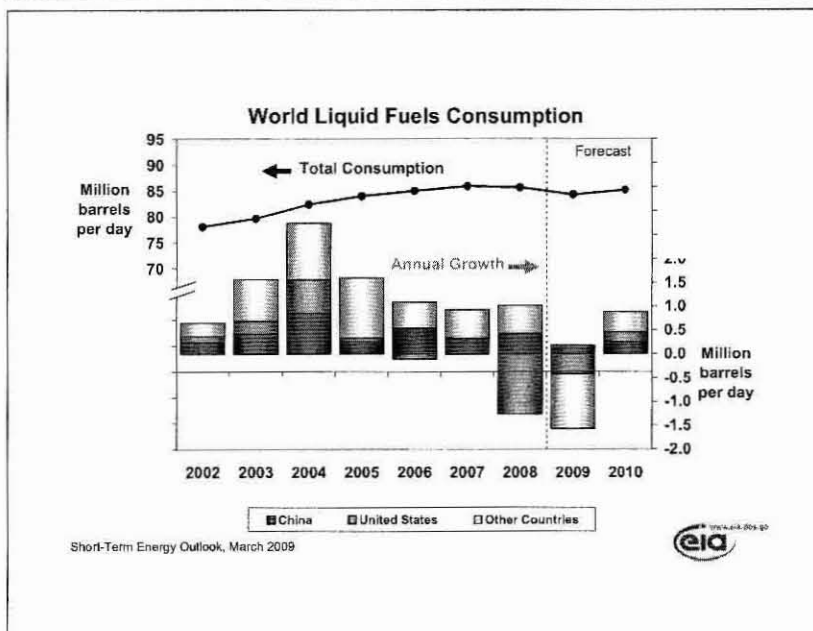
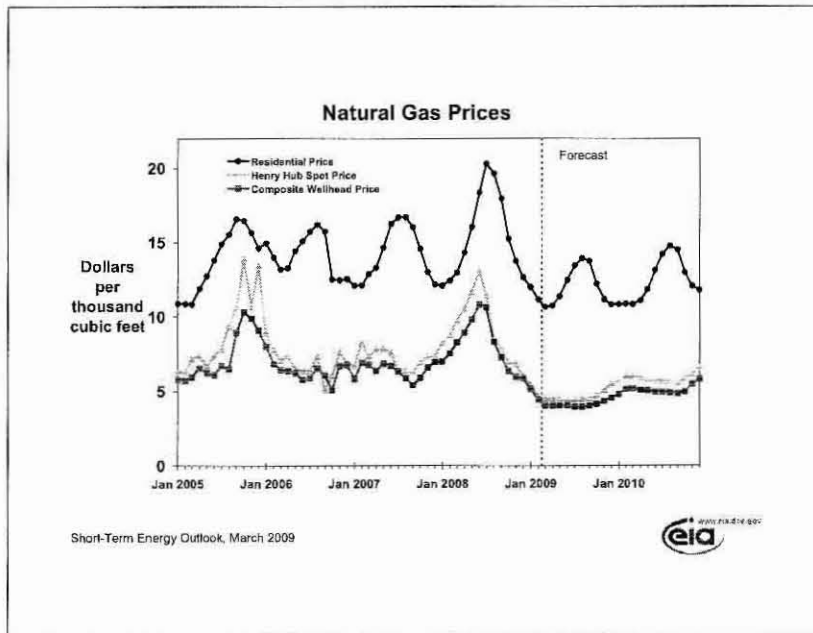
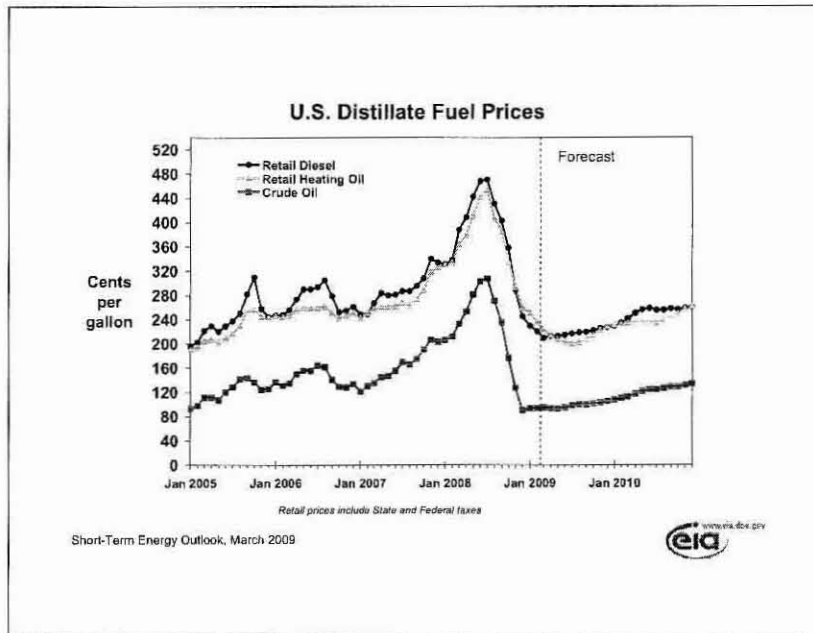
Coal

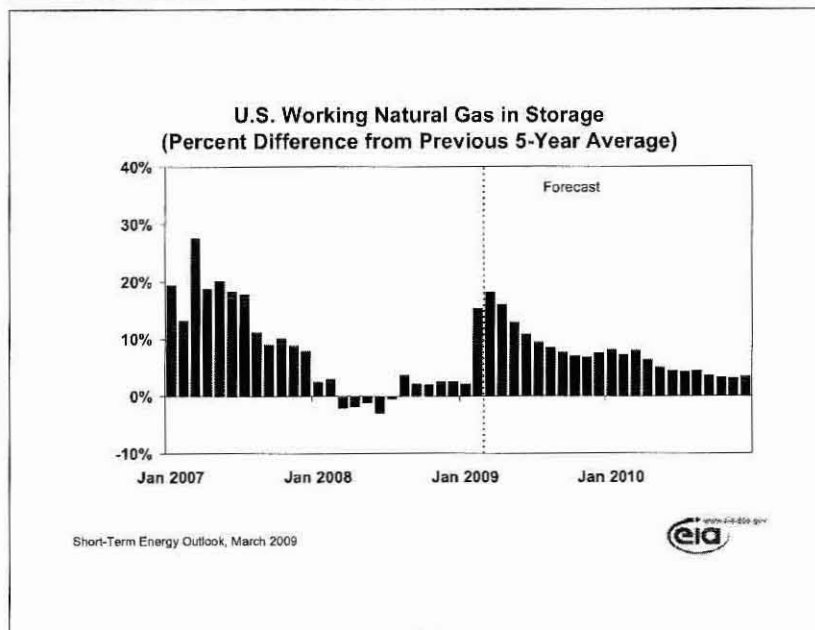
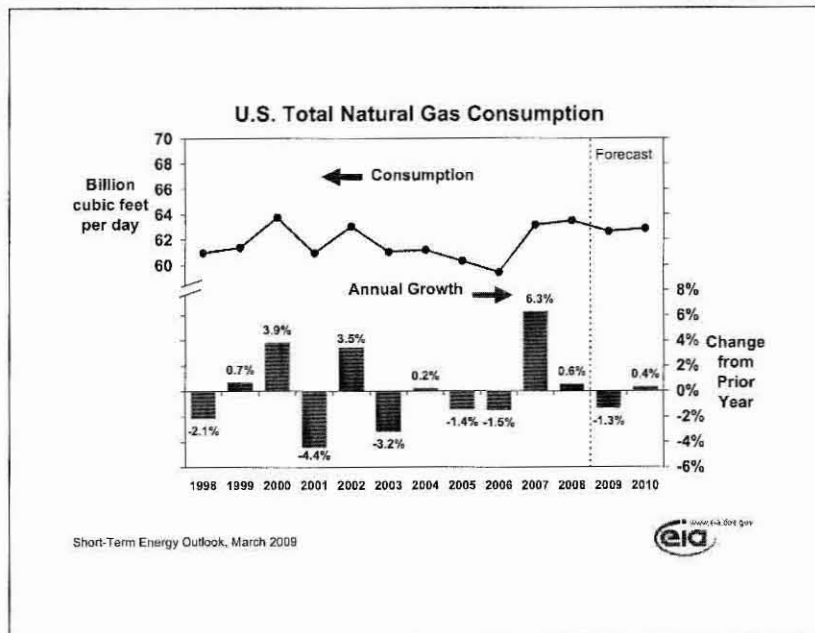
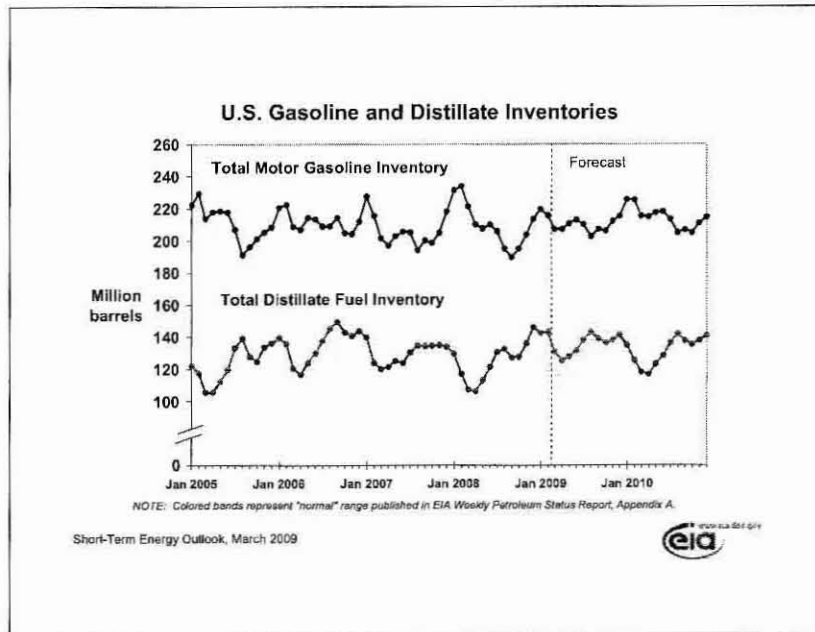
Consumption. The projected decline in electricity consumption and projected increases from some other generation sources is expected to lead to a 1.7-percent decline in coal consumption for electricity generation. An expected increase in electricity consumption of 1.2 percent in 2010 will lead to a 0.4-percent increase in coal consumption for electricity generation (U.S. Coal Consumption Growth).

Production. A significant increase in coal exports in 2008 contributed to a 2.1-percent increase in coal production. Production is expected to fall by 4.9 percent in 2009 as lower total domestic coal consumption is combined with declines in exports and an increase in imports. Production is projected to increase by 1.8 percent in 2010 as domestic consumption and exports increase with an improving economy (U.S. Annual Coal Production).

Exports. Reductions in global coal demand, coupled with the return to normal supply conditions in other major coal-producing and exporting countries, are expected to reduce U.S. coal exports by about 10 million short tons, an 11.8-percent decrease, in 2009. The improving global economy is expected to spur global coal demand in 2010, leading to a projected 12-percent increase in exports.

Prices. The average delivered coal price to the electric power sector is estimated to have increased by about 17 percent in 2008. Declines in electricity demand and lower transportation costs should result in average delivered coal prices falling by 1 percent in 2009 and remaining flat in 2010. Delivered coal prices tend to move more slowly than spot prices because of the nature of existing long-term coal supply contracts.





**MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE MAY 2009**

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$4.365	\$4.455	\$3.445	\$3.429
Prior Gas Cost	<u>4.772</u>	<u>4.855</u>	<u>3.863</u>	<u>3.846</u>
Current Gas Cost Adjustment	(\$0.407)	(\$0.400)	(\$0.418)	(\$0.417)
<u>Surcharge Adjustment:</u>				
Current Adjustment	\$0.845	\$0.845	\$0.349	\$0.167
Prior Adjustment	<u>0.845</u>	<u>0.845</u>	<u>0.349</u>	<u>0.167</u>
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<u>Market Based Pricing Differential</u>				
Current Adjustment	(\$0.008)	(\$0.008)	\$0.000	\$0.000
Prior Adjustment	<u>(0.008)</u>	<u>(0.008)</u>	<u>0.000</u>	<u>0.000</u>
Change in Margin Sharing Provision	\$0.000	\$0.000	\$0.000	\$0.000
Net Increase (Decrease) in Gas Costs	<u>(\$0.407)</u>	<u>(\$0.400)</u>	<u>(\$0.418)</u>	<u>(\$0.417)</u>
Gas Cost Level	\$4.365	\$4.455	\$3.445	\$3.429
Plus: Surcharge	<u>0.845</u>	<u>0.845</u>	<u>0.349</u>	<u>0.167</u>
Total Gas Cost Level in Tariff Rates	<u><u>\$5.210</u></u>	<u><u>\$5.300</u></u>	<u><u>\$3.794</u></u>	<u><u>\$3.596</u></u>

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE MAY 2009**

	Amount
Total Gas Costs 1/	\$58,434,281
Residential and General Service dk Requirements 2/	13,447,110
Average Cost of Gas per dk	\$4.345
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.365
Less: Gas Cost Level in Rates 3/	4.772
Current Gas Cost Adjustment	(\$0.407)

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -13 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 February 28, 2009, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-122:

Cost of Purchased Gas	\$4.751
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.772

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE MAY 2009**

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$58,434,281
Less: Annual MDDQ Costs 1/	<u>11,501,344</u>
Total Gas Costs excluding MDDQ	\$46,932,937
Firm Service Requirements 1/	13,447,110
Other Gas Costs per Dk (excluding MDDQ)	\$3.490
Summer Seasonal Rate, adjusted for losses 2/	3.506
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,501,344
Winter Firm Service Requirements	12,174,178
MDDQ Costs per Winter Dk	\$0.945
Add: Other Gas Costs per Dk	<u>3.490</u>
Winter Seasonal Rate	4.435
Winter Seasonal Rate, adjusted for losses 2/	\$4.455
Less: Gas Cost Level in Rates 3/	<u>4.855</u>
Current Gas Cost Adjustment	<u><u>(\$0.400)</u></u>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-122:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.907	\$4.833
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.925	\$4.855

**MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE MAY 2009**

	Amount
Total Gas Costs 1/	\$12,009,487
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.429
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.445
Less: Gas Cost Level in Rates 2/	3.863
Current Gas Cost Adjustment	(\$0.418)

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -13 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-09-122:

Cost of Purchased Gas	\$3.846
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.863

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE MAY 2009

	<u>Amount</u>
Total Gas Costs 1/	\$3,017,162
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$3.429
Less: Gas Cost Level in Rates 2/	<u>3.846</u>
Current Gas Cost Adjustment	<u><u>(\$0.417)</u></u>

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -13 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-09-122:
Cost of Purchased Gas \$3.846

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
May 2009 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, page 11 for Schedule FT-D.

Source Gas (f/k/a Kinder Morgan, Inc. and Northern Gas Company) – Contract rate so there are no tariff sheets.

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

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

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	0.170	N.A.	N.A.	3.290
MINIMUM A/B/	RATE PER DKT	3.120	0.170	N.A.	N.A.	3.290
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.170	N.A.	N.A.	31.054
MINIMUM A/B/	RATE PER DKT	3.120	0.170	N.A.	N.A.	3.290

- A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.262%, CONSISTING OF 2.175% FOR THE CURRENT PERCENTAGE AND 0.087% 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 0.241 CENTS, CONSISTING OF 0.241 CENTS FOR THE CURRENT RATE AND 0.000 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

Issued by: Keith A. Tiggelaar - Director of Regulatory Affairs

Issued on: May 19, 2005

Effective on: April 19, 2005

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP00-107, et al., issued April 19, 2005

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 0.266%, CONSISTING OF 0.369% FOR THE CURRENT PERCENTAGE AND (0.103%) 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 0.093 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.093 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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

Seventh Revised Sheet No. 98
Superseding
Sixth Revised Sheet No. 98

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 on this sheet are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

Issued by: Raymond D. Neppl, Vice President
Issued on: November 21, 2006
Effective on: January 1, 2007
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP06-72-000, issued November 21, 2006, 17 FERC ¶ 61,217

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

Twelfth Revised Sheet No. 99
Superseding
Eleventh Revised Sheet No. 99

STATEMENT OF RATES

	Commodity Rate -----
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	\$0.0017
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	\$0.0023

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 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 45 of the General Terms and Conditions.

Issued by: Bambi L. Heckerman, Manager, Regulatory Affairs

Issued on: August 26, 2008

Effective on: October 1, 2008

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) \$168.24/10 ³ m ³		
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D	FT-D Demand Rate per month \$ 4.45/GJ		
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate		
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate		
6. Rate Schedule FT-A	FT-A Commodity Rate \$ 0.48/10 ³ m ³		
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month		
8. Rate Schedule LRS	<u>Contract Term</u>		<u>Effective LRS Rate (\$/10³m³/day)</u>
	1-5 years		10.08
	6-10 years		8.42
	15 years		7.55
	20 years		6.71
9. Rate Schedule LRS-2	LRS-2 Rate per month \$50,000		
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month \$129.55/10 ³ m ³		
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point		
12. Rate Schedule IT-D	IT-D Rate \$ 0.1606/GJ		
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
14. Rate Schedule PT	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9006-01000-0	\$ 67.22/d	1.0 10 ³ m ³ /d
15. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	2003034359-2	\$ 899.00 / month	
	2007262666-1	\$ 434.00 / month	
	2006253651-1	\$ 11.00 / month	
	2007262711-1	\$ 6.00 / month	
	2007262709-1	\$ 303.00 / month	
	2007262728-1	\$ 859.00 / month	
	2007262705-1	\$ 1,220.00 / month	
	2007263949-1	\$ 46.00 / month	
	2007262175-1	\$ 438.00 / month	
	2007262669-1	\$ 95.00 / month	
	2007262602-1	\$ 4.00 / month	
	2007262701-1	\$ 9.00 / month	
	2007262727-1	\$ 17.00 / month	
	2007262698-1	\$ 43.00 / month	
	2007262609-1	\$ 7.00 / month	
	2007262668-1	\$ 19.00 / month	
	2007262697-1	\$ 1,760.00 / month	
2007263948-1	\$ 90.00 / month		
2003004522-2	\$ 83,333.00 / month		
16. Rate Schedule CO ₂	<u>Tier</u>	<u>CO₂ Rate (\$/10³m³)</u>	
	1	630.10	
	2	503.07	
	3	349.65	

NATURAL GAS TARIFF

NorthWestern
Energy

Canceling $\frac{15^{\text{th}}}{14^{\text{th}}}$ Revised Revised

Sheet No. 80.1
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	\$ 100.75	(R)
10,001 to 30,000	\$ 144.90	(R)
>30,000	\$ 321.50	(R)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for
Maximum Daily Delivery Quantity (MDDQ) \$ 8.238700 (R)

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum \$ 0.062431 (R)

Minimum \$ 0.017935

GTAC Amortization \$ 0.019020

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)

Commission Approved: December 23, 2008
Docket No.: D2008.12.143
Tariff Letter No. 148-G

Effective for service rendered on or after
January 1, 2009

PUBLIC SERVICE COMMISSION

Vernon Stewart 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. 3
Original Sheet No. 1

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is \$2.398 per dekatherm.

Issued By: Lisa A. Murphy, Vice President-Chief Financial Officer
STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE MAY 2009**

	General Service		
	Storage Balance 1/	Commodity Balance 2/	Prepaid Demand
October 2008	\$11,590,437	\$1,100,150	\$3,040,391
November	10,346,230	998,226	2,461,118
December	4,059,007	621,772	1,157,690
January 2009	(535,124)	246,050	(397,864)
February	(3,569,219)	(7,421)	(1,320,609)
March	(5,563,480)	(180,860)	(1,917,784)
April	(5,918,718)	(228,709)	(1,736,700)
May	(3,653,569)	(162,698)	(1,025,858)
June	(104,176)	(47,430)	(42,795)
July	3,323,259	64,209	987,777
August	6,680,957	190,180	1,998,107
September	8,852,711	532,990	2,798,144
October	9,988,405	558,998	3,058,392
13 month average	<u>\$2,730,517</u>	<u>\$283,497</u>	<u>\$696,924</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$240,040	\$24,922	\$61,267
Return Requirement - Revenue	<u>\$397,483</u>	<u>\$41,268</u>	<u>\$101,452</u>

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

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

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2008									<u>\$11,725,941</u>
August	\$891,059	\$0	\$11,188	\$902,247	229,458	(\$0.233)	(\$33,640) 2/	\$935,887	12,661,828
September	(334,878)	0	7,928	(326,950)	286,271	0.000	0	(326,950)	12,334,878
October	(838,712)	0	4,631	(834,081)	479,761	0.845	183,238 3/	(1,017,319)	11,317,559
November	469,987	0	1,170	471,157	969,656	0.845	819,360	(348,203)	10,969,356
December	449,232	4,160 4/	179	453,571	1,894,641	0.845	1,600,972	(1,147,401)	9,821,955
January 2009	635,716	0	694	636,410	2,891,983	0.845	2,443,726	(1,807,316)	8,014,639
February	(1,836,624)	0	1,305	(1,835,319)	2,176,867	0.845	1,839,453	(3,674,772)	4,339,867
Balance @ February 28, 2009									<u>\$4,339,867</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 144,378.1 Dk @ (\$0.233).

3/ Reflects 216,850.3 Dk @ \$0.845.

4/ Prior period adjustment related to Minot Air Force Base account switch from firm to interruptible service.

**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, 2008									<u>\$291,680</u>
August	\$155,690	\$0	\$284	\$155,974	35,230	(\$0.416)	(\$14,655) 2/	\$170,629	462,309
September	(28,185)	0	292	(27,893)	37,026	0.000	0	(27,893)	434,416
October	(163,211)	0	165	(163,046)	34,765	0.349	1 3/	(163,047)	271,369
November	59,141	0	28	59,169	64,484	0.349	22,505	36,664	308,033
December	(30,525)	0	5	(30,520)	113,467	0.349	39,600	(70,120)	237,913
January 2009	154,837	0	17	154,854	157,399	0.349	54,932	99,922	337,835
February	(61,289)	0	55	(61,234)	112,404	0.349	39,228	(100,462)	237,373
Balance @ February 28, 2009									<u>\$237,373</u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 35,229 Dk @ (\$0.416).

3/ Reflects 2 Dk @ \$0.349.

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

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ July 31, 2008									<u><u>\$121,188</u></u>
August	\$164,522	\$0	\$121	\$164,643	6,154	(\$0.135)	(\$831) 2/	\$165,474	286,662
September	50,064	0	182	50,246	6,042	0.000	0	50,246	336,908
October	(44,176)	0	128	(44,048)	10,916	0.167	0 3/	(44,048)	292,860
November	24,159	0	31	24,190	33,725	0.167	5,632	18,558	311,418
December	(15,997)	(4,986) 4/	5	(20,978)	56,147	0.167	9,377	(30,355)	281,063
January 2009	85,231	0	20	85,251	90,482	0.167	15,110	70,140	351,203
February	(49,634)	0	58	(49,576)	95,984	0.167	16,029	(65,605)	285,598
Balance @ February 28, 2009									<u><u>\$285,598</u></u>

1/ Interest calculated at 90 day Treasury Note rate.

2/ Reflects 6,154 Dk @ (\$0.135).

3/ Reflects 0 Dk @ \$0.167