

May 8, 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 (75<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered June 1, 2009.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.213 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.

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 June 2009.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.213 per dk for residential and firm general service customers, a decrease of \$0.221 per dk for small and large interruptible customers and a decrease of \$0.220 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 June 2009. The average cost of gas for firm customers, adjusted for losses, is \$4.152.

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 \$73,300 during the month of June 2009. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 91,055 customers in North Dakota as of April 30, 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

Attachment

**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  
 75th Revised Sheet No. 3  
 Canceling 74th 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	\$4.989	\$5.801
Air Force Rate 64	7	\$1,000.00 per month \$135.00 per month			
Minot Air Force Base					
PAR Site					
Firm Service			\$0.138	\$4.989	\$5.127
Interruptible Service - PAR			\$0.120	\$3.573	\$3.693
Interruptible Service - MAFB			\$0.120	\$3.376	\$3.496
Firm General Service Rate 70	13	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.597	\$4.989	\$5.586
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$3.573	(Maximum) \$4.444
Optional Seasonal Gas Service Rate 72	15	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet					
Winter Gas Usage			\$0.597	\$5.078	\$5.675
Summer Gas Usage			\$0.597	\$4.129	\$4.726
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.015	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.015	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$3.573	(Maximum) \$4.292
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$7.350	\$8.162
Firm General Propane Rate 92	34	\$0.52 per day \$1.75 per day			
Meters rated < 500 cubic feet					
Meters rated > 500 cubic feet			\$0.597	\$7.350	\$7.947

Date Filed: May 8, 2009

Effective Date:

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

Case No.:

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

**June 2009**

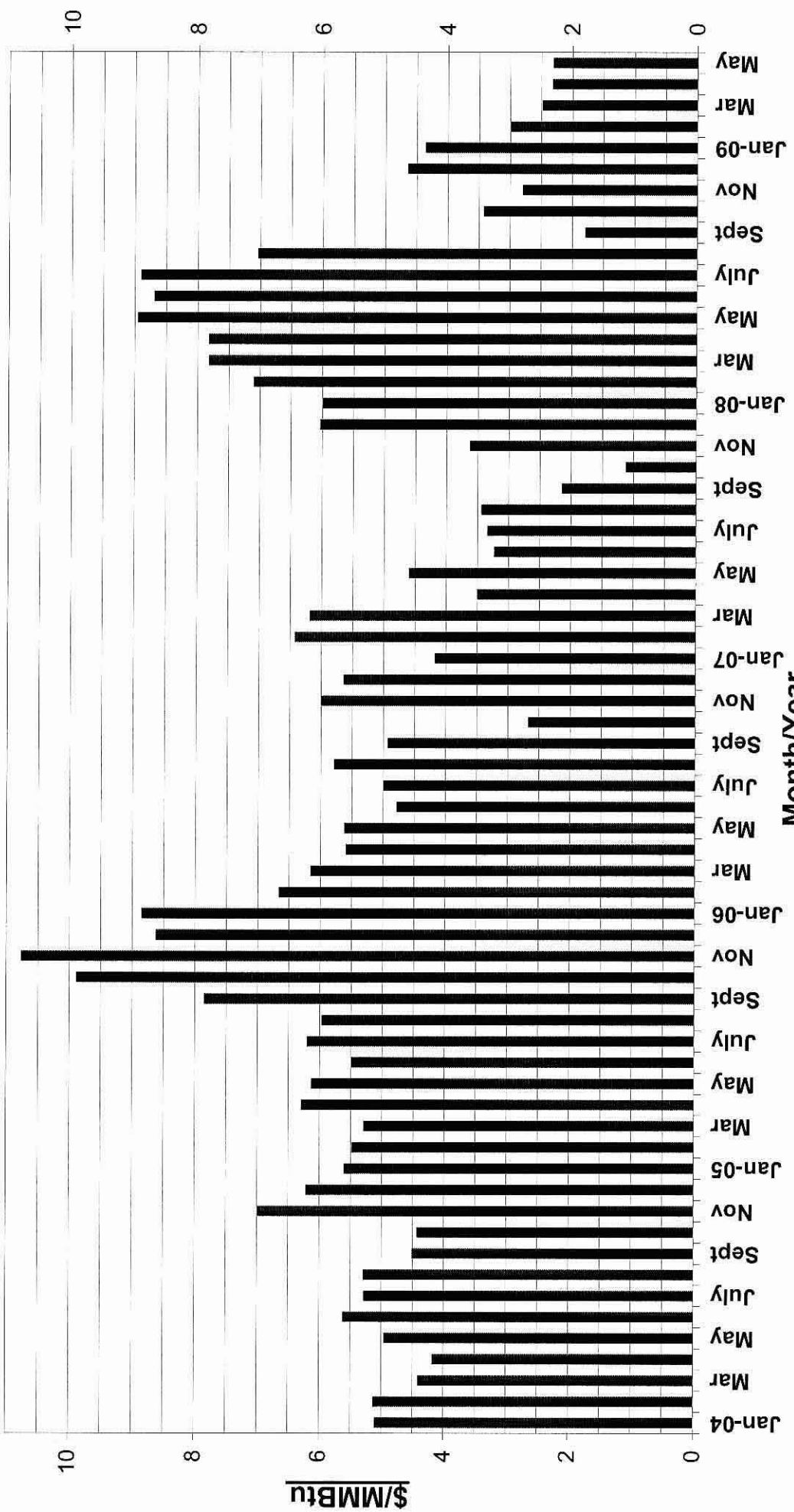
The established May monthly price for the Rocky Mountain CIG Index decreased slightly from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices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

Milder weather has contributed to the fall in prices, as heating demand has fallen. Additional factors include reduced demand as a result of the current economic downturn and increased year over year volumes from domestic production. The Energy Information Administration (EIA) reported storage levels nationwide as of May 1, 2009 were 23.3 percent above the five-year average and 34.4 percent above last year's balance.

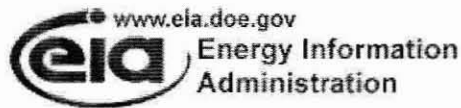
The EIA provides various publications on energy issues. The information is available on their website: <http://www.eia.doe.gov>.

The April Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 13. The May Outlook is to be published May 12.

# 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-\$2.88



April 2009

## Short-Term Energy and Summer Fuels Outlook

April 14, 2009 Release

### *Highlights*

- The price of West Texas Intermediate (WTI) crude oil averaged \$100 per barrel in 2008. The global economic slowdown is projected to reduce the average price to \$53 per barrel this year. Assuming an economic recovery next year, WTI prices are expected to average \$63 in 2010.
- Regular-grade gasoline prices have increased to more than \$2 per gallon, rising slowly but steadily since the beginning of the year in conjunction with rising crude oil prices and refiner margins recovering from recent near-historic lows. During this summer driving season (April through September) regular gasoline retail prices are projected to average \$2.23 per gallon, down almost \$1.60 from last summer. The average regular gasoline price for all of 2009 is expected to be \$2.17 per gallon, increasing to an average of \$2.42 in 2010. Diesel prices are projected to average about \$2.27 per gallon during this driving season and to average \$2.30 and \$2.69 per gallon annually in 2009 and 2010, respectively.
- Total consumption of natural gas is projected to fall by nearly 2 percent in 2009, leading to lower natural gas prices. Industrial natural gas consumption is expected to decline by more than 7 percent, as industrial production declines during the current economic downturn. However, natural gas consumption in the electric power sector is projected to increase by almost 1 percent, since the lower natural gas prices will back out some coal consumption in this sector. 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 \$4.24 per Mcf in 2009, then increase in 2010 to an average of more than \$5.80 per Mcf.

### *Global Petroleum*

*Overview.* Despite high oil inventories in Organization for Economic Cooperation and Development (OECD) countries, crude oil prices rose steadily in March. Lower crude oil production by members of the Organization of the Petroleum Exporting

Countries (OPEC) has lowered world petroleum supplies, substantially offsetting reduced oil demand caused by the global economic recession. Higher oil prices, as well as the change in market sentiment to a slightly less pessimistic outlook, may also reflect the market's belief that economic recovery policies from central banks and governments have slowed down the decline in demand and even improved the chances for an economic upturn and, consequently, higher oil demand, later this year.

The timing and pace of the global economic recovery will determine whether the higher crude oil prices seen during March are sustainable. The prospects of limited growth in non-OPEC production and the expected start of economic recovery later this year, that should increase oil consumption and the demand for OPEC oil, are the main factors supporting the upward price path. If economic recovery begins earlier and is stronger than assumed in this *Outlook*, there is an upside risk of higher oil prices than currently projected. The downside risk to oil prices is a scenario of a prolonged economic downturn followed by a weak recovery, which could produce a greater decline in consumption than currently expected. This latter scenario would challenge the willingness of OPEC's members to sustain lower output levels for a longer period.

**Consumption.** World oil consumption is expected to drop by 1.35 million barrels per day (bbl/d) in 2009 compared with year-earlier levels, due to the global economic recession. EIA assumes that the global gross domestic product (GDP), weighted by oil consumption, will fall by 0.8 percent this year. Consumption is expected to fall by 1.6 million bbl/d in the OECD countries and rise by 270,000 bbl/d in non-OECD nations. The bulk of the decline is expected to be concentrated in the first half of the year (World Liquid Fuels Consumption). World oil consumption is expected to grow by 1.1 million bbl/d in 2010, driven by a recovery of global GDP growth to 2.6 percent.

**Non-OPEC Supply.** Non-OPEC supplies in 2009 are expected be close to last year's levels. The United States, Brazil, and Azerbaijan will show large growth in supplies this year. However, these increases in production are offset by large declines in production from Mexico, the North Sea, and Russia (Non-OPEC Crude Oil and Liquid Fuels Production Growth). Even this pessimistic forecast still contains considerable downside risk, especially from additional project delays and higher-than-anticipated decline rates. Non-OPEC supply is expected to increase by a modest 260,000 bbl/d in 2010, due to increasing production from Brazil, the United States, and the former Soviet Union.

**OPEC Supply.** OPEC left its production targets unchanged from last month, citing concern that reducing production further might harm the world economy. Estimated OPEC crude oil production fell by 1.1 million bbl/d during the fourth quarter of 2008,

reaching 30.6 million bbl/d, then fell by an additional 2.1 million bbl/d in the first quarter of 2009 to 28.5 million bbl/d. EIA expects production to remain close to that level in the second quarter, then gradually increase to about 29.2 million bbl/d in the fourth quarter. EIA expects OPEC crude oil production in 2009 to average 28.8 million bbl/d, then rise to 29.8 million bbl/d in 2010 in response to an expected increase in world oil consumption. In addition, EIA expects that OPEC production of non-crude liquids will grow by 420,000 bbl/d in 2009 and by 720,000 bbl/d in 2010.

**Inventories.** OECD commercial inventories at year-end 2008 stood at 2.68 billion barrels. At 56 days of forward cover, OECD commercial inventories were above average levels for that time of year (Days of Supply of OECD Commercial Stocks). Preliminary estimates suggest that OECD commercial inventories at the end of March 2009, measured in terms of days of forward supply, continued to remain substantially above average levels for this time of year.

### ***U.S. Crude Oil and Liquid Fuels***

**Consumption.** Total U.S. 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 430,000 bbl/d, or 2.2 percent, because of a continued weak economy. The economic recovery is projected to boost total liquid fuels consumption in 2010 by 270,000 bbl/d, or 1.4 percent, with all of the major fuels registering consumption increases.

**Production.** Crude oil production declined by 110,000 bbl/d in 2008, primarily due to hurricane outages, and is projected to increase by 440,000 bbl/d in 2009 to an average of 5.40 million bbl/d (U.S. Crude Oil Production). This would be the first increase in production since 1991. Output is projected to rise by an additional 150,000 bbl/d in 2010. Contributing to the increases in output are two platforms in the Gulf of Mexico: Thunder Horse, which is already in production, and Tahiti, which is expected to come on stream later this year.

**Prices.** Under current economic and world crude oil supply assumptions, EIA expects WTI prices to average \$53 per barrel in 2009 and \$63 per barrel in 2010 (Crude Oil Prices). A stronger-than-expected 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 \$2.17 per gallon in 2009 and \$2.42 per gallon in 2010. On-highway diesel fuel retail prices are projected to average \$2.30 per gallon in 2009 and \$2.69 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 lower refining margins for distillate throughout the forecast period. Because of the global weakness in industrial output and the onset of a recovery in motor gasoline consumption, domestic diesel prices could fall below gasoline prices this summer.

### *Summer Transportation Fuels Outlook*

The increase in consumption provided by the dramatic fall in petroleum prices from last year is being offset by the weak economy. These counter-balancing forces are expected to be prominent features of the summer driving season, defined as the period from April 1 to September 30.

*Prices.* Regular-grade gasoline retail prices, which averaged \$3.81 per gallon last summer, are projected to average \$2.23 per gallon during the current driving season. The monthly average gasoline price is expected to peak at about \$2.30 per gallon late this summer. Diesel fuel prices, which averaged \$4.37 per gallon last summer, are projected to average \$2.27 this summer. However, because short-term prices can be quite volatile, weekly prices will be higher (or lower) than the monthly average. In addition, if consumption turns out to be greater than projected in this *Outlook*, there could be increases in the monthly price averages.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by the change in crude oil prices and wholesale margins. These retail price projections reflect lower prices for the refiner's average acquisition cost of crude oil, projected to average about \$52 per barrel this summer, significantly lower than the \$116 per barrel average last summer. Wholesale gasoline margins (the difference between the wholesale price of gasoline and the average cost of crude oil) are expected to be relatively unchanged from the average of 39 cents per gallon last summer. Wholesale diesel margins, on the other hand, are projected to be significantly lower this summer (31 cents per gallon) than last summer (80 cents per gallon) because of global weakness in distillate markets.

*Motor Gasoline.* During the summer season, motor gasoline consumption is projected to increase by 1.0 percent to 9.1 million bbl/d. Gasoline consumption last summer was low due to the high gas prices and hurricane-related distribution

problems, and consumption is not expected to begin showing consistent year-over-year growth until the third quarter.

Motor gasoline is supplied by four sources: domestic crude oil refinery output, domestic production and imports of fuel ethanol for gasoline blending, primary inventories, and net imports of motor fuel and blending components. This summer's domestic refinery gasoline supply is expected to increase by about 240,000 bbl/d from last summer's average. Refinery production of gasoline was depressed last year as refiners maximized distillate production because of the much stronger diesel fuel market relative to gasoline. This year the diesel market is being hit the hardest by the economic downturn, and refiners are expected to lean toward more gasoline production.

Fuel ethanol blending into gasoline increased from an average of 437,000 bbl/d during the summer of 2007 to 635,000 bbl/d during the summer of 2008, and is projected to average 670,000 bbl/d this summer. EIA expects the growth in ethanol plant capacity and production over the last few years to slow dramatically in 2009 as lower gasoline prices depress ethanol production profits, and financial market constraints curtail construction plans and contribute to the temporary shutdown of several facilities.

At the onset of the summer driving season (April 1), total gasoline stocks, at 217 million barrels, are estimated to be ample. That level is 4 million barrels below last year, but 8 million barrels above the previous 5-year average (U.S. Gasoline and Distillate Inventories). Because of the lower current inventory level than last year, EIA projects the average stock draw will be about 60,000 bbl/d, compared with last summer's 173,000 bbl/d stock draw and the average of 45,000 bbl/d over the last 5 years.

For the current summer season, net imports of motor gasoline and blending components are projected to average 900,000 bbl/d, down almost 80,000 bbl/d from last summer's average because of the expected higher refinery gasoline yields and increase in ethanol blending this year.

**Diesel Fuel.** Distillate fuel consumption, which includes both diesel fuel and heating oil, is projected to be about 170,000 bbl/d, or 4.5 percent, lower than last summer's average.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. Refinery production this summer is projected to average about 300,000 bbl/d lower than last summer's record average of 4.33 million bbl/d. Refiners maximized production of distillate fuel last year since

diesel fuel wholesale prices were about 40 cents per gallon higher than gasoline wholesale prices. Biodiesel is a small part of the distillate pool. Biodiesel blending averaged about 20,000 bbl/d last summer and is expected to grow to about 35,000 bbl/d this summer as refiners and blenders adjust to the 500-million-gallon biodiesel blending mandate for 2009 under the Renewable Fuels Standard.

Distillate inventories are projected to start the summer season at a record 142 million barrels, about 30 million barrels higher than the previous 5-year average. While distillate stocks normally build during the summer season in preparation for winter heating demand by an average of 21 million barrels during the five previous summers, inventories this summer are expected to show little change.

Continuing strong world demand for distillate fuels last year despite record-high prices contributed to U.S. net exports of distillate fuel averaging almost 420,000 bbl/d during last summer. During the previous five summers (2003 – 2007) the United States was a net importer of distillate fuel, at an average of 120,000 bbl/d. This summer, despite the cutback in domestic refinery production, the United States is expected to continue to be a net exporter, averaging about 380,000 bbl/d.

### *Natural Gas*

**Consumption.** Total natural gas consumption is projected to decline by 1.8 percent in 2009 and remain relatively unchanged in 2010 (Total U.S. Natural Gas Consumption Growth). EIA expects the current decline in economic activity will have a significant impact on natural gas consumption in the industrial sector, which is forecast to fall by 7.4 percent this year. In the residential and commercial sectors, where consumption is influenced more by weather than by macroeconomic conditions, natural gas use is expected to increase slightly in 2009. The expected 0.7-percent increase in natural gas consumption in the electric power sector this year is supported by a projection of lower natural gas prices for power generation relative to coal, particularly in the Southeast. The outlook for natural gas consumption in 2010 remains subject to uncertainty about the status of future economic conditions. If the economy begins to recover later this year as currently expected and weather remains near normal, small consumption growth in the industrial and electric power sectors should be offset by small declines in the residential and commercial sectors.

**Production and Imports.** Total U.S. marketed natural gas production is expected to decline by 0.3 percent in 2009 and by 1.0 percent in 2010. Total working natural gas rigs in the United States have declined from slightly more than 1,600 in late August 2008 to slightly below 800 as of April 9, according to Baker Hughes. The precipitous drop in drilling activity and declining productivity of wells already in place are

expected to cause production to steadily decline as the year progresses. The resultant impact of lower production in the lower-48 non-Gulf of Mexico (GOM) during the second half of 2009 is expected to more than offset higher year-over-year production during the first half of the year. Additional supply curtailments may be necessary as natural gas storage levels approach capacity later this summer. Marketed production from the Federal GOM is expected to increase by 1.9 percent in 2009 because of continued recovery from the 2008 hurricane season and new supplies associated with the startup of offshore oil production facilities. Despite expectations of higher prices and the recovery of drilling programs next year, total production in 2010 is expected to be lower in both the lower-48 non-GOM and Federal GOM regions.

Projected U.S. liquefied natural gas (LNG) imports are expected to increase to about 480 billion cubic feet (Bcf) in 2009, from 352 Bcf in 2008, because of lower global economic activity and the start up of new liquefaction capacity in the Middle East and other parts of the world. Depressed LNG demand in Asia and Europe should tend to increase the amount of LNG available to the United States. However, the LNG projection is subject to considerable uncertainty. Initial production from new liquefaction capacity has been slowed or delayed for extended periods, and U.S. natural gas demand is also projected to be lower in 2009. As a result, expanded LNG flows into the United States likely would depend on there being less domestic natural gas production or imports from Canada than forecast. In the current outlook, U.S. pipeline imports are expected to decline by about 11 percent in 2009.

**Inventories.** On April 3, 2009, working natural gas in storage was 1,674 Bcf ([U.S. Working Natural Gas in Storage](#)). Current inventories are now 310 Bcf above the 5-year average (2004–2008) and 438 Bcf above the level during the corresponding week last year. This year's end-of-March working natural gas storage level was the second highest recorded since 1991, exceeded only by the 1,692 Bcf recorded at the end of March 2006. Working natural gas inventories are projected to rise to possibly new record-high levels by the end of the summer injection season.

**Prices.** The Henry Hub spot price averaged \$4.08 per Mcf in March, \$0.57 per Mcf below the average spot price in February. Lower consumption, brought about by the economic slowdown, and higher production levels have been the primary contributors to lower natural gas prices. Henry Hub spot prices began April below \$4 per Mcf and, absent signs of dramatic economic recovery, are expected to remain below \$4 until seasonal space heating demand picks up this fall. Higher prices are expected in 2010 as the economy improves. In addition to demand recovery, the current drilling cutback and limited access to credit for producers could lead to even higher prices if supply fails to keep pace with demand in the short-term. On the other hand, a larger-than-expected increase in LNG import volumes coupled with sustained

economic weakness could keep prices depressed. The Henry Hub spot price is expected to average \$4.24 per Mcf in 2009 and \$5.83 per Mcf in 2010.

### *Electricity*

**Consumption.** Cooling degree-days this summer are projected to be 5 percent lower than during the summer of 2008 (U.S. Summer Cooling Degree-Days). The reduced need for air conditioning combined with the impact of the recession on electricity sales, especially in the industrial sector, are expected to reduce total electricity consumption by 1.6 percent in 2009. Consumption is expected to return to a more normal growth rate of 1.4 percent in 2010 (U.S. Total Electricity Consumption).

**Prices.** The reduction in electricity sales has increased the average cost of electricity for many utilities. Under cost-of-service regulation, fixed capital costs are spread out among a declining number of kilowatthours, in some cases offsetting the reduction in variable fuel costs. As a result, residential electricity prices are projected to increase slowly, at an average annual rate of about 1.8 percent in both 2009 and 2010 (U.S. Residential Electricity Prices).

**Generation.** Coal-fired generation in the electric power sector is expected to decline by 3.2 percent in 2009 while generation fueled by natural gas is expected to increase by 1.6 percent, primarily due to the favorable natural gas prices compared with delivered coal prices. Difficulties in obtaining credit reportedly have hampered the addition of windpower capacity by some developers. Thus, growth in wind generation is expected to slow appreciably through 2010, after having grown 50 percent last year.

### *Coal*

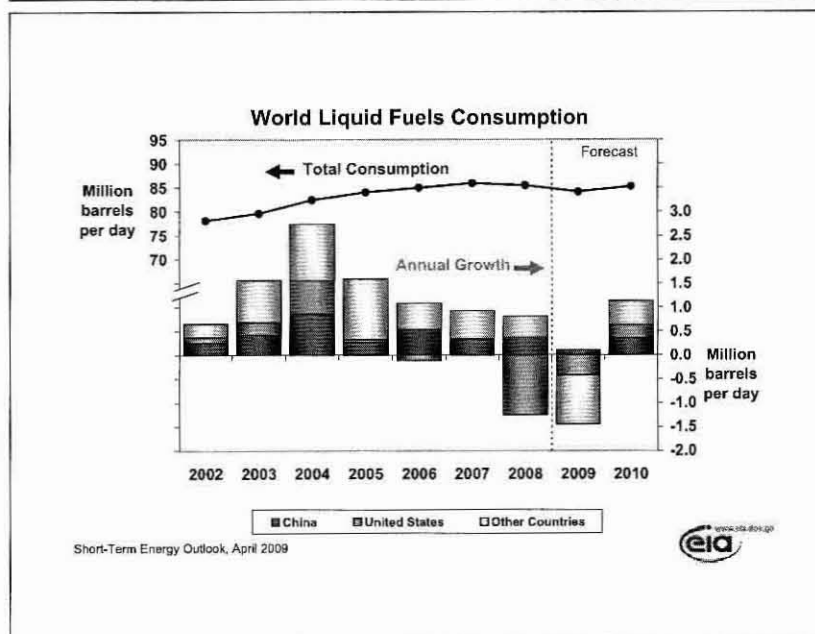
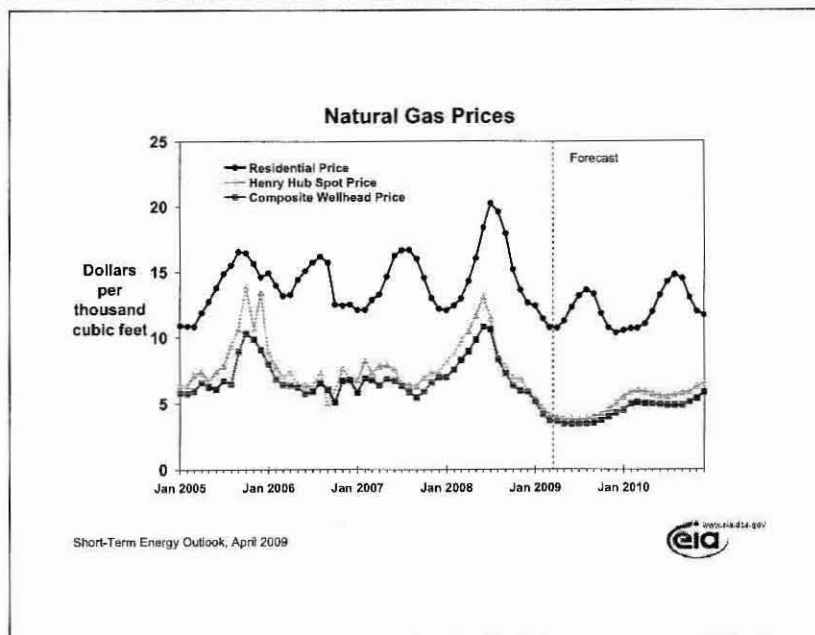
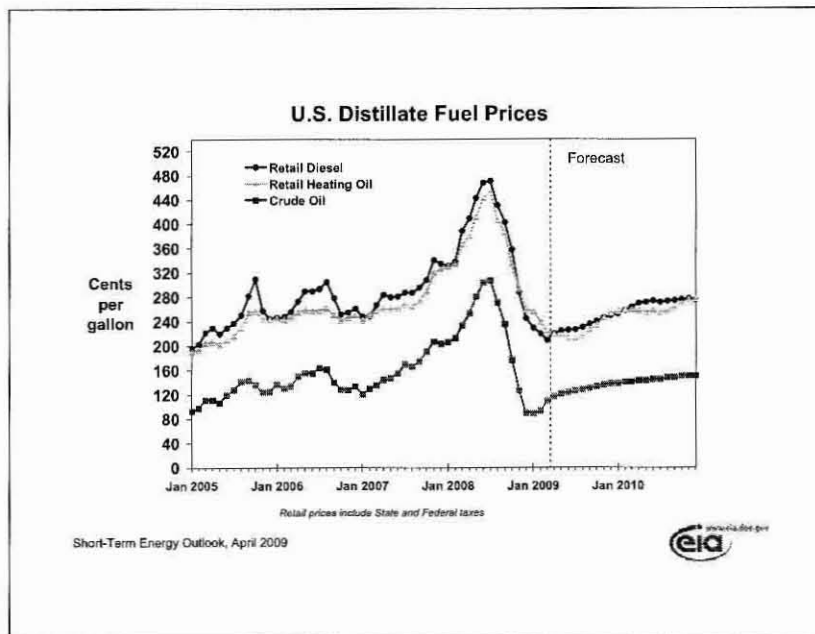
**Consumption.** Coal consumption in the electric power sector fell by 0.3 percent in 2008. A decline in overall electricity generation, combined with projected increases from other fossil-based (natural gas and petroleum) and renewable generation sources (hydroelectric and wind), are projected to lead to a 2.6-percent decline in electric-power-sector coal consumption. An expected increase in total electricity generation of 1.5 percent in 2010 is expected to lead to a 1.1-percent increase in electric-power-sector coal consumption. Consumption growth in the coke plant sector is expected to continue falling over the forecast period (U.S. Coal Consumption Growth).

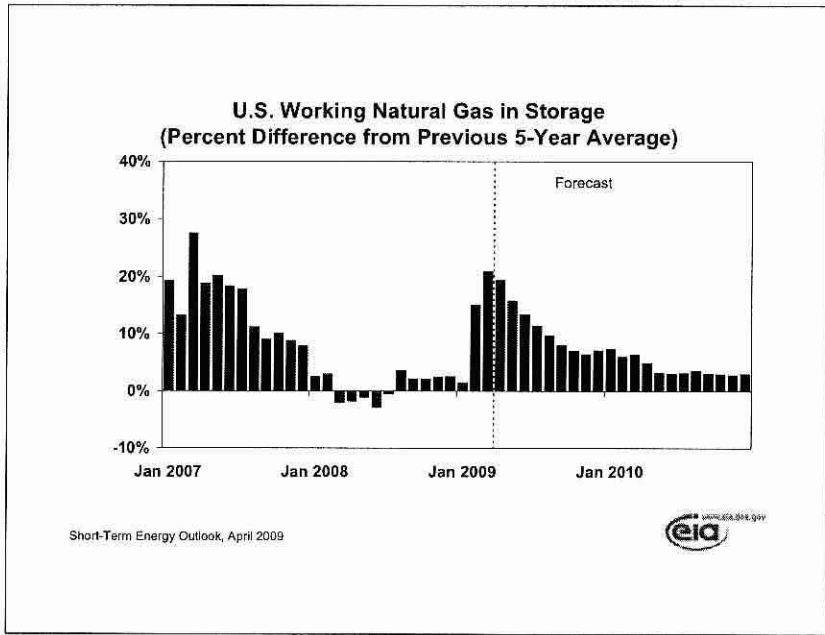
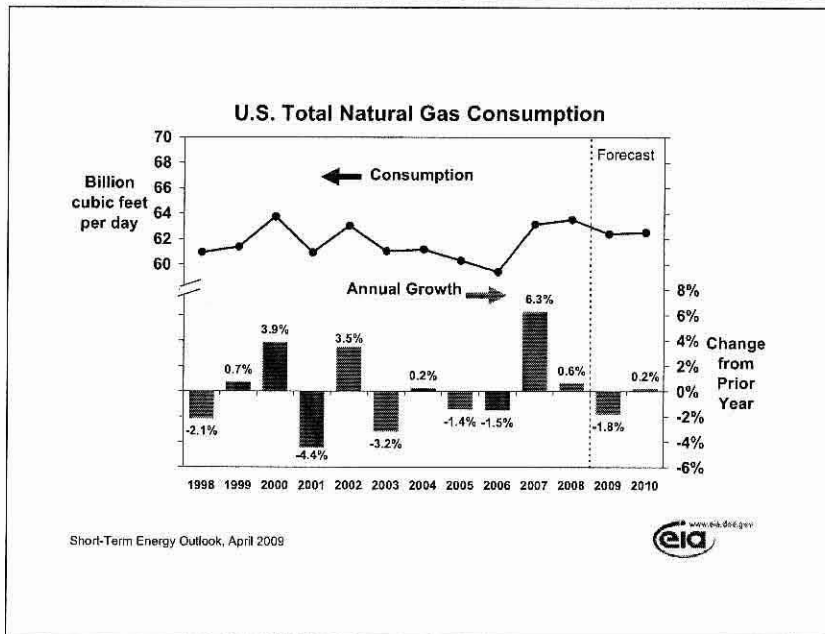
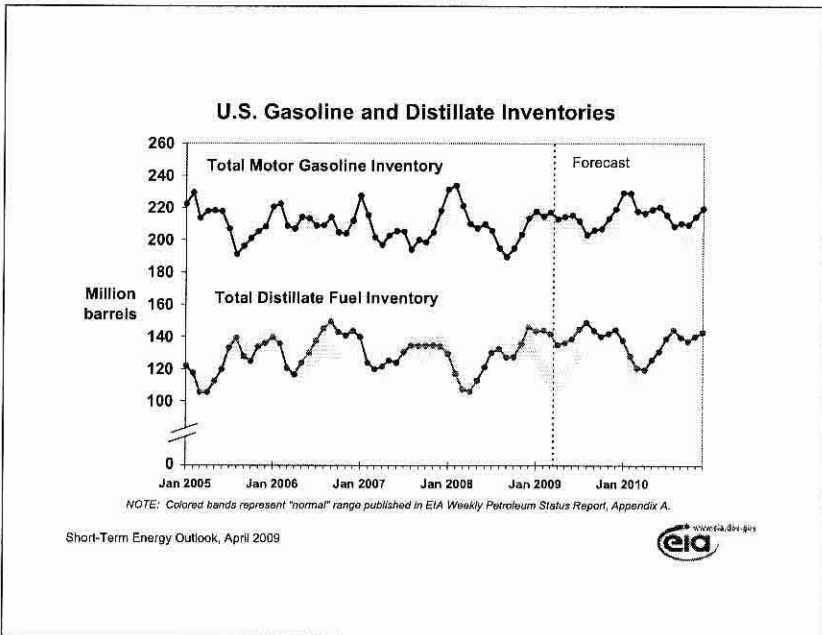
**Production.** A significant increase in coal exports in 2008 contributed to a 2.2-percent increase in coal production. Production is expected to fall by 5.3 percent in 2009 as lower total domestic coal consumption is combined with export declines. Production

is projected to increase by 2.3 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 9 million short tons, an 11-percent decrease, in 2009 relative to 2008. The improving global economy in 2010 is expected to increase global coal demand and lead to a projected 11-percent increase in exports.

*Prices.* The average delivered coal price to the electric power sector is estimated to have increased by more than 17 percent in 2008, to an average \$2.07 per million Btu. Although record increases in spot prices (some well over 100 percent) for several types of coal contributed to the increase in the cost of coal, a rise in transportation charges was the primary reason for the cost increase. Declines in electricity demand and lower transportation costs should cause the annual average delivered coal price to decline to \$2.03 per million Btu in 2009 and \$1.91 in 2010.





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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$4.152	\$3.292	\$3.224	\$3.209
Prior Gas Cost	4.365	4.455	3.445	3.429
Current Gas Cost Adjustment	(\$0.213)	(\$1.163)	(\$0.221)	(\$0.220)
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment	\$0.845	\$0.845	\$0.349	\$0.167
Prior Adjustment	0.845	0.845	0.349	0.167
Change in Surcharge Adjustment	\$0.000	\$0.000	\$0.000	\$0.000
<b><u>Market Based Pricing Differential</u></b>				
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
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>(\$0.213)</u></b>	<b><u>(\$1.163)</u></b>	<b><u>(\$0.221)</u></b>	<b><u>(\$0.220)</u></b>
Gas Cost Level	\$4.152	\$3.292	\$3.224	\$3.209
Plus: Surcharge	0.845	0.845	0.349	0.167
Total Gas Cost Level in Tariff Rates	<u>\$4.997</u>	<u>\$4.137</u>	<u>\$3.573</u>	<u>\$3.376</u>

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

	Amount
Total Gas Costs 1/	\$55,545,416
Residential and General Service dk Requirements 2/	13,440,377
Average Cost of Gas per dk	\$4.133
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.152
Less: Gas Cost Level in Rates 3/	4.365
<b>Current Gas Cost Adjustment</b>	<b>(\$0.213)</b>

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 March 31, 2009, adjusted for losses at .45%

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-155:

Cost of Purchased Gas	\$4.345
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.365

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$55,545,416
Less: Annual MDDQ Costs 1/	<u>11,501,344</u>
Total Gas Costs excluding MDDQ	\$44,044,072
Firm Service Requirements 1/	13,440,377
Other Gas Costs per Dk (excluding MDDQ)	\$3.277
Summer Seasonal Rate, adjusted for losses 2/	3.292
Less: Gas Cost Level in Rates 3/	<u>4.455</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>(\$1.163)</u></u></b>

<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,501,344
Winter Firm Service Requirements	12,168,083
MDDQ Costs per Winter Dk	\$0.945
Add: Other Gas Costs per Dk	<u>3.277</u>
Winter Seasonal Rate	4.222
Winter Seasonal Rate, adjusted for losses 2/	\$4.241

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-09-155:

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$3.490	\$4.435
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$3.506	\$4.455

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

	Amount
Total Gas Costs 1/	\$11,240,971
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$3.209
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.224
Less: Gas Cost Level in Rates 2/	3.445
<b>Current Gas Cost Adjustment</b>	<b>(\$0.221)</b>

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-09-155:

Cost of Purchased Gas	\$3.429
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.445

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

	<u>Amount</u>
Total Gas Costs 1/	\$2,824,076
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$3.209
Less: Gas Cost Level in Rates 2/	<u>3.429</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>(\$0.220)</u></u></b>

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-09-155:  
Cost of Purchased Gas \$3.429

**Montana-Dakota Utilities Co.**  
**Schedule of Applicable Effective Pipeline Rates**  
**June 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.

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

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

SourceGas Distribution LLC – Exhibit B, Page 14 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
-----						
RATE SCHEDULE FT-1						
-----						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.170	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

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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.

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Issued by: Raymond D. Nepl, 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

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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.

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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 <sup>3</sup> m <sup>3</sup>		
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 <sup>3</sup> m <sup>3</sup>		
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 (\$/10<sup>3</sup>m<sup>3</sup>/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 <sup>3</sup> m <sup>3</sup>		
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 <sup>3</sup> m <sup>3</sup> /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 <sub>2</sub>	<u>Tier</u>	<u>CO<sub>2</sub> Rate (\$/10<sup>3</sup>m<sup>3</sup>)</u>	
	1	630.10	
	2	503.07	
	3	349.65	

NATURAL GAS TARIFF



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:

<u>Meters Rated @</u> <u>Cu. Ft. per hour</u>	<u>Per Meter</u> <u>Charge</u>	
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

 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

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**TRANSPORTATION SERVICE Rate 1**

Transportation rate is \$2.398 per dekatherm.

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

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5  
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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
TC (Casper)						
Firm						
Transportation	MLI	MLI	\$0.00	\$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 JUNE 2009**

	General Service		
	Storage Balance 1/	Prepaid 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	(5,566,203)	(172,337)	(1,909,458)
April	(5,086,922)	(171,580)	(1,733,502)
May	(3,215,432)	(126,228)	(1,025,061)
June	(465,377)	(39,399)	(42,999)
July	2,568,414	58,426	988,012
August	6,171,142	189,155	1,998,767
September	9,289,043	550,403	2,799,078
October	10,801,719	591,250	3,059,214
13 month average	<u>\$2,799,055</u>	<u>\$295,267</u>	<u>\$698,060</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$246,065	\$25,957	\$61,366
Return Requirement - Revenue	<u>\$407,460</u>	<u>\$42,982</u>	<u>\$101,616</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 &amp; 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>
<b>Balance @ July 31, 2008</b>									<b><u><u>\$11,725,941</u></u></b>
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
March	(2,301,822)	0	517	(2,301,305)	2,207,860	0.845	1,865,642	(4,166,947)	172,920
<b>Balance @ March 31, 2009</b>									<b><u><u>\$172,920</u></u></b>

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
<b>Balance @ July 31, 2008</b>									<b><u>\$291,680</u></b>
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
March	(70,155)	0	29	(70,126)	68,683	0.349	23,971	(94,097)	143,276
<b>Balance @ March 31, 2009</b>									<b><u>\$143,276</u></b>

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 &amp; 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>
<b>Balance @ July 31, 2008</b>									<b><u>\$121,188</u></b>
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
March	(92,358)	0	34	(92,324)	80,958	0.167	13,520	(105,844)	179,754
<b>Balance @ March 31, 2009</b>									<b><u>\$179,754</u></b>

1/ Interest calculated at 90 day Treasury Note rate.

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

3/ Reflects 0 Dk @ \$0.167

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