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

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

August 9, 2010

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

Re: Cost of Gas Adjustment
(COG) Rate 88 and Rate 99
Case No. PU-10-___

In accordance with North Dakota Century Code Section 49-05-05, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (88th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered September 1, 2010.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased $0.285 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, increasing the cost of gas $0.001 per dk

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of September 2010.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of $0.284 per dk for residential and firm general service customers, a decrease of $0.277 per dk for small and large interruptible customers and a decrease of $0.275 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 September 2010. The average cost of gas for firm customers, adjusted for losses, is $5.333.

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.

12 PU-10-8 Filed 08/09/2010 Pages: 39
Sept. 2010 Cost of Natural Gas & Propane Adjustment
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Rita Mulkem

The overall rate of return of 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota will not seek a Cost of Gas – Propane (COG) adjustment change for the month of September 2010. The Purchased Propane Cost Adjustment tariff (Rate 99), Section 2(b) provides that "Montana-Dakota shall file an adjustment to reflect changes in its average cost of propane supply only when the amount of such adjustment is at least 10 (ten) cents per dk." The COG adjustment for the month of September 2010 results in a change of less than 10 cents per dk, and therefore, in accordance with the authorized tariff, Montana-Dakota will not seek a purchased propane cost adjustment change.

This proposed adjustment, calculated in accordance with Rate 88, will amount to a decrease of approximately $145,500 for natural gas customers during the month of September 2010. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 92,175 natural gas customers in North Dakota as of July 31, 2010.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern
Regulatory Analysis Manager
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Also, please send copies of all written inquiries, correspondence and pleadings to:

Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

Montana-Dakota submitted a check for the amount of $1,200 in accordance with North Dakota Century Code Section 49-05-05 on January 9, 2009. This payment will cover the filing fee associated with this monthly COG.

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Regulatory Analysis Manager

Attachment

Attachment A

Rate Summary Sheet
(Proposed)

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	$0.30 per day	$0.812	$4.807	$5.619
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$4.807	$4.945
Interruptible Service - PAR			$0.120	$4.245	$4.365
Interruptible Service - MAFB			$0.120	$4.401	$4.521
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	$4.807	$5.404
Small Interruptible Gas Rate 71	14	$100.00 per month	(Maximum) $0.871	$4.245	(Maximum) $5.116
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	$4.901	$5.498
Summer Gas Usage			$0.597	$3.952	$4.549
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.020	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.020	
Large Interruptible Gas Rate 85	27	$675.00 per month	(Maximum) $0.719	$4.245	(Maximum) $4.964
Residential Propane Rate 90	32	$0.30 per day	$0.812	$11.428	$12.240
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	$11.428	$12.025

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

September 2010

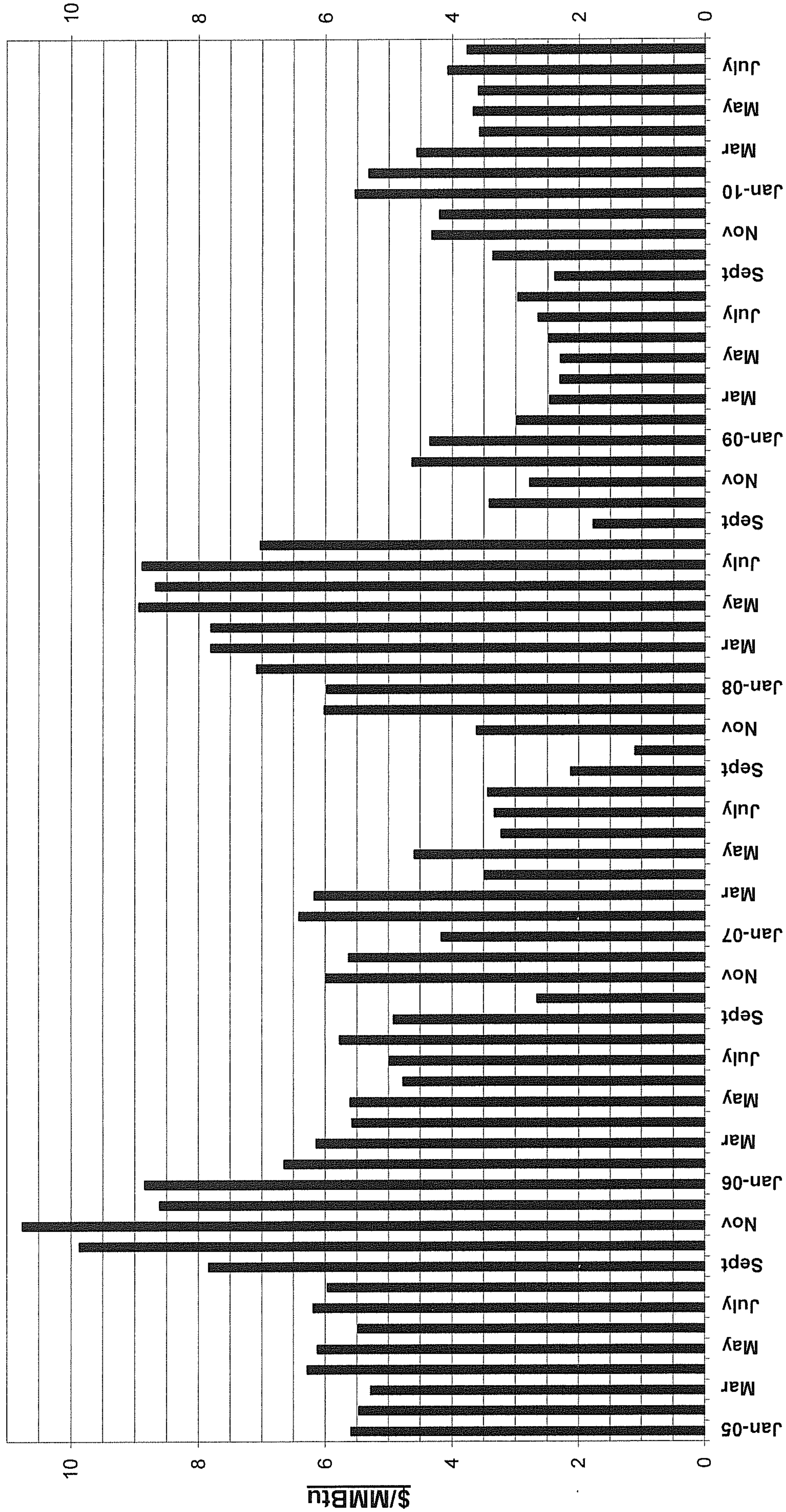
The established monthly price for the Rocky Mountain CIG Index decreased from the previous month. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by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

Despite warm weather over much of the U.S. during the month of July, the continued strong U.S. production and high levels of natural gas in storage were factors leading to the price decrease. The Energy Information Administration (EIA) reported storage levels nationwide as of July 30, 2010 were 8.1 percent above the five-year average and 4.3 percent below last year's record storage balance.

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

The July Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 14. The August Outlook is to be published August 10th.

CIG Rocky Mountains Index
Monthly Gas Prices 2004-2010YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2008-$6.24; 2009-$3.07; 2010YTD - $4.26

U.S. Energy
Information
Administration

July 2010

Short-Term Energy Outlook

July 7, 2010 Release

Highlights

- EIA projects that the West Texas Intermediate (WTI) spot price, which ended June near $76 per barrel, will average $79 per barrel over the second half of 2010 and $83 per barrel in 2011. This forecast is unchanged from last month's *Outlook*.

- EIA expects that regular-grade motor gasoline retail prices will average $2.80 per gallon during this summer's driving season (the period between April 1 and September 30), up from $2.44 per gallon last summer. The summer gasoline price forecast is up only slightly ($0.01) from last month's Outlook, but $0.12 per gallon lower than we had forecast in April, when oil prices were significantly higher.

- This *Outlook* includes EIA's revised estimates of reductions in production resulting from the 6-month deepwater drilling moratorium announced by Secretary of the Interior Salazar on May 27. The reductions in crude oil production resulting from the moratorium are estimated to average about 31,000 barrels per day (bbl/d) in the fourth quarter of 2010 (compared with an estimated 26,000 bbl/d in last month's *Outlook*) and about 82,000 bbl/d in 2011 (up from 70,000 bbl/d). EIA will continue to refine its estimated moratorium impacts as additional information becomes available.

- EIA expects the Henry Hub natural gas spot price to average $4.70 per million Btu (MMBtu) this year, a $0.75-per-MMBtu increase over the 2009 average and $0.22 per MMBtu higher than in last month's *Outlook*. Most of the increase in the price forecast occurs in the third quarter of this year, due to projections of increased hurricane activity in the Gulf of Mexico this season, which pushed spot prices higher. EIA expects the Henry Hub spot price to average $5.17 per MMBtu in 2011, up $0.11 per MMBtu from last month's Outlook.

- The annual average residential electricity price changes only moderately over the forecast period, averaging 11.6 cents per kilowatthour (kWh) in 2010, up slightly from 11.5 cents per kWh in 2009, and rising to 12 cents per kWh in 2011.

- Estimated U.S. carbon dioxide (CO_2) emissions from fossil fuels, which declined by 7.0 percent in 2009, are expected to increase by 3.2 percent and 1.6 percent in 2010 and 2011, respectively, as economic growth spurs higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA's view of the world oil market is largely unchanged from recent *Outlooks*. EIA forecasts that world oil prices will rise slowly as an expected renewal of global economic growth leads to higher world oil demand and members of the Organization of the Petroleum Exporting Countries (OPEC) continue their support of prices near current levels.

Global Crude Oil and Liquid Fuels Consumption. EIA projects world oil consumption to grow by about 1.5 million bbl/d in both 2010 and 2011, mostly unchanged from last month's *Outlook*. However, estimates for oil consumption in 2009 were revised upwards, with these changes carried through the forecast period. Consequently, the level of forecasted demand in 2010 and 2011 is higher than last month's *Outlook*. Countries outside of the Organization for Economic Cooperation and Development (OECD) represent nearly all of the expected growth in world oil consumption, led by China, Saudi Arabia, and Brazil (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. EIA has revised its forecast of non-OPEC supply upwards from the last *Outlook*, with non-OPEC supply now expected to increase by 0.6 million bbl/d in 2010 and decline by less than 0.1 million bbl/d in 2011. The forecast for oil production in Mexico is more optimistic than last month. Data for the first half of the year have been higher than expected, as recent decline rates at the Cantarell field have fallen and the country has boosted output from other offshore areas. Nonetheless, oil production in Mexico is still expected to fall by 0.1 million bbl/d in 2010 and roughly 0.2 million bbl/d in 2011. Over the forecast period, Brazil, the United States, and Azerbaijan should provide the largest sources of non-OPEC supply growth.

OPEC Supply. The 12 members of OPEC produced an estimated 29.4 million bbl/d of crude oil in the second quarter of 2010. After remaining relatively steady for the past four quarters, EIA expects OPEC crude oil production to rise slightly through 2011 to accommodate increasing world oil consumption and maintain the organization's market objectives. Even with the increase in crude oil production, OPEC surplus capacity should remain over 5 million bbl/d in 2010 and 2011, versus 4.3 million bbl/d in 2009 and 1.5 million bbl/d in 2008 (OPEC Surplus Crude Oil Production Capacity Chart). OPEC production of non-crude petroleum liquids, which are not subject to OPEC production targets, are expected to increase by 0.6 million bbl/d in 2010 and 0.7 million bbl/d in 2011.

OECD Petroleum Inventories. Commercial oil inventories held in the OECD stood at about 2.7 billion barrels at the end of the first quarter of 2010, equivalent to about 57 days of forward cover, and roughly 67 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). The level of OECD oil inventories is expected to decline through the forecast period, though days-forward-cover should remain high due to falling OECD oil consumption.

Crude Oil Prices. WTI crude oil spot prices averaged $75.34 per barrel in June 2010 ($1.60 per barrel above the prior month's average), close to the $76 per barrel projected in the forecast in last month's *Outlook*. EIA projects WTI prices will average about $79 per barrel over the second half of this year and rise to $84 by the end of next year (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain, as history has shown (Energy Price Volatility and Forecast Uncertainty). WTI futures for September 2010 delivery for the 5-day period ending July 1 averaged $77 per barrel, and implied volatility averaged 35 percent. This made the lower and upper limits of the 95-percent confidence interval $60 and $98 per barrel, respectively.

Last year at this time, WTI for September 2009 delivery averaged $70 per barrel, and implied volatility averaged 44 percent, rendering the limits of the 95-percent confidence interval $52 and $95 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption is beginning to show signs of recovery after having fallen by 810,000 bbl/d in 2009, the fourth consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). The year-over-year decline in total liquid fuels consumption slowed to 20,000 bbl/d in the first quarter of 2010. Total consumption for the second quarter, however, rose by 500,000 bbl/d compared with the same period last year. For the year as a whole, projected total liquid fuels consumption grows by 200,000 bbl/d in 2010 and by 170,000 bbl/d in 2011 as all of the major petroleum products register consumption growth in each of those years.

U.S. Liquid Fuels Supply and Imports. Projected domestic crude oil production increases by 75,000 bbl/d in 2010 (U.S. Crude Oil Production Chart). Based on the forecast of a more active hurricane season by the National Oceanic and Atmospheric Administration (NOAA), EIA estimates a median outcome of 26 million barrels of total shut-in crude oil production because of tropical storm activity in the Gulf of Mexico this year (see *2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*).

Reversing a pattern of increases over several years, forecast crude oil production in 2011 falls by 26,000 bbl/d to 5.37 million bbl/d. The lower production forecast includes EIA's estimates of reductions in the output of crude oil from the deepwater Gulf of Mexico of 31,000 bbl/d in the fourth quarter of 2010 and 82,000 bbl/d in 2011 because of the recently imposed 6-month drilling moratorium. The reductions in crude oil production increase from a monthly average of about 10,000 bbl/d in September 2010 to nearly 100,000 bbl/d by December 2011.

Projected ethanol production, which averaged 700,000 bbl/d in 2009, increases to an average of 850,000 bbl/d in 2010 and 880,000 bbl/d in 2011. EIA forecasts that liquid fuel net imports (including both crude oil and refined products), which declined by 1.4 million bbl/d in 2009, will fall by a further 110,000 bbl/d in 2010. In 2011, projected total liquid fuel net imports increase by 80,000 bbl/d.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average $2.35 per gallon in 2009 to an average $2.77 per gallon in 2010 and $2.90 per gallon in 2011. Forecast regular-grade pump prices average $2.80 per gallon this summer, an increase of 36 cents from the previous summer. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.98 per gallon in 2010 and $3.13 in 2011 in this forecast.

Natural Gas

U.S. Natural Gas Consumption. EIA projects total natural gas consumption will average 64.7 billion cubic feet per day (Bcf/d) and 64.8 Bcf/d in 2010 and 2011, respectively (Total U.S. Natural Gas Consumption Growth Chart). Estimated year-over-year consumption growth averaged 2.8 Bcf/d (4.3 percent) in the first half of 2010, with significant increases in the electric power and industrial sectors. This growth is expected to continue at a slower pace in the second half of the year with an increase of 1.5 Bcf/d (2.6 percent). EIA's projected natural-gas-weighted industrial production index (a measure of industrial activity in natural-gas-intensive industries) increases by 7.5 percent in 2010, leading to a 1.0 Bcf/d (5.9-percent) increase in natural gas consumption in the industrial sector.

Projected natural gas consumption is virtually flat in 2011. The projected 2.7 percent increase in the natural-gas-weighted industrial production index and NOAA forecast of slightly colder weather next year (1.4 percent increase in heating degree-days) contribute to consumption growth in the residential, commercial, and industrial sectors in 2011. However, this growth is offset by a decline in natural gas consumption in the electric power sector because of the forecast increase in natural gas prices relative to coal prices next year.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production of 61.3 Bcf/d in 2010, an increase of 1.3 Bcf/d over 2009 levels. EIA projects a continuing decline in Gulf of Mexico production, which is offset by gains in onshore production. Forecast marketed production declines by 0.4 Bcf/d to 60.9 Bcf/d in 2011.

Federal Gulf of Mexico natural gas production falls by about 10 percent in both 2010 and 2011 as a result of hurricane outages, the announced offshore drilling moratorium, and the decline in active drilling rigs over the last 4 years. The estimated median outcome for hurricane outages from June through November is a cumulative 166 Bcf this year, compared with 19 Bcf in 2009 (*2010 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico*). The offshore drilling moratorium is projected to reduce Gulf of Mexico production by an average of 0.05 Bcf/d for the last 6 months of 2010 and 0.25 Bcf/d for 2011.

Projected lower-48 onshore production increases by 2 Bcf/d (3.8 percent) in 2010 and 0.2 Bcf/d (0.3 percent) in 2011. According to Baker-Hughes, natural gas rig counts have climbed from under 670 in July 2009 to about 950 in April this year and have remained relatively stable since then.

Forecasted imports of liquefied natural gas (LNG) average 1.37 Bcf/d in 2010, a downward revision of about 0.14 Bcf/d from last month. Projected imports increase to 1.52 Bcf/d in 2011. While imports are expected to grow, higher prices in European and Asian markets will likely divert LNG cargoes from the United States. EIA also forecasts gross pipeline imports of 8.8 Bcf/d in 2010, a decrease of about 2.9 percent from 2009. EIA expects gross pipeline imports of 8.2 Bcf/d in 2011.

U.S. Natural Gas Inventories. On June 25, 2010, working natural gas in storage was 2,684 Bcf (U.S. Working Natural Gas in Storage Chart). This is 27 Bcf below last year's level and 287 Bcf higher than the 5-year (2005-2009) average. EIA expects working gas inventories this year to remain very near last year's levels, reaching 3,810 Bcf at the end of October 2010.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.80 per MMBtu in June, $0.66 per MMBtu higher than the average spot price in May (Henry Hub Natural Gas Price Chart). The forecast price for the second half of 2010 averages $4.68 per MM Btu, $0.32 per MMBtu higher than last month's *Outlook*. The risk of hurricane outages and the projected reduction in drilling activity combine to strengthen prices through the year. A small decline in U.S. production alongside increased consumption leads to higher prices in 2011; the projected Henry Hub spot price averages $5.17 per MMBtu.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for September 2010 delivery for the 5-day period ending July 1 averaged $4.77 per MMBtu, and the average implied volatility over the same period was 53 percent. This produced lower and upper bounds for the 95-percent confidence interval of $3.16 and $7.18 per MMBtu, respectively. At this time last year the natural gas September 2009 futures contract averaged $4.00 per MMBtu and implied volatility averaged almost 76 percent. This rendered the lower and upper limits of the 95-percent confidence interval at $2.25 and $7.14 per MMBtu.

Electricity

U.S. Electricity Consumption. This summer has started out much warmer than last summer, resulting in more demand for air conditioning. Cooling degree-days during June were 28 percent higher than in June 2009 (U.S. Summer Cooling Degree Days). EIA estimates the total consumption of electricity across all sectors during the first half of this year increased by 3.8 percent from the first half of 2009. Consumption is expected to show similar year-over-year growth of 3.5 percent during the second half of 2010. Growth in electricity consumption should return to a more typical rate of 1.1 percent in 2011 (U.S. Total Electricity Consumption Chart).

U.S. Electric Power Sector Generation. Snowmelt runoff projections earlier this spring pointed to low levels of hydropower generation during the summer. However, heavy rainfall in the Pacific Northwest during May and June has pushed generation by hydroelectric plants much higher than normal. An increase in EIA's expectation for overall electricity consumption offsets higher expected natural gas fuel costs, keeping growth in natural gas generation at 5.6 percent during 2010, unchanged from last month's *Outlook*. The level of natural gas generation is expected to stay relatively flat in 2011.

U.S. Electricity Retail Prices. EIA estimates that residential retail electricity prices during the first half of 2010 were about the same as in the first half of 2009. However, rising fuel costs for natural gas and coal generation are likely to push up retail prices later this year, causing prices over the entire year to grow by about 0.8 percent. Increased fuel costs should push residential prices higher by about 2.7 percent during 2011 (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. EIA projects that coal consumption in the electric power sector will increase by 4.6 percent in 2010. Continued electricity demand growth in 2011 combined with minimal growth in nuclear and natural-gas-fired generation results in an additional 2.4-percent increase in electric-power-sector coal consumption next year (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Projected coal production falls by 0.4 percent in 2010 despite increases in domestic consumption and lower imports. The balance between supply and consumption is satisfied through significant reductions in both producer (14 percent) and end-user (11 percent) inventories (U.S. Electric Power Sector Coal Stocks Chart). EIA projects a 3.6-percent increase in coal production in 2011 to meet continued growth in coal consumption (U.S. Annual Coal Production Chart).

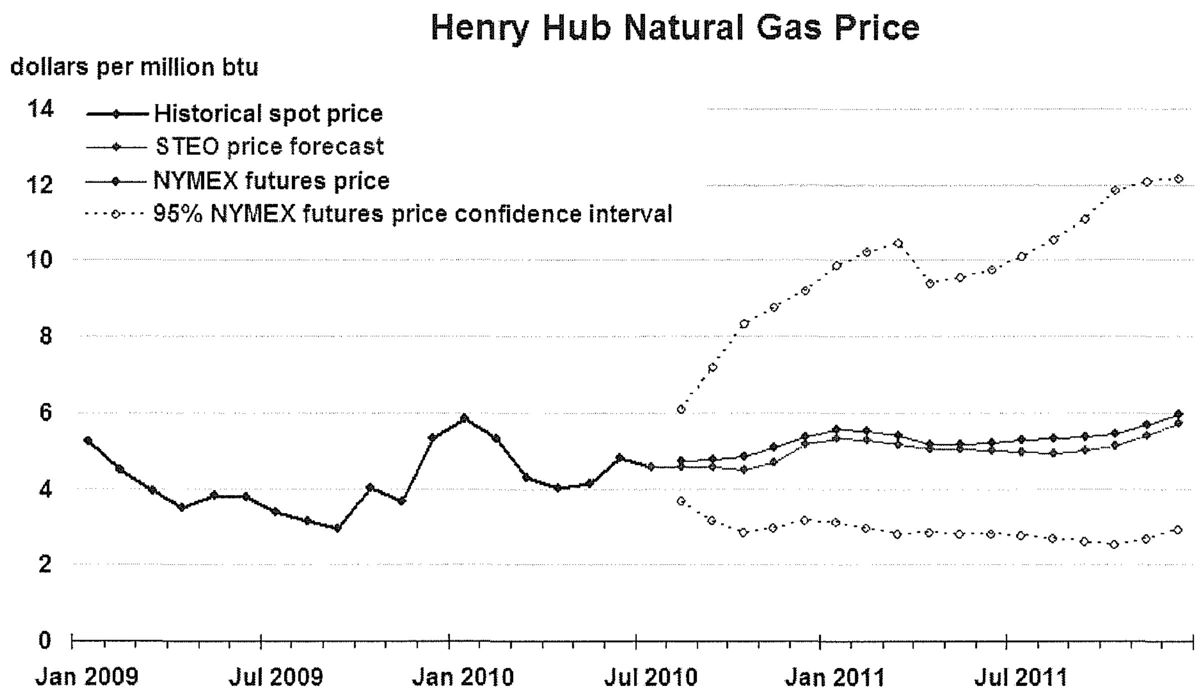
U.S. Coal Trade. U.S. coal imports and exports fell by 34 percent and 28 percent in 2009, respectively. EIA projects imports to decline another 15 percent in 2010 as increased domestic consumption is met by draws on U.S. coal inventories. Forecast coal exports, on the other hand, grow by 25 percent in 2010, driven in part by rising demand for metallurgical coal in China and other Southeast Asian countries. Metallurgical coal is an essential component of the steelmaking process, and currently constitutes a larger share of the U.S. coal export market than steam coal (burned in thermal electric power plants). From January through April 2010, the United States exported 19.6 million tons of metallurgical coal, 95 percent higher than the comparable period in 2009.

Projected coal imports grow by 35 percent in 2011, but the annual tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons. Forecast coal exports in 2011 are relatively unchanged from 2010 levels.

U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by about 7 percent despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in coal-fired electricity generation. This higher cost of delivered coal reflects the impacts of longer-term power-sector coal contracts initiated during a period of high prices and rising transportation costs. The projected electric-power-sector delivered coal price increases slightly (by 1.4 percent) to average $2.24 per MMBtu in 2010, and then declines to an average of $2.19 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Forecast economic growth combined with increased use of coal and natural gas in the electric power sector contribute to increases in fossil-fuel CO_2 emissions of 3.2 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). Increased demand for petroleum in the transportation sector (motor gasoline, diesel fuel and jet fuel), combined with continued electric-power-sector coal demand growth, contribute to the projected 1.6-percent increase in fossil-fuel CO_2 emissions in 2011. However, even with increases in 2010 and 2011, projected CO_2 emissions are lower than annual emissions were from 1999 through 2008.



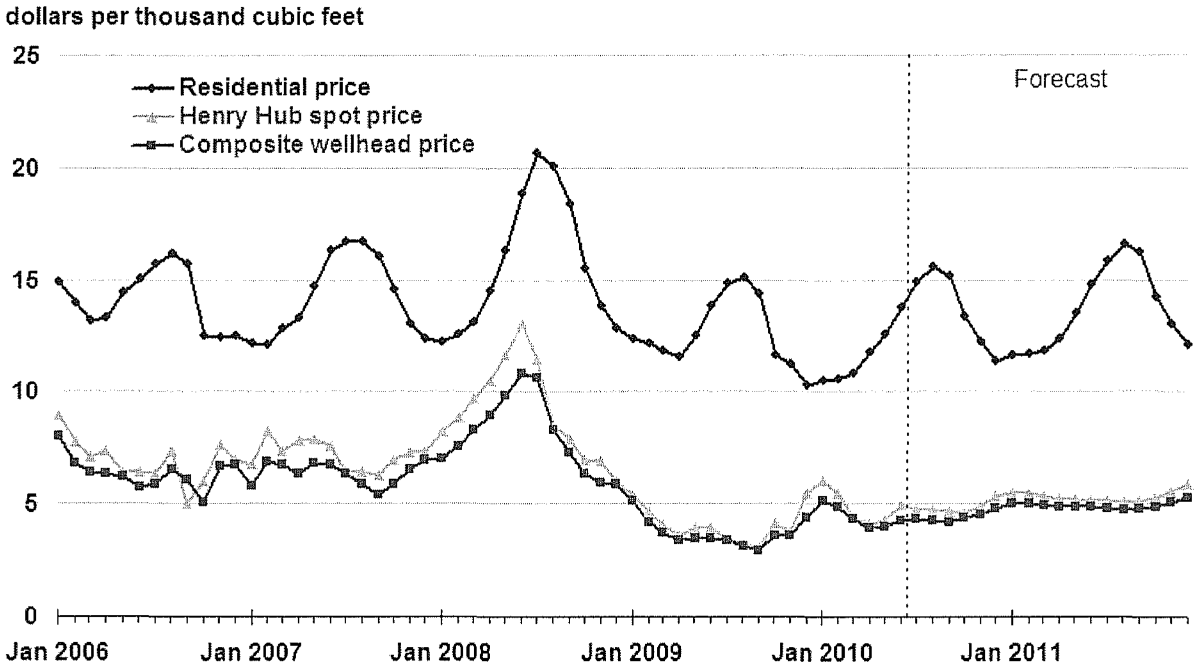
Note: Confidence interval derived from options market information for the 5 trading days ending July 1, 2010

Intervals not calculated for months with sparse trading in "near-the-money" options contracts

eia U.S. Energy Information Administration

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

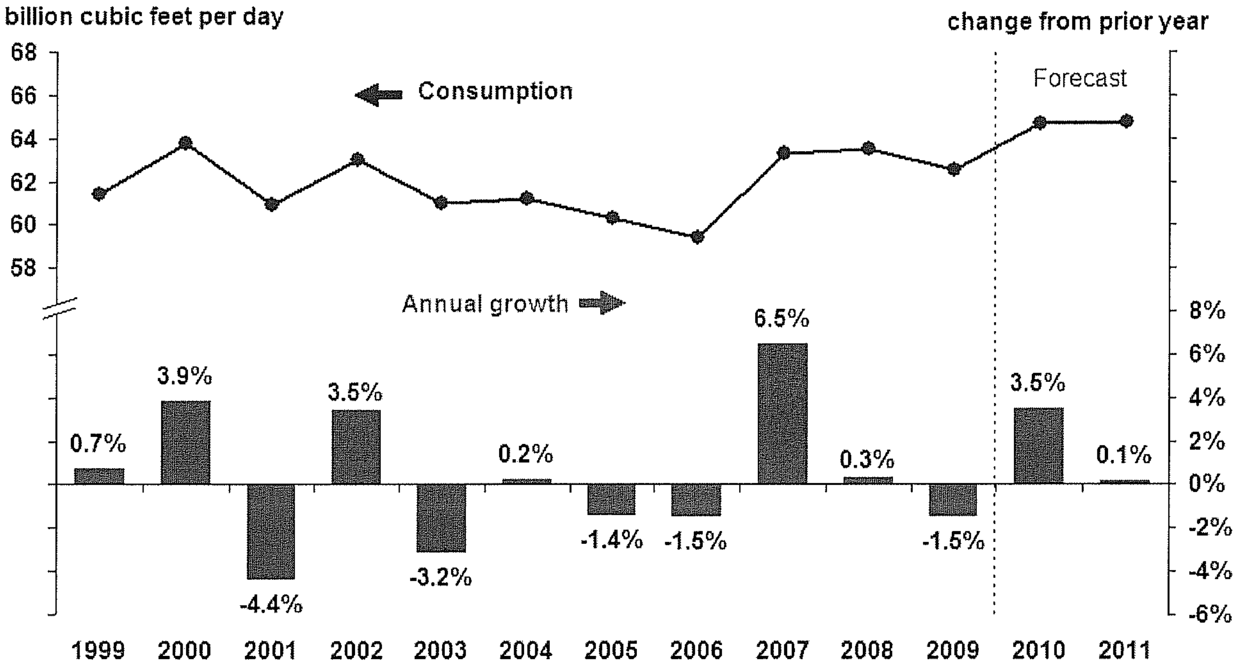
Natural Gas Prices



U.S. Energy Information Administration

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

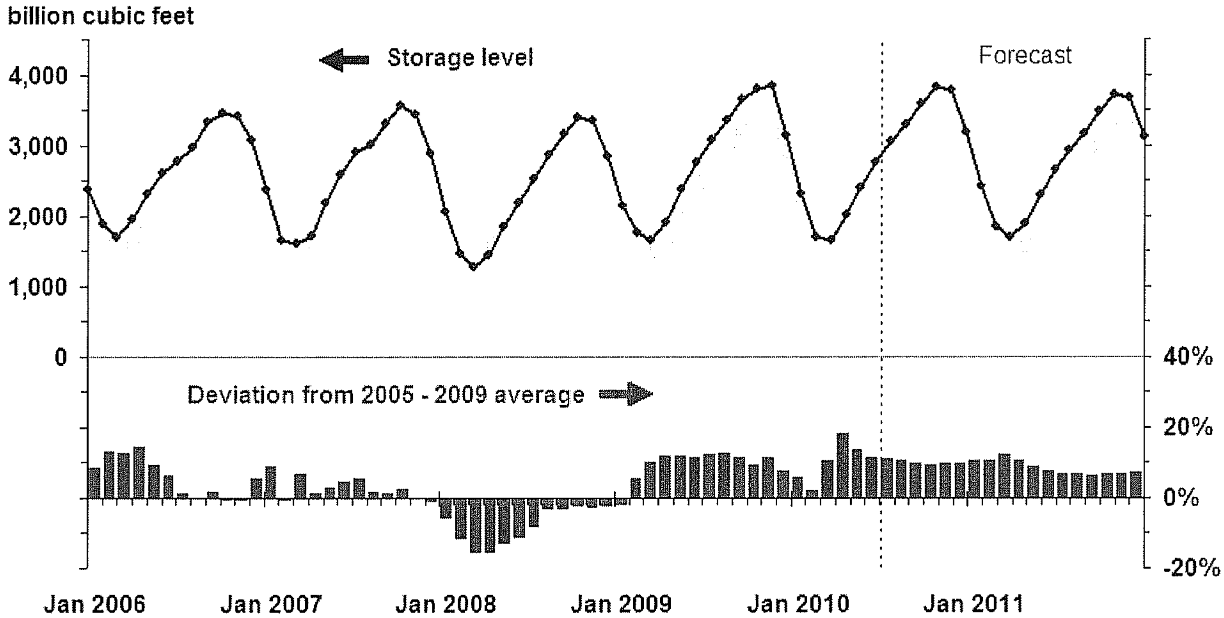
U.S. Total Natural Gas Consumption



U.S. Energy Information Administration

Source: Short-Term Energy Outlook, July 2010

U.S. Working Natural Gas in Storage



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

U.S. Energy Information Administration

Source: Short-Term Energy Outlook, July 2010

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

NorthWestern Energy

On October 16, 2009, NorthWestern Energy filed an Application for Authority to Establish Increased Natural Gas Rates with the Montana Public Service Commission. On July 8, 2010, the Montana Public Service Commission approved Interim rates in Docket No. D2009.9.129 Order No. 7046g effective July 8, 2010.

Approximate impact on Montana-Dakota's cost of gas – 0.001 cents per dk

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE SEPTEMBER 2010

	Firm: Residential & General Service	Firm: Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$5.333	$4.478	$4.397	$4.377
Prior Gas Cost	5.617	4.757	4.674	4.652
Current Gas Cost Adjustment	($0.284)	($0.279)	($0.277)	($0.275)
Surcharge Adjustment:				
Current Adjustment	($0.515)	($0.515)	($0.152)	$0.024
Prior Adjustment	(0.515)	(0.515)	(0.152)	0.024
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
Current Adjustment	($0.011)	($0.011)	$0.000	$0.000
Prior Adjustment	(0.011)	(0.011)	0.000	0.000
Change in Margin Sharing Provision	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**($0.284)**	**($0.279)**	**($0.277)**	**($0.275)**
Gas Cost Level	$5.333	$4.478	$4.397	$4.377
Plus: Surcharge	(0.515)	(0.515)	(0.152)	0.024
Total Gas Cost Level in Tariff Rates	$4.818	$3.963	$4.245	$4.401

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE SEPTEMBER 2010

	Amount
Total Gas Costs 1/	$72,298,674
Residential and General Service dk Requirements 2/	13,617,219
Average Cost of Gas per dk	$5.309
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.333
Less: Gas Cost Level in Rates 3/	5.617
Current Gas Cost Adjustment	**($0.284)**

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 June 30, 2010, adjusted for losses at .45%
3/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

Cost of Purchased Gas	$5.592
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$5.617

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE SEPTEMBER 2010

Summer - June - September	
Total Gas Costs 1/	$72,298,674
Less: Annual MDDQ Costs 1/	11,592,671
Total Gas Costs excluding MDDQ	$60,706,003
Firm Service Requirements 1/	13,617,219
Other Gas Costs per Dk (excluding MDDQ)	$4.458
Summer Seasonal Rate, adjusted for losses 2/	4.478
Less: Gas Cost Level in Rates 3/	4.757
Current Gas Cost Adjustment	**($0.279)**

Winter - October - May	
Annual MDDQ Costs 1/	$11,592,671
Winter Firm Service Requirements	12,267,275
MDDQ Costs per Winter Dk	$0.945
Add: Other Gas Costs per Dk	4.458
Winter Seasonal Rate	5.403
Winter Seasonal Rate, adjusted for losses 2/	$5.427

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

	Summer	Winter
Cost of Purchased Gas	$4.736	$5.686
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$4.757	$5.712

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE SEPTEMBER 2010

	Amount
Total Gas Costs 1/	$15,332,346
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$4.377
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.397
Less: Gas Cost Level in Rates 2/	4.674
Current Gas Cost Adjustment	**($0.277)**

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:

Cost of Purchased Gas	$4.653
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.674

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE SEPTEMBER 2010

	Amount
Total Gas Costs 1/	$3,851,955
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$4.377
Less: Gas Cost Level in Rates 2/	4.652
Current Gas Cost Adjustment	**($0.275)**

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

2/ Gas Cost Level in Current Tariff Rates Case No. PU-10-8:
Cost of Purchased Gas $4.652

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

Williston Basin Interstate Pipeline Company - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company – Exhibit B, pages 9-10 for Schedule T-1.

Foothills Pipe Lines, Ltd. - Billed on a cost of service basis so there are no tariff sheets.

NOVA Gas Transmission – Exhibit B, 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	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 1.823%, CONSISTING OF 2.284% FOR THE CURRENT PERCENTAGE AND (0.461%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.271 CENTS, CONSISTING OF 0.283 CENTS FOR THE CURRENT RATE AND (0.012) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FTN-1						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	47.491	N.A.	N.A.	N.A.	47.491
MINIMUM	RATE PER EQV. DKT PER MO.	1.589	N.A.	N.A.	N.A.	1.589
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	1.561	N.A.	N.A.	N.A.	1.561
MINIMUM	RATE PER DKT	0.052	N.A.	N.A.	N.A.	0.052

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1						
CAPACITY RESERVATION						
MAXIMUM	RATE PER EQV. DKT PER MO.	2.102	N.A.	N.A.	N.A.	2.102
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
CAPACITY DELIVERABILITY						
MAXIMUM	RATE PER EQV. DKT PER MO.	190.602	N.A.	N.A.	N.A.	190.602
MINIMUM	RATE PER EQV. DKT PER MO.	0.000	N.A.	N.A.	N.A.	0.000
INJECTION						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
SCHEDULED OVERRUN CHARGE						
INJECTION						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888
WITHDRAWAL						
MAXIMUM A/B/	RATE PER DKT	23.920	N.A.	N.A.	N.A.	23.920
MINIMUM A/B/	RATE PER DKT	0.888	N.A.	N.A.	N.A.	0.888

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.437%, CONSISTING OF 0.603% FOR THE CURRENT PERCENTAGE AND (0.166%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS (0.164) CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND (0.164) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

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

STATEMENT OF RATES

	Commodity Rate
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	$0.0020

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 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.

TABLE OF RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $213.83/$10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D	FT-D Demand Rate per month $ 5.66/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 $ 0.55/10^3m^3
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month
8. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 1-5 years — 10.43 6-10 years — 8.72 15 years — 7.82 20 years — 6.94
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/$10^3m^3$
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 $ 0.2045/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	Schedule No — PT Rate — PT Gas Rate 9006-01000-0 — $ 60.50/d — 1.0 10^3m^3/d 9009-01001-1 — $660.00/d — 50.0 10^3m^3/d
15. Rate Schedule OS	Schedule No. — Charge 2010418777 — $ 209.00 / month 2010416547 — $ 24.00 / month 2010416549 — $ 63.00 / month 2010416543 — $ 7.00 / month 2010416546 — $ 5.00 / month 2010416548 — $ 1.00 / month 2010416540 — $ 42.00 / month 2010416550 — $ 96.00 / month 2010418778 — $ 350.00 / month 2010416545 — $ 1,688.00 / month 2010418000 — $ 151.00 / month 2010416551 — $ 46.00 / month 2010417322 — $ 153.00 / month 2010416544 — $ 79.00 / month 2010416541 — $ 209.00 / month 2003004522 — $ 83,333.00 / month
16. Rate Schedule CO_2	Tier — CO_2 Rate ($/$10^3m^3$) 1 — 520.03 2 — 411.79 3 — 272.12

NATURAL GAS TARIFF

NorthWestern Energy

	20th	Revised	Sheet No.	80.1
Canceling	19th	Revised	Sheet No.	80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
5,001 to 10,000	$ 102.95	(I)
10,001 to 30,000	$ 148.05	(I)
>30,000	$ 328.50	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	$ 0.063787	(I)
Minimum	$ 0.017935	
GTAC Amortization	$ 0.000962	
Balancing Penalty Rate	Higher of $25.00 / Dkt. Or 150% of Market Price	

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

GAS RATE SCHEDULE

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

SD P.U.C. Section 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

South Dakota Intrastate Pipeline Company SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

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

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

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	$0.00	$1.0551	$0.0100	0.781%
	MLI	MLE	$163.00	$1.0551	$0.0100	0.781%
	MLI	DSE	$163.00	$2.0988	$0.0200	3.425%
Interruptible Transportation 4/	MLI	MLI	$0.00	$0.8439	$0.0100	0.781%
	MLI	MLE	$163.00	$0.8439	$0.0100	0.781%
Administrative Fee 5/			$325.00			

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per Dekatherm.

3/ For fuel, lost and unaccounted for gas, SourceGas shall be entitled to retain the stated percentage of all Dekatherms received for transportation, unless otherwise agreed in writing.

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):

MLI Mainline System Interconnect
MLE Mainline System End-user
DSE Distribution System End-user

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

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

MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE SEPTEMBER 2010

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2009	$12,185,122	$676,026	$3,129,297
November	11,254,366	597,205	2,522,196
December	8,704,183	412,412	1,199,079
January 2010	3,383,952	215,680	(391,041)
February	(1,135,224)	79,587	(1,342,013)
March	(2,453,618)	8,012	(1,948,156)
April	(1,844,777)	(5,405)	(1,766,156)
May	(391,428)	53,497	(1,047,086)
June	2,378,801	134,270	(52,274)
July	6,026,123	234,662	990,328
August	9,331,859	333,864	2,012,453
September	11,328,769	574,754	2,818,429
October	12,861,378	609,129	3,072,654
13 month average	$5,509,962	$301,823	$707,516
Rate of Return	8.791%	8.791%	8.791%
Return	$484,381	$26,533	$62,198
Return Requirement	$666,706	$36,520	$85,610

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

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

	(Over) Under Recovery	Refunds & Other		Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2009											**($6,530,761)**
August	($284,184)	$9,408	2/	($929)	($275,705)	261,090	$0.845	$220,621		($496,326)	(7,027,087)
September	1,597	0		(706)	891	256,293	0.845	216,567		(215,676)	(7,242,763)
October	122,909	0		(424)	122,485	583,825	(0.515)	149,323	3/	(26,838)	(7,269,601)
November	671,644	0		(304)	671,340	1,022,685	(0.515)	(526,683)		1,198,023	(6,071,578)
December	50,832	7,503	4/	(254)	58,081	1,808,016	(0.515)	(931,125)		989,206	(5,082,372)
January 2010	78,170	0		(255)	77,915	2,540,386	(0.515)	(1,308,299)		1,386,214	(3,696,158)
February	1,979,702	0		(341)	1,979,361	2,172,589	(0.515)	(1,118,883)		3,098,244	(597,914)
March	(615,605)	0		(77)	(615,682)	2,108,094	(0.515)	(1,085,668)		469,986	(127,928)
April	(633,699)	0		(19)	(633,718)	1,180,990	(0.515)	(608,210)		(25,508)	(153,436)
May	(599,923)	0		(22)	(599,945)	714,250	(0.515)	(367,839)		(232,106)	(385,542)
June	(442,748)	0		(39)	(442,787)	470,536	(0.515)	(242,325)		(200,462)	(586,004)
Balance @ June 30, 2010											**($586,004)**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Prior period adjustment to correct the allocation between jurisdictions.
3/ Reflects 330,877 Dk @ $0.845 and 252,948 Dk @ ($0.515).
4/ Billing adjustment.

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, 2009									**($92,116)**
August	($16,499)	$522 2/	($13)	($15,990)	25,403	$0.349	$8,865	($24,855)	(116,971)
September	3,789	0	(12)	3,777	27,818	0.349	9,709	(5,932)	(122,903)
October	(20,599)	0	(7)	(20,606)	32,507	0.349	11,344	(31,950)	(154,853)
November	55,639	0	(7)	55,632	70,459	(0.152)	(10,710)	66,342	(88,511)
December	39,061	0	(4)	39,057	88,074	(0.152)	(13,388)	52,445	(36,066)
January 2010	(69,893)	0	(2)	(69,895)	108,660	(0.152)	(16,516)	(53,379)	(89,445)
February	123,160	0	(8)	123,152	89,489	(0.152)	(13,602)	136,754	47,309
March	(11,118)	0	6	(11,112)	79,157	(0.152)	(12,031)	919	48,228
April	(33,352)	0	6	(33,346)	61,541	(0.152)	(9,354)	(23,992)	24,236
May	(41,136)	0	3	(41,133)	39,195	(0.152)	(5,958)	(35,175)	(10,939)
June	(3,511)	0	(1)	(3,512)	38,655	(0.152)	(5,875)	2,363	(8,576)
Balance @ June 30, 2010									**($8,576)**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Prior period adjustment to correct the allocation between jurisdictions.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2009									**$14,785**
August	($15,035)	$336 2/	$2	($14,697)	7,141	$0.167	$1,193	($15,890)	(1,105)
September	877	0	0	877	6,410	0.167	1,070	(193)	(1,298)
October	(4,862)	0	0	(4,862)	7,589	0.167	1,267	(6,129)	(7,427)
November	23,780	0	0	23,780	37,871	0.024	909	22,871	15,444
December	19,124	0	1	19,125	42,502	0.024	1,020	18,105	33,549
January 2010	(53,605)	0	2	(53,603)	88,110	0.024	2,115	(55,718)	(22,169)
February	114,176	0	(2)	114,174	83,044	0.024	1,993	112,181	90,012
March	(9,074)	0	11	(9,063)	71,569	0.024	1,717	(10,780)	79,232
April	(20,516)	0	11	(20,505)	49,451	0.024	1,187	(21,692)	57,540
May	(31,175)	0	8	(31,167)	28,214	0.024	677	(31,844)	25,696
June	(4,190)	0	2	(4,188)	20,992	0.024	504	(4,692)	21,004
Balance @ June 30, 2010									**$21,004**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Prior period adjustment to correct the allocation between jurisdictions.