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

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

April 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 (85th Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered May 1, 2010.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased $0.933 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 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 May 2010.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of $0.933 per dk for residential and firm general service customers, a decrease of $0.940 per dk for small and large interruptible customers and a decrease of $0.936 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of May 2010. The average cost of gas for firm customers, adjusted for losses, is $5.143.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid demand and commodity balances using the calculation procedure set forth in Rate 88.

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

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane. Attachment B page 2 explains the reasons for the decrease in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of May, 2010. The net effect of this filing is a decrease of $3.383 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of May 2010. The average cost of propane for all customers, adjusted for losses, is $12.076 per dk.

Exhibit F shows the calculation of the surcharge adjustment under Montana-Dakota's proposed amortization which will apply during the period May 1, 2010 through April 30, 2011. The surcharge is $0.461 per dk, an increase of $1.008 per dk for all customers.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to a decrease of approximately $561,200 for natural gas customers and a decrease of approximately $7,800 for propane customers during the month of May 2010. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 92,338 natural gas customers and 333 propane customers in North Dakota as of March 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

NDPSC Volume 7
85th Revised Sheet No. 3
Canceling 84th Revised Sheet No. 3

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	$0.30 per day	$0.812	$4.617	$5.429
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$4.617	$4.755
Interruptible Service - PAR			$0.120	$4.033	$4.153
Interruptible Service - MAFB			$0.120	$4.190	$4.310
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	$4.617	$5.214
Small Interruptible Gas Rate 71	14	$100.00 per month	(Maximum) $0.871	$4.033	(Maximum) $4.904
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	$4.714	$5.311
Summer Gas Usage			$0.597	$3.747	$4.344
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.019	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.019	
Large Interruptible Gas Rate 85	27	$675.00 per month	(Maximum) $0.719	$4.033	(Maximum) $4.752
Residential Propane Rate 90	32	$0.30 per day	$0.812	$12.526	$13.338
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	$12.526	$13.123

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

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

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

May 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 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.

Seasonal warmer temperatures throughout most of the lower 48 States and continued strength in natural gas production contributed to falling natural gas prices. The Energy Information Administration (EIA) reported storage levels nationwide as of March 26, 2010 are 10.8 percent above the five-year average and 1.0 percent below 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 December Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 18.

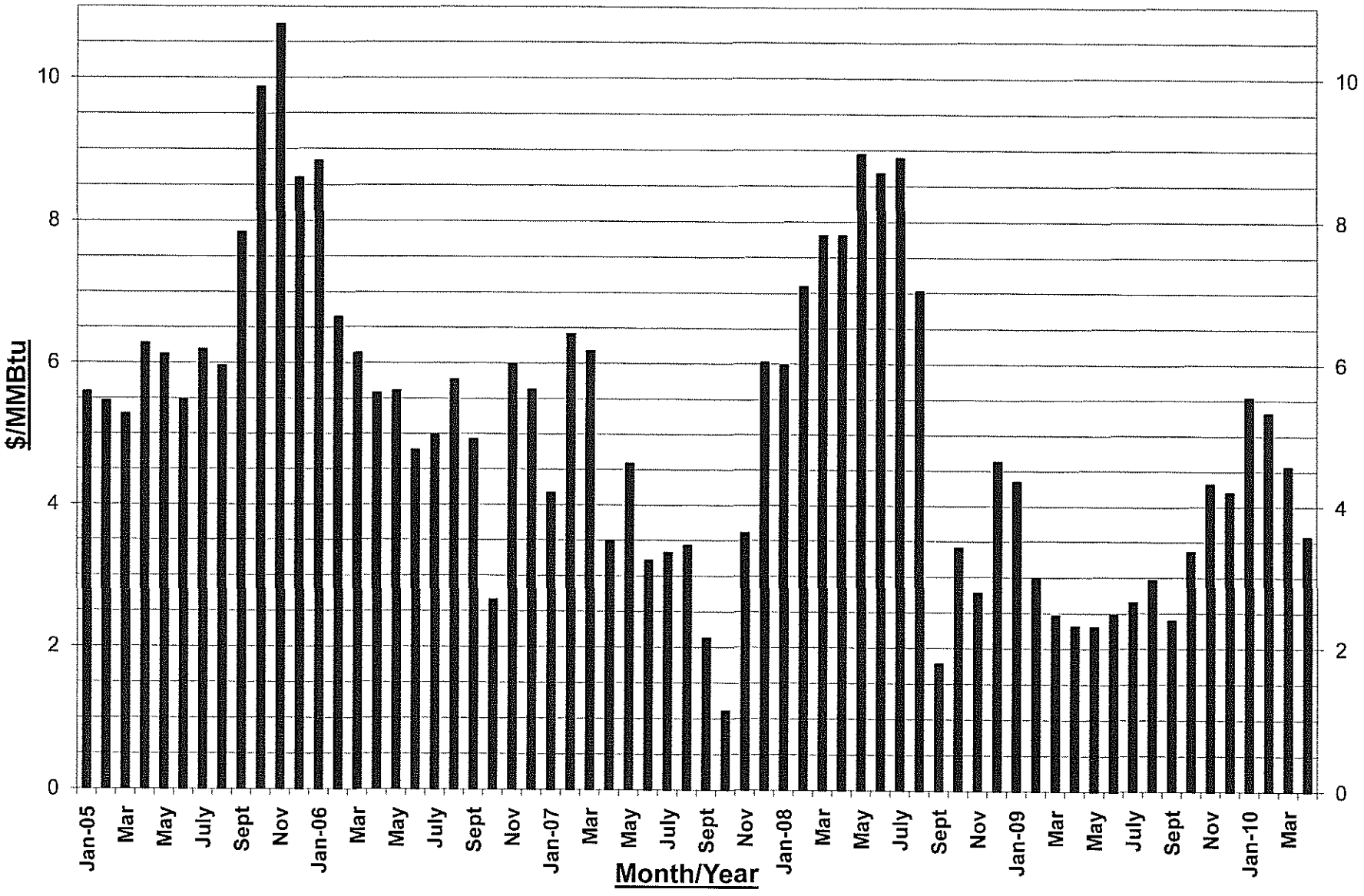
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
May 2010

Montana-Dakota uses three regional bulk wholesale propane suppliers for obtaining the lowest prices for Hettinger customers. Each time Montana-Dakota purchases propane, it requests a price quote from each supplier for a specific delivery date and quantity in truckloads, delivering 8,000 to 12,000 gallons. Montana-Dakota selects the lowest price, all other things being equal.

The April prices for propane have decreased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage declines, this has resulted in a decrease in the price of propane.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on Energy issues. The information is available on their website: http://www.eia.doe.gov

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 - $4.75

U.S. Energy Information Administration

April 2010

Short-Term Energy and Summer Fuels Outlook

April 6, 2010 Release

Highlights

- EIA's projections for West Texas Intermediate (WTI) crude oil spot prices have changed very little over the last five *Outlooks* even as spot crude oil prices continue to fluctuate on a daily basis. EIA expects WTI prices to average above $81 per barrel this summer, slightly less than $81 per barrel for 2010 as a whole, and $85 per barrel by the fourth quarter of 2011.

- EIA forecasts that regular-grade motor gasoline retail prices will average $2.92 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 forecast has the annual average regular grade retail gasoline price increasing from $2.35 per gallon in 2009 to $2.84 in 2010 and to $2.96 in 2011, primarily because of projected rising crude oil prices. Average U.S. pump prices for regular gasoline are likely to exceed $3 per gallon at times during the driving season, and already exceed $3 per gallon in some areas. Projected annual average retail diesel fuel prices are forecast at $2.95 and $3.12 per gallon in 2010 and 2011, respectively.

- EIA expects the Henry Hub natural gas spot price to average $4.44 per million Btu (MMBtu) this year, a $0.49-per-MMBtu increase over the 2009 average, but a significant downward revision from the $5.17 per MMBtu projected in last month's *Outlook*. The price outlook is lower primarily because of an average 2 billion cubic feet per day (Bcf/d) upward revision to the 2010 domestic natural gas production forecast.

- The annual average residential electricity price changes only slightly over the forecast period, averaging 11.5 cents per kilowatthour (kWh) in both 2009 and 2010 and then rising to 11.7 cents per kWh in 2011.

- Estimated carbon dioxide (CO_2) emissions from fossil fuels, which declined by 6.6 percent in 2009, increase by 2.1 percent and 1.1 percent in 2010 and 2011, respectively, as economic growth fuels higher energy consumption.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. EIA's assessment of world oil markets is largely unchanged from last month's *Outlook*, and world oil prices will likely continue to firm and increase slightly in response to the global economic recovery. As long as the global economy continues to recover, and the Organization of the Petroleum Exporting Countries (OPEC) remains satisfied with its constrained supply targets, global oil markets should remain in this situation. Major uncertainties include the pace of global economic recovery and the extent to which the largest economies continue their stimulus and other economic policies.

Global Crude Oil and Liquid Fuels Consumption. EIA projects that world oil consumption will grow by 1.5 million barrels per day (bbl/d) in 2010 and 1.6 million bbl/d in 2011, similar to the forecast of last month. This growth is the result of an expected recovery in the global economy, with world gross domestic product (GDP, on an oil-weighted basis) assumed to rise by more than 3 percent per year. EIA has revised its assessment for Asia upwards and Europe downwards for 2010 in response to preliminary first-quarter data for those regions. Most of the growth in oil consumption is expected in the Asia-Pacific and Middle East regions (World Liquid Fuels Consumption Chart).

Non-OPEC Supply. Non-OPEC supply is projected to increase by 600,000 bbl/d in 2010, about 50,000 bbl/d more than last month's *Outlook,* because of a revised forecast for production in North America. Non-OPEC supplies are then expected to fall slightly in 2011, as declining production in mature areas more than offsets any new production growth. The largest source of growth in 2010 is the United States, followed by Brazil, Azerbaijan, and Kazakhstan. Offsetting this projected supply growth in 2010 are further declines in mature fields in Mexico, the United Kingdom, and Norway.

OPEC Supply. OPEC left its production policy unchanged at its last meeting in Vienna on March 17, 2010, and is not scheduled to meet again until October 14 to review its crude oil production targets. EIA projects that OPEC production of crude oil will increase by 0.3 million bbl/d in 2010, primarily in Angola and Nigeria. However, 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. Overall, EIA also projects a slight increase in OPEC surplus

crude oil production capacity through 2011 from first-quarter 2010 levels (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. EIA estimates that commercial oil inventories held in the Organization for Economic Cooperation and Development (OECD) countries stood at 2.67 billion barrels at the end of the first quarter of 2010. This level is equivalent to about 58 days of forward cover, and is about 69 million barrels more than the previous 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). Although OECD oil inventories are still projected to remain at the upper end of the historical range over the forecast period, they are falling as a result of higher oil consumption and OPEC production restraint.

Crude Oil Prices. WTI crude oil spot prices averaged $81 per barrel in March 2010, almost $5 per barrel above the prior month's average and $3 per barrel higher than forecast in last month's *Outlook*. Oil prices rose from a low this year of $71.15 per barrel on February 5 to $80 per barrel by the end of February, generally on news of robust economic and energy demand growth in non-OECD Asia and the Middle East, and held near $81 until rising to $85 at the start of April. EIA expects WTI prices to average above $81 per barrel this summer, slightly less that $81 for 2010 as a whole, and $85 per barrel by the fourth quarter 2011 (West Texas Intermediate Crude Oil Price Chart). As always, these energy price forecasts are highly uncertain, as both recent experience and the sizable participation in near-term futures options contracts (with a wide range of strike prices) clearly demonstrate that prices can move within a wide range in a relatively short period.

Over the 5-day period ending April 1, June 2010 WTI futures contracts averaged $83.07 per barrel. Over the same 5-day period, the lower and upper limits for the 95-percent confidence interval for June 2010 futures were $68 and $101 per barrel, respectively, based on the June 2010 implied volatility of 28 percent calculated from New York Mercantile Exchange (NYMEX) near-the-money options on WTI futures (see Energy Price Volatility and Forecast Uncertainty). One year ago, futures contracts for WTI delivered into Cushing, Oklahoma, in June 2009 averaged about $45 per barrel and implied volatility, at 74 percent, was more than twice the rate now trading in the options markets.

The market's assessment of the probability of the realized WTI spot price exceeding $100 per barrel during 2010 increases from 3 percent for the June 2010 contract to 21 percent for the December 2010 contract. These probabilities showed little change across the forward curve in March. The probability for each month is calculated using the futures price for that contract, its implied volatility, and its time to expiration. Like the confidence intervals reported by EIA, this is a market-based probability

estimate derived using traded futures and options prices (see STEO Supplement, Probabilities of Possible Future Prices).

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. U.S. liquid fuels consumption declined by 810,000 bbl/d (4.2 percent) to 18.7 million bbl/d in 2009, the fourth consecutive annual decline (U.S. Liquid Fuels Consumption Growth Chart). Motor gasoline was the only major petroleum product whose annual consumption did not decline, having remained unchanged from the previous year. Distillate fuel consumption declined by 310,000 bbl/d (8.0 percent) in 2009, led by a sharp economy-related drop in transportation usage.

The economic recovery contributes to projected growth in total liquid fuels consumption of 160,000 bbl/d in 2010 and 210,000 bbl/d in 2011. Nevertheless, expected U.S. consumption in 2011 is lower than it was in 1999 and is 1.7 million bbl/d lower than the highest level of annual consumption, reached in 2005.

U.S. Liquid Fuels Supply. Domestic crude oil production averaged 5.32 million bbl/d in 2009, up about 370,000 bbl/d from 2008 (U.S. Crude Oil Production Chart). Projected growth in domestic crude oil production moderates to 200,000 bbl/d in 2010 and 70,000 bbl/d in 2011. The primary contributors to the production growth in 2009 and 2010 are the Thunder Horse, Tahiti, Shenzi, and Atlantis offshore fields in the Federal Gulf of Mexico (GOM).

Several new GOM hubs and fields are scheduled to begin production this year, such as the Great White field in the Perdido Spar and the Petrobras floating production storage and offloading (FPSO) vessel operating in the Chinook and Cascade fields. Despite this new production, projected GOM production declines by 100,000 bbl/d in 2011 because of declining output from existing wells. Offsetting the projected decline in GOM production are forecast increases in production from lower-48 non-GOM fields of 50,000 bbl/d and 200,000 bbl/d in 2010 and 2011, respectively.

Summer Transportation Fuels Outlook

The boost to gasoline consumption from the economic recovery is being countered by higher gasoline prices compared with last year. These counter-balancing forces are expected to be prominent features of the summer driving season.

Prices. Regular-grade gasoline retail prices, which averaged $2.44 per gallon last summer, are projected to average $2.92 per gallon during the current driving season.

The monthly average gasoline price is expected to peak at about $2.97 per gallon in early summer. Average U.S. pump prices likely will exceed $3 per gallon at times during the forthcoming spring and summer driving season. Diesel fuel prices, which averaged $2.46 per gallon last summer, are projected to average $2.97 this summer. However, because short-term prices can be quite volatile, weekly prices will differ from the monthly average.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in crude oil prices and wholesale margins. As noted in our discussion of crude oil markets, the current value of options contracts implies a 95 percent confidence band for future crude oil prices that is wide and widens further over time. Realized crude oil prices that differ from our forecast would be reflected in the price of motor fuels, with each dollar per barrel sustained difference in crude oil prices relative to the forecast translating into approximately a 2.4 cent-per-gallon change in prices absent consideration of factors specific to the markets for gasoline and diesel fuel.

Retail price projections reflect higher prices for the refiner acquisition cost of crude oil, expected to average about $79 per barrel this summer compared with the $62 per barrel average of last summer. EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) to average 43 cents per gallon this summer, up 5 cents per gallon from last summer. Similarly, EIA forecasts higher wholesale diesel margins this summer (33 cents per gallon) than last summer (25 cents per gallon) because of the expected worldwide recovery in distillate markets.

Motor Gasoline. During this summer season, projected motor gasoline consumption increases by 0.5 percent over last summer, substantially lower than the 0.8-percent growth rate recorded last summer. Gasoline consumption last summer was stimulated by both the beginning of economic recovery and a $1.37-per-gallon decline in gasoline prices from the previous year. In addition, there was a reversal in the trend of public transportation usage, which fell by 3.8 percent in 2009 after having risen by 4 percent in 2008 (American Public Transportation Association). This summer, the stimulus to demand from the continuing modest economic recovery is constrained by the projected $0.48-per-gallon average increase in gasoline prices over last summer.

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 gasoline and gasoline blending components. Refinery production of gasoline will be under considerable downward pressure from growth

in fuel ethanol blending and the current high level of gasoline inventories. This summer's domestic refinery gasoline supply is expected to decline by about 120,000 bbl/d from last summer's average.

Fuel ethanol blending into gasoline increased from an average of 645,000 bbl/d during the summer of 2008 to 717,000 bbl/d during the summer of 2009 and is projected to average 816,000 bbl/d this summer, about 8.9 percent of the total gasoline consumed. The growth in ethanol blending is driven by the Renewable Fuel Standard, which requires an increase in renewable fuels from a total of 10.6 billion gallons in 2009 to 12.3 billion gallons in 2010 (excluding the biomass-based diesel fuel volume requirement). The growth in ethanol consumption is being met primarily by domestic production. EIA expects the month-to-month growth in ethanol plant capacity and production to slow significantly in 2010 as the boom in ethanol plant construction and startups over the last 3 years comes to an end.

At the onset of the summer driving season (April 1) total gasoline stocks, at 224 million barrels, are 7 million barrels above the level of year-ago and 11 million barrels above the previous 5-year average (U.S. Gasoline and Distillate Inventories). Because of the higher current inventory level than last year, EIA projects the average stock draw over the summer will be about 87,000 bbl/d compared with last summer's 25,000 bbl/d average stock draw and the 5-year-average of 55,000 bbl/d.

For the current summer season, EIA expects net imports of motor gasoline and blending components to average 721,000 bbl/d, up slightly from last summer.

Diesel Fuel. Forecast distillate fuel consumption, which includes both diesel fuel and heating oil, is about 70,000 bbl/d, or 2.1 percent, higher 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 50,000 bbl/d lower than last summer.

Biodiesel is a small part of the distillate pool. Biodiesel blending averaged 28,000 bbl/d last summer and is expected to grow to about 40,000 bbl/d this summer as refiners and blenders adjust to the 650-million-gallon biodiesel blending mandate for 2010 under the Renewable Fuel Standard.

Distillate inventories are projected to start the summer season at 143.1 million barrels, almost matching last year's record-high 143.6 million barrels, and 24 million barrels higher than the previous 5-year average. Distillate stocks normally build during the summer season in preparation for winter heating demand. This summer's projected

15-million-barrel stock build is lower than the average 23-million-barrel build over the five previous summers and the 29 million barrel build last summer.

Continuing strong world demand for distillate fuels contributed to U.S. net exports of distillate fuel averaging 430,000 bbl/d during last summer. Before 2008, the United States was typically a net importer of distillate fuel, averaging 160,000 bbl/d over the summers of 2000 through 2007. Projected distillate net exports this summer decline slightly, averaging about 390,000 bbl/d.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption to increase by 1.9 percent to 63.8 Bcf/d in 2010 and decline by 0.6 percent in 2011 (Total U.S. Natural Gas Consumption Growth Chart). Total U.S. heating degree-days (HDDs) during the first quarter 2010 were about 0.7 percent higher than last year. However, in the South region, first-quarter HDDs were about 20 percent higher than the same period last year. The cold weather helped boost year-over-year natural gas consumption in the electric power sector, adding to the increase in industrial sector consumption brought about by the improved economic conditions.

In last month's *Outlook*, EIA revised upward the forecast for natural gas consumption in the electric power sector for this year largely because of the higher space heating demand due to cold weather in the South. This month's *Outlook* includes another upward revision to the electric power sector consumption forecast. However, this revision reflects EIA's expectation that lower natural gas prices relative to coal prices will increase the utilization of natural-gas-fired generating facilities in the baseload power supply.

EIA's forecast for 2011 includes consumption declines in all sectors except the industrial sector. The projected return to near-normal weather reduces consumption in the residential and commercial sectors, while higher natural gas prices reverse the coal-to-gas switching trend observed in 2009 and forecast to continue in 2010. Consumption in the industrial sector, supported by continued economic growth, is projected to increase by 1.7 percent in 2011.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production to increase by 0.4 Bcf/d (0.7 percent) to 60.9 Bcf/d in 2010 and decrease by 0.7 Bcf/d (1.2 percent) in 2011. In last month's *Outlook*, domestic production growth was forecast to decline by 0.5 Bcf/d in 2010, reflecting the lagged effect of lower drilling rates last year. The higher production forecast in this *Outlook* reflects the latest January 2010 production estimate from the EIA-814 survey and the continuing

increase in the number of working natural gas rigs over the last month. Any significant revision to estimated January 2010 natural gas production (see Changes to the EIA-914 Sampling and Estimation Processes) would affect this forecast. The number of working natural gas rigs has increased by almost 200 since the end of last year. With no further increase from the current 950 natural gas rigs currently working, EIA expects production to begin to show month-to-month declines beginning in the second quarter this year. However, production is not expected to begin to show year-over-year declines until the first quarter of 2011.

EIA expects U.S. net natural gas imports to decline in 2010 as higher imports of liquefied natural gas (LNG)--and lower pipeline exports--are more than offset by a steep decline in pipeline imports as Canadian natural gas production drops off. The global LNG market appears to be well-supplied in 2010. In addition to the ramp-up of new global liquefaction capacity brought on-stream last year, about 3 Bcf/d of new capacity is set to start up this year. Spain, which relies on LNG in part for electricity generation, currently has hydroelectric reserves 34 percent above last year and 47 percent above the previous 5-year average. While EIA currently expects U.S. LNG imports to increase by about 0.5 Bcf/d this year over last, the failure of global demand to keep pace with increased global supply could lead to even higher U.S. LNG imports than currently forecast. EIA expects that an increase in global LNG demand next year will keep U.S. LNG imports roughly unchanged from 2010.

U.S. Natural Gas Inventories. On March 26, 2010, working natural gas in storage was 1,638 Bcf (U.S. Working Natural Gas in Storage Chart), 160 Bcf above the previous 5-year average (2005–2009) and 16 Bcf below the level during the corresponding week last year. Warmer-than-normal weather in March (HDDs were 10 percent below the 30-year normal for the month) contributed to an estimated monthly storage withdrawal of about 49 Bcf, or around 116 Bcf below the previous 5-year average for the month. Natural gas stocks at the end of March (the end of the withdrawal season) are estimated to be 1,656 Bcf, an amount comparable to stocks at the end of March last year. EIA expects continued production strength to contribute to high inventories again this fall. The current forecast for the end of October is 3,771 Bcf, only slightly below the record storage volume reached last fall. The forecast injection of 2,063 Bcf between March and November is about 5 percent below the stock build that occurred over the corresponding period last year, but it is more than 6 percent above the previous 5-year average.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $4.29 per MMBtu in March, $1.03 per MMBtu lower than the average spot price in February and $0.64 per MMBtu lower than the forecast for March in last month's Outlook (Henry Hub Natural Gas Price Chart). In the same way that colder-than-normal weather

contributed to higher prices in January and February, warmer-than-normal weather contributed to lower prices in March. In particular, prices touched a 4-month low during the final days of the month as lower demand and higher production resulted in storage injections. EIA expects prices to remain low for the next several months. With strong production and the absence of meaningful space-heating demand, lower-priced natural gas will once again compete with coal for a share of the baseload electricity supply—particularly in the spring and fall. Sustained low prices could reduce drilling activity over time. As a result, EIA expects production to decline and prices to increase in 2011. The Henry Hub spot price forecast averages $4.44 per MMBtu in 2010 and $5.33 per MMBtu in 2011.

Volatility in the June 2010 futures and options markets trended lower during the first half of March but rose in the second half as natural gas spot prices fell to $4 per MMBtu. For the 5-day period ended April 1, implied volatility for June 2010 natural gas options averaged 41 percent per annum, while June 2010 futures prices averaged $4.04 per MMBtu. The lower and upper limits of the 95-percent confidence interval, therefore, were $3.00 and $5.50 per MMBtu, respectively.

A year earlier, natural gas delivered to the Henry Hub in June 2009 was trading at $3.90 per MMBtu and implied volatility averaged about 63 percent. This generated a lower and upper limit for the 95-percent confidence interval of $2.45 and $6.20 per MMBtu, respectively.

Despite the increase in the implied volatilities during March, the probability of the Henry Hub realized price rising above $6.50 million Btu in December 2010 fell from 30 percent last month to 19 percent this month (see STEO Supplement, Probabilities of Possible Future Prices).

Electricity

U.S. Electricity Consumption. Residential retail sales of electricity grew by an estimated 7.6 percent in the first quarter of 2010 compared with the same period last year. Much of this growth was the consequence of the cold weather experienced during January and February in the South, where many households use electricity for space heating. EIA expects residential electricity sales to grow by about 7 percent during the third quarter of 2010 as summer temperatures are expected to return to normal levels after the cool summer experienced last year. Total consumption of electricity across all sectors is projected to grow by 2.9 percent during 2010 and by 1.2 percent next year (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. Last year, electricity generation from coal declined by 10.8 percent while generation from natural gas increased by 5.1 percent as lower natural gas prices motivated fuel switching in the electric power sector. Although natural gas prices are projected to be higher this year than last year, EIA still expects significant incentives to remain for electricity generation from natural gas, particularly in the South. EIA projects total natural gas generation in the electric power sector to grow by 2.0 percent in 2010. Low snow pack in the Northwest indicates hydropower generation will be low during 2010, falling by an estimated 7.6 percent for the entire United States compared with last year.

U.S. Electricity Retail Prices. The average U.S. residential electricity price during the first quarter of 2010 was estimated to be about 10.8 cents per kWh, almost 3 percent lower than in the same period last year. However, the annual average residential electricity price changes only slightly over the forecast period, averaging 11.5 cents per kWh in both 2009 and 2010 and then rising to 11.7 cents per kWh in 2011 because of higher coal and natural gas generation fuel costs (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Weather-related increases in electricity demand will contribute to the projected 4.2-percent growth in coal consumption in the electric power sector in 2010. Forecast coal consumption in the electric power sector grows by an additional 1.1 percent in 2011, though staying under 1 billion short tons for the third consecutive year. Coal consumption in the electric power sector had been over 1 billion short tons from 2003 through 2008 (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. EIA estimates that 2009 coal production fell by more than 8 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. Production declines by an additional 4 percent in 2010 in this forecast despite increases in domestic consumption and exports. The balance between production and consumption is satisfied through significant reductions in both producer (primary) and end-user (secondary) inventories. EIA projects a 5-percent increase in coal production in 2011 to meet continued growth in coal consumption and exports as existing inventories are reduced (U.S. Annual Coal Production Chart).

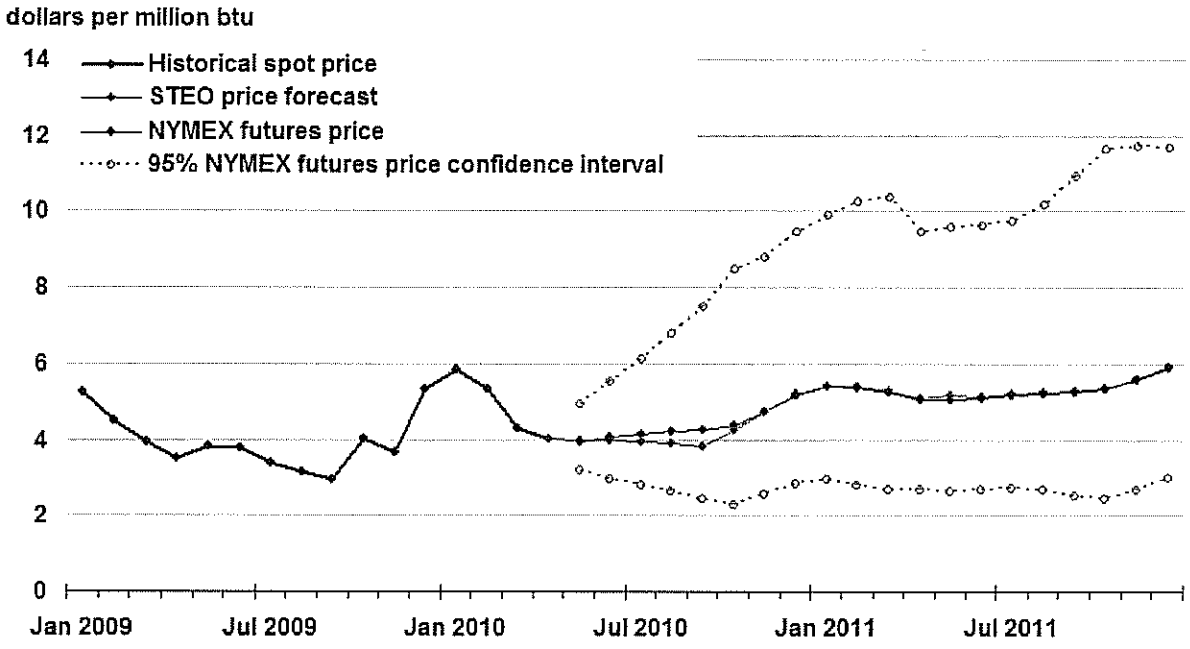
U.S. Coal Trade. U.S. coal imports fell by more than a third in 2009, and the slightly more than 22 million short tons imported was the smallest amount received since 2002. Forecast increases in coal consumption will lead to higher imports in 2010 and 2011; imports grow by 4.5 percent in 2010 and by an additional 16.6 percent in 2011.

U.S. Coal Prices. EIA estimates that the 2009 delivered electric-power-sector coal price increased by nearly 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 impact of longer-term power-sector coal contracts that were initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price falls by more than 3 percent to average $2.14 per MMBtu in 2010 and declines by an additional 2.3 percent in 2011.

U.S. Carbon Dioxide Emissions

Forecast continued economic growth combined with increased use of coal in the electric power sector contribute to expected increases in CO_2 emissions of 2.1 percent and 1.1 percent in 2010 and 2011, respectively (U.S. Carbon Dioxide Emissions Growth Chart). However, even with increases in 2010 and 2011, projected CO_2 emissions in 2011 are lower than annual emissions from 1999 through 2008.

Henry Hub Natural Gas Price

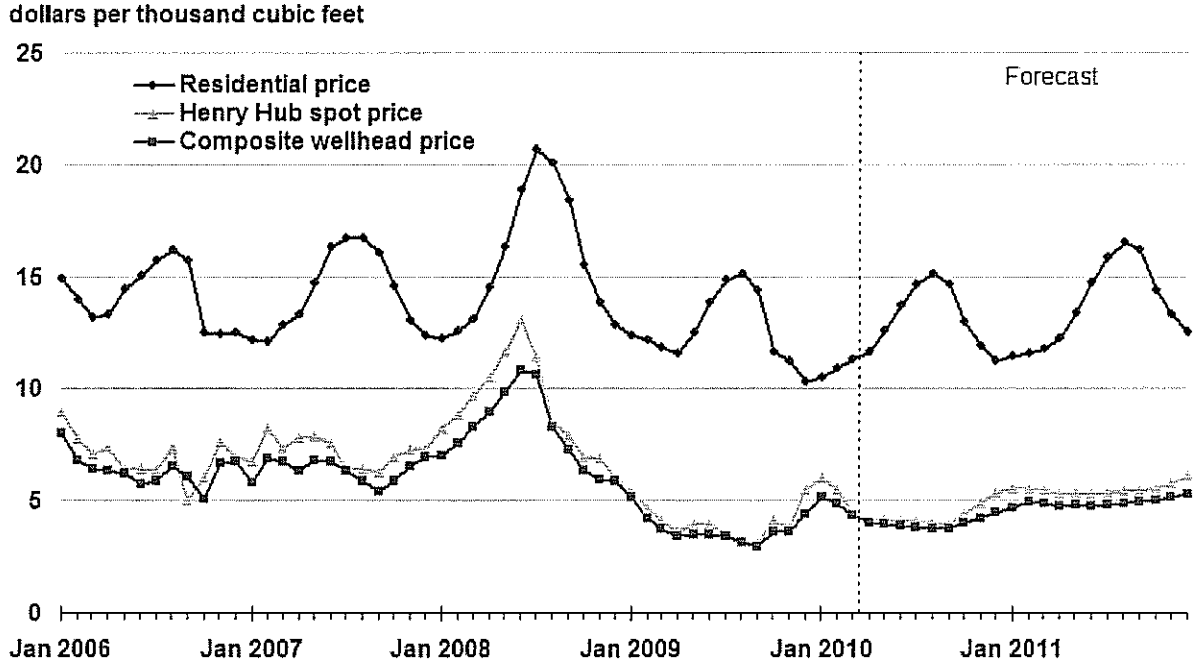


Note: Confidence interval derived from options market information from 5 trading days ending April 1, 2010
Intervals not calculated for months with sparse trading in "close-to-the-money" options contracts

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

U.S. Energy Information Administration

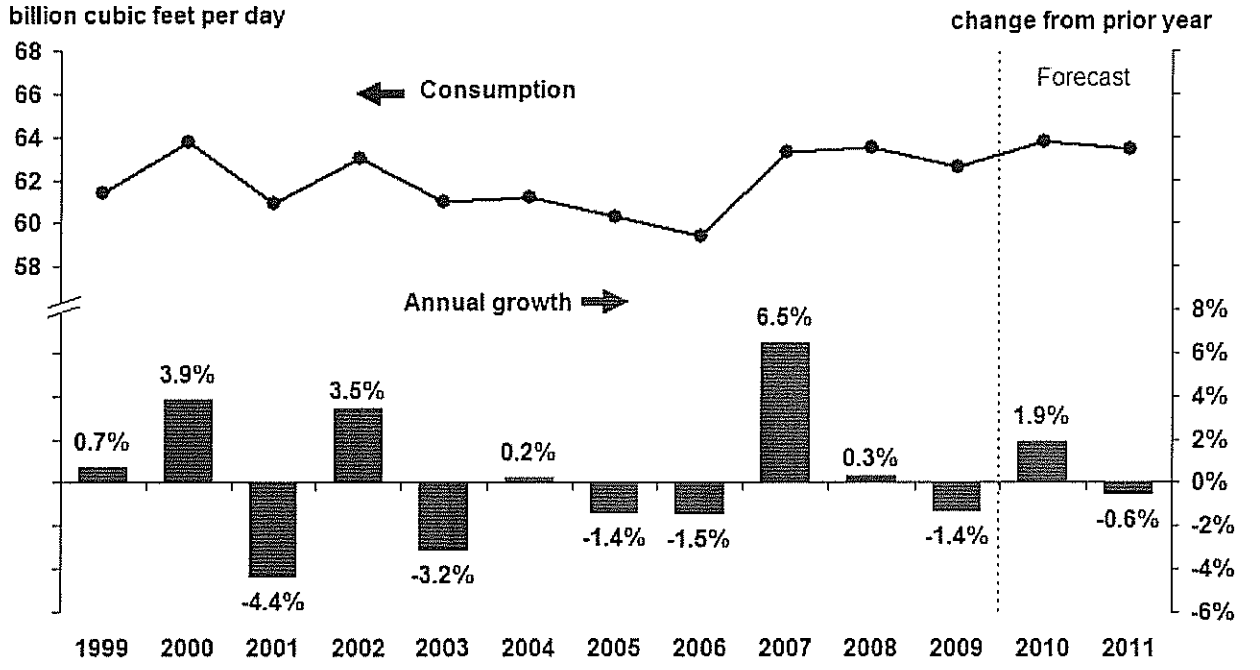
Natural Gas Prices



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

U.S. Energy Information Administration

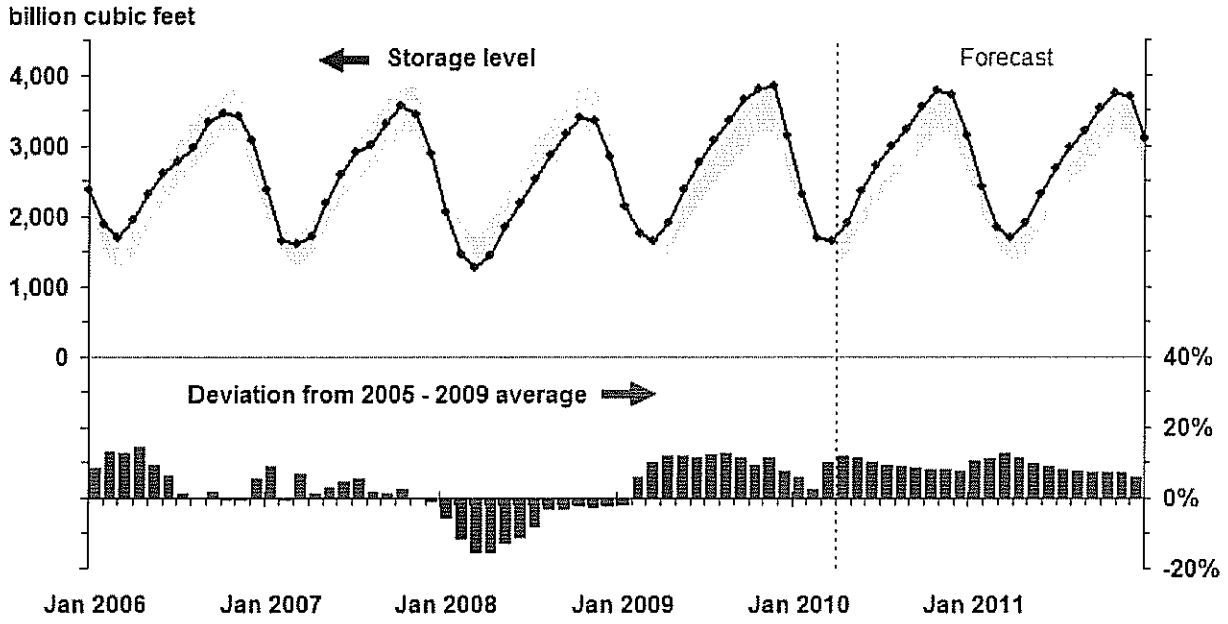
U.S. Total Natural Gas Consumption



Source: Short-Term Energy Outlook, April 2010

U.S. Energy Information Administration

U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, April 2010

U.S. Energy Information Administration

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$5.143	$5.240	$4.185	$4.166
Prior Gas Cost	6.076	6.168	5.125	5.102
Current Gas Cost Adjustment	($0.933)	($0.928)	($0.940)	($0.936)
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	**($0.933)**	**($0.928)**	**($0.940)**	**($0.936)**
Gas Cost Level	$5.143	$5.240	$4.185	$4.166
Plus: Surcharge	(0.515)	(0.515)	(0.152)	0.024
Total Gas Cost Level in Tariff Rates	$4.628	$4.725	$4.033	$4.190

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

Cost of Gas - Propane:	
Current Propane Cost (Exhibit D)	$12.076
Prior Propane Cost	16.467
Current Propane Cost Adjustment	($4.391)
Surcharge Adjustment:	
Current Adjustment (Exhibit F)	$0.461
Prior Adjustment	(0.547)
Change in Surcharge Adjustment	$1.008
Market Based Pricing Differential	
Current Adjustment	($0.011)
Prior Adjustment	(0.011)
Change in Margin Sharing Provision	$0.000
Net Increase (Decrease) in Gas Costs	**($3.383)**
Propane Cost Level	$12.076
Plus: Surcharge	0.461
Total Propane Cost Level in Rates	**$12.537**

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

	Amount
Total Gas Costs 1/	$68,489,256
Residential and General Service dk Requirements 2/	13,376,718
Average Cost of Gas per dk	$5.120
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.143
Less: Gas Cost Level in Rates 3/	6.076
Current Gas Cost Adjustment	**($0.933)**

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 February 28, 2010, adjusted for losses at .45%

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

Cost of Purchased Gas	$6.049
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$6.076

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

Summer - June - September	
Total Gas Costs 1/	$68,489,256
Less: Annual MDDQ Costs 1/	11,587,067
Total Gas Costs excluding MDDQ	$56,902,189
Firm Service Requirements 1/	13,376,718
Other Gas Costs per Dk (excluding MDDQ)	$4.254
Summer Seasonal Rate, adjusted for losses 2/	4.273
Winter - October - May	
Annual MDDQ Costs 1/	$11,587,067
Winter Firm Service Requirements	12,050,616
MDDQ Costs per Winter Dk	$0.962
Add: Other Gas Costs per Dk	4.254
Winter Seasonal Rate	5.216
Winter Seasonal Rate, adjusted for losses 2/	$5.240
Less: Gas Cost Level in Rates 3/	6.168
Current Gas Cost Adjustment	**($0.928)**

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	$5.186	$6.140
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$5.209	$6.168

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

	Amount
Total Gas Costs 1/	$14,592,959
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$4.166
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.185
Less: Gas Cost Level in Rates 2/	5.125
Current Gas Cost Adjustment	**($0.940)**

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	$5.102
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$5.125

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

	Amount
Total Gas Costs 1/	$3,666,200
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$4.166
Less: Gas Cost Level in Rates 2/	5.102
Current Gas Cost Adjustment	**($0.936)**

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 $5.102

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

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

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 0.437%, 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.

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.

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

Fourteenth Revised Sheet No. 99
Superseding
Thirteenth Revised Sheet No. 99

STATEMENT OF RATES

	Commodity Rate
Annual Charge Adjustment (ACA) Rate (per Dekatherm) 1/	$0.0019
Compressor Usage Surcharge (per 100 Dekatherm-miles) 2/	$0.0026

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

	18th	Revised	Sheet No.	80.1
Canceling	17th	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	$ 100.85	(I)
10,001	to	30,000	$ 145.05	(I)
>30,000			$ 321.90	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	$ 8.248586	(I)

Transmission Commodity Rate (Monthly Rate per Dkt):

Maximum	$ 0.062506	(I)
Minimum	$ 0.017935	
GTAC Amortization	$ (0.001275)	
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

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 MAY 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	(2,040,215)	9,785	(1,947,308)
April	(2,145,152)	(15,097)	(1,764,279)
May	(457,034)	28,089	(1,045,828)
June	2,207,334	106,965	(51,689)
July	5,255,294	198,840	990,691
August	8,279,705	289,960	2,012,595
September	11,031,874	553,598	2,818,363
October	13,151,897	606,864	3,072,419
13 month average	$5,359,700	$289,224	$707,883
Rate of Return	8.791%	8.791%	8.791%
Return	$471,171	$25,426	$62,230
Return Requirement	$649,006	$35,023	$85,718

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.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE MAY 2010

Cost of Purchased Propane	$27,650
Gallons Purchased	25,136
Projected dk Sales	2,300
Propane Cost per Dk	$12.022
Average Cost of Propane as Adjusted for Losses @ 99.55%	12.076
Less: Propane Cost Level in Rates 1/	16.467
Current Propane Cost Adjustment	($4.391)

1/ Propane Cost Level in Current Rates - Case No. PU-10-8

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)
Balance @ February 28, 2010									**($597,914)**

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
Balance @ February 28, 2010									**$47,309**

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
Balance @ February 28, 2010									**$90,012**

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 ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
PROPANE
TO BE EFFECTIVE MAY 1, 2010 THROUGH APRIL 30, 2011

(Over)/under recovered gas costs @ February 28, 2010			$14,923
Less: Projected recovery from rates already established			
	Volume	Rate	Amount
March	6,639	($0.547)	(3,632)
April	4,000	($0.547)	(2,188)
	10,639		(5,820)
Additional recovery required			$20,743
Projected sales volumes (dk)			
May 2010		2,300	
June		1,500	
July		1,100	
August		1,100	
September		1,100	
October		2,700	
November		3,600	
December		7,400	
January 2011		8,200	
February		6,000	
March		6,000	
April		4,000	
Total			45,000
Total (over)/under recovered gas cost adjustment to be effective May 1, 2010 through April 30, 2011			**$0.461**

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

	(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 @ February 29, 2009									**($50,643)**
March	($17,997)	$0	($6)	($18,003)	7,318	$0.406	$2,971	($20,974)	(71,617)
April	(15,404)	0	(6)	(15,410)	4,900	0.406	1,989	(17,399)	(89,016)
May	(5,623)	0	(13)	(5,636)	2,630	(0.547) 2/	(411)	(5,225)	(94,241)
June	582	0	(14)	568	1,767	(0.547)	(967)	1,535	(92,706)
July	(1,141)	0	(14)	(1,155)	1,142	(0.547)	(625)	(530)	(93,236)
August	(7,065)	0	(13)	(7,078)	1,112	(0.547)	(608)	(6,470)	(99,706)
September	(2,117)	4,848 3/	(10)	2,721	1,055	(0.547)	(577)	3,298	(96,408)
October	8,937	0	(5)	8,932	3,172	(0.547)	(1,735)	10,667	(85,741)
November	9,145	0	(4)	9,141	3,756	(0.547)	(2,055)	11,196	(74,545)
December	29,925	0	(3)	29,922	7,215	(0.547)	(3,945)	33,867	(40,678)
January 2009	33,552	0	(2)	33,550	8,550	(0.547)	(4,677)	38,227	(2,451)
February	13,104	0	0	13,104	7,807	(0.547)	(4,270)	17,374	14,923
	$45,898	$4,848	($90)	$50,656	50,424		($14,910)	$65,566	
Balance @ February 28, 2010									**$14,923**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Surcharge adjustment change implemented during this period. Reflects 1,078 dk @ $0.406 and 1,552 @ ($0.547).
3/ Prior period adjustment for August.

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
PROPANE

	1/	2/	3/	Total
March 2009				
Cost of Gas - Actual	$8.30405	$13.04960	$8.30405	
Cost of Gas - Recovered	13.17300	13.17300	13.17300	
(Over) Under recovery per dk	($4.86895)	($0.12340)	($4.86895)	
dk billed	7,315	3,716	(3,713)	7,318
(Over) Under recovery	($35,614)	($459)	$18,076	($17,997)
April 2009				
Cost of Gas - Actual	$7.20382	$8.30405	$7.20382	
Cost of Gas - Recovered	8.78300	13.17300	13.17300	
(Over) Under recovery per dk	($1.57918)	($4.86895)	($5.96918)	
dk billed	2,847	1,224	829	4,900
(Over) Under recovery	($4,495)	($5,958)	($4,951)	($15,404)
May 2009				
Cost of Gas - Actual	$5.43263	$7.20382	$5.43263	
Cost of Gas - Recovered	7.90500	8.78300	8.78300	
(Over) Under recovery per dk	($2.47237)	($1.57918)	($3.35037)	
dk billed	1,552	1,031	47	2,630
(Over) Under recovery	($3,838)	($1,628)	($157)	($5,623)
June 2009				
Cost of Gas - Actual	$9.33058	$5.43263	$9.33058	
Cost of Gas - Recovered	7.90500	7.90500	7.90500	
(Over) Under recovery per dk	$1.42558	($2.47237)	$1.42558	
dk billed	0	497	1,270	1,767
(Over) Under recovery	$0	($1,229)	$1,811	$582
July 2009				
Cost of Gas - Actual	$6.16497	$9.33058	$6.16497	
Cost of Gas - Recovered	7.90500	7.90500	7.90500	
(Over) Under recovery per dk	($1.74003)	$1.42558	($1.74003)	
dk billed	0	267	875	1,142
(Over) Under recovery	$0	$381	($1,522)	($1,141)
August 2009				
Cost of Gas - Actual	$0.00000	$6.16497	$0.00000	
Cost of Gas - Recovered	7.90500	7.90500	7.90500	
(Over) Under recovery per dk	($7.90500)	($1.74003)	($7.90500)	
dk billed	0	280	832	1,112
(Over) Under recovery	$0	($488)	($6,577)	($7,065)

MONTANA-DAKOTA UTILITIES CO.
CALCULATION OF (OVER) UNDER RECOVERY OF GAS COSTS
APPLICABLE TO NORTH DAKOTA
PROPANE

	1/	2/	3/	Total
September 2009				
Cost of Gas - Actual	$7.71346	$0.00000	$7.71346	
Cost of Gas - Recovered	7.90500	7.90500	7.90500	
(Over) Under recovery per dk	($0.19154)	($7.90500)	($0.19154)	
dk billed	0	248	807	1,055
(Over) Under recovery	$0	($1,962)	($155)	($2,117)
October 2009				
Cost of Gas - Actual	$11.34034	$7.71346	$11.34034	
Cost of Gas - Recovered	8.23400	7.90500	7.90500	
(Over) Under recovery per dk	$3.10634	($0.19154)	$3.43534	
dk billed	1,819	376	977	3,172
(Over) Under recovery	$5,651	($72)	$3,358	$8,937
November 2009				
Cost of Gas - Actual	$11.17138	$11.34034	$11.17138	
Cost of Gas - Recovered	9.33100	8.23400	8.23400	
(Over) Under recovery per dk	$1.84038	$3.10634	$2.93738	
dk billed	1,957	1,527	272	3,756
(Over) Under recovery	$3,601	$4,745	$799	$9,145
December 2009				
Cost of Gas - Actual	$16.76240	$11.17138	$16.76240	
Cost of Gas - Recovered	12.62500	9.33100	9.33100	
(Over) Under recovery per dk	$4.13740	$1.84038	$7.43140	
dk billed	3,697	2,059	1,459	7,215
(Over) Under recovery	$15,297	$3,790	$10,838	$29,925
January 2010				
Cost of Gas - Actual	$16.28731	$16.76240	$16.28731	
Cost of Gas - Recovered	12.62500	12.62500	12.62500	
(Over) Under recovery per dk	$3.66231	$4.13740	$3.66231	
dk billed	8,541	4,712	(4,703)	8,550
(Over) Under recovery	$31,278	$19,497	($17,223)	$33,552
February 2010				
Cost of Gas - Actual	$16.05559	$16.28731	$16.05559	
Cost of Gas - Recovered	16.46700	12.62500	12.62500	
(Over) Under recovery per dk	($0.41141)	$3.66231	$3.43059	
dk billed	3,776	3,588	443	7,807
(Over) Under recovery	($1,553)	$13,138	$1,519	$13,104

1/ Consumed in current month.
2/ Consumed in prior month.
3/ True-up of prior month volumes.