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

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

November 12, 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 (91st Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered December 1, 2010.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased $0.316 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, which has no effect on the cost of gas. In addition, Montana-Dakota has increased its overall firm transportation capacity, resulting in a system wide change in demand allocation and an increase of approximately $0.012 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 December 2010.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of $0.304 per dk for residential and firm general service customers, a decrease of $0.326 per dk for small and large interruptible customers and a decrease of $0.325 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 December 2010. The average cost of gas for firm customers, adjusted for losses, is $4.660.

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 increased since the last COG filing due to an increase in the market price of propane. Attachment B page 2 explains the reasons for the increase in the market price of propane.

Montana-Dakota requests a deviation from Section 4 of the Cost of Gas - Propane tariff, which specifies that the surcharge adjustment is effective May 1 of each year. Montana-Dakota is proposing to implement an out of cycle surcharge adjustment effective December 1, 2010 and recalculate the surcharge adjustment in May 2011, pursuant to the terms of the tariff. The current surcharge adjustments were established in May 2010 and reflected an under recovery of gas costs. Montana-Dakota is now in the position of having an over recovery of gas costs as shown in Exhibit F. The proposed surcharge adjustment is a negative $0.666, a decrease of $1.127 from the current level.

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 December 2010. The net effect of this filing is a decrease of $0.577 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 December 2010. The average cost of propane for all customers, adjusted for losses, is $13.723 per dk.

Montana-Dakota requests a deviation from Section 4 of the Cost of Gas - Propane tariff, which specifies that the surcharge adjustment is effective May 1 of each year. Montana-Dakota is proposing to implement an out of cycle surcharge adjustment effective December 1, 2010 and recalculate the surcharge adjustment in May 2011, pursuant to the terms of the tariff. The current surcharge adjustments were established in May 2010 and reflected an under recovery of gas costs. Montana-Dakota is now in the position of having an over recovery of gas costs as shown in Exhibit F. The proposed surcharge adjustment is a negative $0.666, a decrease of $1.127 from the current level.

These proposed adjustments, calculated in accordance with Rates 88 and 99, will amount to a decrease of approximately $765,300 for natural gas customers and a decrease of approximately $4,300 for propane customers during the month of December 2010. All of Montana-Dakota's retail gas customers in North Dakota may be affected by this proposal. There were 93,217 natural gas customers and 332 propane customers in North Dakota as of September 30, 2010.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota also submits herewith its check for $50.00 as a filing fee pursuant to North Dakota Century Code Section 49-05-05.

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
91st Revised Sheet No. 3
Canceling 90th 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	$4.629	$5.441
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$4.629	$4.767
Interruptible Service - PAR			$0.120	$3.692	$3.812
Interruptible Service - MAFB			$0.120	$3.716	$3.836
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	$4.629	$5.226
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$3.692	$4.563
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	$4.724	$5.321
Summer Gas Usage			$0.597	$3.764	$4.361
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.017	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.017	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$3.692	$4.411
Residential Propane Rate 90	32	$0.30 per day	$0.812	$13.049	$13.861
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$13.049	$13.646

Date Filed: November 12, 2010 **Effective Date:**

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

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

December 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.

Factors contributing to the decrease in natural gas prices are historically high volumes of natural gas in storage and weak demand for cooling. The Energy Information Administration (EIA) reported storage levels nationwide as of November 5, 2010 were 9.8 percent above the five-year average and 0.8 percent above last year's record storage balance.

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

The December Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 16.

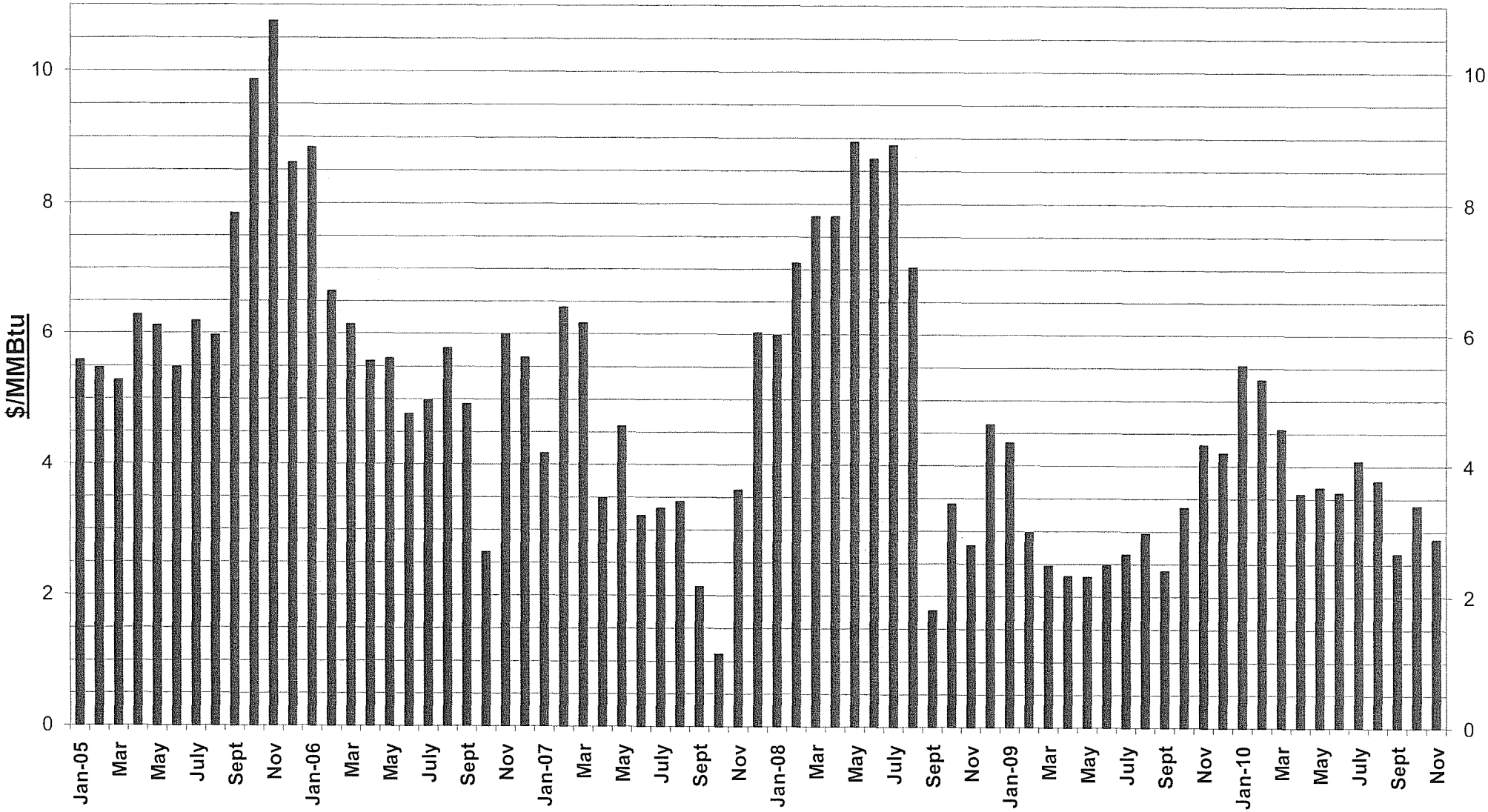
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
December 2010

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 November prices for propane have increased 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 increases, this has resulted in a increase 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 2005-2010YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2008-$6.24; 2009-$3.07; 2010YTD - $3.91

www.eia.doe.gov
Energy Information Administration

October 2010

Short-Term Energy and Winter Fuels Outlook

October 13, 2010 Release

Highlights

- EIA projects average household expenditures for space-heating fuels will total $986 this winter (October 1 to March 31), an increase of $24, or 2.5 percent, from last winter. EIA projects higher expenditures in all fuels except electricity, where expenditures decline by 2 percent. This forecast reflects moderately higher prices for all the fuels, although slightly milder weather than last winter for much of the Nation should contribute to lower consumption in many areas (see EIA Short Term and Winter Fuels Outlook slideshow).

- According to the National Oceanic and Atmospheric Administration's (NOAA) most recent projection of heating degree-days, the lower-48 states are forecast to be 3 percent warmer during the October through March winter heating season compared with last winter and 1 percent warmer than the 30-year average (1971-2000). However, heating degree-day projections vary widely between regions. For example, the Northeast, the principal market for heating oil, is projected to be about 5 percent colder than last winter, while the South is projected to be about 15 percent warmer.

- EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $80 per barrel this winter, a $2.50-per-barrel increase over last winter. The forecast for average WTI prices rises gradually to $85 per barrel by the fourth quarter of 2011 as U.S. and global economic conditions improve. EIA's forecast assumes U.S. gross domestic product (GDP) grows by 2.6 percent in 2010 and 2.1 percent in 2011, while world oil-consumption-weighted GDP grows by 3.8 percent and 3.3 percent, respectively, in 2010 and 2011.

- Projected natural gas inventories reach more than 3.7 trillion cubic feet (Tcf) at the end of this year's injection season (October 31). This projected volume will be about 3 percent lower than last year's record-setting level but will still represent the second highest underground storage level on record for the month of October. The projected Henry Hub annual average spot price

increases from $3.95 per million Btu (MMBtu) in 2009 to $4.47 in 2010 and $4.58 in 2011.

Projected Winter Fuel Expenditures by Fuel and Region

The average household winter heating fuel expenditures discussed in this *Outlook* provide a broad guide to changes compared with last winter, but fuel expenditures for individual households are highly dependent on local weather conditions, market size, the size and energy efficiency of individual homes and their heating equipment, and thermostat settings (see Winter Fuel Outlook table).

Natural Gas. EIA expects households heating primarily with natural gas to spend an average of $27 (4 percent) more this winter. About 52 percent of all U.S. households depend on natural gas as their primary heating fuel. The 4-percent increase in natural gas expenditures reflects a 6-percent increase in prices and a 2-percent decrease in consumption. In the Midwest, where 72 percent of all households rely on natural gas, a projected 6-percent increase in average household expenditures results from an increase of more than 6-percent in prices and a slight drop in consumption, based on the forecast of slightly warmer weather than last winter.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of about $220 (12 percent) more this winter than last winter. About 7 percent of U.S. households depend on heating oil for winter fuel. The Northeast accounts for 80 percent of U.S. heating oil consumption. The average Northeast household is projected to spend 13 percent more ($259) than last winter as a result of a 5-percent increase in consumption and regional prices 8 percent higher than last winter. EIA projects residential heating oil prices in the Northeast to average about $3.06 per gallon during the winter season, 22 cents per gallon more than last winter.

Propane. About 6 percent of total U.S. households heat with propane. EIA expects households heating primarily with propane to spend an average of $136 (8 percent) more this winter, but that increase varies across regions. EIA expects that households in the Midwest will see an average increase in winter propane expenditures of 14 percent as projected residential propane prices increase by over 15 percent from last winter and consumption falls by about 1 percent. Forecast household propane expenditures in the South are 6 percent less this winter because a 13 percent decline in consumption more than offsets a projected 7 percent increase in prices.

The most significant concern in this winter fuels outlook is propane supply in parts of the Northeast. A leak was found in the TEPPCO propane pipeline east of Watkins

Glen, New York, in late August. The pipeline closed its Oneonta, Harford Mills and Selkirk terminals, which are not expected to re-open until later in the year. While much of New England's propane supply comes from imports, the relatively low level of inventory in the region means that any water-borne delays or an early cold snap will likely drive prices higher since suppliers may have to travel extended distances for incremental barrels until supplies normalize.

Electricity. Households heating primarily with electricity can expect to spend an average of $18 (2 percent) less this winter. Projected household electricity expenditures are 2 percent lower this winter because a 4-percent decline in consumption more than offsets a 2-percent increase in prices. About 37 percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 13 percent in the Northeast to 61 percent in the South. The number of households heating with electricity is growing at an estimated annual rate of 2.9 percent. This relatively high growth rate primarily reflects the population movement to the South, where electric heat pumps are popular.

Global Crude Oil and Liquid Fuels

Crude Oil and Liquid Fuels Overview. As member states of the Organization of the Petroleum Exporting Countries (OPEC) prepare to meet on October 14 to discuss market conditions, they face an oil market outlook largely unchanged from the previous few months. While commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remain high, floating oil storage has been declining, and EIA believes that a gradual projected reduction in OECD oil inventories over the forecast period should support firming oil prices. The economic outlook has also remained substantially the same, with Asian countries continuing to lead global economic growth. World oil prices are expected to rise gradually as global economic growth leads to higher global oil demand and growth in non-OPEC oil supply slows in 2011. EIA expects OPEC production will rise over the forecast period, keeping oil prices from increasing dramatically. Should OPEC not increase production as global consumption recovers, oil prices could be significantly higher than the central forecast. Conversely, should the global economic recovery be slower than expected, prices could be lower than our forecast.

Global Crude Oil and Liquid Fuels Consumption. World oil consumption growth for 2010 has been revised up slightly to 1.7 million barrels per day (bbl/d) in response to stronger-than-expected growth in oil demand during the first half of 2010 in China, as well as in the OECD. Non-OECD regions, especially China, the Middle East, and Brazil, represent most of the expected growth in world oil demand in 2011 (World Liquid Fuels Consumption Chart). While other OECD regions are showing declines,

North America is expected to show oil consumption growth in 2011 of 0.2 million bbl/d. Projected global oil consumption growth in 2011 is 1.4 million bbl/d, unchanged from last month's *Outlook*.

Non-OPEC Supply. EIA projects non-OPEC liquids supply will increase by 0.9 million bbl/d in 2010, with the growth coming mainly from the United States, Brazil, and the former Soviet Union. The non-OPEC supply projection for 2010 is 0.2 million bbl/d higher than in last month's *Outlook*, primarily the result of continued near-record crude oil production occurring in Russia. Forecasted total non-OPEC supply falls by 240,000 bbl/d in 2011, chiefly because of declining total North Sea and North American production--with Mexico's production falling by 170,000 bbl/d--as well as decreasing supplies from Russia. This would be only the third time in the last 15 years that non-OPEC supplies fail to grow year-over-year, following non-OPEC production declines in 2005 and 2008, which were mainly the result of supply disruptions in the Gulf of Mexico.

OPEC Supply. EIA expects that OPEC crude oil production will rise slightly through 2011 to accommodate increasing world oil consumption and to maintain OPEC market objectives. OPEC crude oil production is projected to increase by 0.3 million bbl/d and 0.6 million bbl/d in 2010 and 2011, respectively, with non-crude petroleum liquids expected to increase by 0.7 million bbl/d in 2010 and 2011. OPEC surplus capacity should remain near 5 million bbl/d, compared with 4.3 million bbl/d in 2009 and 1.5 million bbl/d in 2008 (OPEC Surplus Crude Oil Production Capacity Chart).

OECD Petroleum Inventories. Commercial oil inventories held in the OECD stood at an estimated 2.78 billion barrels at the end of the third quarter of 2010, equivalent to about 60 days of forward cover, and roughly 90 million barrels more than the 5-year average for the corresponding time of year (Days of Supply of OECD Commercial Stocks Chart). OECD oil inventories are expected to decline through the forecast period, though days-forward-cover should remain high by historical standards.

Crude Oil Prices. WTI oil prices averaged $75 per barrel in September but rose above $80 at the end of the month and into early October as expectations of higher oil consumption pushed up prices. EIA has raised the average fourth quarter 2010 forecasted WTI spot price to $79 per barrel compared with $77 per barrel in last month's *Outlook*. WTI spot prices are projected to rise to $85 per barrel by the fourth quarter of next year. Projected WTI prices average $78 per barrel in 2010 and $83 per barrel in 2011.

Energy price forecasts are highly uncertain, as history has shown (Energy Price Volatility and Forecast Uncertainty). WTI futures for December 2010 delivery for the

5-day period ending October 7 averaged $83 per barrel, and implied volatility averaged 30 percent. This made the lower and upper limits of the 95-percent confidence interval $68 per barrel and $101 per barrel, respectively, for WTI delivered in December 2010. Last year at this time WTI for December 2009 delivery averaged $69 per barrel and implied volatility averaged 48 percent, with the limits of the 95-percent confidence interval at $49 per barrel and $96 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Projected total U.S. liquid fuels consumption grows by 200,000 bbl/d (1.1 percent) in 2010, and by 110,000 bbl/d (0.6 percent) in 2011, as all of the major petroleum products register consumption growth (U.S. Liquid Fuels Consumption Growth Chart). This reverses the trend of falling consumption from 2006 through 2009. A year-over-year decline in total liquid fuels consumption averaging 40,000 bbl/d in the first quarter of 2010 was followed by a year-over-year rise averaging 430,000 bbl/d in the second and third quarters of 2010, led by increases in motor gasoline and distillate fuel oil consumption. During 2010 as a whole, gasoline consumption is projected to increase by 0.2 percent and distillate consumption to increase by 2.7 percent. Projected gasoline consumption growth increases to 0.8 percent in 2011 while distillate fuel consumption growth moderates to 0.4 percent. Jet fuel consumption grows at an average annual rate of about 0.7 percent through 2011.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production, which increased by 410,000 bbl/d in 2009, is projected to increase by 100,000 bbl/d in 2010 (U.S. Crude Oil Production Chart). Forecast total domestic crude oil production falls by 60,000 bbl/d to 5.4 million bbl/d in 2011. This projection includes a 170,000 bbl/d decline in the Federal Gulf of Mexico (GOM) and a 130,000 bbl/d increase in lower-48 non-GOM production next year. Projected ethanol production, which averaged 710,000 bbl/d in 2009, increases to an average of 850,000 bbl/d in 2010 and 870,000 bbl/d in 2011.

EIA forecasts that liquid fuel net imports (including both crude oil and refined products), which fell from 57 percent to 51 percent of total U.S. consumption between 2008 and 2009, will average about 50 percent of total consumption in 2010 and 2011.

U.S. Petroleum Product Prices. Projected regular-grade gasoline retail prices rise from an average $2.35 per gallon in 2009 to an average $2.74 per gallon in 2010 and $2.92 per gallon in 2011. On-highway diesel fuel retail prices, which averaged $2.46 per gallon in 2009, average $2.96 per gallon in 2010 and $3.14 in 2011 in this forecast. Refining margins, which have been at their lowest levels since 2003, are projected to

average about $2 per barrel higher next year because of growing global product demand and shutdowns of excess global refining capacity.

Natural Gas

U.S. Natural Gas Consumption. EIA projects total natural gas consumption will increase by 4.6 percent and 0.1 percent in 2010 and 2011, respectively (Total U.S. Natural Gas Consumption Growth Chart). Consumption of natural gas in the industrial and electric power sectors makes up the bulk of the year-over-year increase in consumption in 2010. Projected industrial natural gas consumption rises by 7.4 percent in 2010, driven by the projected 6.7 percent increase in the natural-gas-weighted industrial production index. The forecasted 7.6 percent growth in 2010 natural gas consumption in the electric power sector is partially due to the very warm summer weather, which led to an increase in electricity demand for cooling. Estimated natural gas consumption for electric power through August 2010 averaged 20.75 billion cubic feet per day (Bcf/d) compared with 19.23 Bcf/d through August 2009, a 7.9-percent increase.

The projected 0.1 percent increase in total natural gas consumption in 2011 is the result of about a 1-percent increase in residential, commercial, and industrial natural gas consumption, offset by a 1-percent decline in electric power sector consumption. The projected increase in residential and commercial consumption next year is the result of a forecasted 1.7-percent increase in U.S. population-weighted heating degree-days. Industrial sector natural gas consumption growth is driven by the projected 2 percent increase in the natural-gas-weighted industrial production index. Despite a slight decrease (0.3 percent) in electricity consumption in 2011, projected electric-power-sector natural gas consumption falls by 1 percent primarily because of forecasted increases in nuclear and renewable-based electricity generation.

U.S. Natural Gas Production and Imports. Marketed natural gas production in the lower-48 states is expected to rise by 3.5 percent this year. EIA expects total U.S. marketed natural gas production to decrease by 1.5 percent in 2011, less than the 1.9 percent reduction forecast in last month's *Outlook*.

The increase in the natural-gas-directed drilling rig count since mid-2009, comprised of a growing share of natural-gas-directed horizontal drilling rigs in the lower-48 states, contributed to the production growth in 2010. Over the last year, the natural gas rig count increased from 712 on October 2, 2009, to 962 on October 1, 2010, according to Baker Hughes. However, the pace if drilling for natural gas is expected to moderate slightly over the forecast period. The growing spread between

petroleum liquids and natural gas prices has also favored a shift towards drilling in shale formations that contain a higher proportion of liquids.

EIA forecasts gross pipeline imports of 9.2 Bcf/d in 2011, an increase of 1.5 percent compared with 2010. Forecasted imports of liquefied natural gas (LNG) average 1.23 Bcf/d in 2010, a slight decline from 2009 levels. Growing domestic production and low U.S. prices relative to European and Asian markets have discouraged LNG imports. Nevertheless, EIA expects LNG imports to grow slightly in 2011 to 1.32 Bcf/d, a 7-percent increase.

U.S. Natural Gas Inventories. On October 1, 2010, working natural gas in storage was 3,499 billion cubic feet (Bcf). Current inventories are now 220 Bcf above the previous 5-year average (2005–2009) and 149 Bcf below the level during the corresponding week last year (U.S. Working Natural Gas in Storage Chart). EIA expects that natural gas inventories will reach 3,726 Bcf at the end of October, which marks the end of the traditional injection season. Last year, injections continued through November; however, this year EIA expects November inventories will end about 16 Bcf below October inventories.

U.S. Natural Gas Prices. The Henry Hub spot price averaged $3.89 per MMBtu in September, $0.43 per MMBtu lower than the average spot price in August (Henry Hub Natural Gas Price Chart). Prices are expected to remain below $4 per MMBtu in October but rise to $4.68 per MMBtu by January as space-heating demand increases this winter. EIA has revised its projections for natural gas prices downward through 2011. Expectations are now for a price of $4.16 per MMBtu for the last quarter of 2010, $0.27 per MMBtu (6 percent) lower than last month's *Outlook*, based on several weeks of strong inventory builds. Price expectations for 2011 are $4.58 per MMBtu, which is $0.18 per MMBtu (4 percent) lower than last month's forecast, primarily due to a stronger domestic production forecast.

Uncertainty over future natural gas prices is lower this year compared with last year at this time. Natural gas futures for December 2010 delivery for the 5-day period ending October 7 averaged $4.07 per MMBtu, and the average implied volatility over the same period was 39 percent. This produced lower and upper bounds for the 95-percent confidence interval of $3.09 per MMBtu and $5.37 per MMBtu, respectively. At this time last year, the natural gas December 2009 futures contract averaged $5.59 per MMBtu and implied volatility averaged 56 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $3.70 per MMBtu and $8.50 per MMBtu.

Electricity

U.S. Electricity Consumption. The summer months of 2010 were warmer than normal, especially in the regions east of the Mississippi. Cooling degree-days in the east during June, July, and August ranged from 26 percent (in the South Atlantic region) to 46 percent (in New England) higher than normal (U.S. Summer Cooling Degree-Days Chart). In contrast, cooling degree-days in the East as a whole were 7 percent lower than normal during 2009. The large year-over-year increase in cooling degree-days should help push up total 2010 consumption of electricity by 5 percent over last year's level. Total consumption is expected to fall slightly in 2011 as forecast temperatures return to near-normal levels (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. Generation in the electric power sector is projected to average 10.9 terawatt-hours per day during 2010, which would be 4.4 percent higher than generation during 2009. Of this amount, 47.0 percent should be produced from coal-fired power plants and 22.5 percent from natural-gas-fired capacity. In contrast, the fuel shares for coal and natural gas during 2009 were 45.9 percent and 22.0 percent, respectively. Projected total generation increases by 0.4 percent 2011, with increases in nuclear and renewable (including hydroelectric) generation of 1.4 percent and 13 percent, respectively, and declines in coal and natural gas generation of 2.0 percent and 1.2 percent, respectively.

U.S. Electricity Retail Prices. Although the average U.S. residential retail price of electricity fell by nearly 1 percent during the first half of 2010 compared with the same period last year, prices are expected to increase by 1.5 percent year-over-year during the second half of 2010. Higher generation fuel costs this year are expected to be passed through to retail consumers during 2011, pushing up residential prices by 1.4 percent next year (U.S. Residential Electricity Prices Chart).

Coal

U.S. Coal Consumption. Coal consumption in the electric power sector rose by 5 percent in the first half of this year compared with the first half of last year, primarily the result of higher electricity consumption. EIA forecasts that higher electric power sector coal consumption will continue for the remainder of the year, with the total annual increase projected at nearly 7 percent. Despite a very slight decrease (0.3 percent) in electricity consumption in 2011, projected coal-fired electricity generation and related coal consumption will decline at a higher rate, primarily because of forecast increases in nuclear and renewable-based generation (U.S. Coal Consumption Growth Chart).

U.S. Coal Supply. Coal production for the first 6 months of 2010 fell by 3 percent despite a 5 percent increase in U.S. coal consumption. Drawdowns in inventories (U.S. Electric Power Sector Coal Stocks Chart) are forecasted to meet the majority of the increased coal consumption in 2010. Projected coal production increases in the second half of 2010, with annual growth projected at 1 percent. EIA projects another 1-percent increase in coal production in 2011 (U.S. Annual Coal Production Chart).

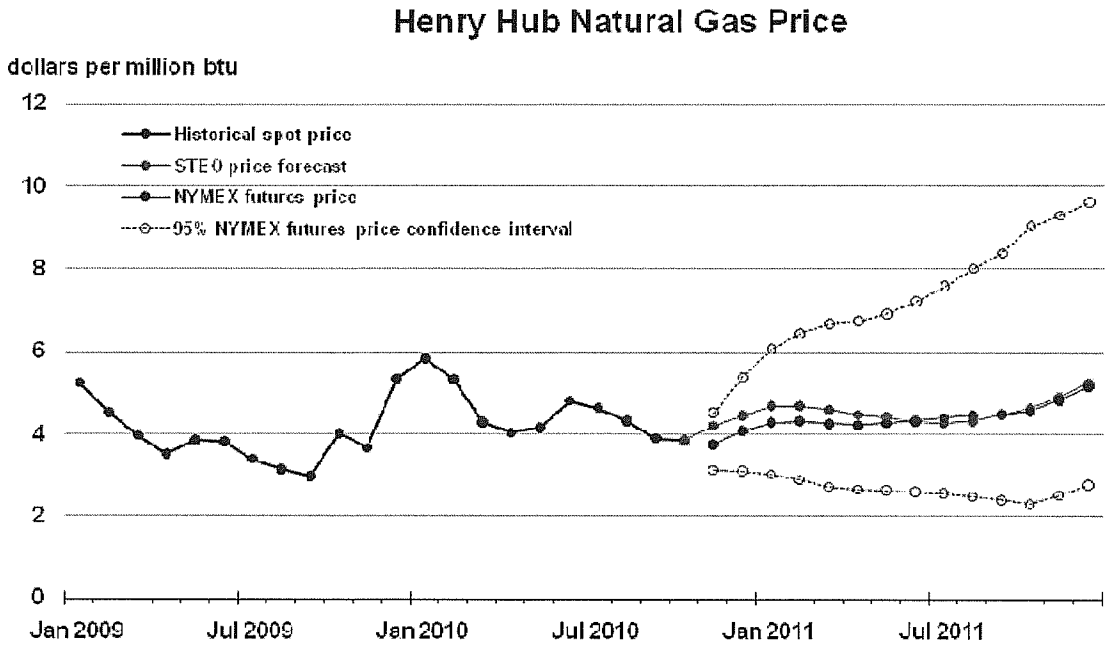
U.S. Coal Trade. The United States is a net exporter of coal, averaging 3.4 percent of production in 2009. Projected coal net exports increase by 58 percent in 2010, then decline by 17 percent in 2011. Metallurgical coal exports have nearly doubled in the first half of 2010 compared with the first half of last year. Metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to a projected 74 percent in 2010. EIA projects coal imports to decline by 17 percent in 2010 recover next year with growth of 37 percent. However, the annual import tonnage (26 million short tons) remains significantly below the 2005-through-2008 average of 34 million short tons.

U.S. Coal Prices. The electric-power-sector coal price rose by 1.3 percent in the first half of 2010 compared with the first half of last year. This higher cost of delivered coal reflects the effect of longer-term power sector coal contracts initiated during a period of high prices, rising transportation costs, increased consumption, and increases in spot coal prices. The projected electric-power-sector delivered coal price averages $2.26 per MMBtu in 2010, and then declines to an average of $2.23 per MMBtu in 2011.

U.S. Carbon Dioxide Emissions

Expected economic growth of 2.6 percent combined with increased use of coal and natural gas is expected to contribute to an increase in fossil-fuel carbon dioxide (CO_2) emissions of 3.9 percent in 2010 (U.S. Carbon Dioxide Emissions Growth Chart). The first half of 2010 saw increases of 5.7 percent and 4.2 percent for coal and natural gas-related CO_2 emissions, respectively. These increases resulted from increased electricity sector usage of coal and natural gas and higher consumption of natural gas in the industrial sector.

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

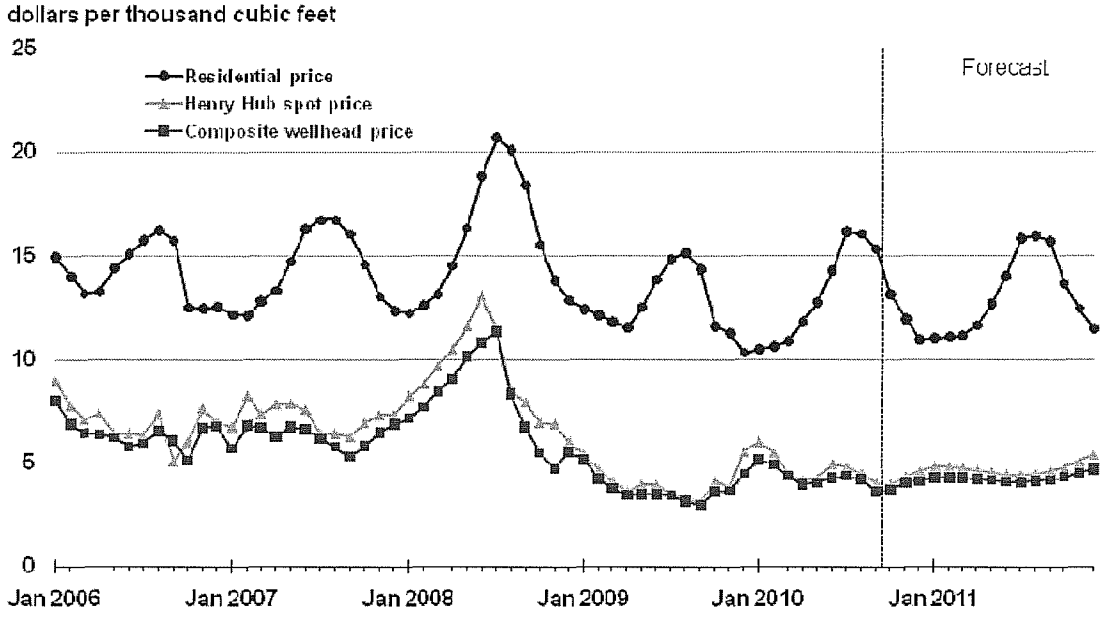


Note: Confidence interval derived from options market information for the 5 trading days ending October 7, 2010.
Intervals not calculated for months with sparse trading in "near-the-money" options contracts.

U.S. Energy Information Administration

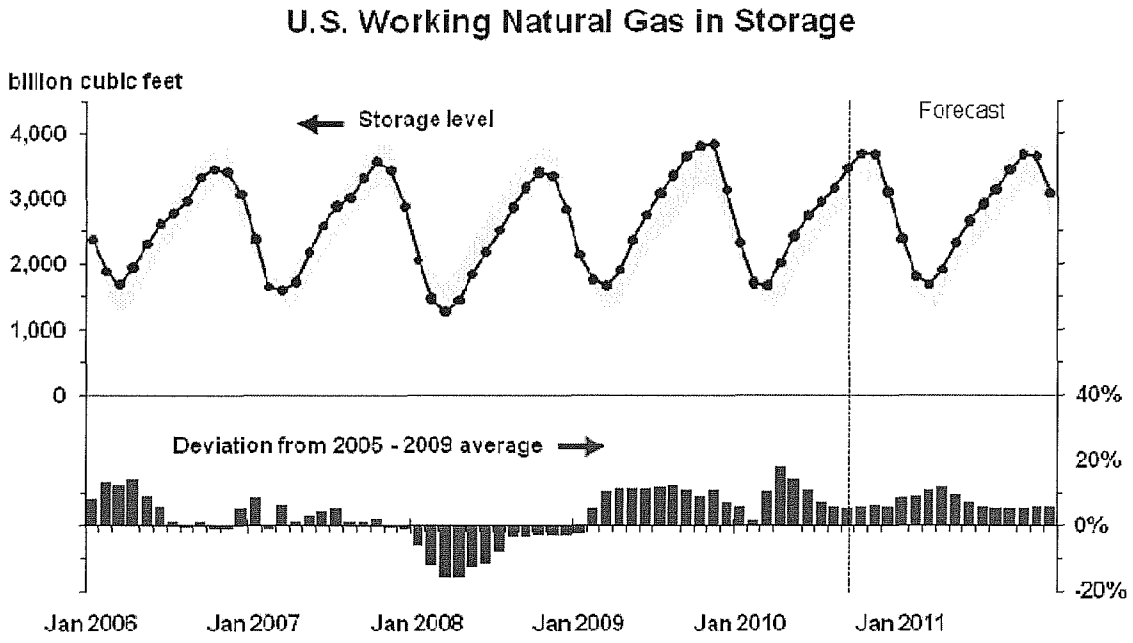
Source: Short-Term Energy Outlook, October 2010; Reuters News Service; and CME Group

Natural Gas Prices



U.S. Energy Information Administration

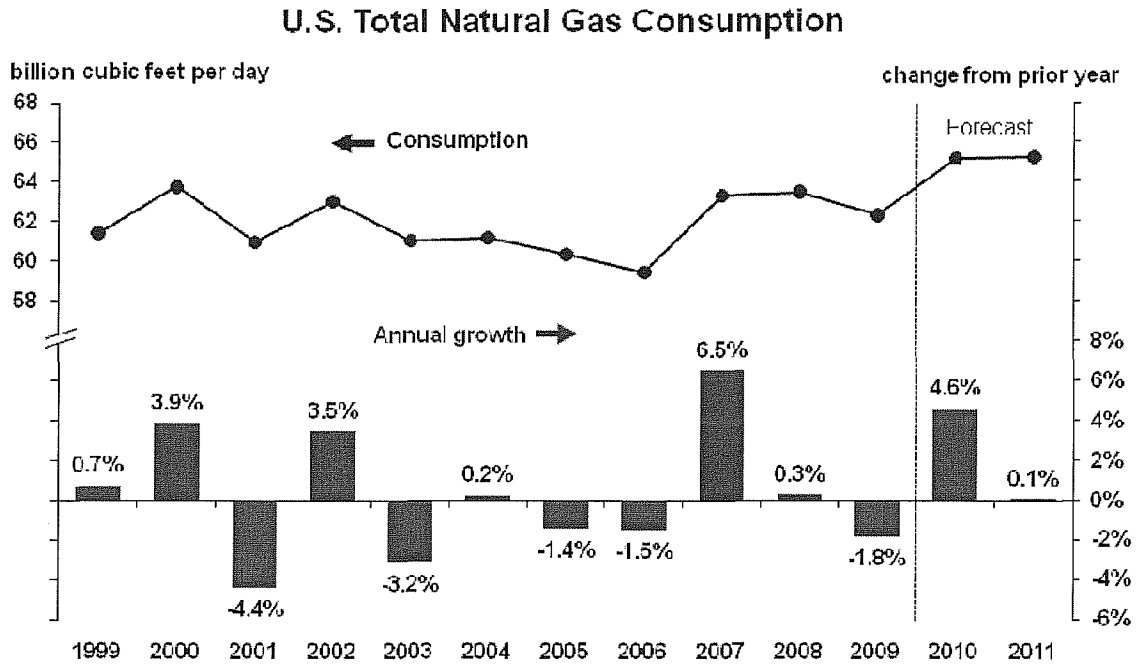
Source: Short-Term Energy Outlook, October 2010; Reuters News Service



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, October 2010



U.S. Energy Information Administration

Source: Short Term Energy Outlook, October 2010

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

Nova Gas Transmission LTD.

On October 4, 2010, TransCanada filed new rates for the Alberta System with the Alberta Energy and Utilities Board to be effective November 1, 2010.

Approximate impact on Montana-Dakota's cost of gas – 0.0 cents per dk

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$4.660	$4.755	$3.702	$3.685
Prior Gas Cost	4.964	5.059	4.028	4.010
Current Gas Cost Adjustment	($0.304)	($0.304)	($0.326)	($0.325)
Surcharge Adjustment:				
Current Adjustment	($0.023)	($0.023)	($0.010)	$0.031
Prior Adjustment	(0.023)	(0.023)	(0.010)	0.031
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
Current Adjustment	($0.008)	($0.008)	$0.000	$0.000
Prior Adjustment	(0.008)	(0.008)	0.000	0.000
Change in Margin Sharing Provision	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**($0.304)**	**($0.304)**	**($0.326)**	**($0.325)**
Gas Cost Level	$4.660	$4.755	$3.702	$3.685
Plus: Surcharge	(0.023)	(0.023)	(0.010)	0.031
Total Gas Cost Level in Tariff Rates	$4.637	$4.732	$3.692	$3.716

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

Cost of Gas - Propane:	
Current Propane Cost (Exhibit D)	$13.723
Prior Propane Cost	13.173
Current Propane Cost Adjustment	$0.550
Surcharge Adjustment:	
Current Adjustment (Exhibit F)	($0.666)
Prior Adjustment	0.461
Change in Surcharge Adjustment	($1.127)
Market Based Pricing Differential	
Current Adjustment	($0.008)
Prior Adjustment	(0.008)
Change in Margin Sharing Provision	$0.000
Net Increase (Decrease) in Gas Costs	**($0.577)**
Propane Cost Level	$13.723
Plus: Surcharge	(0.666)
Total Propane Cost Level in Rates	**$13.057**

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

	Amount
Total Gas Costs 1/	$62,989,360
Residential and General Service dk Requirements 2/	13,578,790
Average Cost of Gas per dk	$4.639
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.660
Less: Gas Cost Level in Rates 3/	4.964
Current Gas Cost Adjustment	**($0.304)**

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 September 30, 2010, adjusted for losses at .45%

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

Cost of Purchased Gas	$4.942
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.964

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

Summer - June - September	
Total Gas Costs 1/	$62,989,360
Less: Annual MDDQ Costs 1/	11,689,211
Total Gas Costs excluding MDDQ	$51,300,149
Firm Service Requirements 1/	13,578,790
Other Gas Costs per Dk (excluding MDDQ)	$3.778
Summer Seasonal Rate, adjusted for losses 2/	3.795
Winter - October - May	
Annual MDDQ Costs 1/	$11,689,211
Winter Firm Service Requirements	12,232,655
MDDQ Costs per Winter Dk	$0.956
Add: Other Gas Costs per Dk	3.778
Winter Seasonal Rate	4.734
Winter Seasonal Rate, adjusted for losses 2/	$4.755
Less: Gas Cost Level in Rates 3/	5.059
Current Gas Cost Adjustment	**($0.304)**

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	$4.090	$5.036
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$4.108	$5.059

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

	Amount
Total Gas Costs 1/	$12,906,846
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$3.685
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.702
Less: Gas Cost Level in Rates 2/	4.028
Current Gas Cost Adjustment	**($0.326)**

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	$4.010
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.028

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

	Amount
Total Gas Costs 1/	$3,242,608
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.685
Less: Gas Cost Level in Rates 2/	4.010
Current Gas Cost Adjustment	**($0.325)**

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 $4.010

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

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

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

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

NOVA Gas Transmission – Exhibit B, pages 11-12 for Schedule FT-D.

NorthWestern Energy – Exhibit B, page 13 for Schedule T-FTG-1.

South Dakota Intrastate Pipeline – Exhibit B, page 14 for Rate 1.

SourceGas Distribution LLC – Exhibit B, Page 15 for Schedule TC.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FT-1						
RESERVATION CHARGE						
MAXIMUM DAILY DELIVERY QUANTITY (MDDQ)						
MAXIMUM	RATE PER EQV. DKT PER MO.	737.928	N.A.	N.A.	N.A.	737.928
MINIMUM	RATE PER EQV. DKT PER MO	0.000	N.A.	N.A.	N.A.	0.000
COMMODITY CHARGE						
MAXIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.190	N.A.	N.A.	31.074
MINIMUM A/B/	RATE PER DKT	3.120	0.190	N.A.	N.A.	3.310
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 2.153%, CONSISTING OF 2.614% FOR THE CURRENT PERCENTAGE AND (0.461%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR TRANSPORTATION. THE APPLICABLE RATE IS 0.818 CENTS, CONSISTING OF 0.830 CENTS FOR THE CURRENT RATE AND (0.012) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.402%, CONSISTING OF 0.568% FOR THE CURRENT PERCENTAGE AND (0.166%) FOR THE DEFERRAL PERCENTAGE. THIS PERCENTAGE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

B/ SHIPPER MUST REIMBURSE TRANSPORTER FOR ELECTRIC POWER USED FOR STORAGE. THE APPLICABLE RATE IS 0.182 CENTS, CONSISTING OF 0.346 CENTS FOR THE CURRENT RATE AND (0.164) CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

STATEMENT OF RATES
2/ 3/

Rate Schedule	Long-Term Base Tariff Rate (per 100 Dth-Miles) 1/
T-1 and T-1B	
Daily Reservation Rate - Port of Morgan, MT to Ventura, IA	
Maximum	$0.0321
Minimum	$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	$0.0345
Minimum	$0.0000
Commodity Rate - Port of Morgan, MT to North Hayden, IN	
Maximum	$0.0004
Minimum	$0.0004

1/ Applicable to any Rate Schedule T-1 U.S. Shippers Service Agreement or any Rate Schedule T-1B Service Agreement with a primary term of at least twelve consecutive months.

2/ The Settlement Base Rates, pursuant to the Stipulation at Docket No. RP06-72-000, et al., remain in effect until such rates are superseded by new base rates placed into effect consistent with the provisions of the Stipulation.

3/ Rates in this section are subject to the revenue retrieval provision pursuant to Article X of the Stipulation at Docket No. RP06-72-000, et al.

STATEMENT OF RATES

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

1/ In accordance with the Commission's regulations, the authorized FERC unit charge per dekatherm is applied to physical transportation deliveries and is applicable to all transportation rate schedules. Pursuant to Section 6.16 of the General Terms and Conditions herein, the ACA is effectively charged at a rate of $0.0002 per 100 Dekatherm-miles.

2/ Rate is charged in accordance with Section 6.44 of the General Terms and Conditions.

TABLE OF RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $207.61/10^3m^3$
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point. Average FT-D Demand Rate for Group 1 Delivery Points $6.01/GJ FT-D Demand Rate for Group 2 Delivery Points[1] $0.98/GJ FT-D Demand Rate for Group 3 Delivery Points[2] N/A
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point
6. Rate Schedule FT-P	Refer to Attachment "3" for applicable FT-P Demand Rate per month
7. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/10^3m^3$/day) 1-5 years 10.43 6-10 years 8.72 15 years 7.82 20 years 6.94
8. Rate Schedule LRS-2	LRS-2 Rate per month $50,000
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month $129.55/10^3m^3$
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point
11. Rate Schedule IT-D	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
13. Rate Schedule PT	Schedule No — PT Rate — PT Gas Rate 9006-01000-0 — $ 60.50/d — 1.0 10^3m^3/d 9009-01001-1 — $ 660.00/d — 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. — Charge 2010416547 $ 24.00 / month 2010416543 $ 7.00 / month 2010416549 $ 63.00 / month 2010416546 $ 5.00 / month 2010416548 $ 1.00 / month 2010416540 $ 42.00 / month 2010416550 $ 96.00 / month 2010416545 $ 1,688.00 / month 2010418000 $ 151.00 / month 2010416551 $ 46.00 / month 2010417322 $ 153.00 / month 2010416544 $ 79.00 / month 2010416541 $ 209.00 / month 2010418777 $ 209.00 / month 2010418778 $ 350.00 / month 2003004522 $ 83,333.00 / month
15. Rate Schedule CO_2	Tier — CO_2 Rate ($/10^3m^3$) 1 520.03 2 411.79 3 272.12

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

NOVA Gas Transmission Ltd.

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

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)
3880	AECO INTERCONNECTION	0.98	0.0353
3868	ALBERTA-MONTANA	5.37	0.1941
3059	ALLISON CREEK SALES	0.98	0.0353
3562	AMOCO SALES (BP SALES TAP)	0.98	0.0353
3488	ARDLEY SALES	0.98	0.0353
3943	ATUSIS CREEK INTERCONNECTION	0.98	0.0353
3135	AURORA SALES	0.98	0.0353
3423	BASHAW WEST SALES	0.98	0.0353
3068	BEAVER HILLS SALES	0.98	0.0353
3933	BIG EDDY INTERCONNECTION	0.98	0.0353
3067	BIGSTONE SALES	0.98	0.0353
3887	BITTERN LAKE INTERCONNECTION	0.98	0.0353
3468	BLEAK LAKE SALES	0.98	0.0353
3471	BLUE RIDGE EAST SALES	0.98	0.0353
3164	BRAINARD LAKE SALES	0.98	0.0353
2364	BROWNVALE SALES	0.98	0.0353
3918	BUFFALO CREEK INTERCONNECTION	0.98	0.0353
3109	CALDWELL SALES	0.98	0.0353
3634	CANOE LAKE SALES	0.98	0.0353
3165	CANOE LK SLS #2	0.98	0.0353
3866	CARBON INTERCONNECTION	0.98	0.0353
3484	CARIBOU LAKE SALES	0.98	0.0353
3157	CARIBOU LK SOUTH SL	0.98	0.0353
3106	CARMON CREEK SALES	0.98	0.0353
3101	CAROLINE SALES	0.98	0.0353
3893	CARROT CREEK INTERCONNECTION	0.98	0.0353
3495	CAVALIER SALES	0.98	0.0353
3907	CHANCELLOR INTERCONNECTION	0.98	0.0353
3151	CHEECHAM W. #2 SALES	0.98	0.0353
3622	CHEECHAM WEST SALES	0.98	0.0353
6014	CHEVRON AURORA SALES	0.98	0.0353
3097	CHICKADEE CREEK SALES	0.98	0.0353
3305	CHIGWELL NORTH SALES	0.98	0.0353
3496	CHIPEWYAN RIVER SALES	0.98	0.0353
3163	CHRISTINA LAKE NORTH SALES	0.98	0.0353
3158	CLYDE N SALES	0.98	0.0353
1417	COLD LAKE BDR	5.37	0.1941
3052	COLEMAN SALES	0.98	0.0353
3168	COLLICUTT SALES	0.98	0.0353
3904	CONKLIN WEST INTERCONNECTION	0.98	0.0353
3416	COUSINS A SALES	0.98	0.0353
1963	COUSINS B & C SALES	0.98	0.0353
3483	CRAMMOND SALES	0.98	0.0353

NATURAL GAS TARIFF

NorthWestern Energy

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

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

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

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Dkt):

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

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

GAS RATE SCHEDULE

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

SD P.U.C. Section No. _
Original Sheet No. 1

Effective Date: January 10, 200

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 DECEMBER 2010

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2010	$13,602,007	$657,654	$3,073,036
November	11,996,534	569,340	2,514,076
December	9,183,646	403,237	1,233,663
January 2011	4,963,005	206,379	(379,624)
February	2,270,005	75,541	(1,335,467)
March	1,081,225	3,880	(1,941,437)
April	961,702	(17,148)	(1,772,196)
May	2,635,774	42,838	(1,049,559)
June	5,149,401	140,921	(53,657)
July	7,902,378	248,651	988,504
August	10,634,548	355,206	2,011,185
September	12,555,565	664,259	2,816,150
October	12,893,527	668,582	3,061,928
13 month average	$7,371,486	$309,180	$705,123
Rate of Return	8.791%	8.791%	8.791%
Return	$648,027	$27,180	$61,987
Return Requirement	$891,949	$37,411	$85,319

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 DECEMBER 2010

Cost of Purchased Propane	$101,091
Gallons Purchased	80,873
Projected dk Sales	7,400
Propane Cost per Dk	$13.661
Average Cost of Propane as Adjusted for Losses @ 99.55%	13.723
Less: Propane Cost Level in Rates 1/	13.173
Current Propane Cost Adjustment	$0.550

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, 2010									**($695,379)**
August	($305,149)	$0	($94)	($305,243)	253,885	($0.515)	($130,750)	($174,493)	(869,872)
September	(418,566)	29,770 2/	(108)	(388,904)	283,887	(0.515)	(146,202)	(242,702)	(1,112,574)
Balance @ September 30, 2010									**($1,112,574)**

1/ Interest calculated at the current investment rate.
2/ True-up related to August gas costs.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2010									**($18,649)**
August	$9,163	$0	($3)	$9,160	29,023	($0.152)	($4,411)	$13,571	(5,078)
September	(15,678)	(11,373) 2/	(1)	(27,052)	37,408	(0.152)	(5,686)	(21,366)	(26,444)
Balance @ September 30, 2010									**($26,444)**

1/ Interest calculated at the current investment rate.
2/ True-up related to August gas costs.

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2010									**$14,139**
August	($14,595)	$0	$2	($14,593)	3,296	$0.024	$79	($14,672)	(533)
September	(16,382)	2,449 2/	0	(13,933)	5,317	0.024	128	(14,061)	(14,594)
Balance @ September 30, 2010									**($14,594)**

1/ Interest calculated at the current investment rate.
2/ True-up related to August gas costs.

MONTANA-DAKOTA UTILITIES CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT
APPLICABLE TO NORTH DAKOTA
PROPANE
TO BE EFFECTIVE DECEMBER 1, 2010 THROUGH NOVEMBER 30, 2011

(Over)/under recovered gas costs @ September 30, 2010			($27,047)
Less: Projected recovery from rates already established			
	Volume	Rate	Amount
October	2,700	$0.461	1,245
November	3,600	$0.461	1,660
	6,300		2,905
Additional recovery required			($29,952)
Projected sales volumes (dk)			
December 2010		7,400	
January 2011		8,200	
February		6,000	
March		6,000	
April		4,000	
May		2,300	
June		1,500	
July		1,100	
August		1,100	
September		1,100	
October		2,700	
November		3,600	
Total			45,000
Total (over)/under recovered gas cost adjustment to be effective December 1, 2010 through November 30, 2011			**($0.666)**

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 28, 2010									**$14,923**
March	($17,376)	$0	$2	($17,374)	6,639	(0.547)	($3,632)	($13,742)	1,181
April	(21,129)	0	0	(21,129)	3,964	(0.547)	(2,168)	(18,961)	(17,780)
May	(4,488)	0	(2)	(4,490)	3,002	0.461 2/	48	(4,538)	(22,318)
June	(3,184)	0	(2)	(3,186)	1,468	0.461	677	(3,863)	(26,181)
July	(737)	0	(4)	(741)	1,217	0.461	562	(1,303)	(27,484)
August	(5,116)	0	(3)	(5,119)	881	0.461	406	(5,525)	(33,009)
September	6,592	0	(4)	6,588	1,358	0.461	626	5,962	(27,047)
	($45,438)	$0	($13)	($45,451)	18,529		($3,481)	($41,970)	
Balance @ September 30, 2010									**($27,047)**

1/ Interest calculated at 90 day Treasury Note rate.
2/ Surcharge adjustment change implemented during this period. Reflects 1,324.7 dk @ ($.547) and 1,677.2 @ $.461.

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

	1/	2/	3/	Total
March 2010				
Cost of Gas - Actual	$11.98417	$16.05559	$11.98417	
Cost of Gas - Recovered	16.46700	16.46700	16.46700	
(Over) Under recovery per dk	($4.48283)	($0.41141)	($4.48283)	
dk billed	0	3,042	3,597	6,639
(Over) Under recovery	$0	($1,251)	($16,125)	($17,376)
April 2010				
Cost of Gas - Actual	$10.53281	$11.98417	$10.53281	
Cost of Gas - Recovered	16.46700	16.46700	16.46700	
(Over) Under recovery per dk	($5.93419)	($4.48283)	($5.93419)	
dk billed	3,964	1,650	(1,650)	3,964
(Over) Under recovery	($23,523)	($7,395)	$9,789	($21,129)
May 2010				
Cost of Gas - Actual	$13.37329	$10.53281	$13.37329	
Cost of Gas - Recovered	12.07600	16.46700	16.46700	
(Over) Under recovery per dk	$1.29729	($5.93419)	($3.09371)	
dk billed	1,677	903	422	3,002
(Over) Under recovery	$2,175	($5,359)	($1,304)	($4,488)
June 2010				
Cost of Gas - Actual	$9.62735	$13.37329	$9.62735	
Cost of Gas - Recovered	12.07600	12.07600	12.07600	
(Over) Under recovery per dk	($2.44865)	$1.29729	($2.44865)	
dk billed	0	110	1,358	1,468
(Over) Under recovery	$0	$143	($3,327)	($3,184)
July 2010				
Cost of Gas - Actual	$10.65347	$9.62735	$10.65347	
Cost of Gas - Recovered	10.97800	12.07600	12.07600	
(Over) Under recovery per dk	($0.32453)	($2.44865)	($1.42253)	
dk billed	752	(165)	630	1,217
(Over) Under recovery	($244)	$404	($897)	($737)
August 2010				
Cost of Gas - Actual	$4.48733	$10.65347	$4.48733	
Cost of Gas - Recovered	10.97800	10.97800	10.97800	
(Over) Under recovery per dk	($6.49067)	($0.32453)	($6.49067)	
dk billed	584	98	199	881
(Over) Under recovery	($3,793)	($32)	($1,291)	($5,116)

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

	1/	2/	3/	Total
September 2010				
Cost of Gas - Actual	$16.40113	$4.48733	$16.40113	
Cost of Gas - Recovered	10.97800	10.97800	10.97800	
(Over) Under recovery per dk	$5.42313	($6.49067)	$5.42313	
dk billed	0	65	1,293	1,358
(Over) Under recovery	$0	($420)	$7,012	$6,592

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