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

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

May 8, 2013

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-13-008

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 two (2) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88.

Attachment A is the Rate Summary Sheet (114th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered June 1, 2013.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.186 per dk since the last filing due to an increase in the overall commodity price of gas. Attachment B explains the reasons for the increase 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, the surcharge adjustment and the market based pricing differential provision that will apply during the month of June 2013.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.186 per dk for residential customers and firm general customers, an increase of $0.180 per dk for small and large interruptible customers and an increase of $0.179 per dk for Air Force interruptible customers from the currently effective rates.

Exhibit B shows the calculation of the current gas cost adjustment that will be applicable to Montana-Dakota's customers for the month of June 2013. The average cost of gas for firm customers, adjusted for losses, is $5.267.

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 June 2013. The net effect of this filing is a decrease of $0.549 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 June 2013. The average cost of propane for all customers, adjusted for losses, is $9.880 per dk.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to an increase of approximately $64,700 for natural gas customers and a decrease of approximately $900 for propane customers during the month of June 2013. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 98,771 natural gas customers and 341 propane customers in North Dakota as of January 31, 2013.

Please refer all inquiries regarding this filing to:

Ms. Rita A. Mulkern
Director of Regulatory Affairs
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 $550 in accordance with North Dakota Century Code Section 49-05-05 on January 10, 2013. This payment will cover the filing fee associated with the monthly COG filings.

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
Director of Regulatory Affairs

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
114th Revised Sheet No. 3
Canceling 113th 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	$5.144	$5.956
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$5.144	$5.282
Interruptible Service - PAR			$0.120	$4.163	$4.283
Interruptible Service - MAFB			$0.120	$3.882	$4.002
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$5.144	$5.741
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$4.163	$5.034
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	$0.597	$4.232	$4.829
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	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$4.163	$4.882
Residential Propane Rate 90	32	$0.30 per day	$0.812	$9.093	$9.905
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	$9.093	$9.690

Date Filed: May 8, 2013 **Effective Date:**

Issued By: Tamie A. Aberle
Director - Regulatory Affairs **Case No.:**

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

June 2013

The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. 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.

The increase in natural gas prices is likely a result of below normal seasonal temperatures during the spring months which extended the use of natural gas for space heating across much of the United States. The increased usage also prolonged the withdrawal of natural gas from storage therefore reducing the inventory to levels below the five year average. The Energy Information Administration (EIA) reported storage levels nationwide as of April 26, 2013 to be 6.2 percent below the five-year average and 30.9 percent below last year's storage balance.

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

The May Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 17.

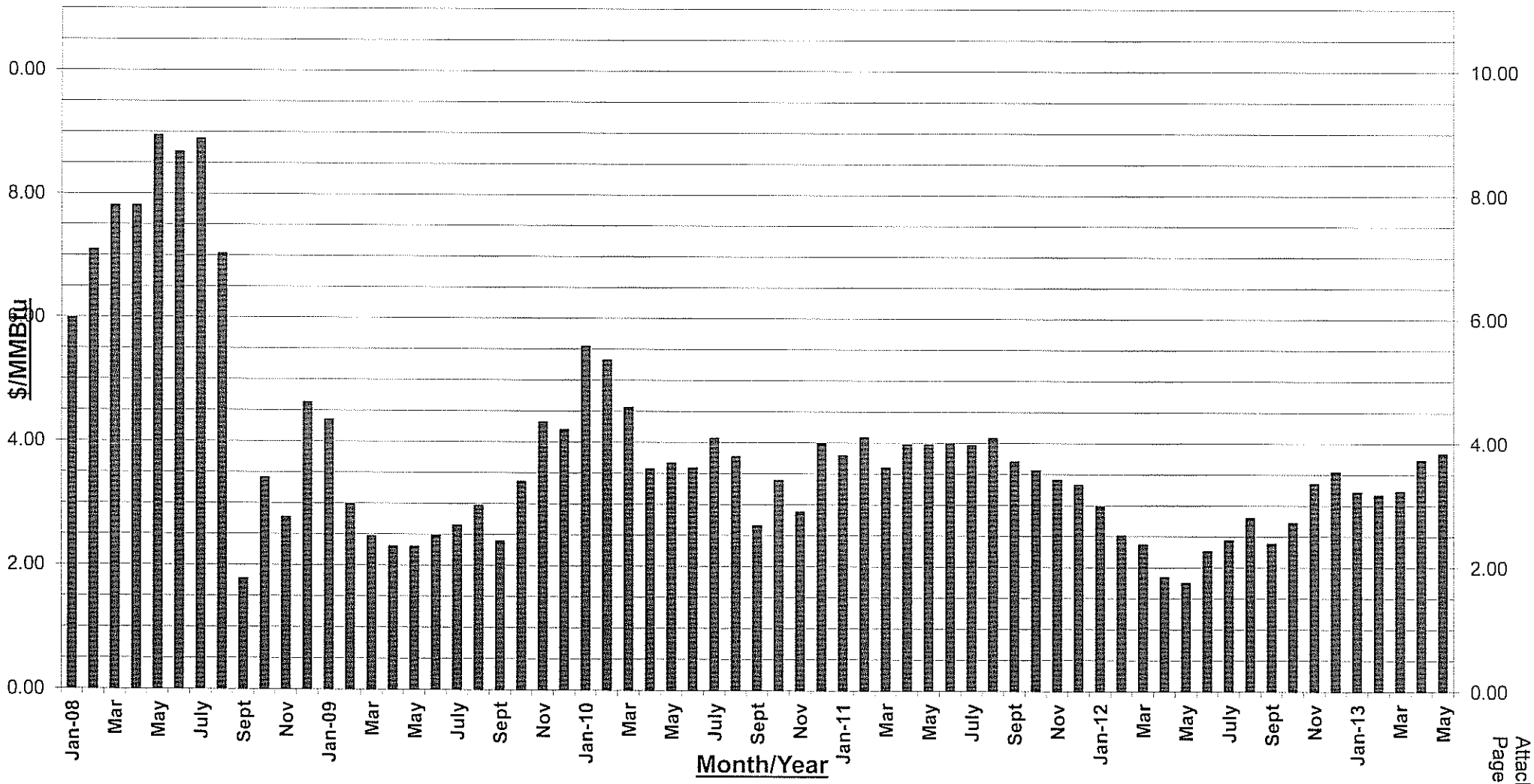
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
June 2013

Montana-Dakota uses two 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 June 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 decreases, 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 2008-2013YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2011-$3.79; 2012-$2.58; 2013YTD - $3.44

Independent Statistics & Analysis
U.S. Energy Information Administration

May 2013

Short-Term Energy Outlook (STEO)

Highlights

- Falling crude oil prices contributed to a decline in the U.S. regular gasoline retail price from a year-to-date high of $3.78 per gallon on February 25 to $3.52 per gallon on April 29. EIA expects the regular gasoline price will average $3.53 per gallon over the summer (April through September), down $0.10 per gallon from last month's STEO. The annual average regular gasoline retail price is projected to decline from $3.63 per gallon in 2012 to $3.50 per gallon in 2013 and to $3.39 per gallon in 2014. Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the projected levels.

- After increasing to $119 per barrel in early February 2013, the Brent crude oil spot price fell to a low of $97 per barrel in mid-April 2013 and then recovered to $105 per barrel on May 3. EIA expects that the Brent crude oil spot price will average $104 per barrel over the second half of 2013 and $101 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which increased to a monthly average of more than $20 per barrel in February 2013, fell to below $9 per barrel in April. EIA expects the discount to increase in the near term and average $13 per barrel in 2013 and $9 per barrel in 2014.

- Natural gas working inventories ended April 2013 at an estimated 1.82 trillion cubic feet (Tcf), about 0.80 Tcf below the level at the same time a year ago and 0.13 Tcf below the five-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged $2.75 per million British thermal units (MMBtu) in 2012, will average $3.80 per MMBtu in 2013 and $4.00 per MMBtu in 2014, about 27 cents per MMBtu and 40 cents per MMBtu higher than forecast in last month's STEO, respectively.

- The projected increasing cost of natural gas relative to coal contributes to higher levels of electricity generation from coal. The share of total generation fueled by coal is forecast to increase from 37.4 percent in 2012 to 40.1 percent in 2013. Conversely, the share of generation fueled by natural gas declines from 30.4 percent in 2012 to 27.8 percent in 2013.

Global Crude Oil and Liquid Fuels

EIA estimates that global liquid fuels consumption outpaced production in the first quarter of 2013, resulting in an average draw in global liquid fuel stocks of 1.2 million barrels per day (bbl/d), which is much higher than the average 0.3-million-bbl/d draw over the last 5 years but consistent with the average 1.1-million-bbl/d draw over the last 10 years. EIA expects world oil production to exceed consumption in the second quarter of 2013, resulting in an average 0.5-million-bbl/d build in global oil stocks, which is consistent with the recent decline in crude oil prices. EIA expects the world oil market to tighten somewhat in the third quarter of 2013 as world demand reaches its summer peak, and to loosen again in the last quarter of the year as world supply grows.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by 0.7 million bbl/d in 2012 to reach 89.0 million bbl/d. EIA expects growth will be higher over the next two years because of a moderate recovery in global economic growth so that world consumption grows by 0.9 million bbl/d in 2013 and by 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA expects refinery crude oil inputs in China to increase in 2013 as new refining capacity continues to come on line and investment in the property market and infrastructure sectors expands. Recent indicators of weaker industrial data at the beginning of 2013 signaled slower economic growth than in prior years and a downside risk to robust oil demand growth. EIA estimates that liquid fuels consumption in China increased by 380,000 bbl/d in 2012. Projected consumption in China will increase by 450,000 bbl/d in 2013 and by 470,000 bbl/d in 2014, albeit still lower than the average annual growth of about 520,000 bbl/d from 2004 through 2012.

OECD liquid fuels consumption fell by 0.6 million bbl/d in 2012. EIA projects OECD consumption to decline by an additional 0.4 million bbl/d in 2013 and 0.2 million bbl/d in 2014, largely because of declining consumption in Europe and Japan.

Non-OPEC Supply. EIA projects non-OPEC liquid fuels production will increase by 1.1 million bbl/d in 2013 and by 1.8 million bbl/d in 2014, an upward revision in the 2014 growth rate of 0.2 million bbl/d from last month's STEO. North America accounts for most of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands. EIA expects non-OPEC supply to also grow in Central and South America by an average of 160,000 bbl/d each year over the next two years, as Brazil and Colombia bring new production on line.

Unplanned production outages in non-OPEC countries averaged 0.9 million bbl/d in April 2013, virtually unchanged from the previous month. Syria, Yemen, and South Sudan accounted for more than three-quarters of the total unplanned non-OPEC supply disruption. EIA expects supply disruptions to persist in Syria and Yemen over the forecast period. Projected production

in Syria and Yemen average about 120,000 bbl/d and 140,000 bbl/d, respectively, over the next two years. EIA expects total non-OPEC outages to abate in the second half of this year due to South Sudan resuming oil production. South Sudan restarted limited oil output at an oil field in Unity State last month. Work is being done to restart production at additional fields in Unity State and the Upper Nile State, although technical challenges may cause delays or constrain production volumes.

OPEC Supply. Projected OPEC total supply falls by 0.5 million bbl/d in 2013 and then rises by 0.1 million bbl/d in 2014. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth, while Iraq and Angola account for most of the increase in 2014.

EIA estimates that OPEC surplus capacity, which is concentrated in Saudi Arabia, averaged about 2.7 million bbl/d in the first quarter of 2013. This was higher than the 2.1-million-bbl/d average during the same period last year but lower than the average 3.8 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 4.6 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line because of the effects of U.S. and EU sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to 57.9 days of supply. Projected OECD oil inventories stay relatively steady in 2013, again ending the year at 2.65 billion barrels. Projected inventories increase to 2.70 billion barrels (59.0 days of supply) at the end of 2014.

Crude Oil Prices. Concerns over global economic growth, seasonal declines in international refinery runs, and increases in North Sea oil production have contributed to a drop in Brent crude oil prices from $109 per barrel on April 1 to a low of $97 per barrel on April 17. EIA projects the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $106 per barrel and $101 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries. After averaging $94 per barrel in 2012, the forecast WTI crude oil spot price averages $93 per barrel in 2013 and $92 per barrel in 2014. By 2014, several pipeline projects from the Midcontinent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a narrowing in the price discount of WTI to Brent.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures contracts for August 2013 delivery traded during the five-day period ending May 2, 2013 averaged $93.41 per barrel. Implied volatility averaged 22 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in August 2013 at $77 per barrel and $113 per barrel, respectively. Last year at this time, WTI for August 2012 delivery averaged $105 per barrel and implied volatility averaged 23 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $86 per barrel and $130 per barrel.

U.S. Crude Oil and Liquid Fuels

Total U.S. liquid fuels consumption during the first quarter of 2013 averaged 190,000 bbl/d higher than the same period last year, the first year-over-year increase in quarterly consumption in two years. Colder weather contributed to an estimated 280,000-bbl/d increase in liquefied petroleum gas and a 120,000-bbl/d increase in distillate fuel consumption. These gains were partially offset by declines in the other major petroleum products, including a 90,000-bbl/d drop in gasoline consumption.

The U.S. crude oil production forecast has been revised upward by 120,000 bb/d in 2013 and 310,000 bbl/d in 2014 from last month's STEO. Production will rise from an average of 7.1 million bbl/d in the first quarter of 2013 to 8.5 million bbl/d in the fourth quarter of 2014. The growing supply of domestic light crude oil in the Midcontinent has already prompted both midstream and downstream changes. Pipelines like Seaway that were once used to carry imported oil up from Gulf Coast ports to reach Midwest refiners have been reversed and are moving inland crude oil down to the Gulf, and their capacity is being dramatically expanded. New pipeline infrastructure is also under construction, including the southern portion of the Keystone XL project, which is slated to be in operation by year-end, and more has been proposed. There have also been major developments in rail transport, where shipments of crude increased dramatically in 2012 compared to 2011. Significant changes in the refining industry are expected over the next few years to accommodate this fast-growing domestic supply of light-sweet crude oil (see This Week in Petroleum, May 1, 2013).

U.S. Liquid Fuels Consumption. After relatively strong growth in the first quarter of 2013 because of cold weather, projected total liquid fuels consumption grows more modestly, increasing by an average 80,000 bbl/d (0.4 percent) in 2013 and unchanged in 2014. Motor gasoline and jet fuel consumption remain flat in 2013 and 2014 as forecast increases in travel growth are offset by fuel economy improvements. Distillate fuel oil consumption, which fell by 160,000 bbl/d (4.0 percent) in 2012, increases by 60,000 bbl/d (1.7 percent) in 2013 and 10,000 bbl/d (0.2 percent) in 2014. Liquefied petroleum gases consumption increases by 70,000 bbl/d in 2013 but then falls by 10,000 bbl/d in 2014.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average 6.5 million bbl/d in 2012 to 7.4 million bbl/d in 2013 and 8.2 million bbl/d in 2014. Drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian basins is expected to account for the bulk of forecast production growth over the next two years.

EIA has increased its short-term forecast for U.S. Lower 48 states onshore oil production, largely because of continued exploration success seen in some of the major plays in the Permian Basin. Operators in the Bone Spring, Spraberry, and Wolfcamp plays are achieving greater success in finding sweet spots and hydraulically fracturing horizontal wells. EIA expects improvements in drilling and completing horizontal wells from multiwell drilling pads in the Permian Basin, which

give operators greater access to large areas of resources in a number of stacked plays from a single surface location.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 5.7 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to fall to 30 percent in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged $3.69 per gallon last summer, will average $3.53 per gallon during the current summer (April through September) driving season, about $0.10 per gallon lower than forecast in last month's STEO. The projected monthly average regular retail gasoline price falls from $3.57 per gallon in April to $3.48 per gallon in September. Diesel fuel prices, which averaged $3.95 per gallon last summer, are projected to fall to an average of $3.88 per gallon this summer. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents per gallon or more.

As is the case with crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor RBOB futures contracts for August 2013 delivery traded over the five-day period ending May 2 averaged $2.73 per gallon. The probability that the RBOB futures price will exceed $3.10 per gallon (consistent with a U.S. average regular gasoline retail price above $3.75 per gallon) in August 2013 is about 11 percent.

Natural Gas

Natural gas spot prices generally increased through March and most of April, hitting a 20-month high in recent weeks. An unusually cold March triggered price increases after three months of stagnant prices, as space-heating demand increased through much of the country and led to large storage withdrawals. Prices continued to rise in April as lingering cold in the Midwest kept market tight. The Henry Hub spot price averaged $4.17 per MMBtu in April, the highest monthly average price since July 2011. EIA expects Henry Hub spot prices will fall through September as natural gas markets loosen with lower summer demand. Going into the summer, EIA expects production to be slightly higher than last year's levels, while summer electric power demand is projected to be lower than last year's record-high levels.

Working natural gas stocks at the end of March 2013 were an estimated 1,683 Bcf, 32 percent lower than the 2,477 Bcf in working storage at the same time last year but roughly in line with earlier years. The very warm winter of 2011-12 contributed to the very high inventory at the start of last year's summer injection season (between the end of March and the end of

October). Consequently, the forecast 2,113-Bcf build in working gas inventories during this summer's injection season is significantly higher than the 1,453 Bcf added last year and in line with longer historical experience. Higher natural gas prices this year contribute to lower natural gas consumption for electricity generation and the higher storage build.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 70.2 Bcf/d and 69.6 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures forecast for 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. The projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.8 Bcf/d in 2013 and 22.2 Bcf/d in 2014.

U.S. Natural Gas Production and Imports. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 69.9 Bcf/d in 2013, and 70.1 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production declines. Natural gas pipeline gross imports, which have declined over the past five years, are projected to remain near their 2012 level over the forecast period. Liquefied natural gas (LNG) imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. As of April 26, 2013, working gas stocks totaled 1,777 Bcf, which is 795 Bcf less than at the same time in 2012, 118 Bcf below the five-year (2008-12) average, and 51 Bcf above the four-year (2008-11) average excluding last year's very unusual experience according to EIA's *Weekly Natural Gas Storage Report*. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,796 Bcf, about 134 Bcf below the level at the same time last year.

U.S. Natural Gas Prices. Natural gas spot prices averaged $4.17 per MMBtu at the Henry Hub in April 2013, up 36 cents from the $3.81-per-MMBtu average seen the previous month. EIA expects the Henry Hub price will increase from an average of $2.75 per million Btu in 2012 to $3.80 per MMBtu in 2013 and $4.00 per MMBtu in 2014.

Natural gas futures prices for August 2013 delivery (for the five-day period ending May 2, 2013) averaged $4.34 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for August 2013 contracts at $3.22 per MMBtu and $5.84 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for August 2012 averaged $2.46 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $1.52 per MMBtu and $3.96 per MMBtu.

Coal

Based on preliminary data and estimates for the first quarter of 2013, U.S. coal exports, which had been steadily growing since 2009 on an annual basis, were down 1.3 million short tons (MMst) compared with the same period in 2012. Coal exports from the Richards Bay coal terminal in South Africa, a major U.S. competitor for the European market, increased by 6.5 percent during the first four months of 2013 compared with same period last year. EIA expects U.S. coal exports to decline from 126 MMst in 2012 to 105 MMst in 2013 and 106 MMst in 2014.

U.S. Coal Consumption. EIA expects total coal consumption will increase by 7.3 percent from 890 MMst in 2012 to 955 MMst in 2013 as consumption in the electric power sector rises due to higher electricity demand and higher natural gas prices. Consumption grows at a more modest pace of 2.2 percent to 976 MMst in 2014.

U.S. Coal Supply. Coal production is expected to increase by 1.0 percent in 2013, from 1,016 MMst in 2012 to 1,027 MMst in 2013, as inventory draws, combined with an increase in coal imports, meet most of the growth in consumption. However, coal production is forecast to grow by 3.5 percent in 2014 to 1,063 MMst as inventories stabilize in the face of increasing consumption.

Production is further diminished by the projected decline in exports from 126 MMst in 2012 to 105 MMst in 2013 and 106 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), falling international coal prices, and increasing production in other coal-exporting countries are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. Delivered coal prices to the electric power industry increased steadily over a 12-year period through 2012, when the delivered coal price averaged $2.40 per MMBtu. EIA forecasts average delivered coal prices of $2.40 per MMBtu in 2013 and $2.44 per MMBtu in 2014.

Electricity

The National Oceanic and Atmospheric Administration's (NOAA) Climate Prediction Center has updated the methodology behind its degree-day outlook based on the new 1981-2010 30-year normals. Projected U.S. cooling degree days for 2013 and 2014 are 3.9 percent and 3.6 percent higher, respectively, compared with last month's forecast. Consequently, projected residential and commercial electricity sales for 2013 and 2014 are about 0.5 percent higher than in last month's STEO.

U.S. Electricity Consumption. During the first four months of 2013, EIA estimates that total U.S. retail sales of electricity to the residential sector averaged 5.4 percent more than residential

electricity sales during the same months last year. Despite the upward revision to NOAA's cooling-degree-day forecast, projected U.S. cooling degree days during the upcoming summer's hottest months (June, July, and August) are 7.3 percent lower than summer of 2012. These lower temperatures relative to last year contribute to a 3.6-percent decline in U.S. residential electricity sales during the summer peak cooling months. For the entire year, U.S. residential retail electricity sales increase by 1.1 percent during 2013 and by 0.5 percent in 2014.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 1.4 percent in 2013 and by 1.0 percent in 2014. The increasing cost of natural gas relative to coal contributes to higher levels of electricity generation from coal. Generators are running their existing coal capacity at higher rates so far this year compared with the same months in 2012. This trend is expected to continue, leading to an 8.7-percent increase in U.S. electricity generation from coal during 2013. The share of total generation fueled by coal is forecast to increase from 37.4 percent in 2012 to 40.1 percent in 2013, still below coal's 42.3-percent fuel share in 2011. Conversely, the rising cost of natural gas pushes the share of generation fueled by natural gas down from 30.4 percent in 2012 to 27.8 percent in 2013, compared with a share of 24.7 percent in 2011.

U.S. Electricity Retail Prices. After an increase of 1.4 percent during 2012, EIA expects U.S. retail residential electricity prices will grow by 2.6 percent in 2013 and by 2.3 percent in 2014.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for power and heat generation to increase by 3.3 percent in 2013. While hydropower declines by 2.2 percent, nonhydropower renewables grow by an average of 7.1 percent in 2013. In 2014, the growth in renewables consumption for power and heat generation is projected to continue at a rate of 4.4 percent, as a 1.8-percent increase in hydropower is combined with a 6.0-percent increase in nonhydropower renewables.

EIA currently estimates that wind capacity will increase by 7 percent this year to nearly 63,000 megawatts, and reach almost 73,000 megawatts in 2014. However, electricity generation from wind is projected to increase by 19 percent in 2013, as capacity that came on line at the end of 2012 is available for the entire year in 2013. Wind-powered generation is projected to grow by 8 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, both from central-station and distributed capacity, although the total amount remains a small share of total U.S. generation. Central-station capacity, which until recently experienced little growth compared with distributed capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all central-station solar growth in 2012, but EIA expects that several large solar thermal generation projects will enter service in 2013 and 2014. However, PV

is still expected to account for the majority of central station and distributed capacity additions in 2013 and 2014.

U.S. Liquid Biofuels. Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.8 billion gallons per year) in the first half of 2012 to 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. Ethanol production recovered somewhat in April, averaging about 840,000 bbl/d, driven largely by increasing Renewable Fuel Standard (RFS) targets and strong demand for Renewable Identification Numbers (RINs) used. EIA expects ethanol production to remain near current levels of about 840,000 bbl/d through mid-2013 before recovering to pre-drought production levels, averaging 860,000 bbl/d for the year. Ethanol production is expected to rise in 2014, averaging 930,000 bbl/d. Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, is forecast to average about 74,000 bbl/d in 2013 and 82,000 bbl/d in 2014 (1.3 billion gallons per year). This forecast assumes that the 2014 renewable fuel volume obligations for biodiesel and advanced biofuel are identical to those in 2013.

In 2013, the RFS requires refiners and importers of gasoline and diesel fuel to deliver RINs to the U.S. Environmental Protection Agency equivalent to 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it). The market price of ethanol RINs increased dramatically during the first quarter of 2013, from $0.05 per gallon at the start of the year to as high as $1.05 per gallon on March 11, and has averaged about $0.70 per gallon during April 2013. The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, a higher ethanol RIN price should lower the market price of E85 gasoline relative to E10 gasoline, thereby stimulating E85 sales. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate increased blending of biodiesel.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 4 percent in 2012, and projects increases of 2.6 percent in 2013 and 0.6 percent in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the U.S. economic projections in the STEO. The GI model used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) will soon be replaced by a combination of income tax increases and spending

cuts that are implemented in 2014. The GI model also assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury (the debt ceiling) in the near term.

U.S. Current Trends. Recent economic indicators have been mixed. The U.S. Bureau of Economic Analysis reported that real gross domestic product (GDP) increased at an annual rate of 2.5 percent in the first quarter of 2013 (that is, from the fourth quarter to the first quarter). This was well above the 0.4-percent growth in the final quarter of 2012, but below the expectations of many forecasters. Consumer spending and residential investment showed strong gains, while net exports and government expenditures showed quarterly reductions. The U.S. Department of Labor also reported that initial unemployment insurance claims dropped by 18,000 in the week ending April 27, 2013 to 324,000 (on a seasonally adjusted basis), down from 371,000 at the same time in 2012. Total nonfarm payroll employment increased by 165,000 in April, near the average employment growth of 169,000 per month over the last 12 months. The U.S. Census Bureau reported that new orders for manufactured durable goods fell 5.7 percent from February to March, following a 4.3-percent increase from January to February. Industrial production rose by 0.4 percent in March after having increased 1.1 percent in February according to the Federal Reserve.

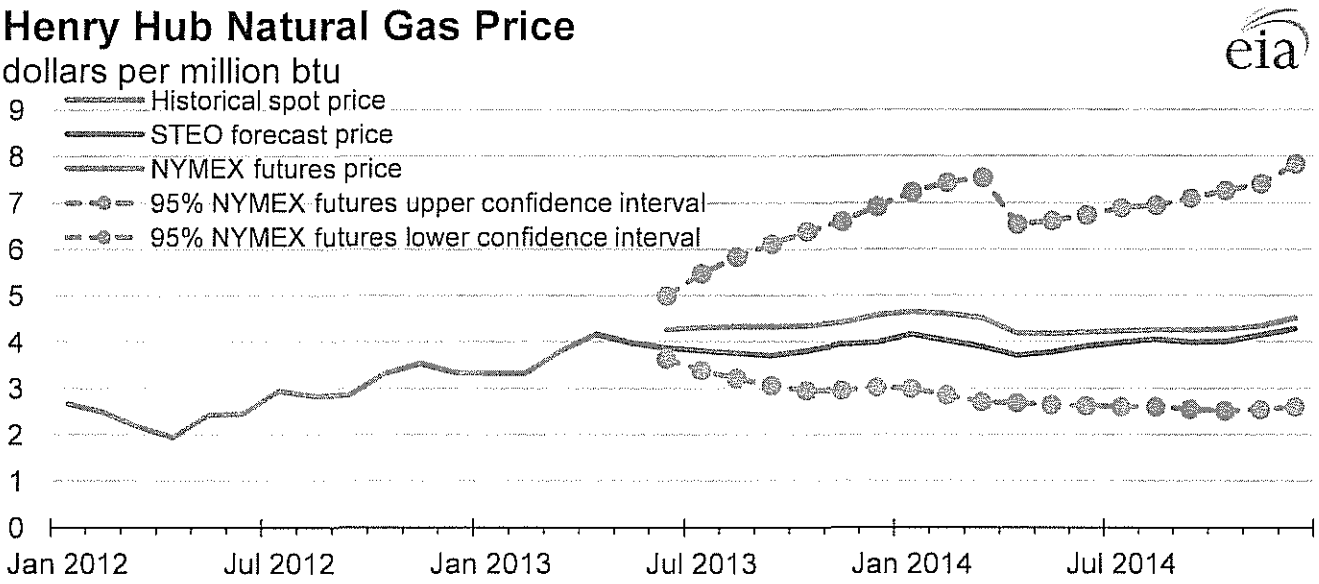
U.S. Production. This STEO assumes 1.8 percent U.S. real GDP growth in 2013, rising to 2.7 percent in 2014. Year-on-year real GDP growth begins to accelerate in 2014, eventually rising to 3.0 percent in its final quarter. Forecast real disposable income increases 0.9 percent in 2013 and 3.4 percent in 2014. Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 3.0 percent and 2.9 percent, respectively.

U.S. Income and Expenditures. Private fixed investment growth averages 6.7 percent and 8.2 percent over 2013 and 2014. This is driven partly by business equipment and software spending, as well as increasing expenditures on buildings. Real consumption expenditures grow faster than real GDP in 2013, at 2.1 percent, but slow below the rate of real GDP growth in 2014, at 2.3 percent. Export growth nearly doubles from 2.6 percent to 5.1 percent over the same two years. Government expenditures fall 2.6 percent in 2013, but are essentially unchanged in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.7 percent over most of 2013, then gradually falls to 7.1 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.5 percent in both 2013 and 2014. Consistent with an improving housing sector, housing starts grow an average of 24 percent and 28 percent over 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

Henry Hub Natural Gas Price

dollars per million btu

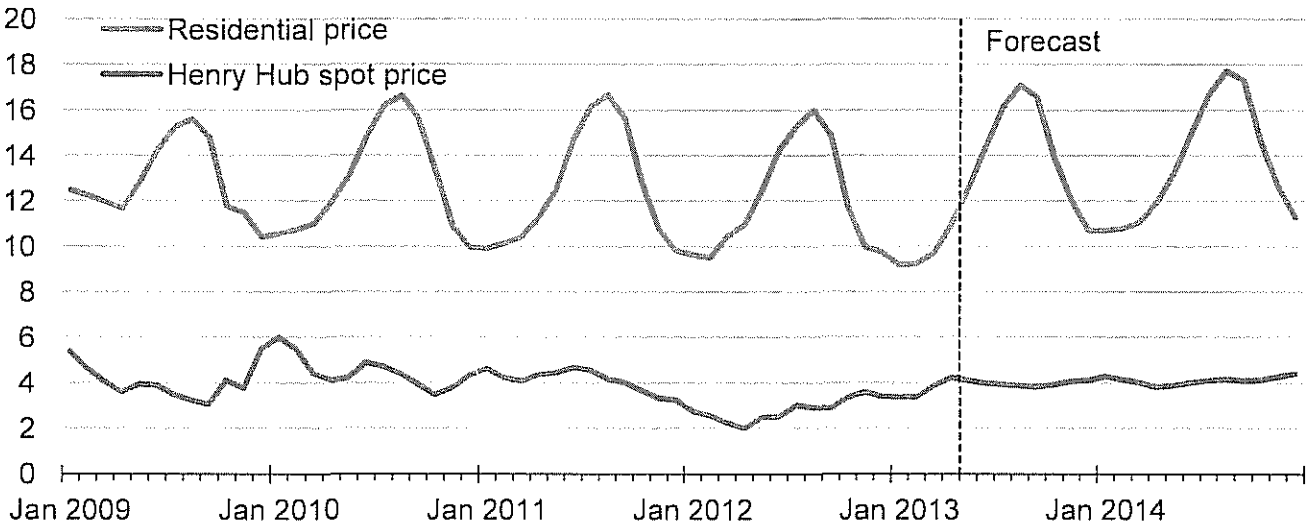


Note: Confidence interval derived from options market information for the 5 trading days ending May 2, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

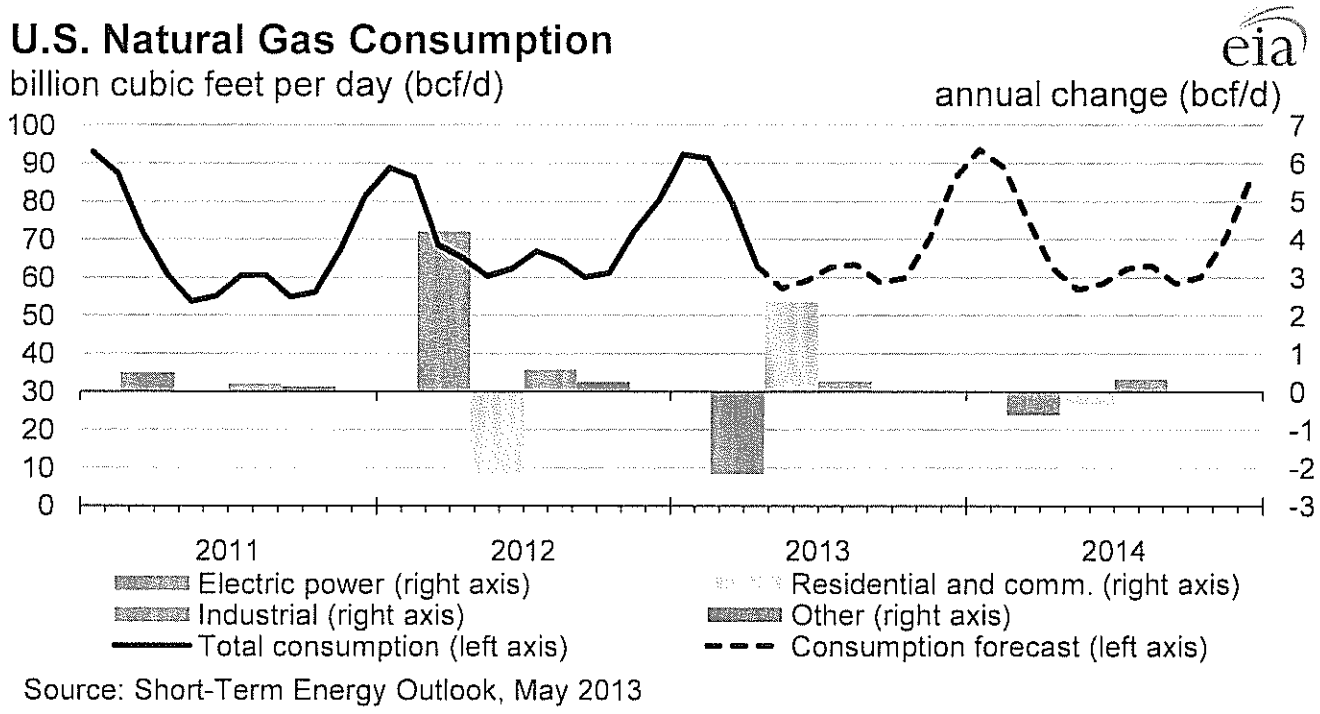
Source: Short-Term Energy Outlook, May 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet

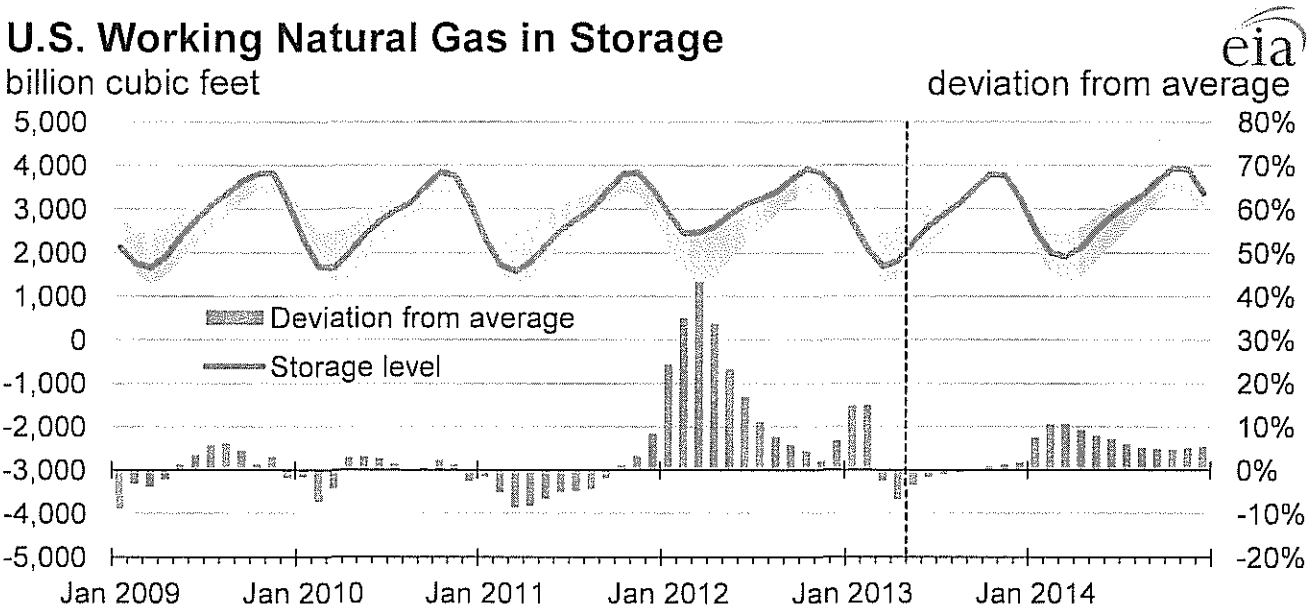


Source: Short-Term Energy Outlook, May 2013



Source: Short-Term Energy Outlook, May 2013

U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, May 2013

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE JUNE 2013

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$5.267	$4.355	$4.278	$4.259
Prior Gas Cost	5.081	5.167	4.098	4.080
Current Gas Cost Adjustment	$0.186	($0.812)	$0.180	$0.179
Surcharge Adjustment:				
Current Adjustment	($0.113)	($0.113)	($0.115)	($0.377)
Prior Adjustment	(0.113)	(0.113)	(0.115)	(0.377)
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
Current Adjustment	($0.010)	($0.010)	$0.000	$0.000
Prior Adjustment	(0.010)	(0.010)	0.000	0.000
Change in Margin Sharing Provision	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**$0.186**	**($0.812)**	**$0.180**	**$0.179**
Gas Cost Level	$5.267	$4.355	$4.278	$4.259
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
Total Gas Cost Level in Tariff Rates	$5.154	$4.242	$4.163	$3.882

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE JUNE 2013

Cost of Gas - Propane	
Current Propane Cost (Exhibit D)	$9.880
Prior Propane Cost	10.429
Current Propane Cost Adjustment	($0.549)
Surcharge Adjustment	
Current Adjustment	($0.777)
Prior Adjustment	(0.777)
Change in Surcharge Adjustment	$0.000
Market Based Pricing Differential	
Current Adjustment	($0.010)
Prior Adjustment	(0.010)
Change in Margin Sharing Provision	$0.000
Net Increase (Decrease) in Gas Costs	**($0.549)**
Propane Cost Level	$9.880
Plus: Surcharge	(0.777)
Total Propane Cost Level in Rates	**$9.103**

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE JUNE 2013

	Amount
Total Gas Costs 1/	$75,684,684
Residential and General Service dk Requirements 2/	14,434,091
Average Cost of Gas per dk	$5.243
Average Cost of Gas as Adjusted for Losses @ 99.55%	5.267
Less: Gas Cost Level in Rates 3/	5.081
Current Gas Cost Adjustment	**$0.186**

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C.
2/ Normalized dk sales for the twelve months ended March 31, 2013, adjusted for losses at .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective May 1, 2013:

Cost of Purchased Gas	$5.058
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$5.081

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE JUNE 2013

Total Gas Costs 1/	$75,684,684
Less: Annual MDDQ Costs 1/	13,113,139
Total Gas Costs excluding MDDQ	$62,571,545
Firm Service Requirements 1/	14,434,091
Other Gas Costs per Dk (excluding MDDQ)	$4.335
Summer - June - September	
Summer Seasonal Rate, adjusted for losses 2/	4.355
Less: Gas Cost Level in Rates 3/	5.167
Current Gas Cost Adjustment	**($0.812)**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-13-008 effective May 1, 2013:

	Winter
Cost of Purchased Gas	$5.144
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$5.167

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE JUNE 2013

	Amount
Total Gas Costs 1/	$14,916,806
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$4.259
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.278
Less: Gas Cost Level in Rates 2/	4.098
Current Gas Cost Adjustment	**$0.180**

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-13-008 effective May 1, 2013:

Cost of Purchased Gas	$4.080
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.098

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE JUNE 2013

	Amount
Total Gas Costs 1/	$3,747,578
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$4.259
Less: Gas Cost Level in Rates 2/	4.080
Current Gas Cost Adjustment	**$0.179**

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-13-008 effective May 1, 2013:
Cost of Purchased Gas $4.080

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
June 2013 PGA

WBI Energy Transmission, Inc. - Exhibit B, pages 6 - 8 for Schedules FT-1, FTN-1, and FS-1.

Northern Border Pipeline Company - Exhibit B, page 9 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 10-11 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	0.180	N.A.	N.A.	3.300
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
SCHEDULED OVERRUN CHARGE						
MAXIMUM A/B/	RATE PER DKT	30.884	0.180	N.A.	N.A.	31.064
MINIMUM A/B/	RATE PER DKT	3.120	0.180	N.A.	N.A.	3.300
VOLUMETRIC CAPACITY RELEASE CHARGE						
MAXIMUM	RATE PER DKT	24.261	N.A.	N.A.	N.A.	24.261
MINIMUM	RATE PER DKT	0.000	N.A.	N.A.	N.A.	0.000

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR TRANSPORTATION FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 1.705%, CONSISTING OF 1.996% FOR THE CURRENT PERCENTAGE AND (0.291%) 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 0.600 CENTS, CONSISTING OF 0.670 CENTS FOR THE CURRENT RATE AND (0.070) 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

8NOTICE 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 CHARGE						
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 CHARGE						
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 CHARGE						
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 CHARGE						
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 0.506%, CONSISTING OF 0.673% FOR THE CURRENT PERCENTAGE AND (0.167%) 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 0.033 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.033 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	$0.0286
Minimum	$0.0000
Daily Reservation Rate - Ventura, IA to North Hayden, IN	
Maximum	$0.0307
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 Rates, pursuant to Articles II and VII of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al., remain in effect until such rates are superseded by new 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 V.A of the September 27, 2012, Stipulation at Docket Nos. RP06-72-000, et al.

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) $ 197.27/10^3m^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 [3]	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 $ 5.34/GJ FT-D Demand Rate for Group 2 Delivery Points [1] $ 3.12/GJ FT-D Demand Rate for Group 3 Delivery Points [2] $ 3.74/GJ
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 [3]	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 — 11.07 6-10 years — 9.25 15 years — 8.30 20 years — 7.36
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 [3]	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: 9009-01001-1 — PT Rate: $ 660.00/d — PT Gas Rate: 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. — Charge 2013568692 — $ 14.00 / month 2013568691 — $ 2.00 / month 2013568690 — $ 2.00 / month 2013568689 — $ 2,125.00 / month 2013568688 — $ 51.00 / month 2013568687 — $ 138.00 / month 2013568686 — $ 88.00 / month 2013568682 — $ 20.00 / month 2013568681 — $ 194.00 / month 2013568680 — $ 210.00 / month 2003004522 — $ 83,333.00 / month 2011476052 / 2011476054 — $ 0.1026 / GJ subject to $ 717,000.00 Minimum Annual Charge 2011475772 — $ 9,250.00 / month 2011475056 — $ 0.095 / GJ and $ 1,000.00 / month 2011476092 — $ 0.095 / GJ and $ 1,000.00 / month 2011494569 — $ 0.095 / GJ and $ 1,000.00 / month

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	5.38	0.1945
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	3.12	0.1128
31110	ALLIANCE EDSON INTERCONNECT APN	3.12	0.1128
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	3.12	0.1128
3002	BOUNDARY LAKE BORDER	3.33	0.1204
1958	EMPRESS BORDER	5.29	0.1912
3886	GORDONDALE BORDER	3.33	0.1204
6404	MCNEILL BORDER	5.29	0.1912

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)	Subject to ATCO Pipelines Franchise Fees[1]
31000	A.T. PLASTICS SALES APN	3.39	0.1226	Yes
31001	ADM AGRI INDUSTRIES SALES APN	3.39	0.1226	Yes
3880	AECO INTERCONNECTION	3.12	0.1128	
31003	AGRIUM CARSELAND SALES APS	3.12	0.1128	
31002	AGRIUM FT. SASK SALES APN	3.12	0.1128	Yes
31004	AGRIUM REDWATER SALES APN	3.12	0.1128	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
3214	AKUINU RIVER WEST SALES	3.12	0.1128	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes[2]
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA BORDER	3.33	0.1204	
3059	ALLISON CREEK SALES	3.12	0.1128	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	3.12	0.1128	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	3.12	0.1128	
3216	AURORA NO 2 SALES	3.12	0.1128	
3135	AURORA SALES	3.12	0.1128	
3423	BASHAW WEST SALES	3.12	0.1128	
31013	BAYMAG SALES APS	3.12	0.1128	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	3.12	0.1128	
3933	BIG EDDY INTERCONNECTION	3.12	0.1128	
3067	BIGSTONE SALES	3.12	0.1128	
3468	BLEAK LAKE SALES	3.12	0.1128	
3225	BOTHA SALES	3.12	0.1128	
3164	BRAINARD LAKE SALES	3.12	0.1128	
3918	BUFFALO CREEK INTERCONNECTION	3.12	0.1128	
31015	BURDETT COGEN SALES APS	3.12	0.1128	
3204	CABIN SALES	3.12	0.1128	
3109	CALDWELL SALES	3.12	0.1128	
31016	CALGARY ENERGY CENTRE SALES APS	3.12	0.1128	Yes
3634	CANOE LAKE SALES	3.12	0.1128	
3165	CANOE LAKE SALES NO 2	3.12	0.1128	
3866	CARBON INTERCONNECTION	3.12	0.1128	
3484	CARIBOU LAKE SALES	3.12	0.1128	
3157	CARIBOU LAKE SOUTH SALES	3.12	0.1128	
3106	CARMON CREEK SALES	3.12	0.1128	
3101	CAROLINE SALES	3.12	0.1128	
31017	CARSELAND COGEN SALES APS	3.12	0.1128	
3495	CAVALIER SALES	3.12	0.1128	
31018	CHAIN LAKES COOP SALES APS	3.12	0.1128	
3907	CHANCELLOR INTERCONNECTION	3.12	0.1128	
3151	CHEECHAM WEST NO 2 SALES	3.12	0.1128	
3622	CHEECHAM WEST SALES	3.12	0.1128	
6014	CHEVRON AURORA SALES	3.12	0.1128	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes
3097	CHICKADEE CREEK SALES	3.12	0.1128	
3305	CHIGWELL NORTH SALES	3.12	0.1128	
3496	CHIPEWYAN RIVER SALES	3.12	0.1128	

NATURAL GAS TARIFF

NorthWestern Energy

	31st	Revised	Sheet No.	80.1
Canceling	30th	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	$ 116.25	(I)
10,001	to	30,000	$ 167.15	(I)
>30,000			$ 370.95	(I)

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	$ 0.9506118	(I)

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	$ 0.0072035	(I)
Minimum	$ 0.0017935	
GTAC Amortization	$ (0.0010312)	
Balancing Penalty Rate	Higher of $25.00/ Dekatherm 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

SD P.U.C. Section No. 3
Original Sheet No. 1

Date Filed: January 24, 2001

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

NG-00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
Fifth Revised Sheet No. 12
Cancels Fourth Revised 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 Demand Charge 6/	Minimum Demand Charge 6/	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	$0.00	$9.50	$0.00	$0.1040	$0.0010	0.611%
	MLI	MLE	$145.00	$0.00	$0.00	$0.1040	$0.0010	0.611%
	MLI	DSE	$225.00	$0.00	$0.00	$0.1978	$0.0020	2.072%
Interruptible Transportation 4/	MLI	MLI	$0.00	$0.00	$0.00	$0.0844	$0.0010	0.611%
	MLI	MLE	$145.00	$0.00	$0.00	$0.0844	$0.0010	0.611%
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 therm.

3/ For fuel, lost and unaccounted for gas, the Company shall be entitled to retain the stated percentage of all therms received for transportation, unless otherwise agreed in writing. On or before March 1 of each year, the Company shall file with the Commission an application to revise the stated percentage to be effective June 1 of that year through May 31 of the following year. The Company shall calculate the stated percentage using not less than twelve (12) consecutive months of actual data.

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.

6/ Per Dth of MDTQ per month.

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

MDTQ Maximum Daily Transportation Quantity

Date Issued: November 20, 2012
By: William N. Cantrell

Date Effective: December 1, 2012
Title: President and CEO

MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE JUNE 2013

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2012	$12,647,019	$616,455	$3,086,520
November	11,646,866	563,795	2,521,344
December	8,000,589	427,541	1,235,777
January 2013	4,079,005	272,801	(365,590)
February	1,206,550	171,608	(1,356,493)
March	(1,423,715)	78,946	(2,036,918)
April	(2,460,471)	40,323	(1,861,403)
May	(851,273)	104,978	(1,083,003)
June	1,269,288	183,982	(6,193)
July	3,916,234	282,745	1,126,734
August	7,571,785	419,698	2,242,631
September	10,483,756	526,741	3,116,457
October	11,770,079	573,626	3,366,249
13 month average	$5,219,670	$327,941	$768,162
Rate of Return	8.791%	8.791%	8.791%
Return	$458,861	$28,829	$67,529
Return Requirement	$625,734	$39,313	$92,087

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 JUNE 2013

Cost of Purchased Propane	$15,737
Gallons Purchased	17,486
Projected dk Sales	1,600
Propane Cost per Dk	$9.836
Average Cost of Propane as Adjusted for Losses @ 99.55%	9.880
Less: Propane Cost Level in Rates 1/	10.429
Current Propane Cost Adjustment	($0.549)

1/ Propane Cost Level in Current Rates - Case No. PU-13-008, effective February 1, 2013.

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, 2012									**($1,670,167)**
August	($117,641)	$0	($140)	($117,781)	264,054	($0.032)	($8,450)	($109,331)	(1,779,498)
September	66,156	0	(163)	65,993	256,762	(0.032)	(8,216)	74,209	(1,705,289)
October	122,687	0	(143)	122,544	571,227	(0.113)	(37,497) 2/	160,041	(1,545,248)
November	519,117	0	(116)	519,001	1,182,061	(0.113)	(133,573)	652,574	(892,674)
December	509,484	0	(52)	509,432	1,863,462	(0.113)	(210,571)	720,003	(172,671)
January 2012	(754)	0	(10)	(764)	2,547,247	(0.113)	(287,839)	287,075	114,404
February	(166,201)	0	7	(166,194)	2,403,906	(0.113)	(271,641)	105,447	219,851
March	(455,645)	0	11	(455,634)	2,116,255	(0.113)	(239,137)	(216,497)	3,354
Balance @ February 28, 2013									**$3,354**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Reflects 333,969.6 Dk @ ($0.032) and 237,257.7 Dk @ ($0.113).

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, 2012									**($144,649)**
August	($620)	$0	($12)	($632)	34,895	$0.064	$2,233	($2,865)	(147,514)
September	20,949	0	(13)	20,936	50,462	0.064	3,230	17,706	(129,808)
October	(5,608)	0	(11)	(5,619)	61,663	(0.115)	2,121 2/	(7,740)	(137,548)
November	37,236	0	(10)	37,226	89,540	(0.115)	(10,297)	47,523	(90,025)
December	52,605	0	(5)	52,600	118,275	(0.115)	(13,602)	66,202	(23,823)
January 2012	24,783	0	(1)	24,782	99,565	(0.115)	(11,450)	36,232	12,409
February	23,033	0	1	23,034	114,013	(0.115)	(13,111)	36,145	48,554
March	1,156	0	2	1,158	93,198	(0.115)	(10,718)	11,876	60,430
Balance @ February 28, 2013									**$60,430**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Reflects 51,466.6 Dk @ $0.064 and 10,197.4 Dk @ ($0.115).

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, 2012									**($189,388)**
August	($10,033)	$0	($16)	($10,049)	3,688	$0.041	$151	($10,200)	(199,588)
September	2,337	0	(19)	2,318	4,426	0.041	181	2,137	(197,451)
October	(2,128)	0	(16)	(2,144)	8,573	(0.377)	352 2/	(2,496)	(199,947)
November	4,067	0	(15)	4,052	35,430	(0.377)	(13,358)	17,410	(182,537)
December	25,326	0	(11)	25,315	57,310	(0.377)	(21,607)	46,922	(135,615)
January 2012	20,733	0	(7)	20,726	77,436	(0.377)	(29,193)	49,919	(85,696)
February	18,711	0	(4)	18,707	82,757	(0.377)	(31,199)	49,906	(35,790)
March	625	0	(2)	623	65,562	(0.377)	(24,717)	25,340	(10,450)
Balance @ February 28, 2013									**($10,450)**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Reflects 8,573.0 Dk @ $0.041.