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

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

November 9, 2012

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

Re: Cost of Gas Adjustment
(COG) Rate 88
Case No. PU-12-008

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 (110th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered December 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.543 per dk since the last filing due to an increase in the overall market price of gas. Attachment B explains the reasons for the increase in the market price of gas. In addition, Montana-Dakota has increased its firm transportation capacity to meet increasing capacity requirements, resulting in a system wide change in demand allocation and an increase of approximately $0.135 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 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.678 per dk for residential customers, an increase of $0.690 per dk for firm general customers, an increase of $0.532 per dk for small and large interruptible customers and an increase of $0.529 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 2012. The average cost of gas for firm customers, adjusted for losses, is $4.756.

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December 2012 cost of natural gas and propane
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

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.

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 2012. The net effect of this filing is an increase of $1.098 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 2012. The average cost of propane for all customers, adjusted for losses, is $10.429 per dk.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to an increase of approximately $565,600 for natural gas customers and an increase of approximately $7,000 for propane customers during the month of December 2012. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 97,280 natural gas customers and 342 propane customers in North Dakota as of October 31, 2012.

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 $500 in accordance with North Dakota Century Code Section 49-05-05 on February 9, 2012. This payment will cover the filing fee associated with this monthly COG filing.

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
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

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	$4.633	$5.445
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$4.633	$4.771
Interruptible Service - PAR			$0.120	$3.593	$3.713
Interruptible Service - MAFB			$0.120	$3.314	$3.434
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	$4.633	$5.230
Small Interruptible Gas Rate 71	14	$100.00 per month	(Maximum) $0.871	$3.593	(Maximum) $4.464
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	$4.735	$5.332
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	
Large Interruptible Gas Rate 85	27	$675.00 per month	(Maximum) $0.719	$3.593	(Maximum) $4.312
Residential Propane Rate 90	32	$0.30 per day	$0.812	$11.065	$11.877
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$11.065	$11.662

Date Filed: November 09, 2012

Effective Date:

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

December 2012

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 higher usage to meet the seasonal heating demands as well as pipeline maintenance that resulted in pipelines issuing force majeure notices that affected the west coast market. The increase in prices occurred despite the record amount of natural gas in storage at 3.91 trillion cubic feet. The Energy Information Administration (EIA) reported storage levels nationwide as of October 26, 2012 to be 7.1 percent above the five-year average and 3.6 percent above 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 November Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 17.

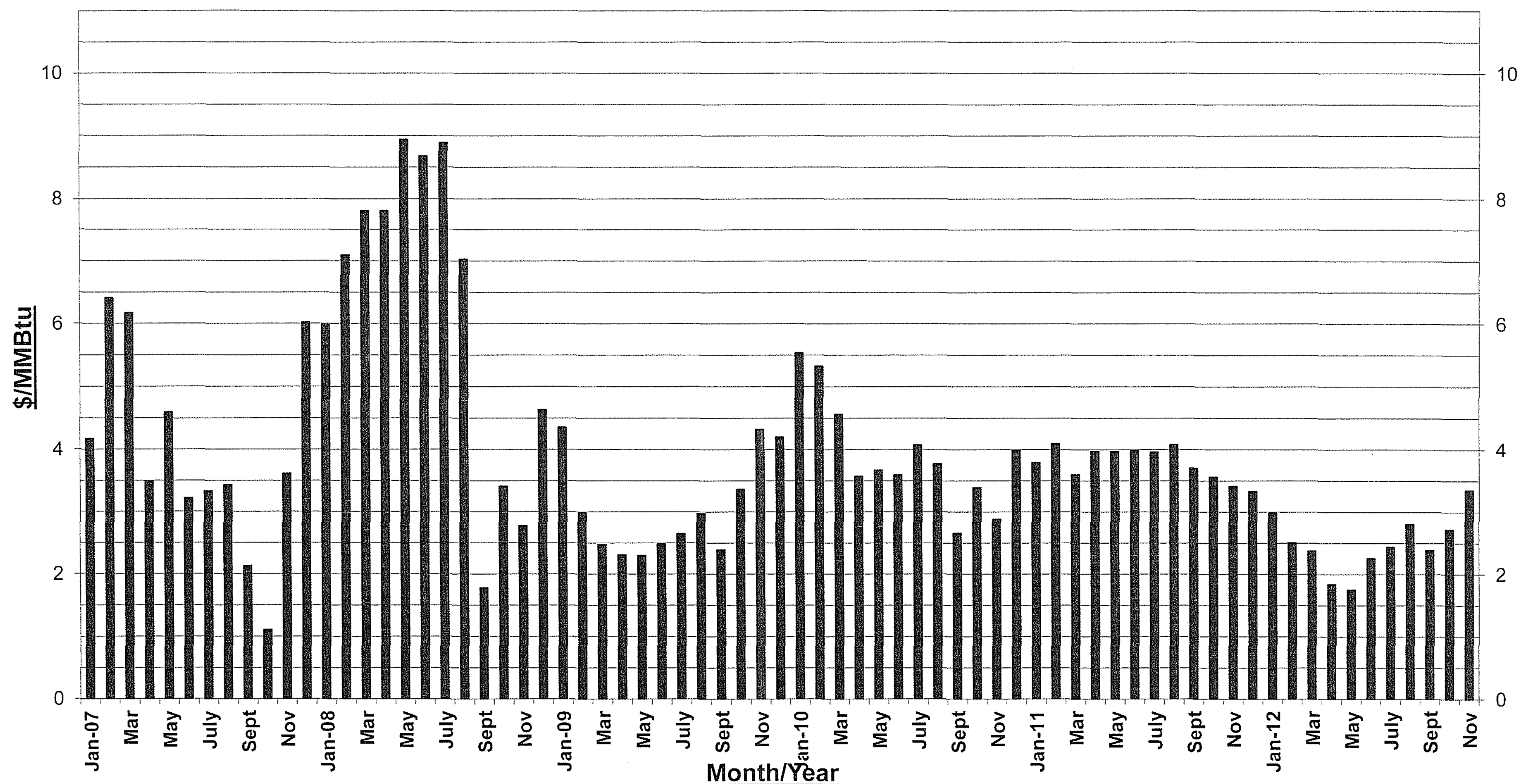
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
December 2012

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 December 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 2007-2012YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2010-$3.92; 2011-$3.79; 2012YTD - $2.49

Independent Statistics & Analysis
U.S. Energy Information Administration

November 2012

Short-Term Energy Outlook

- Hurricane Sandy resulted in the loss of electric power to about 8.5 million customers on the East Coast and the shutdown of two refineries, major petroleum distribution terminals, and pipelines because of power outages and flooding. Progress reports on the status of electricity and liquid fuels supply are available in the U.S. Department of Energy's *Hurricane Sandy Situation Reports*.

- EIA projects that the West Texas Intermediate (WTI) crude oil price will average $89 per barrel in the fourth quarter of 2012, about $4 per barrel lower than in last month's *Outlook*, while the Brent crude oil price is expected to average about $1 per barrel less than in last month's forecast at about $110 per barrel over the same period. The projected WTI discount to Brent crude oil, which averaged $22 per barrel in October 2012, falls to an average of $11 per barrel in the fourth quarter of 2013. WTI crude oil is forecasted to average $88 per barrel in 2013, while the Brent crude oil forecast remains unchanged at $103 per barrel.

- U.S. regular gasoline retail prices began October 2012 at $3.80 per gallon and fell to $3.49 per gallon on November 5, 2012. Projected U.S. regular gasoline retail prices average $3.56 per gallon during the fourth quarter of 2012. Hurricane Sandy, however, has contributed to higher wholesale gasoline prices on the East Coast, and the recovery schedule for affected refineries, pipelines, and distribution terminals contributes to uncertainty over the near-term price outlook. EIA expects regular gasoline retail prices, which averaged $3.53 per gallon in 2011, to average $3.64 per gallon in 2012 and $3.44 per gallon in 2013.

- EIA expects U.S. total crude oil production to average 6.3 million barrels per day (bbl/d) in 2012, an increase of 0.7 million bbl/d from last year. Projected U.S. domestic crude oil production increases to 6.8 million bbl/d in 2013, the highest level of production since 1993.

- Working natural gas inventories are at a record high level. As of October 26, 2012, working inventories totaled 3,908 billion cubic feet (Bcf), which is 56 Bcf greater than the previous record high of 3,852 Bcf on November 18, 2011. EIA expects the Henry Hub natural gas spot price, which averaged $4.00 per million British thermal units (MMBtu) in 2011, to average $2.77 per MMBtu in 2012 and $3.49 per MMBtu in 2013.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects global oil markets to loosen in the fourth quarter of 2012 as forecast liquid fuels supply, which was 0.7 million bbl/d lower than world consumption in the third quarter of 2012, outpaces consumption by 0.1 million bbl/d in the fourth quarter, leading to an increase in world inventories. Projected liquid fuels consumption declines by 0.3 million bbl/d from the third quarter of 2012 to the fourth quarter of 2012 while global production increases by 0.5 million bbl/d over the same period, as members of the Organization of the Petroleum Exporting Countries (OPEC) continue to produce more than 30 million bbl/d of crude oil and non-OPEC countries recover from unplanned outages and scheduled maintenance. EIA also expects global inventory builds to continue during the first half of 2013, mostly due to an increase in non-OPEC supply.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 1.0 million bbl/d in 2011. EIA expects world consumption growth of about 0.7 million bbl/d in 2012 and 0.9 million bbl/d in 2013, with countries outside of the Organization for Economic Cooperation and Development (OECD) driving global consumption growth.

Projected OECD liquid fuels consumption declines by 0.4 million bbl/d in 2012 and by an additional 0.2 million bbl/d in 2013 below 2012. Although EIA forecasts U.S. liquid fuels consumption to grow by 110 thousand bbl/d in 2013, this is more than offset by declines in consumption in Europe and other OECD countries. At the same time, EIA expects that China's annual consumption growth to increase from 330 thousand bbl/d in 2012 to 430 thousand bbl/d in 2013.

Non-OPEC Supply. EIA estimates non-OPEC liquid fuels production in October 2012 to be 0.3 million bbl/d above the same month last year, primarily because of increased crude oil production from tight oil plays in the United States. Projected non-OPEC production increases by 1.3 million bbl/d in 2013 over 2012, largely due to continued production growth from U.S. tight oil formations and Canadian oil sands. EIA slightly increased its forecast for Canada's oil sands output from last month's *Outlook*, as Cenovus announced that its phased expansions of the Christina Lake project are proceeding faster than expected.

Unplanned production outages in non-OPEC countries declined in October to 0.9 million bbl/d, from an average of 1.1 million bbl/d in September. The decrease was mostly due to the return of the U.S. production in the U.S. Gulf of Mexico following disruptions related to the late August landfall of Hurricane Isaac. Hurricane Isaac led to a peak shut-in of 1.3 million bbl/d of U.S. production in the Gulf of Mexico and average disruption volumes of 210 thousand bbl/d in August and September.

Other unplanned disruptions persist in non-OPEC countries, including those in Syria and Sudan. An estimated 220 thousand bbl/d of production was offline in Syria in October, an increase relative to September's outage of 180 thousand bbl/d as a result of infrastructure damage related to cross-border shelling between Turkey and Syria. South Sudan's production still remains offline as well, though the government recently ordered oil companies to restart production and estimated that exports would resume in the following three months. EIA forecasts Sudan and South Sudan's production to average 120 thousand bbl/d in 2012 and recover to 310 thousand bbl/d in 2013, still well below the pre-shut-in level of around 460 thousand bbl/d.

OPEC Supply. EIA expects that OPEC members will continue to produce more than 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil consumption and to counterbalance supply disruptions. Projected OPEC crude oil production increases by about 1.2 million bbl/d in 2012 and falls by 0.5 million bbl/d in 2013. OPEC production of noncrude oil liquids, which are not subject to production targets, increases by 0.3 million bbl/d and 0.2 million bbl/d in 2012 and 2013, respectively.

Production from OPEC member states has increased over the past year, especially in Libya and Iraq, while Saudi Arabia continues to produce nearly 10 million bbl/d. There has also been growth, although smaller, in Kuwait and the United Arab Emirates. Iraq's production increased to 3.2 million bbl/d in October 2012, compared with the year-ago level of 2.7 million bbl/d. The increased production was boosted by new infrastructure that facilitates exports of oil from Iraq's southern fields. Furthermore, new agreements on payments between the central government in Baghdad and the Kurdistan Regional Government (KRG) have resulted in resumed exports from the oil fields located in the area controlled by the KRG. Libyan crude oil production remained near 1.5 million bbl/d in October, slowly approaching the pre-crisis level of near 1.7 million bbl/d.

A number of recently published reports indicate that Iranian crude oil exports experienced precipitous declines in July, due to the enforcement of the latest round of U.S. and European Union (EU) sanctions, although Iran's difficulties in exporting its oil seemed to have eased somewhat since then. See the U.S. Energy Information Administration's October 25, 2012, report *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*.

Nigerian oil production declined for a second consecutive month in October to slightly less than 2.0 million bbl/d. Maintenance-related outages reduced Nigeria's production in September, which fell again in October due to floods and pipeline sabotage. The floods mostly affected onshore oil and gas production from Total and Eni and curtailed natural gas shipments to the Bonny liquefied natural gas (LNG) facility. However, Total stated that increases from some of its offshore oil fields partially compensated for the lost output. Meanwhile, pipeline sabotage caused production delays and led Shell to declare force majeure on Bonny and Forcados crude oil exports in mid-October.

Global OPEC surplus capacity, overwhelmingly concentrated in Saudi Arabia, remains relatively tight by historical standards, and is estimated at 2.0 million bbl/d over the past two months.

OPEC surplus capacity grows slowly over the next year to 3.3 million bbl/d by the second quarter of 2013. This estimate does not include additional capacity that may be available in Iran, but which is currently offline due to the impacts of U.S. and EU sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2011 at 2.60 billion barrels, equivalent to just under 56 days of forward-cover. Projected OECD oil inventories increase to 2.65 billion barrels and just over 57 days of forward-cover by the end of 2012. Forecast days of supply are at the highest end-of-year levels since 1991 because of the decline in OECD consumption over the past seven years.

Crude Oil Prices. EIA projects the price of Brent crude oil will average $112 per barrel in 2012 and $103 per barrel in 2013, both mostly unchanged from last month's *Outlook*. EIA expects the WTI price to average $89 per barrel in the fourth quarter of 2012, about $4 lower than last month's *Outlook*, and to mostly remain at this level throughout the forecast period averaging $88 per barrel in 2013. After increasing to $22 per barrel in October of this year, the WTI crude oil spot price discount to the Brent crude oil spot price will average $20 per barrel in the fourth quarter of 2012 before falling to $11 per barrel by the end of 2013, according to EIA.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for February 2013 delivery during the five-day period ending November 1, 2012, averaged $87.21 per barrel. Implied volatility averaged 31 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in February 2013 at $66 per barrel and $115 per barrel, respectively. Last year at this time, WTI for February 2012 delivery averaged $93 per barrel and implied volatility averaged 39 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $66 per barrel and $130 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total liquid fuels consumption fell 230 thousand bbl/d (1.2 percent) in 2011, driven by a 240-thousand-bbl/d drop in motor gasoline consumption. Forecast total liquid fuels consumption falls by 290 thousand bbl/d (1.5 percent) in 2012, including a decline in motor gasoline consumption of 30 thousand bbl/d. Warm weather during the first half of the year contributes to a projected 120-thousand-bbl/d decline in distillate fuel oil consumption in 2012. In 2013, total liquid fuels consumption increases by 110 thousand bbl/d (0.6 percent). Most of the recovery in consumption next year comes from distillate fuel oil and natural gas liquids consumption, which rise because of continued growth in freight shipments and industrial use as well as the assumption of near-normal weather this coming winter compared with warmer weather last winter.

Despite higher assumed growth in U.S. real disposable income and a projected decline in retail gasoline pump prices of 5.6 percent in 2013, forecast motor gasoline consumption remains almost unchanged from 2012 because of continued slow growth in the driving-age population, improvements in the average fuel economy of new vehicles, and increased rates of retirement of older, less-fuel-efficient vehicles.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 170 thousand bbl/d (3.0 percent) to 5.65 million bbl/d in 2011. Forecast crude oil production increases to 6.33 million bbl/d in 2012 with Lower-48 (excluding the federal Gulf of Mexico) crude oil production growing by 790 thousand bbl/d, primarily from the Bakken, Permian Basin, and Eagle Ford producing areas. Total crude oil output rises a further 520 thousand bbl/d in 2013. The number of oil-directed drilling rigs reported by Baker Hughes has increased from 777 at the beginning of 2011 to 1,191 at the start of 2012, and to 1,414 as of June 8, 2012; the oil rig count has remained near 1,400 since then.

The share of total U.S. consumption met by liquid fuel net imports of both crude oil and products has been falling since peaking at over 60 percent in 2005. In 2011, it averaged 45 percent, down from 49 percent in 2010. EIA expects that the total net import share of consumption will continue to decline to 41 percent in 2012 and to 39 percent in 2013 because of the substantial increases in domestic crude oil production. If the 2013 forecast holds true, it would be the first time the share of total U.S. consumption met by liquid fuel net imports is less than 40 percent since 1991.

U.S. Petroleum Product Prices. U.S. monthly average regular gasoline retail prices increased from $3.44 per gallon in July to $3.85 in September. Prices then fell by 10 cents to $3.75 per gallon in October, as the gasoline market transitioned from summer-grade to lower-cost winter-grade gasoline specifications, and crude oil prices fell. Projected regular gasoline retail prices average $3.56 per gallon during the fourth quarter of 2012, down slightly from $3.60 per gallon projected in last month's *Outlook*. However, outages caused by Hurricane Sandy and low gasoline and distillate stocks on the East Coast could put upward pressure on prices in this region. Projected regular gasoline retail prices average $3.64 per gallon in 2012 and $3.44 per gallon in 2013.

Diesel fuel retail prices rose from a monthly average of $3.83 per gallon to January 2012 to a high of $4.13 per gallon in March, and then fell to a low of $3.72 per gallon in July. After reaching an average of $4.12 per gallon in September, continued tight market conditions and strong global demand kept on-highway diesel fuel prices at an average of $4.09 per gallon in October. EIA expects that on-highway diesel fuel retail prices will average $4.00 per gallon during the fourth quarter of this year and $3.83 per gallon in 2013. Wholesale diesel margins (the difference between the wholesale price of diesel and the U.S. average refiner acquisition cost of crude oil) averaged $0.60 per gallon in the first half of 2012 before climbing to an estimated $0.97 per gallon in October, the highest level since October 2005. EIA projects those margins will average $0.72 per gallon in 2012 and $0.75 per gallon in 2013, compared with the previous 5-year average of $0.52 per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.7 Bcf/d in 2012, an increase of 3.2 Bcf/d (4.8 percent) from 2011. Large gains in electric power use in 2012 more than offset declines in residential and commercial use. Projected consumption of natural gas in the electric power sector averages 25.4 Bcf/d in 2012, 22 percent higher than in 2011, primarily driven by the increased relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector during 2012 reached a record level of 35.3 Bcf/d in July 2012, when electricity demand for air conditioning was highest.

Projected total natural gas consumption decreases by 0.5 Bcf/d (0.7 percent) in 2013. Expected declines in the electric power sector offset increases in residential, commercial, and industrial consumption. A forecast of near-normal weather during the upcoming winter (but colder than last year's abnormally warm winter) drives 2013 increases in residential and commercial consumption of 11.5 percent and 10.2 percent, respectively. Although projected higher natural gas prices contribute to a 11.2-percent decline in forecast natural gas consumption in the electric power sector in 2013, consumption in the power sector next year is still expected to be about 1.8 Bcf/d higher than 2011 levels and high by historical standards. The consumption forecast for 2012 and 2013 is largely unchanged from last month's *Outlook.*

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by 4.8 Bcf/d (7.9 percent) in 2011. EIA forecasts that total marketed production growth will slow in 2012, and that 2013 production will be near the 2012 level. So far during 2012, production has fluctuated slightly around an average of 69 Bcf/d, in contrast to the strong upward growth seen between 2009 and 2011. EIA expects some small declines in production in the coming months, related to recent drops in the rig count. According to Baker Hughes, the natural gas rig count was 424 as of November 2, 2012, compared with 811 at the start of 2012. EIA expects that growth in associated gas from crude oil, as well as continued drilling in liquids-rich areas, will help offset the decline in drilling activity. This month's 2013 forecast represents a downward revision of 0.4 Bcf/d from last month's *Outlook.*

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.6 percent) in 2012, as domestic supply continues to displace Canadian sources. The warm winter in the United States early this year also added to the year-over-year decline in imports, particularly to the Northeast where imported natural gas can serve as additional supply in times of very cold weather. EIA expects an increase of 0.1 Bcf/d in (1.3 percent) in pipeline gross imports in 2013. Pipeline gross exports grew by 1.0 Bcf/d (33 percent) in 2011, driven by increased exports to Mexico, but are expected to remain mostly flat in 2012, and grow by 0.1 Bcf/d in 2013.

Liquefied natural gas (LNG) imports are expected to fall by about one-half in 2012 from the year before. EIA expects that an average of slightly less than 0.5 Bcf/d will arrive in the United States (mainly at the Elba Island terminal in Georgia and the Everett terminal in New England) both in

2012 and 2013, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions. Higher prices for LNG, particularly in Asian markets, have made the United States a market of last resort for LNG suppliers. Even as natural gas prices are expected to rise in the United States next year, prices in Japanese and Korean markets have historically been much higher.

U.S. Natural Gas Inventories. Working natural gas inventories are at a record high level. As of October 26, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 3,908 Bcf, which is 56 Bcf greater than the previous weekly high of 3,852 Bcf on November 18, 2011. Inventories are 136 Bcf greater than last year's level and 259 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will total 3,935 Bcf, and injections are likely to continue for a few weeks in November. Because of very high inventories at the start of the summer injection season this year, working inventories have remained high and weekly stock builds have been below both the five-year average and last year's level since April 2012, with a few exceptions. The projected increase of 1,458 Bcf in working gas inventory during the 2012 injection season (from the beginning of April through the end of October) would be the smallest build since 1991. Last year's inventory build from April through October, for comparison, was 2,224 Bcf.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.31 per MMBtu at the Henry Hub in October 2012, up $0.46 per MMBtu from the September 2012 average and $0.25 per MMBtu less than the October 2011 average. EIA expects the Henry Hub natural gas price will average $2.77 per MMBtu in 2012 and $3.49 per MMBtu in 2013, increases of $0.06 per MMBtu in 2012 and $0.14 per MMBtu in 2013 from last month's *Outlook.*

Natural gas futures prices for February 2013 delivery (for the five-day period ending November 1, 2012) averaged $3.86 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for February 2013 contracts at $2.76 per MMBtu and $5.39 per MMBtu, respectively. At this time last year, the February 2012 natural gas futures contract averaged $3.97 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $2.89 per MMBtu and $5.45 per MMBtu.

Coal

U.S. Coal Consumption. EIA expects that coal consumption in the electric power sector will be below 1 billion short tons for a fourth consecutive year in 2012. EIA forecasts coal consumption in the electric power sector to total 825 million short tons (MMst) in 2012. Lower natural gas prices to electric generators have led to a significant increase in the share of natural gas-fired generation. EIA projects power sector coal consumption to grow by 6 percent in 2013 as higher natural gas prices lead to a reduction in natural gas-fired generation.

U.S. Coal Supply. EIA forecasts that coal production will decline by 7 percent in 2012 as domestic consumption falls. Coal production for the first three quarters (January-September) of 2012 was 46 million short tons (MMst) below the same period in 2011. EIA expects production to remain flat in 2013 as inventory draws and lower exports offset an increase in domestic consumption in the forecast. Electric power sector stocks, which ended 2011 at 175 MMst, are forecast to total 185 MMst at the end of the 2012 and 180 MMst in 2013.

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong in 2012 and exceed the 107 MMst exported in 2011. The 98 MMst of coal exported in the first three quarters of 2012 was larger than any annual total exported from 1993 through 2009. EIA projects coal exports to total a record 125 MMst in 2012. EIA expects that coal exports will decline in 2013 but remain above 100 MMst for the third straight year. Continuing economic weakness in Europe, lower international coal prices, and increasing production in Asia are primary reasons for the expected decline in coal exports. U.S. exports could be higher if there are significant supply disruptions from any of the major coal-exporting countries.

U.S. Coal Prices. Delivered coal prices to the electric power industry increased steadily over the 10-year period ending in 2011, when the delivered coal price averaged $2.39 per MMBtu (a 6-percent increase from 2010). However, EIA expects the decline in domestic demand for coal, combined with large coal inventories, will slow increases in coal prices and contribute to the shut-in of higher-cost production. EIA forecasts that the delivered coal price will average $2.40 per MMBtu in 2012 and $2.44 per MMBtu in 2013.

Electricity

U.S. Electricity Consumption. Residential sales of electricity in the United States are projected to fall by 3.5 percent in 2012. The decline in residential sales this year reflects the mild winter temperatures in the first quarter of this year, particularly in the south where many households heat using electricity. Residential electricity sales decline by 0.5 percent in 2013 as lower electricity demand for space cooling during the summer offsets the increase in first quarter consumption.

According to the U.S. Department of Energy's *Hurricane Sandy Situation Report*, at least 8.5 million customers were without power at some point as a result of Hurricane Sandy, compared with a peak number of 6.7 million customers during Hurricane Irene in August 2011. EIA expects outages caused by Hurricane Sandy will reduce October and November total retail sales of electricity in the Mid-Atlantic region (New Jersey, New York, and Pennsylvania) by about 2 to 3 percent from their forecasted level absent disruptions caused by the storm.

U.S. Electricity Generation. The shares of total U.S. electricity generation fueled by natural gas and coal during 2012 averaged 30.6 percent and 37.2 percent, respectively. EIA expects that prices for natural gas delivered to electric generators during 2013 will average 22 percent higher than during 2012, while the average cost of coal is just over 1 percent higher. The projected higher price of natural gas relative to coal contributes to a decline in the share of total generation fueled by natural gas 27.2 percent next year and an increase in the coal share to 40.1 percent.

U.S. Electricity Retail Prices. EIA expects the nominal U.S. residential electricity price will rise by just 0.1 percent during 2012, which would be the smallest year-over-year increase in ten years. Residential prices during 2013 are projected to rise by 1.5 percent to an average of 11.98 cents per kilowatthour.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 14.0 percent in 2011, total renewable energy consumption is projected to decline by 2.6 percent in 2012. This decrease is the result of hydropower use falling by 0.4 quadrillion Btu (13.8 percent) as it begins to return to its long-term average. The decline in hydropower from 2011 to 2012 more than offsets the projected growth in the consumption of other renewable energy forms. Renewable energy consumption increases 2.5 percent in 2013 as hydropower continues to decline (2.4 percent) but nonhydropower renewables grow by an average of 5.0 percent.

Under current law, federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 27 percent in 2011, is forecast to grow an additional 16 percent in 2012. The outlook for wind capacity additions and generation in 2013 will likely depend on whatever decision is made regarding the extension of production tax credits.

Solar energy continues robust growth, although the total amount remains relatively small. Consumption is projected to grow by about 30 percent in both 2012 and 2013.

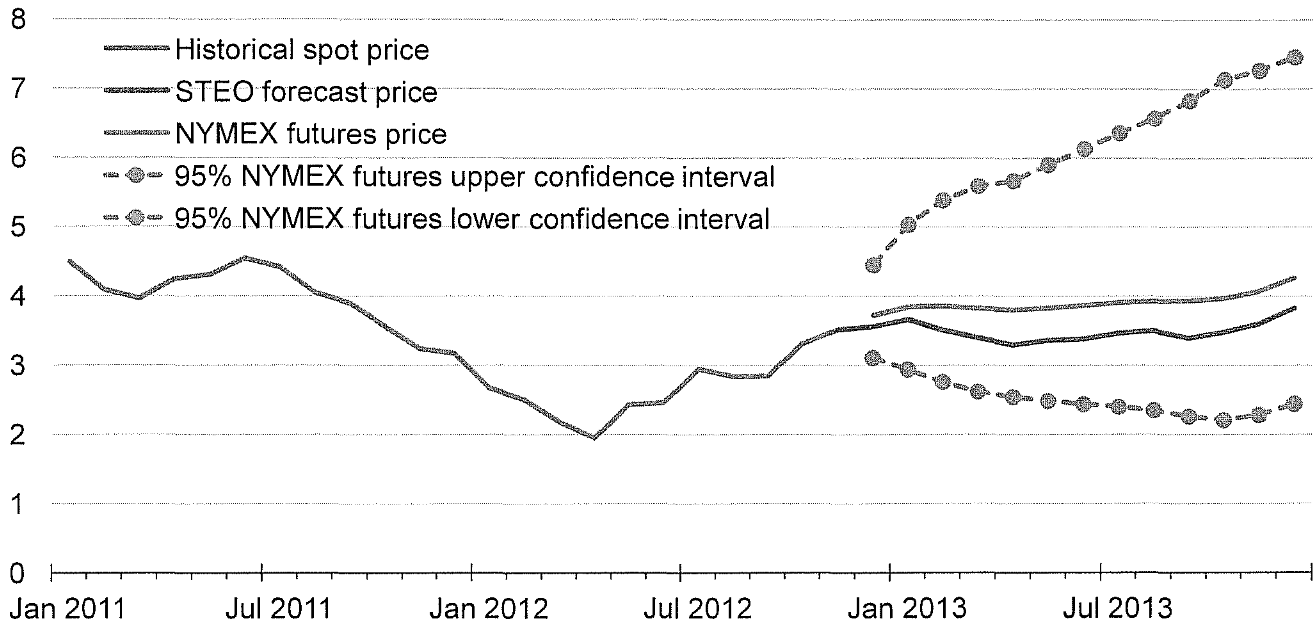
As a result of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 890 thousand bbl/d during the second quarter of 2012 to an average of about 806 thousand bbl/d in October 2012. EIA expects ethanol production will remain near current levels through the first half of 2013 and recover in the second half of 2013, averaging over 850 thousand bbl/d (13.0 billion gallons) for the year. The projected lower ethanol production is generally matched by higher ethanol imports and lower ethanol exports. Biodiesel production averaged about 63 thousand bbl/d (0.97 billion gallons) in 2011. Forecast biodiesel production averages 67 thousand bbl/d in 2012 and 82 thousand bbl/d in 2013, with biodiesel blending meeting the Renewable Fuel Standard requirements of 1.0 billion gallons and 1.28 billion gallons, respectively, in those years.

U.S. Energy-Related Carbon Dioxide Emissions. After declining by 2.1 percent in 2011, fossil fuel emissions are projected to further decline by 2.9 percent in 2012. This decline is followed by an increase of 2.2 percent in 2013. Petroleum emissions fall by 1.5 percent in 2012 and grow by 0.2 percent in 2013. Projected natural gas emissions rise by 5.1 percent in 2012 and fall by

0.8 percent in 2013. Forecast coal emissions decline 10.1 percent in 2012, but are projected to rise by 7.2 percent in 2013 as rising natural gas prices lead to increases in coal-fired electricity generation.

Henry Hub Natural Gas Price

dollars per million btu



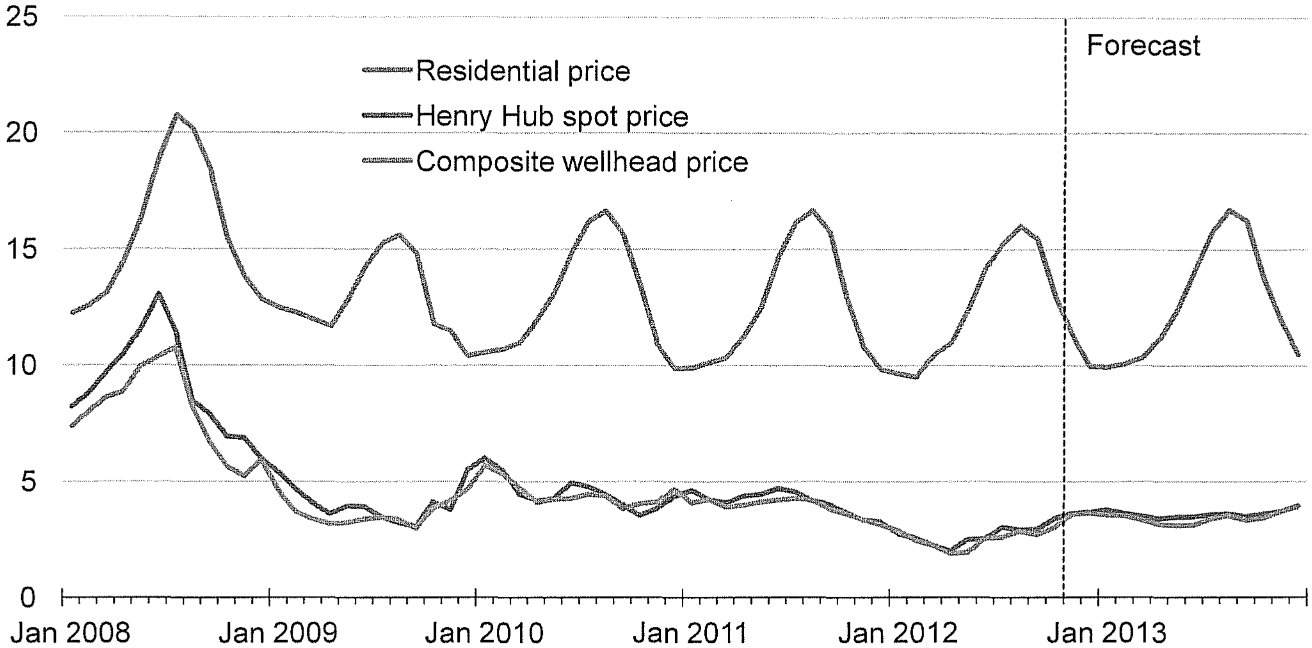
Note: Confidence interval derived from options market information for the 5 trading days ending November 1, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, November 2012

eia

U.S. Natural Gas Prices

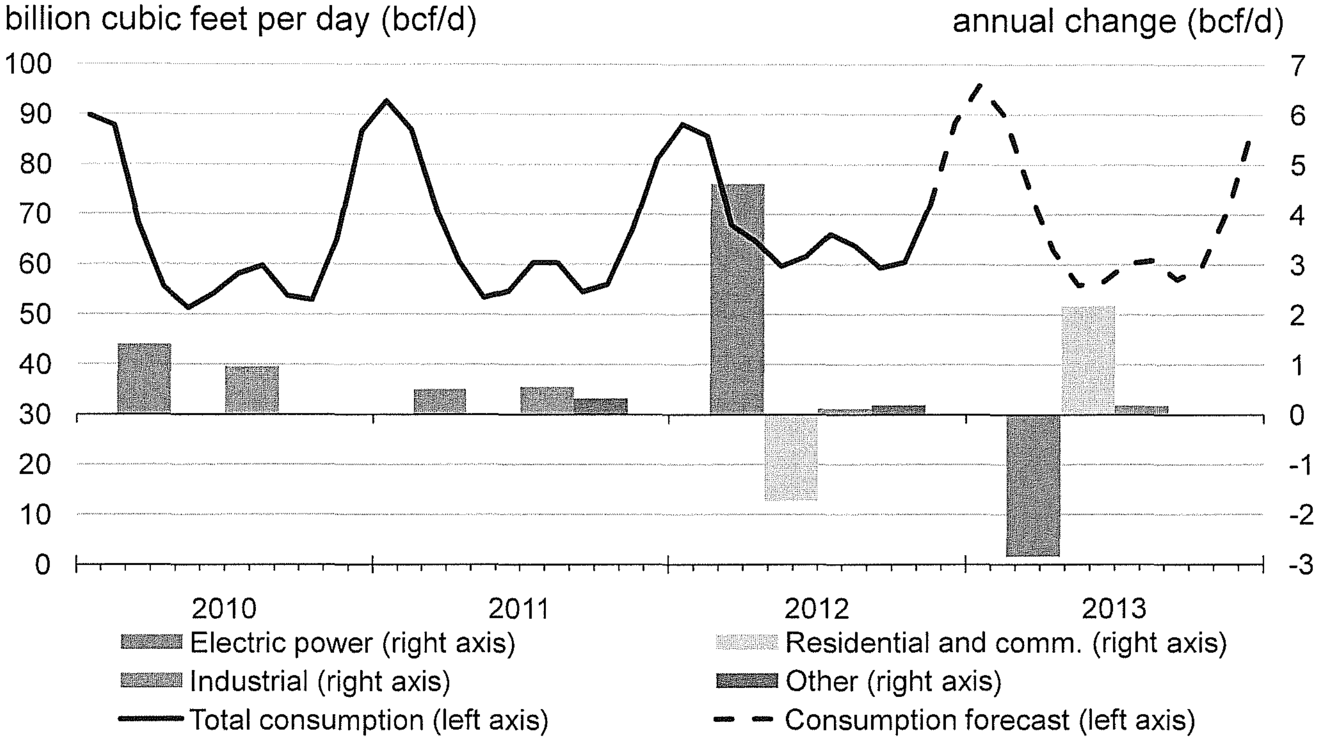
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, November 2012

eia

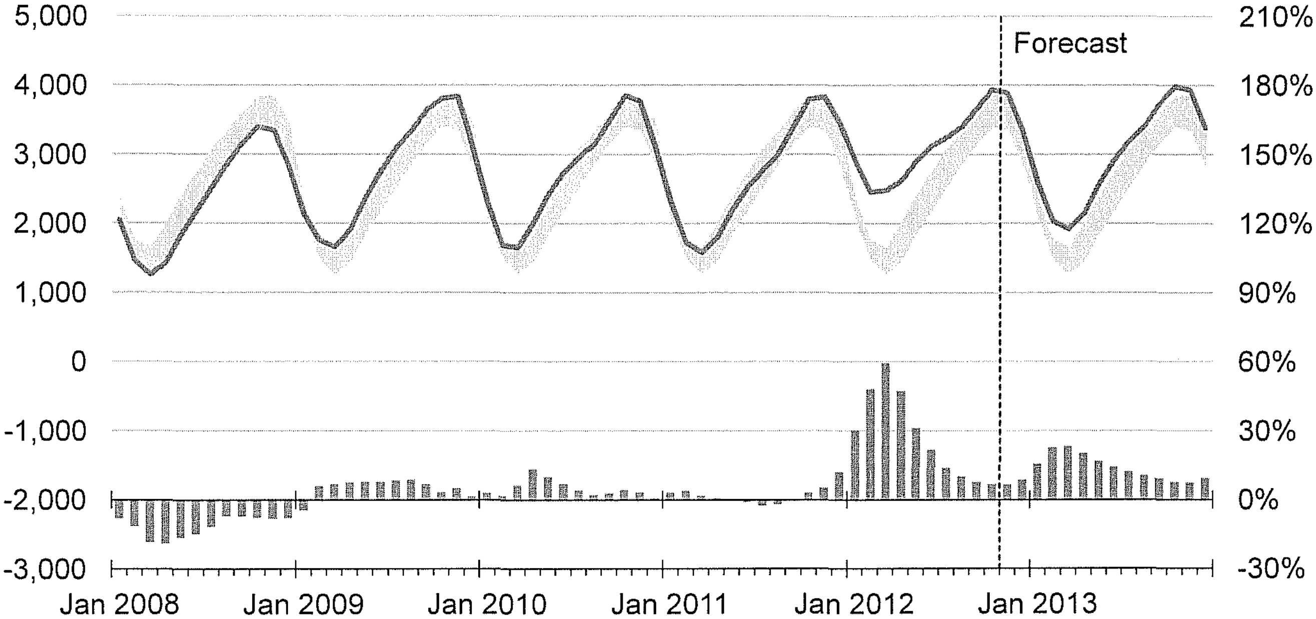
U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, November 2012

U.S. Working Natural Gas in Storage

billion cubic feet | deviation from average



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2007 - Dec. 2011.

Source: Short-Term Energy Outlook, November 2012

eia

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS TARIFF SHEET
NORTH DAKOTA GAS
EFFECTIVE DECEMBER 2012

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$4.756	$4.858	$3.708	$3.691
Prior Gas Cost	4.078	4.168	3.176	3.162
Current Gas Cost Adjustment	$0.678	$0.690	$0.532	$0.529
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	**$0.678**	**$0.690**	**$0.532**	**$0.529**
Gas Cost Level	$4.756	$4.858	$3.708	$3.691
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
Total Gas Cost Level in Tariff Rates	$4.643	$4.745	$3.593	$3.314

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE TARIFF SHEET
NORTH DAKOTA PROPANE
EFFECTIVE DECEMBER 2012

Cost of Gas - Propane	
Current Propane Cost (Exhibit D)	$10.429
Prior Propane Cost	9.331
Current Propane Cost Adjustment	$1.098
Surcharge Adjustment	
Current Adjustment	$0.646
Prior Adjustment	0.646
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	**$1.098**
Propane Cost Level	$10.429
Plus: Surcharge	0.646
Total Propane Cost Level in Rates	**$11.075**

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
RESIDENTIAL AND GENERAL SERVICE
EFFECTIVE DECEMBER 2012

	Amount
Total Gas Costs 1/	$67,253,571
Residential and General Service dk Requirements 2/	14,202,380
Average Cost of Gas per dk	$4.735
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.756
Less: Gas Cost Level in Rates 3/	4.078
Current Gas Cost Adjustment	**$0.678**

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, 2012, adjusted for losses at .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective November 1, 2012:

Cost of Purchased Gas	$4.060
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.078

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
OPTIONAL SEASONAL - RATE 72
EFFECTIVE DECEMBER 2012

Total Gas Costs 1/	$67,253,571
Less: Annual MDDQ Costs 1/	13,421,734
Total Gas Costs excluding MDDQ	$53,831,837
Firm Service Requirements 1/	14,202,380
Other Gas Costs per Dk (excluding MDDQ)	$3.790
Winter - October - May	
Annual MDDQ Costs 1/	$13,421,734
Winter Firm Service Requirements	12,836,012
MDDQ Costs per Winter Dk	$1.046
Add: Other Gas Costs per Dk	3.790
Winter Seasonal Rate	$4.836
Winter Seasonal Rate, adjusted for losses 2/	$4.858
Less: Gas Cost Level in Rates 3/	4.168
Current Gas Cost Adjustment	**$0.690**

1/ Exhibit B, page 1.
2/ Loss factor of .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective November 1, 2012:

	Winter
Cost of Purchased Gas	$4.149
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$4.168

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
INTERRUPTIBLE
EFFECTIVE DECEMBER 2012

	Amount
Total Gas Costs 1/	$12,930,296
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$3.691
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.708
Less: Gas Cost Level in Rates 2/	3.176
Current Gas Cost Adjustment	**$0.532**

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-12-008 effective November 1, 2012:

Cost of Purchased Gas	$3.162
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.176

MONTANA-DAKOTA UTILITIES CO.
CURRENT GAS COST ADJUSTMENT - NORTH DAKOTA
AIR FORCE INTERRUPTIBLE
EFFECTIVE DECEMBER 2012

	Amount
Total Gas Costs 1/	$3,248,497
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.691
Less: Gas Cost Level in Rates 2/	3.162
Current Gas Cost Adjustment	**$0.529**

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-12-008 effective November 1, 2012:
Cost of Purchased Gas $3.162

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
December 2012 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 1.932%, CONSISTING OF 2.209% FOR THE CURRENT PERCENTAGE AND (0.277%) 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 0.801 CENTS, CONSISTING OF 0.677 CENTS FOR THE CURRENT RATE AND 0.124 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 0.938%, CONSISTING OF 0.863% FOR THE CURRENT PERCENTAGE AND 0.075% 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 0.528 CENTS, CONSISTING OF 0.323 CENTS FOR THE CURRENT RATE AND 0.205 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.

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) $ 179.94/10^3m^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 $ 5.44/GJ FT-D Demand Rate for Group 2 Delivery Points [1] $ 2.39/GJ FT-D Demand Rate for Group 3 Delivery Points [2] $ 2.87/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 — 10.85 6-10 years — 9.07 15 years — 8.13 20 years — 7.22
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 — PT Rate — PT Gas Rate 9009-01001-1 — $ 660.00/d — 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. — Charge 2012302568 — $ 22.00 / month 2012302633 — $ 8.00 / month 2012302635 — $ 14.00 / month 2012302571 — $ 2.00 / month 2012302570 — $ 1.00 / month 2012302644 — $ 2,082.00 / month 2012302639 — $ 2.00 / month 2012302641 — $ 55.00 / month 2012302505 — $ 126.00 / month 2012302608 — $ 70.00 / month 2012302575 — $ 19.00 / month 2012302497 — $ 226.00 / month 2012302643 — $ 203.00 / month 2003004522 — $ 83,333.00 / month 2011476052 / 2011476054 — $ 0.0783 / 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

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	5.51	0.1986
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	2.39	0.0861
31110	ALLIANCE EDSON INTERCONNECT APN	2.39	0.0861
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	2.39	0.0861
3002	BOUNDARY LAKE BORDER	3.44	0.1242
1958	EMPRESS BORDER	5.30	0.1911
3886	GORDONDALE BORDER	3.44	0.1242
6404	MCNEILL BORDER	5.30	0.1911

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	2.39	0.0861	
31003	AGRIUM CARSELAND SALES APS	2.39	0.0861	
31002	AGRIUM FT. SASK SALES APN	2.39	0.0861	Yes
31004	AGRIUM REDWATER SALES APN	2.39	0.0861	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
3214	AKUINU RIVER WEST SALES	2.39	0.0861	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes[2]
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA	3.44	0.1242	
3059	ALLISON CREEK SALES	2.39	0.0861	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	2.39	0.0861	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	2.39	0.0861	
3216	AURORA NO 2 SALES	2.39	0.0861	
3135	AURORA SALES	2.39	0.0861	
3423	BASHAW WEST SALES	2.39	0.0861	
31013	BAYMAG SALES APS	2.39	0.0861	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	2.39	0.0861	
3933	BIG EDDY INTERCONNECTION	2.39	0.0861	
3067	BIGSTONE SALES	2.39	0.0861	
3468	BLEAK LAKE SALES	2.39	0.0861	
3225	BOTHA SALES	2.39	0.0861	
3164	BRAINARD LAKE SALES	2.39	0.0861	
3918	BUFFALO CREEK INTERCONNECTION	2.39	0.0861	
31015	BURDETT COGEN SALES APS	2.39	0.0861	
3204	CABIN SALES	2.39	0.0861	
3109	CALDWELL SALES	2.39	0.0861	
31016	CALGARY ENERGY CENTRE SALES APS	2.39	0.0861	Yes
3634	CANOE LAKE SALES	2.39	0.0861	
3165	CANOE LK SLS #2	2.39	0.0861	
3866	CARBON INTERCONNECTION	2.39	0.0861	
3484	CARIBOU LAKE SALES	2.39	0.0861	
3157	CARIBOU LK SOUTH SL	2.39	0.0861	
3106	CARMON CREEK SALES	2.39	0.0861	
3101	CAROLINE SALES	2.39	0.0861	
31017	CARSELAND COGEN SALES APS	2.39	0.0861	
3495	CAVALIER SALES	2.39	0.0861	
31018	CHAIN LAKES COOP SALES APS	2.39	0.0861	
3907	CHANCELLOR INTERCONNECTION	2.39	0.0861	
3151	CHEECHAM W. #2 SALES	2.39	0.0861	
3622	CHEECHAM WEST SALES	2.39	0.0861	
6014	CHEVRON AURORA SALES	2.39	0.0861	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes

NATURAL GAS TARIFF

NorthWestern Energy

	29th	Revised	Sheet No.	80.1
Canceling	28th	Revised	Sheet No.	80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	$ 100.20
10,001 to 30,000	$ 144.10
>30,000	$ 319.75

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	$ 0.8193411

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	$ 0.0062088	
Minimum	$ 0.0017935	
GTAC Amortization	$ (0.0010312)	(I)
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
Date Filed: January 24, 2001

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

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is $2.398 per dekatherm.

Issued By: Lisa A. Murphy, Vice President-Chief Financial Officer

NG00-001

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
Fourth Revised Sheet No. 12
Cancels Third 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 Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	$0.00	$0.1040	$0.0010	0.611%
	MLI	MLE	$145.00	$0.1040	$0.0010	0.611%
	MLI	DSE	$225.00	$0.1978	$0.0020	2.072%
Interruptible Transportation 4/	MLI	MLI	$0.00	$0.0844	$0.0010	0.611%
	MLI	MLE	$145.00	$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.

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: March 1, 2012
By: William N. Cantrell

Date Effective: June 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 DECEMBER 2012

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2012	$13,382,450	$586,918	$3,153,880
November	11,812,751	515,957	2,591,111
December	7,054,633	378,749	1,244,097
January 2013	4,195,679	277,781	(505,397)
February	2,728,161	225,953	(1,534,914)
March	2,380,543	213,677	(2,187,358)
April	2,364,142	213,098	(1,979,492)
May	2,907,357	237,643	(1,165,138)
June	3,987,942	286,474	(50,584)
July	5,422,328	351,286	1,115,082
August	8,060,992	470,636	2,263,333
September	10,031,412	559,689	3,164,043
October	10,874,675	597,785	3,426,623
13 month average	$6,554,082	$378,127	$733,484
Rate of Return	8.791%	8.791%	8.791%
Return	$576,169	$33,241	$64,481
Return Requirement	$785,703	$45,330	$87,931

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 2012

Cost of Purchased Propane	$66,447
Gallons Purchased	69,944
Projected dk Sales	6,400
Propane Cost per Dk	$10.382
Average Cost of Propane as Adjusted for Losses @ 99.55%	10.429
Less: Propane Cost Level in Rates 1/	9.331
Current Propane Cost Adjustment	$1.098

1/ Propane Cost Level in Current Rates - Case No. PU-12-008, effective November 1, 2012.

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)
Balance @ September 30, 2012									**($1,705,289)**

1/ Interest calculated at the 90 day Treasury Note rate.

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 2/	(13)	20,936	50,462	0.064	3,230	17,706	(129,808)
Balance @ September 30, 2012									**($129,808)**

1/ Interest calculated at the 90 day Treasury Note rate.

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)
Balance @ September 30, 2012									**($197,451)**

1/ Interest calculated at the 90 day Treasury Note rate.