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

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

October 10, 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 seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88.

Attachment A is the Rate Summary Sheet (109th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered November 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.290 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.

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 November 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.290 per dk for residential and firm general customers, an increase of $0.310 per dk for small and large interruptible customers and an increase of $0.309 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 November 2012. The average cost of gas for firm customers, adjusted for losses, is $4.078.

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.

20 PU-12-8 Filed 10/10/2012 Pages: 44
November 2012 cost of natural gas and propane
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

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 November 2012. The net effect of this filing is an increase of $2.194 per dk for all customers, including the change in the market based pricing differential credit 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 November 2012. The average cost of propane for all customers, adjusted for losses, is $9.331 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 $7,200 for propane customers during the month of November 2012. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 96,224 natural gas customers and 340 propane customers in North Dakota as of September 30, 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

NDPSC Volume 7
109th Revised Sheet No. 3
Canceling 108th 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	$3.955	$4.767
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$3.955	$4.093
Interruptible Service - PAR			$0.120	$3.061	$3.181
Interruptible Service - MAFB			$0.120	$2.785	$2.905
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	$3.955	$4.552
Small Interruptible Gas Rate 71	14	$100.00 per month	(Maximum) $0.871	$3.061	(Maximum) $3.932
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	$4.045	$4.642
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.014	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.014	
Large Interruptible Gas Rate 85	27	$675.00 per month	(Maximum) $0.719	$3.061	(Maximum) $3.780
Residential Propane Rate 90	32	$0.30 per day	$0.812	$9.967	$10.779
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	$9.967	$10.564

Date Filed: October 10, 2012 **Effective Date:**

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

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

November 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 upcoming anticipated higher winter demand combined with the national supply and demand coming more into balance. The level of natural gas in storage remains above average. The Energy Information Administration (EIA) reported storage levels nationwide as of September 28, 2012 to be 8.3 percent above the five-year average and 8.0 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 October Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 4 through 18.

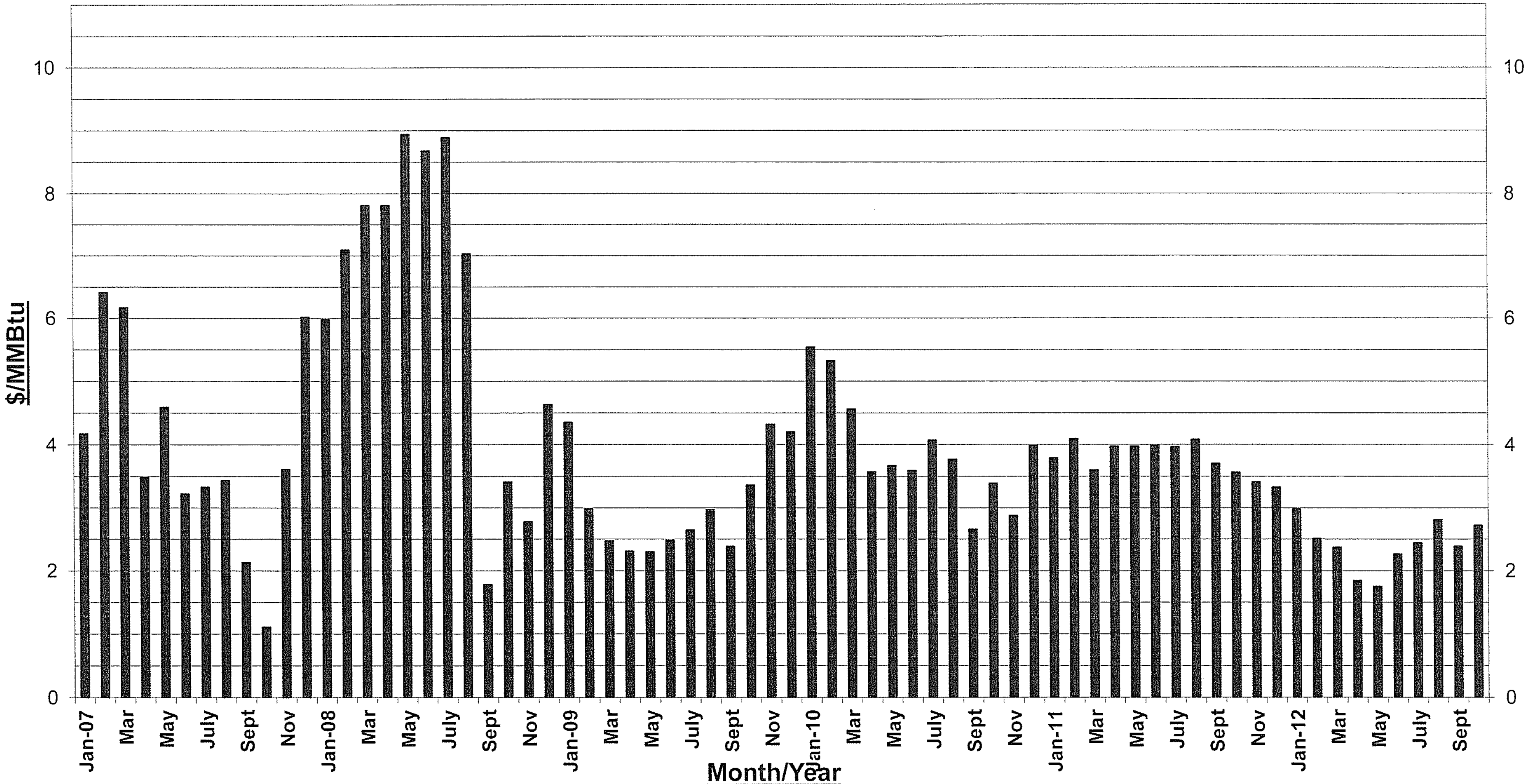
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
November 2012

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 November prices for propane have increased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage increases, this has resulted in a increase in the price of propane.

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

CIG Rocky Mountains Index
Monthly Gas Prices 2007-2012YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2010-$3.92; 2011-$3.79; 2012YTD - $2.41

Independent Statistics & Analysis
U.S. Energy Information Administration

October 2012

Short-Term Energy and Winter Fuels Outlook

- EIA projects average household expenditures for heating oil and natural gas will increase by 19 percent and 15 percent, respectively, this winter (October 1 through March 31) compared with last winter. Projected household expenditures are 5 percent higher for electricity and 13 percent higher for propane this winter. Average expenditures for households that heat with heating oil are forecast to be higher than any previous winter on record (see EIA *Short-Term Energy and Winter Fuels Outlook* slideshow).

- The forecast for higher household expenditures primarily reflects a return to roughly normal winter temperatures east of the Rocky Mountains compared with last winter's unusual warmth. According to the National Oceanic and Atmospheric Administration's (NOAA) most recent projection of heating degree days, the Northeast, Midwest, and South will be about 2 percent warmer than the 30-year average (1971 – 2000), but still 20 percent to 27 percent colder than last winter, while the West is projected to be only about 1 percent colder than last winter.

- Projected residential heating oil prices average 2 percent higher and natural gas prices 1 percent higher this winter. Winter average electricity and propane prices average about 2 percent and 4 percent lower than last winter, respectively.

- 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 6.9 million bbl/d in 2013, the highest level of production since 1993.

- Forecast U.S. real gross domestic product (GDP) grows by 2.2 percent this year and by 1.7 percent next year. Projected world oil-consumption-weighted real GDP grows by 2.7 percent and 2.5 percent in 2012 and 2013, respectively, similar to last month's *Outlook*. EIA expects Brent crude oil prices to fall from recent highs over the rest of 2012, averaging $111 per barrel over the fourth quarter of 2012 and $103 per barrel in 2013. EIA expects WTI spot prices to average $93 per barrel in 2013, with the WTI discount to Brent narrowing to $9 per barrel by the end of 2013.

- Natural gas working inventories ended September 2012 at an estimated 3.7 trillion cubic feet (Tcf), about 8 percent above the same time last year. EIA expects the Henry Hub natural gas spot price, which averaged $4.00 per million British thermal units (MMBtu) in 2011, to average $2.71 per MMBtu in 2012 and $3.35 per MMBtu in 2013.

Projected Winter Fuel Expenditures by Fuel and Region

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

Natural Gas. About one-half of U.S. households use natural gas as their primary heating fuel. EIA expects households heating with natural gas to spend an average of $89 (15 percent) more this winter than last winter. The increase in natural gas expenditures represents less than a 1-percent increase in the average U.S. residential price from last winter and a 14-percent increase in consumption. The expected increase in consumption is the result of the forecast of near-normal temperatures this winter, in contrast to the unusually warm winter of 2011-12. The projected changes in residential natural gas prices this winter range from a 3-percent decline in the South to a 4-percent increase in the Northeast. Price changes vary across regions because of a number of factors such as regional changes in production, pipeline supply capacity, and differences in regulatory constraints in passing price changes through to customers.

Heating Oil. EIA expects households heating primarily with heating oil to spend an average of about $407 (19 percent) more this winter than last winter as a result of a 2-percent increase in prices and a 17-percent increase in consumption. About 6 percent of U.S. households depend on heating oil for space heating; however, the Northeast accounts for about 80 percent of these households. Low distillate stocks in the East Coast and Gulf Coast states, which provide over 60 percent of the Northeast's distillate supply, and the state of New York's switchover from higher sulfur heating oil to fuel with less than 15 parts per million sulfur, all contribute to an expected tighter market this winter.

Propane. About 5 percent of total U.S. households heat with propane. EIA expects households heating primarily with propane to spend more this winter, but that increase varies across regions. EIA expects that households in the Midwest will see an average increase in both propane consumption and winter propane expenditures of 17 percent and 11 percent, respectively, with residential propane prices 5 percent lower than last winter. With consumption projected to increase by 16 percent over last winter in the Northeast, households there may see an increase in expenditures of 15 percent with prices lower by an average 1 percent.

Electricity. Households heating primarily with electricity can expect to spend an average of $49 (5 percent) more this winter because of forecasted colder weather despite a projected 2-

percent decrease in prices. About 38 percent of all U.S. households rely on electricity as their primary heating fuel, ranging from 14 percent in the Northeast to 62 percent in the South.

Wood. Wood consumption in homes has risen over the past 10 years, reversing a trend seen in the last two decades of the 20th century. In 2009, U.S. households consumed about 0.5 quadrillion Btu (quads) of wood. Household fuel oil consumption, by comparison, was only slightly higher at 0.6 quads. In homes across the United States, wood is most commonly used as a secondary source of heat and is second only to electricity as a supplemental heating fuel. Twenty percent of New England homes (1.1 million) used wood for space heating, water heating, or cooking in 2009 (EIA, Residential Energy Consumption Survey, 2009). This is nearly twice the national rate. Almost half of all rural households used wood in this area of the country. In contrast, only 12 percent of urban New England households used the fuel.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects the oil market to loosen in the fourth quarter of 2012, as global liquid fuels consumption falls from its seasonal peak and output from countries outside of the Organization of the Petroleum Exporting Countries (OPEC) recovers from unplanned outages and scheduled maintenance. Persistent unplanned production outages in non-OPEC countries helped keep the spot price for Brent crude oil near $110 per barrel in the third quarter of 2012. EIA forecasts that Brent crude, a benchmark for the global oil price, will average $111 per barrel for the fourth quarter of 2012. In 2013, EIA projects the Brent crude price to fall to an average of $103 per barrel, although a lingering supply risk because of instability in the Middle East and North Africa could keep prices higher. EIA also expects global inventory builds in the first half of 2013 to reach higher levels relative to the same period in 2012, mostly due to an increase in non-OPEC supply.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 1.1 million bbl/d in 2011. EIA expects consumption growth of about 0.8 million bbl/d in 2012 and 0.9 million bbl/d in 2013, with China, the Middle East, Central and South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for essentially all consumption growth. However, forecast consumption falls by 0.5 million bbl/d during the fourth quarters of 2012, following the end of the global seasonal demand peak in the third quarter.

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. Although EIA forecasts U.S. liquid fuels consumption to grow by 0.1 million bbl/d in 2013, this is more than offset by declines in consumption in Europe and other OECD countries. One possible exception is Japan, where only a handful of nuclear facilities, at best, will be brought back online in 2013, which could cause its oil consumption to remain relatively resilient through the forecast period.

China has been experiencing a slowing of its economic growth rate. EIA's forecast for China's oil consumption growth remains at lower levels than the country experienced in previous years. EIA projects China's liquid fuels consumption to rise by 3.6 percent (355 thousand bbl/d) in 2012, the lowest rate of annual growth since 2001, and by 400 thousand bbl/d in 2013.

Non-OPEC Supply. EIA expects non-OPEC liquid fuels production to rise by 570 thousand bbl/d in 2012, and by a further 1.2 million bbl/d in 2013. The largest area of non-OPEC growth is North America, where production increases by 1.0 million bbl/d and 670 thousand bbl/d in 2012 and 2013, respectively, due to continued production growth from U.S. onshore shale and other tight oil formations and from Canadian oil sands.

Some large non-OPEC producers continue to undergo planned maintenance that traditionally takes place during this time of the year. Kazakhstan's crude and condensate production was down by about 160 thousand bbl/d in September 2012 because of planned maintenance at Tengiz. The field is slowly returning to normal operations. In the North Sea the Buzzard, Elgin, and Franklin fields are currently out for maintenance. Buzzard is expected to return to full production at the end of October. Total announced that Elgin and Franklin maintenance will be extended through December. Maintenance in Norway's fields reduced output by more than 20 thousand bbl/d in September 2012. This was mainly due to maintenance at the Troll field, but also includes smaller volumes from other fields, such as Gullfaks and Ekofisk.

Unplanned outages and disruptions to non-OPEC production increased in August and September, averaging around 1.1 million bbl/d. Hurricane Isaac contributed to production shut-ins in the Gulf of Mexico averaging about 210 thousand bbl/d in both August and September.

EIA has made slight adjustments in its forecasts for Colombia and Brazil, the two leading sources of non-OPEC supply in South America, due in part to lower output in recent months. In Colombia, anti-government rebels had intensified the frequency and severity of their attacks on the Caño Limón pipeline and other oil infrastructure, which contributed to an estimated decline in August production relative to the previous month and year-ago levels. However, security threats have abated in anticipation of peace talks and Colombian oil production is estimated to have partially recovered in September, which has led to renewed optimism that the country can resume its production gains. Brazilian liquid fuels production has also consistently failed to meet expectations in recent months due to persistent maintenance-related shutdowns, larger-than-expected field declines, the impacts of a relatively poor sugarcane harvest on ethanol production, and the continued outage at the Chevron-operated Frade field. Unless output is quickly restored, Brazilian liquids production is likely to decline on a year-to-year basis.

Sudan and South Sudan signed a series of agreements to settle their dispute and restart oil production in the South, eight months after South Sudan halted its crude oil exports via pipelines through Sudan and shut in all production. Sudan and South Sudan had already reached an understanding on oil transit fees, but the resumption of production was contingent on a broader deal on border security. The two countries have now signed an agreement on security arrangements; however, some post-independence issues such as border demarcation, rights to the disputed Abyei region, and Sudan's claim for compensation of Sudapet's assets that went to South Sudan remain unresolved. Nonetheless, South Sudan expects to restart production and exports before the end of this year, but has previously cautioned it could take four to six months to bring output back to full volumes, possibly longer for areas damaged during military clashes.

Forecasting South Sudan's oil restart and the pace of the ramp-up remains a challenge given uncertainties include: the extent of damage to infrastructure at fields within the Greater Nile Oil Project; the ability for some mature fields that were previously declining in output to reach pre-shut-in levels; the extent to which the shut-in left any permanent irreversible damage that could compromise future output; how quickly export pipelines will be flushed out; and any other mechanical issues that may arise during the restart. EIA does not expect South Sudan's production to return to pre-shut-in levels in the forecast period.

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 remains mostly flat in 2013. OPEC non-crude oil liquids (condensates, natural gas liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, averaged 5.3 million bbl/d in 2011 and are forecast to increase by 0.3 million bbl/d in 2012 and by 0.2 million bbl/d in 2013.

EIA estimates that Iran's crude oil production declined by 50 thousand bbl/d in September 2012, following a 100-thousand-bbl/d decline the month before. EIA expects Iran's crude oil production to fall by about 1 million bbl/d by the end of 2012, relative to an estimated output level of 3.6 million bbl/d at the end of 2011. The decline in Iran's crude oil production capacity will continue due to the country's inability to carry out investment projects that are necessary to offset the natural decline in production from existing wells.

It is difficult to differentiate between the effects of the latest round of sanctions on Iran and those enacted in previous years when assessing impacts on Iranian oil production. While countries in the European Union appear to have ceased imports of Iranian crude oil, the reinsurance ban affected Iran's ability to sell its crude to some of its largest customers in Asia, including Japan and South Korea. Most of Iran's crude oil customers have been able to replace insurance coverage, once provided by European protection and indemnity (P&I) clubs, over the last two months, although preliminary data show a very small increase in imports of Iranian crude oil by those customers in August. EIA bases this assessment on preliminary commercial data on tanker liftings from Iran, press reports, official Iranian statements, and other relevant information. This tentative interpretation of a very fluid situation could change as data are revised and more details emerge.

The attacks on American personnel in Benghazi, Libya, serve as a tragic reminder that insecurity continues to plague the country, including some areas in which oil infrastructure is concentrated. Though Libya has continued to maintain production at relatively high levels and recently restarted its largest refinery, it poses a downside risk to the supply forecast given the possibility of future disruption.

World oil surplus production capacity is almost entirely concentrated in one country: Saudi Arabia. With Saudi Arabian oil production at or near 10 million bbl/d for much of 2012, global surplus production capacity has been in the neighborhood of 2 million bbl/d during this time.

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 2.64 billion barrels and 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 last 7 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 $93 per barrel in the second half of 2012 and largely remain at this level throughout the forecast period. After increasing to as high as $19 per barrel in August and September of this year, EIA expects that the WTI crude oil spot price discount to the Brent crude oil spot price will average $17 per barrel in the fourth quarter of 2012 before falling to $9 per barrel by the end of 2013.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for January 2013 delivery during the five-day period ending October 4, 2012, averaged $92.09 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 January 2013 at $70 per barrel and $121 per barrel, respectively. Last year at this time, WTI for January 2012 delivery averaged $79 per barrel and implied volatility averaged 50 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $51 per barrel and $123 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 280 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 110-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.

Despite higher assumed growth in U.S. real disposable income and projected declines in retail gasoline pump prices of 6 percent in 2013, forecast motor gasoline consumption remains almost unchanged from that of the previous year 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 180 thousand bbl/d (3.2 percent) to 5.7 million bbl/d in 2011. Forecast crude oil production increases to 6.3 million bbl/d in 2012 with lower-48 (excluding the federal Gulf of Mexico) crude oil production growing by 780 thousand bbl/d, primarily from the Bakken, Permian basin, and Eagle Ford producing areas. Hurricane Isaac in the Gulf of Mexico led to U.S. crude oil production shut-ins averaging 220 thousand bbl/d in August and 200 thousand bbl/d in September. Total crude oil output rises a further 530 thousand bbl/d in 2013. The number of onshore 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 1,398 as of October 5, 2012.

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. After a sharp increase in retail gasoline prices earlier this year, the monthly average price for regular grade gasoline reached $3.90 per gallon in April 2012. Prices then fell for three consecutive months, averaging $3.44 per gallon in July. Rising crude prices contributed to a second run-up in regular gasoline retail prices to an average of $3.85 per gallon in September 2012. EIA expects retail gasoline prices to begin declining in October as the gasoline market transitions from summer-grade to winter-grade gasoline specifications and forecast crude oil prices begin to fall. Projected regular gasoline retail prices average $3.60 per gallon during the fourth quarter of 2012, up slightly from $3.58 per gallon projected in last month's *Outlook*. Projected regular gasoline retail prices average $3.65 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 in March, then fell to a low of $3.72 in July. Tight market conditions and increasing crude oil prices drove on-highway diesel fuel prices back near monthly highs for the year average $4.12 per gallon in September. EIA expects that on-highway diesel fuel retail prices will average $3.98 per gallon during the fourth quarter of this year and $3.81 per gallon in 2013. Wholesale diesel margins (the difference between the wholesale price of diesel and the refiner acquisition cost of crude oil) averaged 60 cents per gallon the first half of 2012 before climbing to an estimated 85 cents per gallon in September, the highest level since May 2008. In 2012, EIA projects those margins will average 68 cents per gallon in 2012 and 63 cents per gallon in 2013, compared with the previous 5-year average of 52 cents per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.8 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.1 Bcf/d (4.7 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 improved relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector during 2012 was 35.1 Bcf/d in July 2012, when electricity demand for air conditioning was highest.

Projected total natural gas consumption decreases by 0.2 Bcf/d (0.2 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 (i.e., colder than last year's abnormally warm winter) drives 2013 increases in residential and commercial consumption of 11.5 percent and 10.3 percent, respectively. Although projected higher natural gas prices contribute to a 10.4-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 1.9 Bcf/d higher than 2011 levels and high by historical standards.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by 4.8 Bcf/d (7.9 percent) in 2011. This strong growth was driven in large part by increases in shale gas production. So far during 2012, production has fluctuated with small ups and downs, 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 437 as of October 4, 2012, compared with 811 at the start of 2012. EIA forecasts that total marketed production growth will slow to 2.6 Bcf/d in 2012 and 0.4 Bcf/d in 2013, as the reduction in drilling activity is offset by growth in production from liquids-rich natural gas production areas such as the Eagle Ford and wet areas of the Marcellus Shale, and associated gas from the growth in domestic crude oil production.

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.3 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 little change 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 about 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.

U.S. Natural Gas Inventories. Working natural gas inventories remain at historically high levels for this time of year. As of September 28, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 3,653 Bcf, which is 272 Bcf greater than last year's level and 281 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will set a record high of 3,903 Bcf. Because of very high inventories at the start of the summer injection season this year, working inventories have remained high and 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 1,426 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 1987.

U.S. Natural Gas Prices. Natural gas spot prices averaged $2.85 per MMBtu at the Henry Hub in September 2012, up $0.01 per MMBtu from the August average and $1.05 per MMBtu (27 percent) lower than the September 2011 average. While abundant supplies have kept prices relatively low, a hot summer and associated increases in demand for natural gas for power generation contributed to Henry Hub spot price increases this summer, from the monthly average low of $1.95 per MMBtu in April 2012. EIA expects the Henry Hub natural gas price will average $2.71 per MMBtu in 2012 and $3.35 per MMBtu in 2013.

Natural gas futures prices for January 2013 delivery (for the five-day period ending October 4, 2012) averaged $3.84 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for January 2013 contracts at $2.77 per MMBtu and $5.31 per MMBtu, respectively. At this time last year, the January 2012 natural gas futures contract averaged $4.10 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $3.10 per MMBtu and $5.40 per MMBtu.

Coal

U.S. Coal Supply. EIA forecasts that coal production will decline by 6 percent in 2012 as domestic consumption falls. EIA expects that production will total 1,027 million short tons (MMst) in 2012, 68 MMst below the 2011 total. EIA expects production to fall by 1 percent (12 MMst) 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 187 MMst at the end of the 2012. Inventories are expected to decline slightly in 2013, but they will remain at elevated levels.

U.S. Coal Trade. EIA expects U.S. coal exports to remain strong in 2012 and exceed the 107 MMst exported in 2011. The United States exported 11.6 MMst of coal in July, the fifth consecutive month with exports exceeding 11 MMst. 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. Falling international coal prices and slower economic growth, particularly in China, 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 exports averaged 56 MMst in the decade preceding 2011.

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 $2.40 per MMBtu (a 6-percent increase from 2010). However, EIA expects the decline in demand for coal, combined with large coal inventories, will begin to put downward pressure on 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 $2.42 per MMBtu in 2013.

Electricity

U.S. Electricity Consumption. During this past winter, U.S. heating degree days during the fourth quarter of 2011 and the first quarter of 2012 totaled 18 percent below the 30-year normal. Temperatures this winter are expected to be colder than last winter. In particular, projected heating degree days in the southern states, where a majority of homes heat with electricity, are 27 percent higher than last winter. As a result of the colder weather, EIA projects retail sales of electricity to the residential sector this winter will average 6.2 percent more than retail sales last winter.

U.S. Electricity Generation. Natural gas prices have risen steadily since this past spring. In September, the Henry Hub price averaged $2.85 per million Btu, which was 46 percent higher than the average in April. With higher natural gas prices EIA expects natural gas to lose some of its recent gains in electricity generation market share. The share of total generation fueled by natural gas in the fourth quarter of 2012 is projected to average 27.8 percent compared with 25.4 percent during the same period last year. By the beginning of 2013, higher natural gas prices should contribute to year-over-year declines in natural gas's share of total generation. EIA expects natural gas to fuel 25.8 percent of generation during the first quarter of 2013, which is 2.8 percentage points lower than during the first quarter of 2012.

U.S. Electricity Retail Prices. EIA expects the nominal U.S. residential electricity price will rise by 0.4 percent during 2012 to an average of 11.84 cents per kilowatthour. During 2013, U.S. residential retail electricity prices increase 1.3 percent over the average 2012 price. When measured in real terms, the U.S. residential electricity price declines by 1.7 percent in 2012 and by 0.3 percent in 2013.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 13.9 percent in 2011, total renewable energy consumption is projected to decline by 2.3 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 2.4 percent in 2013 as hydropower continues to decline (2.3 percent) but non-hydropower renewables grow by an average of 4.8 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 26 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.

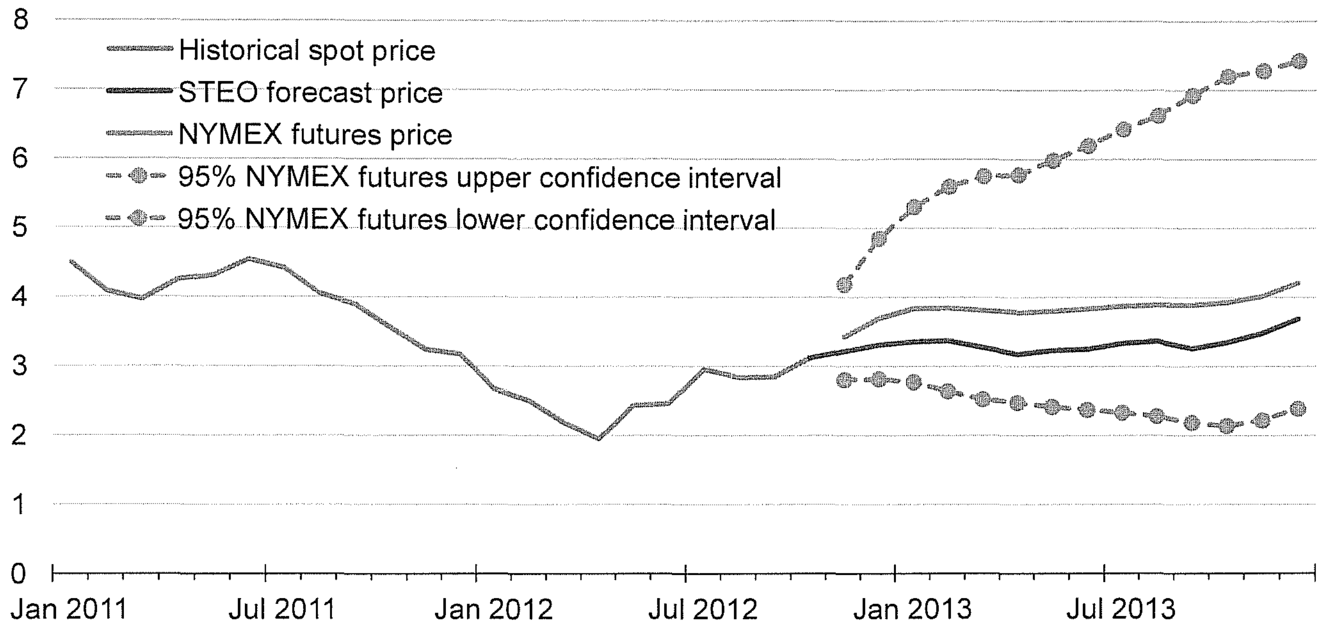
As a result of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 890 thousand bbl/d during the second quarter of 2012 to an average of 820 thousand bbl/d in the third quarter 2012. EIA expects ethanol production will remain near current levels through the first half of 2013 and recover in the second half of 2013, averaging 850 thousand bbl/d (13.03 billion gallons) for the year. The projected lower ethanol production is generally matched by 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 83 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 2.3 percent in 2011, fossil fuel emissions are projected to further decline by 2.7 percent in 2012. This decline is followed by an increase of 1.9 percent in 2013. Petroleum emissions fall by 1.4 percent in 2012 and grow 0.2 percent in 2013. Natural gas emissions rise by 5.2 percent in 2012 and fall by 0.4 percent in 2013. Coal emissions decline 9.7 percent in 2012, but are projected to rise by 6.0 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

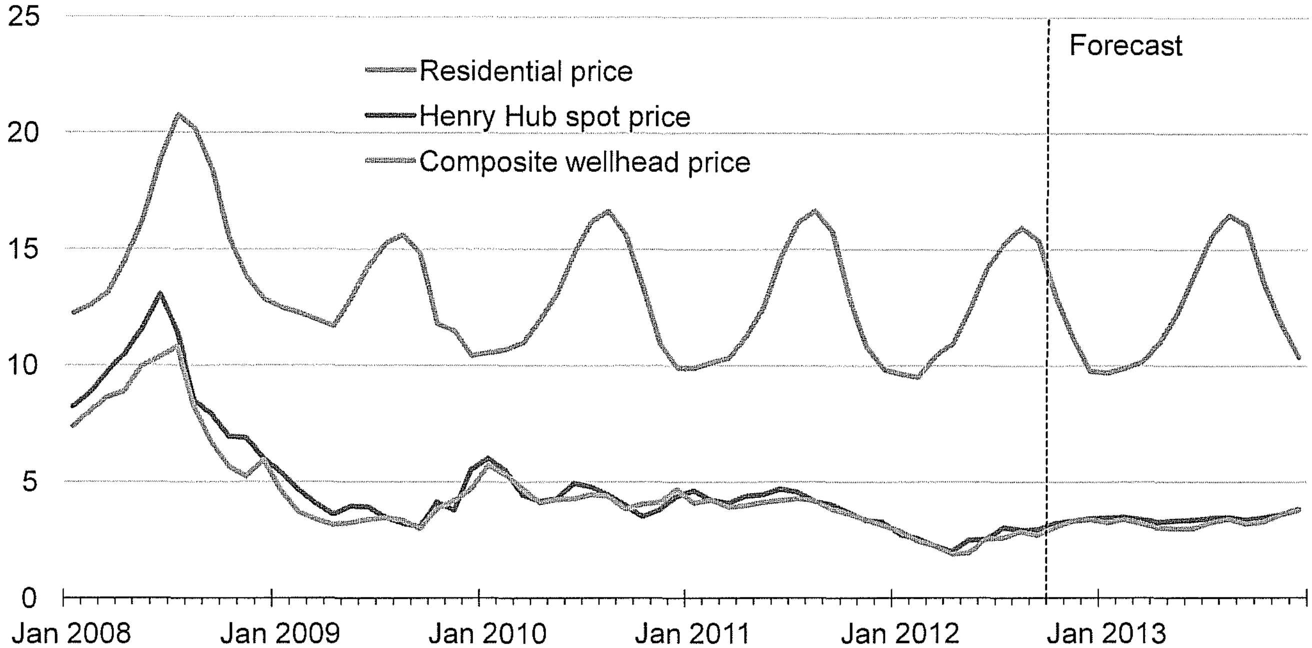


Note: Confidence interval derived from options market information for the 5 trading days ending October 4, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, October 2012

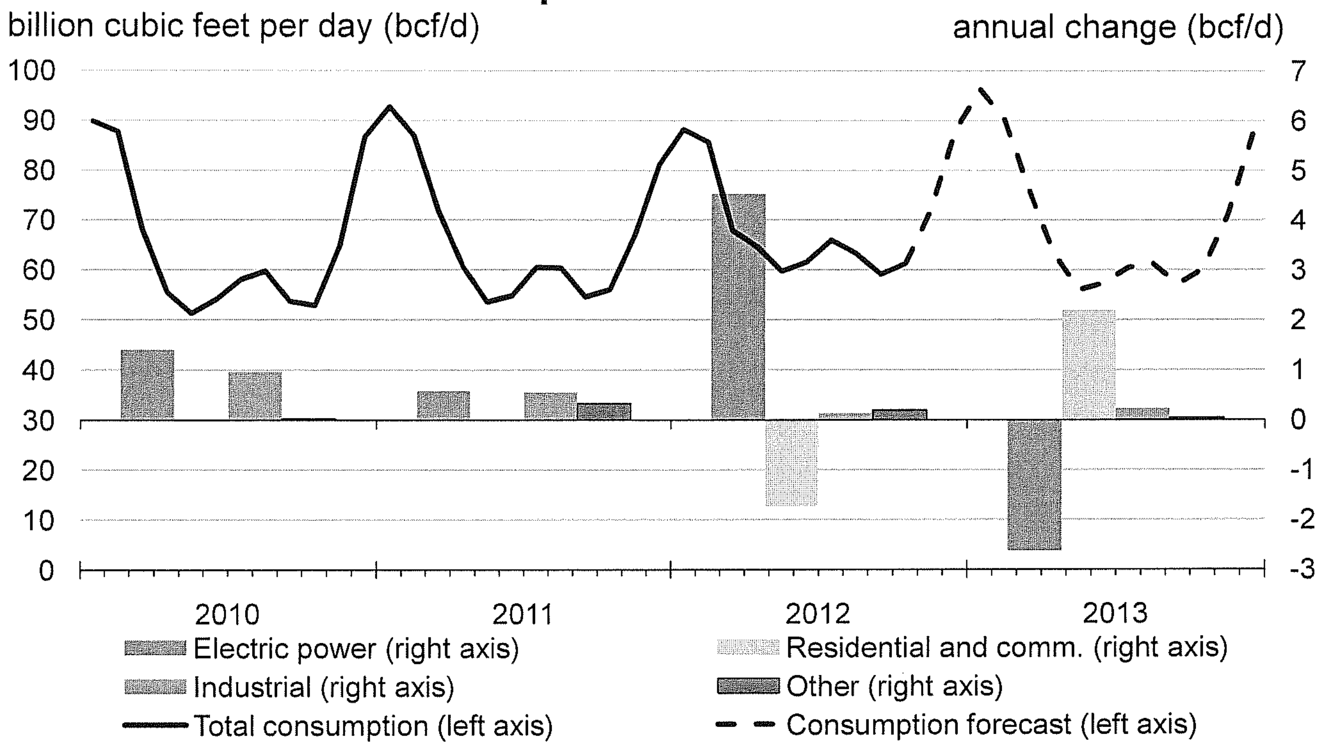
U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, October 2012

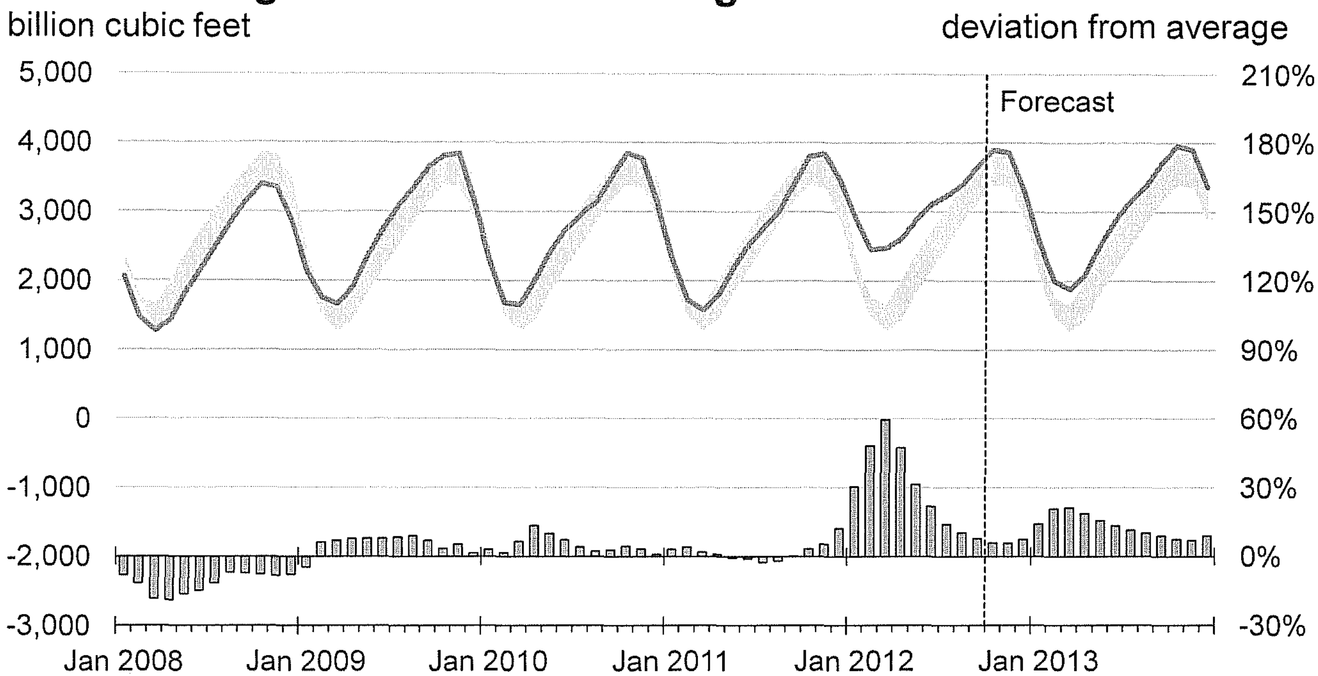
U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, October 2012

eia

U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, October 2012

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$4.078	$4.168	$3.176	$3.162
Prior Gas Cost	3.788	3.877	2.866	2.853
Current Gas Cost Adjustment	$0.290	$0.291	$0.310	$0.309
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	**$0.290**	**$0.291**	**$0.310**	**$0.309**
Gas Cost Level	$4.078	$4.168	$3.176	$3.162
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
Total Gas Cost Level in Tariff Rates	$3.965	$4.055	$3.061	$2.785

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

Cost of Gas - Propane	
Current Propane Cost (Exhibit D)	$9.331
Prior Propane Cost	7.136
Current Propane Cost Adjustment	$2.195
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	(0.009)
Change in Margin Sharing Provision	($0.001)
Net Increase (Decrease) in Gas Costs	**$2.194**
Propane Cost Level	$9.331
Plus: Surcharge	0.646
Total Propane Cost Level in Rates	**$9.977**

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

	Amount
Total Gas Costs 1/	$57,563,509
Residential and General Service dk Requirements 2/	14,178,595
Average Cost of Gas per dk	$4.060
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.078
Less: Gas Cost Level in Rates 3/	3.788
Current Gas Cost Adjustment	**$0.290**

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 August 31, 2012, adjusted for losses at .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective October 1, 2012:

Cost of Purchased Gas	$3.771
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.788

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

Total Gas Costs 1/	$57,563,509
Less: Annual MDDQ Costs 1/	11,821,667
Total Gas Costs excluding MDDQ	$45,741,842
Firm Service Requirements 1/	14,178,595
Other Gas Costs per Dk (excluding MDDQ)	$3.226
Winter - October - May	
Annual MDDQ Costs 1/	$11,821,667
Winter Firm Service Requirements	12,814,515
MDDQ Costs per Winter Dk	$0.923
Add: Other Gas Costs per Dk	3.226
Winter Seasonal Rate	$4.149
Winter Seasonal Rate, adjusted for losses 2/	$4.168
Less: Gas Cost Level in Rates 3/	3.877
Current Gas Cost Adjustment	**$0.291**

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

	Winter
Cost of Purchased Gas	$3.860
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.877

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

	Amount
Total Gas Costs 1/	$11,076,781
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$3.162
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.176
Less: Gas Cost Level in Rates 2/	2.866
Current Gas Cost Adjustment	**$0.310**

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 October 1, 2012:

Cost of Purchased Gas	$2.853
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$2.866

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

	Amount
Total Gas Costs 1/	$2,782,835
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.162
Less: Gas Cost Level in Rates 2/	2.853
Current Gas Cost Adjustment	**$0.309**

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 October 1, 2012:

Cost of Purchased Gas	$2.853

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
November 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 NOVEMBER 2012

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2012	$12,383,415	$603,139	$3,101,013
November	11,160,242	541,892	2,555,212
December	7,721,798	421,561	1,291,938
January 2013	3,776,079	269,270	(329,884)
February	1,193,590	169,595	(1,295,172)
March	95,434	127,211	(1,916,615)
April	66,747	126,102	(1,753,557)
May	581,759	150,894	(1,037,453)
June	2,046,858	221,398	(47,610)
July	4,629,598	345,795	994,681
August	7,413,038	479,884	2,021,401
September	9,551,847	582,875	2,826,790
October	10,612,142	633,926	3,061,612
13 month average	$5,479,427	$359,503	$728,643
Rate of Return	8.791%	8.791%	8.791%
Return	$481,696	$31,604	$64,055
Return Requirement	$656,873	$43,097	$87,350

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 NOVEMBER 2012

Cost of Purchased Propane	$30,655
Gallons Purchased	36,065
Projected dk Sales	3,300
Propane Cost per Dk	$9.289
Average Cost of Propane as Adjusted for Losses @ 99.55%	9.331
Less: Propane Cost Level in Rates 1/	7.136
Current Propane Cost Adjustment	$2.195

1/ Propane Cost Level in Current Rates - Case No. PU-12-008, effective September 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)
Balance @ August 31, 2012									**($1,779,498)**

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)
Balance @ August 31, 2012									**($147,514)**

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)
Balance @ August 31, 2012									**($199,588)**

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