

September 10, 2012

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

Re: Cost of Gas Adjustment  
(COG) Rate 88 and Rate 99  
Case No. PU-12-\_\_\_\_

In accordance with North Dakota Century Code Section 49-05-05, Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., respectfully submits an original and seven (7) copies of a Cost of Gas (COG) change pursuant to the terms of Rates 88 and 99.

Attachment A is the Rate Summary Sheet (108<sup>th</sup> Revised Sheet No. 3) showing the proposed natural gas and propane rates, to be effective with service rendered October 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has decreased \$0.428 per dk since the last filing due to a decrease in the overall market price of gas. Attachment B explains the reasons for the decrease in the market price of gas. There has also been a change in pipeline rates, as shown on Attachment C, increasing the cost of gas by \$0.008 per dk. In addition, this filing reflects the annual change in the surcharge adjustment, which is a decrease of \$0.081 per dk for residential and firm general service customers. The market based pricing differential credit increased by \$0.001 per dk resulting in a decrease of \$0.502 per dk for residential and firm general customers.

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 October 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is a decrease of \$0.502 per dk for residential and firm general service customers, a decrease of \$0.597 per dk for small and large interruptible customers and a decrease of \$0.834 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 October 2012. The average cost of gas for firm customers, adjusted for losses, is \$3.788.

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.

Exhibit D shows the calculation of the surcharge adjustment that will apply during the period October 1, 2012 through September 30, 2013. The total surcharge is a negative \$0.113 per dk for residential and general service customers, a negative \$0.115 per dk for small and large interruptible customers and a negative \$0.377 per dk for the Air Force, or a decrease of \$0.081 per dk for residential and general service customers, a decrease of \$0.179 per dk for small and large interruptible customers and a decrease of \$0.418 per dk for the Air Force from the adjustment effective October 1, 2011.

Exhibit E shows the calculation of the interruptible market based pricing differential pursuant to the terms of Rate 88. Fifty percent of the non-gas commodity revenues received from small and large interruptible sales in excess of the authorized level are credited to residential and firm general service customers through the COG. A credit of \$0.010 per dk will be applicable to all residential and general service customers for the period October 1, 2012 through September 30, 2013. This reflects a decrease of \$0.001 per dk to customers from the current adjustment.

Montana-Dakota will not seek a Cost of Gas – Propane (COG) adjustment change for the month of October 2012. The Purchased Propane Cost Adjustment tariff (Rate 99), Section 2(b) provides that "Montana-Dakota shall file an adjustment to reflect changes in its average cost of propane supply only when the amount of such adjustment is at least 10 (ten) cents per dk." The COG adjustment for the month of October 2012 results in a change of less than 10 cents per dk, and therefore, in accordance with the authorized tariff, Montana-Dakota will not seek a purchased propane cost adjustment change.

This proposed adjustment, calculated in accordance with Rate 88, will amount to a decrease of approximately \$582,200 for natural gas customers during the month of October 2012. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 95,716 natural gas customers in North Dakota as of August 31, 2012.

Please refer all inquiries regarding this filing to:

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

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

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

Montana-Dakota submitted a check for the amount of \$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.

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  
Regulatory Affairs Manager

Attachment

**Attachment A**

**Rate Summary Sheet  
(Proposed)**



# Montana-Dakota Utilities Co.

A Division of MDU Resources Group, Inc.  
 400 N 4th Street  
 Bismarck, ND 58501

## State of North Dakota Gas Rate Schedule

NDPSC Volume 7  
 108<sup>th</sup> Revised Sheet No. 3  
 Canceling 107<sup>th</sup> Revised Sheet No. 3

### RATE SUMMARY SHEET

Page 1 of 2

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	\$3.665	\$4.477
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$3.665	\$3.803
Interruptible Service - PAR			\$0.120	\$2.751	\$2.871
Interruptible Service - MAFB			\$0.120	\$2.476	\$2.596
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	\$3.665	\$4.262
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$2.751	(Maximum) \$3.622
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	\$3.754	\$4.351
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.013	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.013	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$2.751	(Maximum) \$3.470
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$7.773	\$8.585
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	\$7.773	\$8.370

Date Filed: September 10, 2012

Effective Date:

Issued By: Tamie A. Aberle  
 Regulatory Affairs Manager

Case No.:

**Montana-Dakota Utilities Co.**  
**Market Conditions for Regional Natural Gas**  
**October 2012**

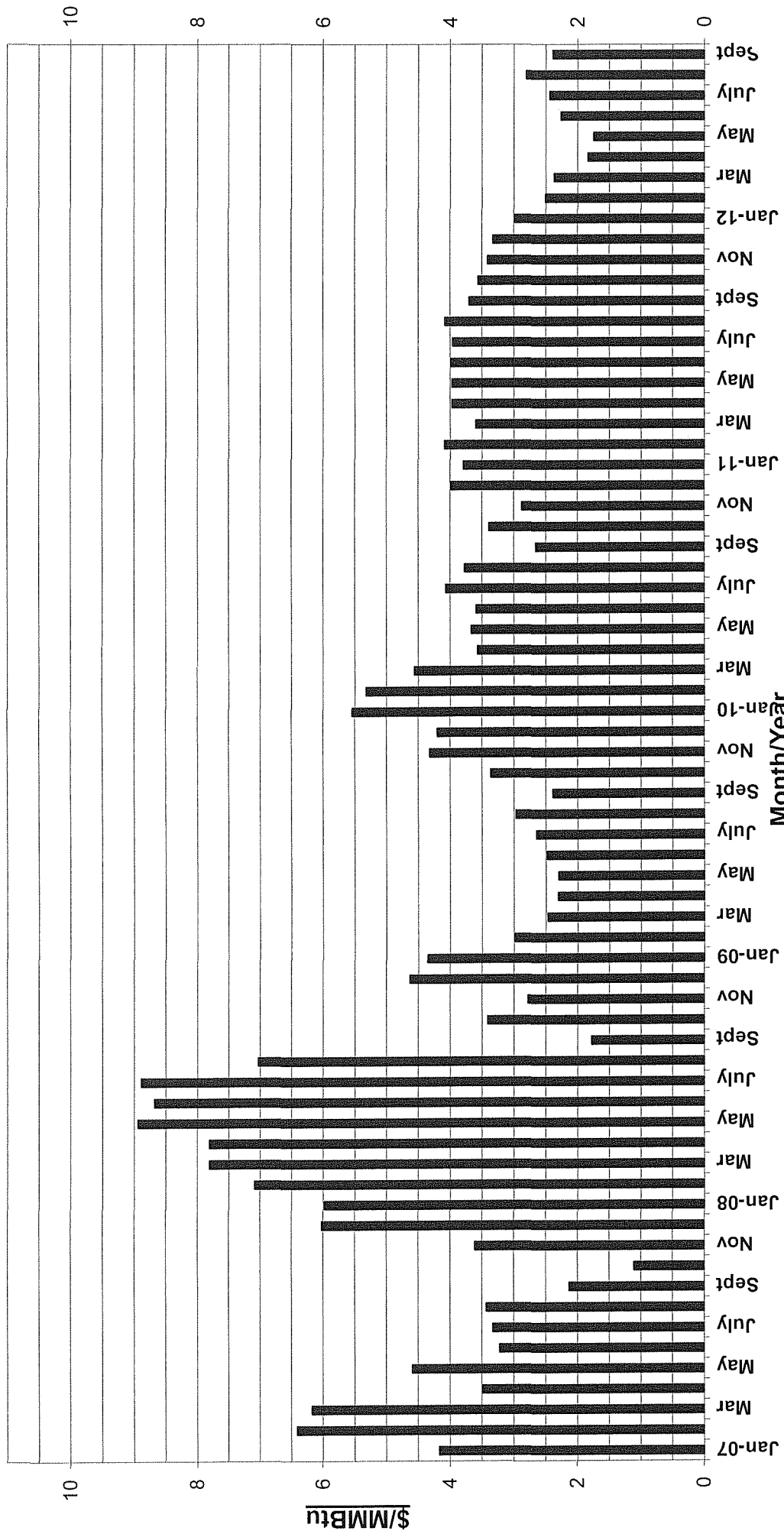
The established monthly price for the Rocky Mountain CIG Index has decreased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including “Inside FERC Gas Market” report and “Gas Daily” by McGraw-Hill Companies, of prices paid 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.

Following the hottest July on record, moderating temperatures in certain regions of the U.S. resulted in the reduction of natural gas electric generation to meet air conditioning demand. In addition, storage levels remained at record levels for this time of the year, with both factors likely contributing to the decrease in the index price of natural gas. The Energy Information Administration (EIA) reported storage levels nationwide as of August 24, 2012 were 12.0 percent above the five-year average and 14.6 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 August Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 18. The September Outlook is to be published September 11, 2012.

# 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 - \$2.37



Independent Statistics & Analysis

U.S. Energy Information  
Administration

August 2012

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## Short-Term Energy Outlook

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### Highlights

- EIA projects that the Brent crude oil spot price will average about \$103 per barrel during the second half of 2012, about \$3.50 per barrel higher than in last month's *Outlook*. The forecast Brent crude oil spot price falls to an average of \$100 per barrel in 2013. The projected West Texas Intermediate (WTI) crude oil spot price discount to Brent crude oil narrows from about \$14 in the third quarter of 2012 to \$9 by late 2013. These price forecasts assume that world oil-consumption-weighted real gross domestic product (GDP), which increased by 3.0 percent in 2011, grows by 2.8 percent in 2012 and 2.9 percent in 2013.
- With higher crude oil prices, EIA has increased the average regular gasoline retail price forecast for the third quarter of 2012 to \$3.49 per gallon from \$3.39 per gallon in last month's *Outlook*. EIA expects regular gasoline retail prices, which averaged \$3.53 per gallon in 2011, to average \$3.53 per gallon in 2012 and \$3.33 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 0.6 million bbl/d from last year, and the highest level of production since 1997. Projected U.S. domestic crude oil production increases to 6.7 million bbl/d in 2013.
- As a result of drought conditions affecting corn harvests and prices throughout the Midwest, ethanol production fell from 920 thousand bbl/d for the week ending June 8, 2012 to 809 thousand bbl/d for the week ending July 27, 2012. EIA has reduced its 2012 ethanol production forecast from 900 thousand bbl/d (13.8 billion gallons) in last month's *Outlook* to 870 thousand bbl/d (13.3 billion gallons). EIA expects ethanol production to recover in the second half of 2013, averaging about 880 thousand bbl/d for the year.
- Natural gas working inventories ended July 2012 at an estimated 3.2 trillion cubic feet (Tcf), about 17 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 \$2.67 per MMBtu in 2012 and \$3.34 per MMBtu in 2013.

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## Global Crude Oil and Liquid Fuels

**Global Crude Oil and Liquid Fuels Overview.** EIA expects global liquid fuels consumption growth of about 0.8 million bbl/d in 2012 and 0.9 million bbl/d in 2013. Despite downside risks to global oil demand, the spot price for Brent crude climbed back above \$100 per barrel in July after prices sank below \$90 per barrel in June. Markets have rallied around expectations that policymakers in the European Union (EU), China, and the United States will provide more economic stimulus to counteract slowing growth. Additionally, Iran's threats to block oil from transiting through the Strait of Hormuz have triggered market anxiety and prompted upward price pressure. Although angst over global growth and supply disruptions may continue to contribute to price volatility, EIA believes that Brent crude oil, a benchmark for the global oil price, will average \$104 per barrel for the third quarter of 2012. EIA estimates that world liquids consumption will outpace production by 0.9 million bb/d in the third quarter, as world demand reaches its seasonal peak. EIA expects that the significant stock builds that occurred in the first half of 2012 will help relieve global oil markets in the second half of 2012.

Several upside and downside risks could move prices higher or lower than projected. The possibility that the economic situation in EU countries could deteriorate further poses a downside risk to global oil demand and prices, though oil prices will likely rise and fall as perceptions about the likelihood of a deeper crisis evolve. In the current *Outlook*, consumption in Europe is expected to fall year-over-year by 0.4 million bbl/d in 2012 and by a further 0.2 million bbl/d in 2013. The possibility of slower growth in China, which has been a key driver of increased oil demand in recent years, could also curb demand. China's weakening exports, particularly to Europe, and slower industrial and domestic growth experienced in the first half of 2012 could place downward pressure on oil prices, while prospects for more economic stimulus could swing the pendulum towards higher prices. EIA currently projects annual increases in consumption in China of around 0.4 million bbl/d in both 2012 and 2013. On the supply side, oil prices could be higher than projected in this *Outlook* if recoveries from supply disruptions are slower than forecast, additional disruptions occur, or supply growth is lower than expected.

**Global Crude Oil and Liquid Fuels Consumption.** World liquid fuels consumption grew by an estimated 0.8 million bbl/d in 2011. EIA expects consumption growth of 0.8 million bbl/d in 2012 and 0.9 million bb/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. Projected OECD liquid fuels consumption declines by 0.4 million bbl/d in 2012 and by a lesser 0.1 million bbd/d in 2013, buoyed by growth in liquid fuels consumption in the United States.

In the third quarter of 2012, world demand will reach its seasonal peak, reflecting both the U.S. driving season and increased oil use for electricity generation in the Middle East. Projected consumption exceeds production by 0.9 million bbl/d, leading to global stock draws. Given overall lower demand expectations, the impact of seasonality on the tightness of global oil markets is expected to be less than in 2010 or 2011, when third-quarter consumption outpaced production by 1.1 million bbl/d and 1.7 million bbl/d, respectively.

**Non-OPEC Supply.** EIA expects liquid fuels production by non-Organization of the Petroleum Exporting Countries (OPEC) to rise by 0.6 million bbl/d in 2012, and by a further 1.3 million bbl/d in 2013. The largest area of non-OPEC growth is North America, where production increases by 940 thousand bbl/d and 440 thousand bbl/d in 2012 and 2013, respectively, resulting from continued production growth from U.S. onshore shale and other tight oil formations and from Canadian oil sands. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field next year, will increase its total production by 200 thousand bbl/d in 2013. In Brazil, output is projected to rise by 140 thousand bbl/d in 2013, with increased output from its offshore, pre-salt oil fields. Forecast production also rises in China, Russia, and Colombia over the next two years, while production declines in Mexico and the North Sea.

EIA revised Brazil's historical and projected liquid fuels production estimates to reflect the seasonality of ethanol production. Brazil's ethanol production fluctuates considerably over the course of the year because, unlike the corn used for ethanol production in the United States, Brazil's sugarcane feedstock must be processed into ethanol almost immediately after it is harvested. Accordingly, ethanol production typically ramps up in the second quarter and peaks in the third quarter of any given year, when the greatest amount of sugarcane in the leading ethanol-producing region of south-central Brazil is harvested, and reaches its nadir in the first quarter. Brazilian ethanol production in April and May was below even the disappointing levels of 2011 due to poor weather conditions. Though preliminary July data indicates that production has since recovered to some extent, Brazil's ethanol production is forecast to remain below the levels reached in the calendar year of 2010, when it averaged almost 500 thousand bbl/d. As a result, Brazil will depend on some combination of higher ethanol and gasoline imports.

The incorporation of seasonal variations into EIA's estimates of Brazilian ethanol production has unique implications for the global liquid fuels balance. The relatively large volumes of Brazilian ethanol that are produced in the third quarter would superficially imply that liquid fuels markets are slightly less tight in that quarter than previously estimated, with countervailing impacts on balances in the historically looser first quarter. Insofar as biofuels are close substitutes for petroleum products, this is a reasonable reflection of reality. However, certain caveats apply. First, Brazilian ethanol consumption, sales, and exports do not fluctuate as significantly as production, although ethanol storage infrastructure is not fully developed and supplies have been constrained in past years during inter-harvest periods. Second, unlike crude oil, which can be refined into various products according to market needs, ethanol is a much less fungible energy commodity given that it can only be used to supplement or supplant gasoline consumption. Moreover, relatively few countries possess automobiles and other relevant infrastructure that can support the use of large volumes of ethanol. Therefore, the relatively niche uses of ethanol in global energy markets should be considered when assessing the extent to which seasonal changes in ethanol production meaningfully contribute to relatively tighter or looser oil market conditions over the course of the year.

Several notable disruptions to non-OPEC production have commenced or intensified since the beginning of this year. Unplanned outages to non-OPEC production totaled around 900 thousand bbl/d in July 2012, slightly lower than the average in June. New developments

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pertaining to unplanned disruptions have prompted EIA to increase or cut back the projected output for some non-OPEC countries. The Marib pipeline in Yemen was restored after several sabotage attacks left the pipeline offline for about a year. The pipeline has experienced over a dozen attacks since political instability escalated last year, compromising about 100 thousand bbl/d of Yemen's oil output. According to various news sources, the pipeline was repaired in July and soon after began pumping crude from connected oil fields to the Ras Eisa port on the Red Sea, from which the oil is shipped to the country's refinery in Aden. However, it is uncertain whether Yemen's production will climb back to its pre-crisis level of around 240 thousand bbl/d, or if the Marib pipeline will encounter another attack, suspending production again at the nearby oil fields. EIA increased the forecast for Yemen's output to reach 200 thousand bbl/d by the end of 2012 and 220 thousand bbl/d by the end of 2013.

In Syria, escalating violence has prompted EIA to cut back that country's projected output. EIA now expects Syria's production to average 200 thousand bbl/d in 2012 and 210 thousand bbl/d in 2013, compared with the forecasts in last month's *Outlook* of 240 thousand bbl/d and 340 thousand bbl/d in 2012 and 2013, respectively. On a more hopeful note, there are recent reports of a breakthrough in the dispute between Sudan and South Sudan. The two sides have apparently reached an understanding on oil transportation arrangements, including the pipeline, marine terminal, processing, and transit fees that South Sudan will pay to Sudan in order to export its oil. Although the understanding on oil transit fees marks a significant step forward, some officials have noted that a signed agreement may be contingent on a broader deal on border security. Given the considerable uncertainty surrounding the negotiations and the practical challenges associated with restarting production, EIA is keeping Sudan and South Sudan's forecasted oil production mostly unchanged from last month's *Outlook*, but will make revisions accordingly when a signed agreement is finalized or as other developments warrant.

Unplanned supply disruptions also persist in Brazil, Colombia, and China. In Brazil, production at the offshore Frade field was halted in March 2012 after the field's operator, Chevron, requested to shut in production to investigate a spill at the field. Prior to the field's initial spill in November 2011, which initiated an investigation by Brazil's National Petroleum Agency (ANP), output at Frade was about 80 thousand bbl/d. In Colombia, additional troops have been deployed to protect the country's energy infrastructure, particularly oil pipelines, from insurgent groups. Increased attacks on the Caño Limón-Covenas pipeline and on trucks transporting oil have curbed production at multiple fields. Although Colombia's production is higher than year-ago levels, analysts have attributed the less than 1 million bbl/d output in 2012 to these attacks. In China, over 100 thousand bbl/d remains offline, as an oil leak in the Bohai Bay in June 2011 caused the Chinese government to suspend all operations at the Penglai 19-3 field. Production is expected to start ramping up gradually by the end of 2012.

Supply disruptions in Norway and Argentina were mitigated in July, as workers' strikes that threatened to curtail a substantial amount of production in both countries were contained. On July 9, Norway's government ordered mandatory arbitration and an end to the strike, forestalling a threatened lockout that could have impacted all of Norway's offshore production. In Argentina, most of the output from the onshore Cerro Dragon field has been restored since a

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workers' strike lowered production from the field in late June and July. The field's production capacity is almost 100 thousand bbl/d, which is about 15 percent of Argentina's crude output.

In addition to unplanned disruptions, some large non-OPEC producers are also undergoing planned maintenance that traditionally takes place during this time of the year. For example, in the North Sea, many gas platforms, pipelines, and power interconnectors undergo annual maintenance between May and September. Overall, planned maintenance is expected to affect more than 70,000 bbl/d in July and August. The Buzzard field, which has experienced a number of technical difficulties over the last year resulting in production shut-ins, will be taken offline for planned maintenance in the first week of September for several weeks. Production at the 200,000 bbl/d oilfield is expected to return to full rate by the middle of October.

**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 0.9 million bbl/d in 2012 and then remains flat in 2013 as non-OPEC supply growth increases and stocks rise slightly. 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 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, and by an additional 200 thousand bbl/d in 2013. Iran's output decline has continued to accelerate since the fourth quarter of 2011. EIA believes that this acceleration reflects erosion in Iran's crude oil production capacity due to the country's inability to carry out investment projects that are necessary to offset the natural decline in production from existing wells, as well as the impact of lower Iranian crude oil exports due to recently enforced EU and U.S. sanctions. A number of foreign companies that were investing in Iran's upstream have halted their activities as a result of previous U.S. sanctions, which have been compounded by tighter measures enforced since the start of this year that have made it increasingly difficult to do business with the country. EIA expects that the forecast decline in Iran's output will be offset by increased production from other OPEC member countries.

The impacts of newly imposed EU and U.S. sanctions on supplies and exports of Iranian oil are not easily extricated from the effects of sanctions enacted in previous years, the more general decline in Iran's production capacity, and other oil market developments. Undoubtedly, the EU embargo eliminates a significant market for Iranian oil. U.S. financial sanctions and EU insurance provisions have also impeded other countries' transactions for Iranian oil, leading to reports that Iran's ability to produce oil has outstripped its ability to sell it. Until recently, Iran could react to lower demand for its oil by adjusting the amount of oil it uses domestically or holds in onshore and offshore storage, in order to temporarily maintain relatively normal, albeit declining, levels of production. EIA estimates that Iranian production continued to fall in July as production capacity continues to be affected by country's inability to carry out investment projects that are

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necessary to offset the natural decline in production from existing wells, as well as the impact of lower Iranian crude oil exports and possibly production shut-ins. EIA bases this assessment on preliminary commercial data on tanker liftings from Iran, press reports, official Iranian statements, and other relevant information. However, this tentative interpretation of a very fluid situation could change as data are revised, independent estimates of Iranian production are issued, and more details about Iranian storage levels, refinery utilization, and domestic consumption emerge.

Iran's threat to block oil shipments passing through the Strait of Hormuz is a potential risk to global supply. Hormuz is the world's most important oil chokepoint, which EIA defines as a narrow channel along widely used global sea routes. EIA estimates that about 17 million bbl/d passed through Hormuz in 2011, or roughly 35 percent of all seaborne traded oil. In response to the threat, Saudi Arabia and the United Arab Emirates (UAE) have recently increased their oil pipeline capacity to circumvent Hormuz. The UAE constructed the 1.5 million bbl/d Abu Dhabi Crude Oil Pipeline that runs from Habshan, a collection point for Abu Dhabi's onshore oil fields, to the port of Fujairah on the Gulf of Oman, allowing crude oil shipments to bypass Hormuz. However, the UAE currently does not have the ability to utilize the pipeline completely until it ramps to full capacity. Saudi Arabia recently converted a natural gas pipeline back to an oil pipeline. The pipeline is a part of a two-pipeline system called Petroline, or the East-West Pipeline, which runs across Saudi Arabia to the Red Sea, avoiding Hormuz. Despite the increased capacity, most potential bypass options in the Gulf are currently not operational and would require extensive renovations. EIA estimates that the available pipeline capacity to bypass Hormuz, which is not currently utilized, was 1 million b/d at the start of 2012 and could potentially increase to 4.3 million b/d by the end of this year.

OPEC members serve as the swing producers in the world market because only OPEC producers possess surplus or spare oil production capacity, most of which is in Saudi Arabia. EIA projects that OPEC surplus production capacity will average 2.3 million bbl/d in 2012 and rise to an average 2.6 million bbl/d in 2013.

**OECD Petroleum Inventories.** EIA estimates that OECD commercial oil inventories ended 2011 at 2.59 billion barrels, equivalent to 56 days of forward-cover. Projected OECD oil inventories increase to 2.62 billion barrels and 57 days of forward-cover by the end of 2012, which is among the highest end-of-year levels in the last decade, because of the decline in OECD consumption.

**Crude Oil Prices.** EIA projects that the discount of the WTI crude oil spot price to Brent crude oil spot price will continue in 2012, averaging \$13 per barrel in the second half of 2012 and \$10 per barrel in 2013. EIA projects the price of Brent crude oil will average \$108 per barrel in 2012 and \$100 per barrel in 2013. EIA expects the WTI price to average \$90 per barrel in the second half of 2012 and generally remain at this level, averaging \$90 per barrel in 2013.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for November 2012 delivery during the 5-day period ending August 2, 2012 averaged \$89 per barrel. Implied volatility averaged 32 percent, establishing the lower and upper limits of the 95-

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percent confidence interval for the market's expectations of monthly average WTI prices in November 2012 at \$67 per barrel and \$119 per barrel, respectively. Last year at this time, WTI for November 2011 delivery averaged \$93 per barrel and implied volatility averaged 32 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$70 per barrel and \$125 per barrel.

## U.S. Crude Oil and Liquid Fuels

**U.S. Liquid Fuels Consumption.** Total consumption fell by 340 thousand bbl/d (1.8 percent) last year. Motor gasoline consumption accounted for the bulk of that decline, shrinking by 260 thousand bbl/d (2.9 percent). In 2012, total consumption falls by a further 170 thousand bbl/d (0.9 percent). The year-over-year decline in total consumption narrowed from 680 thousand bbl/d in the first quarter of 2012 to 110 thousand bbl/d in the second quarter. In the third and fourth quarters of 2012 EIA expects a turnaround in total liquid fuels consumption with a smaller year-over-year decline of 30 thousand bbl/d (0.2 percent) in the third quarter and a projected year-over-year increase of 120 thousand bbl/d (0.6 percent). Most of the recovery comes from natural gas liquids, which rise because of continued growth in industrial use and the assumption of near-normal weather this coming winter.

In 2013, total liquid fuels consumption grows by 60 thousand bbl/d (0.3 percent), led by a 50-thousand-bbl/d (1.2-percent) increase in distillate consumption and 30 thousand bbl/d growth in liquefied petroleum gas consumption. Despite an assumed increase in the growth rate of U.S. real disposable income from 1.1 percent in 2012 to 1.7 percent in 2013 and projected declines in retail pump prices of almost 6 percent in 2013, forecast motor gasoline consumption declines by 30 thousand bbl/d (0.4 percent). Gasoline consumption continues to fall because of slow growth in the driving-age population, the acceleration of 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 210 thousand bbl/d (3.9 percent) to 5.7 million bbl/d in 2011. Forecast U.S. total crude oil production increases to 6.3 million bbl/d in 2012, the highest annual level of production since 1997. Forecast lower-48 onshore crude oil production grows by a robust 670 thousand bbl/d in 2012 and output in the Gulf of Mexico stabilizes after having fallen last year, but Alaskan output continues to decline by 30 thousand bbl/d. In 2013, total crude oil output rises a further 390 thousand bbl/d, most of which is accounted for by increases in lower-48 onshore production. That increase is driven by increased oil-directed drilling activity, particularly in onshore tight oil formations. 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 1,429 as of August 3, 2012.

Concerns regarding the supply of refined products on the U.S. East Coast have eased considerably in recent months (see [\*This Week in Petroleum - Update of the Status of East Coast\*](#)

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*Refineries*, July 25, 2012). Following the recently formed joint venture between The Carlyle Group and Sunoco, the Sunoco Philadelphia refinery is now expected to remain in operation. In addition, Delta Air Lines has purchased the Trainer refinery and has announced plans to restart it in the third quarter of 2012. The previously estimated regional "supply gap" of approximately 420,000 bbl/d for gasoline and ultra-low-sulfur diesel (ULSD) combined that would have resulted from the idling of three Philadelphia-area refineries (*Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets*, February 2012) is now expected to be just 50,000 bbl/d of ULSD, with the gasoline gap disappearing almost entirely. The remaining potential ULSD supply gap is largely the result of an expected increase in demand for ULSD because of New York State's requirement that, beginning in July 2012, all distillate fuel used for heating purposes be ULSD.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and products) has been falling since peaking at over 60 percent in 2005, and averaged 45 percent in 2011, 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 as a result of lower consumption and the substantial increases in domestic crude oil production. If the 2013 estimate holds true, it would be the first time the share of total U.S. consumption met by total liquid fuel imports is less than 40 percent since 1991.

**U.S. Petroleum Product Prices.** After a sharp increase in gasoline prices earlier this year, reaching a monthly average of \$3.90 per gallon (regular grade) in April, gasoline prices have fallen for the third consecutive month, averaging \$3.44 per gallon in July. EIA expects regular gasoline retail prices to average \$3.49 per gallon during the third quarter of 2012, up from the \$3.39 per gallon projected in last month's *Outlook*, primarily as a result of the rise in oil prices in mid-July. EIA projects that crude oil prices will remain near their current levels through 2013, resulting in regular gasoline retail prices averaging \$3.53 per gallon in 2012 and \$3.33 per gallon in 2013, both about 4 cents per gallon higher than in last month's *Outlook*. EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.84 per gallon and \$3.62 per gallon in 2012 and 2013, respectively.

## 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 3.2 Bcf/d (4.8 percent) from 2011. Large gains in electric power use in 2012 will 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 peaks at 31.6 Bcf/d in the third quarter, when electricity demand for air conditioning is highest. As a result of the extreme heat last month, estimated electric-

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power-sector natural gas consumption during July 2012 averaged 34.8 Bcf/d, 1.8 Bcf/d higher than projected in last month's *Outlook*.

Growth in total natural gas consumption slows in 2013, with forecast consumption averaging 70.9 Bcf/d. Growth in 2013 is driven by consumption increases from the residential, commercial, and industrial sectors, as consumption in the electric power sector levels off. A forecast of near-normal weather next winter drives 2013 increases in residential and commercial consumption of 9.2 percent and 6.4 percent, respectively. Although projected natural gas burn in the electric power sector declines by 3.5 percent from 2012, it remains near historically high levels in 2013.

**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. EIA expects continued year-over-year growth in 2012 of 2.5 Bcf/d. EIA, however, expects a small drop in production in the coming months, reflecting both expected losses from hurricanes ([2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)) and declines related to recent drops in the rig count. According to Baker Hughes, the natural gas rig count was 498 as of August 3, 2012, compared with 811 at the start of 2012. While some declines in production have occurred so far in 2012, production remained flat from April to May. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale, as well as the continued long-term decline in the Gulf of Mexico, 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 0.1 Bcf/d (1.3 percent) in 2012, as domestic supply continues to displace Canadian sources. The warm winter in the United States 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 pipeline gross imports will remain flat in 2013, at around 8.4 Bcf/d. Pipeline gross exports grew by 1.0 Bcf/d (33 percent) in 2011, driven by increased exports to Mexico, but are expected to remain flat in 2012, and grow by 0.2 Bcf/d in 2013.

Liquefied natural gas (LNG) imports are expected to fall by 0.5 Bcf/d (51 percent) in 2012 from the year before. EIA expects that an average of about 0.5 Bcf/d and 0.6 Bcf/d will arrive in the United States (mainly at the Elba Island terminal in Georgia) in 2012 and 2013, respectively, 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 U.S. a market of last resort for LNG.

**U.S. Natural Gas Inventories.** Working natural gas inventories remain at historically high levels for this time of year. As of July 27, 2012, according to EIA's [Weekly Natural Gas Storage Report](#), working inventories totaled 3,217 Bcf, 472 Bcf greater than last year's level and 407 Bcf above the five-year average. EIA expects that inventory levels at the end of October 2012 will set a new record of 3,954 Bcf, slightly lower than last month's *Outlook*, which forecast inventories

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slightly above 4,000 Bcf. Though absolute levels of working inventories remain high (because of very high storage entering the summer injection season this year), builds since April, for the most part, have been below the five-year average and below last year's levels. The projected increase of 1,477 Bcf in working gas inventory during the 2012 injection season (from the end of March to the end of October) would be the smallest build since 1991. In 2013, working inventory levels recede from current record highs, although they will still remain abundant compared with recent history.

**U.S. Natural Gas Prices.** Natural gas spot prices averaged \$2.95 per MMBtu at the Henry Hub in July 2012, up \$0.49 per MMBtu from the June average, but still \$1.47 per MMBtu (33 percent) lower than the July 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 the increase in prices in July. EIA expects the Henry Hub natural gas price will average \$2.67 per MMBtu in 2012, with prices remaining below \$3.00 per MMBtu until December. EIA expects 2013 prices will average \$3.34 per MMBtu.

Natural gas futures prices for November 2012 delivery (for the 5-day period ending August 2, 2012) averaged \$3.26 per MMBtu, and the average implied volatility based on options and futures prices was 44 percent (*Market Prices and Uncertainty Report*). Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for November 2012 contracts at \$2.13 per MMBtu and \$4.98 per MMBtu, respectively. At this time last year, the November 2011 natural gas futures contract averaged \$4.23 per MMBtu and implied volatility averaged 32 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.12 per MMBtu and \$5.74 per MMBtu.

## Coal

**U.S. Coal Consumption.** Power-sector coal consumption, which averaged over 1 billion short tons annually from 2003 through 2008, fell by 46 million short tons (MMst) in 2011. Lower electric power sector natural gas prices have led to a significant increase in the share of natural-gas-fired generation. EIA expects coal consumption in the electric power sector to total 825 MMst in 2012, the lowest amount in 20 years. EIA projects power sector coal consumption will remain flat in 2013 as the effects of higher electric power sector natural gas prices are offset by the weak increase in electricity consumption.

**U.S. Coal Supply.** EIA forecasts that coal production will decline by 7 percent in 2012 as domestic consumption falls. Production for the first six months of 2012 was 33 MMst (6 percent) below last year's level for the same period. EIA predicts that production will continue to decline in 2013, but at a slightly slower rate (4 percent). Despite declines in production, EIA projects that secondary inventories will increase in 2012, reaching near-record levels. Electric

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power sector stocks are forecast to be 194 MMst by the end of the year (estimated stocks for May 2012 were 203 MMst) and inventories will remain at elevated levels 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 U.S. exported 12.3 MMst of coal in May, which was slightly below April's record-setting amount. EIA projects coal exports to total 116 MMst in 2012. EIA expects that coal exports will fall by 16 percent in 2013. Major reasons for the export decline include China's economic slowdown and high coal stockpiles, and increased exports from Indonesia and Australia. U.S. coal exports averaged 56 MMst in the decade preceding 2011.

**U.S. Coal Prices.** Delivered coal prices to the electric power industry had increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per MMBtu (a 6-percent increase from 2010). However, EIA expects the decline in demand for coal, combined with the 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 average delivered coal price in 2012 will average \$2.41 per MMBtu, about the same as last year. EIA predicts the 2013 average delivered coal price to average \$2.36 per MMBtu, or about 2 percent lower than the 2012 price.

## Electricity

**U.S. Electricity Consumption.** Many areas of the United States have experienced record temperatures this summer, similar to the hot weather last summer. According to the National Oceanic and Atmospheric Administration, U.S. cooling degree-days during July 2012 were about 25 percent higher than the 30-year average, but about the same as July 2011. EIA estimates that retail sales of electricity to the residential sector during the first half of this year were about 6.4 percent lower than the same period in 2011, as a result of mild winter temperatures in the South where many households heat using electricity. Residential sales for the entire year are projected to average about 3.0 percent lower than sales during 2011. Projected sales of electricity to the residential sector grow by 1.9 percent in 2013.

**U.S. Electricity Generation.** Starting with this month's *Outlook*, EIA has expanded its modeling of electricity generation to the four Census regions (Northeast, South, Midwest, and West) in addition to its standard U.S. projections. EIA expects total U.S. generation across all sectors during 2012 will average 0.4 percent lower than in 2011. However, generation fueled by natural gas is projected to rise this year by 23.2 percent. The South Census region accounts for the largest absolute increase in natural gas generation—an annual increase of 303 thousand megawatthours per day (MWh/d), or 18.4 percent. Yet, the Midwest region has the largest relative increase in natural gas generation—rising by 93.0 percent, or 152 thousand MWh/d, during 2012. This substantial increase in the share of generation fueled by natural gas is occurring at the expense of coal generation, which is projected to fall by 12.1 percent nationwide during 2012. Higher natural gas prices relative to coal prices leads to a reversal of

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this trend next year, when U.S. natural gas generation falls by 4.3 percent and coal generation increases by 1.7 percent.

**U.S. Electricity Retail Prices.** EIA expects the average U.S. residential electricity price will rise by 1.6 percent during 2012 to an average of 11.99 cents per kilowatthour. The forecast cost of natural gas delivered to the electric power sector is about 28 percent lower in 2012 compared with the previous year, which should slow the growth in retail electricity rates. EIA projects U.S. residential retail electricity prices to rise by 0.9 percent in 2013. When measured in real terms, the average 2013 residential electricity price is 2.9 percent less than the price in 2009.

### Renewables and Carbon Dioxide Emissions

**U.S. Renewables.** After growing by 14 percent in 2011, total renewable energy consumption is projected to decline by 2.4 percent in 2012. This decrease is the result of hydropower resource levels beginning to return to the long-term average, with consumption falling by 0.4 quadrillion Btu (13 percent). 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 2.1 percent in 2013 as hydropower continues to decline (2.9 percent) but non-hydropower renewables grow by an average of 4.7 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 17 percent in 2012. The forecast for wind capacity additions and generation in 2013 will likely respond to whatever decision is made regarding the extension of production tax credits.

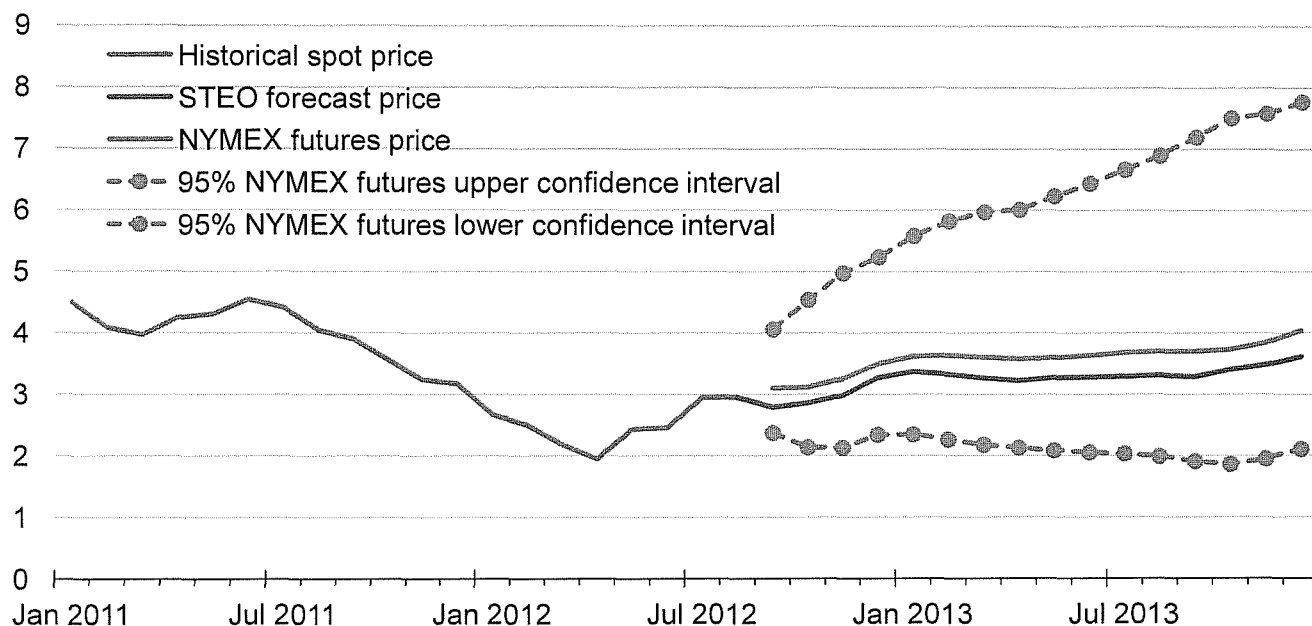
As a result of drought conditions affecting corn harvests throughout the Midwest, EIA has reduced its ethanol production forecast for the second half of 2012 from an average of 900 thousand bbl/d in last month's *Outlook* to 830 thousand bbl/d. EIA expects ethanol production to recover in the second half of 2013, averaging 880 thousand bbl/d (13.5 billion gallons) for the year. The projected decline in ethanol production is generally matched by lower ethanol exports.

EIA estimates that biodiesel production in 2011 averaged about 63 thousand bbl/d (971 million gallons of total annual production). Forecast biodiesel production averages 72 thousand bbl/d in 2012 and 79 thousand bbl/d in 2013.

**U.S. Energy-Related Carbon Dioxide Emissions.** After declining by 2.4 percent in 2011, fossil fuel emissions are projected to further decline by 2.3 percent in 2012, but increase by 1.0 percent in 2013. Petroleum emissions decline in 2012 (1.1 percent) and then remain flat in 2013, while natural gas emissions rise by 5.3 percent and 1.3 percent in 2012 and 2013, respectively. Coal emissions decline by 9.0 percent in 2012 but rise by 1.9 percent in 2013.

## Henry Hub Natural Gas Price

dollars per million btu



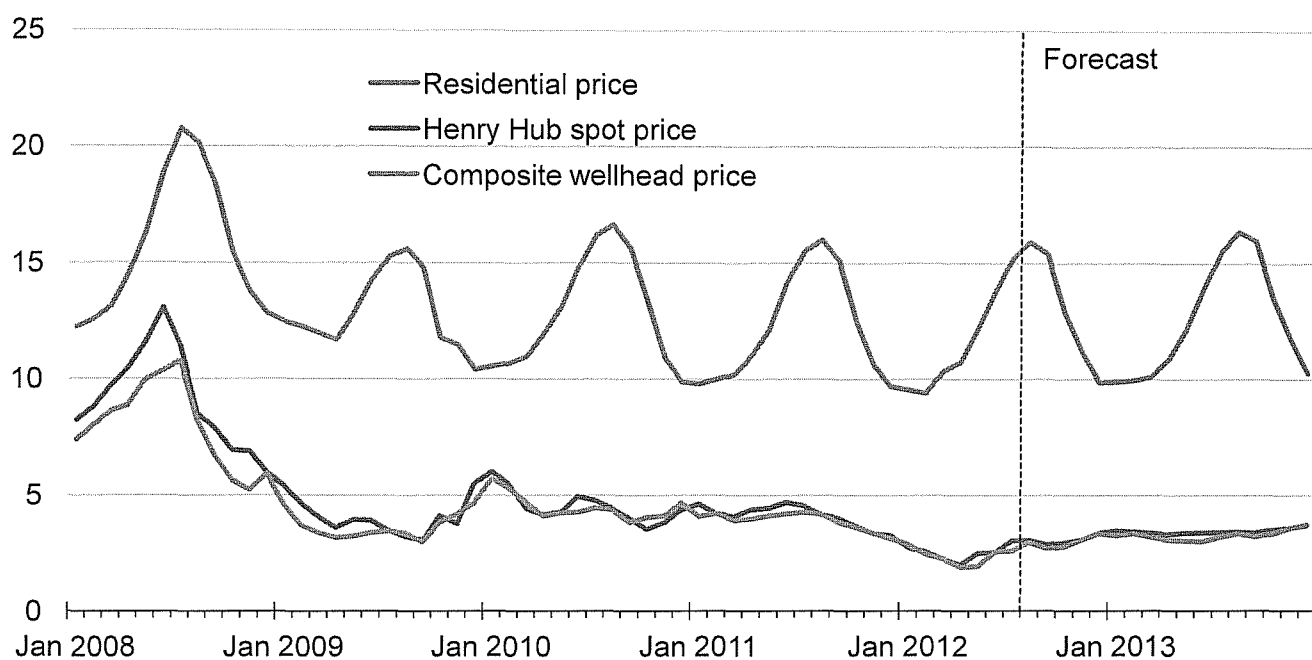
Note: Confidence interval derived from options market information for the 5 trading days ending August 2, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, August 2012



## U.S. Natural Gas Prices

dollars per thousand cubic feet



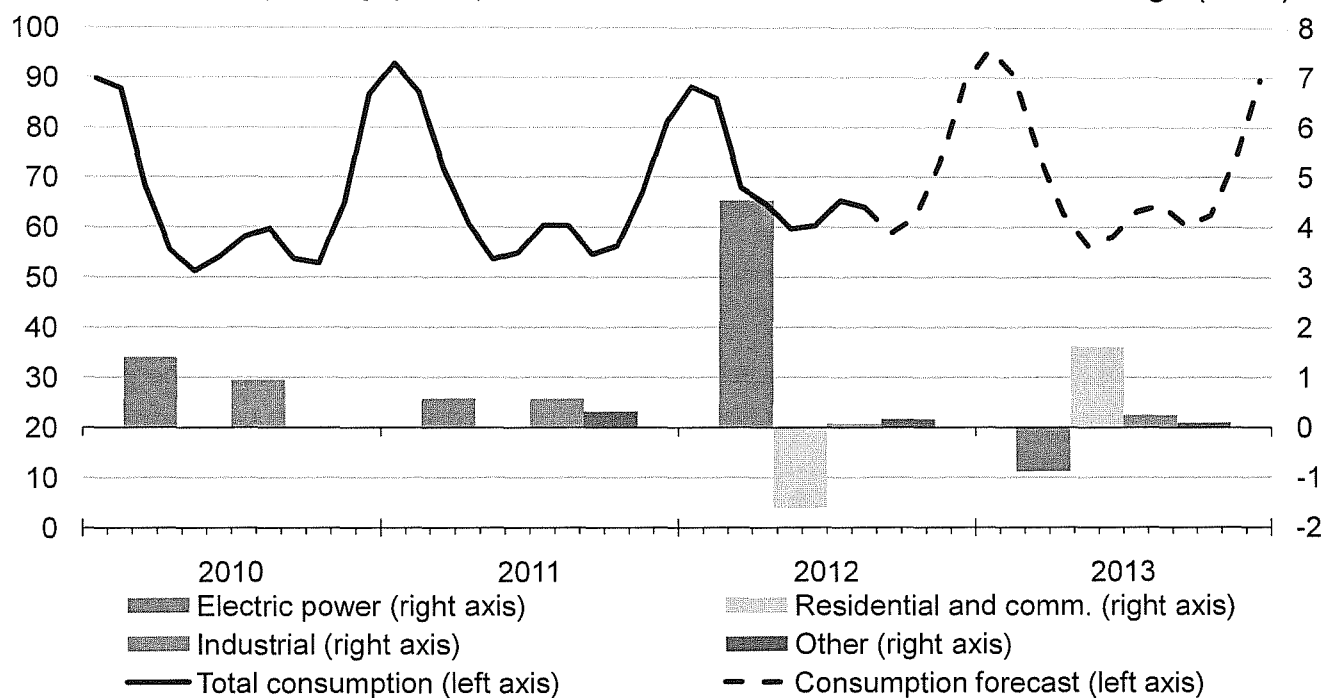
Source: Short-Term Energy Outlook, August 2012



## U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

annual change (bcf/d)

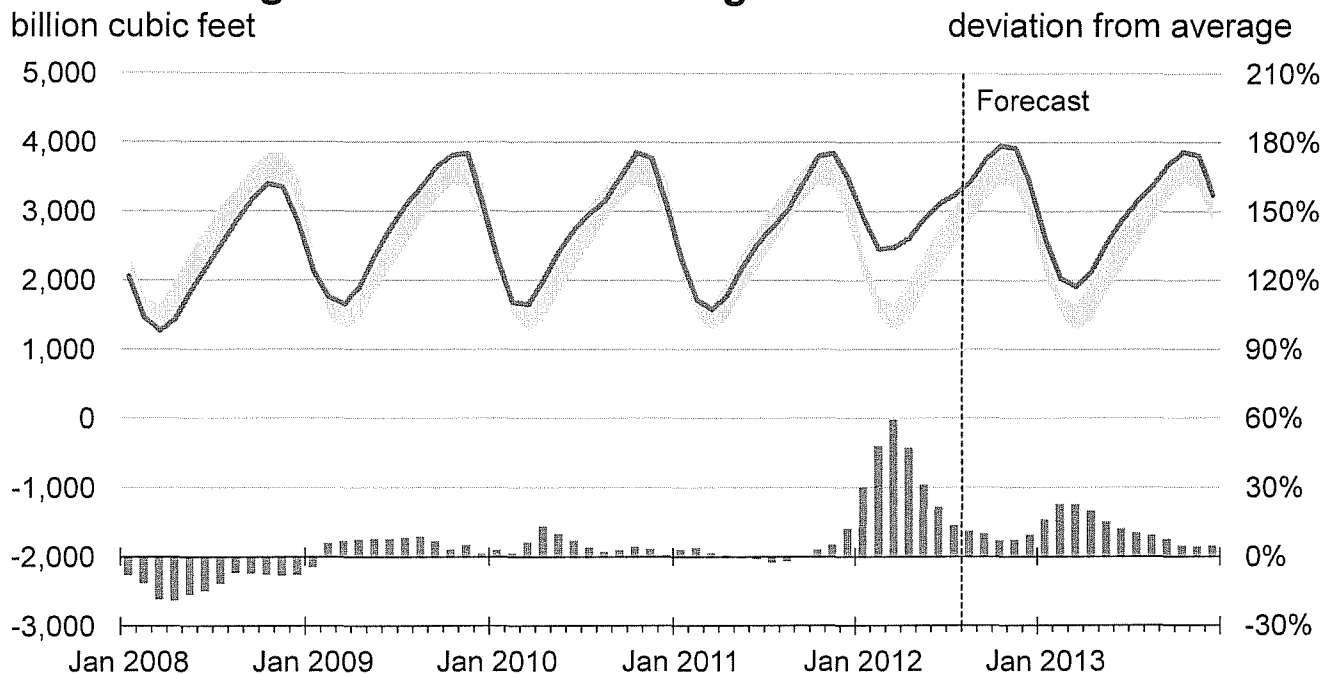


Source: Short-Term Energy Outlook, August 2012



## U.S. Working Natural Gas in Storage

billion cubic feet



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

Source: Short-Term Energy Outlook, August 2012



**Montana-Dakota Utilities Co.  
Pipeline Rate Changes Since Last Annual COG  
North Dakota  
October 2012 COG**

**NOVA Gas Transmission LTD.**

On May 16, 2011, TransCanada filed for approval of final rates, tolls and charges for the Alberta System services for 2011 with the National Energy Board to be effective October 1, 2011. On August 19, 2011, the Board issued an order approving these rates effective October 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – 0.000 cents per dk

**Williston Basin Interstate Pipeline Company Docket No. RP11-2476-001**

On August 31, 2011, Williston Basin filed with the FERC its semi-annual fuel and electric power reimbursement adjustment reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective October 1, 2011. On September 28, 2011, the Federal Energy Regulatory Commission issued a letter order approving these rates effective October 1, 2011.

Approximate impact on Montana-Dakota's cost of gas – 2.5 cents per dk

**Foothills Pipe Lines Ltd.**

On October 31, 2011, TransCanada filed new rates for the Foothills Pipe Lines Ltd. System with the National Energy Board to be effective January 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: 0.3 cents per dk

**NOVA Gas Transmission Ltd.**

TransCanada filed new rates for the Alberta System with the National Energy Board to be effective January 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: (0.2) cents per dk

**NorthWestern Energy**

On December 8, 2011, NorthWestern Energy filed its 2012 Electric and Natural Gas State and Local Tax and Fee tracking filing in Docket No. D2011.12.97. On January 17, 2012, the Montana Public Service Commission issued an order approving these rates effective January 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: (0.1) cents per dk

**WBI Energy Transmission, Inc. Docket No. RP12- 444-000**

On March 1, 2012, WBI Energy filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP12-444-000, reflecting revisions to the fuel and electric power components of WBI Energy's transportation and storage rates to be effective April 1, 2012. On March 27, 2012, the Federal Energy Regulatory Commission issued a letter order approving these rates effective April 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: (4.5) cents per dk

**WBI Energy Transmission, Inc.**

On July 1, 2012, Williston Basin Interstate Pipeline Company changed its name to WBI Energy Transmission, Inc.

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

**Williston Basin Interstate Pipeline Company Docket No. RP12- 986-000**

On August 31, 2012, Williston Basin filed its semi-annual fuel and electric power reimbursement adjustment with the FERC in Docket No. RP12-986-000, reflecting revisions to the fuel and electric power components of Williston Basin's transportation and storage rates to be effective October 1, 2012.

Approximate impact on Montana-Dakota's cost of gas: 0.8 cents per dk

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
<b><u>Gas Cost Adjustment:</u></b>				
Gas Cost Level (Exhibit B)	\$3.788	\$3.877	\$2.866	\$2.853
Prior Gas Cost	4.208	3.369	3.284	3.269
Current Gas Cost Adjustment	(\$0.420)	\$0.508	(\$0.418)	(\$0.416)
<b><u>Surcharge Adjustment:</u></b>				
Current Adjustment (Exhibit D)	(\$0.113)	(\$0.113)	(\$0.115)	(\$0.377)
Prior Adjustment	(0.032)	(0.032)	0.064	0.041
Change in Surcharge Adjustment	(\$0.081)	(\$0.081)	(\$0.179)	(\$0.418)
<b><u>Market Based Pricing Differential</u></b>				
Current Adjustment (Exhibit E)	(\$0.010)	(\$0.010)	\$0.000	\$0.000
Prior Adjustment	(0.009)	(0.009)	0.000	0.000
Change in Margin Sharing Provision	(\$0.001)	(\$0.001)	\$0.000	\$0.000
<b>Net Increase (Decrease) in Gas Costs</b>	<b><u>(\$0.502)</u></b>	<b><u>\$0.426</u></b>	<b><u>(\$0.597)</u></b>	<b><u>(\$0.834)</u></b>
Gas Cost Level	\$3.788	\$3.877	\$2.866	\$2.853
Plus: Surcharge	(0.113)	(0.113)	(0.115)	(0.377)
Total Gas Cost Level in Tariff Rates	<u>\$3.675</u>	<u>\$3.764</u>	<u>\$2.751</u>	<u>\$2.476</u>

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

	Amount
Total Gas Costs 1/	\$53,509,625
Residential and General Service dk Requirements 2/	14,190,038
Average Cost of Gas per dk	\$3.771
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.788
Less: Gas Cost Level in Rates 3/	4.208
<b>Current Gas Cost Adjustment</b>	<b>(\$0.420)</b>

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 July 31, 2012, adjusted for losses at .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective September 1, 2012:

Cost of Purchased Gas	\$4.189
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$4.208

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

Total Gas Costs 1/	\$53,509,625
Less: Annual MDDQ Costs 1/	<u>11,821,667</u>
Total Gas Costs excluding MDDQ	\$41,687,958
Firm Service Requirements 1/	14,190,038
Other Gas Costs per Dk (excluding MDDQ)	\$2.938
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,821,667
Winter Firm Service Requirements	12,824,857
MDDQ Costs per Winter Dk	\$0.922
Add: Other Gas Costs per Dk	<u>2.938</u>
Winter Seasonal Rate	\$3.860
Winter Seasonal Rate, adjusted for losses 2/	\$3.877
Less: Gas Cost Level in Rates 3/	<u>3.369</u>
<b>Current Gas Cost Adjustment</b>	<b><u><u>\$0.508</u></u></b>

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective September 1, 2012:

	<u>Summer</u>
Cost of Purchased Gas	\$3.354
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.369

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

	Amount
Total Gas Costs 1/	\$9,994,385
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$2.853
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.866
Less: Gas Cost Level in Rates 2/	3.284
<b>Current Gas Cost Adjustment</b>	<b>(\$0.418)</b>

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 September 1, 2012:

Cost of Purchased Gas	\$3.269
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.284



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

Issued On: August 31, 2012  
 Docket Number:  
 FERC Order Date:

Effective On: October 1, 2012

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

Issued On: September 30, 2010  
 Docket Number: RP10-1378-000  
 FERC Order Date: November 1, 2010

Effective On: September 30, 2010

NOTICE OF CURRENTLY EFFECTIVE RATES

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

RATE SCHEDULE	UNIT	BASE TARIFF RATE	ACA SURCHARGE	TOP THROUGHPUT SURCHARGE	GAS SUPPLY REALIGNMENT SURCHARGE	BASE TARIFF RATE PLUS SURCHARGES
RATE SCHEDULE FS-1						
CAPACITY RESERVATION 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.

Issued On: August 31, 2012  
 Docket Number:  
 FERC Order Date:

Effective On: October 1, 2012

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

PART 4.1  
4.1 - Statement of Rates  
T-1 and T-1B - Long Term Base Tariff Rates  
v.1.0.0 Superseding v.0.0.0

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 <sup>3</sup> m <sup>3</sup>		
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 <sup>3</sup>	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 <sup>1</sup> \$ 2.39/GJ FT-D Demand Rate for Group 3 Delivery Points <sup>2</sup> \$ 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 <sup>3</sup>	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10<sup>3</sup>m<sup>3</sup>/day)</u>	
	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 <sup>3</sup> m <sup>3</sup>	
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
11. Rate Schedule IT-D <sup>3</sup>	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	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 <sup>3</sup> m <sup>3</sup> /d
14. Rate Schedule OS	<u>Schedule No.</u>	<u>Charge</u>	
	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.

Attachment 2  
Table of Rates, Tolls and Charges  
Page 1 of 5

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 APG	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 <sup>1</sup>
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 <sup>2</sup>
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 <sup>2</sup>
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

Canceling  $\frac{29^{th}}{28^{th}}$  Revised Revised

Sheet No. 80.1  
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)

Commission Approved: June 19, 2012  
Docket No.: D2012.5.48, Interim Order No. 7218  
Tariff Letter No. 211-G

Effective for service rendered on or after  
July 1, 2012

PUBLIC SERVICE COMMISSION  
*Alisha Salem* Secretary

**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

NG-00-001

**STATE OF SOUTH DAKOTA**  
**GAS RATE SCHEDULE**

**South Dakota Intrastate Pipeline Company**

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5  
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

<u>Division</u>	<u>Receipt Point</u>	<u>Delivery Point</u>	<u>Monthly Customer Charge</u>	<u>Maximum Transportation Charge 2/</u>	<u>Minimum Transportation Charge 2/</u>	<u>Fuel Reimbursement Quantity Percentage 3/</u>
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 OCTOBER 2012**

	General Service		
	Storage Balance 1/	Prepaid Commodity Balance 2/	Prepaid Demand
October 2011	\$14,843,510	\$727,522	\$3,066,232
November	12,931,691	618,119	2,523,623
December	9,767,572	426,234	1,229,961
January 2012	6,908,042	318,632	(365,795)
February	4,284,312	46,778	(1,378,772)
March	4,262,438	(31,537)	(1,971,479)
April	4,797,117	(49,083)	(1,788,888)
May	6,211,047	17,524	(1,067,018)
June	7,901,983	83,691	(79,547)
July	9,775,611	141,954	958,948
August	11,420,803	201,350	1,996,236
September	12,376,956	627,448	2,815,821
October	12,349,436	616,528	3,085,536
13 month average	<u>\$9,063,886</u>	<u>\$288,089</u>	<u>\$694,220</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$796,806	\$25,326	\$61,029
Return Requirement	<u>\$1,086,578</u>	<u>\$34,536</u>	<u>\$83,223</u>

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.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT  
APPLICABLE TO NORTH DAKOTA  
FIRM  
TO BE EFFECTIVE OCTOBER 1, 2012 THROUGH SEPTEMBER 30, 2013**

(Over)/under recovered gas costs @ July 31, 2012 (\$1,670,167)

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	269,000	(\$0.032)	(8,608)
September	462,000	(0.032)	(14,784)
	731,000		(23,392)

Additional recovery required (\$1,646,775)

Projected sales volumes (dk)

October 2012	959,000		
November	1,726,000		
December	2,402,000		
January 2013	2,660,000		
February	2,070,000		
March	1,760,000		
April	1,054,000		
May	558,000		
June	312,000		
July	264,000		
August	278,000		
September	477,000		
Total			<u>14,520,000</u>

Total (over)/under recovered gas cost adjustment  
to be effective October 1, 2012 through September 30, 2013 (\$0.113)

**MONTANA-DAKOTA UTILITIES CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT  
APPLICABLE TO NORTH DAKOTA  
INTERRUPTIBLE  
TO BE EFFECTIVE OCTOBER 1, 2012 THROUGH SEPTEMBER 30, 2013**

(Over)/under recovered gas costs @ July 31, 2012 (\$144,649)

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	25,000	\$0.064	1,600
September	30,000	0.064	1,920
	55,000		3,520

Additional recovery required (\$148,169)

Projected sales volumes (dk)

October 2012	56,000		
November	206,000		
December	214,000		
January 2013	211,000		
February	203,000		
March	212,000		
April	44,000		
May	41,000		
June	26,000		
July	20,000		
August	25,000		
September	30,000		
Total			<u>1,288,000</u>

Total (over)/under recovered gas cost adjustment  
to be effective October 1, 2012 through September 30, 2013 (\$0.115)

**MONTANA-DAKOTA UTILITIES CO.  
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ADJUSTMENT  
APPLICABLE TO NORTH DAKOTA  
AIR FORCE INTERRUPTIBLE  
TO BE EFFECTIVE OCTOBER 1, 2012 THROUGH SEPTEMBER 30, 2013**

(Over)/under recovered gas costs @ July 31, 2012 (\$189,388)

Less: Projected recovery from rates already established

	Volume	Rate	Amount
August	11,000	\$0.041	451
September	17,000	0.041	697
	28,000		1,148

Additional recovery required (\$190,536)

Projected sales volumes (dk)

October 2012	34,000		
November	60,000		
December	82,000		
January 2013	91,000		
February	71,000		
March	61,000		
April	37,000		
May	20,000		
June	11,000		
July	10,000		
August	11,000		
September	17,000		
Total			505,000

Total (over)/under recovered gas cost adjustment  
to be effective October 1, 2012 through September 30, 2013 (\$0.377)

**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
<b>Balance @ July 31, 2011</b>									<b><u>(\$469,960)</u></b>
August	\$229,854	\$0	(\$8)	\$229,846	257,122	(\$0.023)	(\$5,914)	\$235,760	(234,200)
September	153,237	(52,739) 2/	(70) 3/	100,428	263,383	(0.023)	(6,058)	106,486	(127,714)
October	(21,312)	0	(2)	(21,314)	389,643	(0.032)	(10,319) 4/	(10,995)	(138,709)
November	(43,536)	0	(1)	(43,537)	881,908	(0.032)	(28,221)	(15,316)	(154,025)
December	6,351	0	(1)	6,350	1,811,727	(0.032)	(57,975)	64,325	(89,700)
January 2012	(75,086)	0	(3)	(75,089)	1,909,213	(0.032)	(61,095)	(13,994)	(103,694)
February	(673,857)	0	(8)	(673,865)	1,950,923	(0.032)	(62,430)	(611,435)	(715,129)
March	141,434	0	(48)	141,386	1,870,460	(0.032)	(59,855)	201,241	(513,888)
April	157,472	0	(35)	157,437	875,608	(0.032)	(28,020)	185,457	(328,431)
May	(578,261)	0	(25)	(578,286)	723,586	(0.032)	(23,155)	(555,131)	(883,562)
June	(524,496)	0	(67)	(524,563)	431,431	(0.032)	(13,806)	(510,757)	(1,394,319)
July	(284,659)	0	(117)	(284,776)	279,012	(0.032)	(8,928)	(275,848)	(1,670,167)
	<u>(\$1,512,859)</u>	<u>(\$52,739)</u>	<u>(\$385)</u>	<u>(\$1,565,983)</u>	<u>11,644,016</u>		<u>(\$365,776)</u>	<u>(\$1,200,207)</u>	<b><u>(\$1,670,167)</u></b>
<b>Balance @ July 31, 2012</b>									

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

2/ Reflects adjustments for the period July 2009- August 2011 to correct border station metering error and for the period December 2010-June 2011 to correct allocation of pipeline commodity costs.

3/ Includes \$68 interest related to September prior period adjustment.

4/ Reflects 238,784.1 Dk @ (\$0.023) and 150,857.5 Dk @ (\$0.032).

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2011</b>									<b><u><u>\$48,803</u></u></b>
August	\$10,522	\$0	\$1	\$10,523	30,906	(\$0.010)	(\$309)	\$10,832	59,635
September	14,424	20,058 2/	32 3/	34,514	33,439	(0.010)	(334)	34,848	94,483
October	(12,066)	0	1	(12,065)	54,461	0.064	(510) 4/	(11,555)	82,928
November	(4,161)	0	1	(4,160)	71,035	0.064	4,546	(8,706)	74,222
December	(22,361)	0	1	(22,360)	97,320	0.064	6,229	(28,589)	45,633
January 2012	(2,234)	0	1	(2,233)	93,302	0.064	5,971	(8,204)	37,429
February	(50,484)	0	2	(50,482)	82,314	0.064	5,268	(55,750)	(18,321)
March	(35,861)	0	(1)	(35,862)	102,326	0.064	6,548	(42,410)	(60,731)
April	(15,457)	0	(4)	(15,461)	61,121	0.064	3,912	(19,373)	(80,104)
May	(41,482)	0	(6)	(41,488)	55,327	0.064	3,541	(45,029)	(125,133)
June	(24,685)	0	(9)	(24,694)	50,898	0.064	3,258	(27,952)	(153,085)
July	11,289	0	(13)	11,276	44,385	0.064	2,840	8,436	(144,649)
	<u>(\$172,556)</u>	<u>\$20,058</u>	<u>\$6</u>	<u>(\$152,492)</u>	<u>776,834</u>		<u>\$40,960</u>	<u>(\$193,452)</u>	<b><u><u>(\$144,649)</u></u></b>
<b>Balance @ July 31, 2012</b>									

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

2/ Reflects adjustments for the period July 2009- August 2011 to correct border station metering error and for the period December 2010-June 2011 to correct allocation of pipeline commodity costs.

3/ Includes \$31 interest related to September prior period adjustment.

4/ Reflects 53,992.4 Dk @ (\$0.010) and 467.7 Dk @ \$0.064.

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

	<u>(Over) Under Recovery</u>	<u>Refunds &amp; Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
<b>Balance @ July 31, 2011</b>									<b><u><u>\$19,988</u></u></b>
August	\$7,881	\$0	\$0	\$7,881	4,781	\$0.031	\$148	\$7,733	27,721
September	11,054	(72,081) 2/	(7) 3/	(61,034)	4,781	0.031	148	(61,182)	(33,461)
October	(2,569)	0	(1)	(2,570)	11,572	0.041	358 4/	(2,928)	(36,389)
November	(9,963)	0	0	(9,963)	25,050	0.041	1,027	(10,990)	(47,379)
December	(12,123)	0	(1)	(12,124)	52,081	0.041	2,135	(14,259)	(61,638)
January 2012	160	0	(2)	158	63,119	0.041	2,588	(2,430)	(64,068)
February	(41,949)	0	(5)	(41,954)	68,854	0.041	2,823	(44,777)	(108,845)
March	(13,085)	0	(8)	(13,093)	60,042	0.041	2,462	(15,555)	(124,400)
April	(3,954)	0	(8)	(3,962)	40,821	0.041	1,673	(5,635)	(130,035)
May	(24,428)	0	(10)	(24,438)	33,727	0.041	1,383	(25,821)	(155,856)
June	(22,290)	0	(12)	(22,302)	17,115	0.041	702	(23,004)	(178,860)
July	(10,231)	0	(15)	(10,246)	6,892	0.041	282	(10,528)	(189,388)
	<u>(\$121,497)</u>	<u>(\$72,081)</u>	<u>(\$69)</u>	<u>(\$193,647)</u>	<u>388,835</u>		<u>\$15,729</u>	<u>(\$209,376)</u>	<b><u><u>(\$189,388)</u></u></b>
<b>Balance @ July 31, 2012</b>									

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

2/ Reflects adjustments for the period July 2009- August 2011 to correct border station metering error and for the period December 2010-June 2011 to correct allocation of pipeline commodity costs.

3/ Includes \$6 interest related to September prior period adjustment.

4/ Reflects 11,571.6 Dk @ \$0.031.

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

	Residential and Firm General				Seasonal	Total
	1/	2/	3/	Total		
<u>August 2011</u>						
Cost of Gas - Actual	\$6.53907	\$6.07399	\$6.53907		\$4.72585	
Cost of Gas - Recovered	5.42600	5.42600	5.42600		4.57200	
(Over) Under recovery per dk	\$1.11307	\$0.64799	\$1.11307		\$0.15385	
dk billed	0	115,478	138,898	254,376	2,746	257,122
(Over) Under recovery	\$0	\$74,827	\$154,605	\$229,432	\$422	\$229,854
<u>September 2011</u>						
Cost of Gas - Actual	\$5.34147	\$6.53907	\$5.34147		\$4.34720	
Cost of Gas - Recovered	5.42600	5.42600	5.42600		4.57200	
(Over) Under recovery per dk	(\$0.08453)	\$1.11307	(\$0.08453)		(\$0.22480)	
dk billed	0	146,689	115,442	262,131	1,252	263,383
(Over) Under recovery	\$0	\$163,275	(\$9,757)	\$153,518	(\$281)	\$153,237
<u>October 2011</u>						
Cost of Gas - Actual	\$5.14800	\$5.34147	\$5.14800		\$4.27757	
Cost of Gas - Recovered	5.17600	5.42600	5.42600		4.57200	
(Over) Under recovery per dk	(\$0.02800)	(\$0.08453)	(\$0.27800)		(\$0.29443)	
dk billed	150,858	254,860	(16,884)	388,834	809	389,643
(Over) Under recovery	(\$4,224)	(\$21,543)	\$4,693	(\$21,074)	(\$238)	(\$21,312)
<u>November 2011</u>						
Cost of Gas - Actual	\$5.08776	\$5.14800	\$5.08776		\$5.02590	
Cost of Gas - Recovered	5.17600	5.17600	5.17600		5.26500	
(Over) Under recovery per dk	(\$0.08824)	(\$0.02800)	(\$0.08824)		(\$0.23910)	
dk billed	0	570,369	311,037	881,406	502	881,908
(Over) Under recovery	\$0	(\$15,970)	(\$27,446)	(\$43,416)	(\$120)	(\$43,536)
<u>December 2011</u>						
Cost of Gas - Actual	\$5.19881	\$5.08776	\$5.19881		\$5.05515	
Cost of Gas - Recovered	5.01700	5.17600	5.17600		5.26500	
(Over) Under recovery per dk	\$0.18181	(\$0.08824)	\$0.02281		(\$0.20985)	
dk billed	573,466	1,134,572	102,999	1,811,037	690	1,811,727
(Over) Under recovery	\$104,262	(\$100,115)	\$2,349	\$6,496	(\$145)	\$6,351
<u>January 2012</u>						
Cost of Gas - Actual	\$4.58719	\$5.19881	\$4.58719		\$4.48501	
Cost of Gas - Recovered	5.01700	5.01700	5.01700		5.10700	
(Over) Under recovery per dk	(\$0.42981)	\$0.18181	(\$0.42981)		(\$0.62199)	
dk billed	0	1,219,157	689,288	1,908,445	768	1,909,213
(Over) Under recovery	\$0	\$221,655	(\$296,263)	(\$74,608)	(\$478)	(\$75,086)

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

	Residential and Firm General				Seasonal	Total
	1/	2/	3/	Total		
<u>February 2012</u>						
Cost of Gas - Actual	\$4.31561	\$4.58719	\$4.31561		\$4.32488	
Cost of Gas - Recovered	4.45800	5.01700	5.01700		5.10700	
(Over) Under recovery per dk	(\$0.14239)	(\$0.42981)	(\$0.70139)		(\$0.78212)	
dk billed	544,738	1,436,200	(30,647)	1,950,291	632	1,950,923
(Over) Under recovery	(\$77,565)	(\$617,293)	\$21,495	(\$673,363)	(\$494)	(\$673,857)
<u>March 2012</u>						
Cost of Gas - Actual	\$4.53637	\$4.31561	\$4.53637		\$3.92356	
Cost of Gas - Recovered	3.93900	4.45800	4.45800		4.54600	
(Over) Under recovery per dk	\$0.59737	(\$0.14239)	\$0.07837		(\$0.62244)	
dk billed	578,789	1,381,525	(90,654)	1,869,660	800	1,870,460
(Over) Under recovery	\$345,751	(\$196,715)	(\$7,105)	\$141,931	(\$497)	\$141,434
<u>April 2012</u>						
Cost of Gas - Actual	\$3.16667	\$4.53637	\$3.16667		\$3.24308	
Cost of Gas - Recovered	3.80100	3.93900	3.93900		4.02700	
(Over) Under recovery per dk	(\$0.63433)	\$0.59737	(\$0.77233)		(\$0.78392)	
dk billed	260,544	582,450	32,108	875,102	506	875,608
(Over) Under recovery	(\$165,271)	\$347,938	(\$24,798)	\$157,869	(\$397)	\$157,472
<u>May 2012</u>						
Cost of Gas - Actual	\$1.92861	\$3.16667	\$1.92861		\$3.01613	
Cost of Gas - Recovered	3.24100	3.80100	3.80100		3.89000	
(Over) Under recovery per dk	(\$1.31239)	(\$0.63433)	(\$1.87239)		(\$0.87387)	
dk billed	211,773	530,911	(19,781)	722,903	683	723,586
(Over) Under recovery	(\$277,929)	(\$336,773)	\$37,037	(\$577,665)	(\$596)	(\$578,261)
<u>June 2012</u>						
Cost of Gas - Actual	\$2.09715	\$1.92861	\$2.09715		\$3.82258	
Cost of Gas - Recovered	3.11600	3.24100	3.24100		3.33000	
(Over) Under recovery per dk	(\$1.01885)	(\$1.31239)	(\$1.14385)		\$0.49258	
dk billed	129,695	303,651	(4,336)	429,010	2,421	431,431
(Over) Under recovery	(\$132,140)	(\$398,509)	\$4,960	(\$525,689)	\$1,193	(\$524,496)
<u>July 2012</u>						
Cost of Gas - Actual	\$2.43247	\$2.09715	\$2.43247		\$3.00897	
Cost of Gas - Recovered	3.63400	3.11600	3.11600		2.27900	
(Over) Under recovery per dk	(\$1.20153)	(\$1.01885)	(\$0.68353)		\$0.72997	
dk billed	91,785	153,904	29,641	275,330	3,682	279,012
(Over) Under recovery	(\$110,282)	(\$156,805)	(\$20,260)	(\$287,347)	\$2,688	(\$284,659)

1/ Consumed in current month.

2/ Consumed in prior month.

3/ True-up of prior month volumes.

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

	1/	2/	3/	Total
<u>August 2011</u>				
Cost of Gas - Actual	\$4.93383	\$4.82929	\$4.93383	
Cost of Gas - Recovered	4.49400	4.49400	4.49400	
(Over) Under recovery per dk	<u>\$0.43983</u>	<u>\$0.33529</u>	<u>\$0.43983</u>	
dk billed	0	29,378	1,528	30,906
(Over) Under recovery	<u>\$0</u>	<u>\$9,850</u>	<u>\$672</u>	\$10,522
<u>September 2011</u>				
Cost of Gas - Actual	\$4.27195	\$4.93383	\$4.27195	
Cost of Gas - Recovered	4.49400	4.49400	4.49400	
(Over) Under recovery per dk	<u>(\$0.22205)</u>	<u>\$0.43983</u>	<u>(\$0.22205)</u>	
dk billed	0	33,011	428	33,439
(Over) Under recovery	<u>\$0</u>	<u>\$14,519</u>	<u>(\$95)</u>	\$14,424
<u>October 2011</u>				
Cost of Gas - Actual	\$4.17866	\$4.27195	\$4.17866	
Cost of Gas - Recovered	4.25700	4.49400	4.49400	
(Over) Under recovery per dk	<u>(\$0.07834)</u>	<u>(\$0.22205)</u>	<u>(\$0.31534)</u>	
dk billed	468	53,569	424	54,461
(Over) Under recovery	<u>(\$37)</u>	<u>(\$11,896)</u>	<u>(\$133)</u>	(\$12,066)
<u>November 2011</u>				
Cost of Gas - Actual	\$4.02356	\$4.17866	\$4.02356	
Cost of Gas - Recovered	4.25700	4.25700	4.25700	
(Over) Under recovery per dk	<u>(\$0.23344)</u>	<u>(\$0.07834)</u>	<u>(\$0.23344)</u>	
dk billed	0	80,084	(9,049)	71,035
(Over) Under recovery	<u>\$0</u>	<u>(\$6,273)</u>	<u>\$2,112</u>	(\$4,161)
<u>December 2011</u>				
Cost of Gas - Actual	\$4.04882	\$4.02356	\$4.04882	
Cost of Gas - Recovered	4.05800	4.25700	4.25700	
(Over) Under recovery per dk	<u>(\$0.00918)</u>	<u>(\$0.23344)</u>	<u>(\$0.20818)</u>	
dk billed	1,503	95,008	809	97,320
(Over) Under recovery	<u>(\$14)</u>	<u>(\$22,179)</u>	<u>(\$168)</u>	(\$22,361)
<u>January 2012</u>				
Cost of Gas - Actual	\$3.44426	\$4.04882	\$3.44426	
Cost of Gas - Recovered	4.05800	4.05800	4.05800	
(Over) Under recovery per dk	<u>(\$0.61374)</u>	<u>(\$0.00918)</u>	<u>(\$0.61374)</u>	
dk billed	0	91,023	2,279	93,302
(Over) Under recovery	<u>\$0</u>	<u>(\$836)</u>	<u>(\$1,398)</u>	(\$2,234)

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

	1/	2/	3/	Total
<u>February 2012</u>				
Cost of Gas - Actual	\$3.28873	\$3.44426	\$3.28873	
Cost of Gas - Recovered	3.51600	4.05800	4.05800	
(Over) Under recovery per dk	(\$0.22727)	(\$0.61374)	(\$0.76927)	
dk billed	1,429	77,563	3,322	82,314
(Over) Under recovery	(\$324)	(\$47,604)	(\$2,556)	(\$50,484)
<u>March 2012</u>				
Cost of Gas - Actual	\$2.89513	\$3.28873	\$2.89513	
Cost of Gas - Recovered	3.00500	3.51600	3.51600	
(Over) Under recovery per dk	(\$0.10987)	(\$0.22727)	(\$0.62087)	
dk billed	1,206	68,734	32,386	102,326
(Over) Under recovery	(\$133)	(\$15,620)	(\$20,108)	(\$35,861)
<u>April 2012</u>				
Cost of Gas - Actual	\$2.17308	\$2.89513	\$2.17308	
Cost of Gas - Recovered	2.87600	3.00500	3.00500	
(Over) Under recovery per dk	(\$0.70292)	(\$0.10987)	(\$0.83192)	
dk billed	563	48,914	11,644	61,121
(Over) Under recovery	(\$396)	(\$5,374)	(\$9,687)	(\$15,457)
<u>May 2012</u>				
Cost of Gas - Actual	\$1.60673	\$2.17308	\$1.60673	
Cost of Gas - Recovered	2.31600	2.87600	2.87600	
(Over) Under recovery per dk	(\$0.70927)	(\$0.70292)	(\$1.26927)	
dk billed	549	50,209	4,569	55,327
(Over) Under recovery	(\$389)	(\$35,293)	(\$5,800)	(\$41,482)
<u>June 2012</u>				
Cost of Gas - Actual	\$2.46826	\$1.60673	\$2.46826	
Cost of Gas - Recovered	2.19500	2.31600	2.31600	
(Over) Under recovery per dk	\$0.27326	(\$0.70927)	\$0.15226	
dk billed	467	37,713	12,718	50,898
(Over) Under recovery	\$128	(\$26,749)	\$1,936	(\$24,685)
<u>July 2012</u>				
Cost of Gas - Actual	\$2.54310	\$2.46826	\$2.54310	
Cost of Gas - Recovered	2.72100	2.19500	2.19500	
(Over) Under recovery per dk	(\$0.17790)	\$0.27326	\$0.34810	
dk billed	2,611	37,245	4,529	44,385
(Over) Under recovery	(\$465)	\$10,178	\$1,576	\$11,289

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

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

	<u>1/</u>	<u>2/</u>	<u>Total</u>
<u>August 2011</u>			
Cost of Gas - Actual	\$6.11845	\$6.63636	
Cost of Gas - Recovered	4.47400	4.47400	
(Over) Under recovery per dk	\$1.64445	\$2.16236	
dk billed	4,748	33	4,781
(Over) Under recovery	<u>\$7,809</u>	<u>\$72</u>	\$7,881
<u>September 2011</u>			
Cost of Gas - Actual	\$6.63636	\$4.25311	
Cost of Gas - Recovered	4.47400	4.47400	
(Over) Under recovery per dk	\$2.16236	(\$0.22089)	
dk billed	5,081	(300)	4,781
(Over) Under recovery	<u>\$10,988</u>	<u>\$66</u>	\$11,054
<u>October 2011</u>			
Cost of Gas - Actual	\$4.25311	\$3.84182	
Cost of Gas - Recovered	4.47400	4.47400	
(Over) Under recovery per dk	(\$0.22089)	(\$0.63218)	
dk billed	11,540	32	11,572
(Over) Under recovery	<u>(\$2,549)</u>	<u>(\$20)</u>	(\$2,569)
<u>November 2011</u>			
Cost of Gas - Actual	\$3.84182	\$4.00572	
Cost of Gas - Recovered	4.23800	4.23800	
(Over) Under recovery per dk	(\$0.39618)	(\$0.23228)	
dk billed	25,282	(232)	25,050
(Over) Under recovery	<u>(\$10,017)</u>	<u>\$54</u>	(\$9,963)
<u>December 2011</u>			
Cost of Gas - Actual	\$4.00572	\$4.02981	
Cost of Gas - Recovered	4.23800	4.23800	
(Over) Under recovery per dk	(\$0.23228)	(\$0.20819)	
dk billed	53,206	(1,125)	52,081
(Over) Under recovery	<u>(\$12,358)</u>	<u>\$235</u>	(\$12,123)
<u>January 2012</u>			
Cost of Gas - Actual	\$4.02981	\$3.42801	
Cost of Gas - Recovered	4.04000	4.04000	
(Over) Under recovery per dk	(\$0.01019)	(\$0.61199)	
dk billed	64,452	(1,333)	63,119
(Over) Under recovery	<u>(\$656)</u>	<u>\$816</u>	\$160

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

	<u>1/</u>	<u>2/</u>	<u>Total</u>
<u>February 2012</u>			
Cost of Gas - Actual	\$3.42801	\$3.27367	
Cost of Gas - Recovered	4.04000	4.04000	
(Over) Under recovery per dk	(\$0.61199)	(\$0.76633)	
dk billed	70,075	(1,221)	68,854
(Over) Under recovery	<u>(\$42,885)</u>	<u>\$936</u>	(\$41,949)
<u>March 2012</u>			
Cost of Gas - Actual	\$3.27367	\$2.88236	
Cost of Gas - Recovered	3.50000	3.50000	
(Over) Under recovery per dk	(\$0.22633)	(\$0.61764)	
dk billed	61,330	(1,288)	60,042
(Over) Under recovery	<u>(\$13,881)</u>	<u>\$796</u>	(\$13,085)
<u>April 2012</u>			
Cost of Gas - Actual	\$2.88236	\$2.10145	
Cost of Gas - Recovered	2.99100	2.99100	
(Over) Under recovery per dk	(\$0.10864)	(\$0.88955)	
dk billed	41,436	(615)	40,821
(Over) Under recovery	<u>(\$4,501)</u>	<u>\$547</u>	(\$3,954)
<u>May 2012</u>			
Cost of Gas - Actual	\$2.10145	\$1.00025	
Cost of Gas - Recovered	2.86300	2.86300	
(Over) Under recovery per dk	(\$0.76155)	(\$1.86275)	
dk billed	34,868	(1,141)	33,727
(Over) Under recovery	<u>(\$26,554)</u>	<u>\$2,126</u>	(\$24,428)
<u>June 2012</u>			
Cost of Gas - Actual	\$1.00025	\$0.69722	
Cost of Gas - Recovered	2.30600	2.30600	
(Over) Under recovery per dk	(\$1.30575)	(\$1.60878)	
dk billed	17,307	(192)	17,115
(Over) Under recovery	<u>(\$22,598)</u>	<u>\$308</u>	(\$22,290)
<u>July 2012</u>			
Cost of Gas - Actual	\$0.69722	(\$0.03135)	
Cost of Gas - Recovered	2.18500	2.18500	
(Over) Under recovery per dk	(\$1.48778)	(\$2.21635)	
dk billed	6,922	(30)	6,892
(Over) Under recovery	<u>(\$10,298)</u>	<u>\$67</u>	(\$10,231)

1/ Consumed in prior month.

2/ True-up of prior month volumes.

**MONTANA-DAKOTA UTILITIES CO.  
NORTH DAKOTA GAS  
INTERRUPTIBLE MARKET BASED PRICING DIFFERENTIAL  
EFFECTIVE OCTOBER 1, 2012 THROUGH SEPTEMBER 30, 2013**

Balance of Accumulated Revenues 1/	\$150,693
Projected Residential & General Service Sales Volumes	<u>14,520,000</u>
Market Based Pricing Differential Provision	<u><u>\$0.010</u></u>

1/ Represents 50% of margin above the approved margin from all interruptible sales.