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

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

ORIGINAL

August 10, 2012

RECEIVED
AUG 13 2012
PUBLIC SERVICE COMMISSION

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

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

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

Attachment A is the Rate Summary Sheet (107th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered September 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased $0.390 per dk since the last filing due to an increase in the overall market price of gas. Attachment B explains the reasons for the increase in the market price of gas. There has also been a change in pipeline rates as shown on Attachment C.

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 September 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of $0.390 per dk for residential and firm general customers, an increase of $0.380 per dk for small and large interruptible customers and an increase of $0.378 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 September 2012. The average cost of gas for firm customers, adjusted for losses, is $4.208.

Exhibit C shows the calculation of the return on storage inventory balances and prepaid

demand and commodity balances using the calculation procedure set forth in Rate 88. The overall rate of return of 8.791% was authorized by the Commission in Case No. PU-04-97.

Montana-Dakota purchases propane supplies from various wholesale suppliers. The cost of propane has decreased since the last COG filing due to a decrease in the market price of propane. Attachment B page 2 explains the reasons for the decrease in the market price of propane.

Exhibit A, page 2 summarizes the cost of gas – propane calculated pursuant to the terms of Rate 99, which will apply during the month of September 2012. The net effect of this filing is a decrease of $1.537 per dk for all customers from the currently effective rates.

Exhibit D shows the calculation of the current cost of gas – propane that will be applicable to Montana-Dakota's customers for the month of September 2012. The average cost of propane for all customers, adjusted for losses, is $7.136 per dk.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to an increase of approximately $226,600 for natural gas customers and a decrease of approximately $1,700 for propane customers during the month of September 2012. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 95,430 natural gas customers and 341 propane customers in North Dakota as of July 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 filing.

Montana-Dakota respectfully requests that this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Rita A. Mulkern
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
107th Revised Sheet No. 3
Canceling 106th Revised Sheet No. 3

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/ Dk
Residential Rate 60	4	$0.30 per day	$0.812	$4.167	$4.979
Air Force Rate 64	7				
Minot Air Force Base		$1,000.00 per month			
PAR Site		$135.00 per month			
Firm Service			$0.138	$4.167	$4.305
Interruptible Service - PAR			$0.120	$3.348	$3.468
Interruptible Service - MAFB			$0.120	$3.310	$3.430
Firm General Service Rate 70	13				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day	$0.597	$4.167	$4.764
			(Maximum)		(Maximum)
Small Interruptible Gas Rate 71	14	$100.00 per month	$0.871	$3.348	$4.219
Optional Seasonal Gas Service Rate 72	15				
Meters rated < 500 cubic feet		$0.52 per day			
Meters rated > 500 cubic feet		$1.75 per day			
Winter Gas Usage			$0.597	$4.255	$4.852
Summer Gas Usage			$0.597	$3.328	$3.925
Transportation Service	24				
Small Interruptible Rate 81		$150.00 per month			
Maximum			$0.427		
Minimum			$0.102		
Fuel Charge				$0.015	
Large Interruptible Rate 82		$725.00 per month			
Maximum			$0.298		
Minimum			$0.061		
Fuel Charge				$0.015	
			(Maximum)		(Maximum)
Large Interruptible Gas Rate 85	27	$675.00 per month	$0.719	$3.348	$4.067
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: August 10, 2012 **Effective Date:**

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

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

September 2012

The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid by willing sellers and buyers of quantities of gas in that region. That price is reflective of natural gas prices in the Rocky Mountain region and indicative of the supplies Montana-Dakota purchases for its requirements.

With additional natural gas power generation capacity available in recent years, combined with extreme summer heat and relatively low natural gas prices, natural gas fuel generation is at historically high levels this summer. The increase by the electric generation sector to meet the air conditioning demand has likely contributed to the increase in the index price of natural gas. This has also resulted in below average storage injections, reducing the above average gas levels for both the five year and prior year comparisons. The Energy Information Administration (EIA) reported storage levels nationwide as of July 27, 2012 were 14.5 percent above the five-year average and 17.2 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 19.

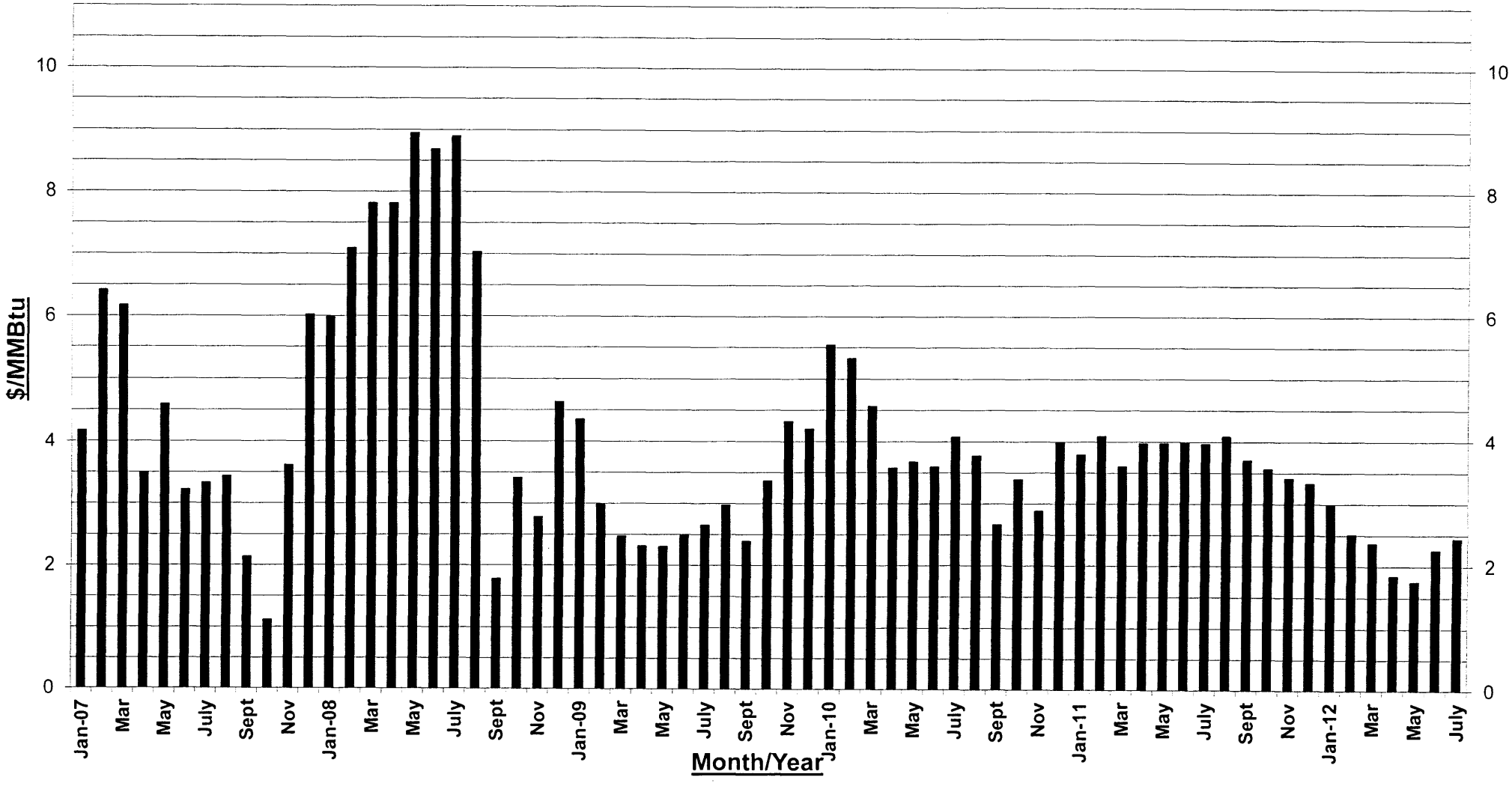
Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
September 2012

Montana-Dakota uses two regional bulk wholesale propane suppliers for obtaining the lowest prices for Hettinger customers. Each time Montana-Dakota purchases propane, it requests a price quote from each supplier for a specific delivery date and quantity in truckloads, delivering 8,000 to 12,000 gallons. Montana-Dakota selects the lowest price, all other things being equal.

The September prices for propane have decreased from the previous level. A change in the price of propane is generally driven by a combination of crude oil prices, weather, demand and inventory levels. As seasonal usage decreases, this has resulted in a decrease in the price of propane.

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

CIG Rocky Mountains Index
Monthly Gas Prices 2007-2012YTD



From Inside F.E.R.C.'s Gas Market Report
Annual Averages: - 2010-$3.92; 2011-$3.79; 2012YTD - $2.31

Independent Statistics & Analysis
U.S. Energy Information Administration

August 2012

Short-Term Energy Outlook

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.

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

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

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

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-

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*

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-

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

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

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

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.

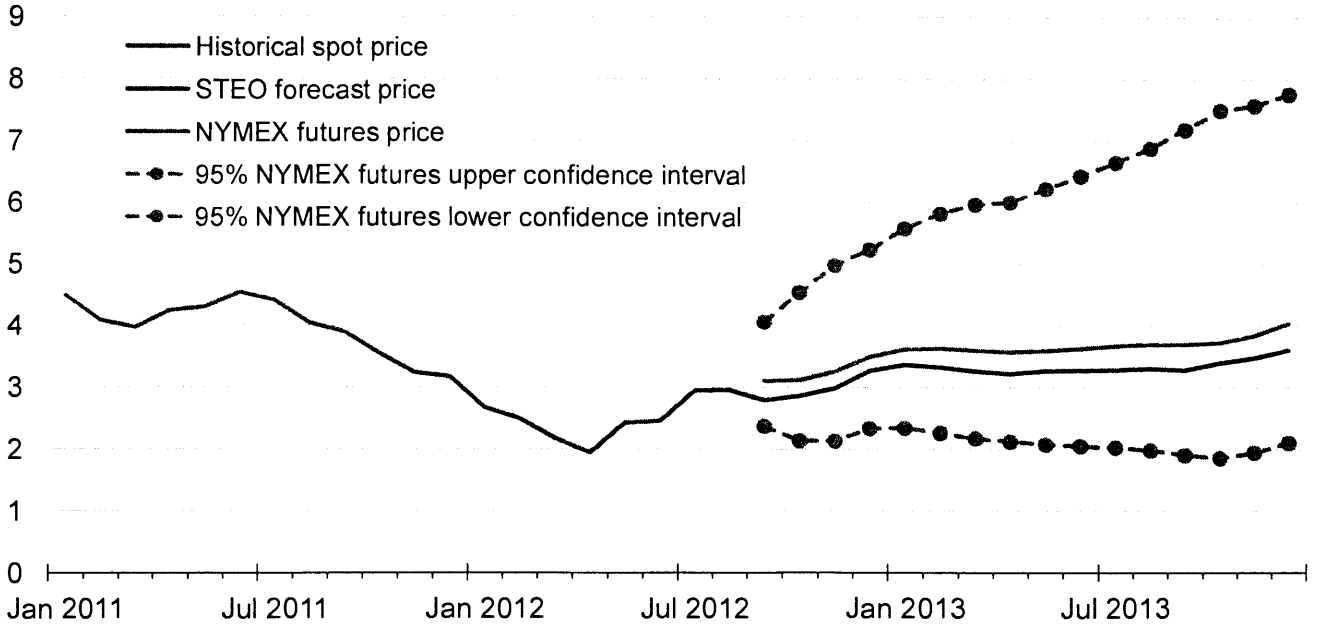
As a result of drought conditions affecting corn harvests throughout the Midwest, EIA has reduced its ethanol production forecast for the second half of 2012 from an average of 900 thousand bbl/d in last month's *Outlook* to 830 thousand bbl/d. EIA expects ethanol production to recover in the second 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



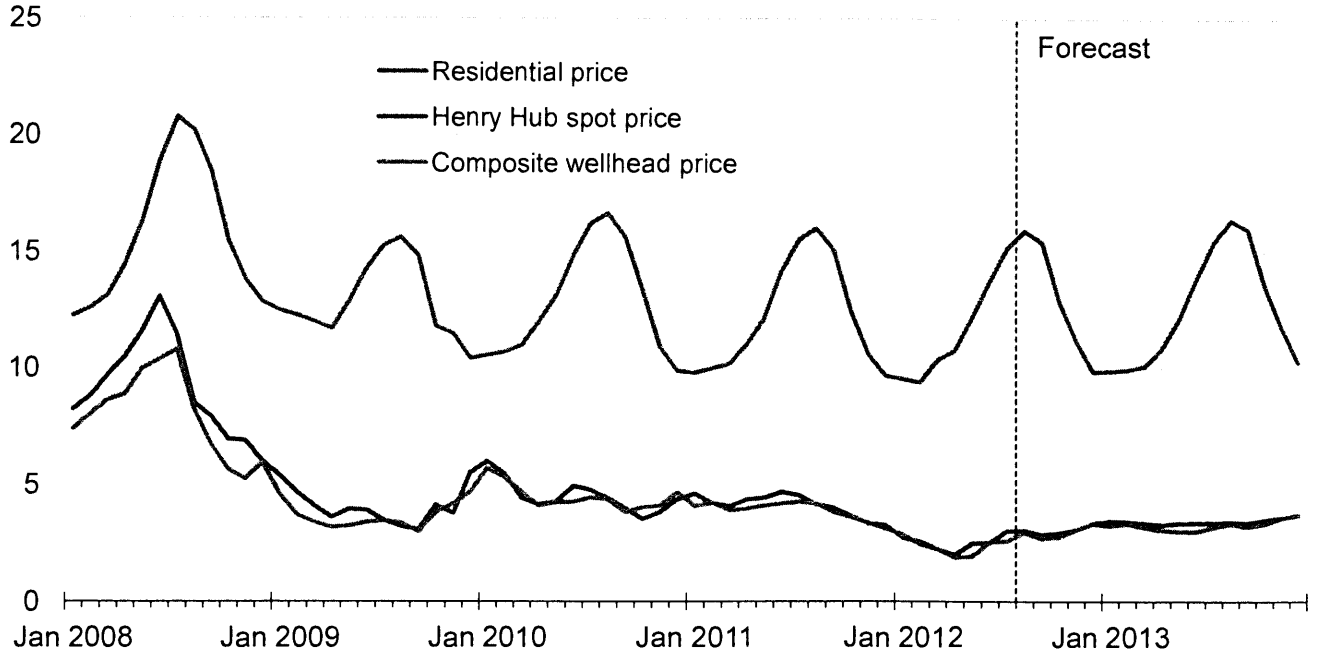
Note: Confidence interval derived from options market information for the 5 trading days ending August 2, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, August 2012

eia

U.S. Natural Gas Prices

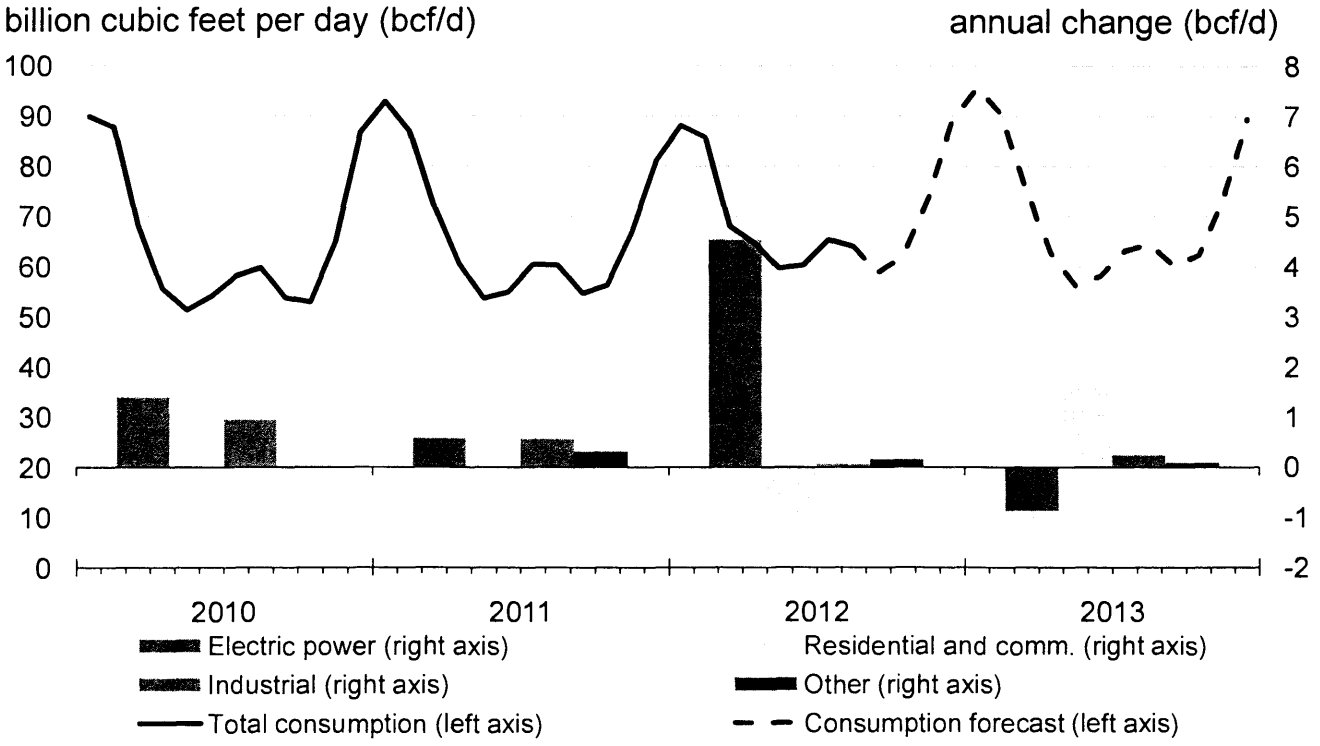
dollars per thousand cubic feet



Source: Short-Term Energy Outlook, August 2012

eia

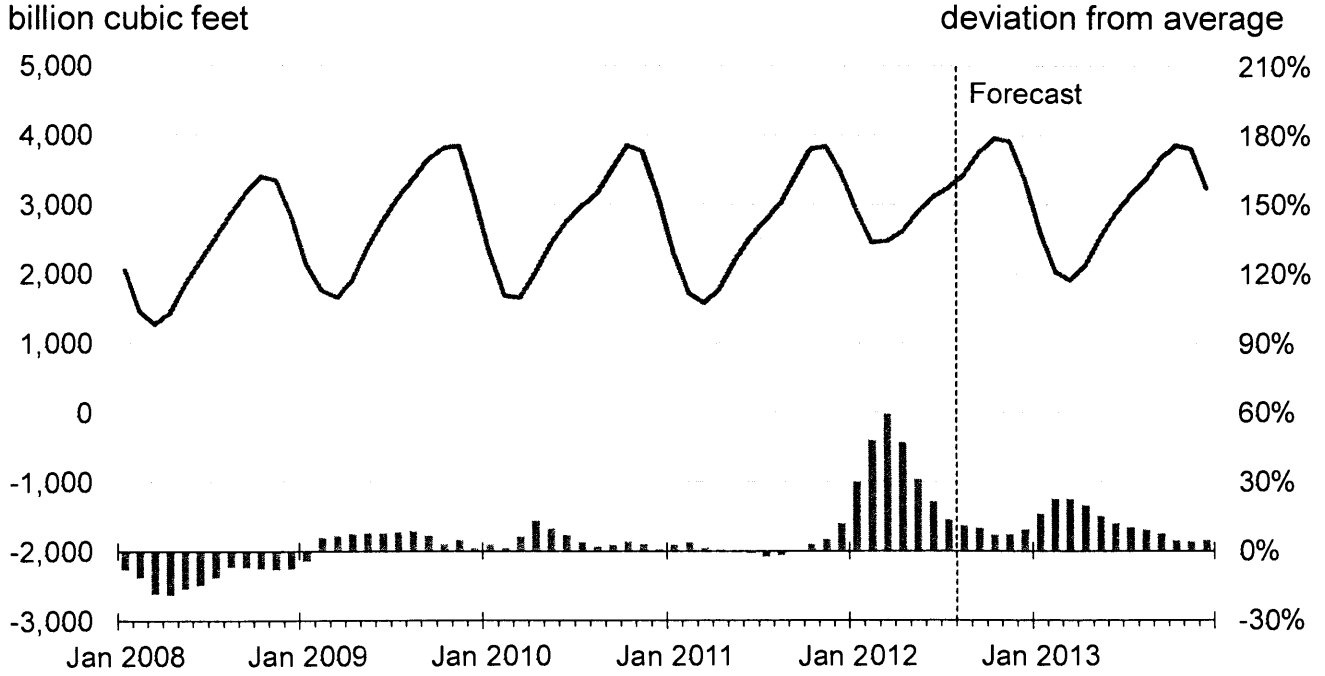
U.S. Natural Gas Consumption



Source: Short-Term Energy Outlook, August 2012

eia

U.S. Working Natural Gas in Storage



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

Source: Short-Term Energy Outlook, August 2012

eia

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

NorthWestern Energy

On May 30, 2012, NorthWestern Energy filed its Annual Unreflected Gas Cost Account Balance and Projected Gas Cost; and Gas Transportation Adjustment Clause Balance with the Montana Public Service Commission (Commission) in Docket No. 2012.5.48. On June 19, 2012, the Commission approved these changes to be effective July 1, 2012 on an interim basis.

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

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

	Firm			
	Residential & General Service	Optional Seasonal	Small & Large Interruptible	Air Force Interruptible
Gas Cost Adjustment:				
Gas Cost Level (Exhibit B)	$4.208	$3.369	$3.284	$3.269
Prior Gas Cost	3.818	2.985	2.904	2.891
Current Gas Cost Adjustment	$0.390	$0.384	$0.380	$0.378
Surcharge Adjustment:				
Current Adjustment	($0.032)	($0.032)	$0.064	$0.041
Prior Adjustment	(0.032)	(0.032)	0.064	0.041
Change in Surcharge Adjustment	$0.000	$0.000	$0.000	$0.000
Market Based Pricing Differential				
Current Adjustment	($0.009)	($0.009)	$0.000	$0.000
Prior Adjustment	(0.009)	(0.009)	0.000	0.000
Change in Margin Sharing Provision	$0.000	$0.000	$0.000	$0.000
Net Increase (Decrease) in Gas Costs	**$0.390**	**$0.384**	**$0.380**	**$0.378**
Gas Cost Level	$4.208	$3.369	$3.284	$3.269
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	$4.176	$3.337	$3.348	$3.310

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

Cost of Gas - Propane	
Current Propane Cost (Exhibit D)	$7.136
Prior Propane Cost	8.673
Current Propane Cost Adjustment	($1.537)
Surcharge Adjustment	
Current Adjustment	$0.646
Prior Adjustment	0.646
Change in Surcharge Adjustment	$0.000
Market Based Pricing Differential	
Current Adjustment	($0.009)
Prior Adjustment	(0.009)
Change in Margin Sharing Provision	$0.000
Net Increase (Decrease) in Gas Costs	**($1.537)**
Propane Cost Level	$7.136
Plus: Surcharge	0.646
Total Propane Cost Level in Rates	**$7.782**

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

	Amount
Total Gas Costs 1/	$59,350,305
Residential and General Service dk Requirements 2/	14,169,619
Average Cost of Gas per dk	$4.189
Average Cost of Gas as Adjusted for Losses @ 99.55%	4.208
Less: Gas Cost Level in Rates 3/	3.818
Current Gas Cost Adjustment	**$0.390**

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 June 30, 2012, adjusted for losses at .45%.
3/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective August 1, 2012:

Cost of Purchased Gas	$3.801
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$3.818

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

Summer - June - September	
Total Gas Costs 1/	$59,350,305
Less: Annual MDDQ Costs 1/	11,821,667
Total Gas Costs excluding MDDQ	$47,528,638
Firm Service Requirements 1/	14,169,619
Other Gas Costs per Dk (excluding MDDQ)	$3.354
Summer Seasonal Rate, adjusted for losses 2/	3.369
Less: Gas Cost Level in Rates 3/	2.985
Current Gas Cost Adjustment	**$0.384**
Winter - October - May	
Annual MDDQ Costs 1/	$11,821,667
Winter Firm Service Requirements	12,806,402
MDDQ Costs per Winter Dk	$0.923
Add: Other Gas Costs per Dk	3.354
Winter Seasonal Rate	$4.277
Winter Seasonal Rate, adjusted for losses 2/	$4.296

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

	Summer	Winter
Cost of Purchased Gas	$2.972	$3.889
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	$2.985	$3.907

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

	Amount
Total Gas Costs 1/	$11,451,154
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	$3.269
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.284
Less: Gas Cost Level in Rates 2/	2.904
Current Gas Cost Adjustment	**$0.380**

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 August 1, 2012:

Cost of Purchased Gas	$2.891
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	$2.904

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

	Amount
Total Gas Costs 1/	$2,876,896
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	$3.269
Less: Gas Cost Level in Rates 2/	2.891
Current Gas Cost Adjustment	**$0.378**

1/ Includes all pipeline demand and commodity charges. See Exhibit B, pages 5 -14 for currently effective pipeline rates. Also includes a return on prepaid demand, commodity and cycle storage balances as shown on Exhibit C, allocated to Air Force interruptible on MDDQ.

2/ Gas Cost Level in Current Tariff Rates Case No. PU-12-008 effective August 1, 2012:
Cost of Purchased Gas $2.891

Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
September 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 1.690%, CONSISTING OF 1.967% 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 0.856 CENTS, CONSISTING OF 0.732 CENTS FOR THE CURRENT RATE AND 0.124 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS TENDERED TO TRANSPORTER FOR SHIPPER'S ACCOUNT AT THE RECEIPT POINT(S) INTO TRANSPORTER'S TRANSMISSION FACILITIES.

NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

8NOTICE OF CURRENTLY EFFECTIVE RATES

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

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

A/ SHIPPER MUST REIMBURSE TRANSPORTER IN-KIND FOR STORAGE FUEL USE, LOST AND UNACCOUNTED FOR GAS. THE APPLICABLE PERCENTAGE IS 0.852%, CONSISTING OF 0.777% 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 0.205 CENTS, CONSISTING OF 0.000 CENTS FOR THE CURRENT RATE AND 0.205 CENTS FOR THE DEFERRAL RATE. THIS RATE SHALL BE APPLIED TO THE APPLICABLE QUANTITIES OF GAS INJECTED AND/OR WITHDRAWN BY TRANSPORTER FOR SHIPPER'S ACCOUNT AT TRANSPORTER'S STORAGE FACILITIES.

STATEMENT OF RATES
2/ 3/

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

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

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

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

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three year term (Price Point "B") & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $ 179.94/10^3m^3
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point
3. Rate Schedule FT-D [3]	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point. Average FT-D Demand Rate for Group 1 Delivery Points $ 5.44/GJ FT-D Demand Rate for Group 2 Delivery Points [1] $ 2.39/GJ FT-D Demand Rate for Group 3 Delivery Points [2] $ 2.87/GJ
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point
6. Rate Schedule FT-P [3]	Refer to Attachment "3" for applicable FT-P Demand Rate per month
7. Rate Schedule LRS	Contract Term / Effective LRS Rate ($/$10^3m^3$/day) 1-5 years 10.85 6-10 years 9.07 15 years 8.13 20 years 7.22
8. Rate Schedule LRS-2	LRS-2 Rate per month $ 50,000
9. Rate Schedule LRS-3	LRS-3 Demand Rate per month $ 129.55/10^3m^3
10. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point
11. Rate Schedule IT-D [3]	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point
12. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
13. Rate Schedule PT	Schedule No 9009-01001-1 / PT Rate $ 660.00/d / PT Gas Rate 50.0 10^3m^3/d
14. Rate Schedule OS	Schedule No. / Charge 2012302568 $ 22.00 / month 2012302633 $ 8.00 / month 2012302635 $ 14.00 / month 2012302571 $ 2.00 / month 2012302570 $ 1.00 / month 2012302644 $ 2,082.00 / month 2012302639 $ 2.00 / month 2012302641 $ 55.00 / month 2012302505 $ 126.00 / month 2012302608 $ 70.00 / month 2012302575 $ 19.00 / month 2012302497 $ 226.00 / month 2012302643 $ 203.00 / month 2003004522 $ 83,333.00 / month 2011476052 / 2011476054 $ 0.0783 / GJ subject to $ 717,000.00 Minimum Annual Charge 2011475772 $ 9,250.00 / month 2011475056 $ 0.095 / GJ and $ 1,000.00 / month 2011476092 $ 0.095 / GJ and $ 1,000.00 / month 2011494569 $ 0.095 / GJ and $ 1,000.00 / month

NOVA Gas Transmission Ltd.

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)
2000	ALBERTA-B.C. BORDER	5.51	0.1986
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	2.39	0.0861
31110	ALLIANCE EDSON INTERCONNECT APN	2.39	0.0861
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	2.39	0.0861
3002	BOUNDARY LAKE BORDER	3.44	0.1242
1958	EMPRESS BORDER	5.30	0.1911
3886	GORDONDALE BORDER	3.44	0.1242
6404	MCNEILL BORDER	5.30	0.1911

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate per Month Price Point "Z" ($/GJ)	IT-D Rate per Day ($/GJ)	Subject to ATCO Pipelines Franchise Fees[1]
31000	A.T. PLASTICS SALES APN	3.39	0.1226	Yes
31001	ADM AGRI INDUSTRIES SALES APN	3.39	0.1226	Yes
3880	AECO INTERCONNECTION	2.39	0.0861	
31003	AGRIUM CARSELAND SALES APS	2.39	0.0861	
31002	AGRIUM FT. SASK SALES APN	2.39	0.0861	Yes
31004	AGRIUM REDWATER SALES APN	2.39	0.0861	
31005	AINSWORTH SALES APGP	3.39	0.1226	
31006	AIR LIQUIDE SALES APN	3.39	0.1226	
3214	AKUINU RIVER WEST SALES	2.39	0.0861	
31007	ALBERTA ENVIROFUELS SALES APN	3.39	0.1226	Yes[2]
31008	ALBERTA HOSPITAL SALES APN	3.39	0.1226	Yes
3868	ALBERTA-MONTANA	3.44	0.1242	
3059	ALLISON CREEK SALES	2.39	0.0861	
31009	ALTASTEEL SALES APN	3.39	0.1226	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	2.39	0.0861	
31012	APL JASPER SALES APN	3.39	0.1226	Yes
3488	ARDLEY SALES	2.39	0.0861	
3216	AURORA NO 2 SALES	2.39	0.0861	
3135	AURORA SALES	2.39	0.0861	
3423	BASHAW WEST SALES	2.39	0.0861	
31013	BAYMAG SALES APS	2.39	0.0861	
31014	BEAR CREEK COGEN SALES APGP	3.39	0.1226	
3068	BEAVER HILLS SALES	2.39	0.0861	
3933	BIG EDDY INTERCONNECTION	2.39	0.0861	
3067	BIGSTONE SALES	2.39	0.0861	
3468	BLEAK LAKE SALES	2.39	0.0861	
3225	BOTHA SALES	2.39	0.0861	
3164	BRAINARD LAKE SALES	2.39	0.0861	
3918	BUFFALO CREEK INTERCONNECTION	2.39	0.0861	
31015	BURDETT COGEN SALES APS	2.39	0.0861	
3204	CABIN SALES	2.39	0.0861	
3109	CALDWELL SALES	2.39	0.0861	
31016	CALGARY ENERGY CENTRE SALES APS	2.39	0.0861	Yes
3634	CANOE LAKE SALES	2.39	0.0861	
3165	CANOE LK SLS #2	2.39	0.0861	
3866	CARBON INTERCONNECTION	2.39	0.0861	
3484	CARIBOU LAKE SALES	2.39	0.0861	
3157	CARIBOU LK SOUTH SL	2.39	0.0861	
3106	CARMON CREEK SALES	2.39	0.0861	
3101	CAROLINE SALES	2.39	0.0861	
31017	CARSELAND COGEN SALES APS	2.39	0.0861	
3495	CAVALIER SALES	2.39	0.0861	
31018	CHAIN LAKES COOP SALES APS	2.39	0.0861	
3907	CHANCELLOR INTERCONNECTION	2.39	0.0861	
3151	CHEECHAM W. #2 SALES	2.39	0.0861	
3622	CHEECHAM WEST SALES	2.39	0.0861	
6014	CHEVRON AURORA SALES	2.39	0.0861	
31019	CHEVRON FT. SASK SALES APN	3.39	0.1226	Yes

NATURAL GAS TARIFF

NorthWestern Energy

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

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

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

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

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

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	$ 0.0062088	
Minimum	$ 0.0017935	
GTAC Amortization	$ (0.0010312)	(I)
Balancing Penalty Rate	Higher of $25.00/ Dekatherm Or 150% of Market Price	

PLUS:

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

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

MINIMUM BILL: Per respective contracts.

(continued)

GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company
1415 N. Airport Rd
Pierre, SD 57501

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

Date Filed: January 24, 2001

Effective Date: January 10, 2001

TRANSPORTATION SERVICE Rate 1

Transportation rate is $2.398 per dekatherm.

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

NG00-001

STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE

South Dakota Intrastate Pipeline Company

SD P.U.C. Section No. 4

PUBLIC SERVICE COMMISSION OF WYOMING

SourceGas Distribution LLC

Wyo. P.S.C. Tariff No. 5
Fourth Revised Sheet No. 12
Cancels Third Revised Sheet No. 12

Statement of Firm and Interruptible Transportation Service Rates
Applicable to Shippers Not Receiving
Choice Gas Service
Rate Schedule TC 1/
Casper Division

Division	Receipt Point	Delivery Point	Monthly Customer Charge	Maximum Transportation Charge 2/	Minimum Transportation Charge 2/	Fuel Reimbursement Quantity Percentage 3/
TC (Casper) Firm Transportation	MLI	MLI	$0.00	$0.1040	$0.0010	0.611%
	MLI	MLE	$145.00	$0.1040	$0.0010	0.611%
	MLI	DSE	$225.00	$0.1978	$0.0020	2.072%
Interruptible Transportation 4/	MLI	MLI	$0.00	$0.0844	$0.0010	0.611%
	MLI	MLE	$145.00	$0.0844	$0.0010	0.611%
Administrative Fee 5/			$325.00			

1/ Casper Division service area is defined on Sheet Nos. 3 and 4 of this Tariff.

2/ All charges are per therm.

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

4/ Interruptible Transportation Service is not available to DSE customers. The Customer Charge will be charged only for those months gas actually flows.

5/ In addition to the transportation charges stated above, Shippers are responsible for the monthly administrative fee as stated, applicable to each meter located at the customer location. For Interruptible Transportation Shippers, the Administrative Fee will be charged only for those months gas actually flows. Firm Transportation Shippers will be charged each month, regardless of gas flow.

Abbreviations (as defined in the General Terms and Conditions of this Tariff):
MLI Mainline System Interconnect
MLE Mainline System End-user
DSE Distribution System End-user

Date Issued: March 1, 2012
By: William N. Cantrell

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

MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE SEPTEMBER 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	9,724,328	134,210	975,386
August	11,355,775	207,976	2,011,179
September	12,311,807	626,883	2,828,547
October	12,257,101	614,478	3,094,224
13 month average	$9,042,825	$287,802	$698,281
Rate of Return	8.791%	8.791%	8.791%
Return	$794,955	$25,301	$61,386
Return Requirement	$1,084,054	$34,502	$83,710

1/ Monthly balance from SENDOUT Model, allocated to North Dakota on ratio of storage capacity MDDQ.
2/ Monthly balance allocated to North Dakota on sales volumes.

MONTANA-DAKOTA UTILITIES CO.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE SEPTEMBER 2012

Cost of Purchased Propane	$7,814
Gallons Purchased	12,022
Projected dk Sales	1,100
Propane Cost per Dk	$7.104
Average Cost of Propane as Adjusted for Losses @ 99.55%	7.136
Less: Propane Cost Level in Rates 1/	8.673
Current Propane Cost Adjustment	($1.537)

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

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2011									**($589,074)**
August	$229,854	$119,111 2/	($5) 3/	$348,960	257,122	($0.023)	($5,914)	$354,874	(234,200)
September	153,237	(52,739) 4/	(70) 5/	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) 6/	(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)
Balance @ June 30, 2012									**($1,394,319)**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Reflects correction to restate June gas costs to include correct dk volumes.
3/ Includes interest associated with June gas cost adjustment.
4/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.
5/ Includes interest associated with the September gas cost adjustments.
6/ Reflects 238,784.1 Dk @ ($0.023) and 150,875.5 Dk @ ($0.032).

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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2011									**$48,803**
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)
Balance @ June 30, 2012									**($153,085)**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.
3/ Includes interest associated with the September gas cost adjustments.
4/ Reflects 53,993.4 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

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ July 31, 2011									**$82,096**
August	$7,880	($62,107) 2/	$0	($54,227)	4,781	$0.031	$148	($54,375)	27,721
September	11,054	(72,081) 3/	(7) 4/	(61,034)	4,781	0.031	148	(61,182)	(33,461)
October	(2,569)	0	(1)	(2,570)	11,572	0.041	358 5/	(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)
Balance @ June 30, 2012									**($178,860)**

1/ Interest calculated at the 90 day Treasury Note rate.
2/ Reflects correction to restate June gas costs to include correct dk volumes.
3/ Adjustment to correct gas costs for the period July 2009 - August 2011 due to incorrect pipeline border station metered volumes and adjustment for the period December 2010 - June 2011 to reflect the correct allocation of the volumes associated with the Billings Landfill.
4/ Includes interest associated with the September gas cost adjustments.
5/ Reflects 11,571.6 Dk @ $0.031.