



MONTANA-DAKOTA
UTILITIES CO.

A Division of MDU Resources Group, Inc.

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

July 10, 2012

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

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

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

Attachment A is the Rate Summary Sheet (106th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered August 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.184 per dk since the last filing due to an increase in the overall market price of gas. Attachment B explains the reasons for the increase in the market price of gas.

The COG tariff sheet, Exhibit A page 1, summarizes the gas cost adjustment, calculated pursuant to the terms of Rate 88, and the surcharge adjustment and market based pricing differential provision that will apply during the month of August 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.184 per dk for residential and firm general customers, an increase of \$0.183 per dk for small and large interruptible customers and an increase of \$0.182 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 August 2012. The average cost of gas for firm customers, adjusted for losses, is \$3.818.

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 will not seek a Cost of Gas – Propane (COG) adjustment change for the month of August 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 August 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.

These proposed adjustments, calculated in accordance with Rate 88, will amount to an increase of approximately \$70,200 for natural gas customers during the month of August 2012. All of Montana-Dakota's retail natural gas customers in North Dakota may be affected by this proposal. There were 95,323 natural gas customers in North Dakota as of June 30, 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

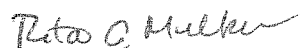
Montana-Dakota submitted a check for the amount of \$500 in accordance with North Dakota Century Code Section 49-05-05 on February 9, 2012. This payment will cover the filing fee associated with this monthly COG filing.

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
106th Revised Sheet No. 3
Canceling 105th 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	\$3.777	\$4.589
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$3.777	\$3.915
Interruptible Service - PAR			\$0.120	\$2.968	\$3.088
Interruptible Service - MAFB			\$0.120	\$2.932	\$3.052
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	\$3.777	\$4.374
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$2.968	(Maximum) \$3.839
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	\$3.866	\$4.463
Summer Gas Usage			\$0.597	\$2.944	\$3.541
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	\$2.968	(Maximum) \$3.687
Residential Propane Rate 90	32	\$0.30 per day	\$0.812	\$9.310	\$10.122
Firm General Propane Rate 92	34				
Meters rated < 500 cubic feet		\$0.52 per day			
Meters rated > 500 cubic feet		\$1.75 per day	\$0.597	\$9.310	\$9.907

Date Filed: July 10, 2012

Effective Date:

Issued By: Tamie A. Aberle
Regulatory Affairs Manager

Case No.:

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

August 2012

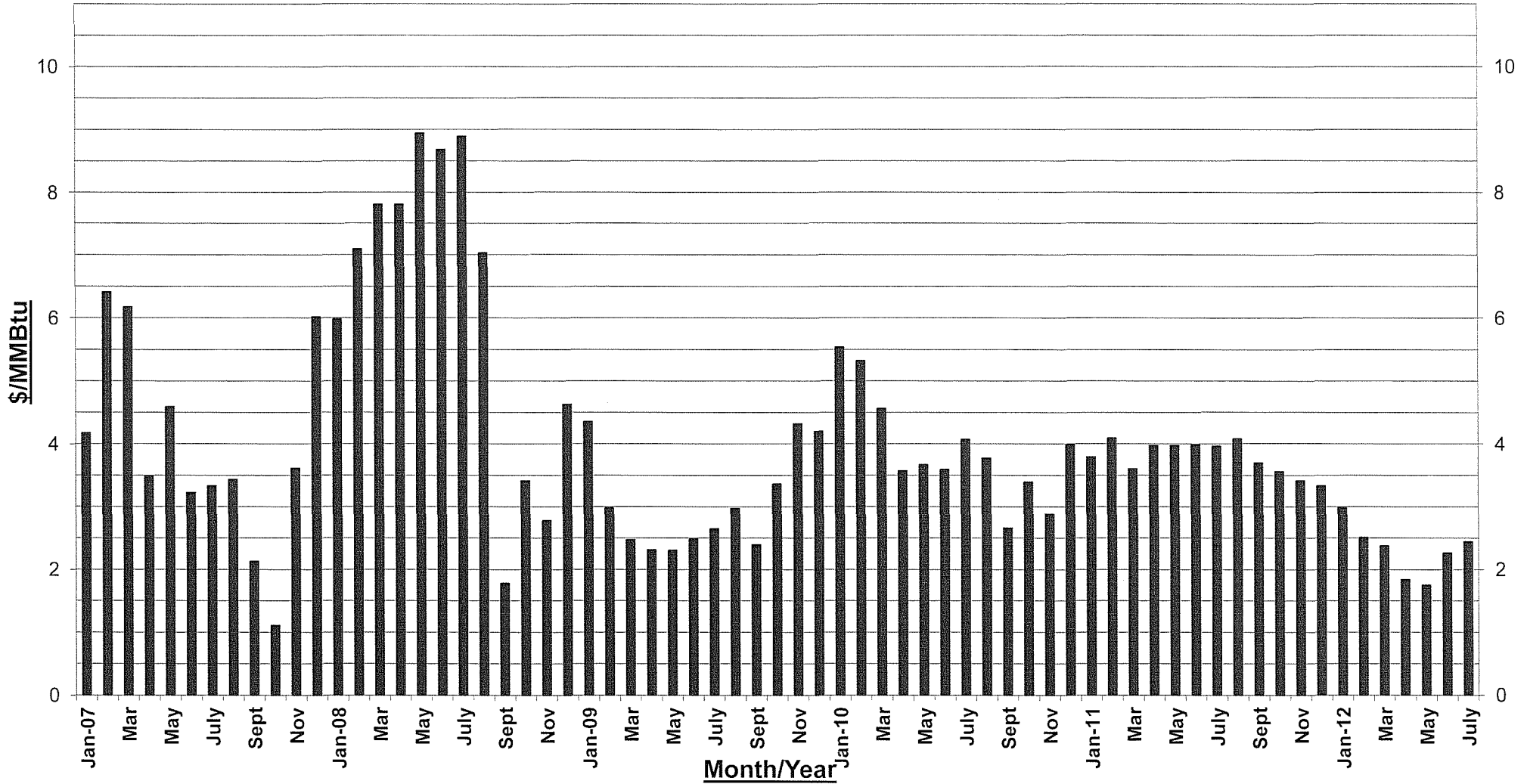
The established monthly price for the Rocky Mountain CIG Index has increased from the previous filing. The CIG Rocky Mountain Index is based on a price discovery survey by several natural gas periodicals, including "Inside FERC Gas Market" report and "Gas Daily" by McGraw-Hill Companies, of prices paid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

Commodity prices have risen due to higher demand for gas resulting from unseasonably warm temperatures across the country. 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 June 22, 2012 were 25.0 percent above the five-year average and 27.1 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 July Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 3 through 17.

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

July 2012

Short-Term Energy Outlook

Highlights

- EIA projects the West Texas Intermediate (WTI) crude oil spot price to average about \$88 per barrel over the second half of 2012 and the U.S. refiner acquisition cost (RAC) of crude oil to average \$93 per barrel, both about \$7 per barrel lower than last month's *Outlook*. EIA expects WTI and RAC crude oil prices to remain roughly at these second half levels in 2013. Beginning in this month's *Outlook*, EIA is also providing a forecast of Brent crude oil spot prices (see [Brent Crude Oil Spot Price Added to Forecast](#)), which are expected to average \$106 per barrel for 2012 and \$98 per barrel in 2013. These price forecasts assume that world oil-consumption-weighted real gross domestic product (GDP) grows by 2.9 percent in both 2012 and 2013.
- With crude oil prices falling over the last month, EIA has lowered the average regular gasoline retail price forecast for the third quarter of 2012 to \$3.39 per gallon. EIA expects regular gasoline retail prices, which averaged \$3.53 per gallon in 2011, to average \$3.49 per gallon in 2012 and \$3.28 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.
- Natural gas working inventories ended June 2012 at an estimated 3.1 trillion cubic feet (Tcf), about 23 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 \$2.58 per MMBtu in 2012 and \$3.22 per MMBtu in 2013.
- In April 2012, the United States exported 12.5 million short tons of coal, which is a monthly record based on EIA data dating back to 1973. Although EIA projects coal exports to total 112 million tons in 2012, 4.6 percent higher than 2011, EIA expects that coal exports will fall by 15.5 million short tons (14 percent) in 2013.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. The projected pace of global oil demand growth in this month's *Outlook* reflects less optimistic assumptions about the global economy. The forecast for global economic growth was lowered by 0.1 and 0.6 percentage points in 2012 and 2013, respectively, from last month's *Outlook*, and is now expected to average 2.9 percent in both years. The weaker growth outlook is prompted by increased economic concerns about the debt crisis in Europe and indications of slowing growth in China, both which could have spillover effects on other economies. The global liquid fuels consumption growth forecast for 2012 was lowered to 0.7 million bbl/d from 0.8 million bbl/d in last month's *Outlook*. Projected global consumption growth in 2013 was lowered by 0.4 million bb/d to 0.7 million bbl/d.

EIA recently released its recurring 60-day report on *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*. As noted in the report, oil markets have loosened over the last several months, which is reflected in a sharp decline in crude oil prices and backwardation since the end of April. EIA's historical supply and demand balance also shows signs of a looser market, as supply outpaced consumption by an average of 1.1 million bbl/d for the first half of 2012, and stocks built counter-seasonally during the first quarter – a marked contrast to significant stock draws during 2011.

EIA's downward price revisions reflect shifts in expectations about oil market balances and the additional downside risks that are currently dominating market sentiments. However, there are both upside and downside uncertainties. The possibility that the economic situation in European Union (EU) countries could deteriorate further poses a downside risk to global oil demand and prices, though the market's positive reaction to recent EU negotiations serves as a reminder that oil prices will fluctuate in both directions 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 0.3 million bbl/d in 2012 and by a further 0.4 million bbl/d in 2013. The prospect 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 continue to place downward pressure on oil prices. EIA currently projects annual increases in consumption in China of about 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.

EU sanctions, including an embargo on Iranian crude and an insurance ban on tankers carrying Iranian oil, became fully effective on July 1, shortly after the latest set of U.S. sanctions entered into force. The United States issued exceptions to all major importers of Iranian oil from sanctions that could have been imposed on foreign financial institutions which facilitated oil-related transactions with the Central Bank of Iran, but only after they had demonstrated or pledged significant reductions in their purchases of Iranian crude oil. The complete market effects of these sanctions are unknown and difficult to disentangle from previous rounds of sanctions, but EIA believes that most of their current and expected effects on Iranian oil supplies

have already been priced into the global oil market. Despite the market's mild reaction to the sanction start dates, upside price risks still persist, particularly if negotiations with Iran fail to progress.

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 0.7 million bbl/d in both 2012 and 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 (World Liquid Fuels Consumption Chart). Projected OECD liquid fuels consumption declines by 0.5 million bbl/d in 2012 and a further 0.3 million bbl/d in 2013.

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 0.7 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 substantially less than in 2010 or 2011, when third-quarter consumption outpaced supply by 1.5 million bbl/d and 1.8 million bbl/d, respectively.

Non-OPEC Supply. EIA expects crude oil and liquid fuels production by non-Organization of the Petroleum Exporting Countries (OPEC) to rise by 0.8 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 880 thousand bbl/d and 540 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 170 thousand bbl/d in 2013. In Brazil, output is projected to rise by 120 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.

Several notable disruptions to non-OPEC production commenced or intensified since the beginning of this year, as discussed in the June 26, 2012 report on *[The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran](#)*. Unplanned outages to non-OPEC production totaled around 1.0 million bbl/d in June 2012, higher than the estimate given in the June 26th report. The increase is due to an offshore workers' strike in Norway that affected 230 to 250 thousand bbl/d of crude oil and natural gas liquids production, according to Statoil. 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.

Unplanned disruptions also rose slightly in the second half of June due to a labor protest in Argentina that lowered production from the Cerro Dragon oil field, which has a capacity of 100

thousand bbl/d. The field's operator is gradually ramping up production at the field as protestors have mostly withdrawn from the area.

OPEC Supply. EIA expects that OPEC members will continue to produce about 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 0.8 million bbl/d in 2012, and then falls by 0.9 million bbl/d 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 5.5 million bbl/d in 2011 and are forecast to increase by 0.3 million bbl/d in 2012 and less than 0.1 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. However, EIA estimates that Iranian production fell faster than the prevailing trend in June as unsold or undelivered Iran cargoes tested the limits of available storage capacity and some combination of production shut-ins, greater-than-anticipated declines in production capacity, or overdue maintenance occurred. 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.

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 2.4 million bbl/d in 2012 and rise to an average 3.6 million bbl/d in 2013 (OPEC Surplus Crude Oil Production Capacity Chart). However, as discussed above, markets may be closely watching the composition of OPEC spare capacity, as well as its aggregate level, as the situation with respect to Iran evolves. Under plausible circumstances, the market may discount a portion of OPEC members' aggregate spare capacity.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2011 at 2.59 billion barrels, equivalent to 55.9 days of forward-cover (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories increase to 2.63 billion barrels and 57.3 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. Beginning in this month's *Outlook*, EIA is providing a forecast of Brent crude oil spot prices (see [Brent Crude Oil Spot Price Added to Forecast](#)). After WTI and Brent fell to year-to-date lows of \$78 per barrel and \$89 per barrel, respectively, on June 21, 2012, oil prices rose following news of a possible Euro-zone agreement regarding debt issues that have clouded the European and global economic outlooks. EIA projects the price of Brent crude oil to average \$106 per barrel in 2012 and \$98 per barrel in 2013. The WTI price forecast has been lowered by \$4 per barrel from last month's *Outlook* to \$93 per barrel in 2012 and by \$9 per barrel to \$89 per barrel in 2013 (West Texas Intermediate Crude Oil Price Chart).

Energy price forecasts are highly uncertain ([Market Prices and Uncertainty Report](#)). WTI futures for October 2012 delivery during the 5-day period ending July 5, 2012 averaged \$85 per barrel. Implied volatility averaged 33 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in October 2012 at \$64 per barrel and \$114 per barrel, respectively. Last year at this time, WTI for October 2011 delivery averaged \$98 per barrel and implied volatility averaged 28 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$76 per barrel and \$125 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Total consumption fell 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 150 thousand bbl/d (0.8 percent). In the first quarter, total consumption fell 700 thousand bbl/d (3.7 percent) from the same period last year (U.S. Liquid Fuels Consumption Chart) as high retail pump prices and increases in fleet-wide fuel efficiency depressed consumption of motor gasoline. In addition, record warm weather and low natural gas prices substantially reduced consumption of heating oil and residual fuel oil. The second quarter witnessed an estimated year-over-year decline of 200 thousand bbl/d due primarily to continued declines in distillate fuel oil and residual fuel oil

consumption. For the second half of 2012, EIA expects a turnaround in liquid fuels consumption with a projected year-over-year increase of 140 thousand bbl/d (0.7 percent). The bulk of that growth comes from natural gas liquids and distillate fuel, which rise because of continued growth in industrial production and the assumption of near-normal weather next winter. Motor gasoline consumption, however, remains unchanged from the same period last year as continued efficiency increases offset modest growth in highway travel. Residual fuel consumption levels off, albeit at close to record-low levels.

In 2013, total liquid fuels consumption grows by just 70 thousand bbl/d (0.4 percent), led by a 60-thousand-bbl/d (1.7-percent) increase in distillate consumption. Despite assumed growth in U.S. real disposable income of 1.8 percent next year, forecast motor gasoline consumption declines by a further 40 thousand bbl/d (0.5 percent) in 2013. This projection reflects continued 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 200 thousand bbl/d (3.7 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 660 thousand bbl/d in 2012; output in the Gulf of Mexico (GOM) stabilizes after having fallen last year, but Alaskan output continues to decline by 30 thousand bbl/d (U.S. Crude Oil and Liquid Fuels Production Chart). In 2013, total crude oil output rises a further 410 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 1,419 on July 6, 2012.

Based on the outlook from the National Oceanic and Atmospheric Administration for the current Atlantic hurricane season, EIA statistical analysis based on a historical averages derives a 70-percent probability that total shut-in crude oil production in the GOM during the current hurricane season (June through November) will fall somewhere between 2.8 and 7.2 million barrels, with a median outcome of 4.5 million barrels (an average 25 thousand bbl/d over the 6 months; see the [2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). In late June, Tropical Storm Debby caused several days of disruption to crude oil and natural gas production. During the peak of Debby-related outages, 600 thousand bbl/d was shut in, or about 44 percent of normal production. Almost all shut-in production resumed after a few days with a total production outage of about 1.3 million barrels.

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 in April 2012, gasoline prices have fallen for the second consecutive month, averaging \$3.54 per gallon in June 2012. Due to the sharp decline in crude oil prices throughout May and June, EIA expects regular gasoline retail prices to average \$3.39 per gallon during the third quarter of 2012, compared with \$3.51 per gallon in last month's *Outlook*, and \$3.63 per gallon during the same period last year. EIA projects that crude oil prices will remain near their current lower levels through 2013, resulting in regular gasoline retail prices averaging \$3.49 per gallon in 2012 and \$3.28 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$3.79 per gallon in 2012, down 11 cents per gallon from last month's *Outlook*. In 2013, diesel fuel retail prices are projected to decline another 21 cents to an average of \$3.58 per gallon (U.S. Diesel Fuel and Crude Oil Prices Chart).

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.9 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.3 Bcf/d (4.9 percent) from 2011 and an upward revision of 0.5 Bcf/d from last month's *Outlook*. EIA expects that 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 grows by 21 percent in 2012, primarily driven by the increased relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector peaks at 31.2 Bcf/d in the third quarter of 2013, when electricity demand for air conditioning is highest. This compares with 27.7 Bcf/d during the third quarter of 2011.

Growth in total natural gas consumption slows in 2013, with forecast consumption averaging 71.1 Bcf/d (U.S. Natural Gas Consumption Chart). However, unlike 2012, growth in 2013 is driven by consumption increases from the residential, commercial, and industrial sectors. A forecast of near-normal weather next winter drives 2013 increases in residential and commercial consumption of 7.7 percent and 4.5 percent, respectively. Although projected natural gas burn in the electric power sector declines by 1.9 percent from 2012, it remains at 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, though not as strong as the previous year (U.S. Natural Gas Production and Imports Chart). This month's *Outlook* revises

upward the forecast for marketed production for 2012, partially reflecting upward revisions to historical data for the first few months of the year. EIA, however, expects a small drop in production in the coming months, reflecting the decline in rigs since October 2011. According to Baker Hughes, the natural gas rig count was 542 as of July 6, 2012, up slightly from last week, which was the lowest rig count since 1999. EIA's production survey indicates natural gas marketed production fell between February and March 2012, but rebounded in April. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale 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.

Based on the outlook from National Oceanic and Atmospheric Administration for the current Atlantic hurricane season, EIA estimates a 70-percent probability that total shut-in natural gas production in the GOM during the upcoming hurricane season (June through November) will fall somewhere between 5.8 and 16.2 Bcf, with a median outcome of 9.5 Bcf (an average of 0.05 Bcf/d over the 6 months; see the [2012 Outlook for Hurricane-Related Production Outages in the Gulf of Mexico](#)). In late June, Tropical Storm Debby caused several days of disruption to crude oil and natural gas production. During the peak of Debby-related outages, 1.6 Bcf/d of natural gas was shut in, or about 35 percent of normal production. Almost all shut-in production resumed after a few days with a total production outage of about 3.9 Bcf.

EIA expects pipeline gross imports will fall by 0.2 Bcf/d (2.6 percent) in 2012, as domestic supply continues to displace Canadian sources. The warm winter in the United States 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 increase by 2.2 percent in 2013, partially due to near-normal winter weather driving higher residential and commercial demand. 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 0.4 Bcf/d (44 percent) in 2012. EIA expects that an average of about 0.6 Bcf/d will arrive in the United States (mainly at the Elba Island terminal in Georgia) in 2012 and 2013, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions.

U.S. Natural Gas Inventories. Working natural gas inventories remain at historically high levels for the time of year. As of June 29, 2012, according to EIA's [Weekly Natural Gas Storage Report](#), working inventories totaled 3,102 Bcf, 602 Bcf greater than last year's level and 573 Bcf above the five-year average. The weekly report from June 15, 2012, marked the first time in EIA's history that working inventories surpassed the 3,000 Bcf mark during the month of June. EIA expects that inventory levels at the end of October 2012 will set a new record high slightly above 4,000 Bcf (U.S. Working Natural Gas in Storage Chart), although the projected increase of 1,525 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 record highs, although they will still remain abundant compared with recent history.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$2.47 per MMBtu at the Henry Hub in June 2012, up \$0.04 per MMBtu from the May average. Prices remain at historically low levels; the June 2012 price averaged 46 percent less than the June 2011 price. Abundant supplies and lack of demand during the warm winter contributed to the current low prices. EIA expects the Henry Hub natural gas price will average \$2.58 per MMBtu in 2012, with modest monthly increases through the rest of the year. EIA expects 2013 prices will average \$3.22 per MMBtu (U.S. Natural Gas Prices Chart).

Natural gas futures prices for October 2012 delivery (for the 5-day period ending July 5, 2012) averaged \$2.90 per MMBtu, and the average implied volatility based on options and futures prices was 55 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 October 2012 contracts at \$1.74 per MMBtu and \$4.82 per MMBtu, respectively. At this time last year, the October 2011 natural gas futures contract averaged \$4.33 per MMBtu and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.12 per MMBtu and \$6.00 per MMBtu.

Coal

U.S. Coal Consumption. Power-sector coal consumption fell from 975 million short tons (MMst) in 2010 to 929 MMst in 2011 (U.S. Coal Consumption Chart). Lower electric power sector natural gas prices have led to a significant increase in the share of natural-gas-fired generation in both 2011 and 2012. EIA expects coal consumption in the electric power sector to total slightly less than 800 MMst in 2012. Although EIA expects the price of natural gas relative to the price of coal at electric utilities to begin to show year-over-year increases beginning in early 2013, projected power sector coal consumption remains flat next year.

U.S. Coal Supply. EIA forecasts that coal production will decline by 9 percent in 2012 as domestic consumption falls (U.S. Coal Production Chart). Production for the first five months of 2012 was 25 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 (6 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 200 MMst by the end of the year (estimated stocks for April 2012 were 203 MMst) and inventories will remain at elevated levels in 2013 (U.S. Electric Power Sector Coal Stocks Chart).

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 12.5 MMst of coal in April, which is a monthly record based on EIA data dating back to 1973. Although EIA projects coal exports to total 112 million tons in 2012, forecast coal exports weaken slightly with year-over-year declines beginning in the fourth quarter of 2012. Major reasons for the export decline include China's economic slowdown and high coal stockpiles, and increased exports from Indonesia and Australia. EIA expects that coal exports will fall by 16 million short tons (14 percent) in 2013. 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 put downward pressure on coal prices and contribute to the shut-in of higher-cost production. EIA forecasts the average delivered coal price in 2012 will be 0.4 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be \$2.33 per MMBtu, or nearly 3 percent (\$0.06) lower than the 2012 price.

Electricity

U.S. Electricity Consumption. This year's summer season has started out with abnormally hot temperatures. According to the National Oceanic and Atmospheric Administration, U.S. cooling degree-days during June 2012 were about 14 percent higher than the 30-year average, but 4 percent lower than June 2011. EIA expects that temperatures during the third quarter of 2012, although above normal, will average about 16 percent lower than last year. This reduced need for summer cooling contributes to EIA's projection of a 3.8-percent decline in residential electricity sales in 2012. EIA expects total consumption of electricity to fall by 1.3 percent during 2012, and then grow by 1.3 percent in 2013 (U.S. Total Electricity Consumption Chart).

U.S. Electricity Generation. For the first time since EIA began compiling monthly statistics, the share of total generation fueled by natural gas during April 2012 rose to the point where it was nearly equal to the share fueled by coal (about 32 percent for each). However, this situation is likely temporary. The year-over-year gains in the share of generation fueled by natural gas should slow and eventually reverse as the higher natural gas costs projected for later in 2012 and in 2013, along with record coal stocks, encourage generators to increase their utilization of coal-fired power plants over the forecast horizon. EIA forecasts total generation by coal across all sectors will decline by 14 percent in 2012, followed by an increase of 1.3 percent in 2013. In contrast, total generation by natural gas is forecast to rise by 23 percent this year and then decline by 1.0 percent next year (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. EIA expects the average U.S. residential electricity price to rise from an average of 11.79 cents per kilowatthour in 2011 to 12.03 cents per kilowatthour this

year, an increase of 2.0 percent (U.S. Residential Electricity Prices Chart). The forecast cost of natural gas delivered to the electric power sector is about 30 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 only 0.2 percent in 2013, which would be the slowest growth rate in nominal prices in 10 years.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 14 percent in 2011, total renewable energy supply is projected to decline by 1.3 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of hydropower resource levels beginning to return to the long-term average, with supply falling by 0.3 quadrillion Btu (11 percent). The decline in hydropower from the 2011 level more than offsets growth in other renewable energy supplies. Renewable energy supply increases slightly (0.5 percent) in 2013 as hydropower continues to decline (5.9 percent) but non-hydropower renewables grow by an average of 3.8 percent.

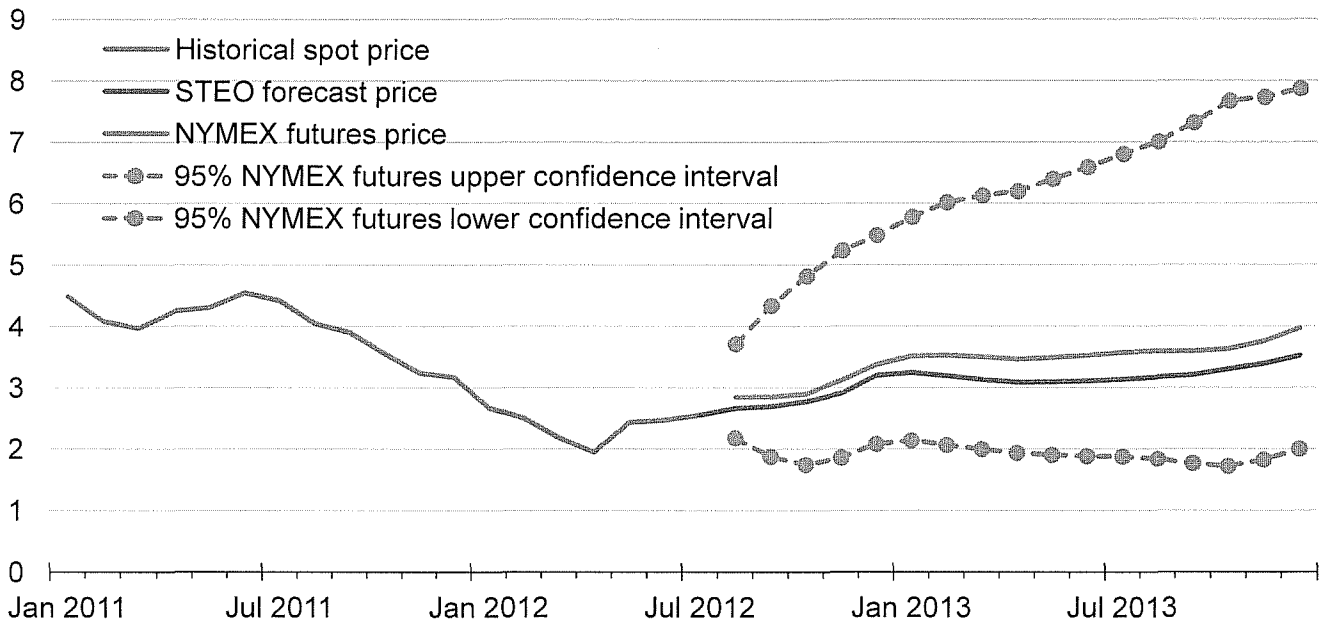
Under current law, Federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 17 percent in 2012. The outlook for wind capacity additions and generation in 2013 will likely respond to whatever decision is made regarding the extension of production tax credits.

EIA expects fuel ethanol production to average 901 thousand bbl/d in 2012 and 2013, almost the same level as last year. This forecast assumes that E15 (gasoline blended with 15 percent ethanol by volume) does not yet reach the market in significant volumes. Consequently, U.S. ethanol production is projected to exceed the volume that can easily be used in the U.S. liquid fuels pool, so the Nation will continue to be a net exporter of ethanol over the next two years. EIA estimates that biodiesel production in 2011 averaged about 63 thousand bbl/d (971 million gallons of total annual production). Forecast biodiesel production averages 70 thousand bbl/d in 2012 and 75 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 3.0 percent in 2012, but increase by 0.8 percent in 2013. Petroleum emissions decline in 2012 (0.9 percent) and then rise by 0.3 percent in 2013, while natural gas emissions rise by 5.3 percent and 1.5 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 11 percent, but rise by 0.8 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

dollars per million btu



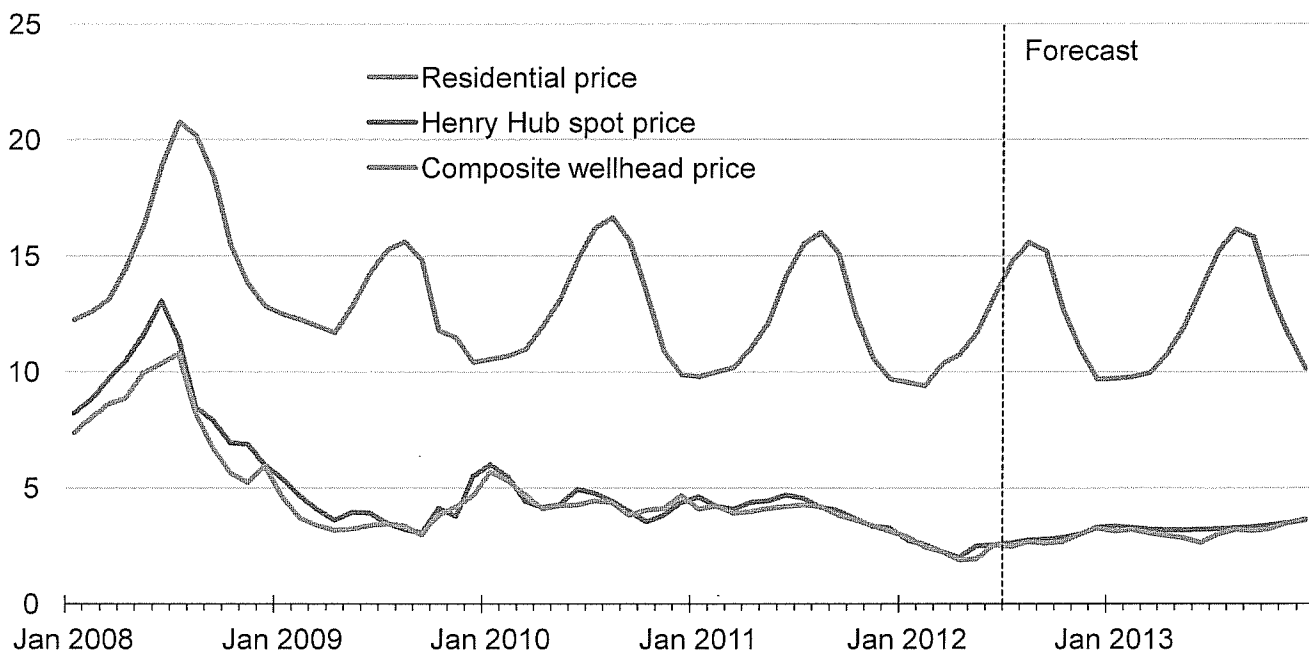
Note: Confidence interval derived from options market information for the 5 trading days ending July 5, 2012. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, July 2012



U.S. Natural Gas Prices

dollars per thousand cubic feet



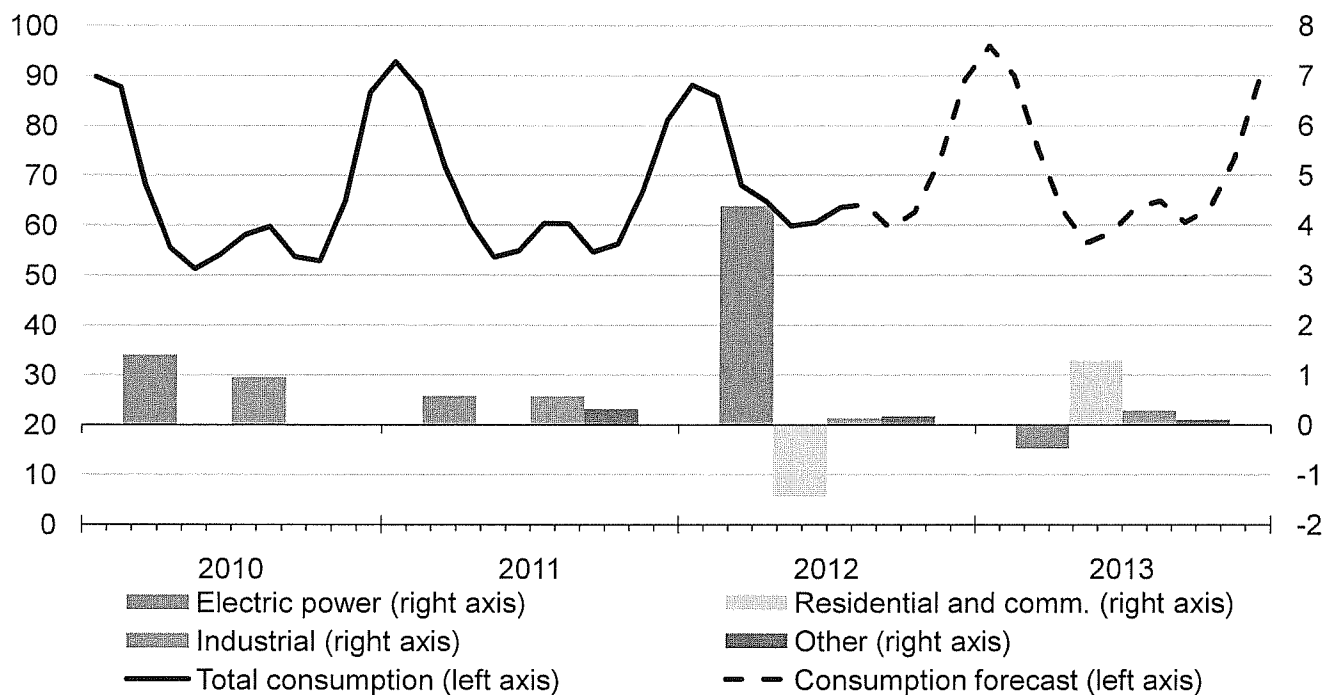
Source: Short-Term Energy Outlook, July 2012



U.S. Natural Gas Consumption

billion cubic feet per day (bcf/d)

annual change (bcf/d)

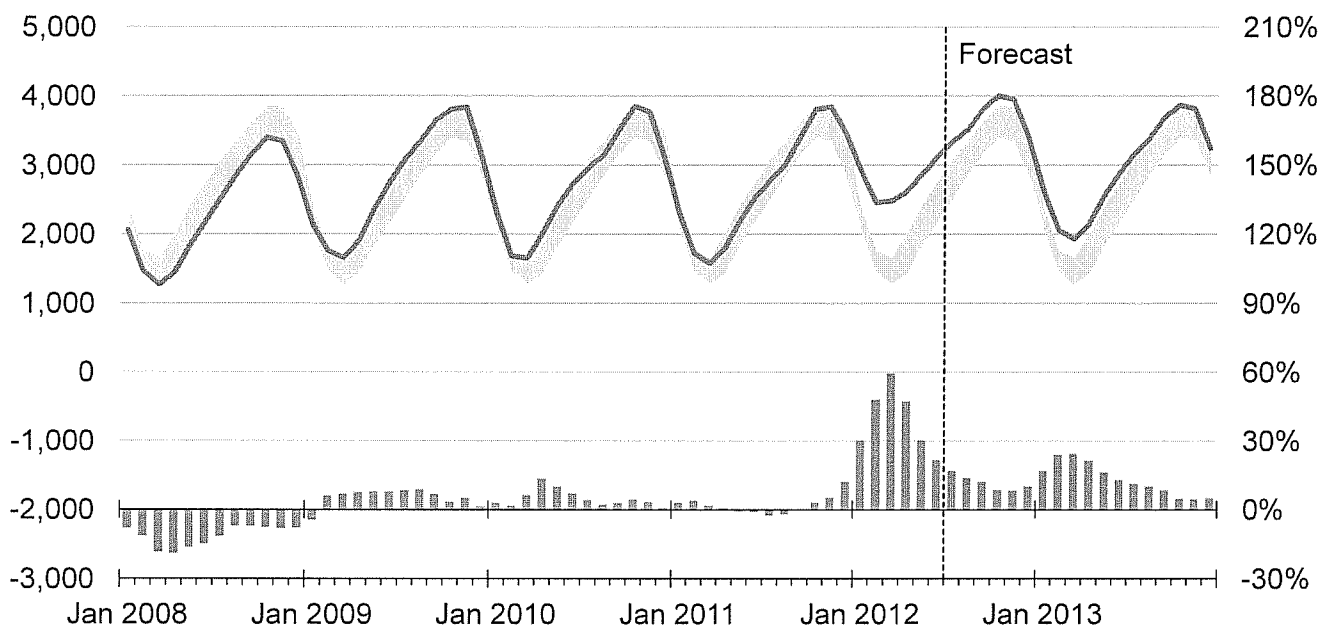


Source: Short-Term Energy Outlook, July 2012



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, July 2012



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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$3.818	\$2.985	\$2.904	\$2.891
Prior Gas Cost	3.634	2.803	2.721	2.709
Current Gas Cost Adjustment	\$0.184	\$0.182	\$0.183	\$0.182
<u>Surcharge Adjustment:</u>				
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
<u>Market Based Pricing Differential</u>				
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	\$0.184	\$0.182	\$0.183	\$0.182
Gas Cost Level	\$3.818	\$2.985	\$2.904	\$2.891
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	\$3.786	\$2.953	\$2.968	\$2.932

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

	Amount
Total Gas Costs 1/	\$54,229,586
Residential and General Service dk Requirements 2/	14,266,932
Average Cost of Gas per dk	\$3.801
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.818
Less: Gas Cost Level in Rates 3/	3.634
Current Gas Cost Adjustment	\$0.184

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

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

Cost of Purchased Gas	\$3.618
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.634

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$54,229,586
Less: Annual MDDQ Costs 1/	<u>11,821,667</u>
Total Gas Costs excluding MDDQ	\$42,407,919
Firm Service Requirements 1/	14,266,932
Other Gas Costs per Dk (excluding MDDQ)	\$2.972
Summer Seasonal Rate, adjusted for losses 2/	2.985
Less: Gas Cost Level in Rates 3/	<u>2.803</u>
Current Gas Cost Adjustment	<u><u>\$0.182</u></u>
 <u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,821,667
Winter Firm Service Requirements	12,894,353
MDDQ Costs per Winter Dk	\$0.917
Add: Other Gas Costs per Dk	<u>2.972</u>
Winter Seasonal Rate	\$3.889
Winter Seasonal Rate, adjusted for losses 2/	\$3.907

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$2.790	\$3.706
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$2.803	\$3.723

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

	Amount
Total Gas Costs 1/	\$10,125,442
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$2.891
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.904
Less: Gas Cost Level in Rates 2/	2.721
Current Gas Cost Adjustment	\$0.183

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 July 1, 2012:

Cost of Purchased Gas	\$2.709
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$2.721

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

	<u>Amount</u>
Total Gas Costs 1/	\$2,543,831
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$2.891
Less: Gas Cost Level in Rates 2/	<u>2.709</u>
Current Gas Cost Adjustment	<u><u>\$0.182</u></u>

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 July 1, 2012:
Cost of Purchased Gas \$2.709

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

Issued On: March 1, 2012
 Docket Number: RP12-444-000
 FERC Order Date: March 27, 2012

Effective On: April 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 0.852%, 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.

Issued On: March 1, 2012
 Docket Number: RP12-444-000
 FERC Order Date: March 27, 2012

Effective On: April 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.

NOVA Gas Transmission Ltd.

Table of Rates, Tolls and Charges
Page 1 of 2

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 ³ m 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	<u>Contract Term</u>	<u>Effective LRS Rate (\$/10³m³/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 ³ m 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	<u>Schedule No</u>	<u>PT Rate</u>	<u>PT Gas Rate</u>
	9009-01001-1	\$ 660.00/d	50.0 10 ³ m ³ /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 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	
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



	28 th	Revised	Sheet No.	80.1
Canceling	27 th	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
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Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	\$ 0.0062088
Minimum	\$ 0.0017935
GTAC Amortization	\$ (0.0011145)
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)

Staff Approved: January 26, 2012
Docket No.: D2011.12.97, Final Order No. 7191a
Tariff Letter No. 205-G

Effective for service rendered on or after
January 1, 2012

PUBLIC SERVICE COMMISSION
Aleisha Zecum 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

**STATE OF SOUTH DAKOTA
GAS RATE SCHEDULE**

NG-00-001

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 AUGUST 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	8,432,133	62,621	(58,038)
July	9,713,112	132,345	995,583
August	10,946,718	194,501	2,030,012
September	11,776,004	610,915	2,845,429
October	11,726,451	598,461	3,107,671
13 month average	<u>\$8,969,242</u>	<u>\$282,541</u>	<u>\$705,271</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$788,486	\$24,838	\$62,000
Return Requirement	<u>\$1,075,233</u>	<u>\$33,871</u>	<u>\$84,547</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 ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM**

	<u>(Over) Under Recovery</u>	<u>Refunds & 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>
Balance @ July 31, 2011									<u>(\$589,074)</u>
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)
Balance @ May 31, 2012									<u>(\$883,562)</u>

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & 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>
Balance @ July 31, 2011									<u><u>\$48,803</u></u>
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)
Balance @ May 31, 2012									<u><u>(\$125,133)</u></u>

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**

	<u>(Over) Under Recovery</u>	<u>Refunds & 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>
Balance @ July 31, 2011									<u><u>\$82,096</u></u>
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)
Balance @ May 31, 2012									<u><u>(\$155,856)</u></u>

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.