



MONTANA-DAKOTA
UTILITIES CO.

A Division of MDU Resources Group, Inc.

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

June 8, 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 (105th Revised Sheet No. 3) showing the proposed natural gas rates, to be effective with service rendered July 1, 2012.

Montana-Dakota purchases gas supplies under a number of contracts. The commodity cost of gas has increased \$0.518 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 July 2012.

The net effect of this filing, calculated pursuant to the terms of Rate 88, is an increase of \$0.518 per dk for residential and firm general customers and an increase of \$0.526 per dk for small and large interruptible customers and an increase of \$0.524 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 July 2012. The average cost of gas for firm customers, adjusted for losses, is \$3.634.

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 July 2012. The net effect of this filing is a decrease of \$3.403 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 July 2012. The average cost of propane for all customers, adjusted for losses, is \$8.673 per dk.

These proposed adjustments, calculated in accordance with Rate 88 and 99, will amount to an increase of approximately \$186,800 for natural gas customers and a decrease of approximately \$3,700 for propane customers during the month of July 2012. All of Montana-Dakota's retail natural gas and propane customers in North Dakota may be affected by this proposal. There were 95,093 natural gas customers and 339 propane customers in North Dakota as of May 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:

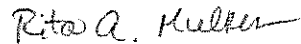
Mr. Daniel S. Kuntz
Associate General Counsel
MDU Resources Group, Inc.
P. O. Box 5650
Bismarck, ND 58506-5650

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
 105th Revised Sheet No. 3
 Canceling 104th 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	\$3.593	\$4.405
Air Force Rate 64	7				
Minot Air Force Base		\$1,000.00 per month			
PAR Site		\$135.00 per month			
Firm Service			\$0.138	\$3.593	\$3.731
Interruptible Service - PAR			\$0.120	\$2.785	\$2.905
Interruptible Service - MAFB			\$0.120	\$2.750	\$2.870
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	\$3.593	\$4.190
Small Interruptible Gas Rate 71	14	\$100.00 per month	(Maximum) \$0.871	\$2.785	(Maximum) \$3.656
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	\$3.682	\$4.279
Summer Gas Usage			\$0.597	\$2.762	\$3.359
Transportation Service	24				
Small Interruptible Rate 81		\$150.00 per month			
Maximum			\$0.427		
Minimum			\$0.102		
Fuel Charge				\$0.012	
Large Interruptible Rate 82		\$725.00 per month			
Maximum			\$0.298		
Minimum			\$0.061		
Fuel Charge				\$0.012	
Large Interruptible Gas Rate 85	27	\$675.00 per month	(Maximum) \$0.719	\$2.785	(Maximum) \$3.504
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: June 8, 2012

Effective Date:

Issued By: Tamie A. Aberle
 Regulatory Affairs Manager

Case No.:

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

July 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 for July have risen from the June levels due to higher demand for gas due to 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 May 25, 2012 were 34.6 percent above the five-year average and 35.1 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 June Short-Term Outlook is not available until June 12. The May Outlook is provided as pages 4 through 18.

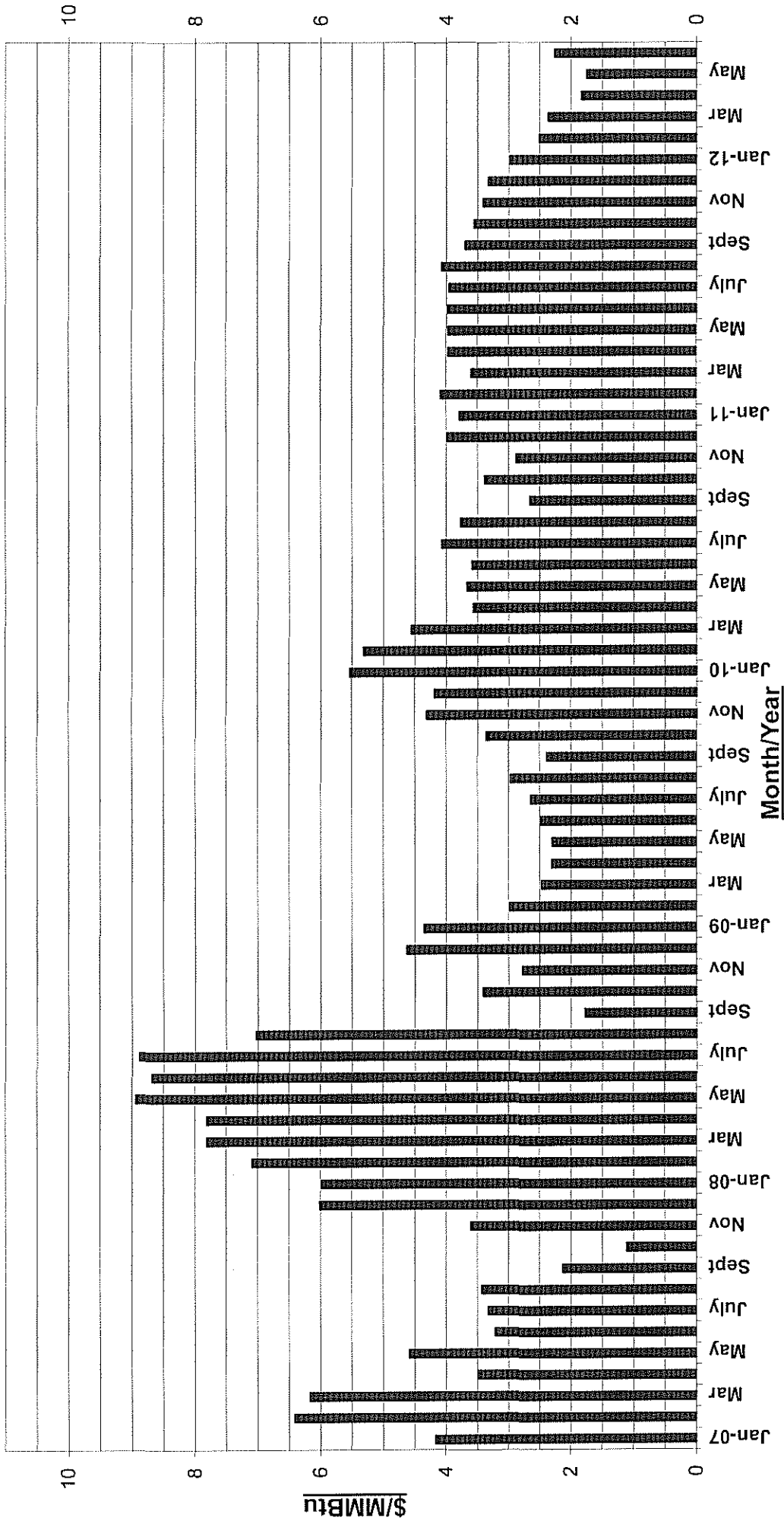
**Montana-Dakota Utilities Co.
Market Conditions for Regional Propane
July 2012**

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 July 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 - \$2.29



Independent Statistics & Analysis

U.S. Energy Information
Administration

May 2012

Short-Term Energy Outlook

Highlights

- EIA's current forecast of the average U.S. refiner acquisition cost of crude oil in 2012 is \$110 per barrel, which is \$2.50 per barrel lower than in last month's *Outlook*, but still about \$8 per barrel higher than last year's average price. EIA expects the price of West Texas Intermediate (WTI) crude oil to average about \$104 per barrel in 2012, about \$2 per barrel lower than the forecast in last month's *Outlook*, but \$9 per barrel higher than the 2011 average price. EIA expects crude oil prices to remain relatively flat in 2013.
- With falling global crude oil prices over the past month, EIA has lowered the average regular gasoline retail price forecast for the current April-through-September summer driving season to \$3.79 per gallon, 16 cents per gallon below the level in the previous *Outlook*. EIA expects regular gasoline retail prices to average \$3.71 per gallon in 2012 and \$3.67 per gallon in 2013, compared with \$3.53 per gallon in 2011. The September 2012 New York Harbor Reformulated Blendstock for Oxygenate Blending (RBOB) futures contract averaged \$2.99 per gallon for the five trading days ending May 3. Based on the market value of futures and options contracts, there is a 22 percent probability that the RBOB contract price at expiration will exceed \$3.30 per gallon, consistent with an average regular-grade gasoline retail price exceeding \$4.00 per gallon in September.
- EIA expects U.S. total crude oil production to average 6.2 million barrels per day (bbl/d) in 2012, an increase of 0.5 million bbl/d from last year, and the highest level of production since 1998. Forecast lower-48 onshore crude oil production in 2012 averages over 4.3 million bbl/d, reaching its highest level since 1993. Projected U.S. domestic crude oil production increases to 6.4 million bbl/d in 2013, driven primarily by growth in lower-48 onshore production.
- Very mild weather over the past winter contributed to natural gas working inventories that continue to set new record seasonal highs, with April 2012 ending at an estimated 2.61 trillion cubic feet (Tcf), about 46 percent more than the same time last year. EIA's average 2012 Henry Hub natural gas spot price forecast is \$2.45 per million British thermal units (MMBtu), a decline of \$1.55 per MMBtu from the 2011 average spot price. EIA expects that Henry Hub spot prices will average \$3.17 per MMBtu in 2013.

- EIA expects electricity generation from coal to decline by about 15 percent in 2012 as generation from natural gas increases by about 24 percent. EIA forecasts that electricity generation from coal will increase by about 4 percent in 2013, as projected coal prices fall slightly while natural gas prices increase, allowing coal to regain some of its power generation share.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects that global oil markets will continue to remain tight in 2012, although markets have eased somewhat since mid-March. Year-over-year supply growth in 2012 should significantly exceed the projected 1.0 million bbl/d rise in consumption, and we expect global commercial stocks to build following the significant draws during 2011. The oil production gains contributed to a counter-seasonal stock build during the 1st quarter of 2012 and a moderate reduction in backwardation in crude oil prices. However, EIA does not expect these large counter-seasonal stock builds to continue throughout the year, and both global oil inventory and spare production capacity levels are projected to be tight enough to support higher average crude oil prices in 2012 than in the previous year. The projected oil market balance reflects the impacts from previous sanctions against Iran, but the potential impacts of the more recent sanctions set to take effect this year are not accounted for in the current *Outlook*.

Crude oil prices have declined after increasing through mid-March, as global liquids supply outpaced consumption by 0.6 million bbl/d in first quarter 2012, which led to global inventory builds. The easing in the backwardation of waterborne light crude prices noted in EIA's April 27th report, *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran*, has also continued in recent days. While price trends and reduced backwardation signal some market easing, the continuing premium on contracts for near-term delivery and a price level that remains elevated relative to the fourth quarter of 2011 is still indicative of tightness in world oil markets.

There are several uncertainties that could push oil prices higher or lower than projected. A number of countries outside of the Organization of the Petroleum Exporting Countries (OPEC) are currently undergoing supply disruptions, as discussed in EIA's April 27th report *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran* and the April 18 edition of *This Week in Petroleum*. 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. Additionally, although the effects of the impending European Union embargo and other sanctions targeting exports of Iranian crude oil and their associated payments are still uncertain, heightened market anxiety surrounding a potentially significant supply disruption could bolster oil prices. On the demand side, economic growth below current expectations could result in reduced oil demand and lower prices.

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 1.0 million bbl/d in 2012 and 1.2 million bbl/d in 2013, with China, the Middle East, Central and South America, and other countries outside of the Organization for Economic Cooperation and Development (OECD) accounting for essentially all consumption growth (World Liquid Fuels Consumption Chart). OECD liquid fuels consumption is projected to decline by 0.4 million bbl/d in 2012, with Europe and, to a lesser extent, the United States accounting for almost all of the decline. In 2013, forecast OECD liquid fuels consumption is expected to remain essentially flat.

Non-OPEC Supply. EIA expects non-OPEC crude oil and liquid fuels production to rise by 0.7 million bbl/d in 2012 and by a further 1.1 million bbl/d in 2013. The largest area of non-OPEC growth will be North America, where production increases by 680 thousand bbl/d and 260 thousand bbl/d in 2012 and 2013, respectively, resulting from continued production growth from U.S. onshore shale and other tight oil formations and Canadian oil sands. In Brazil, output is projected to rise annually by an average of 130 thousand bbl/d over the next two years, with increased output from its offshore, pre-salt oil fields. EIA expects that Kazakhstan, which will commence commercial production in the Kashagan field next year, will increase its total production by 160 thousand bbl/d in 2013. Production also rises in China 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 both the April 27th report *The Availability and Price of Petroleum and Petroleum Products Produced in Countries Other Than Iran* and in the April 18 edition of *This Week in Petroleum*. Unplanned outages to non-OPEC production totaled over 1.2 million bbl/d in March and are estimated to remain at an elevated level.

OPEC Supply. EIA expects that OPEC members will continue to produce slightly over 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil demand and to counterbalance supply disruptions. Projected OPEC crude oil production increases by about 1.0 million bbl/d in 2012 and then falls by 0.3 million bbl/d in 2013 as non-OPEC supply growth increases and stocks remain flat. OPEC non-crude petroleum liquids (condensates, natural gas liquids, coal-to-liquids, and gas-to-liquids), which are not covered by OPEC's production quotas, are forecast to increase by 0.2 million bbl/d in 2012, and by 0.1 million bbl/d in 2013.

EIA expects Iran's crude production to fall by about 500 thousand bbl/d by the end of 2012 and by an additional 200 thousand bbl/d in 2013, from its previous output level of 3.55 million bbl/d at the end of 2011. Iran's output decline began to accelerate during the last quarter of 2011 and has continued. EIA believes that this acceleration reflects a lack of investment, which is needed to offset natural production declines. A number of foreign companies that were investing in Iran's upstream have halted their activities as a result of previous sanctions against Iran that have made it difficult to do business with the country. EIA expects that the forecast decline in Iran's output will be offset by increased production in other OPEC member countries.

EIA's forecast of market balances does not factor in any potential effects of the more recent sanctions targeting Iran's central bank and the impending European Union embargo on Iran's crude oil production, or their possible impact on the production, spare capacity, or inventories of Iran and other OPEC member countries. As noted in EIA's April 27th report, there are indications that the U.S. and EU sanctions are already affecting sales of Iranian crude oil. Current and continuing difficulties in placing export volumes from Iran could result in a buildup of Iranian oil in storage, whether onshore or offshore. An increase in Iranian crude oil storage would drive an increase in global oil inventories. However, insofar as inventories held by Iran are building due to the effect of sanctions on its ability to sell oil, those volumes would not be available to consumers in the same way as traditional inventories.

Moreover, if Iran's difficulties in finding markets for its oil persist or intensify, or outstrip available storage capacity, Iran may have to shut in production. EIA expects that any volumes that are shut-in could be replaced by increased production from spare capacity held by other OPEC member countries. In such a scenario, the shut-in production capacity in Iran may technically be counted as new spare capacity, but—like inventories that accumulate for similar reasons—would not be readily available to alleviate market tightness in the same manner that regular spare capacity not forced by sanctions typically would be.

OPEC members serve as the swing producers in the world market because only OPEC producers possess surplus or spare oil production capacity. EIA projects that OPEC surplus production capacity will average 2.8 million bbl/d in 2012 and rise to an average 3.5 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 56.1 days of forward-cover (Days of Supply of OECD Commercial Stocks Chart). Projected OECD oil inventories increase to 2.64 billion barrels and 57.3 days of forward-cover by the end of 2012. Although the forecast December 2012 inventory is slightly lower than the 2.66-billion-barrel level at the end of December 2010, the days of forward-cover are still among the highest end-of-year levels since 1991 because of the decline in OECD consumption.

Crude Oil Prices. EIA has lowered the forecast 2012 average U.S. refiner acquisition cost of crude oil by \$2.50 per barrel from last month's *Outlook* to \$110 per barrel, still about \$8 per barrel higher than last year's average price. EIA expects the price of WTI crude oil to average about \$104 per barrel in 2012, about \$2 per barrel lower than last month's *Outlook*, but \$9 per barrel higher than the 2011 average price. EIA expects crude oil prices to remain relatively flat in 2013, with WTI and the U.S. refiner acquisition cost of crude oil averaging about \$104 per barrel and \$108 per barrel, respectively (West Texas Intermediate Crude Oil Price Chart). The

projected WTI price discount to the average U.S. refiner acquisition cost of crude oil narrows over the forecast from about \$6 per barrel in the second quarter of 2012 to \$4 per barrel by the fourth quarter of 2013, as transportation bottlenecks diminish.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for July 2012 delivery during the 5-day period ending May 3, 2012 averaged \$105 per barrel. Implied volatility averaged 23 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in July 2012 at \$90 per barrel and \$123 per barrel, respectively. Last year at this time, WTI for July 2011 delivery averaged \$110 per barrel and implied volatility averaged 29 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$91 per barrel and \$133 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 the first quarter of 2012, total consumption continued to display weakness, falling by 670 thousand bbl/d (3.5 percent) from the same period last year (U.S. Liquid Fuels Consumption Chart). Higher retail gasoline prices contributed to the 150-thousand-bbl/d (1.7-percent) decline in motor gasoline consumption during the first quarter 2012 from the year before. Distillate fuel consumption also shrank by 150 thousand bbl/d (3.7 percent), largely due to unusually warm weather. For the rest of 2012, EIA expects more moderate year-over-year declines in motor gasoline consumption, averaging about 30 thousand bbl/d. In contrast, projected distillate fuel oil consumption recovers from the very warm winter with year-over-year growth averaging about 80 thousand bbl/d, boosted by continued growth in manufacturing production.

Despite assumed growth in U.S. real disposable income of 1.9 percent next year, forecast motor gasoline consumption continues to decline by 30 thousand bbl/d (0.3 percent) in 2013. This *Outlook* reflects high gasoline prices, slowing growth in the driving-age population, and the improving average fuel economy of new vehicles. Distillate fuel consumption, on the other hand, increases by 90 thousand bbl/d (2.4 percent), buoyed by an assumed near-normal winter and continuing growth in manufacturing output.

U.S. Liquid Fuels Supply and Imports. Domestic crude oil production increased by an estimated 190 thousand bbl/d (3.4 percent) to 5.66 million bbl/d in 2011. An increase of 450 thousand bbl/d in lower-48 onshore production in 2011 was partly offset by a 30-thousand-bbl/d production decline in Alaska and a 230-thousand-bbl/d production decline in the Federal Gulf of Mexico (GOM).

Forecast U.S. total crude oil production increases to 6.17 million bbl/d in 2012, an upward revision of 150 thousand bbl/d from last month's *Outlook*, and the highest level of production

since 1998. Growth in lower-48 onshore crude oil production of 560 thousand bbl/d in 2012 overshadows declines averaging about 30 thousand bbl/d in Alaskan output and 20 thousand bbl/d in GOM production (U.S. Crude Oil and Liquid Fuels Production Chart). The rise in production 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 increased from 777 at the beginning of 2011 to 1,355 on May 4, 2012.

The share of total U.S. consumption met by total liquid fuel net imports (including both crude oil and products) has been falling since 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 43 percent in 2012 and to 42 percent in 2013.

U.S. Petroleum Product Prices. Regular-grade gasoline retail prices averaged \$3.53 per gallon in 2011, \$0.74 per gallon (27 percent) higher than the 2010 average. The price increase in 2011 largely reflected higher crude oil costs (\$0.60 per gallon) and higher refinery gasoline margins (\$0.10 per gallon). EIA expects the regular-grade gasoline retail price to increase to an average of \$3.71 per gallon in 2012, primarily due to higher crude oil costs (U.S. Gasoline and Crude Oil Prices Chart). Regular-grade gasoline prices peaked at \$3.90 per gallon in April and are projected to average \$3.79 per gallon during the summer season (April through September) compared with last summer's average of \$3.71 per gallon. Forecast regular-grade gasoline prices decline to an average of \$3.67 per gallon in 2013.

EIA expects that on-highway diesel fuel retail prices, which averaged \$3.84 per gallon in 2011, will average \$4.06 per gallon in 2012, down 9 cents per gallon from last month's *Outlook*. In 2013, diesel fuel retail prices are projected to decline to \$4.03 per gallon, 8 cents per gallon lower than the previous *Outlook* (U.S. Diesel Fuel and Crude Oil Prices Chart).

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect higher prices for the average refiner acquisition cost of crude oil, which averages \$110 per barrel (\$2.61 per gallon) in 2012, compared with the \$102-per-barrel (\$2.43-per-gallon) average for 2011. EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the refiner acquisition cost of crude oil) will average 42 cents per gallon and 41 cents per gallon in 2012 and 2013, respectively, which are slightly higher than the previous 5-year average of 40 cents per gallon. In contrast, wholesale diesel margins are robust during the forecast interval due to strong world-wide demand for the fuel. In 2012, those margins average 60 cents per gallon, similar to the 2011 average and higher than the previous 5-year average of 52 cents per gallon. The diesel wholesale margin for 2013 remains wide, averaging 59 cents per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 70.2 billion cubic feet per day (Bcf/d) in 2012, an increase of 3.4 Bcf/d (5.1 percent) from 2011 and an upward revision of 0.6 Bcf/d from last month's *Outlook*. EIA expects that large gains in electric power use will offset declines in residential and commercial use. Because of the much-warmer-than-normal winter this year, EIA expects both residential and commercial consumption to fall by over 6 percent in 2012, reflecting a downward revision in projected consumption from last month's *Outlook*. The downward revisions in residential and commercial consumption reflect the decline in total projected 2012 heating degree-days as reported by the National Oceanic and Atmospheric Administration.

Projected consumption of natural gas in the electric power sector grows by almost 21 percent in 2012, primarily driven by the increasing relative cost advantages of natural gas over coal for power generation in some regions. Consumption in the electric power sector peaks in the third quarter of 2012, at 31.2 Bcf/d, 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 71.2 Bcf/d (U.S. Natural Gas Consumption Chart). However, unlike 2012, growth in 2013 is driven by consumption from the residential, commercial, and industrial sectors. A forecast of closer-to-normal winter temperatures drives increases in residential and commercial consumption in 2013 of 7.1 percent and 4.2 percent, respectively. The increase in consumption in these sectors, as well as a 1.4-percent increase in industrial consumption, more than offsets a 2.0-percent decline in power-sector natural gas burn.

U.S. Natural Gas Production and Imports. Total marketed production of natural gas grew by an estimated 4.8 Bcf/d (7.9 percent) in 2011. This strong growth was driven in large part by increases in shale gas production. While EIA expects year-over-year production growth to continue in 2012, the projected increases occur at a slower rate than in 2011 as low prices reduce new drilling plans. According to Baker Hughes, the natural gas rig count was 613 as of April 27, 2012, down from a 2011 high of 936 in mid-October, making it the lowest rig count since 2002. EIA's production survey indicates natural gas marketed production fell by 420 Bcf/d from January 2012 to February 2012. EIA expects growth in U.S. production during 2012 to average 4.4 percent. Declining production from less-profitable "dry" natural gas plays such as the Haynesville Shale are 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 0.3 Bcf/d (3.3 percent) in 2012 as domestic supply displaces Canadian sources. The warm winter in the United States also adds 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 2.3 percent in 2013, partially due to near-normal winter weather driving higher residential and commercial demand. Additionally, EIA expects increased pipeline imports to help meet continued high demand for natural gas for electric power generation. Pipeline gross exports grew by 1.0 Bcf/d in 2011, driven by increased exports to Mexico, and are expected to continue to grow at a slower rate in 2012 and 2013.

Liquefied natural gas (LNG) imports are expected to fall by 0.3 Bcf/d (32 percent) in 2012. EIA expects that an average of about 0.7 Bcf/d will arrive in the United States (mainly at the Everett LNG terminal in New England and the Elba Island terminal in Georgia) in both 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 continue to set new seasonal record highs as the very mild winter contributed to much-lower-than-normal inventory draws. As of April 27, 2012, according to EIA's *Weekly Natural Gas Storage Report*, working inventories totaled 2,576 Bcf, 840 Bcf greater than last year's level and 857 Bcf above the 5-year (2007-2011) average. EIA expects that inventory levels at the end of October 2012 will set a new record high at 4,096 Bcf (U.S. Working Natural Gas in Storage Chart), although the record will largely be due to high levels already present at the start of the injection season. The projected increase of 1,623 Bcf in working gas inventory during the 2012 injection season (from the end of March to the end of October) is the smallest build since 2002. Limits on storage capacity, as well as high demand from the electric power sector this summer, will limit the overall level of injections. In 2013, working inventory levels recede from record highs, although they will still remain robust compared with recent history.

U.S. Natural Gas Prices. Natural gas spot prices averaged \$1.95 per MMBtu at the Henry Hub in April 2012, down \$0.23 per MMBtu from the March 2012 average and the lowest average monthly price since March 1999, which also was the last time the Henry Hub price averaged less than \$2 per MMBtu. Abundant supplies and lower winter heating demand this year have contributed to the recent low prices. EIA expects the Henry Hub natural gas price will average \$2.45 per MMBtu in 2012, a small downward revision from \$2.51 per MMBtu expected in last month's *Outlook*. EIA revised its forecast for 2013 down to \$3.17 per MMBtu, from \$3.40 per MMBtu in last month's *Outlook* (U.S. Natural Gas Prices Chart).

Natural gas futures prices for July 2012 delivery (for the 5-day period ending May 3, 2012) averaged \$2.39 per MMBtu, and the average implied volatility based on options and futures prices was 51 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 July 2012 contracts at \$1.63 per MMBtu and \$3.50 per MMBtu, respectively. At this time last year, the July 2011 natural gas futures contract averaged \$4.65 per MMBtu and implied volatility averaged 34 percent. The corresponding lower and upper limits of the 95-percent confidence interval were \$3.61 per MMBtu and \$5.98 per MMBtu.

Coal

U.S. Coal Consumption. EIA forecasts that electric power sector coal consumption will be about 800 million short tons (MMst) in both 2012 and 2013. Prices for natural gas delivered to the electric power industry fell by 7.5 percent in 2011, which contributed to a significant increase in the share of natural-gas-fired generation. EIA expects this trend to continue in 2012, with electric power sector coal consumption falling by 14 percent (U.S. Coal Consumption Chart). EIA expects that electric power sector coal consumption will increase by 1.2 percent in 2013, as projected power industry coal prices fall (4 percent) and natural gas prices increase.

U.S. Coal Supply. EIA forecasts that coal production will decline by 10.2 percent in 2012 as domestic consumption and exports fall (U.S. Coal Production Chart). Production for the first three months of 2012 was 22 MMst below last year's value for the same period. Annual production declines greater than 25 MMst are expected in each of the three coal-producing regions (Appalachia, Interior and Western). Despite declines in production, EIA projects that secondary inventories will increase in 2012, with electric power sector stocks exceeding 200 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 but fall below the 107 MMst exported in 2011. Forecast U.S. coal exports are 100 MMst in 2012 and 97 MMst 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 5.8 percent increase from 2010). However, EIA expects the decline in demand for coal to generate electricity will put downward pressure on coal prices and contribute to the shut-in of higher-cost production. Several companies have recently announced the curtailment of operations, particularly in Appalachia, where production costs at some older mines are high. EIA forecasts the average delivered coal price in 2012 will be 2.8 percent lower than the 2011 average price. EIA predicts the 2013 average delivered coal price to be \$2.24 per MMBtu, or 3.8 percent lower than the previous year's price.

Electricity

U.S. Electricity Consumption. Heating degree-days nationwide during the first quarter of 2012 were at the lowest level since record keeping began in 1895. Winter temperatures were particularly mild in the South, where a majority of homes use electric heat pumps. The mild weather contributed to an 11-percent decline in U.S. residential electricity sales compared with the same period last year. For the summer months, EIA expects U.S. cooling degree-days to average 16 percent lower than last summer. Overall, residential electricity sales fall about 4

percent during 2012. EIA expects total consumption of electricity to decline by 0.8 percent during 2012 and then grow by 1.9 percent in 2013.

U.S. Electricity Generation. Natural-gas-fired generation continues to expand its share of total generation at the expense of coal-fired generation. During the first quarter of 2012, natural gas accounted for 28.7 percent of total generation compared with 20.7 percent during the same quarter last year. In contrast, coal's share of total generation declined from 44.6 percent to 36.0 percent over the same period. Much of the recent increase in natural gas generation has stemmed from increased utilization of combined cycle capacity, which typically does not exhibit as much seasonal fluctuation as other types of natural gas plants used primarily for peaking generation. This trend in capacity utilization, along with summer weather that is projected to be milder than last year, should dampen year-over-year growth in natural gas generation during the third quarter (U.S. Electricity Generation Chart).

U.S. Electricity Retail Prices. EIA forecasts average U.S. residential electricity prices to rise by 0.6 percent in 2012, and then fall by 2.1 percent in 2013 (U.S. Residential Electricity Prices Chart). The rising costs of transmitting and distributing electricity to retail customers offset some of the declining fuel costs.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. After growing by 14 percent in 2011, total renewable energy supply is projected to decline by 1.5 percent in 2012 (U.S. Renewable Energy Supply Chart). This decrease is the result of hydropower resource levels beginning a return to the long-term average, with supply falling by 0.3 quadrillion Btu (10 percent). The decline in hydropower from the 2011 level more than offsets growth in other renewable energy supplies. Renewables supply decreases further in 2013 as hydropower continues to decline (6.7 percent) and non-hydropower renewables growth of 2.2 percent is not enough to offset the decline.

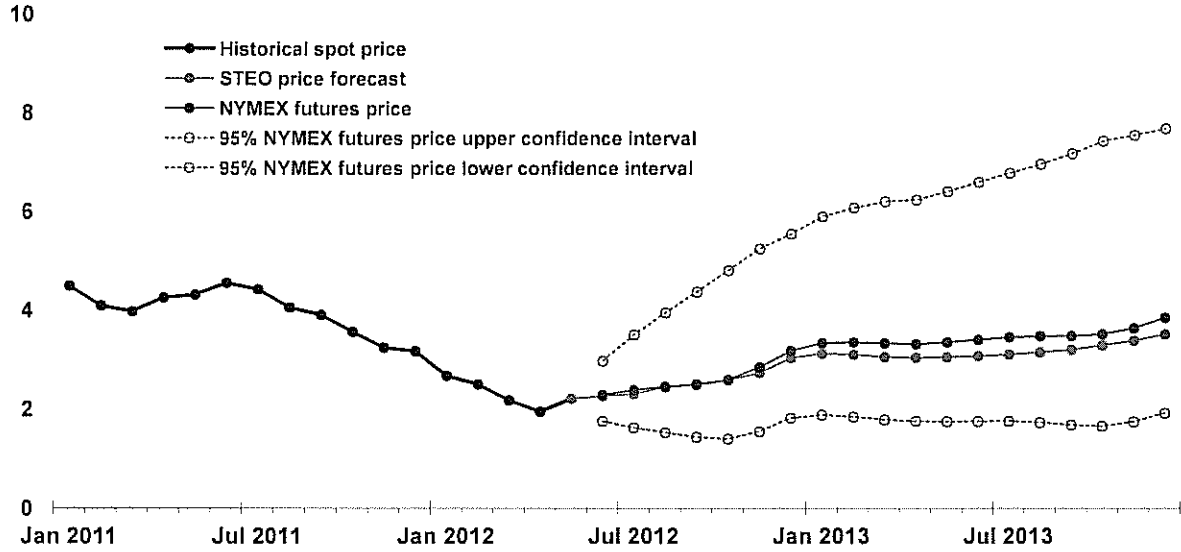
Under current law, federal production tax credits for wind-powered generation will not be available for turbines that begin operating after the end of 2012. Wind-powered generation, which grew by 26 percent in 2011, is forecast to grow an additional 13 percent in 2012 and 5 percent in 2013. Since the last *Outlook*, the amount of new wind capacity reported to EIA as possibly coming on line in 2013 has fallen by 26 percent.

In terms of liquid renewable fuels, EIA expects fuel ethanol production to remain steady from 2011 through 2013 averaging about 900 thousand bbl/d for all 3 years. This forecast assumes that E15 (gasoline blended with 15 percent ethanol by volume) does not yet reach the market. 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 63 thousand bbl/d in 2012, and 71 thousand bbl/d in 2013.

U.S. Energy-Related Carbon Dioxide Emissions. After declining by 1.9 percent in 2011, fossil fuel emissions are projected to further decline by 2.9 percent in 2012, but increase by 1.2 percent in 2013. Petroleum emissions decline slightly in 2012 (0.3 percent) and then rise by 0.6 percent in 2013, while natural gas emissions rise by 5.5 percent and 1.2 percent in 2012 and 2013, respectively. Coal emissions decline in 2012 by 11.9 percent, but rise by 2.1 percent in 2013 (U.S. Carbon Dioxide Emissions Growth Chart).

Henry Hub Natural Gas Price

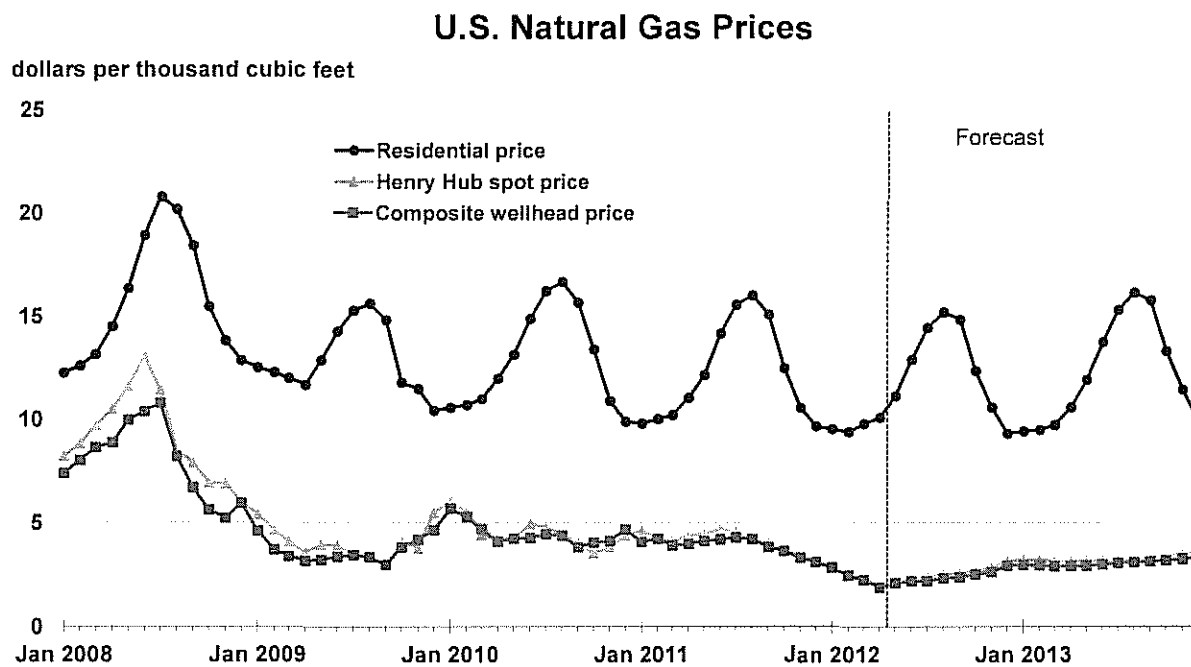
dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending May 3, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

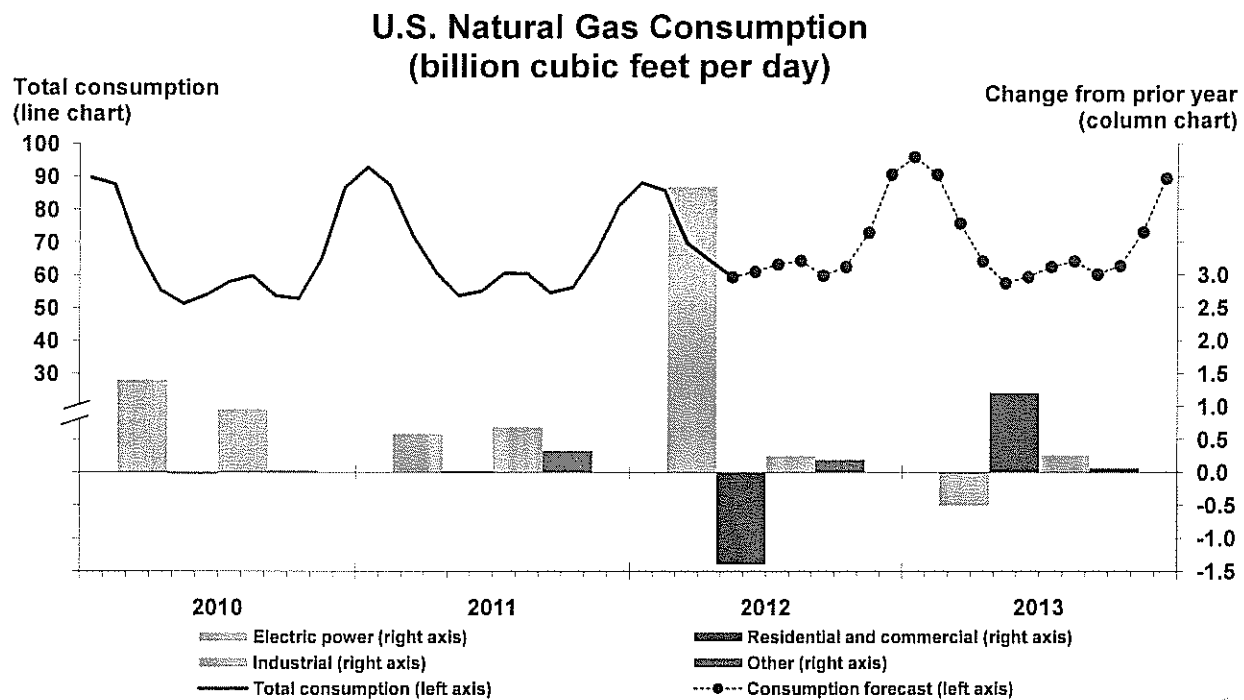
Source: Short-Term Energy Outlook, May 2012





Source: Short-Term Energy Outlook, May 2012

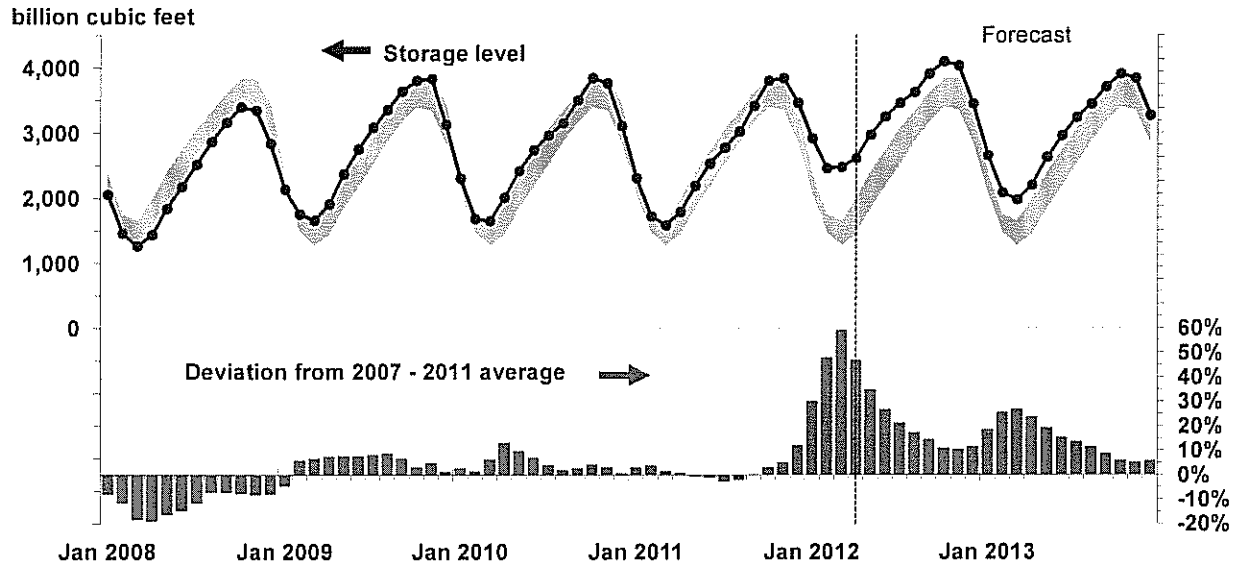




Source: Short-Term Energy Outlook, May 2012



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, May 2012



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

	Firm		Small & Large Interruptible	Air Force Interruptible
	Residential & General Service	Optional Seasonal		
<u>Gas Cost Adjustment:</u>				
Gas Cost Level (Exhibit B)	\$3.634	\$2.803	\$2.721	\$2.709
Prior Gas Cost	3.116	2.279	2.195	2.185
Current Gas Cost Adjustment	\$0.518	\$0.524	\$0.526	\$0.524
<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	\$0.518	\$0.524	\$0.526	\$0.524
Gas Cost Level	\$3.634	\$2.803	\$2.721	\$2.709
Plus: Surcharge	(0.032)	(0.032)	0.064	0.041
Total Gas Cost Level in Tariff Rates	\$3.602	\$2.771	\$2.785	\$2.750

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

<u>Cost of Gas - Propane</u>	
Current Propane Cost (Exhibit D)	\$8.673
Prior Propane Cost	<u>12.076</u>
Current Propane Cost Adjustment	<u><u>(\$3.403)</u></u>
<u>Surcharge Adjustment</u>	
Current Adjustment	\$0.646
Prior Adjustment	<u>0.646</u>
Change in Surcharge Adjustment	\$0.000
<u>Market Based Pricing Differential</u>	
Current Adjustment	(\$0.009)
Prior Adjustment	<u>(0.009)</u>
Change in Margin Sharing Provision	\$0.000
Net Increase (Decrease) in Gas Costs	<u><u>(\$3.403)</u></u>
Propane Cost Level	\$8.673
Plus: Surcharge	<u>0.646</u>
Total Propane Cost Level in Rates	<u><u>\$9.319</u></u>

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

	Amount
Total Gas Costs 1/	\$51,648,225
Residential and General Service dk Requirements 2/	14,275,505
Average Cost of Gas per dk	\$3.618
Average Cost of Gas as Adjusted for Losses @ 99.55%	3.634
Less: Gas Cost Level in Rates 3/	3.116
Current Gas Cost Adjustment	\$0.518

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 April 30, 2012, adjusted for losses at .45%.

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

Cost of Purchased Gas	\$3.102
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$3.116

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

<u>Summer - June - September</u>	
Total Gas Costs 1/	\$51,648,225
Less: Annual MDDQ Costs 1/	<u>11,821,667</u>
Total Gas Costs excluding MDDQ	\$39,826,558
Firm Service Requirements 1/	14,275,505
Other Gas Costs per Dk (excluding MDDQ)	\$2.790
Summer Seasonal Rate, adjusted for losses 2/	2.803
Less: Gas Cost Level in Rates 3/	<u>2.279</u>
Current Gas Cost Adjustment	<u><u>\$0.524</u></u>
<u>Winter - October - May</u>	
Annual MDDQ Costs 1/	\$11,821,667
Winter Firm Service Requirements	12,902,101
MDDQ Costs per Winter Dk	\$0.916
Add: Other Gas Costs per Dk	<u>2.790</u>
Winter Seasonal Rate	\$3.706
Winter Seasonal Rate, adjusted for losses 2/	\$3.723

1/ Exhibit B, page 1.

2/ Loss factor of .45%.

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

	<u>Summer</u>	<u>Winter</u>
Cost of Purchased Gas	\$2.269	\$3.191
Adjustment for Distribution Losses	0.9955	0.9955
Gas Cost Level in Base Tariff Rates	\$2.279	\$3.205

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

	Amount
Total Gas Costs 1/	\$9,488,228
Interruptible Service dk Requirements	3,502,739
Average Cost of Gas per dk	\$2.709
Average Cost of Gas as Adjusted for Losses @ 99.55%	2.721
Less: Gas Cost Level in Rates 2/	2.195
Current Gas Cost Adjustment	\$0.526

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 June 1, 2012:

Cost of Purchased Gas	\$2.185
Adjustment for Distribution Losses	0.9955
Gas Cost Level in Base Tariff Rates	\$2.195

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

	Amount
Total Gas Costs 1/	\$2,383,744
Air Force Interruptible dk Requirements	880,000
Average Cost of Gas per dk	\$2.709
Less: Gas Cost Level in Rates 2/	2.185
Current Gas Cost Adjustment	\$0.524

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 June 1, 2012:
Cost of Purchased Gas \$2.185

**Montana-Dakota Utilities Co.
Schedule of Applicable Effective Pipeline Rates
July 2012 PGA**

Williston Basin Interstate Pipeline Company - 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

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.

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	AQUINU 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

NorthWestern
Energy

Canceling $\frac{28^{th}}{27^{th}}$ Revised Revised

Sheet No. 80.1
Sheet No. 80.1

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

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

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

<u>Meters Rated @</u> <u>Cu. Ft. per hour</u>	<u>Per Meter</u> <u>Charge</u>
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	\$ (0.0011145)
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
Alestra Salim 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-60-001

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
Third Revised Sheet No. 12
Cancels Second 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	0.885%
	MLI	MLE	\$145.00	\$0.1040	\$0.0010	0.885%
	MLI	DSE	\$225.00	\$0.1978	\$0.0020	2.425%
Interruptible Transportation 4/	MLI	MLI	\$0.00	\$0.0844	\$0.0010	0.885%
	MLI	MLE	\$145.00	\$0.0844	\$0.0010	0.885%
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, 2011
By: William N. Cantrell

Date Effective: June 1, 2011
Title: President and CEO

**MONTANA-DAKOTA UTILITIES CO.
RETURN ON CYCLE STORAGE BALANCES
AND PREPAID DEMAND AND COMMODITY BALANCES
NORTH DAKOTA GAS
EFFECTIVE JULY 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	7,215,955	(26,322)	(1,052,102)
June	8,340,136	34,332	(47,391)
July	9,580,822	98,882	1,005,464
August	10,811,911	161,451	2,039,104
September	11,647,495	572,577	2,853,471
October	11,625,342	561,864	3,114,004
13 month average	<u>\$9,001,257</u>	<u>\$266,111</u>	<u>\$709,802</u>
Rate of Return	8.791%	8.791%	8.791%
Return	\$791,301	\$23,394	\$62,399
Return Requirement	<u>\$1,079,071</u>	<u>\$31,902</u>	<u>\$85,091</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.
COST OF GAS - PROPANE
NORTH DAKOTA
EFFECTIVE JULY 2012

Cost of Purchased Propane	\$9,497
Gallons Purchased	12,022
Projected dk Sales	1,100
Propane Cost per Dk	\$8.634
Average Cost of Propane as Adjusted for Losses @ 99.55%	8.673
Less: Propane Cost Level in Rates 1/	<u>12.076</u>
Current Propane Cost Adjustment	<u><u>(\$3.403)</u></u>

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

**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)
Balance @ April 30, 2012									<u>(\$328,431)</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>\$48,803</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)
Balance @ April 30, 2012									<u>(\$80,104)</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>\$82,096</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)
Balance @ April 30, 2012									<u>(\$130,035)</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.