

Natural Gas in Montana: Current Trends, Forecasts and the Connection with Electric Generation

Natural gas is a major source of energy for Montana's homes, businesses, and industries. This chapter discusses current natural gas trends in Montana, and what to expect in the coming years. Montana is part of the North American gas market, with gas prices and availability set more by events outside than inside Montana. As electricity generation around the country comes to rely more on natural gas and as production from North American gas wells levels out or declines, the price and availability of gas are already moving in ways Montanans have not experienced in previous decades.

I. Natural Gas Supplies for Montana

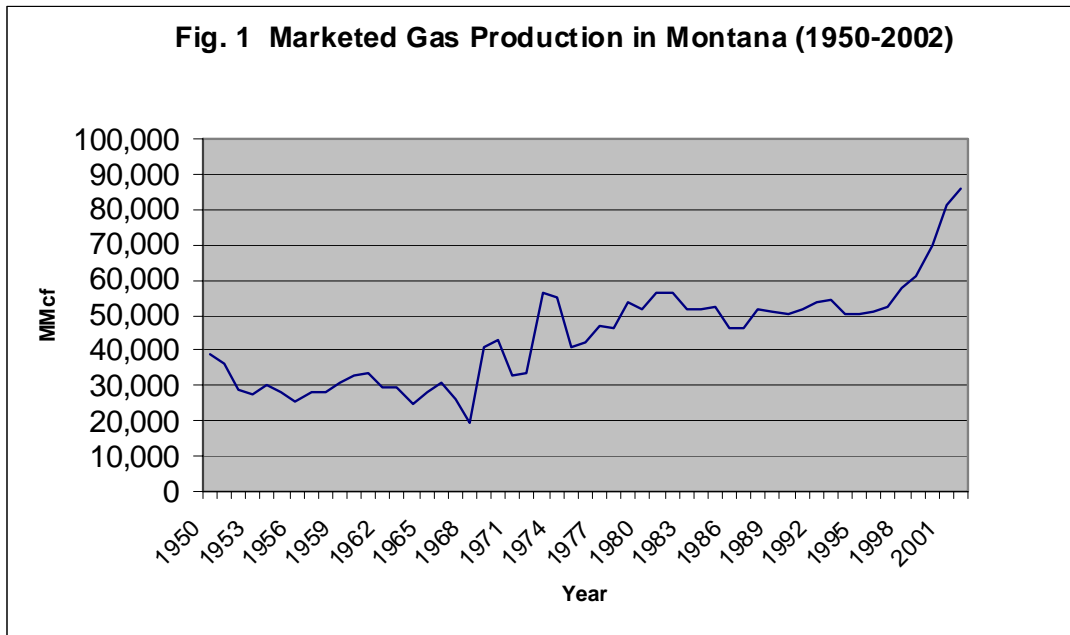
Alberta provides the largest supply of natural gas for Montana customers and will likely continue to do so in the years to come. The reason for this is our proximity to Alberta's large gas reserves. The next largest supply for Montana is from in-state wells mostly located in the north-central portion of the state. Supplies from the other Rocky Mountain states represent a small portion of total in-state usage and continue to decline from historic levels. Future changes in supplies from in-state development and from other Rocky Mountain states are uncertain at this point. Coal bed methane may eventually increase the portion of gas used in Montana that comes from Rocky Mountain states, but the peak of that production is still a few years off.

Montana currently produces more gas than it consumes. In 2002, Montana produced 86.1 billion cubic feet (bcf) and consumed 69.6 bcf (Tables NG1 and NG2). The bulk of what Montana produces is exported, and the bulk of what Montana consumes is imported. In 1999, for example, Montana produced 61.2 bcf of gas and exported 51.8 bcf total to North Dakota, South Dakota and the Midwest. The reasons for this are the way in which natural gas utilities structure their gas purchasing contracts and the configuration of gas pipelines in Montana.

Most gas produced in Montana comes from the north-central portion of the state. In 2002, the north-central portion accounted for 71% of total production and the northeastern portion of the state accounted for 15% (MBOGC 2003). In-state gas production has been increasing in recent years (Figure 1, below). The south-central and northeastern portions have greatly increased their production level since 1998, resulting in most of the recent statewide increase (MBOGC 2003). Because most gas is exported, increases or decreases in natural gas production in Montana likely have little impact on Montana natural gas consumers.

Coal bed methane development in Montana has not yet become significant, due in part to difficult environmental issues. Some residents in Montana have forcefully opposed methane

development, especially in or near the Powder River Basin. However, with the Montana Environmental Impact Statement completed and released to the public in the fall of 2003, in-state development is expected to increase in the near future. The total amount of methane development that will occur in Montana is yet to be determined. The future extraction of other known gas reserves along Montana’s Rocky Mountain Front likewise is uncertain at this point.



Source: U.S. EIA, Natural Gas Annual Reports, 1950-2002 (Table NG1).

2. Natural Gas Supplies for the United States

U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. About half of current U.S. reserves are located in Texas, Louisiana and offshore in the Gulf of Mexico. As of 2001, about a quarter of U.S. reserves were located in the Rocky Mountain states of New Mexico, Wyoming, and Colorado (U.S. EIA 2001). As of 2002, Texas, New Mexico, Oklahoma, Wyoming, and Louisiana (including Federal offshore production) accounted for about 80% of domestic marketed production (U.S. EIA 2004a). The Rocky Mountain states are the most important source of domestic natural gas supply to the Pacific Northwest region in which Montana is located. Alaska’s North Slope is potentially the largest source of new natural gas resources for the nation as a whole (U.S. EIA 2001).

After declining during the 1990s, natural gas drilling in the U.S. picked up dramatically in early 2000 and 2001 in response to high gas prices, only to fall off again in 2002 as prices returned to their historic average levels. Drilling increased again after 2002 (U.S. EIA 2004a and U.S. EIA, 2004a). Today in 2004, more than 1,000 rigs are drilling for natural gas in the U.S., which is close to the 2001 high. If natural gas prices remain at their current high levels, domestic drilling will continue to grow, perhaps at higher rates than recently experienced.

According to the U.S. Energy Information Administration (U.S. EIA), domestic natural gas production, with its large and accessible resource base, is expected to increase from 19.9 trillion cubic feet (tcf) in 2002 to a projected 24.4 tcf in 2020 to meet growing domestic demand. Increased production would come primarily from lower-48 onshore conventional sources, although onshore *unconventional* production is expected to increase at a faster rate than other sources during that time (U.S. EIA 2004b).

Today, 15-16% of the total natural gas consumed in the U.S. is imported from other countries with most of that coming from Canada (US EIA 2004a). In 2002, the United States imported 3.79 tcf of natural gas from Canada. Imports from Canada have been increasing over time with 2002 being the sixteenth consecutive year of increased imports from our neighbors to the north (U.S. EIA 2004a). Net natural gas imports into the U.S. are expected to increase from 3.6 tcf in 2002 to a projected 7.2 tcf in 2025, with imports making up an increasingly larger share of the total percentage consumed in the U.S. (U.S. EIA 2004b).

It is hard to predict how much natural gas is left in North American reserves that could go toward U.S. consumption. Reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. The Northwest Power and Conservation Council estimates between 2,100 and 2,650 tcf remaining of North American gas *resources* and about 290 tcf remaining in gas *reserves* (excluding Mexico).¹ Mexico used to send gas supplies to the U.S., but not longer does. Using these numbers and assuming that U.S. and Canadian consumption grows at 2.3 percent per year from current levels, estimated remaining North American resources would satisfy North American consumption for about 40 or 50 more years (not including imports and exports and unforeseen events). The entire world is estimated to contain 13,000 tcf in natural gas reserves with much of that located in the Middle East (Northwest Power and Conservation Council 2003; Morlan 2001). Proved reserves for the U.S. as of 2003 are 183 tcf (U.S. EIA 2003)

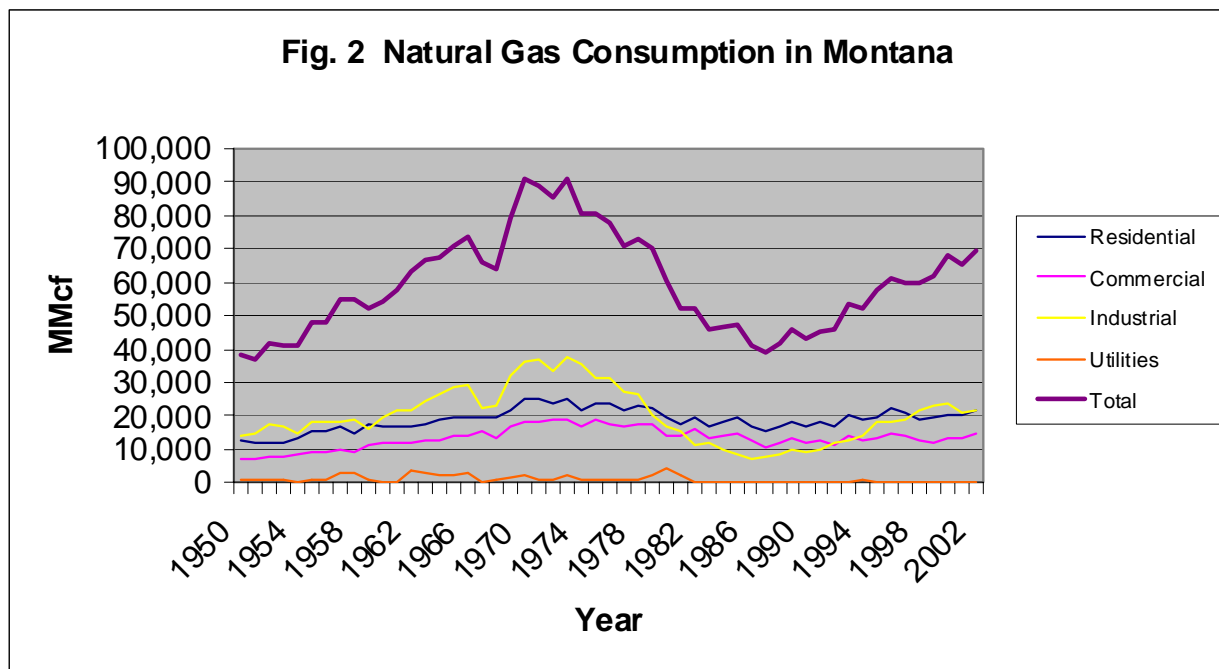
In the last year, some important trends in gas production have occurred with respect to North American supply. The government of Canada recently announced that they did not expect Alberta natural gas production to grow in the coming years as it has in the past, but instead to level off (Morlan 2004). Also, new wells being drilled in the U.S. by Devon Energy, the largest U.S. independent producer of gas, are finding fewer reserves than predicted with greater decline rates in their wells. Furthermore, the cost of finding natural gas in North America is rising. From 2001 through 2003, the three-year average finding cost for natural gas was \$1.53/dkt, which was up 29% from the three-year average the year

¹ “Reserves” refers to natural gas that has been discovered and proved producible given current technology and markets. Natural gas “resources” are more speculative estimates of natural gas that might be developable with known technology and at feasible costs. By definition, resource estimates are more uncertain than reserve estimates.

before. In 2003 alone, the average finding cost was \$1.73/dkt² (Wall Street Journal 2004). It is therefore possible that the gas production in North America in future years may not grow as quickly as the above projections say nor as quickly as historical trends.

3. Natural Gas Consumption in Montana

Recent Montana natural gas consumption has averaged 60-70 billion cubic feet (bcf) per year. Future Montana natural gas consumption, excluding that for new electric generation built in-state, is expected to increase slowly at less than 1 percent annually according to projections by Montana’s largest gas utilities, Northwestern Energy and Montana-Dakota Utilities Co. Both residential and commercial gas consumption are growing very slowly, and usage by industry is expected to stay fairly level over time (see figure 2). In the 1970’s, Montana’s industrial sector used much more natural gas than it does now. The closure of smelters in Anaconda, in particular, contributed to the drop in industrial usage that occurred in the 1980’s.



Source: U.S. EIA, *Natural Gas Annual Report*, 1950-2002 (Table NG2).

If new gas-fired electric generation plants get built in Montana, total gas consumption in Montana could significantly increase over current levels. The unfinished Montana First Megawatts gas-fired electric generation plant just north of Great Falls was expected to create a significant increase in total Montana annual natural gas consumption, but the project is on hold indefinitely and may be scrapped. Average new gas usage by this plant

² One dekatherm (dkt) is equal to a million British Thermal Units (BTUs). Often, natural gas prices will be reported either in dekatherms or in units of ‘a thousand cubic feet’ (Mcf’s). Assuming an average BTU content for U.S. natural gas at standard conditions, 1.0 Mcf = 1.03 dkt according to the U.S. EIA (U.S. EIA, *Natural Gas Annual*, Table B2, 2002).

was expected to be around 13 bcf per year for first 160 MW of electric generation capacity built. This would have been equivalent to about 20 percent of the current total gas consumption in Montana. The proposed 500 MW Silver-Bow electrical generation plant near Butte is also on hold indefinitely with no action currently taking place. If it ever comes on line, the plant would consume about 30 bcf per year of gas—equivalent to almost 50 percent of current total gas consumption in Montana. The Silver-Bow project would have demanded a major upgrade in NorthWestern Energy's (NWE) gas pipeline system. Recent high natural gas prices and recent changes in the electric generation market are significant reasons why these plants have not been built. The Basin Creek plant near Butte at 51 MW generating capacity is negotiating with NWE, but may be up and running by late 2005. Natural gas usage at the Basin Creek plant would only constitute a small percentage of Montana's total usage right now, and would not require extensive upgrades to the NWE's pipeline system (Waterman 2004).

4. Natural Gas Consumption in the U.S.

Over the past two decades, a number of changes in energy markets, policies, and technologies have combined to spur an increase in the total usage of natural gas in the U.S. (U.S. EIA 2001). These include:

- Deregulation of wellhead prices begun under the Natural Gas Policy Act of 1978 and accelerated under the Natural Gas Wellhead Decontrol Act of 1989;
- Deregulation of transmission pipelines by Federal Energy Regulatory Commission (FERC) Orders 436 (1985), 636 (1992), and 637 (2000). The FERC orders separated natural gas commodity purchases from transmission services so that pipelines transport gas on an equal basis. These orders were intended to ensure that all natural gas suppliers compete for gas purchasers on an equal footing, to enhance competition in the natural gas industry, to ensure that adequate and reliable service is maintained, to improve efficiency in the gas transportation marketplace, and to protect customers from the exercise of market power. Also, Order 636 allows gas customers to purchase natural gas from a supplier other than the utility that delivers their natural gas;
- Passage of the Clean Air Act Amendments of 1990 and subsequent regulations affecting air quality standards for industries and electricity generators in non-attainment areas, which favor natural gas since it burns relatively clean compared to coal;
- Deregulation of the wholesale electricity market. High-efficiency combined cycle combustion turbine technology, coupled with low gas prices, has made gas the fuel of choice for conventional electric generation nationwide. Though coal is expected to continue to be the leading fuel for electricity generation, the natural gas share of total electric generation is expected to increase from 16 to 36 percent between 1999 and 2020. Today, over 95 percent of new electric generation coming on-line in the western U.S. is gas fired;
- Improvements in exploration and production technologies and a reduction in their associated costs, improving the return for exploration and production efforts;
- Investment in major pipeline construction expansion projects from 1991 through 2000 adding about 50 billion cubic feet per day of capacity; and
- Increased imports from Canada.

These factors created new markets and lowered the price of natural gas for existing markets. However, it is important to note that some of these trends are on the decline in 2004. For example, Canadian exports to the U.S. are beginning to level off, production in major producing areas like Alberta is leveling off, and gas prices are currently very high relative to historical norms. This reversal in trends may or may not be temporary.

In 2002, the U.S. consumed over 23.0 trillion cubic feet (tcf) of natural gas, the highest level ever recorded. In 2003, it tapered off slightly to 21.9 tcf. In the U.S., natural gas consumption is increasing at a healthy pace and the Pacific Northwest region is no exception. Three reasons for increased use in the Pacific Northwest are a historically ample and attractively priced gas supply (although prices are currently high), strong regional economic growth, and increased gas-fired electrical generation. At present, the use of gas for electricity generation is the second-largest consuming sector in the U.S. Industrial use is the largest consuming sector (36% of the total in 2002), but has been declining as a share of the total market. Residential usage is the third largest (US EIA 2004a). The U.S. EIA forecasts that U.S. total natural gas consumption will increase from the current level of about 23.0 trillion cubic feet per year to nearly 29.0 trillion cubic feet per year in 2020, which would indicate an annual growth rate in usage of about 1.4% (U.S. EIA 2004b). The 1.4% number is lower than the 2.3% increase in U.S. consumption per year predicted up through 2020 by the Northwest Power and Conservation Council in 2003 (US EIA 2004a).

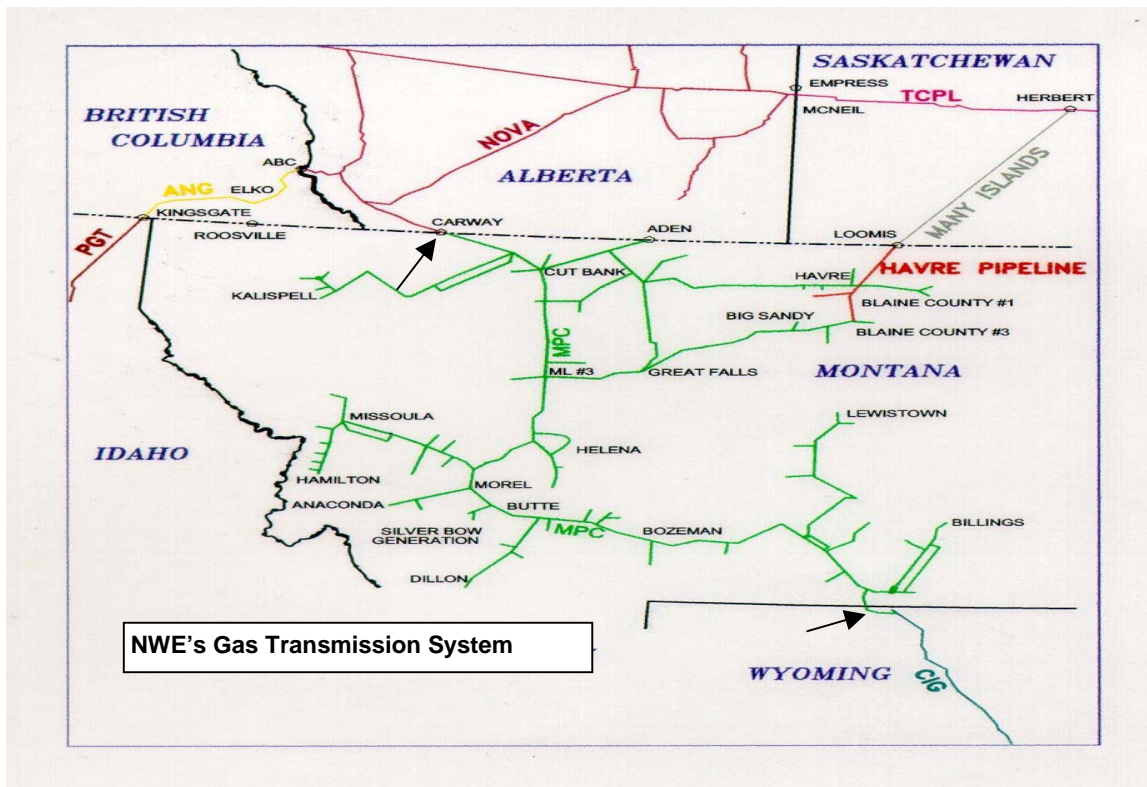
5. Montana's Natural Gas Pipeline System

Three distribution utilities and two transmission pipelines handle over 99 percent of the natural gas consumed in Montana (Table NG5). The distribution utilities are NorthWestern Energy (NWE; previously the Montana Power Company), Montana-Dakota Utilities Co. (MDU) and Energy West of Great Falls, which uses NWE for gas transmission. NWE and the Williston Basin Interstate pipeline (affiliated with MDU) provide transmission service for in-state consumers and, with a handful of other pipelines, export Montana natural gas.

Northwestern Energy (NWE) is the largest provider of natural gas in Montana, accounting for about 60 percent of all regulated sales in the state according to annual reports from Montana utilities (Table NG5). NWE provides natural gas transmission and distribution services to about 162,000 natural gas customers in the western two-thirds of Montana (including the Conoco and Cenex oil refineries in Billings). These customers include residences, commercial businesses, municipalities, state and local governments and industry. NWE's gas transportation system, both long-distance pipeline transmission and local distribution, lies entirely within Montana. NWE's transmission system is regulated by the Montana Public Service Commission. The NWE system consists of over 2,100 miles of transmission pipelines, 3,300 miles of distribution pipelines and three in-state storage facilities. NWE's system has pipeline interconnections with Alberta's NOVA Pipeline, the Havre Pipeline Company, the Williston Basin Interstate Pipeline Company and the Colorado

Interstate Gas Company. The Havre pipeline also is regulated by the Montana Public Service Commission.

Alberta sends natural gas to Montana primarily through NWE's pipeline at Carway and at Aden where it ties in with Alberta's NOVA Pipeline. Referring to the diagram below, NWE's pipeline system runs in a north-south direction from Carway (top arrow) and Aden at the Canadian border down through Cut Bank and south towards Helena approximately paralleling the Rocky Mountain Front. Near Helena, the main pipeline turns west and runs close to Highway 12 and then turns south and runs close to I-90 passing near Anaconda. It then turns east towards Butte, still following I-90. From Butte, it runs approximately east passing near Bozeman. At Big Timber it turns southeast and runs towards the Grizzly Interconnect near the Wyoming Border where it connects (bottom arrow) with the Colorado Interstate Gas line (CIG) and the Williston Basin Interstate/Warren line (WBI). The NWE gas system branches out from the main pipeline at various locations and runs to Missoula, Great Falls, the Flathead Valley, Dillon, Livingston and Billings. NWE's natural gas delivery system includes two main storage areas. The Cobb Storage is located north of Cut Bank near the Canadian border. The Dry Creek storage is located northwest of the Grizzly Interconnect, near the Wyoming border. Natural gas storage provides a critical supply component during the heating season, helps satisfy sudden shifts in demand and supply, and smoothes gas production throughout the year (U.S. EIA 2003).



A majority of NWE's natural gas purchases come from Alberta. The NWE pipeline system has a daily peak capacity of 300 million cubic feet of gas (MMcf). The system delivers about

40 bcf of total gas per year to its customers on average compared with total annual Montana consumption of about 60-70 bcf. About one half of the total gas throughput on NWE's system is used by "core" customers, who include residential and commercial business users. NWE has the obligation to meet all the supply needs of core customers. The other half of gas throughput is used by non-core customers including industry, local and state governments and by Energy West, which supplies Great Falls. NWE only provides delivery service for these non-core customers; they contract on their own for their gas supply. Peak gas usage occurs on cold weather days when daily demand is often close to peak pipeline capacity. Significantly smaller amounts are used when the weather is warm (Waterman 2001).

As of 2004, there is no unused firm capacity on the NWE pipeline transmission system. This means that no additional gas user of significant size, such as a large industrial company, can obtain guaranteed, uninterrupted gas delivery on the current system. At times of peak consumer usage, the pipeline is full and cannot deliver any more gas. As of mid-2004, customer peak daily demand on the system is an estimated 300 million cubic feet (MMcf), and thus the system's maximum daily capacity is currently matched by peak daily demand. The projected growth rate of maximum daily load and thus of required "daily pipeline delivery capacity" (excluding future electric generation plants) is 1.7 percent annually which translates to 5 MMcf/day annually. This growth is expected to come almost solely from core customers (Waterman 2001). Meeting the demands of the Montana First Megawatts gas-fired plant (240 MW if completed) would require pipeline upgrades beyond those already needed. The same is true for the proposed Silver-Bow plant near Butte. Both, however, are on hold indefinitely, and may not get built.

In 2004, the NWE's main gas transmission system is adding two loops to meet its projected increasing peak load in the coming years. The first loop to be built in 2004 is the Lewis and Clark loop, which will provide additional capacity to customers in the Flathead Valley. The existing Kalispell line (to which this loop would be added) runs west from NWE's mainline near the Canadian border, over Marias Pass (along Route 2), along the lower boundary of Glacier National Park, and over to the Flathead Valley. If all goes as planned, this loop should be in service in time for the 2004 winter heating season. The second loop to be built is the Rock Creek Loop that will increase capacity off of the main NWE pipeline (near Deer Lodge) to Missoula and the Bitterroot Valley. This project should begin in the fall of 2004 (Waterman 2004). The Bitterroot Valley (fed by the Missoula line) and the Flathead Valley (fed by the Kalispell line) are two of the fastest growing areas in Montana.

Montana-Dakota Utilities Co. (MDU) is the second largest natural gas utility in Montana and accounts for about 25-30 percent of all regulated natural gas sales in Montana (Table NG5). It distributes natural gas to most of the eastern third of the state, including Billings. MDU primarily uses the Williston Basin Interstate/Warren (WBI) pipeline for the transmission of its purchased gas. The WBI gas pipeline provides service for other utilities and is regulated at the federal level by FERC. MDU buys its gas from over 20 different suppliers. Most of its

purchased gas is domestic with about 50 percent coming from Wyoming, various percentages coming from North Dakota and Montana, and about 10 percent coming from Canada. Periodically, MDU buys a certain amount of pipeline capacity on the WBI pipeline to match what it feels will be needed for the busiest usage day, based on the number of homes in its area. MDU expects less than 1 percent growth per year in its gas sales for the near future (Ball 2004).

Energy West (formerly Great Falls Gas Co.) is the third largest gas provider in Montana, accounting for about 11-13 percent of all regulated gas sales in Montana (Table NG5). It provides gas to the Great Falls area, and uses NWE's pipeline system for gas transmission. The other Montana utilities account for about 1 percent of all gas sales and include the Cut Bank Gas Company and Shelby Gas Association. All of these rely on NWE to provide transmission service.

Alberta, which contains a significant share of the Canadian natural gas supply, sends gas to the West Coast of the U.S. primarily through the GTN pipeline, which enters the U.S. in Idaho. Alberta sends gas to the U.S. Midwest and East Coast through the Alliance and Northern Border pipelines. Finally, Alberta sends gas to Montana through several smaller pipelines connected to its main pipeline system. Northern Border, which passes through the northeast part of Montana, is the largest pipeline in the state, though it has no injection points in Montana. The large Alliance pipeline (1.3 bcf transport capacity per day) runs from the Edmonton, Alberta area to the Chicago, Illinois area and allows other parts of the U.S. to compete with Montana and the Pacific Northwest for Alberta's large gas supply (Smith 2001). All of these Alberta lines also tie in with the large Trans-Canadian Pipeline that runs east to west across Canada.

6. Measuring Natural Gas Commodity Prices in Montana and the U.S.

Natural gas prices are measured in different ways at different points in the gas supply system. The "wellhead" price is the price of the gas itself right out of the ground. The wellhead price for natural gas (which varies a bit from region to region) is set in the national wholesale market, which was deregulated by the federal government in 1978. No state, including Montana, can regulate this wholesale market. The gas prices on the major indices such as the Henry Hub and AECOC Hub reflect the wellhead price of gas plus a relatively small fee to transport the gas to the particular hub. The difference between the Henry Hub price of natural gas and the US wellhead price from 1989 to late 2001 was about \$0.12/dkt (Northwest Power and Conservation Council 2003). Thus, the major U.S. gas indices are a good approximation of wellhead prices. The "citygate" price typically reflects the wellhead price *plus* pipeline transmission fees (to get the gas to a particular locale or distribution system). The "delivered" gas price we pay in our homes and businesses is the citygate price *plus* local distribution fees and other miscellaneous charges from the utility. Transmission and distribution fees are set by utilities and/or pipelines and are regulated by state and federal agencies.

Natural gas prices on the major indices (or the “commodity market”) are measured in several ways. There are “spot market” prices for immediate sales, and “futures market” prices for long-term contracts. Spot prices are volatile and represent a small portion of market sales. One pays the current market price on the spot market for natural gas, just as one would pay the current price for a stock in a financial market. A futures price is the cost of natural gas obtained by contract for delivery at some future point at a set price. Futures contracts are more commonly used by larger buyers than spot prices and cover purchases over some length of time. NorthWestern Energy, as an example, buys much of its natural gas for core customers using long-term contracts (up to 1 year) to lock in an acceptable price and to avoid large price swings on the spot market (Smith 2001).

Because Montana continues to rely on Alberta for much of its natural gas, what happens with Alberta gas directly affects Montana. Alberta sets the wellhead price for natural gas in Montana and in other parts of the U.S. that directly obtain their supply from there. The wellhead price of Alberta natural gas is, in turn, determined largely by the North American free market, subject to the contract conditions agreed to by each buyer and seller.

Prices in Alberta’s main trading forums are determined by the AECOC index. This index, named after the AECO C storage hub in Alberta, is the equivalent in our area of the New York Mercantile Exchange (NYMEX) for gas and is very liquid for trading. Gas can be bought in spot or futures markets (Morris 2001). The AECOC index generally tracks the Henry Hub Index with some price differential. The Henry Hub Index is measured at the Henry Hub in southern Louisiana, a major pipeline interconnection and transshipment point. It is America’s largest natural gas index and sets the nationwide price. Due to its geographic location, AECOC’s price is often 20 to 30 cents cheaper per Mcf than the Henry Hub price.

Increases in demand for Alberta gas tend to cause contracted gas prices to rise in Montana, all else being equal. Conversely, as Alberta’s supply increases, prices in Montana tend to go down, all else being equal. It is the interplay between the supply and demand of Alberta’s gas that has the greatest effect on the gas prices paid in Montana. Today, this interplay occurs both on a national level and regionally for both supply and demand. Thus, the price of gas in Montana is determined by forces well beyond our state borders.

Historically, the delivered price for natural gas to Montana customers was at least twice the average wellhead price. Thus, typically less than 50 percent of what residences paid in their final gas bill was for the actual gas itself. Today, with wellhead prices so high, that situation is no longer true. As of January 2004, NWE residential customers paid an average delivered gas price of about \$8.00/dkt. About \$4.60 of that was for the commodity itself, whereas \$3.33 of that was for transmission and distribution charges (Burchett 2004). Had the wellhead price of gas purchased in 2004 by NWE been around \$2.00 as in previous years, then most of the final cost of gas to residential consumers would have been in transmission and distribution fees.

7. Natural Gas Prices in Montana

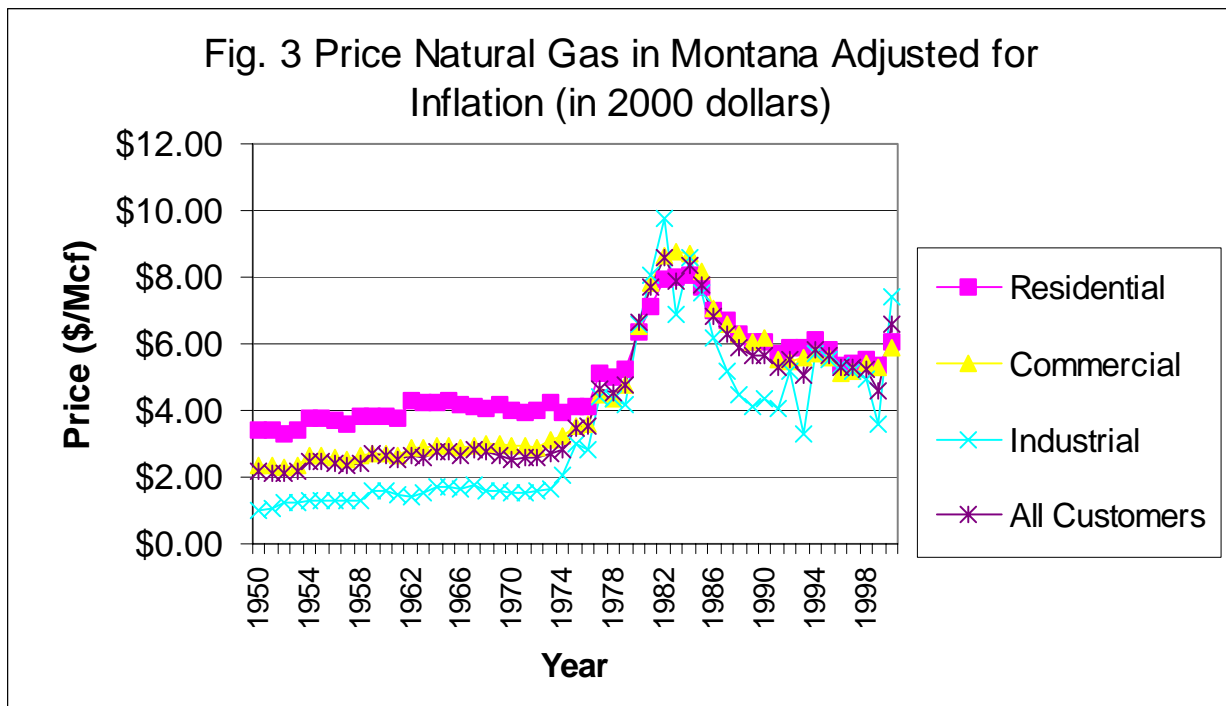
Natural gas customers in Montana and in the Pacific Northwest have historically paid relatively low gas rates compared to the rest of the U.S. In the past few years, however, gas prices across this region have risen to be more in line with the rest of the nation. In fact, the region's relatively low rates may be a thing of the past. More pipelines connect gas supplies in western Canada and the western U.S. to buyers in the eastern U.S. This means that more customers are competing for the same gas that supplies Montana. If demand for a commodity goes up, all else equal, prices also go up. Another reason for potentially higher long-term prices is that the pipeline infrastructure of the Northwestern U.S. is less and less able over time to meet today's gas demand. This means that the regional gas market could more easily be upset by extreme events such as very cold weather.

The historical delivered gas prices (the price seen on one's gas bill) in Montana for all

real dollars (below \$4/Mcf) until the 1980's (see Table NG3). Delivered prices then rose in the mid-80's and mostly settled in the \$5-6/Mcf range using today's dollars. Recently, they have shot up to \$8.00/dkt range in 2004 and are nearing \$9.00/dkt in the Fall of 2004. This increase in delivered gas price is due almost solely to the recent increases in the U.S. wellhead price of gas.

Figure 3 shows *delivered* natural gas prices in Montana adjusted for inflation and reported in 2000 dollars. Recent high prices from 2003 and 2004 are not available, because the data for those years is not yet available on an annual basis. The delivered prices graphed below are the prices that residents and businesses see in their final energy bill reflecting all charges (wellhead gas price, plus transmission and delivery fees, plus additional fees).

The average U.S. wellhead price of gas as of May 2004 was about \$6.00/dkt which is well above historical norms and well above the long-term U.S. EIA forecast for wellhead price in 2020 of \$4.40/dkt in today's dollars. The U.S. EIA, in its current short-term energy outlook from May of 2004, predicts that natural gas spot prices (composites for major gas producing hubs) are likely to average about \$6.00/dkt (\$5.80/Mcf) for 2004. Spot prices averaged about \$5.65/dkt (\$5.50/Mcf) in the first quarter of 2004 and were near \$6.20/dkt (\$6.00/Mcf) as of May 2004. These prices are very high with respect to historical norms. According to the U.S. EIA, the likelihood appears small that spot prices will fall significantly below \$6.00/dkt (\$5.80/Mcf) for the rest of 2004 (U.S. EIA, 2004a). Within the next several years, gas prices are likely to fall back closer to historical norms. The stark change between the EIA 2004 short-term price outlook (about \$6.00/dkt) and their long-term price outlook (about \$4.40/dkt in 2020) demonstrates how quickly the gas market can change and how volatile gas prices are today.



Source: U.S. EIA, *Natural Gas Annual Report*, 1950-2002 (Table NG3).

Utilities are prohibited from earning any profit on the cost of gas they purchase. Rather, they simply pass higher gas costs to consumers. They earn their profit through a return on their capital investment, such as the gas transmission and distribution systems, but don't earn a profit on their expenses, such as gas purchases. The average price of gas purchased by NWE, MDU and Energy West reflects current gas market conditions and that price is constantly changing. Any price change requested by NWE must be approved by the Public Service Commission in what is called a 'tracker' hearing. A tracker hearing covers only the cost of purchased gas, and not any of the other costs of the utility. Trackers usually are routine procedures, but can sometimes be contentious. NWE currently computes a new tracker each month to more accurately reflect the gas costs it incurs.

NWE raised gas bills for its core customers, who are mostly residential and commercial users, by 35% in December 2002. This increase was due to the expiration of a five-year contract NWE held with Pan-Canadian. Finishing this contract caused a 55% increase in the price of the natural gas commodity, from \$2.17/dkt in a mid-2002 tracker to \$3.37/dkt as of December 15, 2002. The increase in wholesale gas costs, and minor reductions in other billing categories, meant that a household consuming 10 dkt of gas per month on average saw an increase in their monthly gas bill at that time from \$46 to about \$62. Retail delivered prices for core customers started December 2002 at \$4.60/dkt and finished the month at about \$6.20/dkt. Delivered gas prices to residential and commercial consumers have steadily increased since the end of 2002 to \$7.80/dkt as of June 2004. The delivered gas price may rise up to \$9.00 later this year (Smith 2004), a 45% increase in gas bills over the

December, 2002 number, or almost a doubling of price from the fall of 2002 when gas was only \$4.60/dkt.

MDU and Energy West customers essentially are in the same boat in terms of rising prices. Customers of both utilities must pay what the wholesale market price is for gas in the utility contract. Delivered prices for customers of both utilities are comparable to what is being paid by NWE customers, with comparable increases over the last two years.

Due to natural gas deregulation, most large industrial customers in Montana contract for gas directly with NWE, MDU and Energy West or with other independent suppliers. Industry still uses the local utilities for distribution and transportation services. Despite typically paying lower gas rates than residents and commercial businesses (i.e. core customers), industry has also faced an increase in gas bills as wholesale gas prices climb. The increase for each industrial customer depends upon each specific contract, who the gas supplier is, and the ability of the given industry to switch from natural gas to some other fuel if prices get too high.

Today, four of the largest natural gas users in Montana are the three oil refineries in and near Billings and Stone Container in Missoula. Montana State University, ASiMi in Butte and Barretts (talc processing) in Dillon are also large users in Montana. The refineries in Billings have some flexibility in switching fuels to run their operations, so they might not be hit as hard by higher gas prices as other customers. Those customers, such as Stone Container and Montana State University, probably have less flexibility to switch fuels, and are likely are feeling more of the cost of recent gas price increases. Large gas users who buy on the spot market, such as Montana State University-Billings, could be hurt more by these high prices, whereas those with longer-term contracts at lower prices are at least partially insulated until their contracts run out.

8. Future Price Increases and Price Volatility

The wellhead price Montana utilities and their customers pay for gas is likely to remain fairly close (within a \$0.30-\$0.70 cent differential) to average U.S. prices on the national market. The AECO C price in Alberta is forecast to run about \$0.45 below the Henry Hub price in the coming years (Northwest Power and Conservation Council 2003), though in 2004, the difference has been closer to \$1.00/Mcf (Terry Morlan 2004). It is likely that any price differential between what Montana pays and what the U.S. pays will partially depend upon how much Canadian supply is available and how much pipeline capacity there is to get that gas to its demand base. Because natural gas prices are determined on a national level, any single large gas-fired project built in Montana should have no significant effect on the Alberta gas price and thus no long-term effect on Montana's price (Smith 2001).

Although gas prices are expected to increase slowly in the long run on average, Montanans may be subject to increasing gas price volatility from extreme or unexpected events such as the California energy crisis of 2000-2001. One reason for potentially greater price volatility

is the increased pipeline capacity from Alberta out to the U.S. Midwest and East Coast. Increased transmission capacity means that the wellhead price paid in Montana today is closely tied to wellhead prices paid nationwide. National prices are sometimes affected by unexpected events worldwide like cold snaps and political turmoil. The Pacific Northwest, for example, now feels the effects of cold snaps in the Northeastern U.S. that drain storage fields (WA OTED 2001). Events outside of Montana will affect our prices more than ever before in coming years.

Another factor in future gas prices paid by Montanans is the fact that domestic and Canadian supplies have leveled off at the present time (in part due to more mature gas fields), while U.S. demand continues to climb with economic recovery and more natural gas fired electric generation on the horizon. This could raise the price of natural gas faster than some of the long-term forecasts included in this document might indicate.

Wholesale electric and natural gas prices are becoming intimately linked. The Northwest Power and Conservation Council states that, "Fuel prices affect electricity planning in two primary ways. They influence electricity demand because they are substitute sources of energy for space and water heating and some other end-uses as well. They also influence electricity supply and price because they are potential fuels for electricity generation. Natural gas, in particular, has become the most cost-effective generation fuel when used to fire efficient combined-cycle combustion turbines." (Page 4, Northwest Power and Conservation Council 2003). The increasing convergence of the electricity and natural gas markets means that extreme events like the California energy crisis are likely to affect both electricity and gas markets simultaneously. Gas prices rose in 2000 nationwide because supplies of natural gas were temporarily tight, due in part to low storage and pipeline constraints. Utilities paid more for natural gas than they did before, but high electricity prices encouraged them to produce electricity anyway, further straining gas supply (Morlan 2001).

The effects of new gas-fired power plants around the nation upon Montana's gas supply and price will depend on the number and timing of both the new plants coming on line and available gas supplies (WA OTED 2001). While the demand from new gas-fired power plants in California and other western states will place pressure on the Northwest's natural gas infrastructure, Montana's infrastructure which runs directly from Alberta and Wyoming will likely not be as strained. Thus, Montana may experience more moderate price fluctuations than in other areas of the U.S.

Utilities and industry can reduce price risks by buying gas at fixed prices and using long-term and futures contracts. They can also store gas to prevent having to buy on the spot market. Residential and commercial customers can use budget billing to smooth out their gas bills over a given billing year, although this does not protect one from yearly fluctuations. There are also programs to help low-income users pay their energy bills. At this point, electricity efficiency improvements may be the 'biggest bang for the buck' for a way to reduce natural gas demand. Residential and commercial air conditioning is a big driver in the U.S. for

marginal electricity demand and thus natural gas demand. Gas often powers peak electricity demands--up to 60% of margin in some areas. This might be an area to target for efficiency in the nation as a whole.

This convergence of the electricity and gas markets bears a number of implications for regional electricity and natural gas utility systems and for industrial customers purchasing their supplies directly. Electric utilities that were caught short in the 2000 energy crisis will likely pursue strategies that provide better insurance against future gas price volatility. New electric generating facilities that do not use natural gas will be more attractive options. For example, most of the major utilities in the Pacific Northwest have acquired, or plan to acquire, wind generation, in part because of the hedge that fixed-priced wind power could provide against volatile natural gas prices for electric generation. Finally, energy efficiency investments are also more attractive than they have been in recent years.

Recent high natural gas prices in the past few years point out three lessons for Montana. First, our natural gas prices are affected by a number of factors beyond any one entity's or state's control. Second, the growing use of natural gas for electricity generation has the potential to upset the traditional seasonal patterns of natural gas storage and withdrawals in Montana. This could lead to high or volatile prices not experienced before. Finally, to the extent that the western United States depends on natural gas for new electricity generation, the price of natural gas will be a key determinant of future electricity prices. Economic theory suggests that in the long run, electricity prices will closely follow the cost of new sources of gas.

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