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Understanding Energy in Montana

EQC 2004

Electricity Supply and Demand in Montana

The electricity industry is not in the crisis it was four years ago. The price spikes and supply disruptions of 2000 and 2001 are gone, though the investigations and court cases continue. The sweeping changes in the electricity industry appear to have slowed almost to a stop. Still, the industry has not returned to where it was before. The deregulation of the wholesale electricity markets through the federal Energy Policy Act (1992) and deregulation of the Montana retail market by SB390 (1997) have not been repealed. NorthWestern Energy, the successor to Montana Power Company, should emerge from bankruptcy this fall. The first new generation in eight years came on-line in 2003. Several more moderate-size plants will be on-line this year and next. Larger ones are in the planning stages. Industrial consumption has dropped dramatically, but loads continue to grow in other sectors. The electricity industry continues to change.

This chapter provides historical supply and demand information needed to put this change in context. Transmission, which affects access to out-of-state markets by Montana suppliers and consumers, is covered in a separate chapter.

1. Necessary Definitions

Certain terms are used throughout this chapter and are explained here. Electricity is measured in kilowatt-hours (kWh) or megawatt-hours (MWh). A MWh is 1,000 kWh. One MWh is produced when a 1 MW generator runs for one hour. A 1 MW generator running for all the 8,760 hours in a year produces 1 average Megawatt (aMW). As one illustration of electricity use, residential customers without electric heat use typically use 10-30 kWh per day. As another, the Helena and the Helena valley at the beginning of the decade used around 80 aMW (700 million kWh), with a peak around 140 MW (Data request MCC-8, PSC Docket No. D2001.10.144).

Montana Power Company (MPC) sold most of its generating units to PPL Montana at the end of 1999. The remainder of the generating units, contracts and leases, as well as the entire distribution utility, was sold to NorthWestern Energy (NWE) in February 2002. Data from the period of MPC ownership are labeled PPL Montana or NWE to be more useful for today's reader.

2. Montana in Perspective

Montana generates more electricity than it consumes. Even so, it is a small player in the western electricity market. Montana generating plants have the capacity to produce 5,100 MW of electricity in the summer. Primarily because hydro generators depend on the rise and fall of river flows, but also because any plant needs downtime for refurbishing and repairs, Montana produced an annual average of 3,000 aMW (1999-2003). This is down about 6 percent from the previous period, primarily because of drought reducing production at hydro facilities. During that

time, Montana sales and transmission losses accounted for slightly more than half of production, or about 1,600 aMW.

Key Electricity Facts for Montana		
Generation capability	-	5,100 MW
Average generation	-	3,000 aMW
Average load	-	1,600 aMW

Montana straddles the two major electric interconnections in the country. Most of Montana is in the western interconnection, which covers all or most of 11 states and two Canadian provinces; it also includes small portions of one Mexican and three other US states. Only about 6 percent of Montana's load and about 2 percent of the electricity generated in Montana is in the eastern interconnection. The 2003 Montana load (sales plus transmission losses) was equivalent to less than 2 percent of the 90,772 aMW load in the western interconnection. Montana generation accounted for over 3 percent of total west-wide generation that year.

3. Generation

There are 44 generating facilities in Montana reported in Table E1. (Over 1 MW of small commercial and residential wind turbines are known to be in operation but aren't formally reported.) The oldest is Madison Dam near Ennis, built in 1906. The largest are the four privately owned coal-fired plants at Colstrip, which have a combined capability of 2,094 MW. (Capability is the maximum amount of power a plant can be counted on to deliver to the grid, net of in-plant use.) The largest hydroelectric plant is U.S. Corps of Engineers' Libby Dam with 598 MW. The smallest commercial plants supplying the grid in Montana are a micro-hydro plant at 60 kW and several wind turbines at 65 kW.

Average Generation by Company, 1999-2003

Company	aMW	Percent
PPL Montana[1,2]	914	30.5%
Puget Sound Power & Light[2]	546	18.2
Avista[2]	360	12.0
Bonneville Power Administration[3]	312	10.4
Western Area Power Administration[3]	239	8.0
Portland General Electric[2]	197	6.6
NorthWestern Energy[2,4]	181	6.0
PacificCorp[2]	122	4.1
Yellowstone Energy Partnership	47	1.6
Other	77	2.6
TOTAL	2,994	100.0%

[1] PPL Montana plants were owned by MPC until mid-December, 1999.
[2] Public data on output for Colstrip 1-4 are reported for the entire facility, not individual units. In this table, the output was allocated among the partners on the basis of their ownership percentages. NWE actually leases its portion of Colstrip.
[3] Distributes power generated at U.S. Corps of Engineers and U.S. Bureau of Reclamation dams.
[4] MPC sold its plant, contracts and leases to NWE in February 2002.
Source: Table E2.

Two plants have come on line this decade: Montana Dakota Utilities' (MDU) Glendive #2 40.7 MW natural gas turbine and Tiber Montana LLC's 7.5 MW hydro plant at Tiber Dam. In the previous decade, the only sizeable additions were two plants built to take advantage of the federal Public Utility Regulatory Policies Act of 1978. PURPA established criteria under which, prior to deregulation of the wholesale electricity markets, non-utility generators (or qualifying facilities—QFs) could sell power to utilities. The Montana One waste-coal plant (41.5 MW) was built near Colstrip in 1990 and the

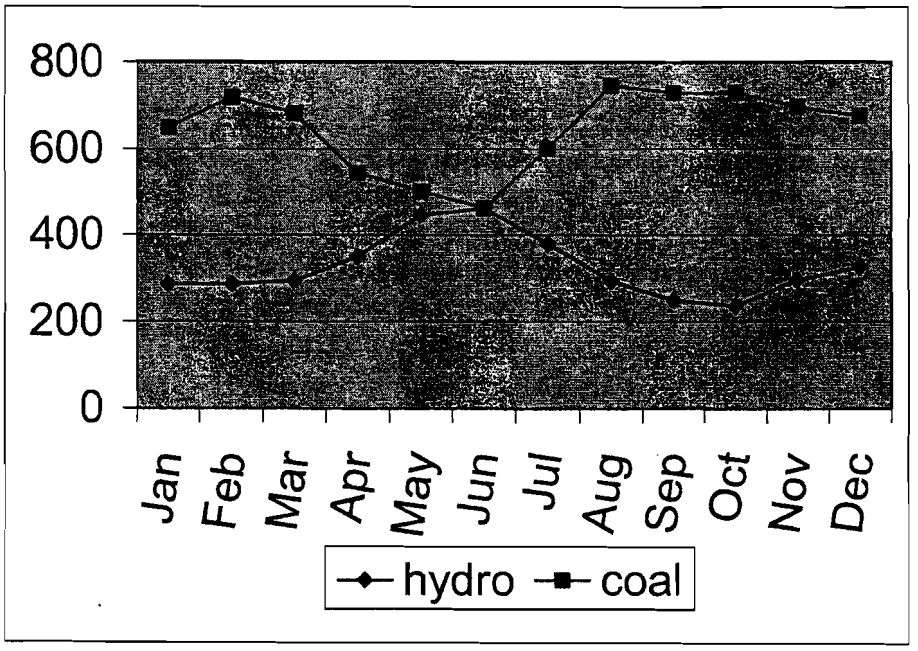
BGI petroleum coke-fired plant (65 MW) was built in Billings in 1995. These two account for about 92 percent of the average production of all QFs in Montana.

PPL Montana plants (previously owned by MPC) produce the largest amount of electricity in Montana (see previous page; Table E2). PPL Montana's facilities accounted for over 30 percent of the total generation in Montana in the period 1999-2003. Federal agencies—Bonneville Power Administration and Western Area Power Administration—collectively produced 18 percent of the electricity generated in Montana. The MPC plants not bought by PPL—Milltown Dam and a lease for a share of Colstrip Unit 4—now belong to NorthWestern Energy and produce 6 percent of the electricity.

Montana generation is powered almost entirely by coal (62 percent average for 1999-2002) and hydro (37 percent). Over the last 15 years, about a quarter of Montana coal production has gone to generate electricity in Montana. Until 1986, hydro was the dominant source of net electric generation in Montana (Table E5). Most of the small amount of petroleum used actually is petroleum coke from the refineries in Billings. Very small amounts of natural gas and wind round out the picture.

During spring runoff, utilities operate their systems to take advantage of cheap hydropower, both on their systems and on the non-firm market around the region. Routine maintenance on thermal plants is scheduled during this period. Thermal plants generally must be run more in the fall when hydro is low. This pattern is apparent in the graph of operations on PPL Montana's plants during 2000 through 2003 (see Figure 1).

Figure 1. Average output of PPL Montana power plants, 2000-2003 (aMW)

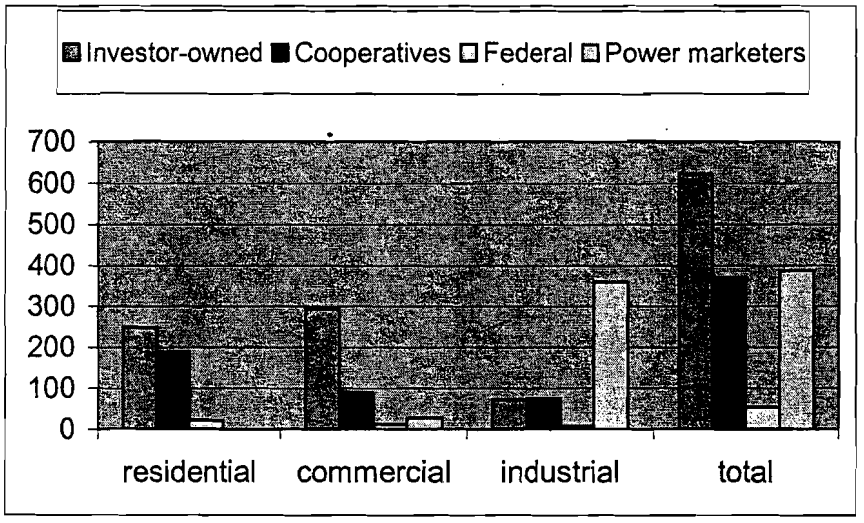


Note: Assumes PPL's monthly production from Colstrip 1- 4 was equal to its ownership share.
Source: U.S. DOE, Energy Information Administration, Form EIA906 databases
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

4. Consumption

Montanans are served by 34 distribution utilities: 4 investor-owned, 26 rural electric cooperatives, 3 federal agencies and 1 municipal (Table E9; Maps). (Four additional co-ops, based in other states, serve a handful of Montanans.) In 2002, NWE and Flathead Electric also distributed power from five power marketers, primarily to industrial customers (Table E8). In 2002, investor-owned utilities made 43 percent of the electricity sales in Montana, co-ops 26 percent, federal agencies 4 percent and power marketers 27 percent (Table E8; Figure 2). Three-quarters of these entities operate mostly or exclusively in Montana.

Figure 2. Distribution of 2002 sales by type of utility (aMW)



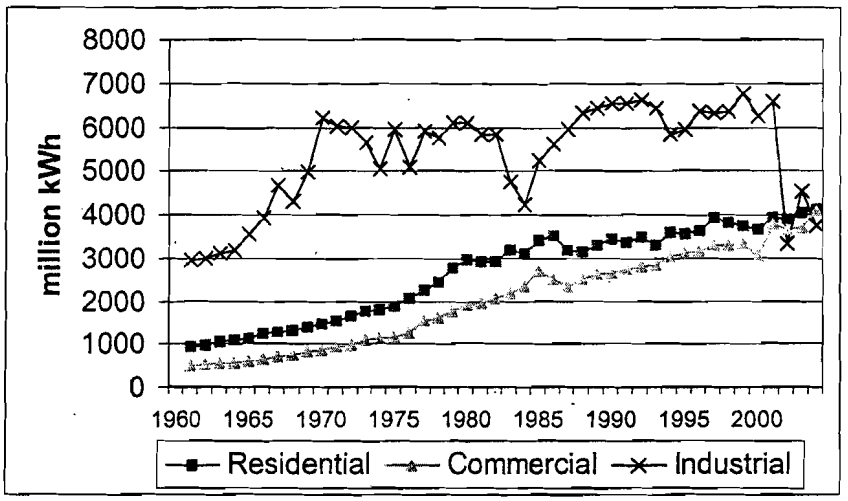
Source: Table E8.

Sales in 2003 were 12.2 billion kWh. The residential, commercial sectors and industrial sectors each accounted for about one-third of sales. Sales tripled between 1960 and 2000, then dropped by over 15 percent as industrial loads tumbled following the electricity crisis of 2000-2001 (Table E6; Figure 3). Growth was faster in the first half of those four decades than in the latter. Since 1990, sales to the commercial sector have grown the most, followed by the residential sector. Industrial sales bounced around, then dropped significantly. Consumption patterns in this decade will be noticeably different than those of the previous decade.

The cost of electricity changed dramatically following 2000 (Table E7). The average price per kWh for residential customers was 7.6 cents in 2003, up from 6.5 cents in 2000 (Table E8). The average price per kWh for commercial customers was 6.5 cents in 2003, up from 5.6 cents in 2000; for industrial, the comparable figures are 4.5 cents and 4.0 cents. The residential and commercial sectors saw about the same increase in price between 2000 and 2003 as they did during the entire previous decade. Like in the other sectors, industrial electricity prices increased between 2000 and 2003 at a faster rate than they did during the 1990's, but the total increase was not as great as in the residential and commercial sectors. On average, the rates of cooperatives and private utilities were within about 6 percent of each other in 2003; however, that average

masks considerable variation. As in previous decades, electricity in Montana costs less than the national average. In 2003, Montana averaged 6.3 cents/kWh vs. 7.4 cents/kWh nationally.

Figure 3. Annual sales in Montana, 1960-2003



Percentage of sales, 2003	
Residential	34 %
Commercial	33
Industrial	31
Other	2
Total	100 %

Source: Table E6.

Montana residential consumption averaged 810 kWh/month in 2003, or about 1.1 akW annually, basically unchanged since 2000 (Table E8). This average covers a wide range of usage patterns. Households without electric heat can run 200 kWh to 1,000 kWh per month (0.3-1.4 akW annually), depending on size of housing unit and amount of appliances. Electrically heated houses easily could range between 1,800 kWh to 3,000 kWh per month (2.5 and 4.1 akW annually). Extreme cases could run higher or lower than these ranges.

Commercial accounts averaged 3,840 kWh/month or 5.2 akW per year. Because so many different types of buildings and operations are included in the commercial sector, it's difficult to describe a typical use pattern.

Variability in the load and pattern of use are even greater in the industrial sector. Some of the largest industrial customers are shown in the following table. These figures date from before the price spikes in 2000 and 2001 forced some companies to cut consumption, but are the only data available. Data on coal mines, which are major consumers, were not available.

Large Industrial Electricity Use (aMW)

ASiMI	~75	Holcim	5.0
Ash Grove Cement	4.6	Roseburg Forest Products*	7.0
Cenex	18	Montana Refining	3.4
Conoco Pipeline	20.0	Montana Tunnels	9.5
Conoco Refinery	27.0	Plum Creek	33
ExxonMobil	27.0	Smurfit-Stone	52.0
Golden Sunlight	10.0	Stillwater Mining	20.0

Data initially provided from best available sources by Don Quander, Large Customer Group; compiled by EQC and DEQ.

*At the time, Louisiana Pacific Corporation.

5. Future Supply and Demand

New generating plants are starting to appear in Montana. Glendive #2, a 40.7 MW gas turbine, came on-line in 2003, followed in 2004 by Tiber Dam, a 7.5 MW hydro facility. Other plants are under construction or have obtained all the necessary permits. Thompson River Co-gen plant, a 16.5 MW coal or biomass-fired fluidized bed plant is nearing completion, though there may be some question about its permits. Rocky Mountain Power, near Hardin is a 116 MW pulverized coal plant expected on-line toward the end of 2005. A 54 MW natural gas combustion plant near Butte and wind plants near Great Falls (9 MW) and Judith Gap (180 MW at build-out) are very near construction. Numerous other coal and wind plants around the state are in various earlier stages of preparation.

Electricity sales show an overall decline. The overwhelming majority of Montana customers, including many of those served by co-ops, have seen significant increases in the cost of electricity since 2000, the start of the electricity crisis. In spite of that, residential consumption rose at an average annual rate of 1.6 percent (2000 to 2003) and commercial consumption at 2.3 percent. Residential growth tends to track population growth, while commercial growth tends to track economic activity, but growth in both sectors will slow if prices continue to rise. Industrial consumption, on the other hand, has fallen dramatically, due to plant closures and operations cutbacks following the surge in electricity prices.

There are no statewide forecasts for future electricity consumption. The rising prices of electricity combined with an economy that has slowed since the early 1990's suggest the growth in electricity consumption will be slower this decade than the last. The drop in the industrial sector has led to Montana loads declining by over 250 aMW since 2000. Improved efficiency, especially in response to higher prices also could reduce loads significantly (see Section 6). Finally, if the trend over the last few decades towards warmer winters continues, Montana's electricity use will decline further.

To be economically viable, any addition to generation resources in Montana will need contracts in out-of-state markets or to displace existing resources for in-state consumption. Therefore, any new generation would need 1) to offer the price and have the transmission access to compete in out-of-state markets; 2) to offer a better package of prices and conditions than those resources currently supplying Montana loads; or 3) to be conceded a Montana market by existing resources choosing to take higher profits by selling out of state. Transmission access is a critical issue; it is discussed in a separate chapter.

6. Potential for Efficiency Improvements

Cost-effective energy efficiency improvements plausibly could meet much or all of the net increase in statewide load over the next decade. There are no comprehensive estimates of the potential for efficiency improvements. However, analyses that have been done and the load reductions seen during the electricity crisis in 2000 and 2001 suggest that significant potential exists.

Efficiency improvements reduce both cost and risk. First, they can reduce the total cost of energy services. For customers, they reduce the monthly bill. For providers, they postpone or eliminate the need to acquire more expensive resources. Second, efficiency improvements reduce exposure to electricity price volatility. By reducing the need for electricity, especially peak-hour electricity, such improvements provide a hedge against the impacts of expensive upswings in price.

The amount of energy efficiency improvements worth pursuing depends on the future price of electricity. The lower or the less volatile expected future prices, the less attractive energy efficiency investments are. The higher or more volatile expected future prices, the more attractive such investments are. Just like any other energy resource, there is a range of energy efficiency rather a fixed amount waiting to be developed.

There are no statewide estimates of the potential energy efficiency improvements, either in total or by sector. While some of the easiest and least difficult to obtain are in large commercial and industrial operations, potential efficiency improvements can be found in all sectors. Based on studies around the country, as well as some in-state estimates, it has been reasonable to assume potential reductions are in a range around 10 percent. Given how perceptions of the electricity industry have changed over the last two years, that range may be low.

NorthWestern Energy currently is developing a program to add energy efficiency to its resource portfolio. As this program gets underway, better estimates of the efficiency potential in Montana should be developed. (NWE still is the largest provider of electricity in Montana, accounting for about 40 percent of total sales.)

The reductions can't be compared to the extensive load reductions in 2001 around the western United States. These were short-term responses to a crisis situation. However, the crisis did give an indication of the amount of flex in electricity use and suggests the magnitude of changes in use that are possible. Those changes are far larger than had been expected previously.

The Readiness Steering Committee of the Pacific Northwest region studied the impact of various actions to reduce energy use in the region during the electricity crisis of 2000-2001. (The committee was an ad hoc group of utility industry, large customer and public agency representatives that advised the Northwest Power Pool and the region on electricity shortages.) The committee, in an October 2001 special report, estimated that the total impact of all electricity demand actions was a reduction by summer of 2001 of about 4,000 megawatts, almost 20 percent of what loads would have been under normal conditions. These actions included utility initiated programs, general appeals to the public and the response of consumers to price increases.

The largest portion of the response came from curtailing industrial production. By July 2001 the electricity use of aluminum smelters had almost completely disappeared, a reduction of more than 2,500 megawatts; operators found it more profitable to resell their contracted supplies than to produce aluminum. Irrigation customers also reduced their use by an average of 300 megawatts over the May-September irrigation season, in exchange for payment from their

suppliers. About 500 megawatts of reduction came from industrial customers who faced high market prices. Not all of this reduced use was due to cutbacks in operations; a portion came from customers beginning to generate some of their own electricity. Another 160 megawatts came from customers in other sectors who accepted payment from their electricity suppliers to reduce their consumption by cutting back operations. Demand response to higher electricity rates charged by some utilities was estimated at about 150 megawatts by July. Finally, while customers of most utilities were insulated from the high prices in the wholesale market, expanded conservation education programs, along with the media coverage of the California shortages, were believed to have caused some reduction in regional loads, though this couldn't be quantified.

The load reductions seen by the summer of 2001 would not be cost-effective or advisable under normal conditions. What they do show is the ability of consumers to change their usage in the face of higher prices, either in terms of what they pay or what they're offered to forego using electricity. As prices for electricity climb, some improvement in the economy's energy efficiency can be expected in any event, though not to the extent that could come from a more formal program of resource acquisition. Difficulties in obtaining information and financing always will deter some individual consumers from otherwise cost-effective investments.

Table E8. Utility Revenue, Retail Sales, Consumers and Average Price per Kilowatt-hour, 2002 (with comparison to 2000 average price)

UTILITY NAME	RESIDENTIAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2002	2000	COMMERCIAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2002	2000	INDUSTRIAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2002	2000	TOTAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2002	2000
Cooperative	$127,744	189.6	140,349	7.7	6.6	$54,651	90.3	18,523	6.9	5.7	$36,136	75.0	488	5.5	3.2	$228,166	371.0	168,305	7.0	5.2
Beartooth Electric Coop Inc	$3,989	5.3	4,571	8.6	7.7	$437	0.7	226	7.0	6.8	--	--	--	--	5.3	$4,553	6.3	4,870	8.3	7.5
Big Flat Electric Coop Inc	$1,433	2.0	1,458	8.2	8.1	$651	0.9	182	8.7	7.4	$230	0.2	6	10.8	10.2	$2,508	3.3	1,712	8.6	8.4
Big Horn County Elec Coop Inc	$2,547	3.6	2,905	8.1	7.7	$1,807	2.7	467	7.7	7.4	--	--	--	--	--	$4,593	6.6	3,454	7.9	7.6
Big Horn Rural Electric Co	$26	0.0	26	7.5	7.6	$69	0.1	23	12.1	11.2	--	--	--	--	--	$95	0.1	49	10.4	10.0
Fall River Rural Elec Coop Inc	$1,223	1.6	1,250	8.7	7.1	$1,884	3.4	482	6.4	5.4	--	--	--	--	--	$3,107	5.0	1,732	7.2	5.9
Fergus Electric Coop Inc	$4,899	6.2	5,160	9.0	8.6	$614	1.0	239	7.3	6.9	--	--	--	--	--	$6,192	8.5	5,560	8.3	8.0
Flathead Electric Coop Inc[4]	$43,317	60.4	43,417	8.2	5.1	$26,938	42.8	8,058	7.2	4.7	$24,427	49.9	14	5.6	2.8	$95,742	154.4	54,077	7.1	3.6
Glacier Electric Coop Inc	$5,431	7.1	5,395	8.8	7.6	$4,099	7.3	1,421	6.4	5.3	$1,317	2.9	5	5.2	4.6	$11,133	17.7	6,945	7.2	6.1
Goldenwest Electric Coop Inc	$370	0.5	456	8.5	9.8	$93	0.1	9	10.1	10.9	--	--	--	--	--	$513	0.6	627	9.2	10.5
Grand Electric Coop Inc	$7	0.0	14	6.7	7.1	--	--	--	--	--	--	--	--	--	--	$7	0.0	14	6.7	7.1
Hill County Electric Coop Inc	$2,969	3.7	3,154	9.1	9.3	$1,224	2.1	132	6.5	6.7	$1,296	4.7	2	3.2	2.8	$5,565	10.7	3,337	6.0	6.1
Lincoln Electric Coop Inc	$2,829	6.1	3,571	5.3	5.1	$1,069	2.4	538	5.0	4.8	$1,654	3.9	9	4.8	4.6	$5,584	12.6	4,124	5.1	4.9
Lower Yellowstone R E A Inc	$1,804	2.8	1,652	7.4	7.5	$604	0.7	424	9.5	9.6	$1,725	2.1	245	9.4	9.8	$4,451	5.9	3,019	8.6	8.8
Marias River Electric Coop Inc	$1,538	3.6	2,524	4.9	4.9	$2,329	4.8	1,190	5.5	5.6	--	--	--	--	5.1	$4,006	8.7	3,731	5.3	5.3
McCone Electric Coop Inc	$3,653	4.5	4,269	9.3	9.3	$1,223	1.9	462	7.2	7.2	$92	0.1	62	8.7	8.8	$4,979	6.5	4,797	8.7	8.7
McKenzie Electric Coop Inc	$42	0.1	105	8.0	7.8	$3	0.0	2	7.0	9.1	--	--	--	--	--	$45	0.1	107	7.9	7.8
Mid-Yellowstone Elec Coop Inc	$1,313	1.9	1,571	7.9	7.4	$208	0.3	152	7.4	7.7	--	--	--	--	--	$1,868	2.9	1,855	7.5	7.2
Missoula Electric Coop Inc	$7,944	14.2	10,740	6.4	6.6	$1,676	3.6	1,051	5.4	5.6	$671	1.5	4	5.0	5.0	$10,537	19.9	12,084	6.0	6.2
Northern Electric Coop Inc	$1,249	1.8	948	7.9	7.9	$1,183	1.4	291	9.7	10.3	--	--	--	--	--	$2,438	3.2	1,242	8.7	8.8
Northern Lights Inc	$2,746	3.6	2,994	8.7	7.2	$543	0.8	227	7.7	5.5	$474	0.5	3	9.9	7.6	$3,763	5.0	3,224	8.7	6.9
Park Electric Coop Inc	$4,136	5.7	4,372	8.2	8.3	$319	0.6	70	6.4	6.5	$2,034	4.8	1	4.8	7.0	$6,860	11.8	4,657	6.7	7.7
Powder River Energy Corp	$47	0.1	89	7.7	8.9	$363	0.7	69	5.7	5.8	--	--	--	--	--	$410	0.8	158	5.9	6.1
Ravalli County Elec Coop Inc	$6,765	11.3	7,551	6.8	6.8	$510	0.9	243	6.2	6.2	$169	0.4	1	5.0	5.0	$7,754	13.4	8,339	6.6	6.6
Sheridan Electric Coop Inc	$1,938	3.2	2,433	6.9	6.6	$3,653	5.4	710	7.8	7.4	--	--	--	--	12.5	$5,873	8.8	3,737	7.6	7.2
Southeast Electric Coop Inc	$1,539	1.6	1,861	11.0	7.6	$39	0.1	15	8.5	9.3	$291	0.6	1	5.7	5.7	$1,875	2.2	1,878	9.5	7.2
Sun River Electric Coop Inc	$3,681	5.0	3,738	8.3	8.4	$484	1.0	47	5.6	5.7	--	--	--	--	--	$5,787	8.6	4,999	7.7	7.0
Tongue River Electric Coop Inc	$3,366	5.8	3,549	6.6	6.8	$561	1.0	480	6.3	6.4	$840	1.7	41	5.6	6.0	$5,306	9.3	4,713	6.5	6.8
Valley Electric Coop Inc	$1,472	1.9	1,560	8.9	8.8	$370	0.5	212	8.3	7.7	--	--	--	--	--	$1,941	2.5	1,840	8.9	8.5
Vigilante Electric Coop Inc	$4,857	8.8	6,457	6.3	6.0	$364	0.8	113	5.3	5.3	--	--	--	--	--	$7,423	14.0	7,606	6.1	5.6
Yellowstone Valley Elec Co-op	$10,614	17.2	12,559	7.1	7.0	$1,334	2.3	988	6.6	6.5	$916	1.6	94	6.7	--	$13,258	21.8	13,818	6.9	6.8
Federal	$9,319	20.8	12,706	5.1	5.2	$5,746	11.7	2,785	5.6	5.8	$2,184	7.5	2	3.3	2.0	$18,772	53.3	18,252	4.0	2.4
Bonneville Power Administration[5]	--	--	--	--	--	--	--	--	--	--	$1,383	5.3	1	3.0	2.0	$1,383	5.3	1	3.0	2.0
USBIA-Mission Valley Power	$9,319	20.8	12,706	5.1	5.2	$5,746	11.7	2,785	5.6	5.8	$801	2.2	1	4.1	4.0	$16,094	34.9	18,228	5.3	5.4
Western Area Power Administration	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	$1,295	13.1	23	1.1	0.4
Municipal												0.0		0.0			1.6		0.0	
Troy City of	$512	1.1	759	5.3	5.3	$141	0.3	78	5.1	4.6	$5	0.0	6	7.2	5.3	$761	1.6	912	5.3	5.1
Investor-Owned	$153,764	248.5	259,359	7.1	6.5	$164,112	293.7	58,201	6.4	5.7	$28,062	72.5	165	4.4	4.0	$357,720	622.4	321,578	6.6	5.7
Avista	$7	0.0	11	4.9	4.6	$2	0.0	1	6.5	8.0	--	--	--	--	--	$15	0.0	19	5.6	5.3
Black Hills Power Inc	$5	0.0	11	6.7	7.3	$18	0.0	19	9.8	12.2	$573	1.5	2	4.5	4.6	$596	1.5	32	4.6	4.7
MDU Resources Group Inc	$10,871	16.9	18,635	7.3	7.4	$11,090	22.9	4,526	5.5	5.6	$8,854	23.1	135	4.4	4.3	$31,615	64.6	23,632	5.6	5.7
NorthWestern Energy	$142,881	231.6	240,702	7.0	6.5	$153,002	270.8	53,655	6.4	5.8	$18,635	47.9	28	4.4	3.9	$325,494	556.2	297,895	6.7	5.7
Power Marketers[6]	$5	0.0	9	3.1	NA	$7,495	27.1	888	3.2	NA	$96,274	360.0	19	3.1	NA	$103,774	387.1	916	3.1	NA
Conoco Inc	--	--	--	--	NA	--	--	--	--	NA	$13,096	44.2	4	3.4	NA	$13,096	44.2	4	3.4	NA
Energy West Resources Inc	$5	0.0	9	3.1	NA	$7,495	27.1	888	3.2	NA	--	--	--	--	NA	$7,500	27.2	897	3.2	2.6
Granite Peak Energy	--	--	--	--	NA	--	--	--	--	NA	$1,953	7.2	1	3.1	NA	$1,953	7.2	1	3.1	NA
Hinson Power Company, L.L.C.	--	--	--	--	NA	--	--	--	--	NA	$30,157	130.1	1	2.6	NA	$30,157	130.1	1	2.6	NA
PPL EnergyPlus LLC	--	--	--	--	NA	--	--	--	--	NA	$51,068	178.5	13	3.3	NA	$51,068	178.5	13	3.3	NA
STATE TOTALS	$291,344	460.0	413,182	7.2	6.5	$232,145	423.2	80,475	6.3	5.7	$162,661	515.0	680	3.6	2.9	$709,193	1,435.4	509,963	5.6	4.9

NA - not applicable

[1]One average megawatt = 8,760 kilowatt-hours.

[2]The number of ultimate consumers is an average of the number of consumers at the close of each month.

[3]Average price is the average revenue per kilowatt-hour of electricity sold, which is calculated by dividing revenue (in current dollars) by sales. It includes hook-up and demand charges.

[4]Between 2000 and 2002, Hinson Power took over provision of power to CFAC from Flathead Cooperative. This increased the average price of both Flathead and cooperatives in general.

[5]Market incentives paid CFAC to suspend operations were not subtracted from total revenue in 2000.

[6]Revenues don't cover transmission and distribution costs. For a rough estimate of price to the consumer, add 2.5 cents/kWh to commercial and 1.0 cents/kWh to industrial.

Source: U.S. DOE, Energy Information Administration, Form 861 Database:http://www.eia.doe.gov/cneaf/electricity/page/eia861.html for 2000 and 2002.

Montana Electric Transmission Grid: Operation, Congestion and Issues

The transmission grid serves the vital function of moving power from many different generating plants to customers and their electric loads. Moreover, it provides service robustly and reliably even though individual elements of the transmission grid may be knocked out of service or taken down for maintenance. This paper describes how the transmission grid developed, how it works in terms of physics and how it is managed commercially, and how reliability is ensured. It discusses the ownership and rights to use the system, the extent of congestion and how it is managed, and how management would be changed under the proposed Grid West. Finally, it discusses several issues involved in the construction of new transmission lines to expand the capacity of the grid.

1. Historical Development Of Transmission In Montana

The transmission network in Montana, as in most places, developed over time as a result of local decisions in response to growing demand for power and decisions on where to build generation. The earliest power plants in Montana were small hydro generators and coal-fired steam plants, built at the end of the nineteenth century to serve local needs for lighting, power and streetcars. The earliest long distance transmission lines were built from the Madison plant, near Ennis, to Butte and from Great Falls to Anaconda. The latter was, at the time of construction, the longest high voltage (100 kilovolt—kV) transmission line in the country.

As the Montana Power Company (MPC—now NorthWestern Energy) system, and rural electric cooperatives (coop) loads dependent on its system for delivery grew, MPC expanded its network to include 161 kV and ultimately a 230 kV backbone. Long distance interconnections did not develop until World War II. During the war the 161 kV Grace line was built from Anaconda south to Idaho. Later, BPA extended its high voltage system into the Flathead Valley to interconnect with Hungry Horse Dam and to serve the aluminum plant at Columbia Falls.

Montana's strongest interconnections with other regions are now the 500 kV lines from Colstrip to Spokane, the BPA 230 kV lines heading west from Hot Springs, PacifiCorp's interconnection from Yellowtail Dam south to Wyoming, WAPA's DC tie to the east at Miles City, and the AMPS line running south from Anaconda parallel to the Grace line to Idaho.

As U.S. and Canadian utilities have grown and increasingly depend on each other for support and reliability, the North American transmission network has developed into two major interconnected grids, divided roughly along a line that runs through eastern Montana south to west Texas. The western United States is a single, interconnected and synchronous electric system (see next page). Most of the eastern United States is a single, interconnected and synchronous electric system. Texas and Quebec are exceptions; Texas is considered a separate interconnection with its own reliability council, ERCOT.

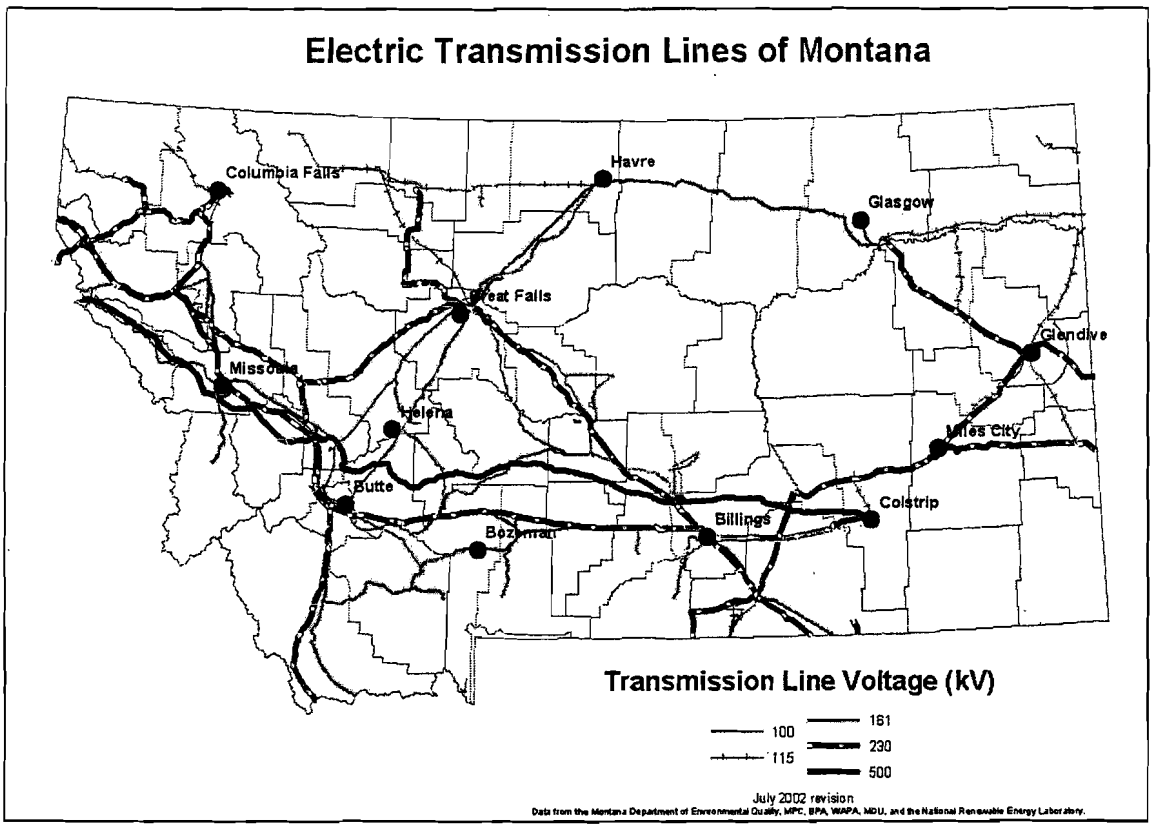


Figure 1. The Montana transmission network

The interconnections are not synchronous with each other. Each interconnection is internally in synch at 60 cycles per second, but each system is out of synch with the other systems. They cannot be directly connected because there would be massive instantaneous flows across any such connection. Therefore they are only weakly tied to each other with AC/DC/AC converter stations. One such station is located at Miles City. It is capable of transferring up to 200 MW in either direction. Depending on transmission constraints, a limited amount of additional power can be moved from one grid to the other by shifting units at Fort Peck Dam. By contrast, this transfer capacity is about one tenth the peak load in Montana, which is one of the smaller loads in the West.

There are currently four DC converter stations between the western and eastern grids with a combined capacity of 710 MW. An additional station at Lamar, CO, with 210 MW capacity, will be operating by the end of 2004. There are also two converter stations with a combined capacity of 420 MW linking the Western Interconnection with ERCOT. The peak load of the Western Interconnection, by comparison, was around 136,000 MW in 2002.

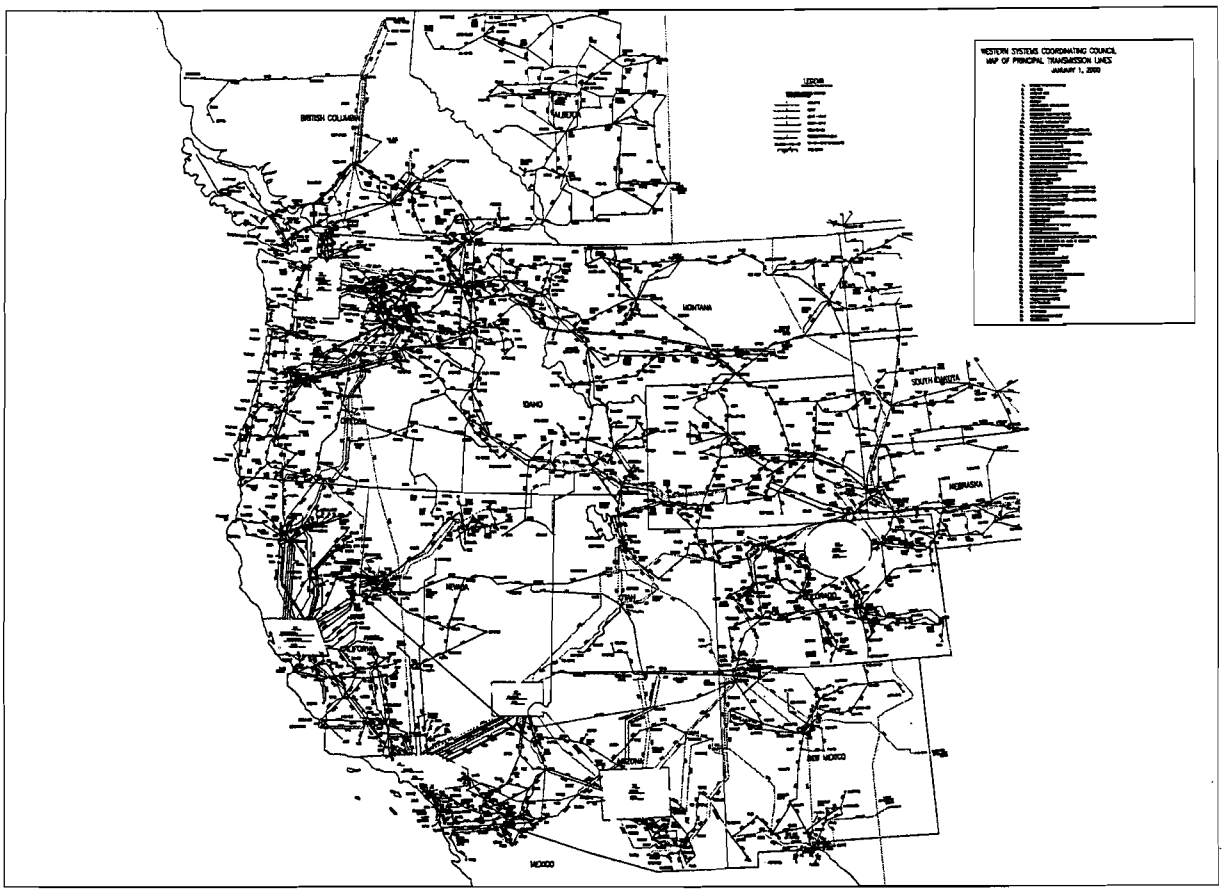


Figure 2. The Western Interconnection transmission network

Most of Montana is integrally tied into the Western electrical grid. However the easternmost part of the state, with around 5 percent of total Montana load, is part of the Eastern Interconnection and receives its power from generators in that grid.

2. How The Transmission System Works

There are big differences between the way the transmission system operates and is managed physically, and the way it is operated commercially. The flows of power on the transmission network follow certain physical laws. Transactions to ship power across the grid follow a different and not fully compatible set of rules.

Physical operation: The transmission grid is sometimes described as an interstate highway system for electricity, but the flow of power on a grid differs in very significant ways from the flow of most physical commodities. First, when power is sent from one point to a distant location on the transmission grid, the power will flow over all connected paths on the network. It will distribute itself so that the greatest portions flow over the paths of lowest resistance ("impedance," in alternating current circuits), and it generally cannot be constrained to any particular physical or contract path. For example, power sent from Colstrip to Los Angeles will flow mostly west to Oregon and Washington and then south to California. But portions will flow

south via Garrison into Idaho, and even southeast from Colstrip into Wyoming and then south to Arizona before continuing to Los Angeles.

A second way in which power flows differently than other commodities is that flows in opposite directions net against each other. If traffic is congested in both directions on an interstate highway it will come to a halt in all lanes and not a single additional vehicle will be able to enter the flow. By contrast, if 100 MW were shipped westbound on a transmission line from point A to point B, and 25 MW were sent simultaneously eastbound from point B to point A, the actual measured flow on the line would be 75 MW in a westbound direction. If 100 MW were sent in each direction the net measured flow would be zero. If power were shipped simultaneously in opposite directions at the full capacity of a transmission line, the net flow would be zero, and additional power still could flow in either direction up to the full capacity of the line.

As a consequence of the above factors, the actual flows on the network are the net result of all generators and all loads on the network. In any real transmission network there are many generators located at hundreds of different points on the network, and many loads of varying sizes located at thousands of different locations. Because of netting, regardless of where power is sent or from where it is purchased, path loadings will depend only on the amounts and locations of electric generation and load.

Management of the grid. In contrast with the physical reality of the transmission network, management of transmission flows has historically been by use of a "contract path": A transaction shipping power between two points will be allowed if space has been purchased on any path connecting the two points, from the utilities owning the wires (or the rights to use those wires, if they are transferable) along that path. Transactions are deemed to flow on the contract path. Portions that flow on other paths are termed "inadvertent flows" or "unscheduled flows."

For example, power sent from Colstrip to the West Coast uses a contract path along the 500 kV lines through Garrison and Taft, then across the West of Hatwai path into western Washington and Oregon. However somewhere between 15 and 20 percent of the power actually flows south across two other paths, the Yellowtail-South path and the Montana-Idaho path south from Anaconda.

The topology of the western grid is such that major inadvertent flows occur around the entire interconnection. Power sent from the Northwest to California flows in part clockwise through Utah and Colorado into New Mexico and Arizona and then west to California. Conversely, a portion of power sent from Arizona to California flows counterclockwise through Utah, Montana and Idaho, then west to Washington and Oregon, and then south into California. These major inadvertent flows are called "loop flow." Expensive devices ("phase shifters") have been installed at several locations to control loop flow and to limit its effect on owners of affected portions of the grid.

Owners of rights or contracts on contract paths are allowed to schedule transactions as long as the total schedules do not exceed the path ratings. Scheduling against reverse flows is not allowed, despite their netting properties, because the capacity created by reverse schedules is not

deemed to be firm. (If the flow scheduled in one direction was reduced at the last minute, capacity to carry power in the opposite direction would automatically go down by the same amount.)

Inadvertent flows may interfere with the ability of path owners to make full use of their rights. The Western Electricity Coordinating Council (WECC) Unscheduled Flow Reduction Procedure requires utilities whose wires are affected by inadvertent flows to first accept flows up to the greater of 50 MW or 5 percent of the path rating by curtailing their own schedules. If further reductions are necessary the path owners can request the operation of phase shifters (to block loop flows) or curtailments of schedules across other paths that affect their ability to use their own path. Phase shifters are limited to operation no more than 2000 hours per year, because they have limited lifetimes and are degraded by use.

The shift to management of the grid by a Regional Transmission Organization (RTO—discussed below) will do away with the use of the contract path, and with it, the necessity for special management of inadvertent flows.

If the scheduled flows do not exhaust the path rating, the unused capacity may be released as non-firm transmission capacity. This capacity cannot be purchased in advance; it can be scheduled only at the last hour. Owners of capacity who do not plan to use it could release it earlier, but often are reluctant to do so because of their own needs for flexibility or a desire to withhold access by competitors to their markets.

3. Grid Capacity and Reliability

The amount of power a transmission line can carry is limited by several factors. A major factor is its thermal limit. When flows get high enough the wire heats up and stretches, eventually sagging too close to the ground and arcing. Other factors relate to inductive and capacitative characteristics of AC networks. (Inductive characteristics are associated with magnetic fields that are constantly expanding and contracting in AC circuits wherever there are coils of wire such as transformers. Capacitative characteristics are associated with electric flows induced in wires that are parallel to each other, such as long transmission lines.) But the most important factor, indeed the limiting factor, is reliability. The transmission network is composed of thousands of elements that are subject to random failure, caused by such things as lightning strikes, ice burdens, pole collapse, trees falling on conductors and vandalism. Since customers value reliability and can be greatly harmed by loss of power, reliability of the grid is assured by building redundancy into it. The grid is designed to withstand the loss of key elements and still provide uninterrupted service to customers. Service is provided by the network, not by individual transmission lines. Reliability concerns limit the amount of power that can be carried to the amount of load that can be served with key elements out of service.

Two examples will show how this applies. Within NorthWestern Energy's (NWE) service area the reliability of the transmission system is evaluated by computer simulation of the network at future load and generation levels, taking individual elements out of service and determining whether all loads can be served with voltage levels and frequencies within acceptable ranges. If acceptable limits are violated, the network must be expanded and

strengthened. Typically this means adding transmission lines or rebuilding existing ones to higher capacities. Identical procedures are used by other utilities and by regional transmission and reliability organizations.

The second example relates to major transmission paths used to serve distant load or to make wholesale transactions. Paths are groups of more or less parallel transmission lines that carry power between the same general areas. Most major paths are rated in terms of the amount of power they can carry, based on their strongest element being unavailable. (In some cases the reliability criteria require the ability to withstand two or more elements out of service.) For example, the Colstrip 500 kV lines are a double circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service.

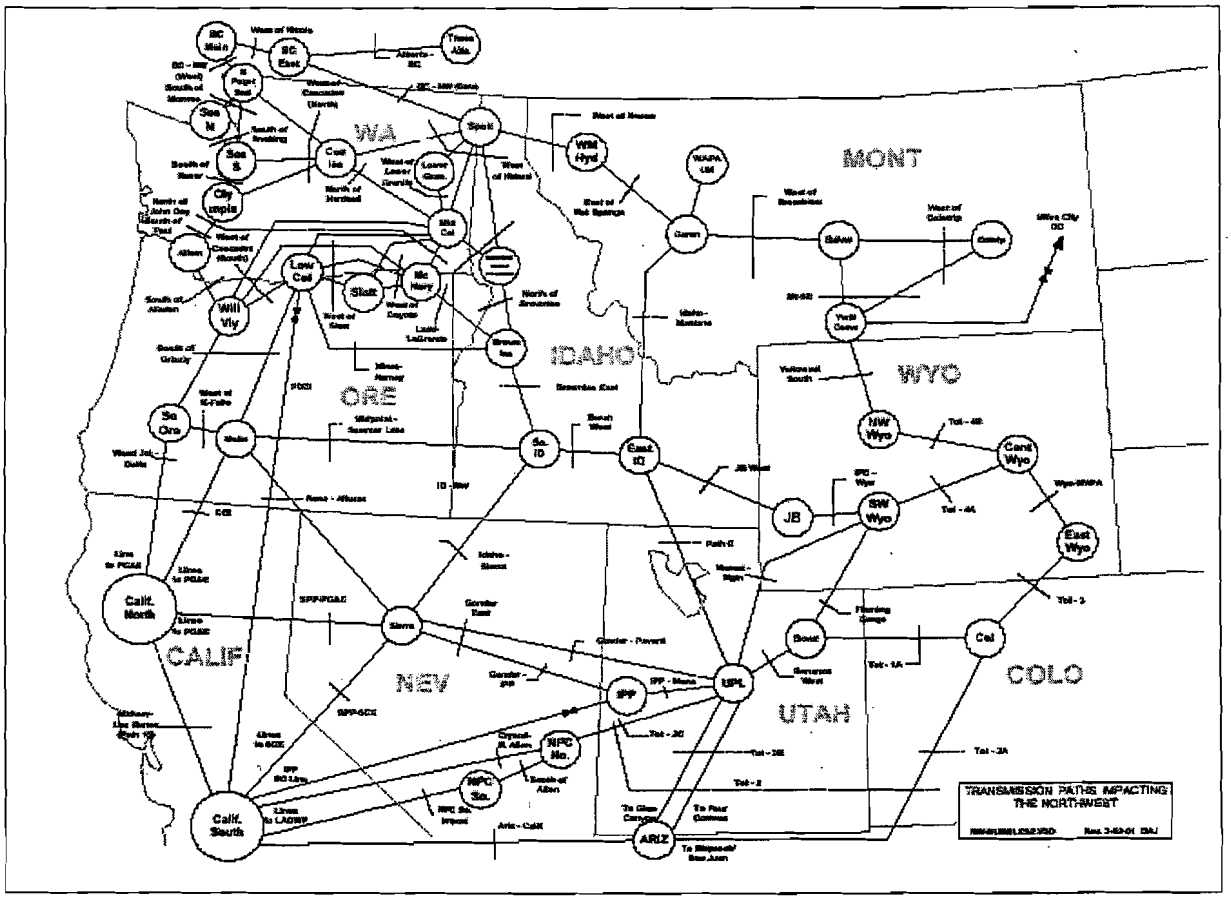


Figure 3. Rated paths on the transmission network

The paths through Montana toward the west have been rated and are limited generally to 2200 MW east to west. The West of Hatwai path, which is comprised of a number of related lines west of the Spokane area, is rated at 2800 MW. West of Hatwai is currently being expanded by approximately 1500 MW. A large but unknown share of that amount is committed to new generation in the Spokane area. Regional transmission studies (Rocky Mountain Area Transmission Study – RMATS – and Northwest Transmission Assessment Committee - NTAC) have identified relatively low-cost improvements that would expand capacity on the Montana-

NW path by about 500 MW, but use of this to access West Coast markets could require additional improvements on West of Hatwai.

4. Ownership And Rights To Use The Transmission System

Rights to use the transmission system are generally held by the owners or by holders of long-term contract rights. Rights to use rated paths have been allocated among the owners of the transmission lines that comprise the paths. In addition the owners have committed to a variety of contractual arrangements to ship power for other parties. Scheduled power flows are not allowed to exceed the path ratings.

FERC Order 888, issued in April 1996, required that transmission owners functionally separate their transmission operations to make them independent of their power marketing operations. They must allow other parties to use their systems under the same terms and conditions as their own marketing arms. They must maintain a web site ("Open Access Same-Time Information System" or OASIS) on which available capacity is posted.

Available transmission capacity (ATC) is calculated by subtracting committed uses and existing contracts from total rated transfer capacity. Little or no ATC is available on most major rated paths, including those leading west from Montana to the West Coast. The rights to use the capacity are fully allocated and closely held. None is available for purchase by new market entrants.

These existing rights – and ATC, if any were available – are rights to transfer power on a firm basis every hour of the year. The owners of the rights on rated paths may or may not actually schedule power in every hour, and when they don't, the space they are not using may be available on a non-firm basis. In fact, the paths are fully scheduled for only a small portion of the year, and non-firm space is almost always available. For example, according to NWE, in the 12 months through September 2001, the West of Hatwai path was fully scheduled or over-scheduled about 8 percent of the time. The remainder of the time, 92 percent of the year, non-firm access was available.

However, non-firm access cannot be scheduled in advance or guaranteed. It is a workable way to market excess power for existing generators. It may be a reasonable way to make firm power transactions if backup arrangements can be made to cover the contracts in the event the non-firm space turns out to be unavailable. However it may be difficult to finance new generation if it cannot be shown with certainty that the power can be moved to market.

5. Congestion

A transmission path may be described as congested if no rights to use it are for sale. Alternately, congestion could mean that it is fully scheduled and no firm space is available. Or it could mean that the path is fully loaded. These are three different concepts.

By the first definition, the paths west of Montana are congested – no rights are available and no ATC is offered for sale on the OASIS.

By the second definition, the paths are congested a few hours of the year - the rights holders fully use their scheduling rights a fraction of the time, and the rest of the time they use only portions of their rights. From October 2000 through September 2001, the West of Hatwai path was congested under this definition around 8 percent of the time.

The third definition is based on actual loadings. Actual loadings are different than scheduled flows because of the difference between the physics and the management of the grid – schedules are contract-path-based, and actual loadings are net-flow-based. Actual flows on the paths west of Montana are almost always below scheduled flows, because of the net impacts of inadvertent flows and loop flows. Actual hourly loadings on the West of Hatwai path are posted on BPA's OASIS site. Figure 4, below, shows that the first eight months of 2001, highest actual loadings were around 90 percent of the path capacity for only a few hours. For most hours the path was not heavily loaded. By the third definition, the lines currently are never congested – even when the lines are fully scheduled, the net flows are below path ratings.

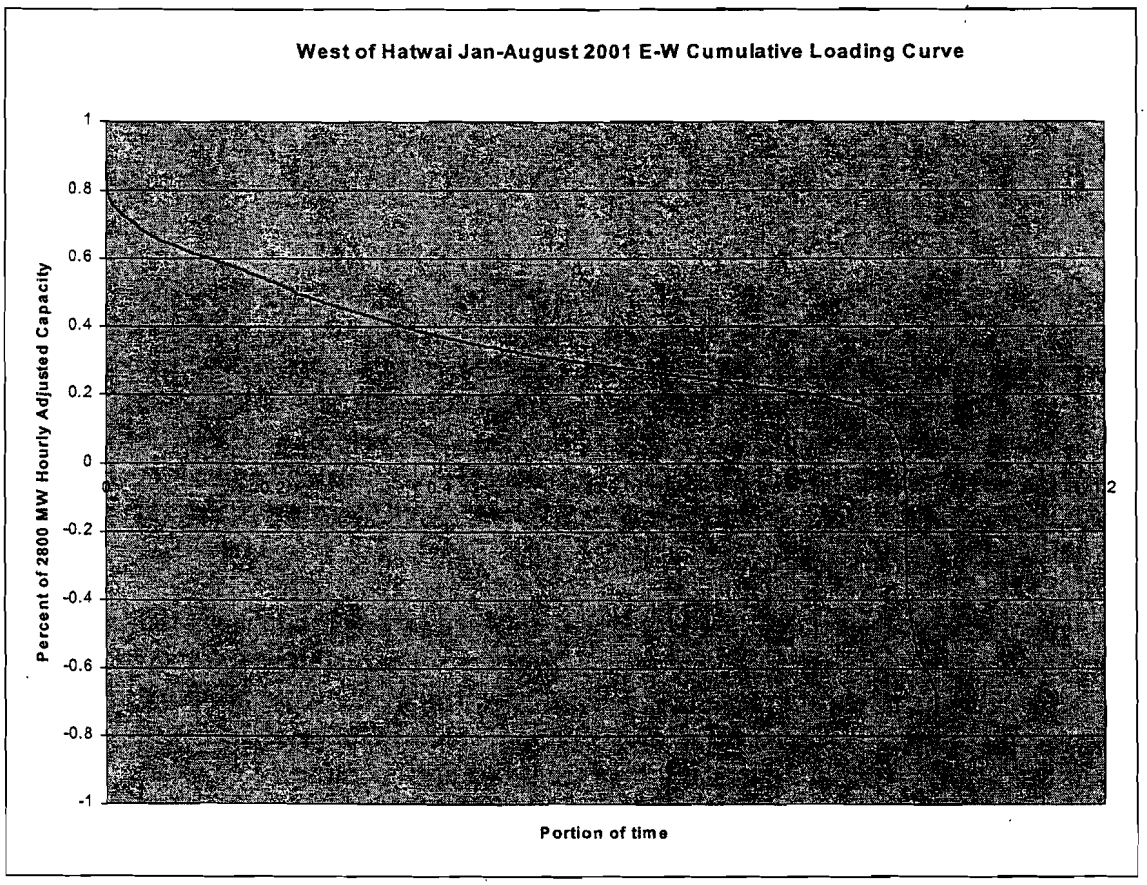


Figure 4. West of Hatwai path cumulative loading curve Jan-Aug 2001
(Negative flows mean power was flowing from west to east)

The Montana-NW path shows a similar cumulative loading pattern – rarely if ever fully loaded and considerable unused capacity most of the time. However, the two paths do not load at the same times, and capacity from Montana to the Pacific Northwest is limited by the amount of

space that is simultaneously available on both paths. Figure 5 shows the cumulative unused capacity that is simultaneously available on Montana-NW and West of Hatwai.

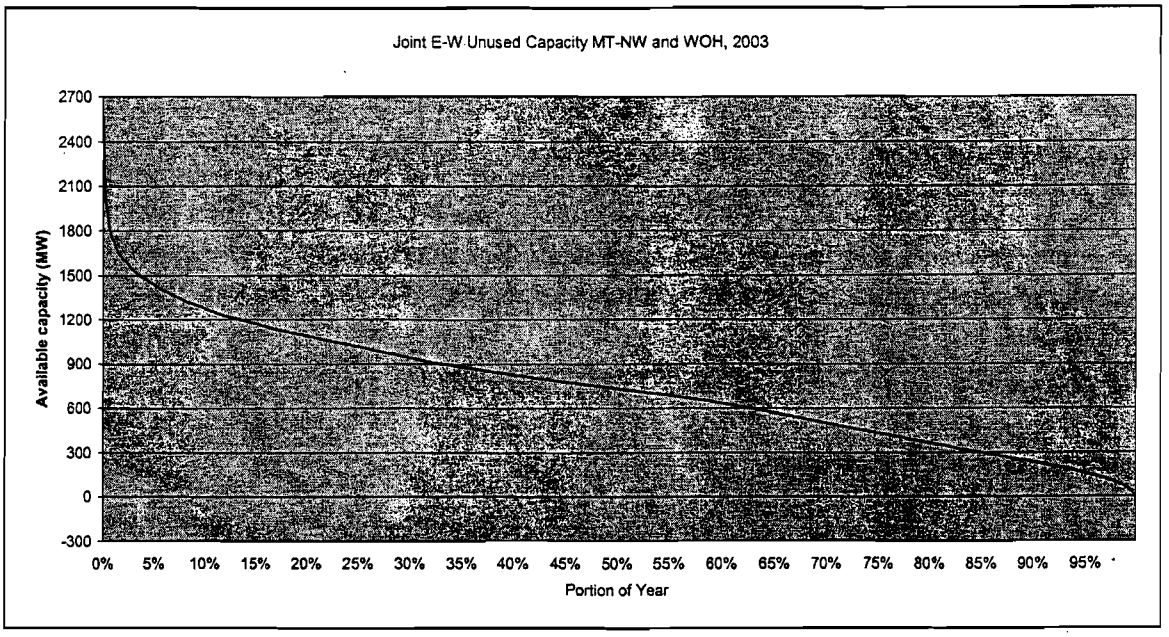


Figure 5. Simultaneous unused capacity, West of Hatwai and Montana-NW Paths 2003

6. Grid Management By Grid West

Discussions to have an independent body take over operation and control of access for the transmission system have been underway since the mid-1990's among the transmission owners and other stakeholders in the Northwest. These started partly out of a recognition by the transmission owners that proof of independence, as required by FERC Order 888, would become an increasingly difficult burden, and partly out of anticipation that FERC would ultimately move to order such a transfer. Initial discussion revolved around IndeGO, a proposed independent system operator that would lease and operate the wires. The IndeGO discussions ultimately foundered on cost-shifting concerns, but after FERC issued Order 2000 the discussions revived, focusing now on a Regional Transmission Organization (RTO) that would operate the system under a contractual Transmission Operating Agreement (TOA) with the participating transmission owning utilities. These discussions have proved to be contentious and prolonged.

Assumption of responsibility for grid management by an independent entity is important because for the first time it would provide for a market-driven means of managing congestion. The current fixed assignment of rights to use the grid prevents non-incumbents from making use of unused capacity, and even hinders their ability to bid for it. The RTO would allow all parties to signal their willingness to pay for access and to make efficient use of the grid. In addition the RTO management would result in congestion price signals that would allow economic decisions on location of new generation and on expansion of capacity on congested transmission paths.

Initial efforts to gain regional consensus on a fully formed RTO resulted in a proposal and a filing with FERC in 2002. Subsequently, issuance by FERC of a draft Standard Market Design proposal created much confusion and much opposition in the region to continued pursuit of the RTO West 2002 proposal. In May, 2003 a "regional representatives group" (RRG) was convened to seek consensus on what the problems were with the current management of the grid, and on some evolutionary means of solving them. This effort has resulted in a proposal, now called Grid West, to form an initial, developmental, independent entity that would try to craft Transmission Operating Agreements and other operating protocols. The proposal includes a governance structure with a stakeholders committee that would elect Board members and that would have to approve the evolutionary steps in the conversion of the developmental body into an operating entity. The operating entity would have limited functions, and would generally have to gain approval for each significant step into its evolution into a full RTO. Details of the proposal can be found at:
http://128.242.83.219/Doc/RRGA_ProcessNarrativeandDiagram_Feb242004.pdf

7. Major Issues of Transmission

There are a number of issues affecting the transmission system and the need for and ability to complete new transmission projects. These include the downgrading of capacity for reliability reasons, the way reliability criteria are set, the limited number of hours the system is congested, the problems involved in siting high voltage transmission lines, the cost of new capacity, making the commitment for new capacity, the alternatives for financing new transmission discussed in the Western Governors Association Transmission Study, the follow-on work to the governors' study, and the proposed National Energy Bill.

Availability of Existing Capacity. A considerable amount of existing capacity is not available for use because it is held off the table for reliability reasons when paths are rated. (See discussion of reliability issues, below.) Transmission owners may withhold capacity because of uncertainty, the need for flexibility and in some cases, a desire to protect their markets.

Uncertainty affects the transmission needs of utilities because they don't know in advance what hourly loads will be or which generating units may be unavailable.

The need for flexibility affects transmission needs because utilities want the right to purchase power to serve their loads from the cheapest source at any given time. When RTO West tried to convert existing contract rights into flow based rights the claims greatly exceeded available capacity. This was largely due to utilities that had a right, for example, to move 100 MW on any of several paths, claiming a simultaneous right of 100 MW on all of them.

Withholding of capacity for market protection is a violation of Order 888. Withholding has been a problem since the order was issued, with a number of utilities around the country being cited and fined by FERC for violations. The failure of Order 888 to result in open and comparable access was a major reason for FERC Order 2000, which requires utilities to form RTOs.

Reliability Criteria. Reliability is an issue because the criteria governing the setting of path capacity and the operation and expansion of the transmission system relate only vaguely to economics. They do not reflect very well the probability or the consequences of the events being protected against. Since the system is quite reliable as currently built and operated, reliability concerns generally focus on very low probability events that may, depending on when they occur, have high costs. The criteria apply everywhere on the transmission grid despite the fact that in some areas and on some paths the consequences may be minimal while in other areas and other paths the same type of event may have large consequences. For example, Path 15 in central California or the Jim Bridger West path in Idaho, where a line outage can result in cascading failure and impact many millions of people, should probably be operated more stringently than parts of the transmission grid where an outage might cause a generating unit to trip off, but not affect any load.

Reliability criteria for the Western Interconnection are set by the Western Electricity Coordinating Council (WECC), which is part of the National Electric Reliability Council (NERC). The Western Electricity Coordinating Council was formed in 2002 from a merger of the Western Systems Coordinating Council (WSCC) with several other transmission organizations.

WECC has much broader representation on its board than the WSCC did, and has stakeholder advisory committees.

Limited Hours of Congestion. As discussed above, the congested portions of the transmission grid tend to be fully or heavily scheduled and loaded only a few hours to a few hundred hours of the year. The rest of the time excess capacity is available, although it is a challenge to make use of it on a firm basis. Expanding capacity is expensive and difficult. Yet it has been the preferred method of gaining access for additional transactions and additional flows. If the costs of new construction could be assigned to the congested hours only it is very likely cheaper alternatives to that construction would be found. For example, some current users with relatively low valued transactions or with ready alternatives might be willing, at some price, to sell their rights to new users.

Siting. High voltage transmission lines can be difficult and contentious to site, especially in forested, mountainous or populous areas. For example, the Colstrip double circuit 500 kV lines were relatively easy to site in eastern Montana where they traversed rolling agricultural and grazing land. Siting in western Montana was a different story, particularly in the areas of Boulder, Rock Creek and Missoula. The resulting route had to stay away from the Interstate highway corridor, instead opening new corridors through forested areas with issues such as impacts to elk security areas and increased access. Lengthy detours around Boulder and Missoula added considerably to the cost of the line. Rural growth and residential construction in western Montana since the Colstrip lines were sited in the early 1980s, combined with the already limited siting opportunities due to wilderness areas and Glacier National Park, can be expected to make siting challenges likely for additional construction.

Cost. High voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may run to $1 million per mile. A double-circuit 500 kV line may cost around $1.5

million or more per mile. 500 kV substations cost around $50 million each, depending on the complexity caused by their location on the network. If series compensation is required, 500 kV substations may cost up to $100 million. 230 kV lines are somewhat cheaper – about half the cost per mile of 500 kV lines, and substation costs run around $25-30 million each. DC lines are cheaper still but the equipment required to convert alternating current to direct current and back is extremely expensive, so this technology is generally used only for very long distance transmission with no intermediate interconnections. At present there are only two DC lines in the Western Interconnection – the Pacific DC Intertie, from Celilo in southern Oregon to Sylmar near Los Angeles, and the IPP line from the Intermountain Power Project generating station in Utah to the Adelanto substation, also near Los Angeles. Neither line has any intermediate connections.

Transmission Capacity to Accommodate New Generation in Montana. There is considerable interest in Montana in building in-state energy facilities as an economic development tool. Rising natural gas prices have improved the climate for marketing coal and wind energy from Montana. The lack of available transmission capacity to reach West Coast markets may be a significant barrier. As discussed above, there is some amount of unused capacity on the existing transmission network for a large part of the time, but it is not available on a firm basis. Changes in the way the transmission system is managed could make this space available, and could support some modest increase in new generation in the state. Significant additional generation would require new transmission capacity.

There is a "chicken and egg" problem in developing new transmission to facilitate economic development. If no capacity is available to reach markets, generation developers may have a difficult time financing their projects. Yet without financing, they probably can't make the firm commitments for transmission services that would encourage utilities to invest on their own in transmission capacity for new projects. The alternative approaches, where the generation developers build needed new capacity or where new merchant transmission capacity is built in the hopes new generation will appear, still need to convince the financial markets that the transmission project is viable. In any event, the regulatory structure requires a showing of need for new transmission projects that may be difficult to make without firm commitments from generators. Of course, the regulatory requirements can be changed to accommodate economic development as a basis of need. Eminent domain is another matter. Eminent domain seizures could be at risk of court challenges if a landowner were to convince the court the public purposes of the line were speculative.

The issues confronting merchant plants are different than those faced under traditional utility procedures, where generation and transmission were planned, financed and built together. Generation developers either must absorb the risk of building new transmission capacity or convince some other party to absorb the risk for them.

Western Governors Association Transmission Study. In the spring of 2001 the WGA asked the utility industry and the Committee for Regional Electric Power Cooperation (CREPC—an organization of western states' public service commissions and energy offices) to study the need for new transmission in the western United States. A working group of experts modeled the transmission grid and the likely growth of demand and new generation, and

concluded that little new transmission (somewhere less than $2 billion over a 10 year period) would be needed beyond that already planned or under construction. This was a result of mostly natural-gas-fired new generation planned for locations close to loads or well served by existing transmission capacity. At the request of the Governors the group also studied a "fuel diversity" scenario in which half of new capacity was coal-fired generation or wind generation. This scenario resulted in a need for approximately $12 billion in new transmission capacity, including construction in Montana of a new 500 kV line to the West Coast and a new 500 kV line to Alberta.

The Western Governors Association then requested a study of how to finance new transmission lines, and the resulting report discussed two alternative proposals. The first was an "interstate highway" model in which all electric customers in the west would share in the costs of all transmission in the west, regardless of use. This model envisioned transmission expansion to eliminate most or all congestion. The second is a model in which the beneficiary pays: regional financing of reliability improvements, utility financing of load service improvements, and generation and customer financing of capacity expansions to eliminate congestion.

Each approach has advantages and disadvantages. The interstate highway model would avoid the need to determine the relative merits of different possible lines and simply eliminate all congestion. It would make a great deal more capacity available and could encourage the development of resources in places previously difficult to build. For Montana, it would make it easier to develop coal and wind resources. On the other hand, it would require agreement by all states and all utilities to spread the costs to all ratepayers. There is no existing agency with the authority to require such spreading and there is unlikely to be universal agreement to spread these costs without such an agency. The interstate highway approach could also result in overbuilding the transmission system, for example to alleviate congestion that may be minimal or that could be more cheaply addressed in other ways.

The "beneficiary pays" model is currently implementable and reflects the way transmission is currently financed for certain types of lines, such as lines needed for reliability and lines needed to serve growing utility loads. It results in a closer correspondence of benefits and costs than the interstate highway approach, and could make siting easier by reducing controversies over need. On the other hand, if future benefits are uncertain it could make financing difficult, and it would not provide the benefits to Montana coal and wind developers unless they were willing to pay the costs of needed transmission. Further, proponents of the interstate highway model are skeptical that the beneficiary pays model will result in the timely construction of new transmission capacity.

Rocky Mountain Area Transmission Study. In 2004 the Governors of Utah and Wyoming convened RMATS as a followup to the WGA transmission study. RMATS was given the task of identifying transmission that would enable the development of coal and wind generation resources in the Rocky Mountain west and carry the power to markets on the West Coast, California, and the Denver area. RMATS was also tasked with figuring out how to finance the desired transmission and how to allocate the costs.

Montana has participated actively in this study. RMATS defined two levels of projects. "Recommendation 1" projects include a moderate upgrade of the existing Montana-Northwest transmission system that would involve installation of capacitors at various points and

construction of a new substation at Ringling, but no new transmission lines. It would expand capacity by approximately 500 MW. Recommendation 1 also includes a transmission line from Wyoming to Colorado, from Wyoming to Utah, and expansions on the Bridger transmission line.

The second level of expansion contained in "Recommendation 2" is more ambitious. It would include a new 500 kV transmission line from Montana to eastern Washington, and another from the Ringling Substation proposed in the first recommendation, south through the Dillon area and Monida Pass to markets in California and to the West Coast via the Bridger transmission lines.

National Energy Bill The omnibus National Energy Bill introduced in the 2003 session included a provision to enable DOE to designate transmission lines of national interest to overcome significant congestion. This provision would also allow FERC to authorize construction and the use of federal eminent domain authority for such lines. No federal funding is provided. As of the summer of 2004 the Bill has not made significant progress toward passage, but DOE has initiated discussions and public hearings on the procedures for designating national interest transmission lines. The transfer of transmission siting authority to the Federal Government raises mixed concerns for the state. Economic development interests see it as a way to speed construction of the infrastructure that would allow the state to develop its energy resources. Environmental interests see it as a loss of the state's ability to permit needed transmission lines and to site them to minimize environmental damage. Other parties question the need for a transfer of authority when there has been no history of difficulties in the west in permitting and siting transmission lines. Instead, they see it as a solution in search of a problem.

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 potentially expect in the coming years. Montana is part of the North American gas market, with 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 North American gas wells level out or decline in their production, the price and availability of gas are already moving in ways Montanans have not experienced in previous decades.

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.

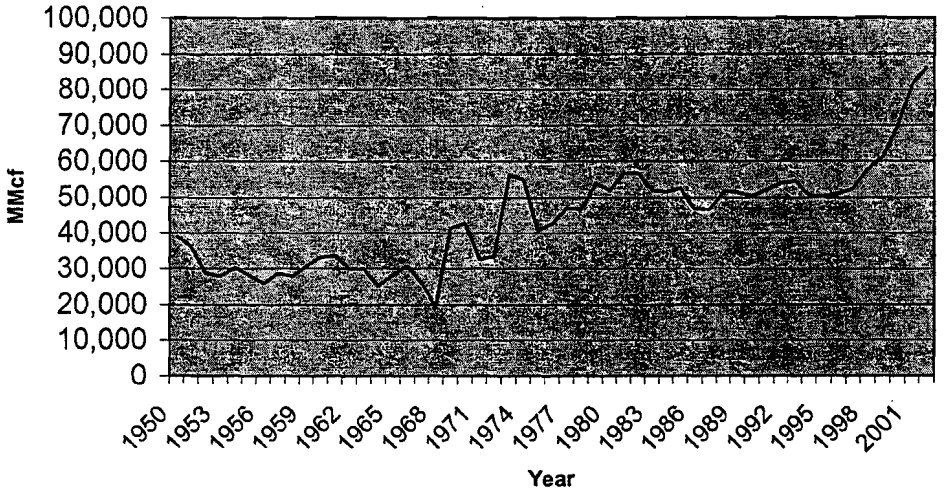
Montana currently produces more gas than it consumes. In 2002, Montana produced 86.1 billion cubic feet (bcf) and consumed 69.6 bcf (Tables NG1 and NG2). The bulk of what Montana produces is exported, and the bulk of what Montana consumes is imported. In 1999, for example, Montana produced 61.2 bcf of 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 also 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.

Fig. 1 Marketed Gas Production in Montana (1950-2002)



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

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, 2004b). 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 *un*conventional production is expected to increase at a faster rate than other sources during that time (U.S. EIA 2004d).

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 2004d).

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 before. In 2003 alone, the average finding cost was $1.73/dkt[2] (Wall Street Journal, 2004). It is therefore possible that the gas

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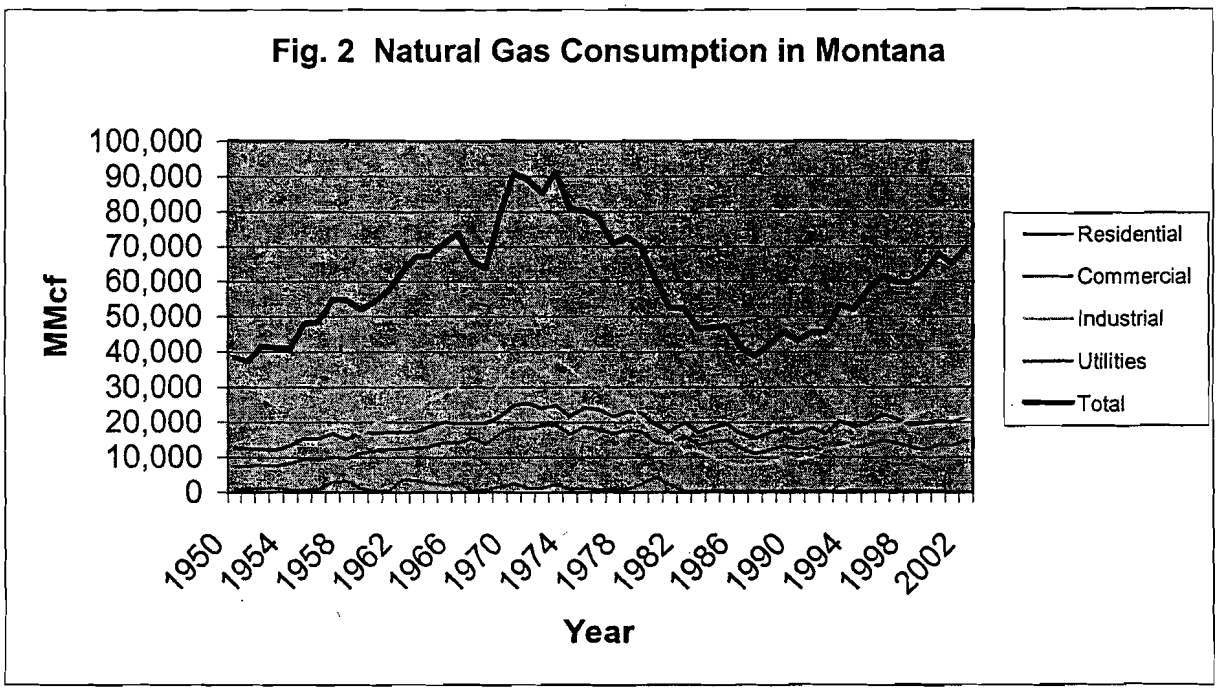
[1] "Reserves" refers to natural gas that has been discovered and proved producible given current technology and markets. Natural gas "resources" are more speculative estimates of natural gas that might be developable with known technology and at feasible costs. By definition, resource estimates are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

[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).

production in North America in future years may not grow as quickly as the above projections say nor as quickly as historical trends.

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 including 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 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 un-built 500 MW Silver-Bow electrical generation plant near Butte is also on hold indefinitely with no action currently taking place. If it had come on line, the plant would have consumed about 30 bcf per year of gas—equivalent to almost 50 percent of current the 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 50 MW generating capacity is negotiating with NWE, but may be up and running in the near future. 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).

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:

- The deregulation of wellhead prices begun under the Natural Gas Policy Act of 1978 and accelerated under the Natural Gas Wellhead Decontrol Act of 1989;
- Natural Gas Deregulation including the Natural Gas Policy Act of 1978 and 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 favors natural gas since it burns relatively cleaner 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.

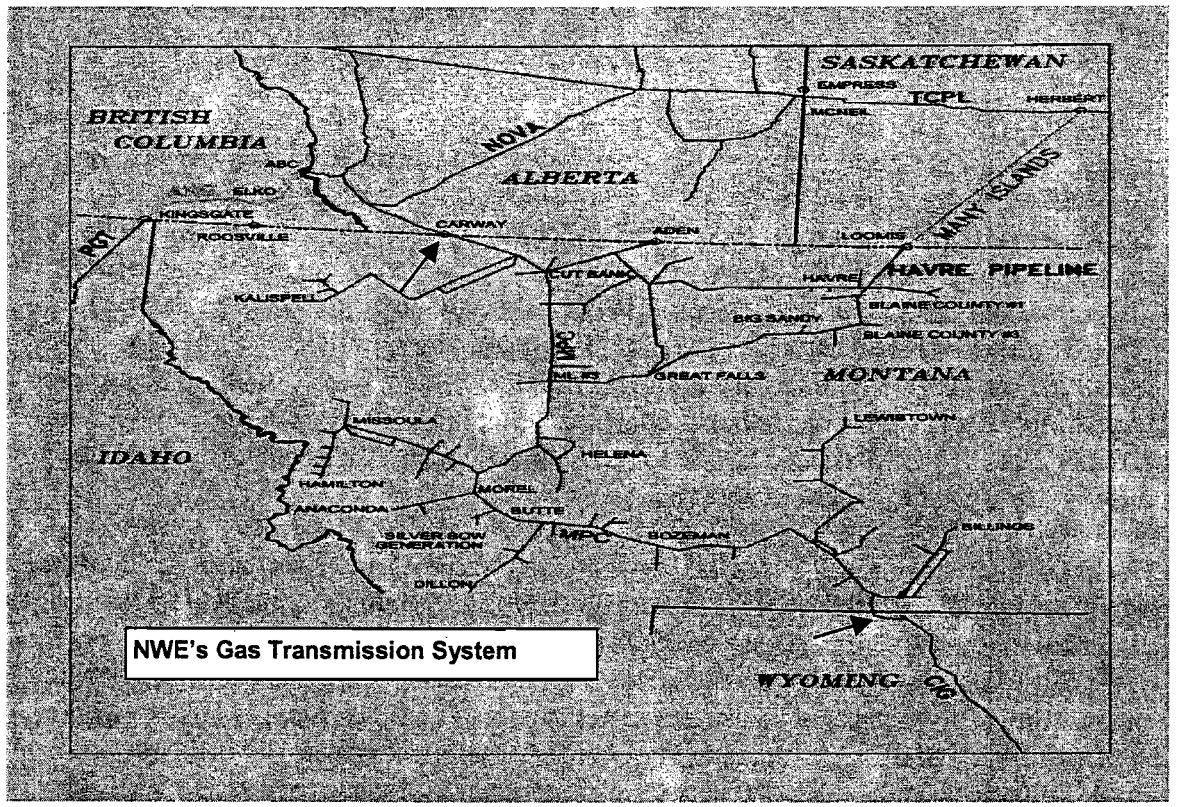
In 2002, the U.S. consumed over 23.0 trillion cubic feet (tcf) of natural gas, the highest level ever recorded. In 2003, it tapered off slightly to 21.9 tcf. In the U.S., natural gas consumption is increasing at a healthy pace and the Pacific Northwest region is no exception. Three reasons for increased 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 2004d). 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 2004b).

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 pipeline system therefore needs to expand. 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 under construction (240 MW when completed) would require pipeline upgrades beyond those already needed in 2003. 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 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 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.

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

Natural gas prices are measured in several different ways. For one, gas prices are measured 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 (1 year) to lock in an acceptable price and to avoid large price swings on the spot market (Smith, 2001). Gas prices are measured at different market locations throughout the United States and are also measured for different end-user groups such as residential, commercial, or industrial consumers and electric utilities.

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 forms 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.

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. Furthermore, a recent five-year contract for cheap gas held by NWE with Pan-Canadian ended in 2002. When the contract expired, the price of gas on the open market was about double that under the contract.

The historical delivered gas prices (the price seen on one's gas bill) in Montana for all consumer classes including residential, commercial and industrial, were relatively low in 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/Mcf range in 2004 with the possibility of reaching $9.00/Mcf by the Fall of 2004 (not reflected in Figure 3). This increase in delivered gas price is due almost solely to the recent increases in the U.S. wellhead price of gas.

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.

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

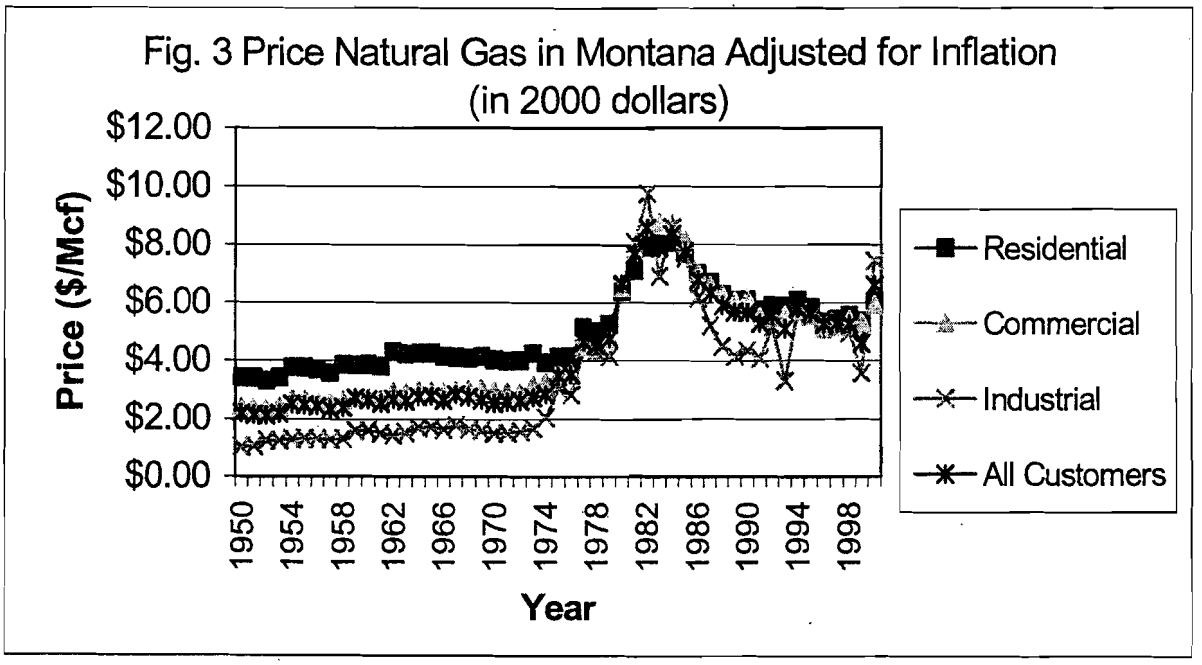


Figure 3 shows *delivered* natural gas prices in Montana adjusted for inflation and reported in 2000 dollars. Recent high prices from 2003 and 2004 are not available, because the data for those years is not yet available on an annual basis. The delivered prices graphed below are the prices that residents 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, 2004b). 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.

NWE raised gas bills for its core customers, who are mostly residential and commercial users, by 35% in December, 2002. This increase was a result of a 55% increase in the price of the wholesale gas itself 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.

According to the U.S. EIA's 2004 long-run natural gas price prediction, long-run average U.S. wellhead prices are expected to be $4.19/Mcf in 2015, $4.28/Mcf in 2020, and $4.40/Mcf for 2025 using 2004 dollars (U.S. EIA 2004d). This expected increase in the average price over time is expected to be driven by natural gas demand growth, particularly in electric generation, and the natural progression of the discovery process from larger and more profitable fields to smaller, more costly ones. The Northwest Power and Conservation Council in 2003 forecasted a medium range U.S. wellhead price of only $3.50/dkt or $3.40/Mcf for 2020 using current dollars (Northwest Power and Conservation Council, 2003) with a price of $3.17/dkt for the AECOC Hub. Both forecasts warn that prices over time will not be smooth but rather swing up and down based on supply and demand conditions. As supply and demand conditions become tighter over time in North America, there is a chance that price volatility could increase over time as well in the U.S. and Montana. This is discussed further below.

The final delivered gas price Montana customers pay (wellhead fees + transmission fees + delivery and other fees) is likely to be slightly lower than average U.S. prices due mainly to

relatively low gas transmission fees in this state since we live fairly close to large gas producing regions in Alberta. According to the U.S. EIA in 2004, Montana residences can expect to pay on average a home delivered price of around $8.50/Mcf in 2015 (using 2004 dollars) and commercial businesses a price of $7.50/Mcf (U.S. EIA, 2004d). The Northwest Power and Conservation Council forecasts U.S. residential delivered gas prices to be $7.75/dkt ($7.52/Mcf) in 2015, and commercial delivered prices around $6.75/dkt or $6.55/Mcf in 2015 (Northwest Power and Conservation Council, 2003). Again, these forecasts represent long-term averages. The delivered gas prices today in Montana are already near the 2015 numbers right now, and are fairly volatile. From July 2003-January 2004, the average delivered price of natural gas in Montana was about $7.70/dkt (David Burchett, 2004).

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 one might think. They also negotiate their own gas prices. Stone Container, in-state fertilizer production plants and Montana State University probably have less flexibility to switch fuels, and are likely 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.

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, 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 the 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 A/C 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, BPA announced in February 2001 that it would seek to acquire up to 1000 MW of wind power, in part because of the hedge that fixed-priced wind power could provide against volatile natural gas prices for electric generation. NWE included 150 MW of wind-generated power into its proposed default supply portfolio. 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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PETROLEUM AND PETROLEUM PRODUCTS IN MONTANA

Montana Petroleum Quick Facts
(in round numbers)

Recent production: 19 million barrels per year

Amount of crude production exported: 90 percent

Refineries in state: Billings (2), Laurel, Great Falls

Total refinery capacity: 180,000 barrels/day

Crude oil receipts at refineries: 60 million barrels per year

Source of crude oil refined in state in recent years:
Montana – 4 percent
Alberta – 75 percent
Wyoming – 21 percent

Amount of liquid fuel refined products exported: 55 percent

States petroleum products are exported to:
Washington
North Dakota
Wyoming (and points south)

Montana consumption of petroleum products: 30 million barrels (includes refinery usage)

Gasoline sold in-state: 500 million gallons

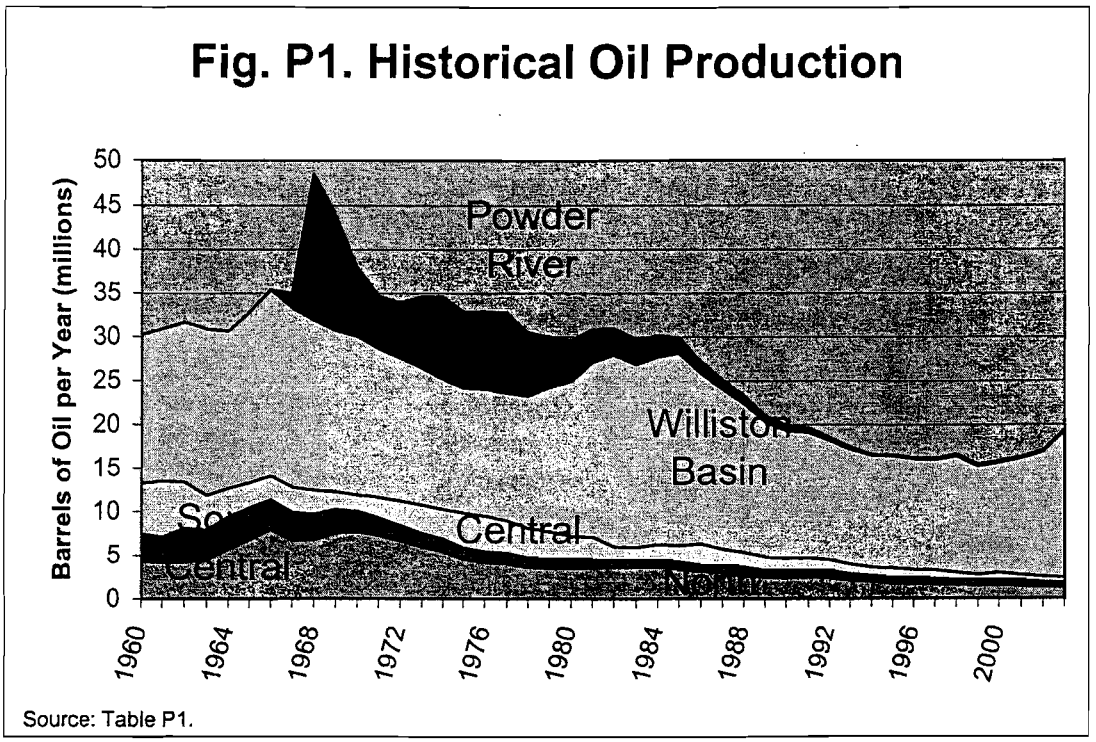
Diesel fuel sold in-state: 350 million gallons (includes railroad usage)

Production History

The first oil wells drilled in Montana were located in the Butcher Creek drainage between Roscoe and Red Lodge, beginning in 1889. These wells were not very successful. The first significant oil production in the state came from wells drilled in the northward extension of Wyoming's existing Elk Basin field in 1915, southeast of Belfry. Montana's first new oil field was Cat Creek, near Winnett, discovered in 1920. That soon was followed by the Kevin Sunburst field discovery in 1922. Over the next 40 years, more oil fields were developed in the Williston Basin (northeast Montana), the Sweetgrass Arch (northern Montana), the Big Snowy Uplift (central Montana), the northern extensions of Wyoming's Big Horn Basin (south central Montana) and the Powder River Basin (southeastern Montana).

Montana's petroleum production peaked in 1968 at 48.5 million barrels (1 barrel = 42 gallons), the result of cresting Williston Basin production combined with a surge of production from the newly discovered Bell Creek field in the Powder River Basin (Table P1 and Fig. P1). Production then declined quickly until 1971, when a series of world oil supply shocks began to

push prices upward, stimulating more drilling. Production remained relatively stable between 1971 and 1974 as Powder River Basin output increased to match a decline in Williston Basin output. After 1974 production began to decline, despite the continued escalation of oil prices (Table P2).

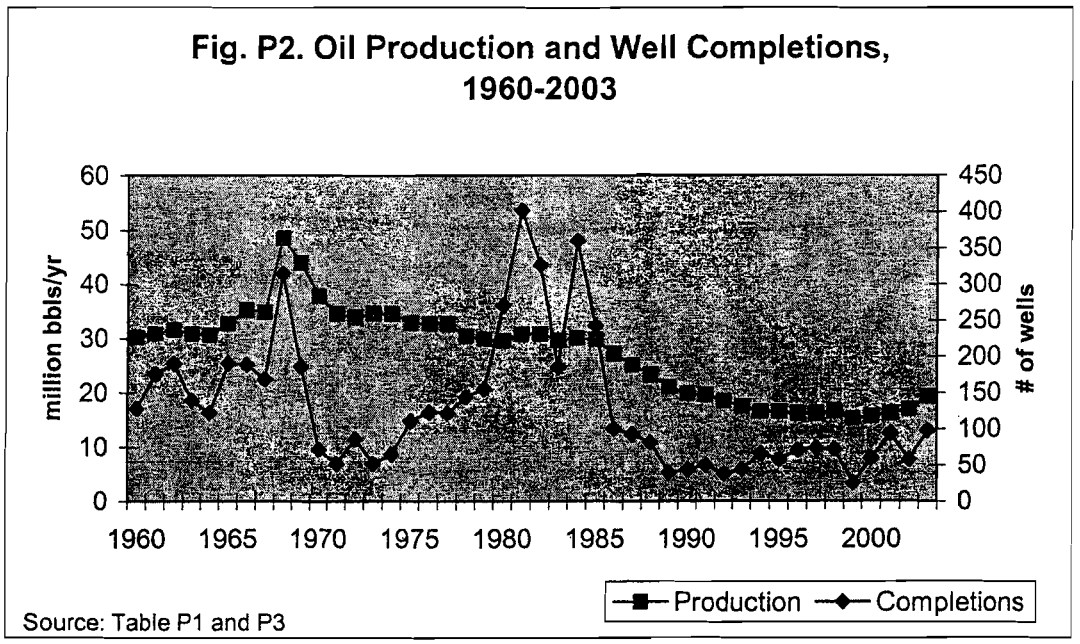


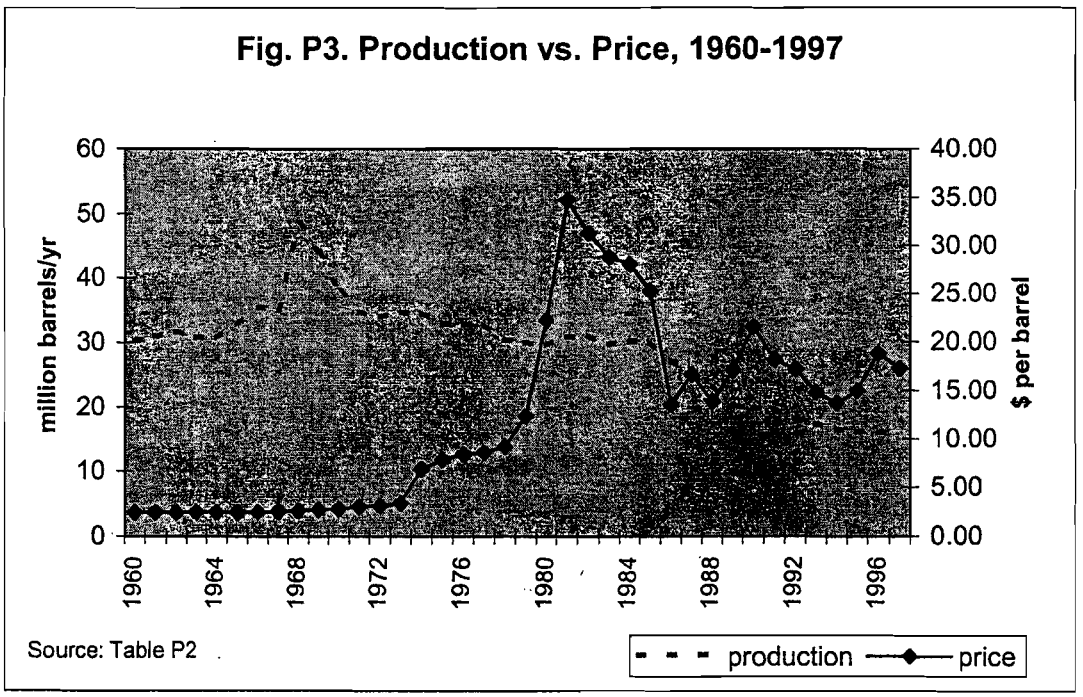
World oil price shocks following the Iran crisis in 1979 sparked a drilling boom, which peaked at 1,149 new wells of all types in 1981 (Table P3). That year, the average price of Montana crude climbed to almost $35 per barrel. While the increase in the price of oil encouraged more drilling, it did little to increase Montana production (Fig. P2). The drilling produced a high percentage of dry holes and was unable to slow the decline in statewide production (Fig. P3). Output increased in the Williston Basin during the early 1980s, but this was matched by a steep decline in output from other areas. Production declined significantly following the drop in world oil prices in 1985, stabilizing around 16 million barrels per year in the mid-1990's. Recent higher prices may bring an increase in production. Wells in Montana are not that prolific, averaging 15-18 barrels per day in recent years (Table P1).

Refineries and Pipelines

Petroleum pipelines serving Montana consist of three separate systems (see Map, below.) One bridges the Williston and Powder River basins in the east and the other two link the Sweetgrass Arch, Big Snowy and Big Horn producing areas in central Montana. All these systems also move crude oil from Canada to Montana and Wyoming. (A fourth—Express—primarily carries Canadian crude through Montana.) In recent years, around 90 percent of oil production has been exported from the state, mostly to Wyoming and beyond through the eastern

pipeline system. This pipeline system is not connected to any of the Montana refineries, which limits the amount of Montana crude they can use.

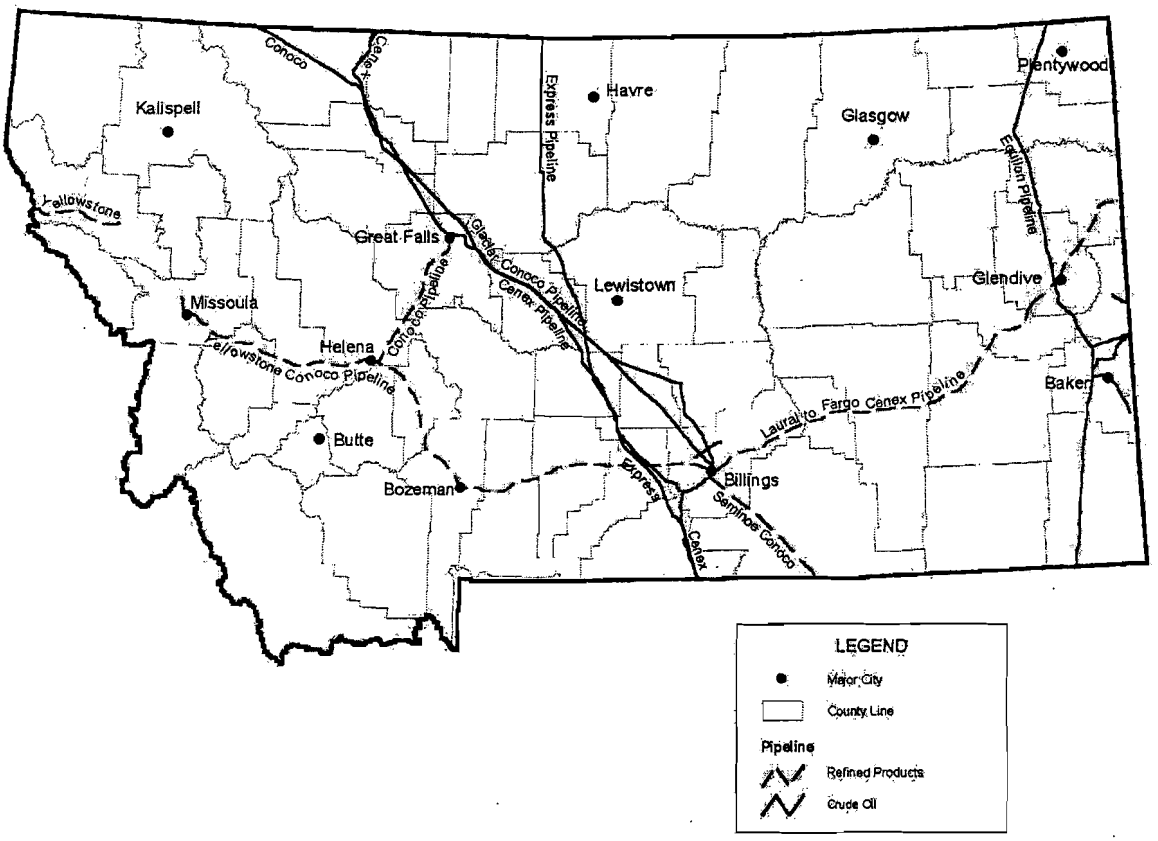




Montana has four refineries, with a combined capacity of 181,200 barrels/day: ConocoPhillips (60,000 bbl/day) and ExxonMobil (58,000 bbl/day) in Billings, Cenex (55,000 bbl/day) in Laurel, and Montana Refining (8,200 bbl/day) in Great Falls. Montana refineries now use around 60 million barrels of crude a year (Table P4). In the last decade, only around 5 percent of that came from Montana crude. Oil fields in the Sweetgrass Arch, Big Snowy and

Big Horn areas provided crude to the Montana refineries. Collectively, 70-80 percent of the refinery crude inputs came from Alberta, Canada and around 20 percent came from Wyoming. The shipments from Canada have increased since the late 1960s, as Montana oil production and imports of Wyoming crude declined. (Fig. P4, below)

MAP: Petroleum Pipelines in Montana

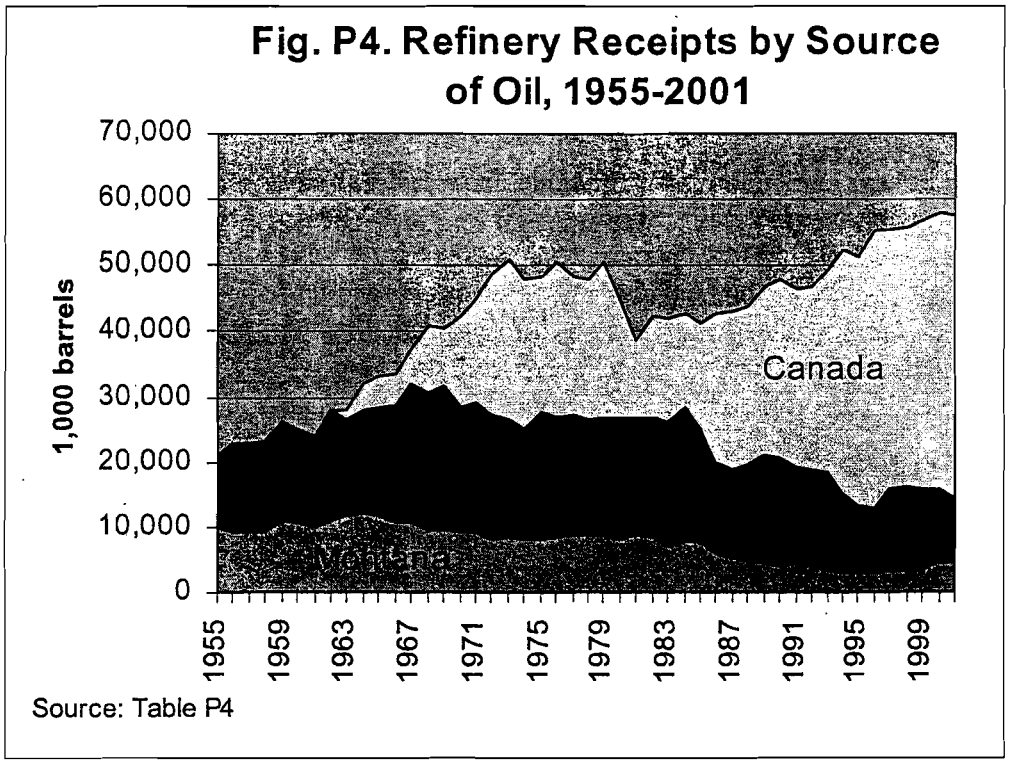


The refineries vary in their sources of crude inputs (Table P5). ConocoPhillips is the most dependent on Canadian crude, taking an average (1998-2003) of 94 percent of its total receipts from Canada. ExxonMobil is the least dependent on Canadian crude (43 percent of receipts) but by far the most dependent on Wyoming (54 percent of receipts).

Almost all of refinery output is moved by pipeline. The Billings area refineries ship their products to Montana cities and east to Fargo, North Dakota (Cenex pipeline), to Wyoming and further south (Conoco Seminoe pipeline) and west to Spokane and Moses Lake, Washington (Conoco Yellowstone pipeline). In 2003, 23 million barrels of product were shipped out of state, with nearly half heading south and the remainder split roughly between east and west.

The four refineries provided almost all of the petroleum products consumed in Montana. Beyond that, around 55 percent of the liquid fuel produced at the refineries is

exported. Montana refineries provided about 10 percent of Washington's combined gasoline and distillate use in recent years. North Dakota received over one-third of its combined gasoline and distillate use from Montana refineries. For both states, Montana provided more gasoline than diesel.



Petroleum Products Consumption

Petroleum product consumption in Montana peaked at 33 million barrels in 1979 (Table P6). It then drifted lower, settling in the mid-1980's around 24 million barrels per year. After that, consumption began a slow climb, to around 30 million barrels per year at present.

The transportation sector is the single largest user of petroleum and the second largest user of all forms of energy in Montana. In 2001, 38 percent of consumption was in the form of motor gasoline and 28 percent was distillate, mostly diesel fuel. Around 20 percent was consumed in petroleum industry operations (Table P6).

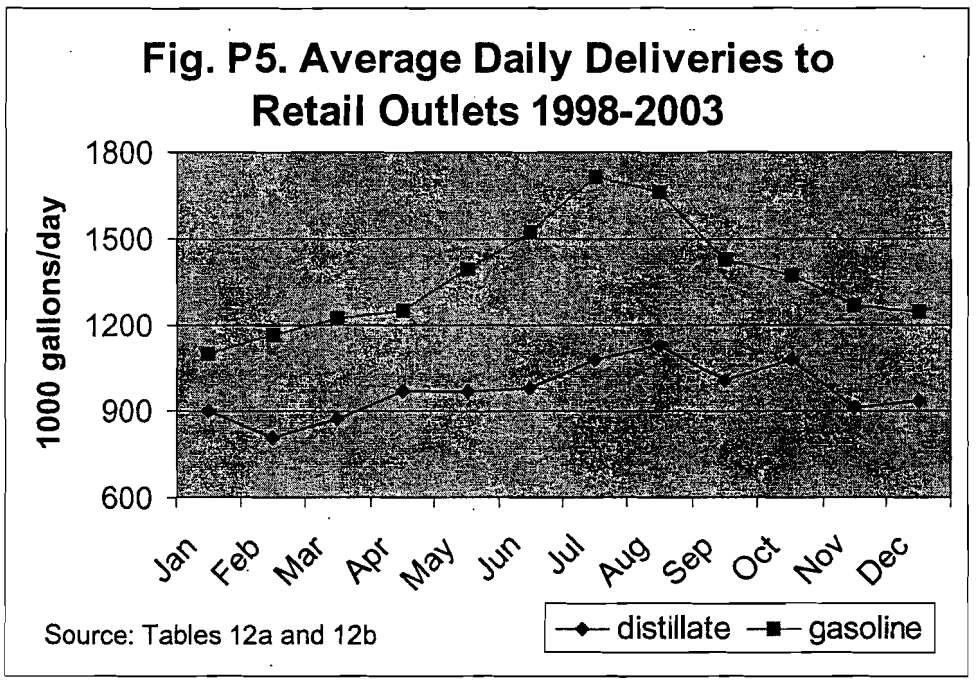
Gasoline use peaked in 1978, at half a billion gallons, dropped and slowly climbed back to near that level currently, with minor fluctuations since the mid-1990s (Tables P10 and P11). Diesel use generally has increased since the 1970's. In the last decade, highway diesel use grew at a far greater rate than did gasoline use (Table P11).

The fluctuations in demand for gasoline and diesel fuel since 1970 reflect changes in the state and national economy and the international price of oil. The embargo by the Organization of Petroleum Exporting Countries (OPEC) in 1973-1974 and the Iranian crisis of 1979-1980 drove prices up and demand down. The increase in prices prompted advances in vehicle efficiency and a fuel switch by heavy-duty trucks from gasoline to diesel. The crash in

international prices in 1985, the economic growth of the 1980's and 1990's, along with the decline in vehicle fleet fuel efficiency in recent years pushed gasoline and diesel demand back up.

Fuel use shows a cyclical rise and fall through the year (Tables 12a and 12b; Fig. P5). Use tends to rise during the summer months and taper off during the winter. The winter trough in fuel use is a third lower from the summer peak. This seasonal pattern is caused by variations in the use of Montana's one million vehicles, by the increase in tourist traffic during the summer, and by seasonal agricultural uses.

The price of gasoline has been rising over the last decade, hitting all-time highs (not adjusted for inflation) in the past year (Table P13 and P14; Fig. P6). The price of gasoline can vary significantly around the state, a fact that is masked by the data, which only are available as statewide averages. (Complete data on the Montana price of diesel were not available.) The price of gasoline has a cyclical rise and fall, just like demand for gasoline; however, price lags demand, with peak prices tending to appear after the peak driving season (Fig. P7).

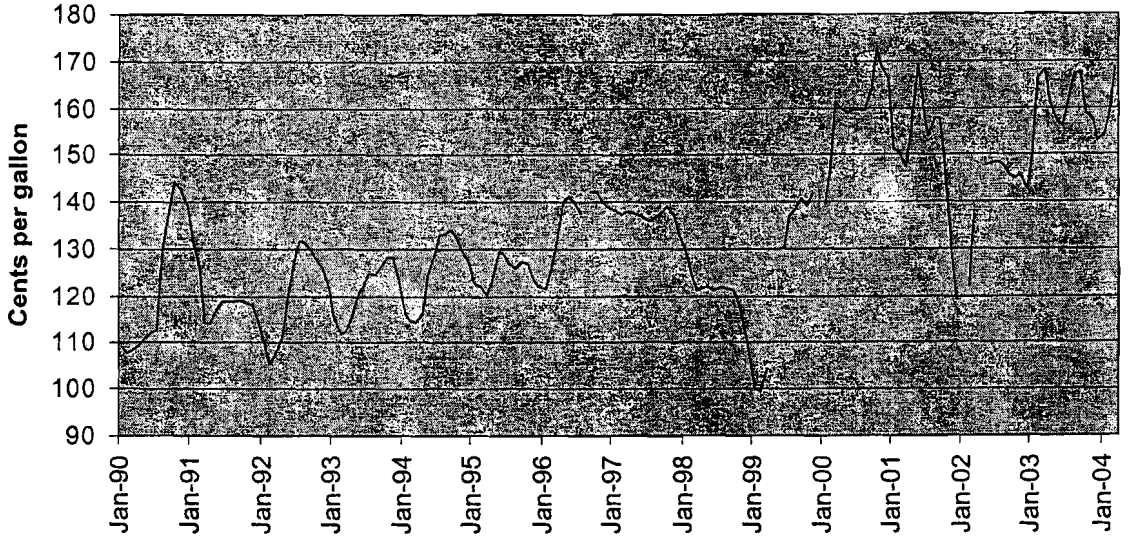


Note: Deliveries are to retail outlets for sale.

Comments on the data

Data for this report come from a variety of sources, which don't always agree exactly. In part this is due to slightly different data definitions and methods of data collection. The reader should always consider the source and context of specific data.

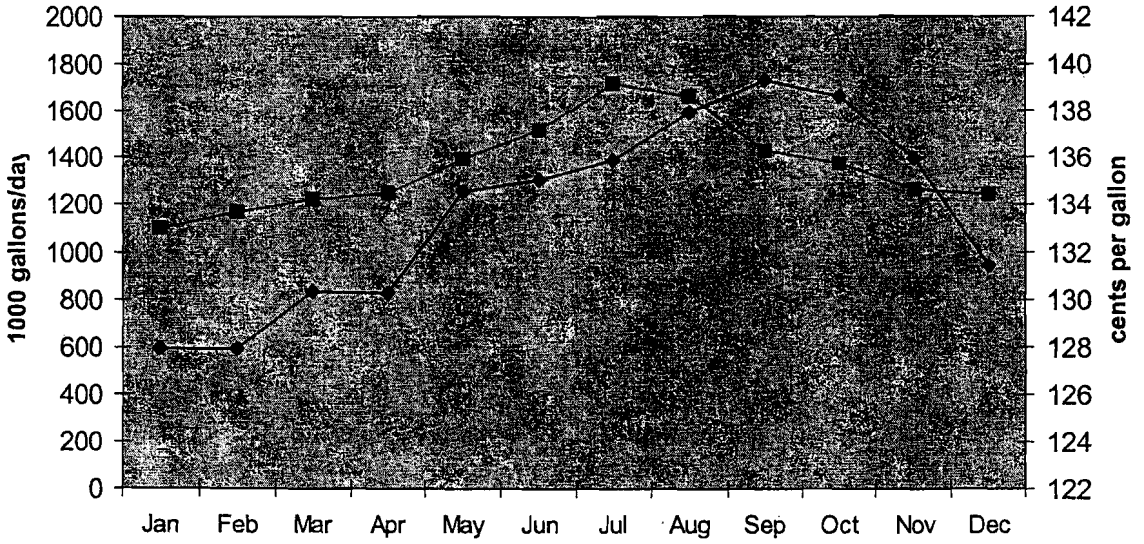
Fig.P6. Retail Price of Gasoline, 1990-2004*



* Average of all grades of gasoline statewide, in nominal dollars (some data missing).

Source: EIA 782a database

Fig. P7. Average Monthly Price of Gasoline vs Delivery for Sale (1998-2003)



Source: Tables P12a and P13

Table P2. Crude Oil Production and Average Wellhead Prices[1], 1960-2003

DNRC Statistics

Year	Crude Oil Production (Mbbls)	Average Wellhead Price ($/bbl)	Gross Value of Production (million $)
1960	30,240	2.41	72.9
1961	30,906	2.42	74.8
1962	31,648	2.42	76.6
1963	30,870	2.44	75.3
1964	30,647	2.43	74.5
1965	32,778	2.43	79.7
1966	35,380	2.44	86.3
1967	34,959	2.50	87.4
1968	48,460	2.57	124.5
1969	43,954	2.69	118.2
1970	37,879	2.78	105.3
1971	34,599	3.01	104.1
1972	33,904	3.06	103.7
1973	34,620	3.33	115.3
1974	34,554	6.85	236.7
1975	32,844	7.83	257.2
1976	32,814	8.42	276.3
1977	32,680	8.63	282.0
1978	30,467	9.25	281.8
1979	29,957	12.39	371.2
1980	29,584	22.24	657.9
1981	30,813	34.73	1070.1
1982	30,917	31.26	966.5
1983	29,665	28.79	854.1
1984	30,080	28.04	843.4
1985	29,934	25.23	755.2
1986	27,165	13.52	367.3
1987	25,104	16.62	417.2
1988	23,317	13.87	323.4
1989	20,269	17.08	358.2
1990	19,835	21.58	428.0
1991	19,573	18.18	355.9
1992[2]	18,237	17.20	313.7
1993[2]	17,327	14.78	256.1
1994[2]	16,425	13.68	224.7
1995[2]	16,170	14.96	241.9
1996[2]	15,957	18.81	300.2
1997[2]	16,233	17.22	279.6
1998			
1999			
2000			
2001			

DOR Statistics

Fiscal Year[3]	Crude Oil Production (Mbbls)	Average Wellhead Price ($/bbl)	Gross Value of Production (million $)
FY1995	16,448	14.60	240.1
FY1996	15,695	15.60	244.8
FY1997			
FY1998			
FY1999			
FY2000			
FY2001	15,736	27.40	431.2
FY2002	16,603	20.56	341.4
FY2003	17,742	27.27	483.8

1 Average wellhead prices were computed by dividing the gross value of production by the number of barrels extracted.

2 Due to a legal opinion on the confidentiality of tax records, the Montana Department of Revenue stopped providing data DNRC used to calculate the average price and valuation for individual fields. The DNRC data published for these years were summaries prepared by DoR. Some oil production is exempt from state taxation and is not included in DoR's production figures. Wells are classified for tax purposes as either oil or gas wells; only oil from wells classified as oil wells is included in DoR figures. After 1997, DNRC stopped publishing this data table.

3 State fiscal years start July 1. They are numbered according to the calendar year in which they end. Thus, FY2003 began July 1, 2002 and ended June 30, 2003. Information for intervening years cannot be retrieved from DoR's computer system.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division, *Annual Review*, 1960-2001; Montana Department of Revenue, Biennial Report 1994-1996 and DoR files for FY01-03.

Coal in Montana

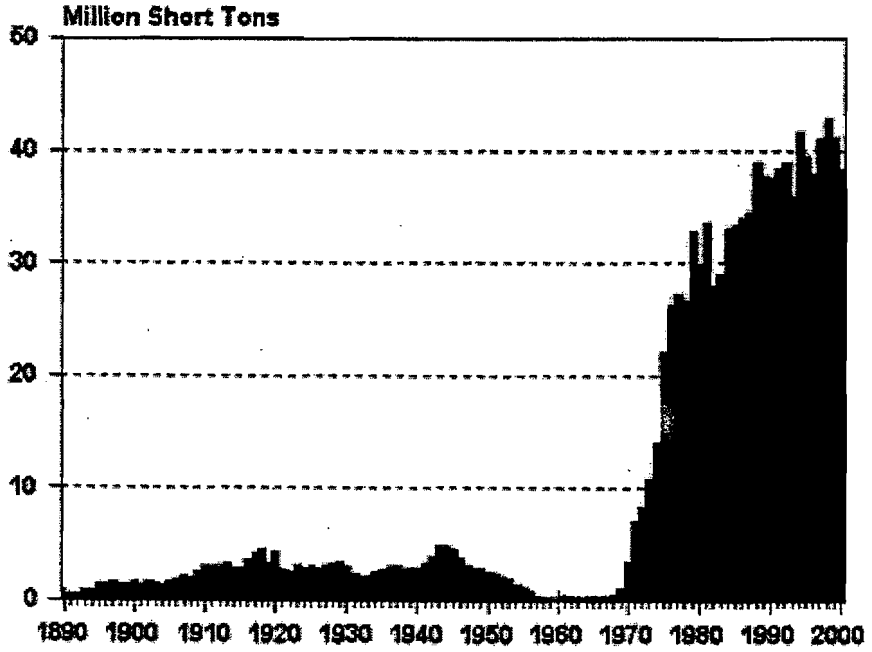
The Montana coal industry exists to support the generation of electricity. All but a tiny fraction of the coal mined in Montana eventually is converted to electricity. In recent years, over half the electricity generated in Montana has come from coal-fired plants. Almost three-quarters of the coal mined in the state are exported, primarily to Midwestern utilities. Even though new generating stations built around the country in recent years have relied on natural gas or wind, coal continues to provide half of the nation's electricity.

1. Production

Montana is the sixth largest producer of coal in the United States, with over 37 million tons mined in 2002 (Table C1). Almost all the mining occurs in the Powder River Basin south and east of Billings. With the exception of the small lignite mine at Sidney, Montana production is entirely low-sulfur subbituminous coal, with around 18 million Btu per ton. Like most Western coal, Montana coal is cleaner but lower in heat content than coal mined in the East.

Coal has been mined in Montana since territorial days, first as a heating fuel and later primarily for the railroads. Production initially peaked in the 1940s at around 5 million tons (see Figure 1). As steam locomotives were phased out, production declined, bottoming in 1958 (Table C2).

Figure 1. Historical coal production

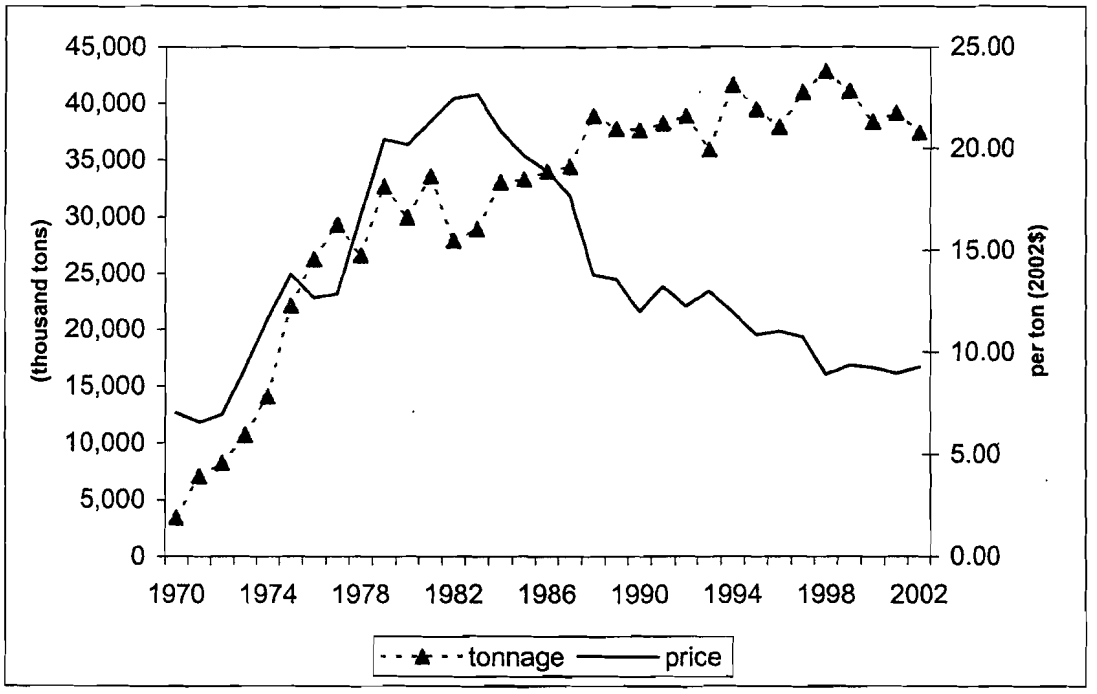


Source: U.S. Department of Energy, Energy Information Administration (http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/mt.htm)

That year, only 305,000 tons were mined, an amount equivalent to less than 1 percent of current output. Output remained stagnant for a decade, maintained by production for a small generating plant opened in Sidney in 1958 by Montana-Dakota Utilities. Production began to grow again in 1968, when Western Energy Company began shipping coal from Colstrip to a generating plant in Billings owned by its parent, Montana Power Company.

As Montana mines began supplying electric generating plants in Montana and the Midwest, coal production jumped. Production in 1969 was 1 million tons; ten years later, it was 32.7 million tons. Since the end of the 1970's, production increased gradually to around 40 million tons in 1998 and then dropped off slightly to its current level (Table C2; see Figure 2). Over the last decade, Montana has more or less maintained its share of the U.S. market. In comparison most eastern states lost market share during this decade, primarily to Wyoming. Western states other than Wyoming followed a path similar to Montana, more or less maintaining market share. Over the past decade Montana has produced a little less than 4 percent of the coal mined each year in the U.S..

Figure 2. Montana production and average price (2002 $)



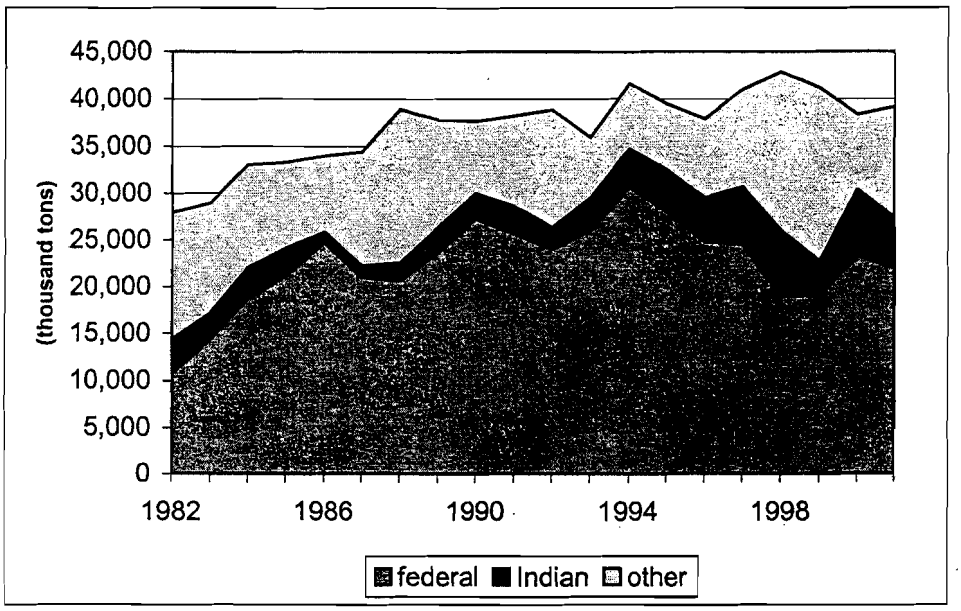
Source: Table C2.

The price of Montana coal averaged $9.27 per ton at the mine in 2002 (Table C2); this includes taxes and royalties. The price of coal has been on a downward trend since the early 1980's, when the average price of coal peaked at $14.22 per ton ($22.67 in 2002 dollars). By 2002 that price had fallen 60 percent in real terms. The decline in Montana prices mirrors the decline in prices nationally.

Most coal in Montana is mined on federal lands (Table C3; see Figure 3). A significant portion also comes from Indian reservations. In 2001, the most recent year for which data are

available, over 55 percent of Montana coal came from federal lands and under 15 percent from reservation lands.

Figure 3. Production by land ownership type



Source: Table C3

Montana had eight coal mines in operation in 2003 (Table C4). The largest mine is Westmoreland's Rosebud Mine at Colstrip, producing 10-11 million tons per year. During the 1990's, the last Montana mine producing less than 100,000 tons annually closed, but a new mine at that site, near Roundup, opened in 2003. No major new mines have opened since 1980, though the West Decker and Spring Creek mines have expanded significantly.

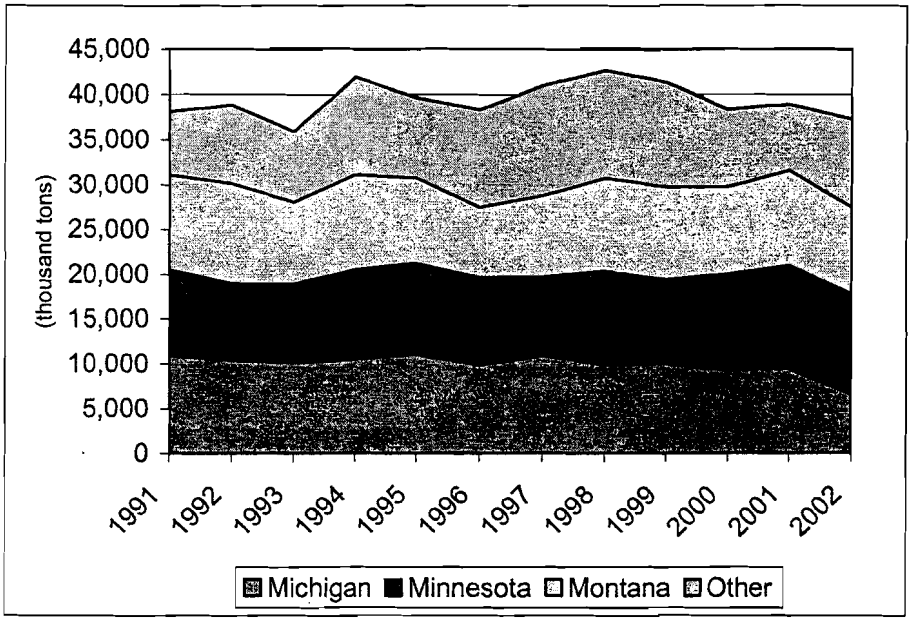
Westmoreland is the largest producer in Montana, accounting for 47 percent of 2003 production. Kennecott is the second largest, accounting for 24 percent of coal production outright and holding a half-interest in mines producing an additional 22 percent of Montana coal. The year 2001 marked the passing of an era in Montana coalfields. With Westmoreland buying Montana Power Company's Western Energy and MDU Resources Group's (Knife River Coal) Savage Strip Mine in 2001, over 40 years of utility ownership of operating coalfields in Montana came to an end. Utility production had been substantial. MPC, through Western Energy, was the 11th largest coal producer in the country in 1998.

2. Consumption

Over 95 percent of the coal consumed in Montana in recent years has been used to generate electricity. Minor amounts of residential and commercial heating and some industrial use account for the remainder. Montana coal consumption has been more or less stable since the late 1980's, after the Colstrip 4 generating unit came on line (Table C5).

Similarly, almost all of Montana coal production is used to generate electricity (Table C6). In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities. Most of the remaining quarter is burned in-state to produce electricity, primarily at Colstrip. Prior to deregulation, about 40 percent of the electricity generated in Montana with coal went to Montana customers, and 60 percent was shipped by wire to out-of-state utilities. No public data are available now, but it's likely that the majority of coal burned in Montana still produces electricity for export. Over the last decade, Michigan, Minnesota and Montana have taken about three quarters or more of all the coal produced in Montana (Table C7; see Figure 4). The remaining quarter now goes to 9 other states and Canada.

Figure 4. Destination for Montana coal



Source: Table C7.

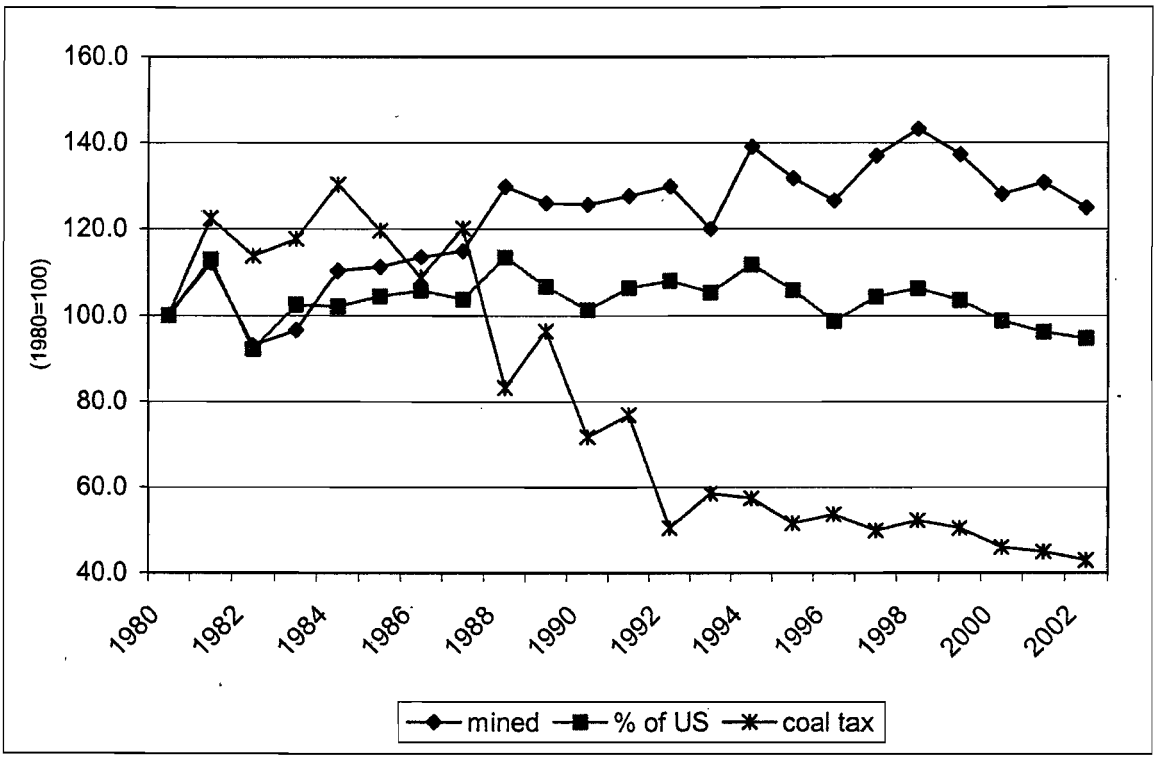
3. Coal Economics

The Montana industry, like the coal industry nationwide, has become more productive, with the number of employees dropping even while the amount of coal mined increased (Table C8; see Figure 5). Taxes on coal, despite decreases from historical highs, remain a major source of revenue for Montana, with $30.1 million collected in coal severance tax in state fiscal year 2003 (July 2002-June 2003).[1] That is one-third in nominal terms the amount collected in fiscal year 1984. Coal severance tax collections dropped due to changes in the tax laws that began with the 1987 Legislature and due to the declining price of coal. While the tax rates vary based on a number of factors, the rate on most coal in Montana has dropped from 30 percent to 15 percent of price. This drop in rates has had a bigger impact on tax collections than the drop in the price of coal. The impact on levels of coal production is less clear. Production has risen modestly since the cut in taxes and Montana has been able to retain most of its share of the national market.

[1] Also, a gross proceeds tax of 5% goes to the county where the coal was mined. Another 0.4% goes for the Resource Indemnity and Groundwater Assessment Tax that, among other things, pays for reclamation of old unreclaimed mined areas.

While significant, Montana's output is dwarfed by Wyoming, which produced 34.1 percent of the country's output in 2002. This is ten times as much coal as Montana produced. This due in part to a combination of physical factors that make Montana coal less attractive than coal from Wyoming. Montana coal generally is more costly to mine because the coal seams tend to be thinner—though still thick in comparison to eastern coal—and buried under more overburden than seams in Wyoming. Moreover, Wyoming coal tends to have slightly higher average Btu content and slightly lower average ash and sulfur content than Montana coal. However, coal from the Decker area has the highest Btu in the entire Powder River Basin and about the same sulfur as Wyoming coal; it has the disadvantage of having a high sodium content, which can cause problems in combustion.

Figure 5. Changes in Montana production, share of U.S. market and severance tax collections



Source: Table C8.

The cost of transportation to distant markets may also affect the competitiveness of Montana coal. Nearly all coal exported from Montana leaves on Burlington Northern Santa Fe lines. Some is later transshipped by barge. Transportation costs can double to more than triple the delivered cost of Montana coal bought by out-of-state generating plants. Though transportation costs have fallen over the last fifteen years, the minemouth cost of coal has fallen faster, making transportation a larger component of final cost. Coal shipped from the Powder River Basin (Wyoming and Montana) in 2000 had the highest ratio of transportation cost to delivered price, on a per ton basis, for U.S. coalfields. The cost of Montana coal may be further affected by the rail transportation network being better developed in the southern end of the Powder River Basin than in the northern end. (U.S. Department of Energy, Energy Information

Administration *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation,* 2000).

Glossary

General
Coal
Electricity Supply and Demand
Electricity Transmission
Natural Gas

General

British Thermal Unit (Btu): A standard unit of energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit (F).

Class of Service: A group of customers with similar characteristics (e.g., residential, commercial, industrial, sales for resale, etc.) identified for the purpose of setting a utility rate structure.

Cogeneration: A process that sequentially produces useful energy (thermal or mechanical) and electricity from the same energy sources.

Consumer Price Index (CPI): This index is issued by the U.S. Department of Labor, Bureau of Labor Statistics as a measure of average changes in the retail prices of goods and services.

Demand-Side Management: Utility activities designed to reduce customer use of natural gas or electricity or change the time pattern of use in ways that will produce desired changes in the utility load.

End-Use Sectors: Energy use is assigned to the major end-use sectors according to the following guidelines as closely as possible:

Residential sector: Energy consumed by private household establishments primarily for space heating, water heating, air conditioning, cooking, and clothes drying.

Commercial sector: Energy consumed by non-manufacturing business establishments, including motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; by health, social, and educational institutions; and by federal, state, and local governments.

Industrial sector: Energy consumed by manufacturing, construction, mining, agriculture, fishing, and forestry establishments.

Transportation sector: Energy consumed to move people and commodities in both the public and private sectors, including military, railroad, vessel bunkering, and marine uses, as well as the pipeline transmission of natural gas.

Electric utility sector: Energy consumed by privately and publicly owned establishments that generate electricity primarily for resale.

Fossil Fuel: Any naturally occurring fuel of an organic nature, such as coal, crude oil, and natural gas.

Fuel: Any substance that, for the purpose of producing energy, can be burned, otherwise chemically combined, or split or fused in a nuclear reaction.

Implicit Price Deflator: A measure over time of price changes of goods and services. Unlike the Consumer Price Index, it is not based on surveys of the cost of a theoretical "market basket" of items, but rather is derived from data collected for the National Income Accounts. For this reason, it reflects price changes in actual current patterns of production and consumption.

Nominal Dollars: Dollars that measure prices that have not been adjusted for the effects of inflation. Nominal dollars reflect the prices paid for products or services at the time of the transaction.

Real Dollars: Dollars that measure prices that have been adjusted for the effects of inflation, using an index such as the Implicit Price Deflator (see Implicit Price Deflator).

Renewable Energy: Energy obtained from sources that are essentially sustainable (unlike, for example, the fossil fuels, of which there is a finite supply). Renewable sources of energy include wood, waste, solar radiation, falling water, wind, and geothermal heat.

Short Ton: A unit of weight equal to 2,000 pounds. All tonnages used in this publication are in short tons.

Coal

Average Mine Price: The total value of the coal produced at the mine divided by the total production tonnage (see FO.B. Mine Price).

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without free access to air and under the influence of moisture and, often, increased pressure and temperature. The rank of coal (anthracite, bituminous, subbituminous, and lignite) is determined by its heating value.

> **Anthracite:** Hard and jet black with a high luster, it is the highest rank of coal and is mined in northeastern Pennsylvania. Anthracite contains approximately 22 to 28 million Btu per ton as received.
>
> **Bituminous:** The most common coal, it is soft, dense, and black with well-defined bands of bright and dull material. Bituminous is ranked between anthracite and subbituminous and is mined chiefly in Kentucky, Pennsylvania, and West Virginia. The heating value ranges from 19 to 30 million Btu per ton as received.
>
> **Lignite:** A brownish-black coal of the lowest rank; it is mined in North Dakota, Montana, and Texas. The heat content of lignite ranges from 9-17 million Btu per ton as received.
>
> **Subbituminous:** A dull black coal ranking between lignite and bituminous; it is mined chiefly in Montana and Wyoming. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received.

Coal Rank: A classification of coal based on fixed carbon, volatile matter, and heating value.

F.O.B. Mine Price: The "free on board" mine price. This is the price paid for coal measured in dollars per short ton at the mining operation site and, therefore, does not include freight/shipping and insurance costs.

Surface Mine: A mine producing coal that is usually within a few hundred feet of the earth's surface. Overburden (earth above or around the coal) is removed to expose the coal bed. The bed is then mined using surface excavation equipment such as draglines, power shovels, bulldozers, loaders, and augers.

Underground Mine: A mine tunneling into the earth to the coal bed. Underground mines are classified according to the type of opening used to reach the coal—i.e. drift (level tunnel), slope (inclined tunnel), or shaft (vertical tunnel).

Electricity Supply and Demand

Average Megawatt: A unit of energy output over a specified time period. For a year, it is equivalent to the total energy in megawatt-hours divided by 8,760 (the number of hours in a year).

Capacity: The amount of electric power which a generator, turbine, transformer, transmission circuit, station, or system is capable of producing or delivering.

Demand: The rate at which electric energy is delivered to a system, part of a system, or piece of equipment at a given instant or during a designated period of time (see Load).

Generation (Electric): The production of electric energy from other forms of energy; also, the amount of electric energy produced, expressed in kilowatt-hours (kWh).

> **Gross:** The total amount of electric energy produced by the generating units in a generating station or stations, measured at the generator terminals.
>
> **Net:** Gross generation less the electric energy consumed at the generating station for station use. (Energy required for pumping at pumped-storage plants is regarded as plant use and is subtracted from the gross generation and from hydroelectric generation.)

Gigawatt (GW): One billion watts.

Gigawatt-hour (GWh): One billion watt-hours.

Hydroelectric Power Plant: A plant in which the turbine generators are driven by falling water.

Kilowatt (kW): One thousand watts. The kW is the basic unit of measurement of electric power.

Kilowatt-hour (kWh): One thousand watt-hours. The kWh is the basic unit of measurement of electric energy, and is equivalent to 3,412 Btu.

Megawatt (MW): One million watts.

Megawatt-hour (MWh): One million watt-hours.

Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturer. Installed station capacity does not include auxiliary or house units. Nameplate capacity is usually shown on the manufacturer's identification plate attached mechanically to the equipment. Because manufacturers have differing standards, there may be no fixed relationship between "nameplate capacity" and maximum sustainable capacity.

Load (Electric): The amount of electric power required by equipment in use at a given time at any specific point or points on a system.

PURPA: Public Utility Regulatory Policies Act of 1978. First federal legislation requiring utilities to buy power from qualifying independent power producers.

Qualifying Facilities: Small power producers or cogenerators that meet the Federal Energy Regulatory Commission's or the Montana Public Service Commission's size, fuel source, and operational criteria as authorized by PURPA.

Steam-Electric (Conventional) Plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler by heat from burning fossil fuels (see Fossil Fuel and Fuel).

Watt: The electrical unit of power or rate of doing work. A watt is the rate of energy

transfer equivalent to 1 ampere flowing under pressure of 1 volt at unity power factor (volt and ampere in phase). It is analogous to horsepower or foot-pound-per-minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

Electricity Transmission

AC/DC/AC converter station: A back-to-back installation that takes Alternating Current power on one side, rectifies it to Direct Current, and then inverts the Direct Current back to Alternating Current in phase with a different system. These stations provide for power transfers between separate synchronous grids. They use the same equipment—AC/DC rectifiers and DC/AC inverters—that are required at each end of a long distance DC transmission line.

ATC: (Available Transmission Capacity) is calculated by subtracting committed uses and existing contracts from total rated transfer capacity.

Contract Path: A path across portions of the interconnected grid, owned by two or more different owners, for which a transaction has gained contractual permission from the owners or other rights holders with transferable rights.

Distribution: Relatively small, low voltage wires used for delivering power from the transmission system to local electric substation and to electric consumers. Compare with Transmission.

ERCOT: The Electric Reliability Council of Texas, a separate synchronous grid connected only by AC/DC/AC converter stations to the Western Interconnection and the Eastern Interconnection.

FERC: Federal Energy Regulatory Commission (formerly the Federal Power Commission). The federal agency that regulates interstate and wholesale power transactions including power sales and transmission services, as well as licensing of dams on rivers under federal jurisdiction.

High voltage: Voltage levels generally at above 69 kV. Some utilities also count 50 and 69 kV lines as transmission lines. Transmission lines in Montana are built at voltage levels of 100 kV, 115 kV, 161 kV, 230 kV and 500 kV. In other states lines have also been built at 345 kV and 765 kV. Canadian utilities build at still other voltage levels. Direct current transmission lines have been built at +/- 400 kV, which may sometimes be described as 800 kV.

Impedance: A measure of the composite force that must be used to push power through an Alternating Current transmission line. Impedance is composed of resistance, inductance and capacitance. Resistance is a property of the wire itself and is also present in DC circuits. Impedance is a function of expanding and collapsing magnetic fields in coils (such as transformers) in AC circuits. Capacitance is a function of expanding and collapsing electric fields in parallel wires in AC circuits. Neither impedance nor capacitance is relevant to DC transmission.

Inadvertent Flows: Portions of power transactions that flow over portions of the interconnected grid that are not on the contract path for the transaction.

IndeGO: "Independent Grid Operator" A failed effort, roughly 1998-1999, to form an organization that would have taken over operation of the Northwest transmission system. The effort was revived and superceded by the RTO West discussions.

Loop Flow: A characteristic of mass power flows across the Western Interconnection in

which seasonal flows in the summer from the Northwest to California, nominally shipped south over the North-South California Intertie, flow in part around the eastern part of the interconnection through Montana, Utah and Arizona and then back into California in a clockwise direction. In the winter seasonal flows from California to the Northwest over the Intertie also flow in part counter-clockwise through the same sections of the grid. A similar phenomenon is associated with seasonal shipment of power from Arizona to California, where portions of the power flow counter-clockwise up to Montana and Idaho, into the Northwest and then south into California over the North-South Intertie.

Phase Shifter: A device for controlling the path of power flows in Alternating Current circuits.

Reliability: The characteristic of a transmission system (or other complex system) of being able to provide full, uninterrupted service despite the failure of one or more component parts.

Synchronous: Operating at the same frequency and on the same instantaneous power cycle. The Western Interconnection is a synchronous grid, which means all generators in the western grid are producing power in phase with each other (always at the same point on the same sine wave). Other synchronous grids in North America include ERCOT, Quebec, and the Eastern Interconnection (the entire continental U.S. except for ERCOT and the Western Interconnection).

Total Transfer Capacity: The rated ability of a transmission line, or group of related transmission lines, to carry power while meeting the regionally accepted reliability criteria.

Transmission: High voltage electric wires used for bulk movement of large volumes of power across relatively long distances. Compare with Distribution, which is composed of relatively smaller, lower voltage wires used for delivering power from the transmission system to local electric substation and to electric consumers.

Unscheduled Flows: See Inadvertent Flows.

Western Interconnection: The interconnected, synchronous transmission grid extending from British Columbia and Alberta in the north, to the U.S.-Mexican border in the south, and from the Pacific Coast to a line extending from the Alberta-Manitoba border through eastern Montana, eastern Wyoming, western Nebraska and the extreme west part of Texas.

West of Hatwai: A transmission path consisting of ten related transmission lines that are generally located in the area west and south of Spokane, WA. The West of Hatwai path is a bottleneck for power flowing from Montana to the West Coast and California and it is relatively heavily used.

Natural Gas

Bcf: One billion cubic feet.

Dekatherm (dkt): One million Btu of natural gas. One dekatherm of gas is roughly equivalent in volume to one mcf.

Gas Condensate Well: A gas well that produces from a gas reservoir containing considerable quantities of liquid hydrocarbons in the pentanes and heavier range generally described as "condensate."

Gas Well: A well that is completed for the production of gas from either nonassociated

gas reservoirs or associated gas and oil reservoirs.

Gross Withdrawals: Full well stream volume excluding condensate separated at the lease.

Lease Condensate: A natural gas liquid recovered from gas well gas (associated and nonassociated) in lease separators or natural gas field facilities. Lease condensate consists primarily of pentanes and heavier hydrocarbons.

Liquefied Petroleum Gases (LPG): Propane, propylene, butanes, butylene, butane-propane mixtures, ethane-propane mixtures, and isobutane produced at refineries or natural gas processing plants, including plants that fractionate raw natural gas plant liquids.

Marketed Production: Gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations.

Mcf: One thousand cubic feet. One mcf of natural gas is roughly equivalent in heat content to one dekatherm.

MMcf: One million cubic feet.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil, and are not distinguishable at the time as separate substances.

Natural Gas-Associated-Dissolved: The combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Natural Gas-Dry: The actual or calculated volumes of natural gas that remain after the liquefiable hydrocarbon portion has been removed from the gas stream (e.g., gas after lease, field, and/or plant separation), and any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Natural Gas-Nonassociated: Natural gas not in contact with significant quantities of crude oil in a reservoir.

Natural Gas-Wet After Lease Separation: The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volumes of natural gas, wet after lease separation, at natural gas processing plants.

Natural Gas Liquids: Those hydrocarbons in natural gas that are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally, such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids, these components are included with natural gas liquids.