Environmental Quality Council
Energy Policy Subcommittee
July 29, 2002

EXHIBIT 3

UNDERSTANDING ELECTRICITY IN MONTANA

A GUIDE TO ELECTRICITY, NATURAL GAS AND COAL PRODUCED AND CONSUMED IN MONTANA

Draft July 29, 2002

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Prepared by
Department of Environmental Quality
for the
Environmental Quality Council

Project Coordinator: Paul Cartwright

Authors of Area Papers and Statistics

Jeff Blend – Natural Gas
Paul Cartwright – Electricity Supply and Demand; Coal
Larry Nordell - Transmission

Introduction

Over the last five years, to talk about energy in Montana is to talk about electricity. The restructuring and sale of Montana Power Company, the California energy crisis, the potential for new markets for Montana coal, all are facets of the electricity industry. Continued public and private actions will be necessary to facilitate and to cope with the industry's on-going transition nationwide. EQC has prepared this guide to provide the background information policy makers and citizens alike will need to make the best decisions they can.

The guide focuses on historical and current patterns of supply and demand, but also gives some consideration to future trends. It lays out the background facts needed to interpret past and future policies. The guide is divided into four sections. First is an overview of electricity supply and demand in Montana. The second section covers the electricity transmission system, especially how it works in Montana and the Pacific Northwest. This is the critical issue affecting access to existing markets and the potential for new generation in Montana. A third section addresses natural gas supply and demand, important in its own right and now much more intertwined with the electricity industry. The final section covers the Montana coal industry, which exists to fuel the generation of electricity and whose future will depend on what happens in that industry.

The guide, with its focus on historical and current patterns, deals primarily with conventional resources, which are most of what exists now. Nonetheless, Montana can expect to see renewables take a larger role in electricity supply in the future. Energy efficiency (sometimes referred to as energy conservation) also is only given brief treatment, simply because so few data are available. Still, improving energy efficiency remains the cheapest way to meet energy demand. Finally, this guide does not address petroleum and transportation issues, even though that sector holds the potential for problems far larger than Montana has seen with electricity. Public agencies, private business and individual citizens need to keep this possibility in the back of their minds, even while they focus on the immediate need of dealing with electricity.

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.

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.

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.

Electricity Supply and Demand in Montana

Electricity is the new energy crisis. During 2000 and 2001, price spikes and supply disruptions spread across the country, most notably in the West. Even before that, the electricity industry had begun sweeping changes, prompted by the deregulation of the wholesale electricity markets in 1992 through the federal Energy Policy Act and deregulation of the Montana retail market in 1997 by SB390. This paper provides historical supply and demand information needed to put the current changes in context, along with some estimates of future consumption. Because of these sweeping changes, the historical data, while still useful, are not as reliable predictors of the future as they once were.

Transmission, which affects access to out-of-state markets by Montana suppliers and consumers, is covered in a separate paper. Prospects for future supplies and their effect on rates, as well as energy efficiency and how it could be encouraged, will be covered in a supplement in November 2002, after the case now before the Public Service Commission is completed and its results digested by the market. The supplement will address both conventional sources (primarily natural gas and coal) and "new" technologies (primarily wind and distributed generation of various types). Still, as this paper shows, growth in the Montana in-state market will not, by itself, justify much new generation construction over the coming decade.

1. Necessary Definitions

Certain terms are used throughout this paper 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 use 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 units and the entire distribution utility were sold to NorthWestern Energy (NWE) in February 2002. Some data from the period of MPC ownership are labeled PPL Montana or NWE where that would be more useful for the reader understanding the current situation.

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 5,200 MW of electricity. 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 3,200 aMW, 1995-1999. During that time, Montana consumption accounted for slightly more than half of production, with Montanans requiring about 1,800 aMW in 2000.

Key Electricity Facts for Montana

Generation capacity	-	5,200 MW
Average generation	-	3,200 aMW
Load in 2000	-	1,800 aMW

Montana straddles the two major electric grids in the country. Most of Montana is in the Western grid, which covers all or most of 11 states, two provinces and a bit of northern Mexico. Only about 5 percent of Montana's load is in the Eastern grid, along with less than 1 percent of the electricity generated. The 1999 Montana load (sales plus transmission losses) was equivalent to about 2 percent of 86,122 aMW load in the Western grid (Western Systems Coordinating Council). Montana generation accounted for less than 4 percent of total West generation that year. As another comparison, 1999 sales in Montana were equivalent to about 6 percent of the 26,807 aMW sold in California (California Energy Commission).

3. Generation

There are 45 generating facilities in Montana (Table E1). The oldest are Milltown Dam, near Missoula, and Madison Dam, near Ennis; both were 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 600 MW. The smallest plants supplying the grid in Montana are a micro-hydro plant at 60 kW and a wind turbine at 65 kW.

Average Generation by Company, 1995-1999

Company	aMW	Percent
PPL Montana[1,2]	940	29.6%
Puget Sound Power & Light[2]	509	16.0
Avista (WPP)[2]	403	12.7
Bonneville Power Administration[3]	382	12.0
Western Area Power Administration[3]	323	10.2
Portland General Electric[2]	223	7.0
NorthWestern Energy[2,4]	169	5.3
PacifiCorp[2]	114	3.6
Yellowstone Energy Partnership	48	1.5
Other	69	2.2
TOTAL	3178	100.0%

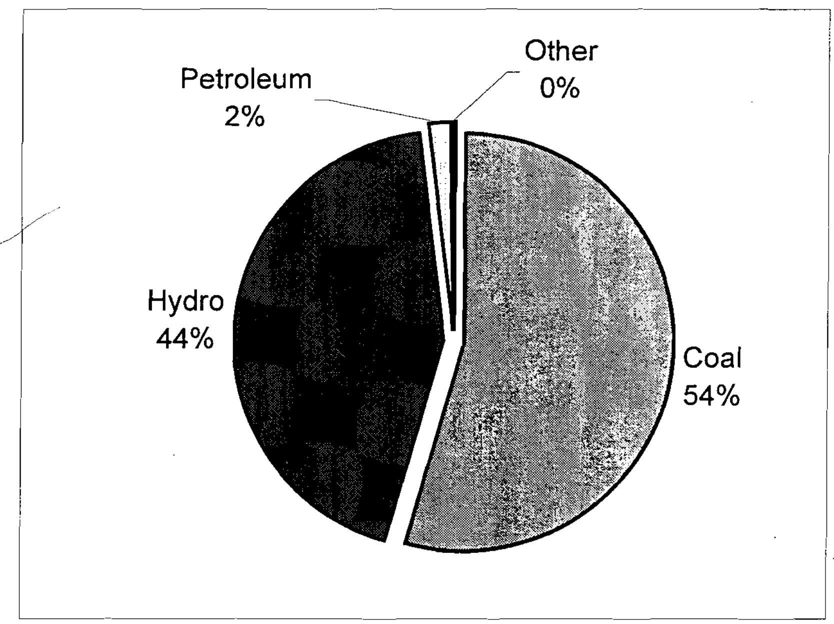
[1] PPL Montana plants were owned by MPC until mid-December, 1999.
[2] Public data on output for Colstrip 1-4 are reported for the entire facility, not individual units. In this table, the output was allocated among the partners on the basis of their ownership percentages.
[3] Distributes power generated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

The only sizeable plants coming on line in the 1990's were two 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 now account for about 92 percent of the average production of all QFs in Montana.

Montana Power Company plants, now owned by PPL Montana, produced the largest amount of electricity on average in 1995-1999 (see previous page; also Table E2). PPL Montana's facilities accounted for about 30 percent of the total generation in Montana. Federal agencies—Bonneville Power Administration and Western Area Power Administration—collectively produced 22 percent of the electricity generated in Montana. The MPC plants not bought by PPL—Milltown Dam and a share of Colstrip 4—now belong to NorthWestern Energy.

Montana generation is powered by coal (54 percent) and hydro (44 percent) (1995-1999 average, Table E3; see Figure 1). Over the last 15 years, about 25 percent of Montana coal production has gone to generate electricity in Montana. Until 1985, hydro was the dominant source of net electric generation in Montana (Table E5). 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.

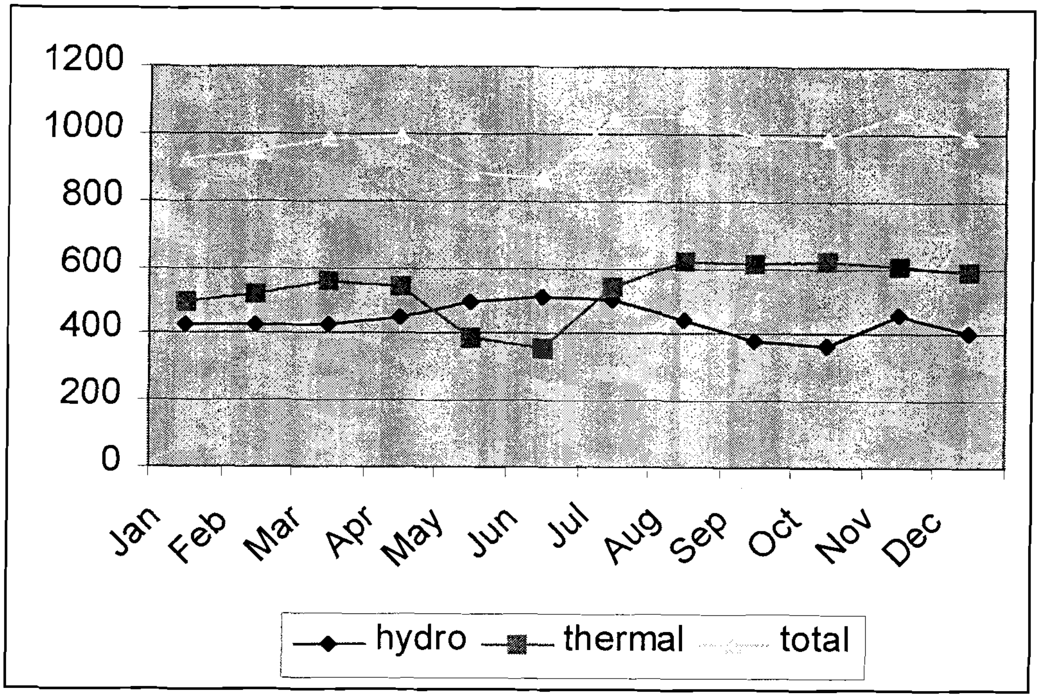
Figure 1. Generation by fuel



Source: Table E3.

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 Montana Power's system during 1997 through 1999 (see Figure 2).

Figure 2. Average output of Montana power plants, 1997-1999 (aMW)

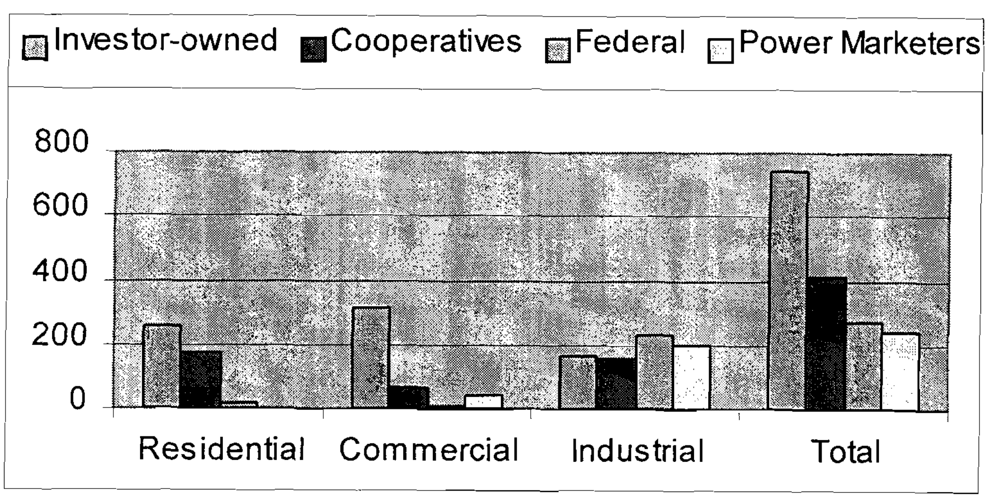


Source: U.S. DOE, Energy Information Administration, Forms 759 and 860 databases.

4. Consumption

Montanans are served by 38 distribution utilities: 4 investor-owned, 30 rural electric cooperatives, 3 federal agencies and 1 municipal (Table E9). (Four of the co-ops only serve a handful of Montanans.) Two-thirds of these utilities operate mostly or exclusively in Montana. Some of the distribution utilities also provide power from power marketers, primarily to industrial customers (Table E8). In 2000, investor-owned utilities

Figure 3. Distribution of 2000 sales by type of utility (aMW)

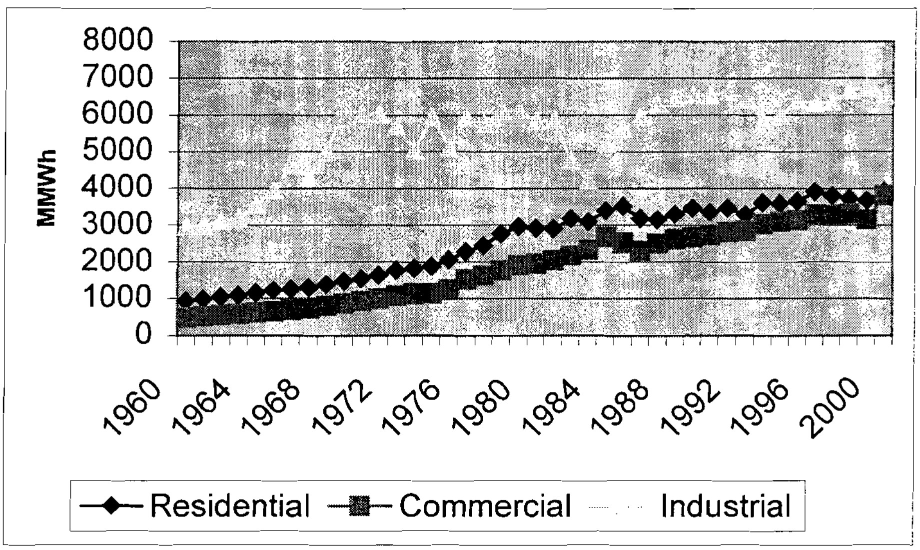


Source: Table E8.

made 45 percent of the electricity sales in Montana, co-ops 25 percent, federal agencies 16 percent and power marketers 14 percent (Table E8; see Figure 3).

Sales in 2000 were 14.5 billion kWh. The residential and commercial sectors accounted for about a quarter each of total sales, and industrial, a little less than half. Sales have tripled since 1960 (Table E6; see Figure 4). Growth was faster in the first half of that period than in the latter. Since 1990, sales to the commercial sector have grown the most, followed by the residential sector. Industrial sales have bounced around, but on the whole haven't increased much. The impact of the 2000-2001 price spike doesn't appear in these data, but it did significantly and permanently reduce industrial consumption. Future consumption patterns will be noticeably different than those of the past decade.

Figure 4. Annual sales in Montana



Percentage of sales, 2000

Residential	- 27 %
Commercial	- 26
Industrial	- 45
Other	- 2
Total	-100 %

Source: Table E6.

The cost of electricity didn't change much during the 1990s (Table E7). Throughout that decade, as in previous decades, electricity in Montana cost less than the national average. In 2000, Montana averaged 4.74 cents/kWh vs. 6.78 cents/kWh nationally. The average price per kWh for residential customers was 6.5 cents in 2000, up from 5.4 cents in 1990 (Table E8). The average price per kWh for commercial customers was 5.7 cents in 2000, up from 4.7 cents in 1990. Complete cost on industrials are not available, due to deregulation; however, the average cost for industrial customers served by private utilities was 4.0 cents/kWh in 2000, up from 3.3 cents in 1990. On average, the rates of cooperatives and private utilities were about the same in 2000; however, that average masks considerable variation.

Montana residential consumption averaged 810 kWh/month in 2000, about 1.1 akW (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), 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 4.0 akW). Extreme cases could run higher or lower than these ranges.

Commercial accounts averaged 4,200 kWh/month or 50 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. The largest industrial customers are shown in the following table. These figures date before the price spikes in 2000 and 2001 forced some companies to cut consumption or to shut down.

Large Industrial Electricity Use (aMW)

ASARCO	8.7	Holnam	5.0
ASiMI	~75	Louisiana Pacific	7.0
Ash Grove Cement	4.6	Montana Refining	3.4
Cenex	18	Montana Resources	43.0
CFAC	342	Montana Tunnels	9.5
Conoco Pipeline	20.0	Plum Creek	33
Conoco Refinery	27.0	Smurfit-Stone	52.0
ExxonMobil	27.0	Stillwater Mining	20.0
Golden Sunlight	10.0	Stimson	6.2

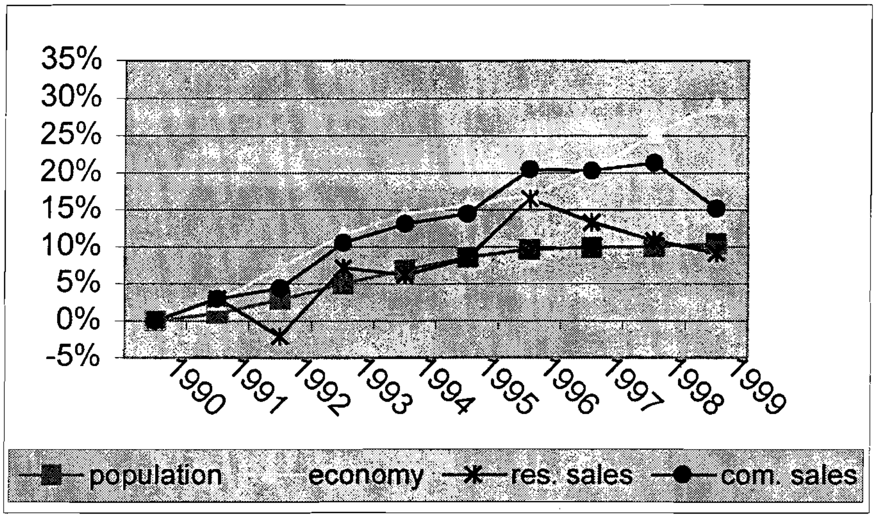
Data initially provided from best available sources by Don Quander, Large Customer Group; compiled by EQC and DEQ. Holnam late last year changed its name to Holcim.

5. Past and Future Changes in Electricity Consumption

During the 1990-2000 decade, residential consumption rose at an average annual rate of 1.5 percent, commercial at 3.4 percent and the overall growth rate was 1.0 percent statewide. Residential growth tracked population growth, while commercial growth tended to track economic activity, as measured by the gross state product (see Figure 5). Even though houses are getting larger, the number of second homes growing and the proliferation of consumer electronics continuing, per capita use of electricity is not climbing significantly in Montana. As for growth in commercial sales, one can expect that to continue slow with the slower economy.

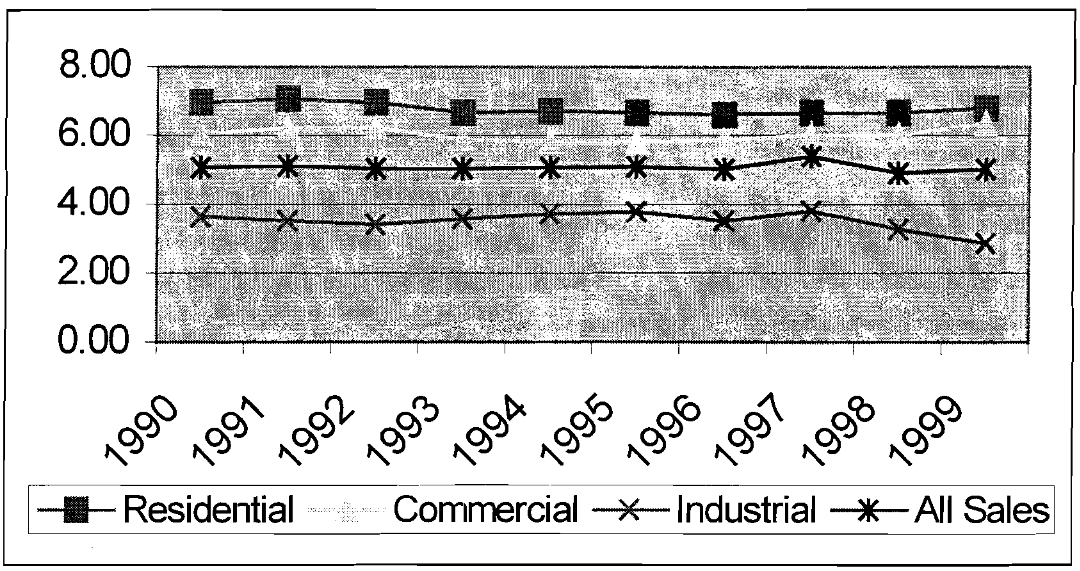
As electricity prices go up, growth in consumption should slow. In the last decade, Montanans saw virtually no change in the price of electricity in real terms (as adjusted by the consumer price index; see Figure 6). In spite of all the news stories about rising rates due to the energy crisis of 2000-2001, only about one-quarter of the Montana load had been exposed to market prices by the start of 2002. The entire impact of increased prices on consumption has yet to hit.

Figure 5. Amount of growth in residential and commercial electricity sales, population, economic activity in the 1990s



Note: The decline in 2000 commercial sales data may reflect an underreporting of actual sales.
Source: U.S Department of Commerce, U.S. Census, Population Estimates Program and Bureau of Economic Analysis, Regional Accounts data; Table E6.

Figure 6. Cost per kWh, 1990-1999 (1999 cents)



Source: Table E7.

The increased prices due to deregulation and the California price spikes hit the customers of Flathead Electric Cooperative and "choice" customers served by MPC (now NWE) distribution lines. MPC customers who had moved to choosing their own power supplier included most of the large industrial load, some commercial customers and a few residential customers. Flathead residential and small commercial customers have seen their rates jump from a base fee of $15 per month and $0.0392/kWh at the start of 2000 to $16 and $0.0622 in October 2001. That is a 53 percent increase in the cost of electricity (assuming an average consumption of 800 kWh per month). Energy costs paid by choice customers served by the Montana Power (now Northwestern Energy) distribution system aren't published, though rates are known to have dropped back down. However, typical bills for Northwestern Energy's default customers, who consume about 40 percent of the electricity sold in Montana, went up July 1 by 10 percent for residential customers and 18 percent for most commercial customers; other customer classes also saw rate increases of varying amounts.

In addition, another large portion of Montana's electricity use was exposed to market prices, albeit in a fashion different from Flathead customers and MPC choice customers. Bonneville Power Administration (BPA) bought back the contracted deliveries it had promised Columbia Falls Aluminum Company (CFAC) and the other aluminum plants in the Pacific Northwest. This buyback offer, which was accepted by all the aluminum smelters, provided BPA with needed power at a lower cost than it could purchase on the open market. For CFAC, reselling the power gave a better profit than could be obtained by smelting aluminum. The shutdown, which reduced Montana consumption by about 340 aMW, lasted over a year with the first potlines reopening in January 2002.

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. Improved efficiency also could reduce loads significantly (see Section 6). Finally, if the trend over the last few decades towards warmer winters continues, as reported by the Climate Prediction Center, National Weather Service (http://www.cpc.ncep.noaa.gov/charts.htm), Montana's electricity use will decline further.

In the absence of forecasts, only scenarios of future growth can provide a sense of the range of future consumption. First, one could assume that the 1990's pattern would continue, with residential and commercial sectors continuing to grow at a combined average rate of 2.4 percent per year and industrial load not dropping. Second, one could assume, as MPC did in its Tier II filing before the Public Service Commission, that non-industrial loads would grow at 1 percent per year and certain industrial loads (ASARCO, MRI and Golden Sunlight) would be lost and not replaced. Finally, as a worst case one could assume MPC's Tier II scenario, plus that the yearlong shutdown of CFAC reoccurs and becomes permanent. These scenarios produce a range of possibilities, from an optimistic 260 aMW increase to an extremely pessimistic loss of 336 aMW.

Possible Increases in Statewide Load by 2010

Scenarios	aMW
The 1990's continue:	260
MPC's Tier II:	33
Tier II minus CFAC:	-336

While these are only scenarios, and not predictions, the range does suggest minimal need for net additional generation to serve increases in Montana loads. To be economically viable, any substantial addition to generation resources in Montana will need to sell to out-of-state markets or to displace existing in-state resources. 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.

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. Better estimates of the potential in Montana might come from the Northwest Power Planning Council's Fifth Regional Plan. DEQ is assisting Council staff with the efficiency estimates and may be able to report on those estimates in the November supplement to this paper.

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.

One of the most cited estimates for Montana is that offered by NorthWestern Energy in the default supply portfolio docket (data request PSC-22—amended, D2001.10.144). NWE estimated the potential for cost-effective efficiency improvements for customers served by their distribution lines, who consume about two-thirds of the non-aluminum plant load in Montana. The estimates were extrapolations from the more detailed analysis done in MPC's 1995 Integrated Least Cost Resource Plan. NWE estimated an achievable reduction of 98 MW in load and 87 aMW reduction in energy, using measures with a levelized cost of no more than $0.035/kWh. The average cost of all measures was $0.023/kWh. For default customers alone, the totals were 76 MW and 62 aMW, or about 7 percent of current load and 9 percent of sales. These estimates do not include any premium amounts the utility—or the customer—might be willing to purchase as protection against future price volatility.

The reductions estimated by NWE and others can't be compared to the recent reductions observed in the Pacific Northwest and in California. The extensive load reductions in 2001 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 is an ad hoc group of utility industry, large customer and public agency representatives that advise 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 demand of aluminum smelters was almost completely cut off, 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 E1. Electric Power Generating Capacity by Company and Plant as of November, 2001[1]

COMPANY	PLANT	COUNTY	ENERGY SOURCE	INITIAL OPERATION (First Unit)	CAPACITY (MW) GENERATOR NAMEPLATE	SUMMER CAPABILITY	WINTER CAPABILITY
Avista	Noxon Rapids	Sanders	Water	1959	466.2	556	513
Mission Valley Power Co.	Hell Roaring	Lake	Water	1916	0.4	0.4	0.4
Montana-Dakota Utilities	Glendive	Dawson	Natural Gas/#2 Fuel Oil	1979	40.5	33.5	42.3
Montana-Dakota Utilities	Lewis & Clark	Richland	Lignite Coal/Natural Gas	1958	70.0	52.3	49.2
Montana-Dakota Utilities	Miles City	Custer	Natural Gas/#2 Fuel Oil	1972	24.5	24.4	28.9
Montana Power Co.[2]	Milltown	Missoula	Water	1906	3.2	2.6	2.2
MPC QF - Colstrip Energy Partnership[2]	Montana One	Rosebud	Waste Coal	1990	41.5	39	39
MPC QF - Hydrodynamics[2]	South Dry Creek	Carbon	Water	1985	2.0	2.1	-
MPC QF - Montana DNRC[2]	Broadwater	Broadwater	Water	1989	9.7	6	8
MPC QF - other hydro[2]	Various	Various	Water	Various	2.4	-	-
MPC QF - wind[2]	Various	Park	Wind	Various	0.3	-	-
MPC QF - Yellowstone Partnership[2]	BGI	Yellowstone	Petroleum Coke	1995	65.0	57	57
Northern Lights Cooperative	Lake Creek	Lincoln	Water	1917	4.5	4.7	4.4
PacifiCorp	Bigfork	Flathead	Water	1910	4.2	4.2	4.2
PPL Montana	Black Eagle	Cascade	Water	1927	21.3	19	17
PPL Montana	Cochrane	Cascade	Water	1958	48.0	52	32
PPL Montana	Hauser Lake	Lewis & Clark	Water	1907	17.0	16	17
PPL Montana	Holter	Lewis & Clark	Water	1918	38.4	36	48
PPL Montana	J. E. Corette	Yellowstone	Subbituminous Coal	1968	163.0	160	160
PPL Montana	Kerr	Lake	Water	1938	211.7	180	165
PPL Montana	Madison	Madison	Water	1906	9.0	9.0	9.0
PPL Montana	Morony	Cascade	Water	1930	45.0	48	48
PPL Montana	Mystic Lake	Stillwater	Water	1925	10.0	11.0	11.0
PPL Montana	Rainbow	Cascade	Water	1910	35.6	37.0	37.0
PPL Montana	Ryan	Cascade	Water	1915	48.0	60	60
PPL Montana	Thompson Falls	Sanders	Water	1915	91.0	90.0	90.0
PPL Montana (50%) Puget Sound Power & Light (50%)	Colstrip I	Rosebud	Subbituminous Coal	1975	333.0	307	307
PPL Montana (50%) Puget Sound Power & Light (50%)	Colstrip II	Rosebud	Subbituminous Coal	1976	333.0	307	307
PPL Montana (30%) Avista (15%) PacifiCorp (10%) Portland General Electric (20%) Puget Sound Power & Light (25%)	Colstrip III	Rosebud	Subbituminous Coal	1983	776.0	740	740
Montana Power Co. (30%)[2] Avista (15%) PacifiCorp (10%) Portland General Electric (20%) Puget Sound Power & Light (25%)	Colstrip IV	Rosebud	Subbituminous Coal	1985	776.0	740.0	740.0
Salish-Kootenai Tribe	Boulder Creek	Lake	Water	1984	0.4	0.4	0.4
US Corps - North Pacific Division	Libby	Lincoln	Water	1975	525.0	600	575
US Corps - Missouri River Division	Fort Peck	McCone	Water	1943	185.3	209.0	209.0
US BurRec - Great Plains Region	Canyon Ferry	Lewis & Clark	Water	1953	50.1	57.6	57.6
US BurRec - Great Plains Region	Yellowtail	Big Horn	Water	1966	250.0	288	252
US BurRec - Pacific Northwest Region	Hungry Horse	Flathead	Water	1952	428.0	424	368
TOTAL MONTANA CAPACITY (MW)					5,129.2	5,173.2	4,998.6

[1] Does not include a 10.9 MW waste-wood facility that supplies the Stone Container plant in Missoula, the various temporary generators, most of which were in operation only in the first part of 2001 or the City of Whitefish's 200 kW hydro plant, currently off line but expected to be repaired.

[2] Bought by NorthWestern Energy in 2002.

Source: Western Systems Coordinating Council, *Existing Generation and Significant Additions and Changes to System Facilities 2000 - 2010*; U.S. Department of Energy, Energy Information Administration, *Inventory of Utility Power Plants in the U.S. 1999* (EIA-0095)/1; U.S. Department of Energy, Energy Information Administration, *Inventory of Nonutility Power Plants in the U.S. 1999* (EIA-0095)/2; Montana Power Company for some data on Qualifying Facilities and FERC Form 1 filing for nameplate capacity; Northwest Power Planning Council for Boulder Creek hydro data; Montana Dakota Utilities for data on its plants.

Table E2. Average Generation by Company, 1995-1999

Company	aMW[1]
Avista (WPP)[2]	403.1
Bonneville Power Administration[3]	381.7
Colstrip Energy Partnership[4]	29.9
Hydrodynamics[4]	0.9
Mission Valley Power	0.2
Montana-Dakota Utilities	27.9
MT Dept of Natural Resources and Conservation[4]	6.0
Northern Lights Cooperative[5]	3.5
NorthWestern Energy (at the time MPC)[2,6]	169.0
NWE QF - other hydro[6,7]	0.9
NWE QF- wind[6,8]	0.1
PacificCorp[2]	113.5
Portland General Electric[2]	222.5
PPL Montana (at the time MPC)[2,9]	939.5
Puget Sound Power & Light[2]	509.0
Salish-Kootenai Tribes	0.2
Western Area Power Administration[3]	322.7
Yellowstone Energy Partnership[10]	47.7
TOTAL	3178.2

[1] aMW = average megawatt, or 8,760 megawatt hours in a year
[2] Output for Colstrip 1-4 is reported for the entire facility, not individual units. In this table, it was allocated among the partners on the basis of their ownership percentages.
[3] Distributes power generated at US Corps of Engineers and US Bureau of Reclamation
[4] Average for July 1995 - June 2000
[5] Average for 1997 - 1999
[6] NWE plants and contracts were owned by Montana Power Company until February 2002
[7] Average for July 1995 - June 2000, except for one facility, July 1997-June 2000.
[8] Average for July 1998 - June 2000
[9] PPL Montana plants were owned by Montana Power Company until mid-December, 1999
[10] Average for July 1996 - June 2000

Source: U.S. Department of Energy, Energy Information Administration, Form 860 and 906 databases, http://www.eia.doe.gov/cneaf/electricity/page/data.html (1995-1999); Montana Power Company for certain information on QFs; Northern Lights Cooperative; Northwest Power Planning Council for data on Boulder Creek.

Table E3. Average Net Electric Generation And Fuel Consumption By Company And Plant, 1995-1999[1]

COMPANY PLANT	GENERATION COAL[2]	PETROLEUM	NATURAL GAS	HYDRO	WIND	TOTAL	FUEL CONSUMPTION COAL[2] (Mtons)	PETROLEUM[3] (MBbl)	NATURAL GAS[3] (MMcf)
	(Thousand kilowatt-hours)								
Avista									
Noxon				2,069,316		2,069,316			
Bonneville Power Administration									
Hungry Horse				904,620		904,620			
Libby				2,439,095		2,439,095			
Colstrip Energy Partnership									
Montana One[4]	262,233	--[5]				262,233	270	1	
Hydrodynamics									
South Dry Creek				6,539		6,539			
Strawberry Creek				1,323		1,323			
Mission Valley Power									
Hellroaring				2,075		2,075			
Montana-Dakota Utilities									
Glendive		46	13,605			13,651		*	183
Lewis-Clark	222,196		567			222,763	217		12
Miles City	1		7,554			7,555		*	112
MT Dept of Nat. Res. and Con.									
Broadwater Dam				52,271		52,271			
Northern Lights Cooperative									
Lake Creek				30,367		30,367			
NorthWestern Energy (previously MPC)									
Milltown				18,265		18,265			
PacifiCorp									
Big Fork				19,790		19,790			
PPL Montana (previously MPC)									
Black Eagle				145,242		145,242			
Cochrane				347,992		347,992			
Colstrip[6]	13,772,932	17,276				13,790,208	8,759	38	
Hauser Lake				137,560		137,560			
Holter				343,712		343,712			
J E Corette	901,882		10,849			912,731	581		110
Kerr				1,169,677		1,169,677			
Madison				59,422		59,422			
Morony				354,340		354,340			
Mystic Lake				50,342		50,342			
Rainbow				254,901		254,901			
Ryan				474,980		474,980			
Thompson Falls				495,455		495,455			
Salish-Kootenai									
Boulder Creek				1,840		1,840			
Various Qualifying Facilities									
Other NWE QF - hydro				7,566		7,566			
Other NWE QF - wind					593	593			
Western Area Power Administration									
Canyon Ferry				436,986		436,986			
Fort Peck				1,223,585		1,223,585			
Yellowtail				1,166,200		1,166,200			
Yellowstone Energy Partnership									
Billings Generation Inc.		417,778	--[7]			417,778		NA	NA
TOTALS	15,159,244	435,100	32,574	12,213,458	593	27,840,970	9,828	39	418

* Less than 0.5

[1] Net generation equals gross generation minus plant use. Some averaging periods were less than 5 years. See Table E2 for detailed listing.

[2] Includes waste coal

[3] Figures are slightly different from Table E4 because of different estimation methods.

[4] Consumption figures are for 1999 only

[5] Minor, included in coal

[6] Operated by PPL; ownership shared by six utilities.

[7] Minor, included in petroleum

Source: U.S. Department of Energy, Energy Information Administration, Form 860 and 906 databases, http://www.eia.doe.gov/cneaf/electricity/page/data.html (1995-1999); Montana Power Company for certain information on QFs; Northern Lights Cooperative; Northwest Power Planning Council for data on Boulder Creek.

Table E4. Annual Consumption of Fuels for Electric Generation, 1960-1999

YEAR	COAL[1] (thousand short tons)	PETROLEUM[1,2] (thousand barrels)	NATURAL GAS (million cubic feet)
1960	186.9	-	341.3
1961	262.5	-	356.2
1962	291.6	1.3	3,712.5
1963	285.5	0.7	3,303.3
1964	293.8	3.6	2,449.5
1965	295.8	0.7	1,992.3
1966	323.5	82.2	2,977.2
1967	325.4	6.1	502.5
1968	399.2	22.9	631.3
1969	576.6	104.9	1,520.5
1970	722.7	26.0	2,529.4
1971	672.0	0.2	1,079.8
1972	768.7	17.5	1,217.4
1973	892.6	152.2	2,167.4
1974	854.6	14.0	1,038.0
1975	1,061.3	62.6	1,073.3
1976	2,373.7	81.1	708.5
1977	3,196.7	195.3	953.3
1978	3,184.2	98.1	909.4
1979	3,461.4	146.5	2,320.4
1980	3,351.6	58.6	4,182.1
1981	3,337.9	38.5	2,069.4
1982	2,595.8	30.6	337.0
1983	2,356.0	31.0	335.0
1984	5,113.0	78.0	360.0
1985	5,480.0	38.0	468.0
1986	7,438.0	25.0	407.0
1987	7,530.0	44.0	478.0
1988	10,410.0	63.0	286.0
1989	10,208.0	60.0	336.0
1990	9,399.0	63.0	418.0
1991	10,223.0	41.0	268.0
1992	10,768.0	35.0	220.0
1993	8,869.0	48.0	270.0
1994	10,513.0	42.0	632.0
1995	9,373.0	53.0	388.0
1996	7,897.0	41.0	470.0
1997	9,286.0	39.0	420.0
1998	10,627.0	33.0	522.0
1999[3]	10,604.9	30.7	306.9

[1] Data series does not include generation from 41.5 MW plant near Colstrip,. The Montana 1 plant came on line in 1990. In 1999, it burned 270,000 tons of waste coal.
[2] Includes propane but does not include petroleum coke. A 65 MW plant using primarily petroleum coke has been in operation in Billings since 1995.
[3] Montana Power Company transferred most of its generating plants in mid-December 1999 to PPL Montana, a non-utility. Data for 1999 include utility and non-utility consumption at these plants.

Sources: Federal Energy Regulatory Commission, Form 4 News Releases (1960-76); U.S. Department of Energy, Energy Information Administration, *Electric Power Statistics*, EIA-0034 (1977-78); U.S. Department of Energy, Energy Information Administration, *Power Production, Fuel Consumption and Installed Capacity,* EIA-0049 (1979); U.S. Department of Energy, Energy Information Administration, *Electric Power Annual,* EIA-0348 (1980-89); U.S. Department of Energy, Energy Information Administration, *Electric Power Monthly*, March 1992, EIA-0226 (1990-91), U.S. Department of Energy, Energy Information Administration, *Electric Power Annual*, EIA-0348 (1992-99); U.S. Department of Energy, Energy Information Administration, Form 860B, 900 and 906 databases, http://www.eia.doe.gov/cneaf/electricity/page/data.html (1999).

Table E5. Net Electric Generation[1] by Type of Fuel Unit, 1960-99

YEAR	HYDROELECTRIC (million kWh)	%	COAL (million kWh)	%	PETROLEUM[2] (million kWh)	%	NATURAL GAS (million kWh)	%	TOTAL
1960	5,801	97	NA		NA		NA		5,992
1961	6,499	96	263	4	0	0	19	*	6,780
1962	6,410	91	291	4	1	*	349	5	7,051
1963	6,011	91	284	4	0	0	299	5	6,594
1964	6,821	93	286	4	2	*	220	3	7,329
1965	8,389	95	285	3	0	0	171	2	8,845
1966	7,940	93	317	4	43	*	273	3	8,573
1967	8,703	96	314	3	3	*	41	*	9,061
1968	8,925	95	434	5	10	*	52	*	9,421
1969	9,447	91	735	7	52	*	147	1	10,381
1970	8,745	88	966	10	14	*	228	2	9,953
1971	9,595	91	901	9	1	*	96	1	10,593
1972	9,444	89	1,079	10	7	*	108	1	10,639
1973	7,517	83	1,303	14	69	*	195	2	9,084
1974	9,726	88	1,210	11	6	*	98	1	11,040
1975	9,560	85	1,544	14	17	*	96	1	11,217
1976	12,402	77	3,558	22	27	*	67	*	16,054
1977	8,460	63	4,788	36	92	1	87	1	13,427
1978	11,708	70	4,871	29	35	*	84	*	16,698
1979	10,344	66	5,114	33	58	*	188	1	15,704
1980	9,966	64	5,140	33	22	*	351	2	15,479
1981	11,323	68	5,047	30	13	*	176	1	16,559
1982	10,920	74	3,853	26	10	*	33	*	14,816
1983	11,561	77	3,452	23	10	*	34	*	15,058
1984	11,112	59	7,650	41	36	*	40	*	18,839
1985	10,175	54	8,465	45	16	*	58	*	18,713
1986	10,857	48	11,469	51	9	*	52	*	22,387
1987	8,925	43	11,836	57	17	*	58	*	20,835
1988	8,237	33	16,462	66	30	*	37	*	24,766
1989	9,550	37	16,129	63	30	*	43	*	25,751
1990	10,672	42	14,903	58	27	*	41	*	25,644
1991	11,921	42	16,132	57	18	*	24	*	28,095
1992	8,223	32	17,126	67	16	*	23	*	25,388
1993	9,549	41	13,775	59	21	*	24	*	23,369
1994	8,096	33	16,488	67	18	*	61	*	24,663
1995	10,698	42	14,656	58	25	*	32	*	25,411
1996[3]	13,745	53	12,242	47	18	*	38	*	26,043
1997[3]	13,771	49	14,410	51	17	*	32	*	28,230
1998[3,4]	11,144	39	16,806	59	407	1	41	*	28,398
1999[3,4]	11,835	40	16,979	58	467	2	20	*	29,302

*Less than or equal to 0.5 percent.

[1] Gross generation less the electric energy consumed at the generating station for facilities owned by or selling to electric utilities and cooperatives. Annual output of non-utility plants selling into the grid is not available, except for 1998-99. Non-utility plants began supplying significant amounts of electricity in 1989. The data also do not include generation from wood-fired plants that do not provide power into the grid; historically, these collectively have produced less (and usually considerably less) than 75 million kWh per year.

[2] Includes propane, fuel oil and petroleum coke.

[3] Includes Lake Creek plant, which dropped from EIA database after it was sold to Northern Lights in 1995.

[4] Includes BGI, Montana 1, Broadwater Dam and South Dry Creek hydro. Annual output data for Montana Power Company's other Qualifying Facilities were not available. These plants, which use hydro and some wind, accounted for a trivial amount of additional generation in Montana in 1999. Minor amounts of electricity from QF natural gas and propane use included in coal and petroleum.

Sources: Federal Power Commission (1960-76); U.S. Department of Energy, Energy Information Administration, *Power Production, Fuel Consumption and Installed Capacity Data*, EIA-0049 (1977-80); U.S. Department of Energy, Energy Information Administration, *Electric Power Annual*, EIA-0348 (1981-89); U.S. Department of Energy, Energy Information Administration, *Electric Power Monthly*, March 1992, EIA-0226 (1990-99); Clint Brewington, Northern Lights Coop, 1996-1999 Lake Creek data; U.S. Department of Energy, Energy Information Administration, Forms 860B and 906 databases - http://www.eia.doe.gov/cneaf/electricity/page/data.html (1999).

Table E6. Annual Sales of Electricity, 1960-2000 (million kilowatt-hours)

	MONTANA					USA
Year	Residential	Commercial	Industrial	Other[1]	Total	TOTAL[2]
1960	935	479	2,951	209	4,575	686,493
1961	982	518	2,975	222	4,697	720,120
1962	1,041	551	3,099	254	4,946	775,381
1963	1,077	574	3,191	259	5,101	830,079
1964	1,139	610	3,544	249	5,541	896,059
1965	1,216	654	3,939	270	6,080	959,493
1966	1,261	698	4,657	286	6,902	1,035,145
1967	1,291	746	4,282	293	6,612	1,099,137
1968	1,373	805	4,982	273	7,433	1,202,871
1969	1,462	863	6,208	247	8,781	1,312,406
1970	1,534	924	6,029	264	8,750	1,392,300
1971	1,633	990	5,999	268	8,890	1,469,306
1972	1,768	1,070	5,660	265	8,763	1,595,161
1973	1,812	1,125	5,034	246	8,217	1,713,380
1974	1,873	1,156	5,929	213	9,171	1,707,852
1975	2,058	1,250	5,069	197	8,575	1,736,267
1976	2,261	1,525	5,922	203	9,911	1,855,246
1977	2,440	1,625	5,759	189	10,013	1,948,361
1978	2,754	1,768	6,106	158	10,786	2,017,922
1979	2,957	1,907	6,111	154	11,129	2,071,099
1980	2,916	1,957	5,815	137	10,825	2,094,449
1981	2,906	2,045	5,848	157	10,956	2,147,103
1982	3,178	2,180	4,759	159	10,276	2,086,441
1983	3,097	2,334	4,217	166	9,813	2,150,955
1984	3,386	2,687	5,229	164	11,466	2,278,372
1985	3,505	2,521	5,623	173	11,822	2,309,543
1986	3,181	2,302	5,948	161	11,593	2,350,835
1987	3,139	2,495	6,304	484	12,423	2,457,272
1988	3,301	2,620	6,438	582	12,942	2,578,062
1989	3,456	2,670	6,535	400	13,061	2,646,809
1990	3,358	2,738	6,529	499	13,125	2,712,555
1991	3,459	2,819	6,622	507	13,407	2,762,003
1992	3,286	2,859	6,414	536	13,096	2,763,365
1993	3,598	3,026	5,837	469	12,929	2,861,462
1994	3,567	3,096	5,961	561	13,184	2,934,563
1995	3,640	3,133	6,368	278	13,419	3,013,287
1996	3,911	3,299	6,306	305	13,820	3,097,810
1997[3]	3,804	3,293	6,352	284	13,733	3,139,761
1998[4]	3,722	3,322	6,655	335	14,034	3,239,818
1999[4]	3,664	3,153	6,722	334	13,874	3,332,473
2000[4]	3,908	3,813	6,536	312	14,569	3,429,000

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and inter-departmental sales.

[2] U.S. sales 1998-2000 may be missing a small amount of retail sales by non-utilities due to data collection problems during the transition to a restructured utility industry.

[3] EIA data on industrial sales corrected by adding BPA sales, which EIA didn't include in this year.

[4] Data calculated by adding Distribution Only Volumes reported by MPC to the Securities and Exchange Commission to the data reported on EIA Form 861. The resulting "Commercial" volumes are slightly higher and "Industrial" slightly lower than had they been reported under Form 861category definitions.

Sources: Federal Power Commission (1960-76); U.S. Department of Energy, Energy Information Administration, *Electric Power Statistics*, EIA-0034 (1977-78); U.S. Department of Energy, Energy Information Administration, *Financial Statistics of Electric Utilities and Interstate Natural Gas Pipeline Companies*, EIA-0147 (1979-80); U.S. Department of Energy, Energy Information Administration, *Electric Power Annual*, EIA-0348 (1981-99); U.S. Department of Energy, Energy Information Administration, Form 861 Database (1999-2000);Montana Power Company 10K filings to the Securities and Exchange Commission (1998-2000) and updated information on sales from Bonneville Power Administration (1997).

Table E7. Average Annual Prices for Electricity Sold, 1960-2000 (cents per kilowatt-hour)

	MONTANA								U.S.
Year	Residential	Commercial	Industrial	Street & Highway Lighting	Other Public Authorities	Railroads & Railways	Interdepart-mental	All Sales	All Sales
1960	2.33	2.25	0.43	2.45	0.79	0.56	1.27	1.05	1.69
1961	2.32	2.18	0.45	2.70	0.74	0.55	1.70	1.06	1.69
1962	2.29	2.13	0.46	2.50	0.61	0.55	1.43	1.07	1.67
1963	2.25	2.06	0.45	2.78	0.78	0.57	1.67	1.07	1.64
1964	2.20	2.02	0.45	2.56	0.71	0.53	2.00	1.03	1.63
1965	2.12	1.93	0.44	2.75	0.70	0.59	1.67	0.98	1.59
1966	2.09	1.92	0.43	2.56	0.66	0.57	1.67	0.92	1.56
1967	2.04	1.89	0.42	2.79	0.63	0.49	1.08	0.95	1.55
1968	1.99	1.83	0.40	2.77	0.61	0.58	1.11	0.90	1.54
1969	2.10	1.93	0.41	2.75	0.57	0.53	1.05	0.88	1.54
1970	2.13	1.94	0.42	2.88	0.60	0.55	1.00	0.94	1.59
1971	2.12	1.94	0.43	3.02	0.62	0.50	0.95	0.95	1.68
1972	2.16	1.98	0.44	3.21	0.53	0.49	1.19	1.00	1.77
1973	2.21	2.04	0.53	3.27	0.60	0.58	1.67	1.16	1.86
1974	2.23	2.05	0.50	3.23	0.58	0.53	1.41	1.10	2.30
1975	2.19	2.08	0.62	2.99	0.58	--	1.51	1.25	2.70
1976	2.23	2.06	0.60	3.32	0.73	--	1.67	1.24	2.89
1977	2.38	1.90	0.67	3.53	0.80	--	1.79	1.38	3.21
1978	2.62	2.50	0.72	3.88	0.87	--	2.16	1.53	3.46
1979	2.67	2.52	0.80	3.86	0.87	--	1.99	1.62	3.82
1980	2.95	2.78	0.98	4.00	0.97	--	1.91	1.87	4.49
1981	3.38	3.19	1.30	4.50	1.42	--	2.34	2.24	5.16
1982	3.58	3.30	2.09	4.69	1.69	--	2.70	2.81	5.79
1983	4.19	3.88	2.37	5.28	1.83	--	3.01	3.31	6.00
1984	4.30	3.88	2.57	5.72	2.02	--	2.58	3.38	6.27
1985	4.70	4.20	2.55	7.35	2.08	--	2.15	3.56	6.47
1986	5.02	4.54	2.60	8.04	2.54	--	1.89	3.71	6.47
1987	5.23	4.68	2.72	8.79	2.65	--	3.49	3.83	6.39
1988	5.41	4.79	3.16	9.41	2.60	--	3.40	4.14	6.36
1989	5.38	4.68	3.09	10.57	2.83	--	3.32	4.09	6.47
1990	5.45	4.74	2.84	11.59	2.07	--	3.87	3.97	6.57
1991	5.77	5.08	2.87	9.27	2.92	--	4.96	4.18	6.76
1992	5.86	5.23	2.86	10.21	2.73	--	4.82	4.23	6.85
1993	5.77	5.10	3.10	7.07	2.44	--	4.65	4.36	6.94
1994	5.96	5.17	3.30	7.17	2.28	--	4.54	4.51	6.91
1995	6.09	5.31	3.44	10.35	3.33	--	4.43	4.65	6.90
1996	6.22	5.51	3.30	11.99	5.38	--	4.73	4.72	6.86
1997	6.40	5.80	3.66	13.51	5.28	--	NA	5.20	6.85
1998	6.50	5.87	3.19	14.09	NA	--	NA	4.80	6.74
1999	6.78	6.35	2.84	14.36	NA	--	NA	5.01	6.66
2000	6.48	5.70	2.48	14.80	NA		NA	4.74	6.78

NA: Not available. These categories now are rolled into Commercial or Other Sales (not included as a separate column, in this table).

Note: Average annual prices were calculated by dividing total revenue by total sales as reported by Edison Electric Institute. Edison Electric Institute data are slightly different from Department of Energy data presented in Table E6.

Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, 1961-2001.

Table E8. Utility Revenue, Retail Sales, Consumers and Average Price per Kilowatt-hour, 2000 (with comparison to 1990 average price)*

UTILITY NAME	RESIDENTIAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2000	1990	COMMERCIAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2000	1990	INDUSTRIAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2000	1990	TOTAL Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	Average price (cents/kWh)[3] 2000	1990
Cooperative	$99,571	171.2	124,343	6.6	6.0	$34,906	69.7	15,598	5.7	5.7	$43,247	153.8	1,120	3.2	4.8	$187,634	414.3	150,385	5.2	5.7
Beartooth Electric Coop Inc	$3,469	5.1	4,348	7.7	6.8	$301	0.5	203	6.8	6.7	$110	0.2	68	5.3	--	$3,880	5.9	4,619	7.5	6.7
Big Flat Electric Coop Inc	$1,357	1.9	1,343	8.1	6.1	$259	0.4	151	7.4	5.2	$604	0.7	41	10.2	--	$2,422	3.3	1,606	8.4	5.5
Big Horn County Elec Coop Inc	$2,298	3.4	2,872	7.7	7.1	$1,619	2.5	443	7.4	8.2	--	--	--	--	7.4	$4,094	6.2	3,397	7.6	7.4
Big Horn Rural Electric Co	$23	0.0	26	7.6	8.3	$66	0.1	16	11.2	10.0	--	--	--	--	--	$89	0.1	42	10.0	9.6
Fall River Rural Elec Coop Inc	$945	1.5	1,170	7.1	7.3	$1,579	3.4	492	5.4	6.1	--	--	--	--	--	$2,535	4.9	1,679	5.9	6.5
Fergus Electric Coop Inc	$4,539	6.0	5,060	8.6	6.3	$629	1.0	254	6.9	5.5	--	--	--	--	4.5	$5,845	8.4	5,487	8.0	6.0
Flathead Electric Coop Inc[4]	$21,718	48.2	30,252	5.1	4.9	$10,212	24.8	5,586	4.7	4.9	$32,904	132.4	12	2.8	--	$66,015	207.7	39,461	3.6	4.9
Glacier Electric Coop Inc	$4,717	7.1	5,345	7.6	5.6	$3,525	7.7	1,405	5.3	4.9	$957	2.4	5	4.6	4.5	$9,549	17.7	6,883	6.1	5.2
Goldenwest Electric Coop Inc	$400	0.5	456	9.8	9.3	$109	0.1	8	10.9	9.0	--	--	--	--	--	$561	0.6	611	10.5	9.2
Grand Electric Coop Inc	$7	0.0	12	7.1	6.2	--	--	--	--	--	--	--	--	--	--	$7	0.0	12	7.1	6.2
Hill County Electric Coop Inc	$2,820	3.5	3,104	9.3	7.9	$1,193	2.0	184	6.7	6.4	$907	3.7	2	2.8	--	$4,920	9.2	3,290	6.1	7.4
Lincoln Electric Coop Inc	$2,617	5.9	3,390	5.1	4.6	$980	2.4	525	4.8	4.7	$1,820	4.5	10	4.6	5.5	$5,449	12.7	3,929	4.9	5.0
Lower Yellowstone R E A Inc	$1,750	2.7	1,667	7.5	7.1	$576	0.7	383	9.6	9.2	$1,657	1.9	238	9.8	8.9	$4,321	5.6	2,968	8.8	8.2
Marias River Electric Coop Inc	$1,507	3.5	2,511	4.9	3.9	$1,637	3.3	1,123	5.6	4.8	$673	1.5	47	5.1	4.5	$3,867	8.4	3,689	5.3	4.4
McCone Electric Coop Inc	$3,497	4.3	4,216	9.3	7.9	$1,076	1.7	455	7.2	6.8	$89	0.1	62	8.8	--	$4,673	6.1	4,737	8.7	7.6
McKenzie Electric Coop Inc	$39	0.1	107	7.8	7.3	$2	0.0	2	9.1	17.6	--	--	--	--	--	$41	0.1	109	7.8	7.7
Mid-Yellowstone Elec Coop Inc	$1,216	1.9	1,564	7.4	5.9	$227	0.3	145	7.7	6.6	--	--	--	--	--	$1,803	2.9	1,837	7.2	5.9
Missoula Electric Coop Inc	$7,924	13.6	9,984	6.6	5.9	$1,667	3.4	974	5.6	5.3	$540	1.2	3	5.0	4.1	$10,417	19.1	11,253	6.2	5.6
Northern Electric Coop Inc	$1,239	1.8	943	7.9	5.7	$894	1.0	279	10.3	7.9	--	--	--	--	--	$2,140	2.8	1,225	8.8	6.5
Northern Lights Inc	$2,324	3.7	2,867	7.2	6.4	$550	1.1	184	5.5	5.0	$293	0.4	2	7.6	2.7	$3,167	5.3	3,053	6.9	3.7
Park Electric Coop Inc	$3,842	5.3	4,120	8.3	7.2	$266	0.5	70	6.5	6.0	$843	1.4	1	7.0	--	$5,358	7.9	4,380	7.7	7.0
Powder River Energy Corp	$46	0.1	91	8.9	--	$251	0.5	42	5.8	--	--	--	--	--	--	$297	0.6	133	6.1	--
Ravalli County Elec Coop Inc	$6,116	10.2	6,770	6.8	5.8	$488	0.9	227	6.2	5.5	$172	0.4	1	5.0	4.3	$7,247	12.6	7,749	6.6	5.5
Sheridan Electric Coop Inc	$1,825	3.1	2,444	6.6	5.8	$3,031	4.7	624	7.4	7.0	$254	0.2	586	12.5	--	$5,116	8.1	3,655	7.2	6.6
Southeast Electric Coop Inc	$1,030	1.6	1,852	7.6	9.2	$44	0.1	14	9.3	8.6	$250	0.5	1	5.7	6.5	$1,330	2.1	1,868	7.2	8.7
Sun River Electric Coop Inc	$3,654	5.0	3,710	8.4	6.4	$459	0.9	42	5.7	7.4	--	--	--	--	--	$5,855	9.6	4,939	7.0	6.6
Tongue River Electric Coop Inc	$3,242	5.5	3,441	6.8	5.0	$546	1.0	468	6.4	4.9	$1,174	2.2	41	6.0	4.5	$5,636	9.5	4,597	6.8	5.0
Valley Electric Coop Inc	$1,346	1.7	1,550	8.8	6.8	$319	0.5	175	7.7	6.3	--	--	--	--	--	$1,753	2.3	1,787	8.5	6.7
Vigilante Electric Coop Inc	$4,427	8.4	6,224	6.0	5.6	$288	0.6	111	5.3	5.8	--	--	--	--	5.7	$7,081	14.3	7,302	5.6	5.2
Yellowstone Valley Elec Co-op	$9,637	15.8	12,904	7.0	5.8	$2,113	3.7	1,013	6.5	5.3	--	--	--	--	6.0	$12,166	20.4	14,088	6.8	5.7
Federal	$9,130	19.9	12,177	5.2	4.1	$5,860	11.5	2,615	5.8	4.7	$39,902	229.9	2	2.0	2.3	$56,313	268.4	15,812	2.4	2.4
Bonneville Power Administration[5]	--	--	--	--	--	--	--	--	--	--	$38,988	227.3	1	2.0	2.3	$38,988	227.3	1	2.0	2.3
USBIA-Mission Valley Power	$9,130	19.9	12,177	5.2	4.1	$5,860	11.5	2,615	5.8	4.7	$914	2.6	1	4.0	3.4	$17,161	36.5	15,794	5.4	4.1
Western Area Power Administration	--	--	--	--	--	--	--	--	--	4.0	--	--	--	--	--	$164	4.7	17	0.4	0.3
Municipal																				
Troy City of	$489	1.1	751	5.3	4.5	$141	0.3	79	4.6	4.2	$4	0.0	6	5.3	5.3	$767	1.7	900	5.1	4.5
Investor-Owned	$143,681	253.2	263,897	6.5	5.3	$156,715	314.2	56,506	5.7	4.5	$57,777	165.2	199	4.0	3.3	$369,137	741.3	324,989	5.7	4.3
Avista[6]	$8	0.0	10	4.6	4.7	$2	0.0	1	8.0	4.6	--	--	--	--	--	$15	0.0	16	5.3	5.0
Black Hills Power Inc	$6	0.0	12	7.3	8.1	$17	0.0	21	12.2	10.5	$606	1.5	2	4.6	5.6	$629	1.5	35	4.7	5.5
Energy Northwest[7]	$5,168	10.9	10,682	5.4	4.8	$7,196	17.7	2,358	4.6	4.6	--	--	--	--	3.6	$12,502	28.9	13,527	4.9	4.4
MDU Resources Group Inc	$10,787	16.6	18,717	7.4	7.5	$11,056	22.6	4,478	5.6	5.8	$7,511	20.1	132	4.3	4.6	$30,158	60.9	23,620	5.7	5.8
Montana Power Co	$127,712	225.7	234,476	6.5	5.2	$138,444	273.8	49,648	5.8	4.4	$49,660	143.6	65	3.9	3.2	$325,833	649.9	287,791	5.7	4.1
Power Marketers[8]	NA	0.8	800	NA	NA	NA	39.5	1,360	NA	NA	NA	197.1	12	NA	NA	NA	237.4	2,172	NA	--
EnergyWest	$151	0.7	800	--	--	$6,390	30.6	1,360	--	--	$6,352	25.4	2	--	--	$12,893	56.7	2,162	--	--
PPL Montana	--	--	--	--	--	--	--	--	--	--	$32,107	33.2	10	--	--	$32,107	33.2	10	--	--
Others (as reported by MPC)[9]	--	0.1	--	--	--	--	8.9	--	--	--	--	138.6	--	--	--	--	147.5	--	--	--
STATE TOTALS[10]	$252,871	446.1	401,968	6.5	5.4	$197,622	435.2	76,158	5.7	4.7	$140,930	746.1	1,339	2.9	2.9	$613,851	1663.1	494,258	4.9	4.0

*Average Price for utilities with a low proportion of their sales in Montana may not be representative of typical bills from that utility. NA - Not available

[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 1990 and 2000, Flathead Cooperative began delivering to CFAC and other large industrials. This dropped the average price of both Flathead and cooperatives in general. [5]Market incentives paid CFAC to suspend operations were not subtracted from total revenue.

[6]Avista previously was Washington Water Power.

[7]The area served by Energy Northwest in 2000 was a portion of PacifiCorp's service area in 1999; however, the 1999 Average Price is for all of PacifiCorp's Montana service area. Energy Northwest became a part of Flathead in 2001.

[8]Some marketers did not provide data to U.S. Department of Energy, Energy Information Administration. Enron was one; there may have been others. Since marketers only charge for the commodity, and not the distribution services, average price was not calculated.

[9]Calculated by subtracting marketer sales reported to EIA from Distribution Only Volumes reported by MPC to SEC. Resulting "Commercial" volumes are slightly higher and "Industrial" slightly lower than had they been reported under EIA Form 861category definitions.

[10]State totals do not include revenue or price data from the marketers.

Source: U.S. DOE, Energy Information Administration, Form 861 Database:http://www.eia.doe.gov/cneaf/electricity/page/eia861.html for 2000 and *Electric Sales and Revenue 1990*, EIA-0540 Montana Power Company, *10K Report 2000*, to Securities and Exchange Commission.

Table E9. Percent Of Utility Sales In Montana And Other States, 1999

Utility	Percentage in Montana	Other States State	Percent	State	Percent	State	Percent
Avista[1]	*	Washington	61	Idaho	39		
Beartooth Electric Coop Inc	100						
Big Flat Electric Coop Inc	100						
Big Horn County Elec Coop Inc	93	Wyoming	7				
Big Horn Rural Electric Co	1	Wyoming	99				
Black Hills Corp	1	South Dakota	91	Wyoming	8		
Bonneville Power Admin	8	Washington	89	California	1	Oregon	1
Energy Northwest Inc[2]	100						
Fall River Rural Elec Coop Inc	22	Idaho	75	Wyoming	3		
Fergus Electric Coop Inc	100						
Flathead Electric Coop Inc	100						
Glacier Electric Coop Inc	100						
Goldenwest Electric Coop Inc	44	North Dakota	56				
Grand Electric Coop Inc	*	South Dakota	100				
Hill County Electric Coop Inc	100						
Lincoln Electric Coop Inc	100						
Lower Yellowstone R E A Inc	78	North Dakota	22				
Marias River Electric Coop Inc	100						
McCone Electric Coop Inc	100						
McKenzie Electric Coop Inc	*	North Dakota	100				
MDU Resources Group, Inc	24	North Dakota	59	Wyoming	11	South Dakota	6
Mid-Yellowstone Elec Coop Inc	100						
Missoula Electric Coop Inc	99	Idaho	1				
Montana Power Co[3]	100	Wyoming	*				
Northern Electric Coop Inc	100						
Northern Lights Inc	20	Idaho	80	Washington	*		
Park Electric Coop Inc	100						
Powder River Energy Corp	*	Wyoming	100				
Ravalli County Elec Coop Inc	100						
Sheridan Electric Coop Inc	93	North Dakota	7				
Southeast Electric Coop Inc	97	South Dakota	2	Wyoming	*		
Sun River Electric Coop Inc	100						
Tongue River Electric Coop Inc	100						
Troy City of	100						
USBIA-Mission Valley Power	100						
Valley Electric Coop Inc	100						
Vigilante Electric Coop Inc	100	Idaho	*				
Western Area Power Admin	*	California	76	Arizona	12	Others	11
Yellowstone Valley Elec Coop Inc	100						

* Less than 0.5 percent.

[1] Formerly known as Washington Water Power.

[2] Formerly part of PacifiCorp; incorporated into Flathead Electric Cooperative in 2001.

[3] Became NorthWestern Energy in 2002.

Source: U.S. Department of Energy, Energy Information Administration, *Electric Sales and Revenue* 1999, E IA-0540.

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. However, it does more than that: it provides service robustly and reliably even though individual elements of the transmission grid may be knocked out of service or taken out of service for maintenance. This paper describes how the transmission 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 RTO West. Finally, it discusses several issues involved in the construction of new transmission lines to expand the capacity of the grid.

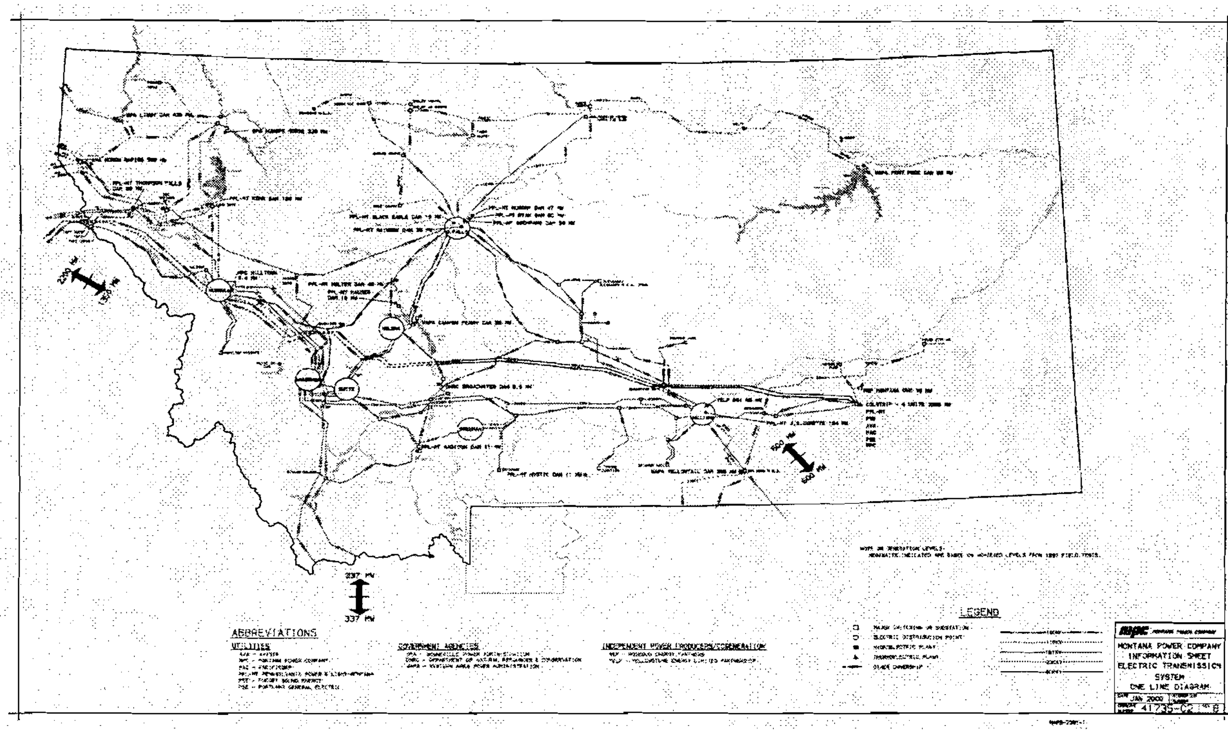
1. Historical Development Of Transmission In Montana

The transmission network in Montana developed, as it did in most places, 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 turn 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 coop loads dependent on MPC's 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.

Figure 1. The western Montana transmission network



As U.S. and Canadian utilities have grown and increasingly depended 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.

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 three DC converter stations between the western and eastern grids with a combined capacity of 510 MW. Three more are planned or under construction at Lamar, in eastern Colorado, Rapid City, and Miles City. 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 131,000 MW in 2000.

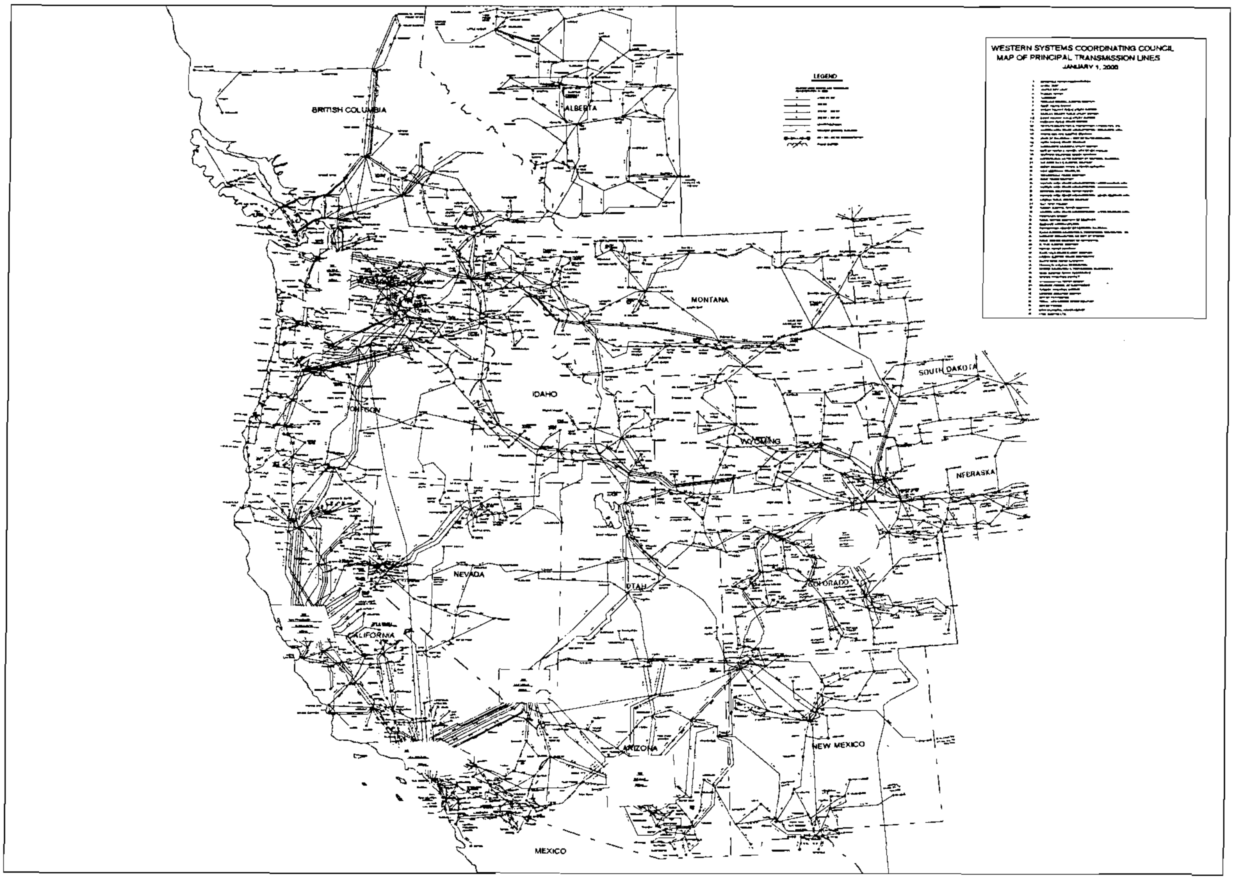


Figure 2. The Western Interconnection transmission network

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 other 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 path 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 an 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 Montana Power's 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 bundles of related 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. Recently there has been a move by the Western Systems Coordinating Council, which is the reliability council for the Western Interconnection, to require the paths of which the Colstrip lines are a part to model both circuits out of service, because of the possibility of a tower collapse.

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.

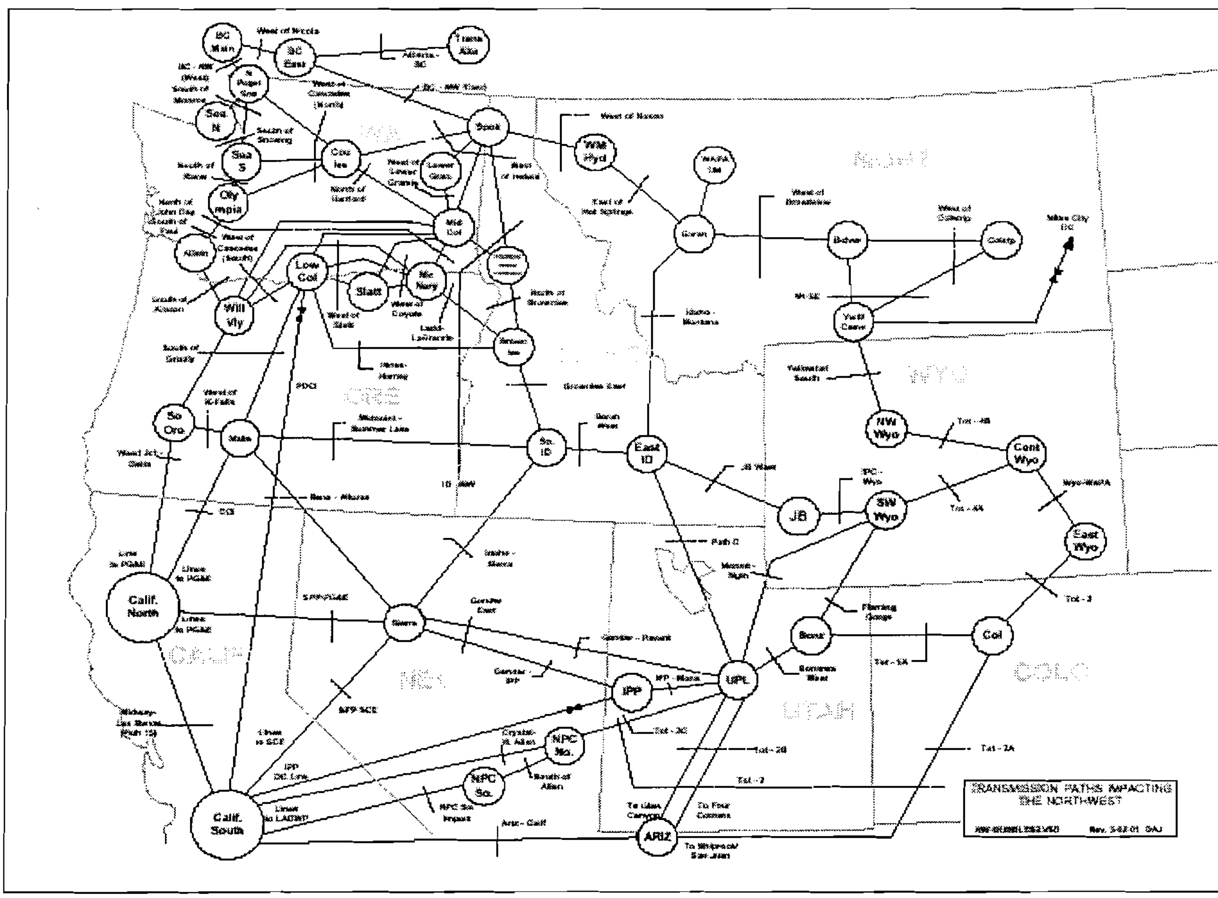


Figure 3. Rated paths on the transmission network

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 on 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 MPC, 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.

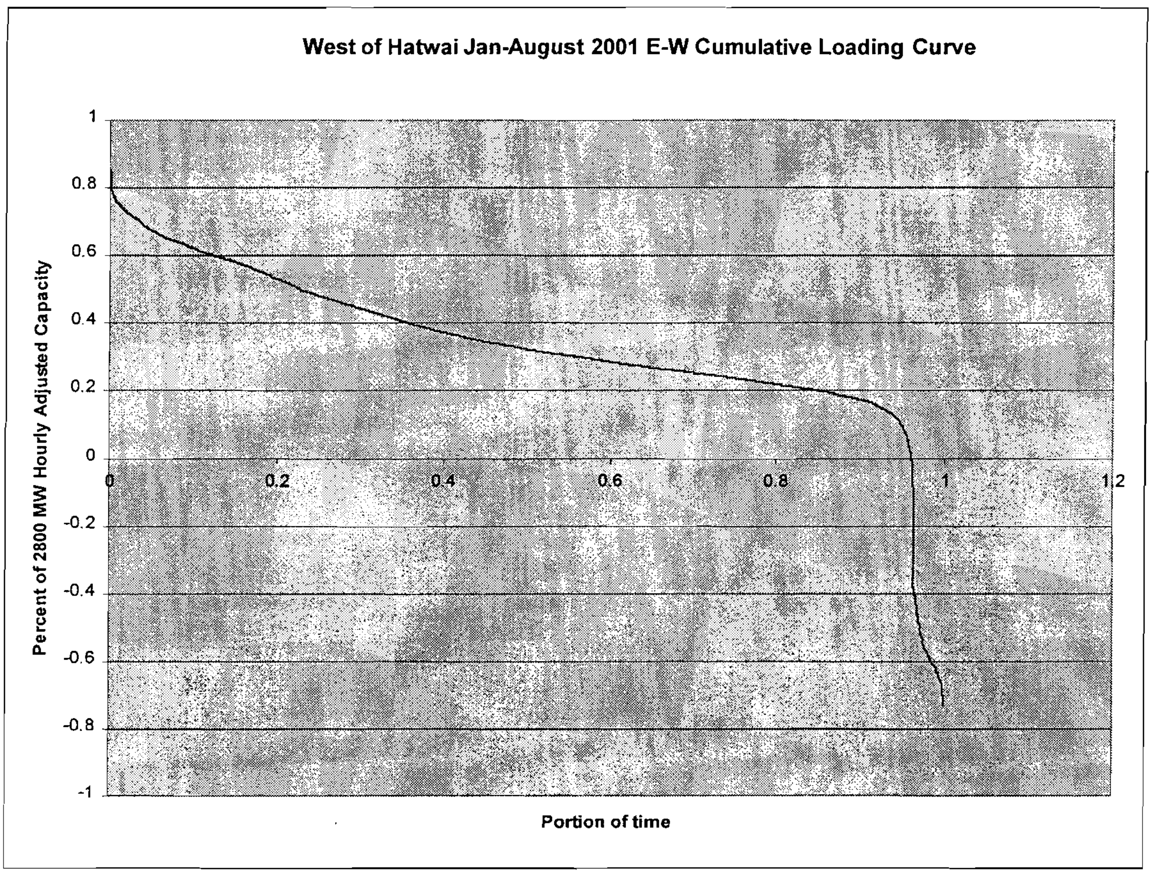


Figure 4. West of Hatwai path cumulative loading curve Jan-Aug 2001
(Negative flows mean power was flowing from west to east)

6. Grid Management By RTO West

Discussions have been underway for several years among the transmission owners and other stakeholders in the Northwest to have an independent body take over operation and control of access for the transmission system. This was 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.

Assumption of responsibility for grid management by RTO West 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. RTO West made its filing with FERC on March 29, 2002. Details of the filing can be found at http://www.rtowest.org/Stage2FERCFiling.htm.

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; and the alternatives for financing new transmission discussed in the Western Governors Association Transmission Study.

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. Further, 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 recently formed from a merger of the Western Systems Coordinating Council (WSCC) with several other transmission organizations.

WSCC was largely a creature of the transmission owning utilities. It historically was unsympathetic to applying cost-benefit considerations to the reliability criteria, although it recently convened a group to develop probablistic criteria that will likely be sensitive to economic concerns.

WSCC, at times, may have tightened reliability standards to increase reliability without regard to the impacts of its decisions. For example in 2001, WSCC set a 1000 foot separation rule for new transmission lines, precluding the use of existing corridors and rights of way for siting new lines adjacent to existing ones. In areas where siting opportunities are limited such a move may greatly increase the difficulty of building additional capacity.

WECC will have much broader representation on its board than the WSCC did, and will have 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 could be assigned to the congested hours only it is very likely cheaper alternatives to new 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.

Further, the recent proposed changes in WECC criteria, mentioned above, have increased the likelihood that new lines would have to open additional corridors instead of making use of existing corridors.

Cost. High voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may run over $1 million per mile. A double-circuit 500 kV line may cost around $1.5 to $1.75 million 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 a bit cheaper 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.

Capacity for new generation in Montana. There is considerable interest in Montana in building in-state energy facilities as an economic development tool. The lack of available transmission capacity to reach west coast markets may be a significant barrier. As discussed above, there is a considerable 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.

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

Many of the electricity generation plants proposed for Montana are planning to use natural gas. At the same time, natural gas is a major source of energy for Montana's homes and industries. This paper lays out the history and current trends in natural gas use in Montana. These are set in the context of the U.S. natural gas industry. Montana is part of a continental 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, the price and availability of gas are already moving in ways Montanans have not previously experienced.

1. Natural Gas Supplies for Montana and the U.S.

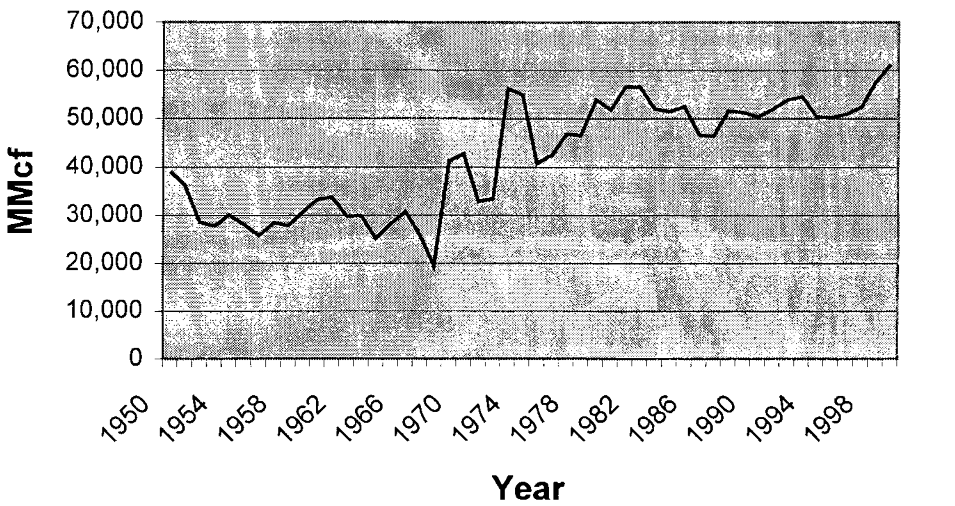
Alberta is by far the largest source of natural gas for Montana. The next largest source is in-state wells mostly located in the north-central portion of the state. Supplies from the other Rocky Mountain states represent only a small portion of total in-state usage and continue to decline from historic levels.

Future changes in supplies from in-state development and other states are uncertain at this point. Coal bed methane (CBM) may eventually increase the portion of gas that comes from the Rocky Mountain states, especially Colorado and Wyoming, but the peak of that production is still a few years off. CBM development in Montana has not yet become significant, due in part to difficult environmental issues, and is still in the permitting stage. The future extraction of existing gas reserves along Montana's Rocky Mountain Front also is uncertain at this point. Alberta's natural gas supply will likely remain the largest source for Montana in the years to come.

Montana actually produces about as much gas as it consumes, but the bulk of that is exported. In 1999, Montana produced 61.6 billion cubic feet (bcf) and exported 51.8 bcf total to North Dakota, South Dakota and the Midwest. The north-central portion of the state accounted for 80 percent of Montana's production, and the northeastern portion of the state another 11 percent (MBOGC 2001). In-state production has been increasing in recent years (Figure1, below). Because most of it is exported, however, efforts to increase (or decrease) natural gas production in Montana may not have much impact on Montana consumers.

U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. About half of U.S. reserves are in Texas, Louisiana and offshore in the Gulf of Mexico. About a quarter are in the Rocky Mountain states of New Mexico, Wyoming, and Colorado. The Rocky Mountain states are the most important source of domestic natural gas supply to the Pacific Northwest. Alaska's North Slope is potentially the largest source of new natural gas resources for the nation as a whole (U.S. EIA 2001c).

Fig. 1. Marketed Gas Production in Montana (1950-1999)



Source: U.S. EIA, Natural Gas Annual Reports, 1950-1999 (Table NG1).

After declining during the 1990s, natural gas drilling in the U.S. picked up dramatically in early 2000 in response to higher prices, only to recently fall off again as prices returned to their historic levels. Domestic natural gas production, with its large and accessible resource base, is expected to increase from 18.7 trillion cubic feet (tcf) in 1999 to 29.0 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 (U.S. EIA 2001c).

In 2000, the United States imported 3.6 tcf of natural gas from Canada; 0.5 tcf of this Canadian supply was imported to the Pacific Northwest. Net natural gas imports are expected to increase from 3.4 tcf in 1999 to 5.8 tcf in 2020 (U.S. EIA 2001c). Alberta, which contains a significant share of Canadian 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 through the Alliance and Northern Border pipelines. The Northern Border is the largest pipeline that passes through Montana in the northeast part of 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).

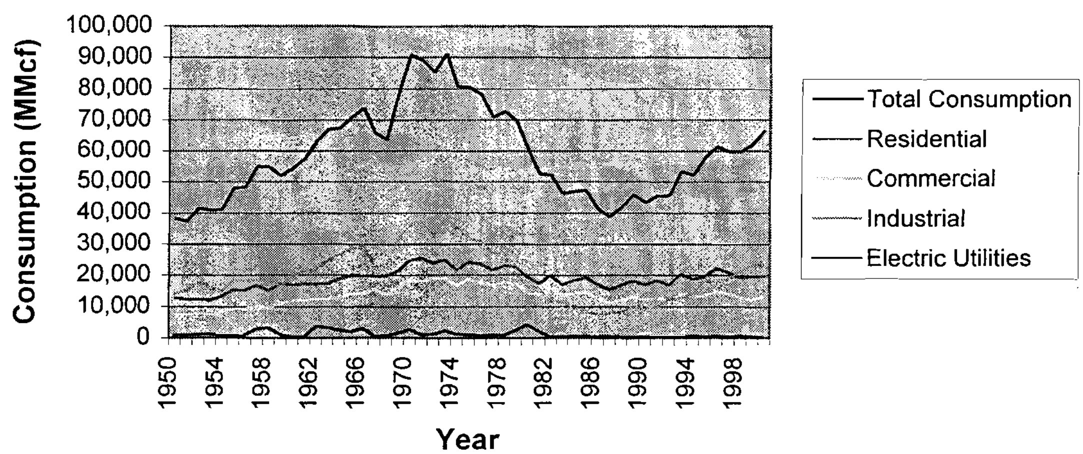
All of these Alberta lines tie in with the large Trans-Canadian Pipeline that runs east to west across Canada.

It is hard to predict how much natural gas is left for U.S. consumption from North American reserves. Reserves are constantly being consumed and replaced and the relative rates of consumption and replacement vary with economic conditions and natural gas prices. The Northwest Power Planning Council estimates between 2,100 and 2,650 tcf remaining of North American gas reserves (excluding Mexico). 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). The entire world is estimated to contain 13,000 tcf in natural gas reserves with much of that located in the Middle East (Morlan 2001).

2. Natural Gas Consumption in Montana

Recent Montana natural gas consumption has been around 60 billion cubic feet (bcf) per year. Future Montana natural gas consumption, excluding that for new electric generation, is expected to increase slowly at less than 1 percent annually according to utility projections. The reason for this slow expected increase is illustrated in Figure 2. Both residential and commercial gas consumption are expected to grow very slowly, and usage by industry is expected to stay fairly level. In the 1970's, the 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.

Fig. 2. Natural Gas Consumption in Montana



Source: U.S. EIA, *Natural Gas Annual Report*, 1950-1999 (Table NG2).

With projected new gas-fired electric generation, total gas consumption in Montana is expected to significantly increase over current levels. The Montana First Megawatts gas-fired electric generation plant, which is currently under construction in Great Falls, will create a significant increase in total Montana annual consumption. Average new usage by this plant could be up to 13 bcf per year once the first 160 MW are built. This is about 20 percent of the current total consumption in Montana. If the Silver-Bow electrical generation plant comes on line its estimated 30 bcf per year would equal almost 50 percent of current total Montana consumption.

3. Natural Gas Consumption in the U.S.

In 2000, the U.S. consumed over 22 trillion cubic feet (tcf) of natural gas, the highest level ever recorded. U.S. consumption is increasing at a healthy pace, and the Pacific Northwest is no exception. Three reasons for increased use in the Pacific Northwest are ample, attractively priced supplies, strong economic growth and increased gas-fired electrical generation. The EIA forecasts that U.S. total natural gas consumption will increase from the current level of about 22 trillion cubic feet per year to nearly 35 trillion cubic feet per year in 2020 (U.S. EIA 2000).

A number of changes in energy markets, policies, and technologies have occurred which explain the increased use of natural gas in the U.S. in the past 15 years (U.S. EIA 2001c):

- Deregulation of wellhead prices begun under the Natural Gas Policy Act of 1978 and accelerated under the Natural Gas Wellhead Decontrol Act of 1989;
- Federal Energy Regulatory Commission (FERC) Orders 436 (1985), 636 (1992), and 637 (2000) separating natural gas commodity purchases and transmission services and affecting access to shipping capacity;
- Passage of the Clean Air Act Amendments of 1990 and subsequent regulations affecting air quality standards for industries and electricity generators in nonattainment areas favor 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. Over 95 percent of new electric generation in the western U.S. is gas fired;
- Improvements in exploration and production technologies and 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.

All of these Alberta lines tie in with the large Trans-Canadian Pipeline that runs east to west across Canada.

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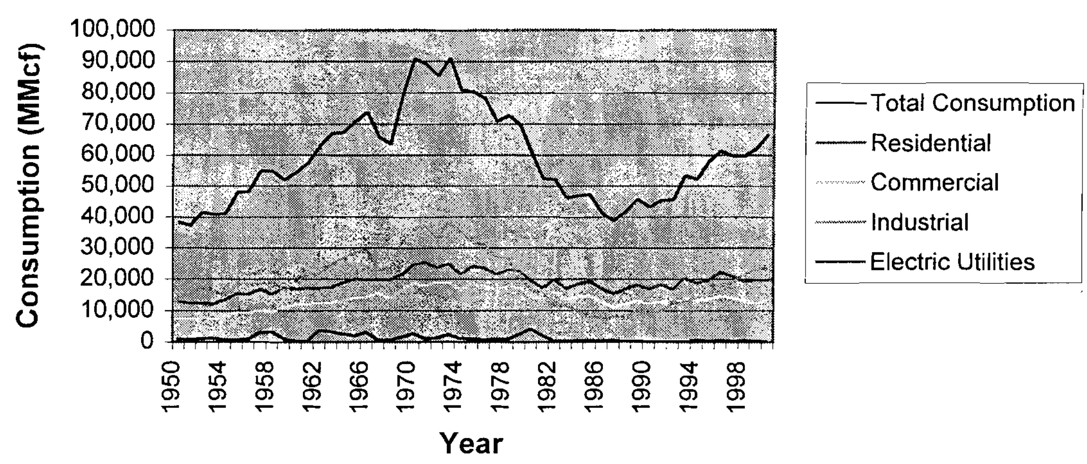

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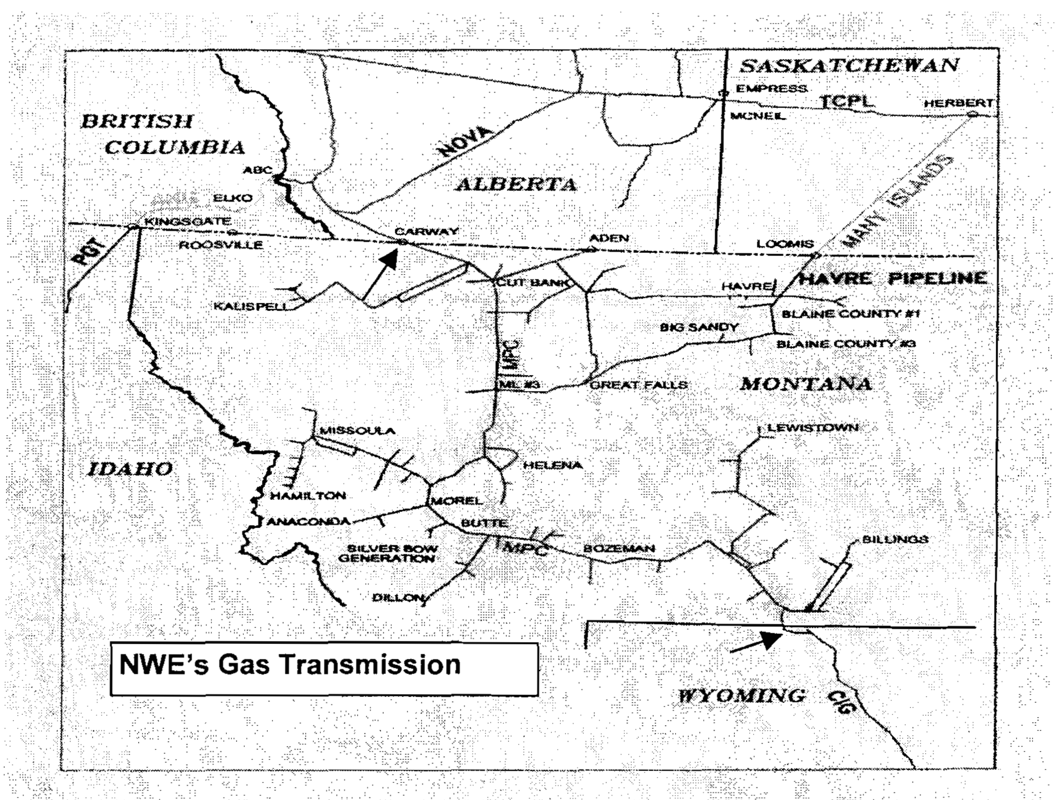
4. Montana's Natural Gas System

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 transmission. NWE and 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 is the largest provider of natural gas in Montana accounting for about 60 percent of all sales in the state according to annual reports from Montana utilities. NWE provides natural gas transmission and distribution services to 151,000 natural gas customers in the western two-thirds of Montana. These customers include residences, commercial businesses, municipalities, state and local governments and industry. Northwestern's gas transportation system, both long-distance pipeline transmission and local distribution, lies entirely within Montana. Therefore, it is regulated by the Montana Public Service Commission and not FERC. The system consists of over 2,100 miles of transmission pipelines, 3,300 miles of distribution pipelines and three in-state storage facilities. Northwestern'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.



NWE's Gas Transmission

Alberta sends natural gas to Montana primarily through Northwestern Energy's pipeline at Carway where it ties in with Alberta's NOVA Pipeline. 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, 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.

A majority of Northwestern's natural gas comes from Alberta. The total NWE system has a daily peak capacity of 300 million cubic feet of gas (MMcf). The system delivers about 40 billion cubic feet (bcf) of gas throughput per year to its customers compared with total annual Montana consumption of about 60-65 bcf. About one half of the total throughput 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 is used by non-core users including industry, local and state governments and by Energy West, which supplies Great Falls. NWE only provides delivery service for these customers; they contract on their own for their gas supply. Peak 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).

There is no unused firm capacity on the NWE system. This means that no one else of significant size, such as a large industrial company, can obtain guaranteed, uninterrupted gas delivery on the current system. By 2003, customer peak daily demand on the system will be an estimated 300 mmcf, and the system's maximum daily capacity will be matched by peak demand. At that time, the system will have to expand to meet its projected peak load. The projected growth rate of maximum daily load and thus of required daily pipeline capacity, excluding the proposed Silver-Bow plant and the Montana First Megawatts plant, is 1.7 percent annually or 5 mmcf/day annually. This growth would 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) will require pipeline upgrades beyond those already needed in 2003. The same is true for the proposed 500 MW Silver-Bow plant near Butte.

Montana-Dakota Utilities Co. (MDU) is the second largest natural gas utility in Montana and accounts for about 25-30 percent of all gas sales in Montana. It distributes natural gas to most of the eastern third of the state—Billings and areas further east. MDU uses the Williston Basin Interstate/Warren (WBI) line 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. MDU buys a certain amount of pipeline capacity on the WBI 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 sales (Ball 2001).

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. 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.

5. Natural Gas Prices in Montana and the U.S.

Natural 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 "citygate" price typically reflects the wellhead price *plus* pipeline transmission fees. The "delivered" 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. The delivered price for natural gas is currently at least twice the wellhead price in Montana. Thus, less than 50 percent of what residences pay in their gas bill typically is for the actual gas itself, although this varies greatly by location.

Natural gas prices in the marketplace 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. Futures prices 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 including the Gulf Coast, the U.S.-Canadian border and the Northeast. Prices are also measured for different end-user groups such as residential, commercial, or industrial consumers and electric utilities.

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. Because Montana continues to rely on Alberta for much of its natural gas, what happens with Alberta gas directly affects Montana.

Alberta basically 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, in turn, is determined 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. 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 basically sets the nationwide price. AECOC's price is often 20 to 30 cents cheaper per thousand cubic feet (Mcf) than the Henry Hub price due mainly to its geographic location. Using the AECOC, gas can be bought in spot or futures markets (Morris 2001).

Increases in demand for Alberta gas tend to cause contracted gas prices to rise in Montana, all else being equal. Conversely, as exploration and drilling increase and 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.

6. Future Price Increases and Price Volatility

The wellhead price Montana pays for gas is likely to remain fairly close (within the 30 cent differential mentioned above) to average U.S. prices on the national market. Average U.S. wellhead prices are expected to increase about 3 percent annually in the next 20 years. They are expected to average $2.04/Mcf in 2002 and $3.20-$3.70/Mcf in 2020 using current dollars (U.S. EIA 2001c). This modest increase will 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 current U.S. price is in the $2.50-$3.00/Mcf range. In contrast, the average U.S. gas price for 2001 was just over $4.00/Mcf at the wellhead due in part to the energy crisis in California.

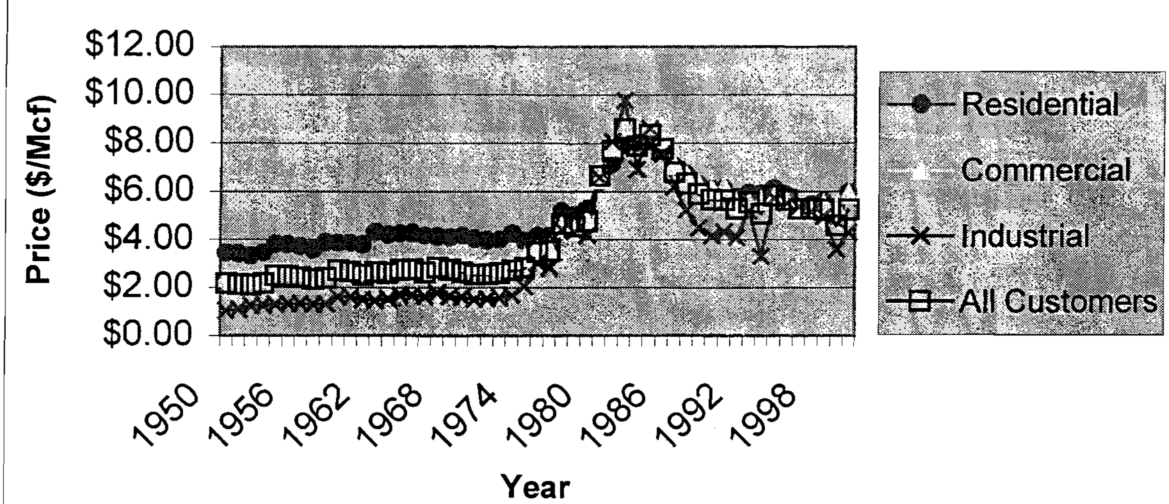
The Northwest Power Planning Council predicts that prices in our region in the long-term will be about $0.30/Mcf below national prices due to AECOC's price differential with Henry Hub. It is likely that any price differential will partially depend both upon how much Canadian supply is available and how 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 project built in Montana such as the proposed Silver-Bow plant should have no significant effect on the Alberta gas price and thus no long-term effect on Montana's price (Smith 2001).

The U.S. Energy Information Administration, in its current short-term outlook, predicts that wellhead natural gas prices over the next five months should remain in the $2-$3 range, with prices easing toward the lower end of that range during the off-season in 2002. The U.S. EIA predicts that the relatively low gas prices should persist throughout 2002 due to weak industrial demand and relatively high gas inventories that are likely to continue throughout the winter, assuming normal weather and barring any major supply disruptions. Expected reductions in gas drilling due to currently falling prices, are likely to produce an increase in natural gas prices going into 2003, especially if the U.S. economy stages a solid economic recovery beginning by mid 2002 (U.S. EIA 2002). Wellhead prices in winter 2001-2002 are projected to be less than half the price they were last winter. In 2002, EIA expects gas inventories to remain at relatively high levels and expects the average annual wellhead price to be about $2.04/Mcf or about 50 percent of 2001 levels (U.S. EIA 2001c).

The final delivered price Montana customers pay (wellhead fees + transmission fees + delivery and other fees) is likely to be significantly lower than average U.S. prices due mainly to relatively low transmission fees in this state since we live fairly close to large gas producing regions in Alberta. Average delivered natural gas prices for the U.S. are forecast to increase slowly over the next 20 years at a rate of about 0.5 percent per year. Montana residences can expect to pay a home delivered price of around $5.00-$5.50/Mcf through 2010 (in current dollars), while the average U.S. residence can expect to pay $6.00-$7.00/Mcf (U.S. EIA 2001c). These forecasts represent long-term averages.

Despite slow expected price growth over the next 20 years, many Montanans will likely see an increase in their gas bill in July 2002. Although NWE currently has access to inexpensive Alberta gas, these low price contracts for its core customers will end June 30, 2002. At that time,

Fig. 3. Price of Natural Gas in Montana (Adjusted for Inflation--2000 dollars)



Source: Table NG3.

NWE may not be able to secure such low prices and its Montana customers may have to pay gas prices closer to average U.S. prices than at present. This could lead to an increase in gas bills for NWE customers, all else equal. (Smith 2001).

Figure 3 shows *delivered* natural gas prices in Montana adjusted for inflation and reported in 2000 dollars. These are the prices that residents and businesses see in their final energy bill reflecting all charges. It is clear that prices for all consumer classes including residential, commercial and industrial, were relatively low in real dollars (below $4/Mcf) until the 1980's. Prices then rose in the mid-80's and have since settled in the $5-6 range. Natural gas still remains a relatively inexpensive way to perform certain services such as heating one's home.

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 last year. One reason for this is the increased pipeline capacity from Alberta out to the U.S. Midwest and East Coast. This increased capacity means that the wellhead price paid in Montana today is closely tied to 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 Northeast that drain storage fields and compete for gas with new gas-fired generators from California to Florida (WA OTED). Events outside of Montana will affect prices in Montana more than ever before.

Price volatility also can be expected due to increased use of natural gas nationwide for electric generation. Wholesale electric and natural gas prices are becoming intimately linked. 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. Increases in the price of electricity nationwide could increase the demand for and price of natural gas as occurred in 2000-2001. Gas prices rose 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).

All of these factors affected gas prices in parts of Montana and much of the U.S. During 1998 and 1999, wellhead gas prices hovered around $2.00/Mcf at the Henry Hub. In the summer of 2000, wellhead prices had increased to about $3.60/Mcf and then shot up to $5/Mcf in the fall. This was more than double the average spot price a year earlier. In late November, gas spot prices moved past $6/Mcf, reaching as high as $10.53 on December 29, 2000. Since that point spot wellhead prices have fallen and are back down to "normal" levels under $3 on the NYMEX.

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 that runs directly from Alberta and Wyoming will likely not be as strained. Thus, Montana will likely experience more moderate price fluctuations than in other areas of the U.S.

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 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, at least partially because of the hedge that fixed-priced wind power could provide against volatile natural gas prices. 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. BPA, for example, announced that its conservation and renewables discount plan would begin several months earlier than previously planned.

The California energy crisis and high gas prices during that time 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. 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 be equal to the cost of new sources of gas.

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Table NG1. Natural Gas Production and Average Wellhead Price, 1950-1999

	Federal Statistics			
Year	Gross Withdrawal[1] (MMcf)	Marketed Production[2] (MMcf)	Average[3] Wellhead Price ($ per Mcf)	Gross Value of Montana Production (thousand $)
1950	40,975	38,972	$0.053	$2,066
1951	36,897	36,225	0.055	1,992
1952	29,140	28,557	0.061	1,742
1953	28,245	27,736	0.059	1,636
1954	30,532	30,087	0.068	2,046
1955	28,841	28,100	0.067	1,883
1956	26,852	25,706	0.068	1,748
1957	30,830	28,481	0.072	2,051
1958	30,830	27,836	0.068	1,893
1959	32,819	30,575	0.075	2,293
1960	37,792	33,235	0.071	2,360
1961	36,798	33,716	0.074	2,495
1962	32,621	29,791	0.074	2,205
1963	31,228	29,862	0.075	2,240
1964	26,653	25,050	0.078	1,954
1965	29,800	28,105	0.082	2,305
1966	36,048	30,685	0.083	2,547
1967	31,610	25,866	0.084	2,173
1968	32,229	19,313	0.091	1,757
1969	68,064	41,229	0.102	4,205
1970	48,302	42,705	0.103	4,399
1971	38,136	32,720	0.121	3,959
1972	38,137	33,474	0.123	4,117
1973	60,931	56,175	0.236	13,257
1974	59,524	54,873	0.253	13,883
1975	44,547	40,734	0.433	17,638
1976	45,097	42,563	0.445	18,941
1977	48,181	46,819	0.719	33,663
1978	48,497	46,522	0.847	39,404
1979	56,094	53,888	1.211	65,258
1980	53,802	51,867	1.454	75,415
1981	58,502	56,565	1.909	107,983
1982	58,184	56,517	2.145	121,229
1983	53,516	51,967	2.410	125,240
1984	52,930	51,474	2.460	126,626
1985	54,151	52,494	2.390	125,461
1986	48,246	46,592	2.050	95,514
1987	47,845	46,456	1.800	83,621
1988	53,014	51,654	1.700	87,812
1989	52,583	51,307	1.550	79,526
1990	51,537	50,429	1.790	90,268
1991	53,003	51,999	1.660	86,318
1992	54,810	53,867	1.620	87,265
1993	55,517	54,528	1.550	84,518
1994	51,072	50,416	1.460	73,607
1995	50,763	50,264	1.360	68,359
1996	51,668	50,996	1.410	71,904
1997	53,621	52,437	1.590	83,375
1998	59,506	57,645	1.530	88,197
1999	61,545	61,163	1.680	102,754

[1] Gross Withdrawal includes marketed production, plus quantities used in re-pressuring, plus quantities vented and flared from both gas and oil wells.

[2] Marketed Production represents gross withdrawals of natural gas from gas and oil wells minus gas used for repressuring, nonhydrocarbon gases removed, and quantities vented and flared. For 1979 and prior years, the volumes of nonhydrocarbon gases included in marketed production were not reported. For 1980 and 1981, the amount of nonhydrocarbon gases removed was not available for the Montana data, so the Department of Energy used the same figure for Montana's marketed production including nonhydrocarbon gases as is used for marketed production excluding nonhydrocarbon gases.

[3] Average wellhead price is computed by dividing the gross value of the gas produced by the respective volume produced.

Sources: U.S. Department of Interior, Bureau of Mines, *Mineral Industry, Natural Gas Production and Consumption Annual Report*, 1950-75; U.S. Department of Energy, Energy Information Administration, *Natural Gas Production and Consumption Annual Report*, 1976-79 (EIA-0131); U.S. Department of Energy, Energy Information Administration, *Natural Gas Annual*,1980-99 (EIA-0131).

Table NG2. Natural Gas Consumption by Customer Class, 1950-2000 (million cubic feet)

Year	Residential	Commercial[1,2]	Industrial[1,3]	Utilities	Consumption
1950	12,596	7,536	13,979	892	38,333
1951	12,287	7,379	15,047	884	37,276
1952	12,263	7,794	17,422	998	41,545
1953	12,029	7,544	16,559	1,237	40,953
1954	13,314	8,277	14,909	601	41,002
1955	15,335	9,427	18,240	630	47,861
1956	15,235	9,314	18,226	876	48,305
1957	16,725	10,116	18,429	2,954	54,868
1958	14,970	9,546	18,960	3,183	54,725
1959	17,310	11,124	16,438	1,005	51,898
1960	16,825	11,820	19,558	339	54,271
1961	17,086	12,140	21,404	354	57,465
1962	17,078	12,302	21,713	3,692	62,952
1963	17,274	12,569	24,613	3,285	66,969
1964	18,792	13,059	26,419	2,437	67,282
1965	19,908	14,110	28,310	1,992	70,895
1966	19,690	14,068	29,571	2,977	73,829
1967	19,756	15,516	22,584	502	65,782
1968	19,711	13,651	23,155	631	63,642
1969	21,463	16,593	31,917	1,520	78,988
1970	24,794	18,564	36,105	2,529	90,823
1971	25,379	18,109	36,800	1,075	89,021
1972	23,787	19,151	33,192	1,218	85,161
1973	24,923	19,143	37,898	2,322	91,148
1974	21,590	16,602	35,202	1,111	80,766
1975	24,097	18,654	31,631	1,059	80,351
1976	23,525	17,831	31,049	709	78,094
1977	21,596	16,706	27,260	953	70,956
1978	22,944	17,766	26,686	909	72,649
1979	22,579	17,396	20,411	2,320	69,805
1980	19,296	14,265	16,717	4,182	60,724
1981	17,245	13,725	15,494	2,069	52,452
1982	19,989	15,987	11,574	337	52,208
1983	16,967	13,534	11,798	335	46,249
1984	18,443	14,256	9,855	360	46,864
1985	19,371	14,820	8,220	468	47,265
1986	16,822	12,536	7,507	407	41,148
1987	15,359	10,989	7,861	478	38,786
1988	16,900	12,041	8,360	286	41,825
1989	18,195	13,141	9,903	336	45,756
1990	16,850	12,164	9,424	418	43,169
1991	18,413	12,848	9,873	268	45,402
1992	16,673	11,559	12,218	220	45,561
1993	20,360	13,884	12,690	270	53,298
1994	18,714	12,987	13,940	632	52,058
1995	19,640	13,497	18,135	388	57,827
1996	22,175	14,836	18,103	470	61,399
1997	21,002	13,927	18,766	420	59,827
1998	19,172	12,961	21,416	522	59,817
1999	19,676	12,095	23,036	289	62,093
2000	19593	13,298	23,195	NA	66,542

NA: Not available due to problems with data reporting under utility deregulation.

[1] Other consumers, including deliveries to municipalities and public authorities for institutional heating, street lighting, etc., were included in the industrial category prior to 1967. From 1967 on, other consumers were included in the Commercial category.

[2] Beginning with 1990 data, Commercial volumes include natural gas delivered for vehicular fuel use.

[3] Industrial use includes refinery use of gas, but excludes pipeline fuel.

[4] Total Consumption includes total gas delivered to consumers, plus lease and plant fuel, plus pipeline fuel.

Sources: U.S. Department of Interior, Bureau of Mines, *Mineral Industry Surveys, Natural Gas Production and Consumption*, annual reports for 1950-75; U.S. Department of Energy, Energy Information Administration, *Natural Gas Production and Consumption*, annual reports for 1976-79 (EIA-0131); U.S. Department of Energy, Energy Information Administration, *Natural Gas Annual*, annual reports for 1980-99 (EIA-0131); U.S. Department of Energy, Energy Information Administration, *Natural Gas Monthly,* Sept. 2001 and Feb. 2002.

Table NG3. Average Natural Gas Prices by Customer Class,[1] 1950-2000

Year	Price by Customer Class (dollars per thousand cubic feet)			
	Residential	Commercial	Industrial	All Customers[2]
1950	0.473	0.328	0.142	0.301
1951	0.510	0.351	0.160	0.320
1952	0.507	0.352	0.192	0.324
1953	0.531	0.368	0.194	0.337
1954	0.589	0.415	0.201	0.388
1955	0.583	0.411	0.202	0.380
1956	0.585	0.412	0.206	0.382
1957	0.583	0.413	0.208	0.380
1958	0.647	0.443	0.218	0.401
1959	0.647	0.457	0.267	0.456
1960	0.660	0.464	0.274	0.454
1961	0.655	0.459	0.257	0.438
1962	0.752	0.506	0.251	0.464
1963	0.746	0.507	0.268	0.462
1964	0.763	0.533	0.303	0.495
1965	0.781	0.541	0.311	0.506
1966	0.779	0.543	0.304	0.495
1967	0.796	0.571	0.341	0.546
1968	0.822	0.603	0.326	0.554
1969	0.882	0.643	0.338	0.562
1970	0.907	0.659	0.339	0.572
1971	0.934	0.685	0.357	0.603
1972	0.965	0.691	0.381	0.630
1973	1.086	0.804	0.425	0.698
1974	1.119	0.926	0.580	0.804
1975	1.296	1.101	0.949	1.089
1976	1.364	1.187	0.930	1.164
1977	1.816	1.584	1.558	1.641
1978	1.894	1.646	1.642	1.720
1979	2.213	2.002	1.749	2.004
1980	3.053	3.117	3.143	3.182
1981	3.754	4.138	4.258	4.057
1982	4.460	4.874	5.488	4.829
1983	4.627	5.065	3.990	4.561
1984	4.861	5.242	5.173	5.025
1985	4.813	5.094	4.706	4.845
1986	4.446	4.476	3.913	4.312
1987	4.410	4.340	3.420	4.160
1988	4.300	4.300	3.080	4.040
1989	4.370	4.360	2.980	4.080
1990	4.590	4.640	3.270	4.260
1991	4.520	4.350	3.220	4.160
1992	4.800	4.460	4.190	4.510
1993	4.920	4.670	2.760	4.250
1994	5.230	4.910	4.910	4.990
1995	5.150	4.920	4.870	4.980
1996	4.860	4.640	4.880	4.790
1997	5.050	4.830	4.790	4.900
1998	5.250	5.130	4.680	4.960
1999	5.160	5.130	3.440	4.420
2000	5.930	5.860	4.290	5.240

1 Average prices were computed by dividing the annual value of natural gas consumed by a customer class by the respective annual volume of natural gas consumed.

2 The All Customers category includes all the consumers in Table NG2.

Sources: U.S. Department of the Interior, Bureau of Mines, Mineral Industry Surveys, *Natural Gas Production and Consumption*, annual reports for 1950-75; U.S. Department of Energy, Energy Information Administration, *Natural Gas Production and Consumption*, annual reports for 1976-79 (EIA-0131); U.S. Department of Energy, Energy Information Administration, *Natural Gas Annual*, annual reports for 1980-1999 (EIA-0131); U.S. Department of Energy, Energy Information Administration, *Natural Gas Monthly*, Sept. 2001 (EIA-0131).

Table NG4. Average Natural Gas Consumption and Annual Cost per Consumer, 1980-1999[1]

Year	Residential		Commercial		Industrial[2]	
	Average Consumption (Mcf)	Average Annual Cost (dollars)	Average Consumption (Mcf)	Average Annual Cost (dollars)	Average Consumption (Mcf)	Annual Cost (dollars)
1980	117	356	670	2,089	32,841	103218
1981	104	389	610	2,523	31,364	133,551
1982	121	538	780	3,800	24,013	131,770
1983	102	470	651	3,298	25,048	99,956
1984	110	534	679	3,558	21,013	108,703
1985	115	555	706	3,595	17,908	84,267
1986	100	445	597	2,672	16,869	66,006
1987	91	404	514	2,231	18,072	61,806 E
1988	98	423	541	2,329	19,219	59,195 E
1989	106	464	591	2,579	23,138	68,951 E
1990	97	444	521	2,419	20,622	67,434 E
1991	104	468	554	2,411	21,842	70,331 E
1992	91	439	490	2,185	26,620	--
1993	108	--	569	--	27,469	--
1994	96	--	512	--	30,773	--
1995	96	--	512	--	39,168	--
1996	108	--	562	--	38,848	--
1997	100	--	507	--	40,619	--
1998	88	--	462	--	47,172	--
1999	--	--	425	--	58,025	--

[E] Estimate

[1] Starting in 1993, figures were no longer given for average cost. Starting in 1999, residential average consumption was no longer given.

[2] Beginning in 1987, industrial costs per consumer are estimated by DEQ using Department of Energy average prices of deliveries to industrial customers times industrial consumption volumes. The Department of Energy did not calculate these numbers in national statistics because values associated with gas delivered for the account of others are not always available. However, those values are not considered to be significant in Montana.

Source: United States Department of Energy, Energy Information Administration, *Natural Gas Annual*, annual reports for 1980-99 (EIA-0131).

Table NG5. Regulated Sales[1] of Natural Gas by Gas Utilities,* 1950-2000 (million cubic feet)

Note: The gas sales numbers in this table are significantly lower than the total gas consumption numbers in Table NG2 for several reasons. First, these sales data are taken from annual reports filed by utilities to the Montana Public Service Commission. The way utilities report gas sales to the PSC is different from the way in which Table NG2 total consumption numbers are calculated by the U.S. Energy Information Administration. Also, much of industrial consumption since 1991 is not reported in this table due to different reporting requirements and processes used by utilities since deregulation. These include the practice of not reporting gas used for pipeline transportation. This table does not include gas sales sold to other utilities for resale in Montana, lease and plant fuel, pipeline fuel, or fuel used by utilities.

	MONTANA POWER COMPANY[2]					MONTANA-DAKOTA UTILITIES[3]				
Year	Residential and Commercial	Industrial	Other	Total	% of Total Montana Sales	Residential and Commercial	Industrial	Other	Total	% of Total Montana Sales
1950	7,909	8,852	NA	16,761	54.2%	4,228	240	469	4,937	16.0%
1951	8,076	12,970	NA	21,046	59.3%	5,514	1,180	499	7,193	20.3%
1952	8,435	13,760	NA	22,195	62.0%	7,340	1,845	468	9,653	26.9%
1953	8,229	13,624	NA	21,853	61.9%	7,223	1,863	480	9,566	27.1%
1954	8,737	12,225	NA	20,962	59.3%	7,912	1,649	495	10,056	28.4%
1955	11,231	15,511	NA	26,742	63.9%	7,594	1,996	533	10,123	24.2%
1956	11,100	15,584	NA	26,684	63.4%	7,708	2,212	509	10,429	24.8%
1957	12,584	15,527	NA	28,111	64.4%	7,797	2,056	492	10,345	23.7%
1958	12,391	15,173	NA	27,564	62.7%	7,429	3,233	551	11,213	25.5%
1959	14,401	12,629	NA	27,030	59.6%	8,678	2,934	507	12,119	26.7%
1960	14,533	15,462	NA	29,995	62.3%	8,516	3,148	342	12,006	25.0%
1961	14,517	16,654	NA	31,171	62.7%	8,689	3,606	177	12,472	25.1%
1962	15,133	18,080	NA	33,213	64.1%	9,148	3,051	103	12,302	23.7%
1963	14,893	19,666	NA	34,559	64.6%	8,826	3,862	79	12,767	23.9%
1964	16,853	20,958	NA	37,811	64.1%	9,620	4,687	55	14,362	24.4%
1965	17,977	22,195	NA	40,172	63.9%	10,955	4,430	61	15,446	24.6%
1966	17,731	23,058	NA	40,789	65.2%	10,414	4,256	55	14,725	23.5%
1967	18,027	20,766	NA	38,793	64.5%	10,584	3,813	67	14,464	24.0%
1968	19,063	21,650	NA	40,713	64.6%	10,847	4,523	65	15,435	24.5%
1969	19,891	25,536	NA	45,427	64.2%	11,534	6,277	55	17,866	25.3%
1970	20,398	26,006	NA	46,404	62.9%	11,499	8,582	102	20,183	27.3%
1971	18,956	25,581	1,628	46,165	62.9%	11,612	8,317	139	20,068	27.3%
1972	20,068	26,128	1,491	47,687	62.4%	12,352	8,218	600	21,170	27.7%
1973	19,771	25,915	1,578	47,264	62.3%	11,525	8,685	1,415	21,623	28.5%
1974	18,931	26,301	1,408	46,640	63.4%	11,230	8,455	588	20,273	27.6%
1975	20,762	24,130	1,523	46,415	62.5%	12,779	7,774	NA	20,553	27.7%
1976	18,795	20,663	1,405	40,863	61.0%	12,208	7,100	NA	19,307	28.8%
1977	18,413	18,101	1,451	37,965	61.4%	11,898	5,923	NA	17,821	28.8%
1978	18,696	17,280	1,498	37,475	60.5%	13,784	3,981	NA	17,765	28.7%
1979	19,142	16,118	2,737	37,997	62.0%	13,500	3,480	NA	16,981	27.7%
1980	17,091	12,655	4,986	34,733	62.9%	11,332	3,627	NA	14,959	27.1%
1981	15,216	9,758	2,754	27,727	57.8%	10,312	5,307	NA	15,618	32.6%
1982	17,032	7,064	1,317	25,413	54.6%	12,228	4,148	60	16,436	35.3%
1983	14,606	6,829	1,152	22,587	54.8%	10,181	3,774	32	13,987	34.0%
1984	16,075	5.967	1,238	23,280	56.3%	10,744	2,451	59	13,254	32.1%
1985	16,916	6.043	1,271	24,230	58.3%	11,094	1,336	19	12,449	29.9%
1986	14,461	5,208	1,099	20,768	58.6%	9,191	607	15	9,813	27.7%
1987	14,090	5,358	748	20,196	62.6%	7,712	254	15	7,981	24.7%
1988	15,027	6,652	732	22,410	63.2%	8,285	475	17	8,776	24.8%
1989	16,771	7,050	771	24,592	64.0%	9,069	161	17	9,247	24.1%
1990	15,915	6,057	744	22,715	64.5%	8,192	54	17	8.262	23.5%
1991	16,522	4,980	683	22,185	62.2%	9,074	12	11	9,096	25.5%
1992	18,641	672	221	19,534	60.4%	8,290	4	13	8,307	25.7%
1993	21,216	756	1481	23,453	60.4%	9,927	12	8	9,947	25.6%
1994	19,680	603	499	20,782	59.5%	9,258	3	10	9,271	26.5%
1995	20,900	616	517	22,033	60.8%	9,345	NA	NA	9,345	25.8%
1996	23,414	681	599	24,694	61.1%	10,891	NA	NA	10,891	26.9%
1997	22,465	619	488	23,572	60.4%	10,148	NA	NA	10,148	26.0%
1998	19,298	309	294	19,901	58.4%	8,906	NA	NA	8,906	26.1%
1999	18,277	281	244	18,802	57.8%	8,906	NA	NA	8,906	27.4%
2000	18,382	211	282	18,875	58.1%	9,301	NA	NA	9301	28.6%

Table NG4. (continued)

Year	GREAT FALLS GAS COMPANY/ ENERGY WEST[4]					OTHER UTILITIES[5]		TOTAL SALES[6]			
	Residential and Commercial	Industrial	Other	Total	% of Total Montana Sales	Total for all Sectors	% of Total Montana Sales	Residential and Commercial	Industrial	Other	TOTAL
1950	2,509	208	53	2,770	9.0%	6,481	20.9%	21,127	9,300	522	30,949
1951	2,697	311	191	3,199	9.0%	4,055	11.4%	20,342	14,461	690	35,493
1952	2,566	228	333	3,127	8.7%	852	2.4%	19,193	15,833	801	35,827
1953	2,478	238	350	3,066	8.7%	814	2.3%	18,744	15,725	830	35,299
1954	2,795	255	400	3,450	9.8%	892	2.5%	20,336	14,129	895	35,360
1955	3,284	243	434	3,961	9.5%	1,049	2.5%	23,158	17,750	967	41,875
1956	3,361	204	396	3,961	9.4%	1,019	2.4%	23,188	18,000	905	42,093
1957	3,510	258	451	4,219	9.7%	955	2.2%	24,846	17,841	943	43,630
1958	3,365	268	475	4,108	9.3%	1,067	2.4%	24,252	18,674	1,026	43,952
1959	4,048	388	566	5,002	11.0%	1,175	2.6%	28,302	15,951	1,073	45,326
1960	3,928	512	516	4,956	10.3%	1,152	2.4%	28,129	19,122	858	48,109
1961	4,067	380	606	5,053	10.2%	1,045	2.1%	28,318	20,640	783	49,741
1962	4,092	371	752	5,215	10.1%	1,078	2.1%	29,451	21,502	855	51,808
1963	4,030	396	793	5,219	9.8%	945	1.8%	28,694	23,924	872	53,490
1964	4,446	480	847	5,773	9.8%	1,018	1.7%	31,937	26,125	902	58,964
1965	4,767	499	868	6,134	9.8%	1,160	1.8%	34,859	27,124	929	62,912
1966	4,593	490	846	5,929	9.5%	1,125	1.8%	33,863	27,804	901	62,568
1967	4,505	397	856	5,758	9.6%	1,160	1.9%	34,276	24,976	923	60,175
1968	4,504	424	852	5,780	9.2%	1,074	1.7%	35,488	26,597	917	63,002
1969	5,042	412	891	6,345	9.0%	1,118	1.6%	37,585	32,225	946	70,756
1970	4,926	378	902	6,206	8.4%	1,010	1.4%	37,833	34,966	1,004	73,803
1971	4,901	367	895	6,163	8.4%	1,048	1.4%	36,517	34,265	2,662	73,444
1972	5,185	353	884	6,422	8.4%	1,105	1.4%	38,710	34,699	2,975	76,384
1973	4,729	414	864	6,007	7.9%	982	1.3%	37,007	35,014	3,857	75,876
1974	4,504	412	807	5,723	7.8%	936	1.3%	35,601	35,168	2,803	73,572
1975	5,145	354	845	6,344	8.5%	1,000	1.3%	39,686	32,258	2,368	74,312
1976	4,875	237	892	6,004	9.0%	762	1.1%	36,640	28,000	2,297	66,936
1977	4,317	246	734	5,297	8.6%	715	1.2%	35,343	24,270	2,185	61,798
1978	4,818	196	826	5,840	9.4%	824	1.3%	38,122	21,457	2,324	61,904
1979	4,512	249	750	5,512	9.0%	804	1.3%	37,958	19,847	3,487	61,294
1980	3,888	266	689	4,842	8.8%	669	1.2%	32,980	16,548	5,675	55,203
1981	3,257	169	619	4,044	8.4%	573	1.2%	29,358	15,234	3,373	47,962
1982	3,289	188	627	4,104	8.8%	596	1.3%	33,145	11,460	1,944	46,549
1983	3,320	206	636	4,162	10.1%	446	1.1%	28,553	10,809	1,820	41,182
1984	3,531	256	530	4,317	10.4%	487	1.2%	30,837	8,674	1,827	41,338
1985	3,719	181	536	4,436	10.7%	474	1.1%	32,203	7,560	1,826	41,589
1986	3,538	285	592	4,415	12.5%	465	1.3%	27,655	6,100	1,706	35,461
1987	3,064	193	442	3,699	11.5%	388	1.2%	25,254	5,805	1,205	32,264
1988	3,189	170	499	3,858	10.9%	386	1.1%	26,887	7,296	1,247	35,431
1989	3,567	160	411	4,138	10.8%	427	1.1%	29,834	7,371	1,199	38,404
1990	3,381	78	401	3,860	11.0%	392	1.1%	27,879	6,189	1,162	35,230
1991	3,435	164	389	3,988	11.2%	400	1.1%	29,430	5,156	1,083	35,669
1992	4,139	0	NA	4,139	12.8%	373	1.2%	31,443	676	234	32,353
1993	4,478	0	490	4,968	12.8%	432	1.1%	36,053	768	1,979	38,800
1994	3,971	0	478	4,449	12.7%	443	1.3%	33,352	606	987	34,945
1995	3,942	0	464	4,406	12.2%	447	1.2%	34,634	616	981	36,231
1996	4,362	0	NA	4,362	10.8%	498	1.2%	39,165	681	599	40,445
1997	4,496	0	314	4,810	12.3%	504	1.3%	37,613	619	802	39,034
1998	3,535	0	1331	4,866	14.3%	418	1.2%	32,157	309	1,625	34,091
1999	3,401	0	996	4,397	13.5%	427	1.3%	31,011	281	1,240	32,532
2000	3,058	0	1009	4,067	12.5%	239	0.7%	30,980	211	1,291	32,482

NA Not Available

* See notes on following page.

Table NG4. (continued)

[1] Sales to other utilities for resale and sales of natural gas to Canada are not included.

[2] From 1950 to 1970, government and municipal sales were reported in the "Residential and Commercial" sector. "Other" includes interdepartmental use, sales to government and municipal authorities for heating, and special off-line sales to firms in Montana where these figures are reported separately.

The following 3 lines from Fran Balkovetz at MPC:

In 1991 is when MPC's Gas Utility started deregulating its customers. As a result, there have been changes in measured sales methodology from 1991 until present. This created differences after 1991 in how MPC's data is reported and is part of the reason why the numbers in the 'industrial' column decrease so sharply in 1992. It is very hard to reconcile these differences and thus the 1990's numbers are given as presented in Schedule 35.

In 1992, some customers in the 'industrial' category left MPC as a result of deregulation

In 1992 and 1993, Schedule 35 was not reported like in later years. In 1992, figures used are from Actual Billed Volumes supplied by Fran Balkovetz at MPC

[3] Prior to 1975 "Other" includes interdepartmental use and natural gas used in MDU's electric generating plants at Baker, Glendive, and Miles City. Company consumption and unbilled customer consumption as part of a lease agreement at Saco are not included

The 1975-81 data uses slightly different sector definitions; as a result, consumption in the "Other" sector is not shown separately for these years

Since 1982 "Other" includes interdepartmental sales.

From 1992-2000, amount sold is reported in Dekatherms rather than MCF. From 1995 on, amounts for industrial and other usage not reported by MDU.

[4] "Other" includes sales to Malmstrom Air Force Base and other public authorities.

In 1999, Great Falls Gas became Energy West.

[5] "Other Utilities" includes the following companies (listed in approximate descending order by volume of sales):

Cut Bank Gas Company	Supplies natural gas to Cut Bank; approximately 80 percent of its gas is purchased from the Montana Power Company/NorthWestern Energy.
Shelby Gas Association:	Supplies natural gas to Shelby; gas is purchased from the Montana Power Company/NorthWestern Energy.
Saco Municipal Gas Ser	Supplied natural gas to Saco from the town's own wells.
Consumers Gas Compa	Supplied natural gas to Sunburst and Sweetgrass; gas was purchased from the Montana Power Company and J.R. Bacon Drilling Company through the Treasure State Pipeline Company.

After 1991, Saco no longer reported any numbers and Consumers Gas was bought out by a municipal provider. Thus, those two are no longer added among "other utilities". No industrial numbers were given by any of these utilities after 1991.

Some of the smaller gas utilities have experienced problems measuring actual gas sales volumes. Therefore, the figures for these utilities should be considered estimates.

In the year 2000, Shelby did not report

[6] All gas sales from "Other" vary from utility to utility and from year to year, as indicated.

NOTE: Source documents from the Public Service Commission often report data at sales pressure rather than at a uniform pressure base. When necessary, the data were converted to the uniform pressure base of 14.73 psia at 60 degrees Fahrenheit using Boyle's law.

The source reports are for the companies' fiscal years ending during the year shown. Because reporting years vary from utility to utility, the data represent various twelve-month periods and are, in that sense, not strictly comparable.

The Saco Municipal Gas Service and the Cut Bank Gas Company have reporting years ending June 30. The Shelby Gas Association's reporting year ends September 30. The Consumer Gas Company, the Montana Power Company/NorthWestern Energy, and Montana-Dakota Utilities use calendar year reporting periods.

The Great Falls Gas Company used a calendar year reporting period through 1981; they filed a six-month report for the period January 1, 1982, through June 30, 1982, and then changed to a twelve-month reporting period ending June 30.

The 1982 figures were estimated by the sector averages from the 1981 and 1983 twelve-month reports. The 1983 figures and those for all subsequent years are based on twelve-month reports ending June 30 of that year.

SOURCE: Annual reports filed with the Montana Public Service Commission by the natural gas utilities (1950-00), supplemented by information obtained directly from the utilities. After 1993, schedule 35 of the annual reports of each utility was used.

Table NG6. Largest Natural Gas Users in Montana

Company	Industry	Location	5-year average nat. gas usage (unless otherwise noted)	2001 usage	2000 usage	1999 usage	1998 usage	1997 usage
			Million Cubic Feet (MMcf)					
Conoco[1]	Oil refinery	Billings	3,705	375	4,164	4,044	5,139	4,804
Stone Container	Pulp/paper mill	Missoula	2,053	1,163	1,787	2,433	2,506	2,374
Exxon Co. USA	Oil refinery	Billings	1042[2]	1,042[3]	0	0	0	0
Cenex Harvest States	Oil refinery	Laurel	792	718	785	1,157	520	780
Montana State University	Heating plant	Bozeman	324	316	328	324	324	330
Advanced Silicon Materials Inc.	Industrial manufacturing	west of Butte	304[4]	290	334	288	-[5]	-[5]
Barretts Minerals Inc.	Talc processing	Dillon	255	237	237	266	268	266
Asarco Inc. (closed Spring 2001)	Smelter	East Helena	241	81	320	228	268	308
MDU Glendive turbine	Electrical generation	Glendive	205[6]	NA	317	NA	NA	NA
Columbia Falls Aluminum Co.	Aluminum manufacturing	Columbia Falls	178	52[7]	193	212	200	235
Luzenac America Inc.	Talc processing	Three Forks	148	133	149	146	141	172
Corette	Electrical generation	Billings	110[8]	NA	NA	NA	NA	NA
MDU Miles City turbine	Electrical generation	Miles City	102[6]	NA	53	NA	NA	NA
American Chemet Corp.	Industrial manufacturing	East Helena	101	116	105	104	83	95

[1]Conoco switched from natural gas as a major fuel in its processes to fuel gas.
[2]One year average for 2001.
[3]This number includes natural gas fuel. Exxon used other types of gas to run their operations from 1997-2000, and avoided natural gas usage completely.
[4]Three year average from 1999-2001.
[5]ASIMI applied for their permit in 1997 and the first emission inventory was 1998. Therefore, there is no data for 1997.
[6]6-Year Average 1995-2000; EIA Form 906 database.
[7]Columbia Falls Aluminum was shut down for much of 2001.
[8]5-Year Average 1995-1999; EIA Form 906 database.

NOTE: Usage based upon annual process rate of particular industrial component that uses gas. Each facility reports their use rates of various fuel including natural gas, and those numbers are entered into the Emissions Inventory Reports. Usage rates for various fuels are reported by the company and they are the actual values for that year. In some cases, best professional judgement has to be made as to actual usage numbers based on the reports at hand. The biggest challenge was figuring out when actual natural gas was used as fuel as opposed to other types of gas.

Source: DEQ Air and Waste Management Bureau, Emissions Inventory Report, Point and Segment List (1997 to1999) taken from EPA's AIRS County Reports;DEQ Air and Waste Management Bureau, Emissions Inventory Summary (2000 and 2001); U.S. Department of Energy, Energy Information Administration, Form 906 database.

Coal in Montana

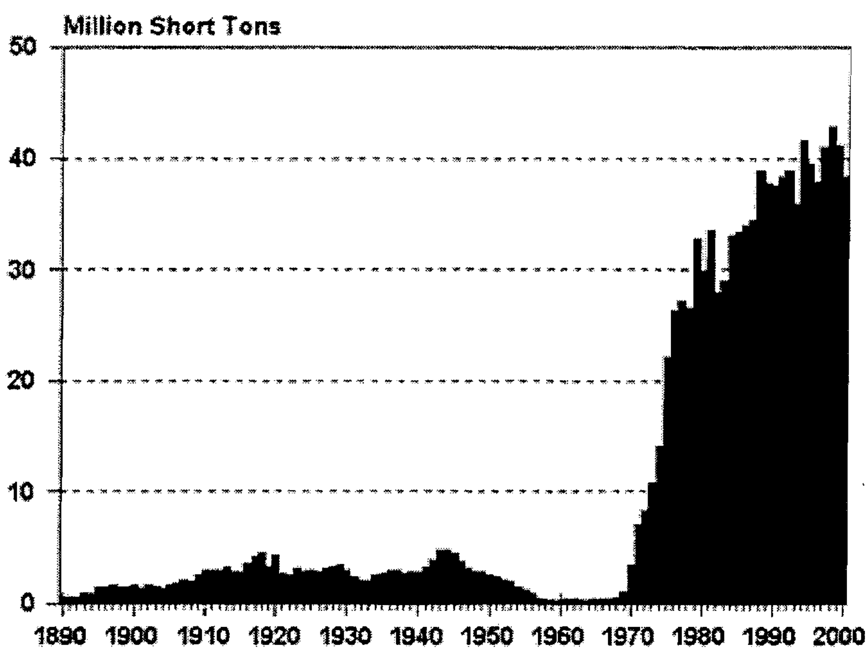
The Montana coal industry exists to support the generation of electricity. All but a tiny fraction of the coal mined in Montana eventually is converted to electricity. In recent years, over half the electricity generated in Montana has come from coal-fired plants. Almost three-quarters of the coal mined in the state is 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 the majority of the nation's electricity.

1. Production

Montana is the sixth largest producer of coal in the United States, with over 38 million tons mined in 2000 (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 Figure1). As steam locomotives were phased out, production declined, bottoming in 1958 (Table C2).

Figure 1. Historical coal production

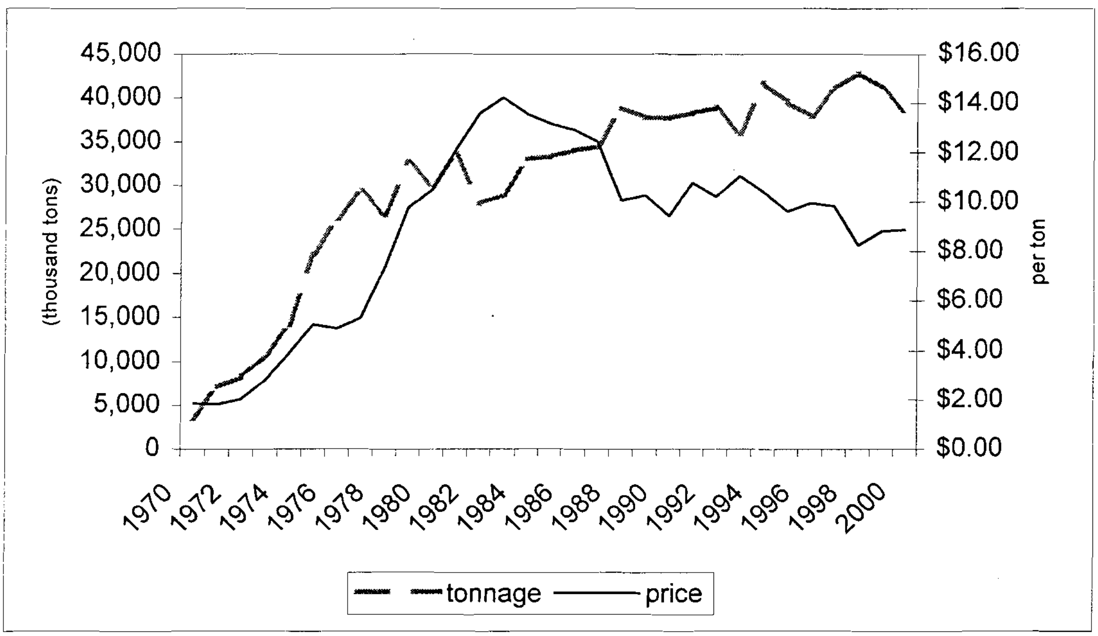


Source: United States Department of Energy, Energy Information Administration (http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/mt.htm)

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 has increased gradually to around 40 million tons (Table C2; see Figure2). Over the last decade, its modest increase in production allowed Montana to more or less maintain 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

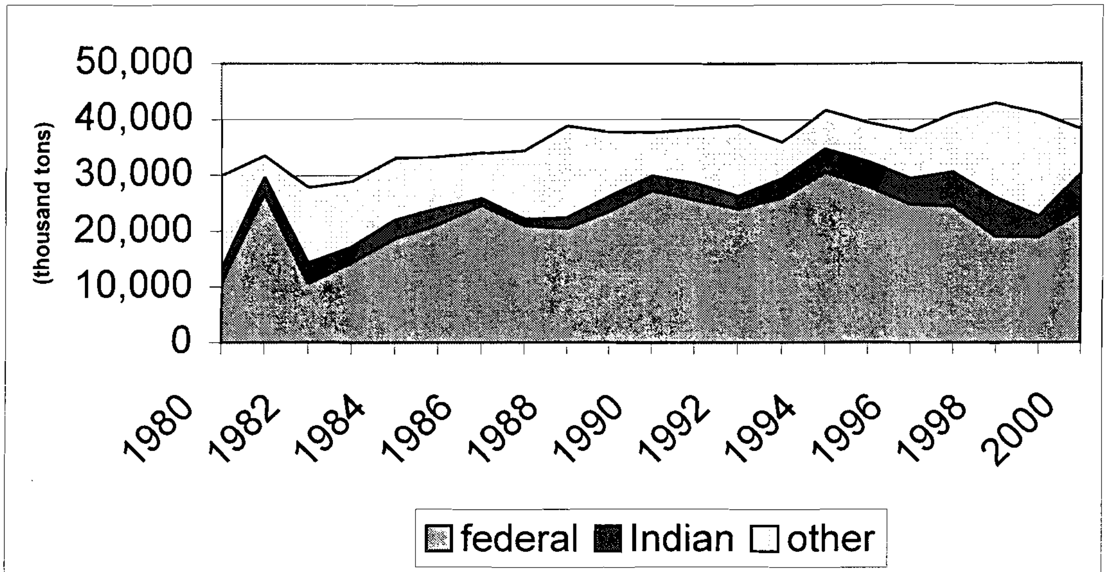


Source: Table C2.

The price of Montana coal averaged $8.87 per ton at the mine in 2000 (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 ($22.10 in 2000 dollars). By 2000 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 Figure3). A significant portion also comes from Indian reservations. In 2000 about 60 percent of Montana coal came from federal lands and under 20 percent from reservation lands.

Figure 3. Production by land ownership type



Source: Table C3

Montana had seven coal mines in operation in 2001 (Table C4). The largest were Westmoreland's Rosebud Mine at Colstrip and Kennecott Energy's Spring Creek Mine near Decker, each producing around 10 million tons per year. During the 1990's, the last Montana mine producing less than 100,000 tons annually closed. A proposed new mine at that site, near Roundup, is in the process of obtaining permits. No major new mines have opened since 1980, though the West Decker and Spring Creek mines have expanded significantly.

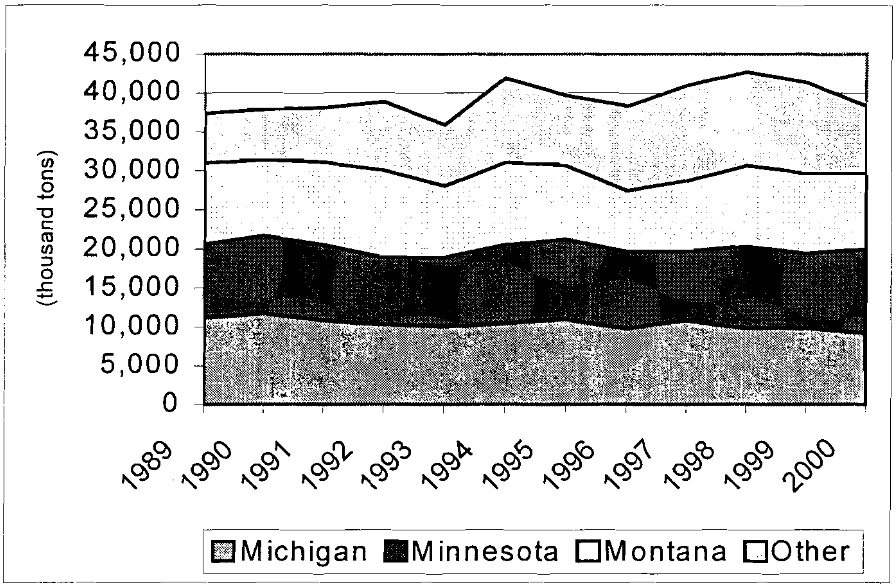
Westmoreland is the largest producer in Montana, accounting for 44 percent of 2001 production. Kennecott is the second largest, accounting for 25 percent of coal production outright and holding a half-interest in mines producing an additional 24 percent of Montana coal. 2001 marked the passing of an era in Montana coalfields. With Westmoreland buying Montana Power Company's Western Energy and MDU Resources Group's (Knife River Coal) Savage Strip Mine, 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 producer in the country in 1998.

2. Consumption

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

Almost all of Montana coal production is used to generate electricity (Table C6). In recent years, about 74 percent has been shipped by rail to out-of-state utilities, about 9 percent has been burned to produce electricity for in-state customers and about 15 percent had been burned to produce electricity and shipped by wire to out-of-state utilities. Over the last decade, Michigan, Minnesota and Montana have each taken about a quarter of all the coal produced in Montana (Table C7; see Figure 4). The remaining quarter has gone to 21 other states, Canada and overseas.

Figure 4. Destination for Montana coal



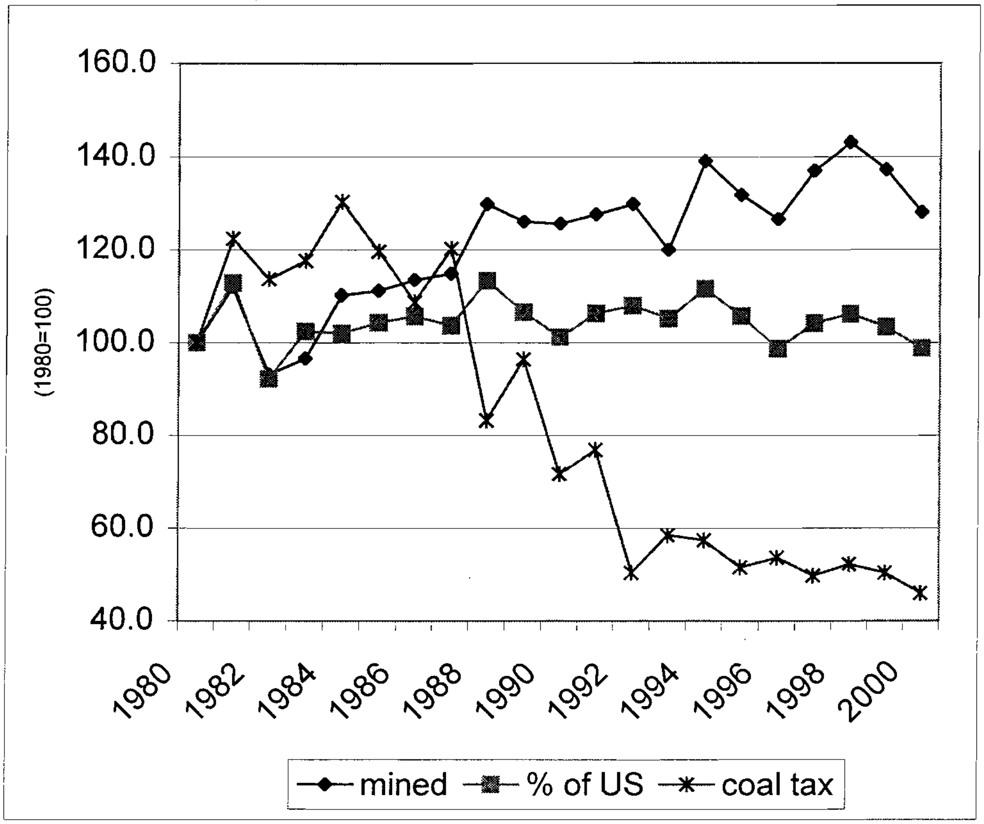
Source: Table C7.

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 $32.3 million collected in state fiscal year 2001 (July 2000-June 2001). That is about one-third in nominal terms the amount collected in 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 almost all of its share of the national market.

While significant, Montana's output is dwarfed by Wyoming, which produced 31.6 percent of the country's output in 2000. This is nine times as much coal as Montana produced. This probably is due 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 deeper than seams in Wyoming. Moreover, Wyoming coal has slightly higher average Btu content and slightly lower average ash and sulfur content than Montana coal.

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) now has 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).

Table C1. Coal Production by State and Coal Rank, 2000 (Thousand Short Tons)

Rank	State	Bituminous Production	Subbituminous Production	Lignite Production	Anthracite Production	Total Production	Percentage of U.S. TOTAL 2000	Percentage of U.S. TOTAL 1991
1	Wyoming	1,985	336,915			338,900	31.6%	19.5%
2	West Virginia	158,257				158,257	14.7%	16.8%
3	Kentucky	130,688				130,688	12.2%	15.9%
4	Pennsylvania	70,046			4,572	74,619	7.0%	6.5%
5	Texas	180		49,319		49,498	4.6%	5.4%
6	Montana		37,980	372		38,352	3.6%	3.8%
7	Illinois	33,444				33,444	3.1%	6.1%
8	Virginia	32,834				32,834	3.1%	4.2%
9	North Dakota			31,270		31,270	2.9%	3.0%
10	Colorado	21,907	7,230			29,137	2.7%	1.8%
11	Indiana	27,965				27,965	2.6%	3.2%
12	New Mexico[1]	6,156	21,167			27,323	2.5%	2.2%
13	Utah	26,656				26,656	2.5%	2.2%
14	Ohio	22,269				22,269	2.1%	3.1%
15	Alabama	19,324				19,324	1.8%	2.7%
16	Arizona	13,111				13,111	1.2%	1.3%
17	Maryland	4,546				4,546	0.4%	0.4%
18	Washington		4,270			4,270	0.4%	0.5%
19	Louisiana			3,699		3,699	0.3%	0.3%
20	Tennessee	2,669				2,669	0.2%	0.4%
21	Alaska		1,641			1,641	0.2%	0.1%
22	Oklahoma	1,588				1,588	0.1%	0.2%
23	Mississippi			902		902	0.1%	--
24	Missouri	436				436	0.0%	0.2%
25	Kansas	201				201	0.0%	0.0%
26	Arkansas	12				12	0.0%	0.0%
-	Iowa					--	--	0.0%
-	California					--	--	0.0%
	East of Miss. River	**502,043**		**902**	**4,572**	**507,517**	47.3%	
	West of Miss. River	**72,233**	**409,203**	**84,659**		**566,094**	52.7%	
	U.S. Total	**574,276**	**409,203**	**85,561**	**4,572**	**1,073,612**	100.0%	

[1]One mine in New Mexico produces both bituminous and subbituminous coal and is double counted as a bituminous and subbituminous mine, but is not double counted in the total.

Notes: Coal production excludes silt, culm, refuse bank, slurry dam, and dredge operations except for Pennsylvania anthracite. Totals may not equal sum of components due to independent rounding.
Total U.S. coal production increased 8.1% between 1991 and 2000.

Sources: U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual 2000* (EIA-0584) and *Coal Production 1991* (EIA-0118).

Table C2. Montana Coal Production and Average Mine Price by Rank of Coal, 1950-2000

Year	PRODUCTION (thousand short tons)			AVERAGE MINE PRICE (dollars per short ton)		
	Subbituminous	Lignite	TOTAL	Subbituminous	Lignite	AVERAGE
1950	2,468	52	**2,520**	$2.30	$3.37	**$2.33**
1951	2,310	35	**2,345**	2.61	3.51	**2.63**
1952	2,039	31	**2,070**	2.80	3.70	**2.81**
1953	1,848	25	**1,873**	2.64	3.77	**2.66**
1954	1,491	NA	**1,491 E**	2.79	NA	**NA**
1955	1,217	30	**1,247**	3.01	3.82	**3.03**
1956	820	26	**846**	4.11	3.70	**4.10**
1957	387	26	**413**	5.33	3.80	**5.23**
1958	211	94	**305**	5.94	2.34	**4.84**
1959	152	193	**345**	7.06	2.08	**4.28**
1960	113	200	**313**	6.87	2.06	**3.79**
1961	97	274	**371**	6.76	2.01	**3.26**
1962	78	304	**382**	6.90	1.99	**2.98**
1963	53	290	**343**	7.51	1.95	**2.82**
1964	46	300	**346**	7.40	1.95	**2.68**
1965	63	301	**364**	7.24	1.96	**2.88**
1966	91	328	**419**	7.10	1.96	**3.08**
1967	65	300	**365**	NA	NA	**NA**
1968	189	330	**519**	3.12	1.89	**2.33**
1969	722	308	**1,030**	2.18	2.03	**2.13**
1970	3,124	323	**3,447**	1.83	2.13	**1.86**
1971	6,737	327	**7,064**	1.79	2.27	**1.82**
1972	7,899	322	**8,221**	2.01	2.45	**2.02**
1973	10,411	314	**10,725**	2.83	2.60	**2.82**
1974	13,775	331	**14,106**	3.91	3.00	**3.90**
1975	21,620	520	**22,140**	5.06	5.04	**5.06**
1976	25,919	312	**26,231**	NA	NA	**4.90**
1977	29,020	300	**29,320**	NA	NA	**5.30**
1978	26,290	310	**26,600**	NA	NA	**7.37**
1979	32,343	333	**32,676**	w	w	**9.76**
1980	29,578	369	**29,948**	w	w	**10.50**
1981	33,341	204	**33,545**	w	w	**12.14**
1982	27,708	174	**27,882**	w	w	**13.57**
1983	28,713	211	**28,924**	w	w	**14.22**
1984	32,771	229	**33,000**	w	w	**13.57**
1985	33,075	212	**33,286**	w	w	**13.18**
1986	33,741	237	**33,978**	w	w	**12.93**
1987	34,123	277	**34,399**	w	w	**12.43**
1988	38,656	225	**38,881**	w	w	**10.06**
1989	37,454	288	**37,742**	w	w	**10.27**
1990[1]	37,266	230	**37,616**	w	w	**9.42**
1991	37,944	283	**38,227**	w	w	**10.76**
1992	38,632	248	**38,879**	w	w	**10.20**
1993	35,626	291	**35,917**	w	w	**11.05**
1994	41,316	323	**41,640**	w	w	**10.39**
1995	39,153	297	**39,451**	w	w	**9.62**
1996	37,635	256	**37,891**	w	w	**9.96**
1997	40,763	242	**41,005**	w	w	**9.84**
1998	42,511	329	**42,840**	w	w	**8.25**
1999	40,827	275	**41,102**	w	w	**8.82**
2000	37,980	372	**38,352**	w	w	**8.87**

NA - Not Available E - Estimated value. w - Withheld to avoid disclosure of individual company data.

[1] The 1990 total includes 120,000 tons of bituminous coal.

NOTES: For 1997 and before, average mine price is calculated by dividing total free on board (f.o.b.) mine value of coal produced by total production. For 1998 and forward, average mine price is calculated by dividing total f.o.b. rail value of coal sold by total coal sold. Excludes silt, culm, refuse bank, slurry dam and dredge operations. Excludes mines producing less than 10,000 short tons, which are not required to provide data.

SOURCES: U.S. Bureau of Mines (1950-76); U.S. Department of Energy, Energy Information Administration, (1977-78); U.S. Department of Energy, Energy Information Administration, *Coal Production*, annual reports for 1979-92 (EIA-0118);U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual*, 1993-2000 (EIA-0584) .

Table C3. Coal Mining Acreage, Production and Royalties from Federal and American Indian Leases in Montana

Year	Federal Leases			American Indian Leases		
	Acres Leased	Production (thousand short tons)	Royalties (thousand dollars)	Acres Leased	Production (thousand short tons)	Royalties (thousand dollars)
1980	NA	10,393	2,677	NA	2,742	1,610
1981	NA	26,727	6,245	NA	3,074	1,425
1982	23,455	10,652	9,517	14,746	3,704	2,603
1983	23,535	14,335	7,947	14,746	2,844	2,031
1984	29,469	18,696	9,709	14,746	3,350	1,557
1985	27,943	21,181	15,174	14,746	2,949	2,016
1986	25,463	24,682	22,447	14,746	1,169	812
1987	30,848	21,012	39,111	14,746	1,232	709
1988	30,031	20,626	35,592	14,746	1,927	1,127
1989	31,931	23,695	26,544	14,746	2,615	1,489
1990	31,821	27,246	29,155	14,746	2,731	1,500
1991	31,821	25,648	35,585	14,746	2,979	1,367
1992	31,821	23,993	34,096	14,746	2,300	1,175
1993	36,728	25,955	38,665	14,746	3,518	1,786
1994	39,141	30,615	41,959	14,746	4,134	1,979
1995	36,612	28,038	38,420	14,746	4,468	2,037
1996	31,540	24,816	32,935	14,746	4,681	2,139
1997	26,996	24,502	32,214	14,746	6,094	2,790
1998	26,562	19,061	25,807	14,746	6,956	3,135
1999	26,461	18,948	25,865	14,746	3,783	1,890
2000	29,408	23,264	25,667	14,746	7,102	3,403

NA - Not available

Notes: U.S. Total for this table represents Federal and American Indian Leases only. Output from Federal and American Indian Lands is reported as sales volume, the basis for royalties. It is approximately equivalent to production, which includes coal sold and coal added to stockpiles. Totals may not equal sum of components due to independent rounding.

Source: United States Department of the Interior, Minerals Management Service, *Mineral Revenues* (1982-1992); United States Department of Energy, Energy Information Administration, *Coal Industry Annual* (1993-2000).

Table C4. Coal Production by Company, 1980-2001 (short tons)

	Beartooth Coal Co.[1]	Coal Creek Mining Co.	Decker Coal[2] East Decker Mine	Decker Coal[2] West Decker Mine	Kennecott Energy (previously Spring Creek Coal)[3]	Peabody Coal Co.	P.M. Coal Co. (Mountain, Inc in 1995-97)[4]	Red Lodge Coal Co.	Storm King Coal Mining Co.[5]	Blaine Warburton (owner)	Westmoreland (previously Knife River Coal)[6]	Westmoreland[7]	Westmoreland (previously Western Energy Co.)[8]	TOTAL
County	Carbon	Powder River	Big Horn	Big Horn	Big Horn	Rosebud	Musselshell	Carbon	Musselshell	Blaine	Richland	Big Horn	Rosebud	
1980	7,321	64,398	5,576,607	5,616,695	118,660	2,964,359	11,189		8,571		305,578	4,905,262	10,401,972	29,980,612
1981		64,142	5,350,113	5,331,626	4,368,885	3,193,570	7,404		8,165		204,492	4,450,296	10,352,966	33,331,659
1982		16,608	4,914,970	4,884,920	1,352,181	2,891,428	15,141		8,062		171,556	4,158,578	9,424,857	27,838,301
1983			5,040,018	5,308,799	2,102,606	2,571,861	11,655		5,896		206,543	3,868,844	9,544,062	28,660,284
1984			5,019,186	5,278,365	2,962,008	3,945,865	15,865		16,379		236,954	3,621,544	11,957,724	33,053,890
1985			5,191,701	6,149,987	2,837,037	3,336,907	21,400		3,251		212,654	3,112,595	12,275,351	33,140,883
1986			5,397,476	6,706,592	4,664,238	2,594,306	23,915			276	252,754	2,028,595	12,074,698	33,742,850
1987			4,042,597	6,355,523	6,557,228	3,234,538	14,495	900		305	290,264	1,858,315	12,022,894	34,377,059
1988			3,655,067	7,068,653	4,704,442	3,788,137	15,542			248	227,603	3,304,822	16,155,867	38,920,381
1989			3,582,885	6,495,027	5,979,405	3,715,325	15,760			96	295,089	4,011,156	13,677,234	37,771,977
1990			2,595,829	6,602,744	7,133,285	3,602,851	14,307				234,010	4,471,345	12,800,898	37,455,269
1991			2,408,968	7,576,380	6,740,401	3,104,829	12,202				282,641	4,101,847	13,802,840	38,030,108
1992			2,621,326	9,323,561	6,641,332	2,212,071	9,235				247,155	3,490,797	14,347,159	38,892,636
1993			2,864,005	7,940,085	7,175,434	2,518,117	11,182				290,928	3,224,143	11,909,423	35,933,317
1994			2,787,908	7,726,969	9,934,305	3,053,125	2,600				323,381	4,363,500	13,390,492	41,582,280
1995			1,802,249	8,475,335	8,512,520	4,708,970	4,128				297,290	4,425,759	11,260,339	39,486,590
1996			601,544	10,388,948	9,015,361	4,984,352	151,024				256,476	4,668,021	7,775,391	37,841,117
1997			1,911,702	9,961,746	8,306,306	4,334,750	24,023				249,593	7,051,062	8,927,138	40,766,320
1998			1,583,454	8,892,053	11,312,935	3,468,192					329,038	6,458,279	10,251,547	42,564,760
1999			1,973,954	8,904,115	10,994,827	2,867,223					274,695	5,466,678	10,362,062	41,103,261
2000			2,465,352	7,466,814	11,301,905	1,404,139					371,971	4,910,907	10,173,297	38,307,961
2001			1,207,580	8,254,718	9,664,969	2,569,541					346,355	5,904,724	11,051,692	39,231,408

[1] Underground mine.

[2] Decker Coal Co. is a 50-50 joint venture between Peter Kiewit Sons' and Kennecott Energy Company. Kennecott purchased the share held by NERCO, a PacifiCorp subsidiary, in 1993.

[3] Kennecott Energy Co. purchased NERCO, a Pacific Power and Light subsidiary which owned Spring Creek Coal, in 1993.

[4] RBM Mining Inc. did contract mining at this site from 1991 to 1994. Both underground and strip mining have been done at this site.

[5] Prior to a change in ownership in 1983, this was called the Divide Coal Mining Company.

[6] Lignite mine. It was purchased from Knife River Coal Co., a subsidiary of MDU Resources Group, in 2001.

[7] The Absaloka Mine (also known as Sarpy Creek Mine) is operated by Washington Group International (previously Morrison-Knudsen).

[8] Purchased from Montana Power Company in 2001. Since 1990, includes over 200,000 tons per year of waste coal sold to CELP generation plant.

Note: Total production is slightly different than in other coal tables. The data come from a state, rather than federal, source.

Source: Montana Department of Labor and Industry, Workers' Compensation Division (1978-2001).

Table C5. Distribution of Coal for Use In Montana, 1974-2000

(thousand short tons)

Year	Electric Utilities	Residential and Commercial	Industrial	TOTAL
1974	843	9	55	**907**
1975	1,203	7	42	**1,252**
1976	2,452	5	108	**2,565**
1977	3,225	1	182	**3,408**
1978	3,334	4	183	**3,522**
1979	3,513	3	214	**3,731**
1980	3,462	14	182	**3,658**
1981	3,318	7	253	**3,578**
1982	2,619	9	197	**2,824**
1983	3,058	8	120	**3,186**
1984	4,979	6	153	**5,138**
1985	5,625	8	220	**5,852**
1986	8,094	22	317	**8,433**
1987	7,603	8	180	**7,791**
1988	10,556	9	230	**10,795**
1989	10,242	53	185	**10,480**
1990	9,574	57	252	**9,883**
1991	10,614	45	265	**10,924**
1992	10,963	21	261	**11,245**
1993	8,818	11	365	**9,194**
1994	10,179	4	548	**10,728**
1995	9,058	10	610	**9,678**
1996	7,869	4	486	**8,359**
1997	9,056	83	478	**9,617**
1998	10,594	4	227	**10,825**
1999	10,517	3	557	**11,077**
2000	9,876	3	576	**10,455**

Note: This data series consistently shows the amount of coal distributed to Electric Utilities to be slightly less (usually 1-2%) than the amount received at Electric Utility Plants shown in Table 3.6. Differences in distribution and receipt data are due to the time lag between distribution and receipt of coal shipments, and due to the survey threshold differences. In addition, coal distributed includes only domestic coal, whereas receipts include imported coal.

Sources: U.S. Department of Interior, Bureau of Mines, *Mineral Industry Surveys, Bituminous Coal and Lignite Distribution* annual reports for 1974-76; U.S. Department of Energy, Energy Information Administration, *Bituminous Coal and Lignite Distribution*, quarterly reports for 1977; U.S. Department of Energy, Energy Information Administration, *Bituminous Coal and Lignite Distribution*, annual report for 1978 (EIA-0125); U.S. Department of Energy, Energy Information Administration, *Bituminous and Subbituminous and Lignite Distribution*, annual report for 1979 (EIA- 0125); U.S. Department of Energy, Energy Information Administration, *Coal Distribution*, annual reports for 1980-97 (EIA-0125); U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual* (1998-2000)(EIA-0584).

Table C6. Receipts of Montana Coal at Electric Utility Plants[1] 1973-2000

(thousand short tons)

Year	Received at Montana Utilities			Received at Out-of-State Utilities	TOTAL
	Subbituminous	Lignite	Montana Total		
1973			882	9,741	**10,623**
1974			822	13,114	**13,936**
1975			1,197	20,180	**21,377**
1976			2,316	22,642	**24,958**
1977			3,223	22,730	**25,954**
1978	3,033	298	3,331	22,976	**26,307**
1979	3,207	304	3,511	24,613	**28,124**
1980	3,071	293	3,364	24,561	**27,925**
1981	3,129	210	3,339	26,634	**29,973**
1982	2,424	177	2,601	25,439	**28,040**
1983	1,804	206	2,010	25,756	**27,766**
1984	4,823	200	5,023	27,432	**32,455**
1985	5,292	168	5,460	25,975	**31,435**
1986	7,308	190	7,498	22,992	**30,490**
1987	7,376	220	7,596	24,607	**32,203**
1988	10,306	168	10,474	26,076	**36,550**
1989	9,989	235	10,224	25,858	**36,082**
1990	9,343	176	9,519	26,108	**35,626**
1991	10,173	225	10,398	26,091	**36,490**
1992	10,683	177	10,860	26,449	**37,309**
1993	8,619	230	8,849	25,052	**33,901**
1994	10,069	241	10,310	28,559	**38,869**
1995	9,089	224	9,313	26,377	**35,690**
1996	7,685	192	7,877	27,540	**35,417**
1997	9,005	155	9,160	29,172	**38,332**
1998[2]	10,243	277	10,520	30,243	**40,763**
1999[2]	10,660	215	10,875	29,803	**40,678**
2000[2]	9,804	317	10,121	27,579	**37,700**

[1] Plants of 25-megawatt capacity or larger (1973-82); plants of 50-megawatt capacity or larger (1983-2000).

[2] Since January 1998, regulated utilities have been selling off their electric plants. Once the divestiture is complete, data are no longer required to be filed on the FERC Form 423 survey. 1999 and 2000 Montana subbituminous data are from Form 906 data base; these are consumption figures, not receipts. 1998-2000 lignite data are from *Cost and Quality of Fuels for Electric Utility Plants*. 1998-2000 out-of-state utility data are from *Coal Industry Annual*; these are distribution figures, which are not the same as receipts. Montana and U.S. totals for 1998-2000 are the sums of their respective components as reported in this table.

Note: This data series consistently shows the amount of coal received at Electric Utility Plants to be slightly more (usually 1-2%) than the amount distributed to Electric Utilities shown in Table 3.6. Differences in distribution and receipt data are due to the time lag between distribution and receipt of coal shipments, and due to the survey threshold differences. In addition, coal distributed includes only domestic coal, whereas receipts include imported coal.

Sources: Federal Energy Regulatory Commission (formerly the Federal Power Commission), Form 423 (1973-77); U.S. Department of Energy, Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants*, annual reports for 1978-2000 (EIA-0191); U.S. Department of Energy, Energy Information Administration, Form EIA-906 "Power Plant Report" database; U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual*, annual reports for 1998-2000 (EIA-0584).

Table C7. Distribution of Montana Coal by Destination, 1989-2000 (thousand short tons)

Destination	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Alabama	*											
Arizona										94	69	198
Colorado	90	94	101	106	86	89	63	26				
Georgia	53											
Illinois	2,880	2,651	3,203	3,013	3,295	4,338	2,713	2,162	1,545	1,679	1,769	2,552
Indiana	352	573	725	451	433	749	720	869	1,259	126	1,308	1,011
Iowa					1		2		105	136		
Kansas									104	379	1,319	1,464
Michigan	11,181	11,795	10,838	10,376	10,055	10,481	11,014	9,806	10,866	9,861	9,952	9,239
Minnesota	9,408	9,920	9,668	8,566	8,852	10,038	10,199	9,791	8,847	10,477	9,429	10,771
Mississippi			105	82	178	1,314	1,234	2,226	3,235	2,833	1,926	151
Missouri							6					
Montana	10,384	9,742	10,578	11,159	9,115	10,581	9,477	7,844	9,019	10,360	10,346	9,723
Nebraska	109	131	150	142	136	71	205	113	47	81		
Nevada	57											
New Mexico												
North Dakota	264	349	425	444	422	559	469	417	402	517	877	145
Ohio								26	42		168	153
Oregon				1,835	355						1,507	
South Dakota							457	1,301	1,867	1,698	1,496	
Tennessee				2								
Washington	55			715	753	1,097	583	113	333	1,503		1,685
Wisconsin	2,115	2,033	2,005	1,878	2,057	2,307	2,135	2,950	2,649	2,053	482	578
Wyoming	102	6	8	11	31	49	71	125	34	62		64
Domestic Total	37,073	37,294	37,812	38,804	35,795	41,672	39,362	37,770	40,363	41,860	40,649	37,735
Canada[1]	330	417	10		54	90	259	316	438	814	682	608
Overseas[1]		155	297	62	67	153		202	141			
TOTAL	37,403	37,866	38,119	38,866	35,916	41,915	39,621	38,288	40,942	42,674	41,331	38,343

* Less than 500 short tons

[1] All distribution was steam coal.

Source: U.S. Department of Energy, Energy Information Administration *Coal Industry Annual* 1993-2000 (EIA-0584).

Table C8. Montana Coal Production, Employment and Severance Tax

YEAR	Coal Produced (thousand tons)[1]	Percentage of U.S. production	Number of miners[2]	Average cost per ton[1]	Coal Severance Tax (for FY)[3]
1980	29,948	3.6%	1131	$10.50	$70,415,018
1981	33,545	4.1%	1227	$12.14	$86,186,886
1982	27,882	3.3%	1051	$13.57	$80,044,981
1983	28,924	3.7%	1024	$14.22	$82,823,410
1984	33,000	3.7%	1112	$13.57	$91,748,856
1985	33,286	3.8%	1173	$13.18	$84,217,213
1986	33,978	3.8%	932	$12.93	$76,546,593
1987	34,399	3.7%	847	$12.43	$84,638,312
1988	38,881	4.1%	872	$10.06	$58,565,583
1989	37,742	3.8%	682	$10.27	$67,870,544
1990	37,616	3.7%	821	$9.42	$50,457,839
1991	38,227	3.8%	794	$10.76	$54,114,111
1992	38,879	3.9%	715	$10.20	$35,481,334
1993	35,917	3.8%	660	$11.05	$41,187,973
1994	41,640	4.0%	705	$10.39	$40,416,167
1995	39,451	3.8%	722	$9.62	$36,260,949
1996	37,891	3.6%	705	$9.96	$37,740,212
1997	41,005	3.8%	708	$9.84	$35,045,243
1998	42,840	3.8%	925	$8.25	$36,767,488
1999	41,102	3.7%	927	$8.82	$35,469,791
2000	38,352	3.6%	867	$8.87	$32,337,172

[1] Coal production and average cost from Table 3.3. For 1997 and prior years, average mine price is calculated by dividing the total free on board (f.o.b.) mine value of the coal produced by the total production. For 1998 and forward, average mine price is calculated by dividing the total f.o.b. rail value of the coal sold by the total coal sold.

[2] Includes all employees engaged in production, preparation, processing, development, maintenance, repair, ship or yard work at mining operations, including office workers for 1998 forward. For 1997 and prior years, includes mining operations management and all technical and engineering personnel, excluding office workers.

[3] For state Fiscal Year, which starts July 1 of the calendar year listed. Includes all interest, penalties and accruals. Does not include temporary Coal Stabilization Tax in FY1993-94, which totaled $2,712,696.

Source: U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 2000* (EIA-0384); U.S. Department of Energy, Energy Information Administration, *Coal Production*, annual reports for 1980-92 (EIA-0118); U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual*, 1993-2000 (EIA-0584); Montana Department of Revenue *Biennial Report* (1980-2000); Montana Department of Revenue files (2001).