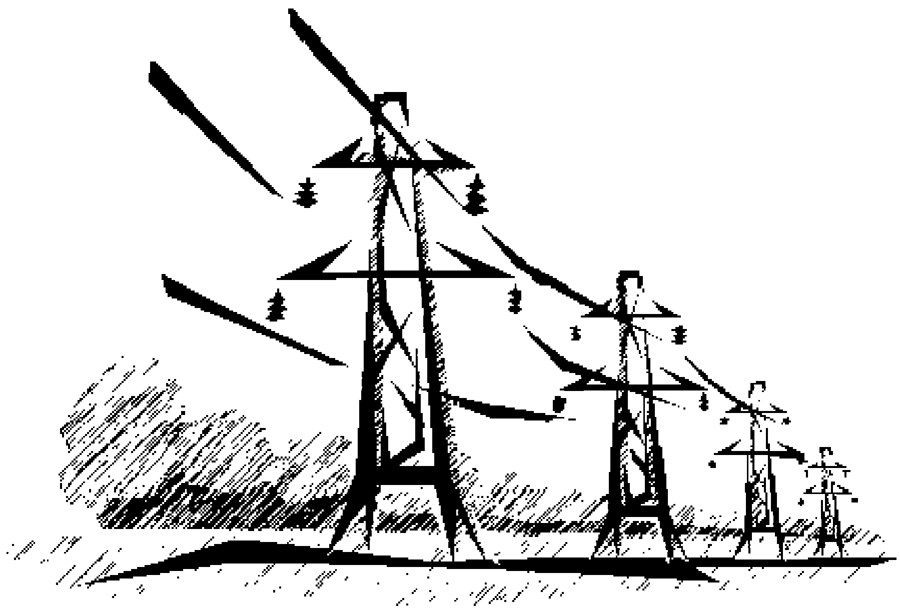
DRAFT DOCUMENT

UNDERSTANDING ENERGY IN MONTANA



A Guide to Electricity, Natural Gas, Coal, and Petroleum Produced and Consumed in Montana

DRAFT

DEQ Report updated for ETIC — January 2010

DEQ Report originally prepared for EQC — October 2002, 2004

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for the

2009-10 Energy and Telecommunications Interim Committee

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Introduction

Energy issues continue to receive significant public attention and scrutiny in Montana. In the decade since the 1997 decision to deregulate Montana's electricity supply, consumers have witnessed the California energy crisis, the bankruptcy and reemergence of NorthWestern Energy, dramatic increases in the price of natural gas, hundred dollar barrels of oil, serious talk of new markets and new transmission lines for Montana, and discussions of climate change and energy independence. The Environmental Quality Council first prepared this guide in 2002, and revised it again in 2004. The Energy and Telecommunications Interim Committee (ETIC) in 2009 agreed to revise the document to provide the most up-to-date background information available to policymakers and citizens alike. Special thanks should be extended to the DEQ, particularly Jeff Blend and Paul Cartwright, who are instrumental in the preparation of the information that provides the backbone of this document, and to Paul Driscoll for his editing.

The 2010 revisions also coincide with the ETIC's statutorily required review and potential revision of Montana's Energy Policy. This document provides groundwork critical to the ETIC in conducting an in-depth study of energy policy. The guide focuses on historical and current patterns of energy supply and demand. These are the background facts needed to interpret past and future policies. The guide is divided into five 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 very intertwined with the electricity industry. The fourth section covers the Montana coal industry, which exists mainly to fuel the generation of electricity and whose future will depend on what happens in that industry. The final section addresses petroleum and transportation, the sector most directly affected by international events.

The guide, with its focus on historical and current patterns, deals primarily with conventional energy resources. Montana continues to see renewable energy sources play a larger role, especially in electricity supply. Energy efficiency and energy conservation are also both given brief treatment, simply because so few data are available. Public agencies, private business and individual citizens need to keep the issues of efficiency, conservation, and renewable resources in mind, as they review the conventional resources included in this document.

Glossary

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 caused by inflation.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Coal

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

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

Anthracite: Hard and jet black with a high luster, it is the highest rank of coal and is mined in northeastern Pennsylvania. Anthracite contains approximately 22 to 28 million Btu per ton as received.

Bituminous: The most common coal, it is soft, dense, and black with well-defined bands of bright and dull material. Bituminous is ranked between anthracite and subbituminous and is mined chiefly in Kentucky, Pennsylvania, and West Virginia. The heating value ranges from 19 to 30 million Btu per ton as received.

Lignite: A brownish-black coal of the lowest rank; it is mined in North Dakota, Montana, and Texas. The heat content of lignite ranges from 9-17 million Btu per ton as received.

Subbituminous: A dull black coal ranking between lignite and bituminous; it is mined chiefly in Montana and Wyoming. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received.

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

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

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

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

Electricity Supply and Demand

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

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

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

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

Gross: The total amount of electric energy produced by the generating units in a generating station or stations, measured at the generator terminals.

Net: Gross generation less the electric energy consumed at the generating station for station use. (Energy required for pumping at pumped-storage plants is regarded as plant use and is subtracted from the gross generation and from hydroelectric generation.)

Gigawatt (GW): One billion watts.

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

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

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

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

Megawatt (MW): One million watts.

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

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

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

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

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

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

Watt: The electrical unit of power or rate of doing work. A watt is the rate of energy transfer equivalent to 1 ampere flowing under pressure of 1 volt at unity power factor (volt and ampere in phase). It is analogous to horsepower or foot-pound-per-minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

Electricity Transmission

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Unscheduled Flows: See Inadvertent Flows.

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

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

Natural Gas

Bcf: One billion cubic feet.

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

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

Gas Well: A well that is completed for the production of gas from either nonassociated gas reservoirs or associated gas and oil reservoirs.

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

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

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

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

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

MMcf: One million cubic feet.

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

Natural Gas 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.

Petroleum

Asphalt: A dark-brown-to-black cement-like material containing bitumens as the predominant constituents obtained by petroleum processing. The definition includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

Aviation Gasoline: All special grades of gasoline for use in aviation reciprocating engines, as given in ASTM Specification D910 and Military Specification MIL-G-5572. Aviation gasoline includes blending components.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Crude Oil (Including Lease Condensate): A mixture of hydrocarbons that exists in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Included are lease condensate and liquid hydrocarbons produced from tar sands and oil shale.

Diesel Fuel: Fuel used for internal combustion in diesel engines, usually that fraction of crude oil that distills after kerosene (See Distillate Fuel Oil).

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating and on- and off-highway diesel engine fuel (including railroad engine fuel and fuel for agricultural machinery), and electric power generation. Included are products known as No. 1, No. 2 and No. 4 fuel oils; No. 1, No. 2, and No. 4 diesel fuel.

Ethanol: Ethyl alcohol or grain alcohol (CH_3CH_2OH). It is the alcohol contained in intoxicating beverages. Ethanol can be produced from biomass by the conversion process called fermentation (See Gasohol).

Gasohol: A blend of finished motor gasoline (leaded or unleaded) and alcohol (generally ethanol but sometimes methanol) in which 10 percent or more of the product is alcohol.

Jet Fuel: The term includes kerosene-type jet fuel and naphtha-type jet fuel. Kerosene-type jet fuel is a kerosene quality product used primarily for commercial turbojet and turboprop aircraft engines. Naphtha-jet fuel is a fuel in the heavy naphtha range used primarily for military turbojet and turboprop aircraft engines.

Kerosene: A petroleum distillate that boils at a temperature between 300-550 degrees F, that has a flash point higher than 100 degrees F, that has a gravity range from 40-46 degrees API, and that has a burning point in the range of 150-175 degrees F. Kerosene is used in space heaters, cook stoves, and water heaters, and is suitable for use as an illuminant when burned in wick lamps.

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.

Lubricants: Substances used to reduce friction between bearing surfaces or as process materials either incorporated into other materials used as processing aids in the manufacturing of other products or as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Other substances may be added to impart or improve certain required properties.

Motor Gasoline: A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, obtained by blending appropriate refinery streams to form a fuel suitable for use in spark-ignition engines. Motor gasoline includes both leaded and unleaded grades of finished motor gasoline, blending components, and gasohol.

Petroleum: A generic term applied to oil and oil products in all forms, such as crude oil, lease condensate, unfinished oil, refined petroleum products, natural gas plant liquids, and nonhydrocarbon compounds blended into finished petroleum products.

Petroleum Products: Petroleum products are obtained from the processing of crude oil (including lease condensate), natural gas, and other hydrocarbon compounds. Petroleum products include unfinished oils, naturalgasoline and isopentane, plant condensate, unfractionated stream, liquefied petroleum gases, aviation gasoline, motor, gasoline, naphtha-type jet fuel, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, naphtha less than 400° F end-point, other oils over 400° F end-point, special naphthas, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products.

Residual Fuel Oil: The topped crude of refinery operation that includes No. 5 and No. 6 fuel oils, Navy special fuel oil, and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

Summary

Summary Points:

UNDERSTANDING ENERGY IN MONTANA

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

These lists of points summarize the guide prepared for the Energy and Telecommunications Interim Committee. They cover the status of electricity, natural gas, coal, and petroleum supply and demand in Montana and the Montana electric transmission grid. The reader should consult the guide itself for detailed explanations of technical points and to see the data tables that underpin these summaries.

Summary

Electricity Supply and Demand in Montana

- Montana generates more electricity than it consumes. Montana generating plants have the capacity to produce 5,445 MW of electricity. Montana produced 3,177 aMW from 1995-1999 and 3,243 aMW from 2003-2007. In 2007, Montana consumed an estimated 1,909 aMW (including estimated line losses). (p. I-2)
- Montana straddles the two major electric interconnections in the country. Most of Montana is in the western interconnection, which covers all or most of 11 states, two Canadian provinces and a bit of northern Mexico. Only about 7 percent of Montana's load is in the eastern interconnection, along with about 2 percent of the electricity generated in-state. (p. I-2)
- Montana is a small player in the western electricity market. (p. I-2)
- There are more than 40 electric generating facilities in Montana. The largest facility is the four privately owned coal-fired plants at Colstrip, which have a combined generation capability of 2,094 MW. The largest hydroelectric plant is the U.S. Corps of Engineers' Libby Dam with a capability of 598 MW. (p. I-2)
- In the last four years, several new plants have come on line in Montana: Basin Creek Power Services (natural gas), Hardin Generating Station (coal), Montana-Dakota Utilities Glendive-Diesel, Judith Gap Wind Energy Center, Diamond Willow Wind Farm, Horseshoe Bend Wind, Two Dot Wind, and, for a brief time, Thompson River Co-Gen. (p. I-6)
- PPL Montana's facilities, previously owned by Montana Power Company, produced just under 30 percent of the total electricity generated in Montana in the period 2003-2007, making PPL the largest generating company in the state. Puget Power was the second largest producer with 17.7 percent. Federal agencies—the Bonneville Power Administration and Western Area Power Administration—collectively produced 15.5 percent of the electricity generated in Montana. (p. I-3)
- Montana generation is powered almost entirely by coal (63 percent) and hydro (34 percent) (2003-2006 average). Until 1986, hydro was the dominant source of electric generation in Montana. Over the last 15 years, about 25 percent of Montana coal production has gone to generate electricity in Montana. (p. I-4)

- Montanans are served by 31 distribution utilities: 2 investor-owned, 25 rural electric cooperatives, 3 federal agencies and 1 municipal. (Two additional investor-owned utilities and four additional co-ops based in other states serve a handful of Montanans.) (p. I-4)
- In 2007, investor-owned utilities made 43 percent of the electricity sales in Montana, co-ops 25 percent, federal agencies 3 percent and power marketers 29 percent. (p. I-4)
- Reported Montana electricity sales in 2008 were 17.2 billion kWh. The residential and commercial sectors in 2008 each accounted for about 25-30 percent of sales and the industrial sector accounted for about 45 percent of sales. (p. I-5)
- Sales tripled between 1960 and 2000, then dropped by over 15 percent as industrial loads tumbled following the electricity crisis of 2000-2001.). Since 2000 sales have increased back to pre-2000 levels. (p. I-5)
- The average price per kWh for residential customers was 9.1 cents in 2008, up from 6.5 cents in 2000. The average price per kWh for commercial customers was 8.5 cents in 2008, up from 5.6 cents in 2000; for industrial, the comparable figures are 5.7 cents and 4.0 cents. (p. I-6)
- As in previous decades, electricity in Montana costs less than the national average. In 2008, Montana averaged 7.4 cents/kWh vs. 9.8 cents/kWh nationally. (p. I-6).
- As many as 50 wind power projects are in various stages in Montana. With the construction of the 230-kilovolt Montana Alberta Tie Line, up to 300 MW of additional wind power could come online. (p. I-7)
- There are no comprehensive estimates of the potential for efficiency improvements in Montana energy use. However, according to the Energy Information Administration, Montana utilities spent $6.7 million on energy efficiency in 2007, saving 43,329 MWh. (p. I-8)

Summary

The Montana Electric Transmission Grid: Operation, Congestion and Issues

- Montana's strongest electrical interconnections with other regions are: the Colstrip 500 kV line which connects as far as Spokane and then into the BPA northwest grid; the BPA 230 kV lines heading west from Hot Springs; PacifiCorp's interconnection from Yellowtail 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. (p. II-1)
- The western United States is a single, interconnected, and synchronous electric system. It is not closely connected with the eastern part of the country. The interconnections are only weakly tied to each other with AC/DC/AC converter stations. One such station connecting the eastern and western grids is located at Miles City, with 200 MW capability in either direction. Also, a limited amount of additional power can be moved from one grid to the other by shifting units at Fort Peck Dam. (p. II-2)
- The transmission system is managed differently than the way it operates physically. (p. II-3)
- The physical reality of electricity (electrons) is that power sent from one point to another flows over all transmission lines in the interconnected system, according to the laws of physics. Actual flows at any time are the net result of all transactions, and are the same for any given pattern of generation and load, regardless of transactions. (p. II-4)
- Management of the grid is different from where the electricity actually flows. Grid management requires a single "contract path" for each scheduled transaction. A "contract path" is permission to use a route across separately owned transmission systems from a point of origin to a point of delivery. In reality, the contract path is often not the major route taken by the actual power flows that occur, which could happen over multiple routes. (p. II-5)
- Power flows are managed on a limited number of "rated paths." Each path consists of a number of more-or-less parallel transmission lines that together can be constrained under some patterns of generation and loads. (p. II-7)
- Path ratings are set to provide reliability by ensuring sufficient redundant capacity to allow for outages of some of the facilities comprising the path. Path ratings may be reduced if reliability standards are tightened. The West of Hatwai path is rated at about

4,300 MW east-to-west under ideal conditions. The Montana-Northwest path has a rating of 2,200 MW east to west and 1350 MW west to east. (p. II-7)

- Rights to use rated paths have been allocated among the owners of the transmission lines that comprise the paths. In addition the line owners have committed to a variety of contractual arrangements to ship power for other parties. Scheduled power flows by rights holders are not allowed to exceed the path ratings. (p. II-7)

- In 1996, FERC ordered transmission owners to separate marketing and transmission operations and to maintain web sites ("OASIS" sites) on which "available capacity" is posted and offered for use by others. "Available capacity" is total transfer capacity less committed uses and existing contracts. Almost no available capacity ever is listed on paths from Montana to the West Coast. (p. II-7)

- Non-firm access is available on uncongested paths but only at the last minute. (p. II-9)

- A path may be fully scheduled, and therefore congested, even though the actual flow may be considerably less than the path capacity. For example, from June 2005 to May 2006, the highest actual loadings on the Montana Northwest path were around 90 percent of the path capacity for only a few hours. For most hours the path was not heavily loaded. For about 90 percent of the hours in that year-long time period, the line was 60 percent loaded or less, east to west, by actual flow. (p. II-8)

- Discussions to have an independent body take over operation and control of access for the transmission system have been underway since the mid-1990's among the transmission owners and other stakeholders in the Northwest U.S. (p. II-10)

- Grid West failed in May of 2006. Columbia Grid (BPA and Washington public and private utilities) and the Northern Tier Transmission Group (public utilities outside Washington and some Utah Cooperatives), continue to try to search for some sort of solution to this issue. (p. II-11)

- Issues involved in the amount and availability of transmission capacity include the need of utilities to withhold capacity because of uncertainty, the way reliability criteria are set, the limited number of hours that transmission paths are congested, and the challenges and costs of siting and building new transmission lines. (p. II-14)

- In the 2005 Energy Bill, lawmakers decided that designating specific energy corridors for future development would help minimize the time it takes to site and approve projects, as well as reducing environmental effects and conflicts with other uses of federal lands. (p. II-18)

Summary

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

- Alberta provides the largest supply of natural gas for Montana customers and will likely continue to do so in the years to come. (p. III-1)
- Most gas produced in Montana comes from the northcentral portion of the state. The bulk of what Montana produces is exported. In-state gas production has been increasing in recent years, standing at 112.8 billion cubic feet in 2006. (p. III-1)
- Recent Montana natural gas consumption has averaged 60-70 billion cubic feet per year. Future Montana natural gas consumption, excluding that used for any new electric generation built in-state or new large industry, is expected to increase slowly at less than 1 percent annually. (p. III-6)
- Over the past two decades, a number of changes in energy markets, policies, and technologies have combined to spur an increase in the total usage of natural gas in the U.S. These include deregulation of the natural gas industry starting in 1978, air quality regulations that favor natural gas, deregulation of wholesale electricity markets, improvements in exploration and production technologies, and investment in major pipeline construction expansion projects. (p. III-7)
- Three distribution utilities and two transmission pipelines handle over 99 percent of the natural gas consumed in Montana. The distribution utilities are NorthWestern Energy, Montana-Dakota Utilities Co. (MDU), and Energy West of Great Falls, which uses NWE for gas transmission. NWE and the Williston Basin Interstate pipeline (affiliated with MDU) provide transmission service for in-state consumers and export Montana natural gas. (p. III-9)
- Northwestern Energy is the largest provider of natural gas in Montana, serving about 165,000 customers in the western two-thirds of the state. Montana-Dakota Utilities Co. is the second largest, serving the eastern third of the state. (pp. III-10, III-12)
- The delivered price of natural gas to homes and businesses includes the wellhead price of gas (price of the gas itself out of the ground), plus transmission and delivery fees, plus other miscellaneous charges. Wellhead prices are set in a continent-wide market. The natural gas transmission and delivery fees are set by utilities and/or pipelines, under regulation by state and federal agencies. (p. III-13)

- The wellhead price for natural gas in Montana is based on the AECO C/ Nova Inventory Transfer (NIT). This index, named after the AECO C storage hub in Alberta, is the equivalent in this area of the Henry Hub Index. The wellhead price of Alberta natural gas is determined largely by the North American free market, with adjustments for transportation costs. (p. III-13)

- Natural gas customers in Montana and in the Pacific Northwest have historically paid relatively low gas rates compared to the rest of the U.S. In the past few years, however, gas prices across this region have risen to be more in line with the rest of the nation. Montana's gas prices have reached high levels rarely seen before and relatively low gas rates may be a thing of the past. As of March 2009, NWE residential customers pay an average delivered gas price of just over $10.00/dkt. (p. III-16)

- The most recent long-term natural gas price forecast is for an average annual U.S. wellhead price to be within the range of $4.80/dkt to $6.50/dkt from 2006-2030 in today's dollars with a price of $5.80/dkt in 2030. Natural gas prices, however, have been volatile and are expected to continue their volatility. (p. III-19)

- Although average gas prices are expected to increase slowly in the long run, Montanans will continue to be subjected to gas price volatility from extreme or unexpected events. (p. III-19)

- Recent high natural gas prices in the past few years point out three lessons for Montana. First, our natural gas prices are affected by a number of factors beyond any one entity's or state's control. Second, the growing use of natural gas for electricity generation may lead to regularly high and volatile gas prices not experienced before in Montana. 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. (p. III-21)

Summary

Coal in Montana

- Montana is the fifth largest producer of coal in the United States, with over 43 million tons mined in 2007. Almost all the mining occurs in the Powder River Basin south and east of Billings. (p. IV-1)
- In 1958, after almost a century of mining, Montana production bottomed at 305,000 tons, an amount equivalent to less than 1 percent of current output. As Montana mines began supplying electric generating plants in Montana and the Midwest in the late 1960's, 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. (p. IV-1 and 2)
- Over the past decade Montana has produced a little less than 4 percent of the coal mined each year in the U.S., more or less maintaining its share of the national 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. (p. IV-2)
- The price of Montana coal averaged $11.79 per ton at the mine in 2007, including taxes and royalties. The price of coal has been on a downward trend since the early 1980's, when the average price of coal peaked at $14.22 per ton ($22.67 in 2002 dollars). By 2002 that price had fallen 60 percent in real terms. Since 2002 the price has gradually increased because the price of electricity has risen. (p. IV-2)
- In 2007 more than 60 percent of Montana coal came from federal lands and slightly less than 35 percent from reservation lands. (p. IV-3)
- There are currently six major coal mines in Montana, operating in Big Horn, Musselshell, Richland, and Rosebud counties. Changes in ownership and expansions at the new mine in the Bull Mountains near Roundup, are expected to bring a 35 percent increase in Montana's total current coal output. (p. IV-3)
- Spring Creek, owned by Rio Tinto Energy America, was the largest producing mine in Montana in 2007, accounting for about 36 percent of production, or about 16 million tons. Western Energy Company (a subsidiary of Westmoreland) operates the Rosebud Mine and is the second largest producer, accounting for 29 percent of coal production in 2007. (p. IV-3)

- Montana coal consumption has been more or less stable since the late 1980's, after Colstrip 4 came on line. (p. IV- 4)
- Almost all of Montana coal production is used to generate electricity. In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities and the rest burned in-state to produce electricity, with over half that electricity going to out-of-state utilities. (p. IV-4)
- Over the last decade, Michigan, Minnesota and Montana used about three quarters or more of all the coal produced in Montana . The remaining quarter now goes to 12 other states and other countries. (p. IV-4)
- Since 2002, the Montana coal industry, has become more productive. The average price of coal has risen and the amount of coal mined has increased along with the number of employees. (p. IV-4)
- Taxes on coal -- despite decreases from historical highs -- remain a major source of revenue for Montana, with $45.3 million collected in coal severance tax in state fiscal year 2007. 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. Production has risen modestly since the cut in taxes. (p. IV-5)
- Montana's output is dwarfed by Wyoming's, which produced close to 40 percent of the country's output in 2007. This is ten times as much coal as Montana produced in 2007. This is due to a combination of geologic, geographic and economic factors that tend to make Montana coal less attractive than coal from Wyoming. (p. IV-5)
- Increasing the use of coal-fired generation for electricity may be closely linked to potential federal climate change activities and restraints on CO_2 emissions. The impact of potential climate change activities on the future price of coal-fired generation is uncertain at this time. (p. IV-6)

Summary

Petroleum in Montana

- The first oil wells in Montana were drilled in 1889 near Red Lodge, but weren't very successful. Cat Creek, near Winnett, was the first commercially successful field discovered in Montana (1920). (p. V-1)
- Montana production peaked in 1968 at 48.5 million barrels. In recent years, Montana oil production peaked during 2006 with approximately 36 million barrels of oil produced during the year. (p. V-3)
- Petroleum pipelines serving Montana consist of three separate systems. One bridges the Williston and Powder River basins in the east and the other two link the Sweetgrass Arch, Big Snowy and Big Horn producing areas in central Montana. All these systems also move crude oil from Canada to Montana and Wyoming. (A fourth—Express—primarily carries Canadian crude through Montana.) (p. V-4)
- In recent years, around 96 percent of crude oil production has been exported. (p. V-4)
- Montana has four refineries, with a combined capacity of 182,500 barrels/day: ConocoPhillips (60,000 bbl/day) and ExxonMobil (58,000 bbl/day) in Billings, Cenex (55,000 bbl/day) in Laurel, and Montana Refining (9,500 bbl/day) in Great Falls. Montana refineries now use around 60-63 million barrels of crude a year (p. V-4)
- In response to the increased production in the Bakken Field and to better serve North Dakota and Montana, Enbridge added 30,000 barrels per day of delivery capacity to its North Dakota system in 2007. Additional expansions are expected to be in service by 2010. In 2008 TransCanada Corp. announced plans to build the Keystone XL pipeline through eastern Montana and five other states to transport Canadian oil to U.S. refineries along the Gulf Coast of Texas. (p. V-6)
- Petroleum product consumption in Montana peaked at 33 million barrels in 1979. In the last few years, consumption has steadily climbed, hitting a new high of nearly 36 million barrels in 2006. (p. V-6)
- The transportation sector is the single largest user of petroleum. . In 2006, 34 percent of petroleum consumption was in the form of motor gasoline and 34 percent was distillate, mostly diesel fuel. (p. V-7)

- To say the least, crude oil prices have been volatile over the last four years. The average price of a barrel of oil produced by the Organization of the Petroleum Exporting Countries doubled from 2001 to 2005. (p. V-8)
- At the end of fiscal year 2008, tax collections from oil and gas hit a record $324 million. Since reaching that highpoint oil and gas production collections have declined because of a significant reduction in commodity prices and production levels – specifically for oil (p. V-8)

Electricity Supply and Demand in Montana

The sweeping changes brought to the electricity industry ten years ago have all but ended. These changes were brought about largely as a result of electricity deregulation and the 2001 crisis in electricity markets. Still, the industry in Montana has not returned to where it was two decades ago. The deregulation of the wholesale electricity markets through the federal Energy Policy Act (1992) and deregulation of the Montana retail market by SB390 (1997) have only partially been repealed as of 2009. NorthWestern Energy, the successor to Montana Power Company, emerged from bankruptcy in late 2004 and looks stronger today than when it first started in Montana. The first new electrical generation in eight years came on-line in 2003, and several more moderate-size plants have come on since then including two large wind farms. Larger plants are currently in the planning stages, and may delayed a few years due to the current recession. Industrial consumption has risen dramatically in the past two years, and loads are modestly growing in other sectors as Montana's population and economy continue to grow. As always, the electricity industry continues to change. This chapter provides historical supply and demand information to put this change in context. Transmission, which affects access to out-of-state markets by Montana suppliers and consumers, is covered in a separate chapter.

1. Necessary Definitions

Certain terms are used throughout this chapter and are explained here. Electricity is measured in kilowatt-hours (kWh) or megawatt-hours (MWh). A MWh is 1,000 kWh. One MWh is produced when a 1 MW generator runs for one hour. A 1 MW generator running for all the 8,760 hours in a year produces 1 average Megawatt (aMW). As one illustration of electricity use, residential customers without electric heat typically use 10 to 30 kWh per day. As another, the Helena and the Helena valley at the beginning of the decade used around 80 aMW (700 million kWh), with a peak around 140 MW.

Montana Power Company (MPC) sold most of its generating units to PPL Montana at the end of 1999. The remainder of the generating units, contracts and leases, as well as the entire distribution utility, was sold to NorthWestern Energy (NWE) in February 2002. Data from the period of MPC ownership are labeled PPL Montana or NWE to be more useful for today's reader. Montana's policy of encouraging retail competition (since 1997) was partially reversed in 2007 following the passage of HB 25 which was entitled the "Electric Utility Industry Restructuring and Generation Reintegration Act,". HB 25 promulgates that electric utilities in Montana can recover the prudently-incurred cost of newly-acquired generation assets on a traditional cost-of-service basis. In other words, electric utilities now have the option of purchasing power in the wholesale market or acquiring generating assets directly as they did before deregulation.

2. Montana in Perspective

Montana generates more electricity than it consumes. Even so, it is a small player in the western electricity market. As of 2009, Montana generating plants have the capacity to produce 5,445 MW [Table E1] of electricity in the summer. Plants do not run all the time, nor do they produce exactly the same amount of electricity year to year. For example, hydro generators depend on the rise and fall of river flows, and any type of plant needs downtime for refurbishing and repairs. Montana produced 3,177 aMW from 1995-1999 and 3,243 aMW from 2003-2007. In general, Montana usage and transmission losses account for slightly more than half of production, or about 1,800 aMW. In 2007, Montana consumed an estimated 1,909 aMW (including estimated line losses) and produced 3,288 aMW. [Table E8 and Table E2].

<u>Electricity Facts for Montana</u>
Generation capability -- 5,450 MW
Average generation -- 3,250 aMW
Average load -- 1,750 aMW
*Note: Numbers are rounded

Montana straddles the two major electric interconnections in the country. Most of Montana is in the western interconnection, which covers all or most of 11 states and two Canadian provinces; it also includes small portions of one Mexican and three other US states. Only about 8 percent of Montana's load and about 2 percent of the electricity generated in Montana is in the eastern interconnection. The 2007 Montana load (sales plus transmission losses) was equivalent to less than 2 percent of the 101,146 aMW load in the western interconnection. Montana generation accounted for more than 3 percent of total west-wide generation that

3. Generation

There are more than 40 generating facilities in Montana as reported in Table E1. (Small commercial and residential wind turbines greater than 1 MW are known to be in operation but aren't formally reported.) The oldest is Madison Dam near Ennis, built in 1906. The newest is the Naturener, Glacier Wind Farm which came on-line in 2009. The largest facility is 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 the U.S. Army Corps of Engineers' Libby Dam at 599 MW. The smallest commercial plants supplying the grid in Montana are a micro-hydro plant at 60 kW and several wind turbines at 65 kW. Montana's ten largest electric generation plants are listed below (Table E1).

Table E1. Ten Largest Plants by Generation Capacity, 2009			
Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MW)
1. Colstrip	Coal	PPL Montana LLC	2,094
2. Libby	Hydroelectric	USCE-North Pacific Division	599
3. Noxon Rapids	Hydroelectric	Avista Corp	548
4. Hungry Horse	Hydroelectric	U S Bureau of Reclamation	419
5. Yellowtail	Hydroelectric	U S Bureau of Reclamation	287
6. Kerr	Hydroelectric	PPL Montana LLC	193
7. Fort Peck	Hydroelectric	USCE-Missouri River District	180
8. J E Corette Plant	Coal	PPL Montana LLC	154
9. Hardin Generator Project	Coal	Rocky Mountain Power Inc	109
10. Thompson Falls	Water	PPL Montana LLC	95

*Note: Colstrip is operated by PPL; actual ownership is shared by six utilities. Wind generation capacity is assumed to be only a fraction of total generator nameplate (typically 30-40%), because wind is an intermittent resource. That is why Judith Gap and NaturEner are not on this list.

Figure 1
Average Generation by Company, 2003-2007

Company	aMW	Percent
PPL Montana[1,2]	947	29.2%
Puget Sound Power & Light[2]	573	17.7
Avista[2]	374	11.5
Bonneville Power Administration[3]	343	10.6
Portland General Electric[2]	251	7.7
NorthWestern Energy [2,4]	189	5.8
Western Area Power Administration[3]	159	4.9
PacificCorp[2]	129	4.0
Rocky Mountain	83	2.6
Invenergy	50	1.6
Yellowstone	48	1.5
Other	97	3.0
TOTAL	3,243	100.0%

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

PPL Montana plants (previously owned by MPC) produce the largest amount of electricity in Montana (see Figure 1; Table E2). PPL Montana's facilities accounted for just under 30 percent of the total generation in Montana in the period 2003-2007. Federal agencies — Bonneville Power Administration and Western Area Power Administration — collectively produced 15.5 percent of the electricity generated in Montana. Two former MPC plants were not purchased by PPL— the recently dismantled Milltown Dam and a lease for a share of Colstrip Unit 4. Both were bought by NorthWestern Energy. NorthWestern's share of Colstrip now accounts for almost 6 percent of the total generation in the state. NorthWestern retained and has added to MPC's Qualifying Facility (QF) contracts, including those with Colstrip Energy Limited Partnership, Montana Department of Natural Resources and Conservation, Hydrodynamics, Two Dot Wind and Yellowstone Energy Limited Partnership. NWE also has contracts for the output from Basin Creek, Judith Gap and Tiber. The output of all these resources under contract to NorthWestern equals less than 5 percent of Montana production. (Table E2 and Table E3)

Montana generation is powered almost entirely by coal (63 percent average for 2003-2006) and hydro (34 percent from 2003-2006). Over the last 15 years, about a quarter of Montana coal production has gone to generate electricity in Montana. Until 1986, when Colstrip 4 was built, hydro was the dominant source of net electric generation in Montana (Table E5). Most of the small amount of petroleum used (1.5 percent in 2006) actually is petroleum coke from the refineries in Billings. Small amounts of natural gas (0.4 percent) and wind (1.7 percent) round out the in-state generation picture1 (Table E5). It is likely that wind will make up a larger percentage of Montana's total generation in the future as more wind farms get built.

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.

4. Consumption

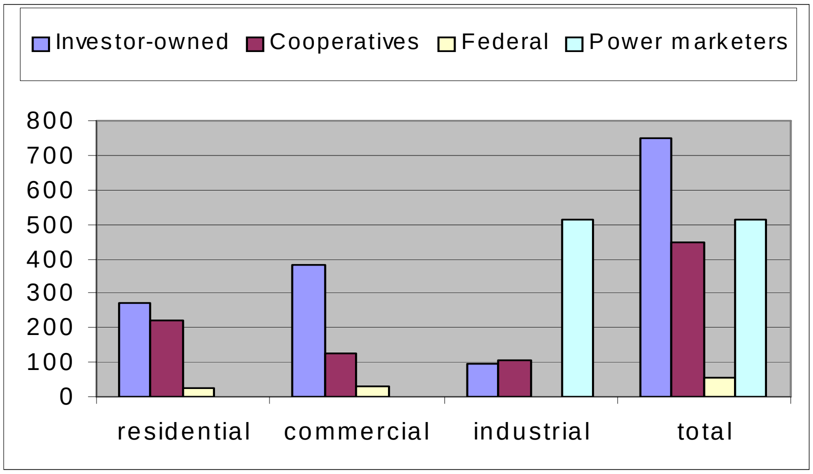
Montanans are served by 31 distribution utilities: Two are investor-owned, 25 are rural electric cooperatives, three are federal agencies and one is a municipality (Table E9). Two additional investor-owned utilities and four co-ops are based in other states but serve a handful of Montanans. In 2007, investor-owned utilities made 43 percent of the electricity sales in Montana, co-ops 25 percent, federal agencies 3 percent and power marketers 29 percent (Table E8; Figure 2). About three-quarters of these entities operate mostly or exclusively in Montana.

Reported sales in 2008 were 17.2 billion kWh. (Unreported power marketer sales may have been around 0.3 billion kWh.) The residential and commercial sectors in 2008 each accounted for about 25-30 percent of sales and the industrial sector accounted for about 45 percent of sales. Sales tripled between 1960 and 2000, then dropped by more than 15

[1] http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept05mt.xls

percent as industrial loads tumbled following the electricity crisis of 2000-2001 (Table E6; Figure 3).

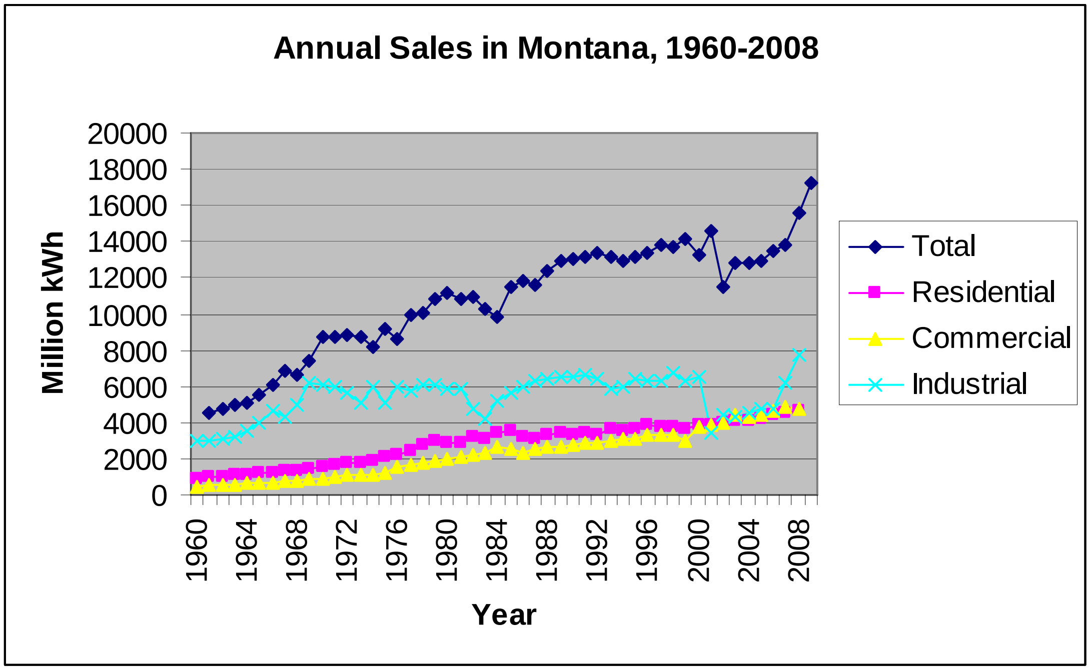
Figure 2. Distribution of 2007 sales by type of utility (aMW)



Source: Table E8.

Sales are now well above their 2000 level and are near an all time high. Since 1990, sales to the commercial sector have grown the most, followed by the residential sector. Industrial sales bounced around, then dropped significantly, held steady from 2002-2006 and are rising quickly over the past three years. Consumption patterns in this decade are noticeably different than those of previous decades.

Figure 3. Annual sales in Montana, 1960-2008



Source: Table E6

The cost of electricity changed dramatically following the year 2000 (Table E7). The average price per kWh for residential customers was 9.1 cents in 2008, up from 6.5 cents in 2000 (40 percent increase). The average price per kWh for commercial customers was 8.5 cents in 2008, up from 5.6 cents in 2000 (52 percent increase); for industrial, the comparable figures are 5.7 cents and 4.0 cents (43 percent increase). In 2007, the average electricity price offered by utilities was 8.9 cents and by coops, 7.0 cents.

As in previous decades, electricity in Montana costs less than the national average. In 2008, Montana averaged 7.4 cents/kWh vs. 9.8 cents/kWh nationally.

Montana residential consumption averaged 824 kWh/month in 2007, or about 1.1 akW annually, basically unchanged since 2000 (Table E8). This average covers a wide range of usage patterns. Households without electric heat can run 200 kWh to 1,000 kWh per month (0.3-1.4 akW annually), depending on size of housing unit and amount of appliances. Electrically heated houses easily could range between 1,800 kWh to 3,000 kWh per month (2.5 and 4.1 akW annually). Extreme cases could run higher or lower than these ranges.

Commercial accounts averaged about 4,000 kWh/month or 5.43 akW per year in 2007. Because so many different types of buildings and operations are included in the commercial sector, it's difficult to describe a typical use pattern.

5. Future Supply and Demand

Eight large generation plants in Montana have come on line this decade, including:

- Montana-Dakota Utilities' (MDU) Glendive No. 2, a 43 MW natural gas turbine
- Tiber Montana LLC's 7.5 MW hydro plant at Tiber Dam
- The Basin Electric natural gas turbine in Butte (50 MW),
- The Rocky Mountain Power coal plant in Hardin (109 MW),
- Thompson River Co-gen plant, a 16.5 MW coal or biomass-fired fluidized bed plant (not currently operating),
- The Judith Gap wind farm (135 MW) just north of Harlowton,
- The Naturener Glacier wind farm (106.5 MW currently, with a future phase of 103.5 MW), and
- MDU's Diamond-Willow Wind Farm near Baker (20 MW).

In addition, a 9 MW wind farm went in near Great Falls in early 2006. Numerous other energy facilities around the state are in various earlier stages of preparation and even expansion. As many as 50 wind power projects are in various stages in Montana. With the construction of the 230-kilovolt Montana Alberta Tie Line, up to 300 MW of power could come online. In 2009 PPL Montana started a $230 million project to expand the Rainbow hydroelectric plant. NorthWestern Energy's 150 MW Mill Creek power generating facility is due for completion by the end of 2010. An additional 50MW of capacity, depending on the requirement, would be added to the natural gas facility later. Southern Montana Electric Generation & Transmission Cooperative is working on a natural gas facility to produce about 120 megawatts of electricity. Phase I would feature two natural-gas-fired turbines, while Phase II would add heat-recovery steam generators that would power an additional turbine

In the previous decade, the only sizeable additions in Montana were two plants built to take advantage of the federal Public Utility Regulatory Policies Act of 1978, known as PURPA. This act 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 plants account for about 92 percent of the average production of all QFs in Montana.

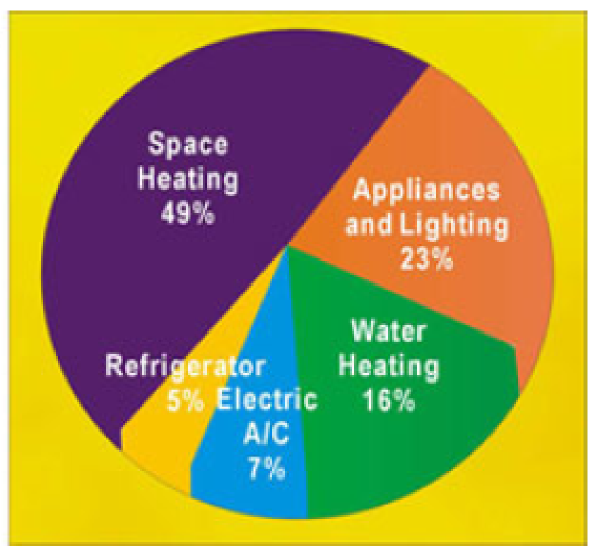
Electricity sales show an overall increase this decade. The overwhelming majority of Montana customers, including many of those served by co-ops, have seen significant increases in the cost of electricity since 2000, the start of the electricity crisis. In spite of that, residential consumption rose at an average annual rate of about two percent (2000 to 2008) and commercial consumption at almost three percent annually. Residential growth tends to track population growth, while commercial growth tends to track economic activity, but growth in both sectors may slow if prices continue to rise. Industrial consumption has increased steadily since 2001, and is at an all time high as of 2008, surpassing its peak year of 1998. There are no statewide forecasts for future electricity consumption.

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

6. Potential for Efficiency and Conservation

Energy conservation refers to activities that reduce the amount of electricity used by a consumer -- like turning a light off when you leave the room. Energy efficiency results from technologies that are more efficient or use less energy -- like a compact florescent light bulb versus an incandescent bulb. Demand response is when customers temporarily alter their behavior in response to signals from the utility. An example is lighting fixtures that are dimmed remotely by utility personnel during times of high electricity demand. The three (efficiency, conservation, and demand response) are often linked and simply referred to as "demand side management" or DSM. Montana's current energy policy (Tile 90, chapter 4, part 10 MCA) promotes energy conservation, energy efficiency, and demand side management.

Montana DEQ - Energy Efficiency In Your Home-Existing Homes



Montana ranked 31st overall among the fifty states on the 2009 State Energy Efficiency Scorecard produced by the American Council on Energy Efficiency Economy in terms of energy efficiency efforts. According to the Energy Information Administration, Montana utilities spent $6.7 million on energy efficiency in 2007, saving 43,329 MWh.

The Northwest Power and Conservation Council produces estimates of the amount of conservation that can be acquired cost effectively in the four state Pacific Northwest region (Washington, Oregon, Idaho, and Montana). The most recent draft report released in September 2009 envisions that 58 percent of the new demand for electricity over the next five years could be met with energy efficiency. Over the entire 20-year horizon of the power plan, energy-efficiency, which is the most cost-effective and least-risky resource available, could meet 85 percent of the Northwest's new demand for power.

In March 2009, NorthWestern Energy provided an annual Universal System Benefits (USB) program report showing about $1.86 million focused on energy conservation programs (This compares to about $3.4 million directed to low-income activities.) NorthWestern, for example, provides an energy audit program for residential customers. In 2008 more than 2,750 on-side audits were funded. In a similar report MDU reported $11,922 directed to energy conservation programs. In MDU's Integrated Resource Plan, it shows a total of $349,274 spent on DSM in 2007 and $386,910 in 2008. Cooperatives also report spending on conservation in the USB reports, so, for example, Flathead Electric Cooperative reported spending about $5.5 million on energy conservation and Yellowstone Valley reported spending $772,758. Many western Montana cooperatives are served by the Bonneville Power Administration. That means they are included in Northwest Power and Conservation Council and Northwest Energy Efficiency Alliance activities.

An increased number of people are taking part in NorthWestern's E+ Audit program. A decision by the PSC in 2008 freed up additional money allowing NorthWestern to increase its audit budget. With the increased budget and increased interest, NorthWestern expects to perform more than 4,000 audits in 2009. NorthWestern also reports growing interest in the E+ Natural Gas program. The E+ Electric Savings program is targeted to a narrow audience because of the low saturation of electric space heater and electric water heat in NorthWestern's customer base.

NorthWestern also completes an Electric Supply Resource Procurement Plan every two years, the plan evaluates "the full range of cost-effective electricity supply and demand-side management options." In the plan, an annual demand-side management goal of 5

MW per year is in place. NorthWestern also has entered into a contract with the National Center for Appropriate Technology to assist with demand side management programs

In early 2008, Governor Brian Schweitzer announced an initiative to reduce energy use at each executive agency by 20% by 2010. Capital projects, including energy conservation projects in state-owned facilities, such as those under the "State Building Energy Conservation" will be used to meet the goal.

More recently energy conservation and efficiency also have gained support from the Western Governor's Association. In July 2007, the Western Governors' Association brought together stakeholders from building and energy industries, government, public interest groups and utilities to discuss opportunities for improving energy efficiency.

Recommendations included:

- The federal government, states, local jurisdictions and utilities should increase the number of incentive options available to consumers and builders who make energy-efficient choices.

- Decoupling and public benefits charges should be considered as mechanisms to fund large-scale energy efficiency programs in all Western states.

Profits for investor-owned utilities are tied to electricity sales, so decoupling can encourage or reward utilities to promote reduced sales and increased conservation. In some states public utility commissions encourage utilities to invest in efficiency and conservation by "decoupling" electricity sales and revenues. Utilities can then compensate for lost sales through rate adjustments.

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.

Table E1. Electric Power Generating Capacity by Company and Plant as of August 2009[1] (Megawatts-MW)

COMPANY	PLANT	COUNTY	ENERGY SOURCE	INITIAL OPERATION (First Unit)	CAPACITY (MW) GENERATOR NAMEPLATE	SUMMER CAPABILITY	WINTER CAPABILITY
Avista	Noxon Rapids 1-5	Sanders	Water	1959	510.3	548	548
NaturEner	Glacier 1	Toole	Wind	2008	106.5	25.695	44.695
Mission Valley Power Co.	Hellroaring	Lake	Water	1916	0.4	0.4	0.4
Rocky Mountain Power	Hardin[2]	Big Horn	Subbituminous Coal	2006	119	109	109
Montana-Dakota Utilities	Diamond Willow	Fallon	Wind	2007	19.5	4.8	15.5
Montana-Dakota Utilities	Glendive #1	Dawson	Natural Gas/#2 Fuel Oil	1979	34.8	36	41.7
Montana-Dakota Utilities	Glendive #2	Dawson	Natural Gas/#2 Fuel Oil	2003	40.7	41.6	44.4
Montana-Dakota Utilities	Glendive Diesel	Dawson	#1 & #2 Blend Diesel	2005	1.8	2.01	2.01
Montana-Dakota Utilities	Lewis & Clark	Richland	Lignite Coal/Natural Gas	1958	44	52.3	48.1
Montana-Dakota Utilities	Miles City	Custer	Natural Gas/#2 Fuel Oil	1972	23.2	24.5	28.6
Northern Lights Cooperative	Lake Creek A&B	Lincoln	Water	1917	4.5	4.7	4.5
NWE Portfolio - Basin Creek Power	Basin Creek 1-9	Silver Bow	Natural Gas	2006	54.9	53.1	53.1
NWE Portfolio - Invenergy Wind	Judith Gap	Wheatland	Wind	2006	135	34	34
NWE Portfolio (winter) - Tiber Montana, LLC	Tiber Dam	Liberty	Water	2004	7.5	7	5.5
NWE QF - Colstrip Energy Partnership	Montana One	Rosebud	Waste Coal	1990	41.5	39	39
NWE QF - Hydrodynamics	South Dry Creek[3]	Carbon	Water	1985	2	2	--
NWE QF - Montana DNRC	Broadwater	Broadwater	Water	1989	10	10	8.1
NWE QF - Two Dot Wind	Martinsdale Colony S.	Wheatland	Wind	2006	2	0.55	0.653266332
NWE QF - other hydro	Various	Various	Water	Various	2.5	0.8	0.8
NWE QF - other wind	Various	Various	Wind	Various	2	0.5	0.6
NWE QF - Yellowstone Partnership	BGI	Yellowstone	Petroleum Coke	1995	65	57	58
PacifiCorp	Big Fork 1-3	Flathead	Water	1910	4.1	4.6	4.6
PPL Montana	Black Eagle 1-3	Cascade	Water	1927	24	20	17
PPL Montana	Cochrane 1-2	Cascade	Water	1958	48	56	36
PPL Montana (50%) Puget Sound Energy (50%)	Colstrip 1	Rosebud	Subbituminous Coal	1975	358	307	307
PPL Montana (50%) Puget Sound Energy (50%)	Colstrip 2	Rosebud	Subbituminous Coal	1976	358	307	307
PPL Montana (30%) Avista (15%), PacifiCorp (10%) Portland General Electric (20%) Puget Sound Energy (25%)	Colstrip 3	Rosebud	Subbituminous Coal	1984	778	740	740
PPL (operator); Avista (15%) NorthWestern Energy (30%), Puget Sound Energy (25%), PacifiCorp (10%) Portland General Electric (20%)	Colstrip 4	Rosebud	Subbituminous Coal	1986	778	740	740
PPL Montana	Hauser 1-6	Lewis-Clark	Water	1911	17	17	17
PPL Montana	Holter 1-4	Lewis-Clark	Water	1918	38.4	50	50

PPL Montana	J. E. Corette	Yellowstone	Subbituminous Coal	1968	172.8	154	154
PPL Montana	Kerr 1-3	Lake	Water	1938	211.5	193	177
PPL Montana	Madison 1-4	Madison	Water	1906	8.8	8	8
PPL Montana	Morony 1-2	Cascade	Water	1930	45	48	47
PPL Montana	Mystic 1-2	Stillwater	Water	1925	12.4	11	11
PPL Montana	Rainbow 1-8	Cascade	Water	1910	35.6	37	37
PPL Montana	Ryan 1-6	Cascade	Water	1915	48	60	60
PPL Montana	Thompson Falls 1-7	Sanders	Water	1915	87.5	95	95
Salish - Kootenai Tribe	Boulder Creek	Lake	Water	1984	0.4	0.4	0.4
Thompson River Co - gen	Thompson River[4]	Sanders	Coal/wood	2004	16	0	0
US BurRec - Great Plains Region	Canyon Ferry 1-3	Lewis-Clark	Water	1953	49.8	57.6	57.6
US BurRec - Great Plains Region	Yellowtail 1-4 [5]	Big Horn	Water	1966	250	287.2	287.2
US BurRec - Pacific Northwest Region	Hungry Horse 1-4	Flathead	Water	1952	428	419.1	393.8
US Corps - Missouri River Division	Fort Peck 1-5 [6]	McCone	Water	1943	185.3	179.5	179.5
US Corps - North Pacific Division	Libby 1-5	Lincoln	Water	1975	525	598.7	544.6
United Materials (Idaho QF/NWE QF)	Horseshoe Bend	Cascade	Wind	2006	9	2	2
TOTAL MONTANA CAPACITY (MW)					5,715.7	5,445.0	5,311.2

[1] Does not include a 17.3 MW waste-wood facility that supplies the Smurfit-Stone plant in Missoula, the 4 MW coal-fired Sidney Sugars facility and other small units that are net-metered or that are located behind the meter.
[2] Purchased from MDU Resources in April 2007 by
[3] Only operates during summer.
[4] Currently idle.
[5] Units 1-4 normally are synchronized to the west (WECC); however, two units may be synchronized to the midwest (MAPP).
[6] Units 1-3 are normally synchronized to the WECC west grid (105.3 MW nameplate) and units 4 and 5 are normally synchronized to the midwest MAPP east grid (80 MW nameplate). Unit 3 (43.5 MW nameplate) can readily be operated on either the WECC or MAPP grids.

Sources: On-line date and nameplate (except where otherwise noted)-U.S.. DOE Energy Information Administration "Form EIA-860 Database Annual Electric Generator Report 2007" http://www.eia.doe.gov/cneaf/electricity/page/eia860.html; Glacier, Hell Roaring, Hardin, all MDU facilities, Lake Creek, Broadwater, Two Dot Wind, Boulder Creek and Horseshoe Bend - Owner; Capability, including wind derating (unless otherwise noted)-WECC, Existing Generation spreadsheet, 8-13-09; capability for Hell Roaring, all MDU facilities, and Lake - owner; capability for NWE QF-other hydro - NWE; capability for Fort Peck and Yellowtail - WAPA.

Table E2. Net Electric Generation By Plant, 2003-2007[1] (MWh)

COMPANY / PLANT	2003	2004	2005	2006	2007	aMW[2] 2003-2007	aMW[2] 1995-1999	03-07 as % of 95-99[3]
Avista								
Noxon	1,542,705	1,595,423	1,588,576	1,823,945	1,590,451	185.9	236.2	-21%
Basin Creek Power Services LLC								
Basin Creek Plant	--	--	--	40,587	80,267	6.9	--	
Bonneville Power Administration								
Hungry Horse	729,010	812,973	850,916	1,055,468	777,371	96.5	103.3	-7%
Libby	1,908,585	2,005,877	2,355,842	2,190,677	2,344,156	246.7	278.4	-11%
Clark Fork and Blackfoot LLC (NWE)								
Milltown[4]	6,508	15,739	13,102	2,326	--	1.1	2.1	-48%
Colstrip Energy Partnership								
Montana One (NWE QF)[4]	302,413	299,017	304,923	309,789	303,650	34.7	29.9	16%
Hydrodynamics								
South Dry Creek (NWE QF)[4]	45	5,458	5,466	6,262	6,605	0.5	0.7	-26%
Strawberry Creek (NWE QF)[4]	1,308	1,134	1,403	1,410	1,519	0.2	0.2	1%
Invenergy Services LLC								
Judith Gap Wind Energy Center	--	--	--	412,442	471,279	50.4	--	
Mission Valley Power								
Hellroaring	1,703	1,919	2,034	1,929	1,767	0.2	0.2	-10%
Montana-Dakota Utilities								
Diamond Willow	--	--	--	--	16	0.0	--	
Glendive	16,344	9,656	8,628	6,512	12,687	1.2	1.6	-21%
Lewis-Clark	323,158	347,857	283,984	336,937	314,675	36.7	25.4	44%
Miles City	2,181	3,310	1,916	1,648	2,623	0.3	0.9	-69%
MT Dept of Nat. Res. and Con.								
Broadwater Dam (NWE QF)[4]	43,837	40,666	43,753	48,249	44,982	5.1	5.9	-14%
Northern Lights Cooperative								
Lake Creek[5]	25,430	28,128	25,411	27,073	27,406	3.0	3.5	-12%
Northwestern Qualifying Facilities								
Other hydro[4]	5,286	6,856	7,142	7,010	5,552	0.7	0.9	-17%
Wind[4,6]	--	--	--	--	6			
PacifiCorp								
Big Fork	26,555	30,084	30,861	31,391	24,435	3.3	2.3	45%
PPL Montana								
Black Eagle	122,072	114,603	126,265	136,211	124,084	14.2	16.6	-14%
Cochrane	234,704	212,246	259,335	276,795	233,765	27.8	39.7	-30%
Colstrip[7]	15,214,950	15,571,229	16,240,783	14,764,749	15,840,087	1,772.4	1,574.2	13%
Hauser Lake	120,040	106,668	119,516	127,815	118,972	13.5	15.7	-14%
Holter	250,752	207,124	251,413	279,655	223,234	27.7	39.2	-29%
J E Corette	1,251,896	1,183,327	1,010,647	1,204,206	1,186,136	133.2	104.2	28%
Kerr	886,695	1,065,767	1,032,058	1,076,089	1,088,593	117.6	133.5	-12%
Madison	60,057	61,255	65,788	67,595	60,099	7.2	6.8	6%
Morony	244,474	215,002	251,361	273,198	241,470	28.0	40.4	-31%
Mystic Lake	45,052	43,319	42,622	43,252	48,577	5.1	5.7	-11%
Rainbow	215,588	211,981	232,736	238,164	228,869	25.7	29.1	-12%
Ryan	347,549	364,224	405,654	411,025	384,540	43.7	54.2	-19%
Thompson Falls	452,393	501,708	458,902	493,070	509,373	55.1	56.6	-2%
Rocky Mountain Power								

2007		
1,590,451	1,590,451	0
80,267	80,267	0
303,650	303,650	0
		0
24,481	24,481	0
6,579	6,605	-26
471,279	471,279	0
16	16	0
12,687	12,687	0
314,675	314,675	0
2,623	2,623	0
44,977	44,982	-5
0		0
24,435	24,435	0
124,084	124,084	0
233,765	233,765	0
15,840,087	15,840,087	0
118,972	118,972	0
223,234	223,234	0
1,186,136	1,186,136	0
1,088,593	1,088,593	0
60,099	60,099	0
241,470	241,470	0
48,577	48,577	0
228,869	228,869	0
384,540	384,540	0
509,373	509,373	0
728,486	728,486	0
		0
38,901	38,901	0
285,725	285,725	0
777,371	777,371	0
380,434	380,434	0
609,731	609,731	0
2,344,156	2,344,156	0

Hardin Generating Station	--	--	--	489,442	728,486	83.2	--	
Salish-Kootenai								
Boulder Creek[6]	225	736	925	1,263	1,042	0.1	0.2	-60%
Tiber Montana, LLC								
Tiber (NWE portfolio)	--	22,798	38,407	42,986	38,901	4.1	--	
Two Dot Wind (NWE QF)								
Martinsdale Colony	--	--	1,113	1,277	1,319	0.1	--	
Martinsdale Colony South	--	--	--	--	533	0.1	--	
Mission	170	173	154	168	131	0.0	0.0	-5%
Moe Wind	--	--	--	144	598	0.0	--	
Montana Marginal	378	462	469	447	376	0.0	0.1	-9%
Sheep Valley	--	512	912	878	923	0.1	--	
United Building Materials								
Horseshoe Bend	--	--	--	23,528	24,481	2.7	--	
Western Area Power Administration								
Canyon Ferry	321,143	241,219	298,412	329,710	285,725	33.7	49.9	-32%
Fort Peck	819,292	692,882	564,077	704,920	609,731	77.4	139.7	-45%
Yellowtail	325,278	320,996	603,803	475,182	380,434	48.1	133.1	-64%
Yellowstone Energy Partnership								
Billings Generation Inc. (NWE QF)[4,8]	378,005	452,112	429,519	424,898	428,640	48.2	46.9	3%
TOTALS	26,225,781	26,794,441	27,958,829	28,190,321	28,798,567	3,242.5	3,177.3	2%

[1] Net generation equals gross generation minus plant use.

[3] 1995-1999 was the period immediately preceding deregulation. It also was a relatively wet period, good for hydro.

[4] NWE plants and contracts were owned by MPC until February 2002.

[5] Data are gross, not net, generation; 1995-1999 actually for 1997-1999.

[6] 1995-1999 average actually is for 1999 only.

[7] Operated by PPL; actual ownership shared by six utilities.

[8] 1995-1999 average actually is for 1996-1999.

[9] A subsidiary of BiCent

Source: U.S. Department of Energy, Energy Information Administration, Form 906 and 920 databases (http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html), Mission Valley Power, Northern Lights Cooperative, NorthWestern Energy for QF and Milltown data, S&K Holdings, Tiber LLC.

481,724	428,640	53,084
28,810,447	28,757,395	53,052

Table E3. Average Generation by Company, 1995-1999 and 2003-2007

Company	aMW[1] 1995-1999[2]	aMW[1] 2003-2007
Avista[3]	403.1	373.8
Basin Creek Power Services	--	6.9
Bonneville Power Administration[4]	381.7	343.2
Colstrip Energy Partnership	29.9	34.7
Hydrodynamics	0.9	0.7
Invenergy	--	50.4
Mission Valley Power	0.2	0.2
Montana-Dakota Utilities	27.9	38.2
MT Dept of Natural Resources and Conservation	5.9	5.1
Northern Lights Cooperative	3.5	3.0
NorthWestern Energy[3,5]	169.0	189.0
NWE QF - other hydro[5]	0.9	0.7
NWE QF- wind[5]	0.1	0.0
PacificCorp[3]	113.5	128.5
Portland General Electric[3]	222.5	250.5
PPL Montana[3,6]	939.5	946.6
Puget Sound Energy[3]	509.0	573.0
Rocky Mountain Power	--	83.2
Salish-Kootenai Tribes	0.1	0.1
Tiber LLC	--	4.1
Two Dot Wind	0.1	0.4
United Building Materials	--	2.7
Western Area Power Administration[4]	322.7	159.2
Yellowstone Energy Partnership	46.9	48.2
TOTAL	3,177.3	3,242.5

[1] aMW = average megawatt, or 8,760 megawatt hours in a year

[2] 1995-1999 was the period immediately preceding deregulation. It also was a relatively wet period, good for hydro.

[3] Output for Colstrip 1-4 is reported for the entire facility, not individual units. In this table, output was allocated among the partners on the basis of their ownership percentages. NorthWestern actually holds a lease on a portion of output from Colstrip 4.

[4] Distributes power generated at US Corps of Engineers and US Bureau of Reclamation dams.

[5] NWE plants and contracts were owned by Montana Power Company until February 2002

[6] PPL Montana plants were owned by Montana Power Company until mid-December 1999

Source: U.S. Department of Energy, Energy Information Administration, Form 906 and 920 databases (http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html), Mission Valley Power, Northern Lights Cooperative, NorthWestern Energy for QF and Milltown data, S&K Holdings, Tiber LLC.

Average Generation by Plant Owner

	1995-1999		2003-2007	
PPL	940	29.6%	947	29.2%
Puget	509	16.0%	573	17.7%
Avista	403	12.7%	374	11.5%
BPA	382	12.0%	343	10.6%
PGE	223	7.0%	251	7.7%
NWE	169	5.3%	189	5.8%
WAPA	323	10.2%	159	4.9%
Pacific	114	3.6%	129	4.0%
Rocky Mt	--	--	83	2.6%
Invenergy	--	--	50	1.6%
Yellowstone	47	1.5%	48	1.5%
Other	69	2.2%	97	3.0%
TOTAL	3,177	100.0%	3,243	100.0%

Colstrip Ownership Percentages (based on capability)

	MW	Percent		
Avista	222	11%	I & II	III & IV
NorthWestern	222	11%	614	1480
PacifiCorp	148	7%		
PPL	529	25%		
Portland	296	14%		
Puget	677	32%		
	2094	100%		

Table E4. Annual Consumption of Fuels for Electric Generation, 1960-2007[1]

YEAR	COAL (thousand short tons)	PETROLEUM[2] (thousand barrels)	NATURAL GAS (million cubic feet)
1960	187	*	341
1961	263	*	356
1962	292	1	3,713
1963	286	1	3,303
1964	294	4	2,450
1965	296	1	1,992
1966	324	82	2,977
1967	325	6	503
1968	399	23	631
1969	577	105	1,521
1970	723	26	2,529
1971	672	0	1,080
1972	769	18	1,217
1973	893	152	2,167
1974	855	14	1,038
1975	1,061	63	1,073
1976	2,374	81	709
1977	3,197	195	953
1978	3,184	98	909
1979	3,461	147	2,320
1980	3,352	59	4,182
1981	3,338	39	2,069
1982	2,596	31	337
1983	2,356	31	335
1984	5,113	78	360
1985	5,480	38	468
1986	7,438	25	407
1987	7,530	44	478
1988	10,410	63	286
1989	10,208	60	336
1990	9,573	67	588
1991	10,460	46	427
1992	11,028	38	370
1993	9,121	51	420
1994	10,781	46	765
1995	9,641	474	626
1996	8,075	663	707
1997	9,465	664	673
1998	10,896	1,072	734
1999	10,903	1,144	520
2000	10,385	1,167	409
2001	10,838	1,081	297
2002	9,746	1,058	245

2003	11,032	981	334
2004[3]	11,322	752	261
2005[3]	11,588	708	276
2006[3]	11,302	727	623
2007[3]	11,929	824	1,045

* less than 0.05

[1] Data includes fuel use at independent power producers, which first came on line in 1990. The data do not include all self-generation at industrial facilities. Data exclude small amounts of waste gases used for generation.

[2] Includes petroleum coke starting in 1995. One ton of petroleum coke equals 6.07 barrels.

[3] A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented for 2004-2007. This new methodology proportionally distributes a combined heat and power (CHP) plant's losses between the two output products (electric power and UTO). This change results in lower fuel consumption for electricity generation, and therefore the appearance of an increase in efficiency of production of electric power between 2003 and 2004.

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 Annual 2002 - Consumption Spreadsheet (Form EIA906 data-http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html)(1990-2007).

Table E5. Net Electric Generation by Type of Fuel Unit, 1960-2007 (million kWh)[1]

YEAR	HYDROELECTRIC (million kWh)	%	COAL (million kWh)	%	PETROLEUM [2] (million kWh)	%	NATURAL GAS (million kWh)	%	WIND (million kWh)	%	TOTAL
1960	5,801	97	NA		NA		NA				5,992
1961	6,499	96	263	4	0	*	19	*			6,780
1962	6,410	91	291	4	1	*	349	5			7,051
1963	6,011	91	284	4	0	*	299	5			6,594
1964	6,821	93	286	4	2	*	220	3			7,329
1965	8,389	95	285	3	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	*			15,057
1984	11,113	59	7,650	41	36	*	40	*			18,839
1985	10,178	54	8,465	45	16	*	58	*			18,717
1986	10,863	49	11,469	51	9	*	52	*			22,393
1987	8,931	43	11,836	57	17	*	58	*			20,842
1988	8,246	33	16,462	66	30	*	37	*			24,775
1989	9,580	37	16,129	63	30	*	43	*			25,782
1990	10,717	41	15,120	58	29	*	55	*			26,030
1991	11,970	42	16,433	58	20	*	32	*			28,553
1992	8,271	32	17,454	67	17	*	35	*			25,900
1993	9,614	40	14,083	59	22	*	35	*			23,873
1994	8,150	32	16,809	67	20	*	73	*			25,153
1995	10,746	41	14,934	58	168	1	49	*			25,961
1996[3]	13,799	51	12,463	46	445	2	55	*			26,842
1997[3]	13,437	47	14,616	51	437	2	49	*			28,617
1998[3]	11,143	39	16,785	59	427	1	56	*			28,486
1999[3,4]	11,879	40	16,993	58	487	2	37	*			29,476
2000[3]	9,649	36	16,201	61	520	2	27	*			26,478
2001[3]	6,627	27	17,036	70	498	2	20	*			24,246
2002[3]	9,596	38	15,338	60	470	2	17	*			25,502

2003[3]	8,727	33	17,049	65	402	2	25	*			26,294
2004[3]	8,923	33	17,380	65	439	2	28	*			26,855
2005[3]	9,664	34	17,823	64	415	1	27	*			28,016
2006[3]	10,160	36	17,085	60	419	1	68	*	437	2	28,274
2007[3]	9,392	32	18,357	63	479	2	106	*	497	2	28,960

NA = Not available *Less than 0.5 percent.

[1] Gross generation less the electric energy consumed at the generating station for facilities with greater than 1 MW nameplate and owned by or selling to electric utilities and cooperatives. Starting in 1983, annual output of non-utility plants selling into the grid is included. From 1990 forward, TOTAL includes minor amounts of generation from sources not listed in the table. Those sources are primarily wood-fired plants that on net supplement a facility's power from the grid; in the period since 1990, all these collectively have produced less (and usually considerably less) than 120,000 MWh per year. This table is useful for long-term trends; Table E3 has more detailed for recent production figures.

[2] Primarily petroleum coke and some fuel oil.

[3] Output from certain hydro and wind facilities, most notably Lake (1996-2007) and Tiber (2004-2005), aren't included in the EIA database and have been added in by DEQ.

[4] U.S. DOE figures appear to have double-counted output from some of the dams MPC sold to PPL in December. Therefore, DEQ adjusted the hydroelectric generation and total generation, based on data presented in Table E3.

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, *1990 - 2007 Net Generation by State by Type of Producer by Energy Source (s* preadsheet derived from EIA-906 and 920 databases - http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html).

Table E6. Annual Sales of Electricity, 1960-2008 (million kilowatt-hours)

	MONTANA					USA
Year	Residential	Commercial	Industrial	Other[1]	Total	TOTAL
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	3,101,127
1997[2]	3,804	3,293	6,353	284	13,734	3,145,610
1998[3]	3,722	3,313	6,774	335	14,145	3,264,231
1999[3]	3,664	3,025	6,258	334	13,282	3,312,087
2000[3]	3,908	3,792	6,568	312	14,580	3,421,414
2001[3]	3,886	3,866	3,370	324	11,447	3,394,458
2002[3]	4,031	4,003	4,463	335	12,831	3,465,466
2003[3]	4,120	4,438	4,267	NA	12,825	3,493,734
2004[3]	4,053	4,330	4,574	NA	12,957	3,547,479
2005[3]	4,221	4,473	4,784	NA	13,479	3,660,969
2006[3]	4,394	4,686	4,735	NA	13,815	3,669,919
2007[3]	4,542	4,828	6,163	NA	15,532	3,764,561
2008[3]	4,652	4,804	7,731	NA	17,187	3,721,562

NA: Not available. This category is now rolled into Commercial or Industrial; there are no Transportation sales in Montana.

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

[2] EIA data on industrial sales corrected by adding BPA sales of 1,816 million kWh, which EIA didn't include in this year.

[3] Some power marketers did not report sales data, did not report it accurately, or reported it in a manner different than traditional utilities. This problem is believed to be most pronounced in 1999, the first full year of deregulation and may be gone by the 2005 data.

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 (1997-2008, http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/sales_tabs.html); updated information on 1197 sales provided by Bonneville Power Administration (1997).

Table E7. Average Annual Prices for Electricity Sold, 1960-2008 (cents per kilowatt-hour)[1]

	MONTANA								U.S.
Year	Residential	Commercial	Industrial	Street & Highway Lighting	Other Public Authorities	Railroads & Railways	Intra-Company Sales	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	4.68	2.87	11.59	2.07	--	3.87	3.96	6.57
1991	5.76	5.00	2.92	9.27	2.92	--	4.96	4.14	6.75
1992	5.84	5.17	2.89	10.21	2.73	--	4.82	4.19	6.82
1993	5.77	5.10	3.10	7.07	2.44	--	4.65	4.36	6.93
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	6.89
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[2]	6.50	5.87	3.26	14.09	NA	--	NA	4.79	6.74
1999[2]	6.78	6.35	3.14	14.36	NA	--	NA	4.96	6.64
2000[2]	6.49	5.60	3.97	NA	NA	--	NA	5.00	6.81

2001[2]	6.88	5.91	6.59	NA	NA	--	NA	6.48	7.29
2002[2]	7.23	6.28	3.71	NA	NA	--	NA	5.70	7.20
2003[2]	7.56	6.85	4.03	NA	NA	--	NA	6.14	7.44
2004[2]	7.86	7.42	4.15	NA	NA	--	NA	6.40	7.61
2005[2]	8.10	7.43	4.83	NA	NA	--	NA	6.72	8.14
2006[2]	8.28	7.44	5.12	NA	NA	--	NA	6.91	8.90
2007[2]	8.77	8.10	5.16	NA	NA	--	NA	7.13	9.13
2008[2]	9.14	8.54	5.73	NA	NA	--	NA	7.44	9.82

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

[1] Average annual prices were calculated by dividing total revenue by total sales as reported by Edison Electric Institute (1960-1999) and by U.S. Department of Energy Energy Information Administration (2000-2006).

[2] Calculation of prices are based on data that include distribution utility receipts for delivering power for power marketers, but may not include revenue and sales for some power marketers. This problem is believed to be most pronounced in 1999, the first full year of deregulation and may be gone by the 2005 data. Errors in price, where they exist, are most likely to occur in industrial prices, and are unlikely to be more than a tenth of a cent or two.

Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, 1961-2000; U.S. Department of Energy, Energy Information Administration, Form 861 Database (2000-2006 Historical Sales and Revenue, http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/sales_tabs.html).

Table E8. Utility Revenue, Retail Sales, Consumers and Average Price per Kilowatt-hour, 2007 (with comparison to 2000 average price)

	RESIDENTIAL			Average price		COMMERCIAL			Average price		INDUSTRIAL			Average price		TOTAL			Average price	
	Revenue	Sales		(cents/kWh)[3]		Revenue	Sales		(cents/kWh)[3]		Revenue	Sales		(cents/kWh)[3]		Revenue	Sales		(cents/kWh)[3]	
UTILITY NAME	('000s)	(aMW)[1]	Consumers[2]	2007	2000	('000s)	(aMW)[1]	Consumers[2]	2007	2000	('000s)	(aMW)[1]	Consumers[2]	2007	2000	('000s)	(aMW)[1]	Consumers[2]	2007	2000
Cooperative	$153,632	219.7	163,663	8.0	6.6	$73,565	124.0	25,240	6.8	5.7	$46,484	104.4	2,950	5.1	3.2	$273,681	448.1	191,853	7.0	5.2
Beartooth Electric Coop, Inc	$5,163	5.6	4,774	10.6	7.7	$384	0.4	258	10.0	6.8	$306	0.4	54	9.2	5.3	$5,853	6.4	5,086	10.5	7.5
Big Flat Electric Coop Inc	$1,571	1.9	1,487	9.7	8.1	$614	0.7	228	9.6	7.4	$362	0.4	71	9.3	10.2	$2,547	3.0	1,786	9.6	8.4
Big Horn County Elec Coop, Inc	$2,959	4.0	3,027	8.4	7.7	$1,614	2.3	526	8.1	7.4		0.0		--	--	$4,573	6.3	3,553	8.3	7.6
Big Horn Rural Electric Co	$34	0.0	33	10.7	7.6	$168	0.2	27	10.6	11.2	$2,028	2.3	1	10.1	--	$2,230	2.5	61	10.1	10.0
Fall River Rural Elec Coop Inc	$1,471	1.7	1,344	9.6	7.1	$2,100	3.4	487	7.1	5.4	$0	0.0	0	--	--	$3,571	5.1	1,831	7.9	5.9
Fergus Electric Coop, Inc	$6,283	6.5	5,630	11.1	8.6	$4,106	7.7	270	6.1	6.9	$249	0.2	100	12.0	--	$10,638	14.4	6,000	8.5	8.0
Flathead Electric Coop Inc	$45,126	72.8	53,875	7.1	5.1	$28,960	50.2	11,879	6.6	4.7	$12,959	33.4	81	4.4	2.8	$87,045	156.5	65,835	6.4	3.6
Glacier Electric Coop, Inc	$5,941	7.2	5,716	9.4	7.6	$5,343	8.8	1,585	6.9	5.3	$1,210	2.5	4	5.6	4.6	$12,494	18.4	7,305	7.7	6.1
Goldenwest Electric Coop, Inc	$507	0.6	661	10.2	9.8	$124	0.2	10	8.9	10.9	$0	0.0	0	--	--	$631	0.7	671	9.9	10.5
Grand Electric Coop, Inc	$9	0.0	9	6.7	7.1	$0	0.0	0	--	--	$0	0.0	0	--	--	$9	0.0	9	6.7	7.1
Hill County Electric Coop, Inc	$3,560	4.1	3,423	9.8	9.3	$1,667	2.6	156	7.2	6.7	$2,788	8.6	3	3.7	2.8	$8,015	15.4	3,582	5.9	6.1
Lincoln Electric Coop, Inc	$4,168	7.7	4,244	6.2	5.1	$1,517	3.0	652	5.7	4.8	$1,119	2.3	5	5.6	4.6	$6,804	13.0	4,901	6.0	4.9
Lower Yellowstone R E A, Inc	$2,098	3.1	2,375	7.7	7.5	$770	1.0	463	9.1	9.6	$5,814	8.5	702	7.8	9.8	$8,682	12.5	3,540	7.9	8.8
Marias River Electric Coop Inc	$1,549	3.4	2,490	5.2	4.9	$3,187	6.5	1,268	5.6	5.6	$0	0.0	0	--	5.1	$4,736	9.9	3,758	5.5	5.3
McCone Electric Coop Inc	$4,051	4.8	4,412	9.6	9.3	$1,359	2.1	554	7.5	7.2	$0	0.0	0	--	8.8	$5,410	6.9	4,966	9.0	8.7
McKenzie Electric Coop Inc	$45	0.1	112	7.9	7.8	$1	0.0	2	100.0	9.1	$0	0.0	0	--	--	$46	0.1	114	8.0	7.8
Mid-Yellowstone Elec Coop, Inc	$2,181	2.4	1,750	10.3	7.4	$289	0.4	167	9.1	7.7	$0	0.0	0	--	--	$2,470	2.8	1,917	10.1	7.2
Missoula Electric Coop, Inc	$11,883	16.4	12,028	8.3	6.6	$3,110	5.1	1,462	6.9	5.6	$881	1.5	5	6.7	5.0	$15,874	23.1	13,495	7.9	6.2
Northern Electric Coop, Inc	$1,316	1.6	924	9.2	7.9	$0	0.0	0	--	10.3	$1,387	1.4	337	11.1	--	$2,703	3.1	1,261	10.1	8.8
Northern Lights, Inc	$3,403	4.4	3,565	8.8	7.2	$686	1.0	241	7.8	5.5	$1,624	5.0	4	3.7	7.6	$5,713	10.4	3,810	6.3	6.9
Park Electric Coop Inc	$5,548	7.7	5,156	8.2	8.3	$450	0.8	81	6.2	6.5	$3,632	8.8	1	4.7	7.0	$9,630	17.4	5,238	6.3	7.7
Powder River Energy Corp	$27	0.0	41	6.2	8.9	$1,583	3.2	152	5.6	5.8	$4,127	10.9	60	4.3	--	$5,737	14.1	253	4.6	6.1
Ravalli County Elec Coop, Inc	$8,955	14.4	9,170	7.1	6.8	$646	1.1	337	6.7	6.2	$175	0.4	1	5.3	5.0	$9,776	15.9	9,508	7.0	6.6
Sheridan Electric Coop, Inc	$2,084	3.2	2,974	7.4	6.6	$5,239	7.8	735	7.6	7.4	$297	0.3	485	10.6	12.5	$7,620	11.4	4,194	7.6	7.2
Southeast Electric Coop, Inc	$1,689	1.7	1,949	11.2	7.6	$64	0.1	18	9.5	9.3	$3,983	12.0	2	3.8	5.7	$5,736	13.8	1,969	4.7	7.2
Sun River Electric Coop, Inc	$4,235	5.1	4,357	9.4	8.4	$754	1.3	138	6.4	5.7	$1,965	2.9	810	7.6	--	$6,954	9.4	5,305	8.4	7.0
Tongue River Electric Coop Inc	$4,699	6.2	4,231	8.7	6.8	$1,123	1.5	655	8.6	6.4	$1,096	1.8	48	6.8	6.0	$6,918	9.5	4,934	8.3	6.8
Valley Electric Coop, Inc	$1,715	1.8	1,596	10.9	8.8	$692	0.8	289	10.5	7.7	$0	0.0	0	--	--	$2,407	2.6	1,885	10.7	8.5
Vigilante Electric Coop, Inc	$5,526	10.0	7,353	6.3	6.0	$3,072	6.4	1,275	5.5	5.3	$0	0.0	0	--	--	$8,598	16.4	8,628	6.0	5.6
Yellowstone Valley Elec Co-op	$15,836	21.0	14,957	8.6	7.0	$3,943	5.5	1,325	8.2	6.5	$482	0.7	176	--	--	$20,261	27.2	16,458	8.5	6.8
Federal	$11,239	23.9	14,044	5.4	5.2	$8,856	27.9	6,107	3.6	5.8	$697	1.8	1	4.5	2.0	$20,792	53.6	20,152	4.4	2.4
Bonneville Power Administration[4]	NA	NA	NA	NA	--	NA	NA	NA	NA	--	NA	NA	NA	NA	2.0	NA	NA	NA	NA	2.0
USBIA-Mission Valley Power	$11,239	23.9	14,044	5.4	5.2	$6,848	13.3	6,088	5.9	5.8	$697	1.8	1	4.5	4.0	$18,784	39.0	20,133	5.5	5.4
Western Area Power Administration	$0	0.0	0	--	--	$2,008	14.6	19	1.6	--	$0	0.0	0	--	--	$2,008	14.6	19	1.6	0.4
Municipal																				
Troy City of	$598	1.2	811	5.7	5.3	$260	0.6	149	5.1	4.6	$5	0.0	3	9.8	5.3	$863	1.8	963	5.5	5.1
Investor-Owned	$232,970	273.6	280,857	9.7	6.5	$299,152	380.1	66,813	9.0	5.7	$52,833	97.6	1,497	6.2	4.0	$584,955	751.3	349,167	8.9	5.7
Avista	$7	0.0	10	4.7	4.6	$10	0.0	9	6.5	8.0	$0	0.0	0	--	--	$17	0.0	19	5.6	5.3
Black Hills Power Inc	$7	0.0	13	8.2	7.3	$71	0.1	20	8.3	12.2	$1,474	3.3	2	5.1	4.6	$1,552	3.4	35	5.2	4.7
MDU Resources Group Inc	$12,046	18.7	18,531	7.4	7.4	$12,656	25.9	5,111	5.6	5.6	$12,299	32.5	135	4.3	4.3	$37,001	77.1	23,777	5.5	5.7
NorthWestern Energy	$220,910	254.9	262,303	9.9	6.5	$286,415	354.1	61,673	9.2	5.8	$39,060	61.8	1,360	7.2	3.9	$546,385	670.8	325,336	9.3	5.7
Power Marketers[5]	$0	0.0	0	--	2.4	$86	0.3	1	3.7	2.4	$208,811	511.2	17	4.7	NA	$208,897	511.5	18	4.7	NA
Conoco Inc	$0	0.0	0	--	NA	$0	0.0	0	--	NA	$23,514	55.3	6	4.9	NA	$23,514	55.3	6	4.9	NA
Energy West Resources Inc	$0	0.0	0	--	2.4	$86	0.3	1	3.7	2.4	$0	0.0	0	--	2.9	$86	0.3	1	3.7	2.6
Hinson Power Company LLC	$0	0.0	0	--	NA		0.0		--	NA	$89,987	210.0	1	4.9	NA	$89,987	210.0	1	4.9	NA
PPL EnergyPlus LLC	$0	0.0	0	--	NA	$0	0.0	0	--	NA	$95,310	246.0	10	4.4	NA	$95,310	246.0	10	4.4	NA
STATE TOTALS [6]	$398,439	518.4	459,375	8.8	6.5	$381,919	532.9	98,310	8.2	5.7	$308,830	715.0	4,468	4.9	2.9	$1,089,188	1,766.3	562,153	7.0	4.9

[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] Market incentives paid CFAC to suspend operations were included in total revenue in 2000. Power to CFAC was provided by Hinson Power in 2007.

[5] Revenues don't include all transmission and distribution costs. These costs add approximately 1- 2 cents to the delivered price of electricity in most cases.

[6] Because transmission and distribution costs are not available for electricity sold by power marketers, the reported State Total Average Cost/kWh is several tenths of a cent below actual average cost. For reasons EIA could not determine, these reported totals are a net of 6.7 aMW below those reported in Table E6.

Source: U.S. DOE, Energy Information Administration, Form 861 Database:http://www.eia.doe.gov/cneaf/electricity/page/eia861.html for 2000 and 2007.

Table E9. Percent Of Utility Sales To End-Users In Montana And Other States, 2007

Utility	Percentage in Montana	Other States State	Percent	State	Percent	State	Percent
Avista Corp	0%	WA	61%	ID	39%		
Beartooth Electric Coop	90%	WY	10%				
Big Flat Electric Coop	100%						
Big Horn County Elec Coop	93%	WY	7%				
Big Horn Rural Electric Co	16%	WY	84%				
Black Hills Power	2%	SD	89%	WY	10%		
Conoco	35%	IL	48%	TX	17%		
Energy West Resources	100%						
Fall River Rural Elec Coop	17%	ID	80%	WY	3%		
Fergus Electric Coop	100%						
Flathead Electric Coop	100%						
Glacier Electric Coop	100%						
Goldenwest Electric Coop	29%	ND	71%				
Grand Electric Coop	0%	SD	100%				
Hill County Electric Coop	100%						
Hinson Power Company LLC	77%	WA	23%				
Lincoln Electric Coop	100%						
Lower Yellowstone R E A	86%	ND	14%				
Marias River Electric Coop	100%						
McCone Electric Coop	100%						
McKenzie Electric Coop	0%	ND	100%				
MDU Resources Group	26%	ND	58%	SD	5%	WY	11%
Mid-Yellowstone Elec Coop	100%						
Mission Valley Power	100%						
Missoula Electric Coop	99%	ID	1%				
Northern Electric Coop	100%						
Northern Lights	29%	ID	71%	WA	0%		
NorthWestern Energy LLC	81%	SD	19%	WY	0%		
Park Electric Coop	100%						
Powder River Energy Corp	4%	WY	96%				
PPL EnergyPlus LLC	100%	PA	0%				
Ravalli County Elec Coop	100%						
Sheridan Electric Coop	95%	ND	5%				
Southeast Electric Coop	100%						
Sun River Electric Coop	100%						
Tongue River Electric Coop	100%						
Troy, City of	100%						
Valley Electric Coop	100%						
Vigilante Electric Coop	100%	ID	0%				
Western Area Power Admin	2%	CA	50%	AZ	21%	Other	26%
Yellowstone Valley Elec Co-op	100%						

Source: U.S. Department of Energy, Energy Information Administration, Form EIA-861 database 2007, file2.xls, http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

Montana Electric Transmission Grid: Operation, Congestion, and Issues

The transmission grid serves the vital function of moving power from generating plants to customers and their electric loads. It provides this service robustly and reliably even though individual elements of the transmission grid may be knocked out of service or taken down for maintenance. This paper describes how the transmission grid developed, how it works in terms of physics, how it is managed commercially, and how its reliability is ensured. From Montana's perspective, this paper discusses the ownership and rights to use the transmission system, the extent of line congestion on in-state lines, and how the system is managed. Finally, it discusses several issues involved in the construction of new transmission lines in-state and out-of-state to expand the capacity of the current grid and make new Montana power generation possible.

1. Historical Development and Current Status of Transmission in Montana

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

The Montana Power Company (MPC) presided over Montana's first integrated transmission system. As the MPC transmission system grew, as well as rural electric cooperatives dependent on that system, MPC expanded its network to include 161 kV lines and ultimately a 230 kV backbone of lines. WAPA's electric transmission system in Montana, began in the 1930's, to transport electricity to Fort Peck during construction of the dam there, and then to move power to markets following construction of the generators at the dam. WAPA's system continued to grow as its needs to serve electric cooperatives expanded and the Big Horn Hydroelectric project came on-line. Long distance interconnections between Montana and other states did not develop until World War II. During the war, the 161 kV Grace line was built from Anaconda south to Idaho. Later, the Bonneville Power Administration (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. In the mid 1980's, a double-circuit 500 kV line was built from the Colstrip generating plant in eastern Montana to the Idaho state line near Thompson Falls, and on into Washington State. These two 500 kV lines are Montana's largest. By 2002, MPC sold off its generation, transmission and energy holdings, becoming Touch America. Its transmission was purchased by Northwestern Energy (NWE) and most of its generation was sold to PPL-Montana.

Today, Montana's strongest transmission interconnections with other regions are the two 500 kV lines leading from Colstrip into Idaho and Spokane, BPA's 230 kV lines running west from Hot Springs, PacifiCorp's interconnection from Yellowtail Dam south to Wyoming, Western Area power Administration's (WAPA) DC tie to the east at Miles City, WAPA's 230 kV lines out of Fort Peck and Miles City into North Dakota, WAPA's two 115 kV line from Yellowtail Dam to Wyoming, and NWE's AMPS line running south from Anaconda parallel to the Grace line into Idaho.

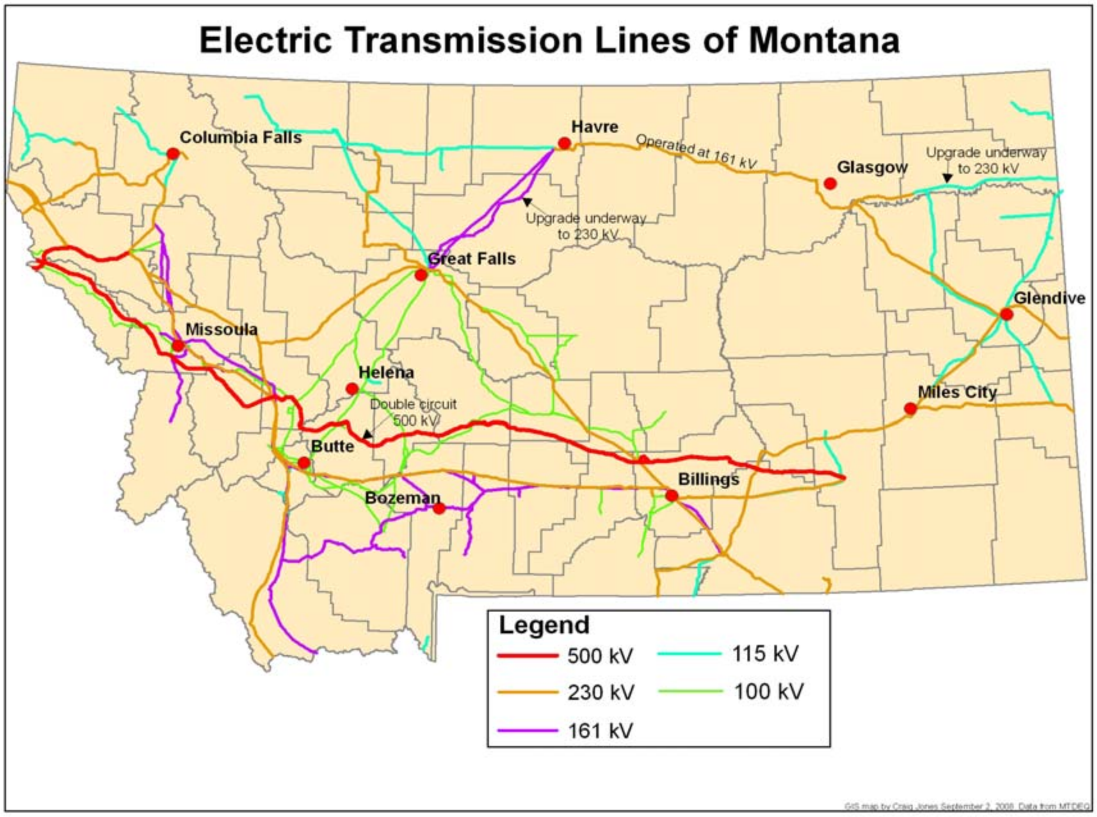


Figure 1-Electric Transmission lines of Montana as of 2009 (Montana DEQ)

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

The east and west 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 the two grids are only weakly tied to each other with AC/DC/AC converter stations. Eight converter stations currently govern the western and eastern grids with a combined capacity of 1590 MW. One such station is located at Miles City. It is capable of transferring up to 200 MW in either direction. There are also two converter stations with a combined capacity of 420 MW linking the Western Interconnection with the Texas grid (ERCOT). Depending on transmission constraints, a limited amount of additional power can be moved from one grid to the other by shifting hydro generation units at Fort Peck Dam. By contrast, this transfer capacity is about one tenth the peak electricity demand load in Montana, which is one of the smaller loads in the West.

Most of Montana is integrally tied into the Western electrical grid or Western Interconnect. However the easternmost part of the state, with around 8 percent of total Montana load, is part of the Eastern Interconnect and receives its power from generators in that grid—generators as far away as the east coast of the U.S. A "load" is the amount of power consumed at a particular moment by a particular area or entity such as a company, city or state. It can to refer to an average amount of consumption over time---average load---or it can refer to the most electricity that entity will consume over a given time period---"peak load". In this paper, "average load" will be the assumed definition used.

Figure 2-U.S. Western Interconnect
(Source: WGA website, http://www.westgov.org/wga/initiatives/wrez/)

2. How the Transmission System Works

There are big differences between the physical properties and capacities of a typical alternating current (AC) electrical transmission system and its actual commercial operation and management. The flow of power on a transmission network (the electrons) obeys the laws of physics. The commercial transactions that ship power across the grid follow a different and not fully compatible set of rules from the flow of electrons.

For the purposes of this paper, transmission "paths" are groups of more or less parallel transmission lines that carry power within the same general areas. A given transmission path can consist of one or more transmission lines that transport electricity from one major electricity 'node' to another. Nodes may consist of large generators, large loads or a major substation. For example, the two transmission lines that run from Dillon into Idaho — the Grace line and the AMPS line — form what is called 'Path 18.'

Physical operation: The transmission grid is sometimes described as an interstate highway system for electricity. But the flow of power on an AC grid differs in very significant ways from the flow of most physical commodities. First, when power is sent from one point to another on the transmission grid, the power will flow over all connected paths on the network, rather than a single path (e.g., the scheduled path) or even the shortest path. A given power transmission from one point to another will distribute itself so that the greatest portions of that power flow over the paths (transmission lines) of lowest resistance ("impedance," in alternating current circuits). The resistance or impedance of a given transmission line depends on its voltage and current. Thus, power flows generally cannot be constrained to any particular physical or contract path, but instead follow the laws of physics.

A second way in which electric 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 given transmission line from point A to point B, and 25 MW were sent simultaneously eastbound on that same line from point B to point A, the actual measured flow on the line would be 75 MW in a westbound direction (holding all other flows on the system constant). If 100 MW were sent in each direction on the same line the net measured flow would be zero. Additional power could still physically flow in either direction up to the full capacity of the line in that particular direction.

Finally, it is important to note that generated power distributed over the grid must be consumed instantaneously off of the grid. Unlike gas, oil, coal and other sources of energy, electricity cannot realistically be stored as inventory. Thus, transmission operators have to constantly balance electricity supply (generation) and demand (consumption). This is a very complicated process that involves significant manpower, technology, computers, complicated balancing routines, equipment, numerous transmission jurisdictions, and federal and state oversight. There are several high-tech and human mechanisms for balancing supplies and demand on the entire Western Grid and within individual operating areas such as Montana's NorthWestern Energy system. There are also new technologies being developed to potentially allow the storage of some electricity on the grid, but they are not available as of yet. The fact that all power generated on the grid must be consumed instantaneously is the reason why steady generation sources such as coal and natural gas are easier to manage than some renewable sources like wind and solar whose generation levels vary with the weather, season, and time of day.

As a consequence of the above factors, the actual physical flows on a grid are the net result of all generators and all loads (electricity demands) 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 flows, actual path loadings at any given moment will depend only on the amounts and locations of electric generation and load, as opposed to the schedules in place at a given time.

<u>Management of the grid</u>. In contrast with the physical reality of the transmission network, management of transmission flows has historically been by "contract path." A transaction involving the shipment of power between two points is allowed to occur if space has been purchased on any path connecting the two points. Purchasers include the utilities or companies owning the lines or entities holding rights to use those wires, if they are transferable, along that path. Such transactions are deemed to flow on the contract path. Due to the laws of physics that ultimately govern the grid, portions of a contracted transaction flow along other paths. These are termed "inadvertent flows" or "unscheduled flows." Major inadvertent flows on the grid are called "loop flows."

The topology of the western grid is such that major inadvertent flows occur around the entire interconnection at any given moment. For example, power sent from hydro dams in Washington State to California flows directly south over the contracted pathways, but it also flows 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. More locally, power sent from Colstrip in eastern Montana to Los Angeles will flow mostly west to Oregon and Washington, via the double-circuit 500 kV line that runs through Garrison and Taft, and then south to California. This westerly path is its contracted path. However, between 15 and 20 percent of Colstrip power flows over two other paths — the Yellowtail-South path into Wyoming and the Montana-Idaho Path 18 south from Anaconda.

Inadvertent flows such as these may interfere with the ability of transmission path owners to make full use of their rights. The Western Electricity Coordinating Council (WECC) addresses inadvertent flow by its Unscheduled Flow Reduction Procedure. Utilities (or other transmission owners) whose wires are affected by inadvertent flows first accept a certain amount of this unscheduled power — up to a small percentage of the path rating — by curtailing their own schedules. If further reductions are necessary, the path owners can request that phase shifters that block loop flows be made operational. Path owners can also call for curtailment of schedules across other paths that affect their ability to use their own path.

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 physical netting properties, because the capacity created by reverse schedules is not deemed to be "firm." Firm capacity is the availability, or room, on existing transmission lines to move power every hour of the year. In a netting situation, if the flow scheduled in one direction is reduced at the last minute, capacity to carry power in the opposite direction automatically goes down by the same amount. Thus, scheduling against reverse flows is not considered firm capacity because the power may not always be available.

If the scheduled flows do not exhaust the path rating, the unused capacity may be released as "non-firm" transmission capacity. Non-firm capacity is only available some hours of the year, not all hours as with firm capacity. Non-firm capacity cannot be purchased very far in advance; it can be scheduled only in the last hours before the actual transaction. Owners of transmission capacity who do not plan to use extra room on their lines could in some instances release it early. Often they are reluctant to do so because of needs for flexibility or a desire to withhold access to markets from competitors.

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 electricity flows get high enough on a particular line, the wire heats up and stretches, eventually sagging too close to the ground or other objects, such as trees. Arcing — where the electricity travels to ground — may result. When that happens, the transmission line can fail, instantly stopping electricity flow, which instantly affects the rest of the grid. This condition can cause major problems. Other limiting factors relate to inductive and capacitative characteristics of alternating current (AC) networks. Inductive characteristics are associated with magnetic fields that constantly expand and contract in AC circuits wherever there are coils of wire, such as transformers. This is not an issue for direct current (DC) lines. Capacitative characteristics are associated with electric flows induced in wires that are parallel to each other, such as long-distance transmission lines. But the most important factor in determining the total amount of power a line can carry is reliability.

Electricity reliability is the ability of the transmission system to provide full, uninterrupted service to its customers despite the failure of one or more component parts of that system. The transmission network is composed of thousands of elements that are subject to random failure. Causes include lightning strikes, ice burdens, pole collapse, animals (such as squirrels and birds) shorting out transmission lines, falling trees and vandalism (such as shooting out conductors). Since electric customers value reliability and can be greatly harmed by a 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 (such as the largest line within an operating system) and still provide uninterrupted service to customers. Grid-wide transmission service is provided by the network, not merely by individual transmission lines.

Reliability concerns limit the amount of power that can be carried to the amount of load that can be served, even with key elements out of service on the grid. Two examples will show how this limit applies. Within NorthWestern Energy's (NWE) service area in Montana, the reliability of the transmission system is evaluated by computer simulation. The network is simulated at future load and generation levels while taking key individual elements out of service. The simulation determines 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 entails adding transmission lines to the system or rebuilding existing ones to higher capacities, but may also include adding phase shifting transformers, series capacitors or other substation equipment. 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 loads or to make wholesale transactions. As mentioned above, 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. The Colstrip 500 kV lines west of Townsend, MT are a double circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service. Therefore, at all times, they carry less power than their thermal limit in either direction.

The actual rating on a path can change hourly, and depends upon several factors including ambient air temperature, other lines being out of service and various load and supply conditions on the larger grid. The Montana transmission lines heading west towards the Idaho panhandle and Washington State are called The Montana-Northwest Path. The Montana-Northwest Path is limited generally to 2,200 MW east-to-west and 1,350 MW west-to-east. These are the maximum ratings under ideal conditions, and the ratings on these paths are often lower. The Montana-Northwest path leads to the West of Hatwai path, which is larger and is comprised of a number of related lines west of the Spokane area. The West of Hatwai path is rated at about 4,300 MW east-to-west under ideal conditions. Regional transmission studies (Rocky Mountain Area Transmission Study – RMATS – and Northwest Transmission Assessment Committee – NTAC) have identified relatively low-cost improvements that would expand capacity on the Montana-Northwest path by 500-700 MW. But use of this upgrade by new generators to access West Coast markets could require additional improvements on the West of Hatwai path ("Rocky Mountain Area Transmission Study," Sept. 2004, http://psc.state.wy.us/htdocs/subregional/FinalReport/reportcover.pdf).

4. Ownership and Rights to Use the Transmission System

Rights to use the transmission system are generally held by the transmission line 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 line owners have committed to a variety of contractual arrangements to ship power for other parties. As previously mentioned, scheduled power flows by rights holders are not allowed to exceed the path ratings.

The U.S. Federal Energy Regulatory Commission (FERC) issued FERC Order 888 in April 1996, which requires that transmission owners functionally separate their transmission operations and their power marketing operations. Power marketing is when transmission owners (utilities) that own generation market it off system to make money or to reduce costs for their native loads. These transmission line owners must allow other parties to use their systems under the same terms and conditions as their own marketing arms. Each transmission owner must maintain a web site called "Open Access Same-Time Information System", or OASIS, on which available capacity is posted.

Available transmission capacity (ATC) is the available room on existing transmission lines to move power every hour of the year. ATC is calculated by subtracting committed uses and existing contracts from total rated transfer capacity on existing transmission lines. These existing rights – and ATC, if any are 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. When they don't, the unused space may be available on a non-firm basis (space for moving power that is not available every hour of the year). Currently, little or no ATC is available on most major rated paths on the U.S. Western grid, including those paths leading west from Montana to the West Coast. The rights to use the existing capacity on these lines are fully allocated and tightly held. None is apparently available for purchase by new market entrants. Only new lines or purchased rights would allow a new market entrant to obtain ATC.

Despite little or no ATC, most transmission paths on the Western Grid are fully scheduled for only a small portion of the year, and non-firm space is almost always available. For example, the West of Hatwai path near Spokane was fully scheduled around 8 percent of the time from October 2000 through September 2001, and from June 2005 to November 2005, it was never fully scheduled (BPA's OASIS website, http://www.transmission.bpa.gov/orgs/opi/misc/Path_RODS_Data_Apr04Nov05.xls and http://www.transmission.bpa.gov/oasis/bpat/outages/oasiscontent.shtm). Thus, most of the time, there is non-firm room available on the West of Hatwai path. However, non-firm access cannot be scheduled far in advance or its access guaranteed. Rather, non-firm access is a workable way to market excess power for existing generators. Non-firm availability may be a reasonable way to develop new firm power transactions as well, if backup arrangements can be made to cover the contracts in the event the non-firm space becomes unavailable. Financing new generation may be difficult, however, unless the power can be shown to move to market via firm line space. Individually, most new generation projects cannot afford to also build new lines or upgrade existing ones. Contemplating new generation far from consumption loads can become an examination of the "chicken and egg" dilemma.

5. Congestion

A transmission path may be described as congested if no rights to use it are for sale. Alternately, congestion could mean that a path is fully scheduled and no firm space is available. Or it could mean that the path is fully loaded in the physical sense—it literally cannot carry any more electrons without violating its rating. These are three different concepts.

By the first definition, the paths through which generators in Montana send their power west, and which includes West of Hatwai, are almost fully congested — few firm rights are currently available for those paths (Marc Donaldson, Northwestern Energy, personal communication, January 2008). By the second definition, the paths west of Montana are congested a few hours of the year — contract holders fully use their scheduling rights a fraction of the time; the rest of the time they use only portions of their rights. As mentioned above, from October 2000 through September 2001, the West of Hatwai path near Spokane was congested under this "scheduling" definition around 8 percent of the time. From June 2005 to November 2005, it was never fully scheduled (which may have to do with the fact that its capacity had recently expanded).

By the third definition, the lines currently are almost never physically congested — even when the lines are fully scheduled, the net flows are almost always below path ratings. 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 affects of inadvertent flows and loop flows in that part of the grid. Actual hourly loadings on the West of Hatwai path are posted on BPA's OASIS site. Figure 3, below, shows that from June 2005 to May 2006, highest actual loadings on the Montana Northwest path were around 90 percent of the path capacity for only a few hours. For most hours the path was not heavily loaded. In fact, for about 90 percent of the hours in that year-long time period, the line was 60 percent loaded or less, east to west, by actual flow.

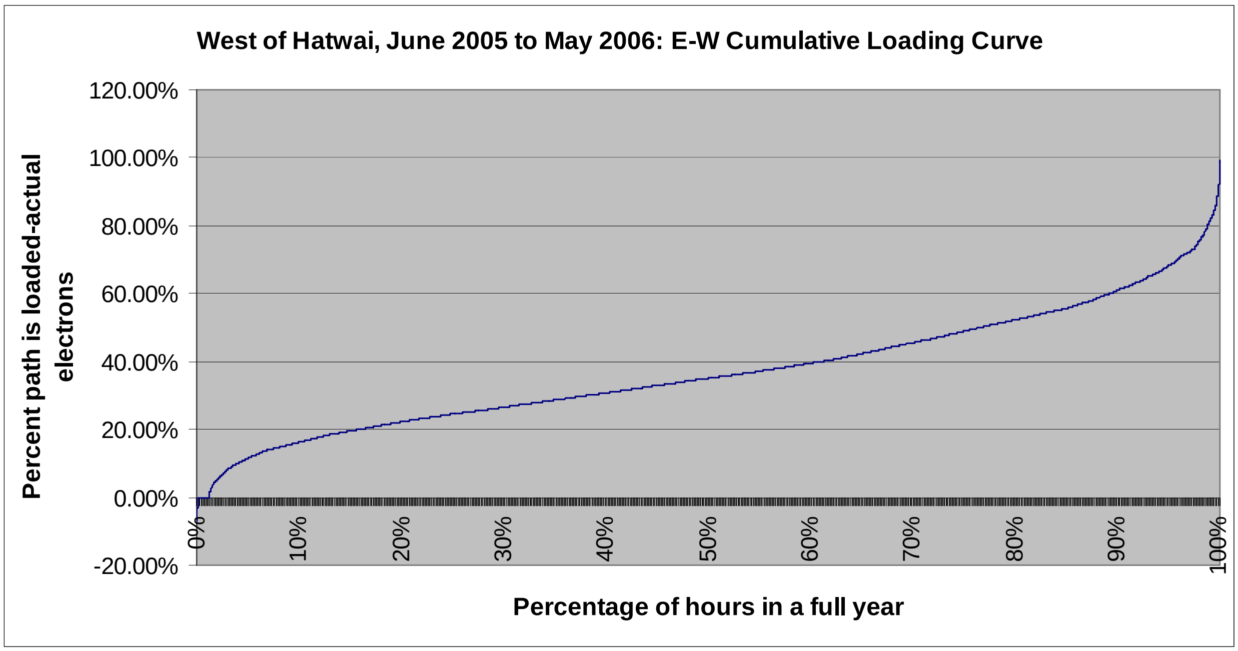


Figure 3. West of Hatwai path cumulative loading curve Jun 2005-May 2006 (Negative flows mean power was flowing from west to east)

The West of Garrison path within Montana that connects to the paths west of Montana shows a similar cumulative loading pattern – a considerable unused capacity most of the time (this data is also on the BPA OASIS website). However, the two paths do not load at the same times, and transmission capacity from Montana to the Pacific Northwest is limited by the amount of space that is simultaneously available on both paths. Figure 4 takes that into account showing the cumulative unused capacity that was simultaneously available on Montana-NW and West of Hatwai from December 1, 2004 to November 28, 2005. Simultaneous capacity was available on the two paths just over 80 percent of the time. However, about half of the time that room was available on the line, capacity was under 500 MW, indicating that additional capacity is somewhat limited on the two paths at any given time (BPA OASIS website).

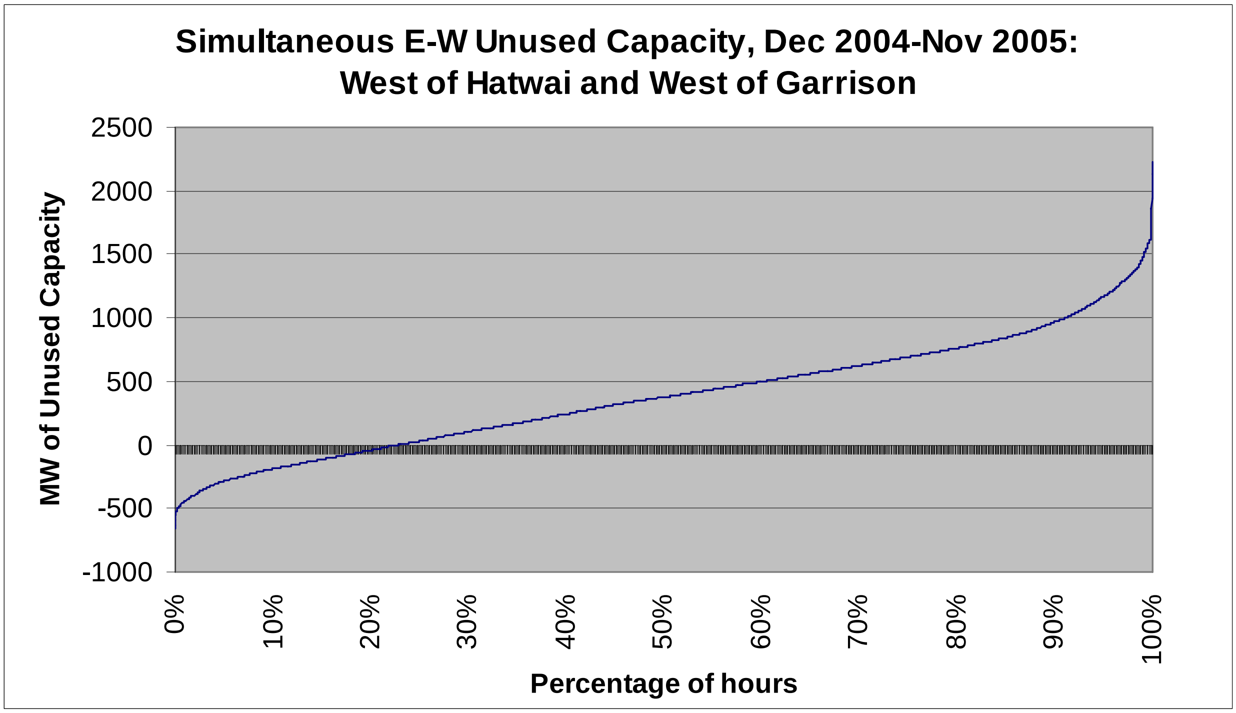


Figure 4. Simultaneous unused capacity, West of Hatwai and Montana-NW Paths, Dec 2004-Nov 2005 (a negative number means that the data indicate that WOG was operating above its rated path east to west—there could be several reasons for this)

A considerable amount of existing capacity on transmission lines is not available for use because it is held off the table for reliability reasons when paths are rated. 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. On the other hand, 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 transmission access was a major reason for FERC Order 2000, which requires utilities to form regional transmission organizations (RTOs).

6. Grid Management by a Regional Transmission Organization (RTO)

The California ISO is a full RTO on the Western Interconnect. Other RTO-type organizations exist in the U.S. including MISO which covers much of the Midwest U.S. Alberta, Canada has AESO as its version.

Discussions to have an independent body take over operation and control of access for the transmission system have been underway since the mid-1990's among transmission owners and other stakeholders in the Northwest U.S. Stakeholders include Montana's

NorthWestern Energy and the Bonneville Power Administration (BPA), among others. These discussions started partly out of a recognition by the transmission owners that proof of independence between transmission and power marketing, as required by FERC Order 888, would become an increasingly difficult burden. Discussions also started partly out of anticipation that FERC would ultimately move to order such a transfer of power. Assumption of responsibility for grid management by an independent entity would provide for a market-driven means of managing transmission congestion. The current fixed assignment of rights to use the grid presents the following problem: Those who own neither lines nor rights are prevented from making firm use of unused capacity, and are even hindered in their ability to bid for it on a non-firm basis. A regional transmission organization (RTO) would allow all parties to signal their willingness to pay for transmission access (in some type of market setting) and to thus make more efficient use of the grid. In addition, RTO management would result in congestion price signals that would allow economic-based decisions on the location of new generation and on the expansion of capacity on congested transmission paths (which may or may not involve building new lines).

Initial discussion in this direction revolved around IndeGO (Independent Grid Operator), which 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 on a Regional Transmission Organization (RTO) that would operate the system under a contractual Transmission Operating Agreement (TOA) with the participating transmission owning utilities. Initial efforts to gain regional consensus on a fully formed RTO resulted in a proposal and a filing with FERC in 2002. Subsequently, issuance by FERC of a draft Standard Market Design proposal (a different way of running the grid) created much confusion and much opposition in the region to continued pursuit of the RTO West 2002 proposal. The RTO West 2002 proposal eventually failed.

In May, 2003 a "regional representatives group" was convened to seek consensus on problems with current management of the grid, and to evolve solutions. This effort resulted in a proposal called Grid West — an initial developmental, independent entity to craft Transmission Operating Agreements and other operating protocols. The proposal included a governance structure with a stakeholders committee. Elected board members would approve the steps to convert the developmental body into an operating entity. However, Grid West failed in May of 2006. Columbia Grid (BPA and Washington public and private utilities) and the Northern Tier Transmission Group (public utilities outside Washington and some Utah Cooperatives), continue to try to search for some sort of solution to this issue.

The Northern Tier Transmission Group is a group of transmission providers and customers actively involved in the sale and purchase of transmission capacity of the power grid that delivers electricity to customers in the Northwest and Mountain states. NTTG coordinates individual transmission systems operations, products, business practices and planning of their high-voltage transmission network to meet and improve transmission services that deliver power to customers.

In 2006, five control areas or balancing authorities (British Columbia transmission Corporation, Idaho Power Company, Northwestern Energy, PacifiCorp-East and PacifiCorp-West) entered into the ACE Diversity Interchange Agreement in order to implement a software tool called ACE Diversity Interchange (ADI). ADI assists the balancing authorities in their management of generation and load within parameters established by the National Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC). ADI is the polling of Area Control Errors (ACE) to take advantage of control error diversity (momentary imbalances of generation and load). As part of the ACE Diversity Interchange Agreement, these balancing authorities and the host for the project, British Columbia transmission Corporation, committed to evaluating ADI in order to ensure efficient and reliable implementation. ADI is intended to relax generation control by enabling the participating balancing authorities to rely upon each other and the ADI algorithm to take advantage of the diversity among area control errors. The ADI project was anticipated to reduce generation changes and thereby reduce generator wear and tear so that generator reliability increases.

7. Proposed Transmission Lines in Montana

Certain transmission lines in Montana are regulated under the Montana Major Facility Siting Act (MFSA) administered by the Montana Department of Quality (DEQ). The Montana Legislature has found that the purposes of MFSA are to ensure the protection of the state's environmental resources, ensure the consideration of socioeconomic impacts from regulated facilities, provide citizens with an opportunity to participate in facility siting decisions and establish a coordinated and efficient method for the processing of all authorizations required for regulated facilities. In general, electrical transmission lines greater than 69 kV may be covered under MFSA if they meet certain criteria. Generally, it is the larger lines that require the more detailed review.

Major new transmission lines currently approved and awaiting construction in Montana include the Montana-Alberta Tie Ltd. (MATL) which would be the first direct interconnection between the Alberta and Montana systems and capable of carrying 300 MW in either direction. The Chinook line is planned by Transcanada, but has not yet applied for MFSA certification. It would be a 500 kV DC line that is proposed to run from the Harlowton area down to Las Vegas. The Chinook line would be capable of carrying 3000 MW in either direction. In addition, Northwestern Energy has applied for MFSA certification for the Mountain States Transmission Intertie (MSTI). It would be a 500 kV line that would run from Townsend, MT to Midpoint, ID. This line would be capable of carrying up to 900 MW south to north, and 1500 MW north to south.

The Montana-Alberta Tie Line (MATL) has completed its regulatory process in Montana under the Major Facility Siting Act (MFSA) and the Montana Environmental Policy Act (MEPA). Several wind farm companies have already purchased all the firm capacity on MATL for proposed projects. Potential benefits from MATL to Montana include the sharing of generation resources for NWE's transmission control area, increased reliability, increased power transactions between Alberta and Montana, increased capacity for new generation, and more options for spot market and regulating reserve purchases made by Montana utilities. MSTI has started its permitting process with the State of Montana. The Chinook Line has not begun permitting yet, but could allow for several new large generating plants in central and eastern Montana. Several other radial lines are under construction in Montana for specific projects as the rebuild of a WAPA 115 kV line between Great Falls and Havre to 230 kV specifications, and the rebuild of a line between Libby and Troy. An upgrade of the double circuit 500 kV lines out of Colstrip is also being studied. Major new lines being considered and/or planned in Montana are illustrated in Figure 5.

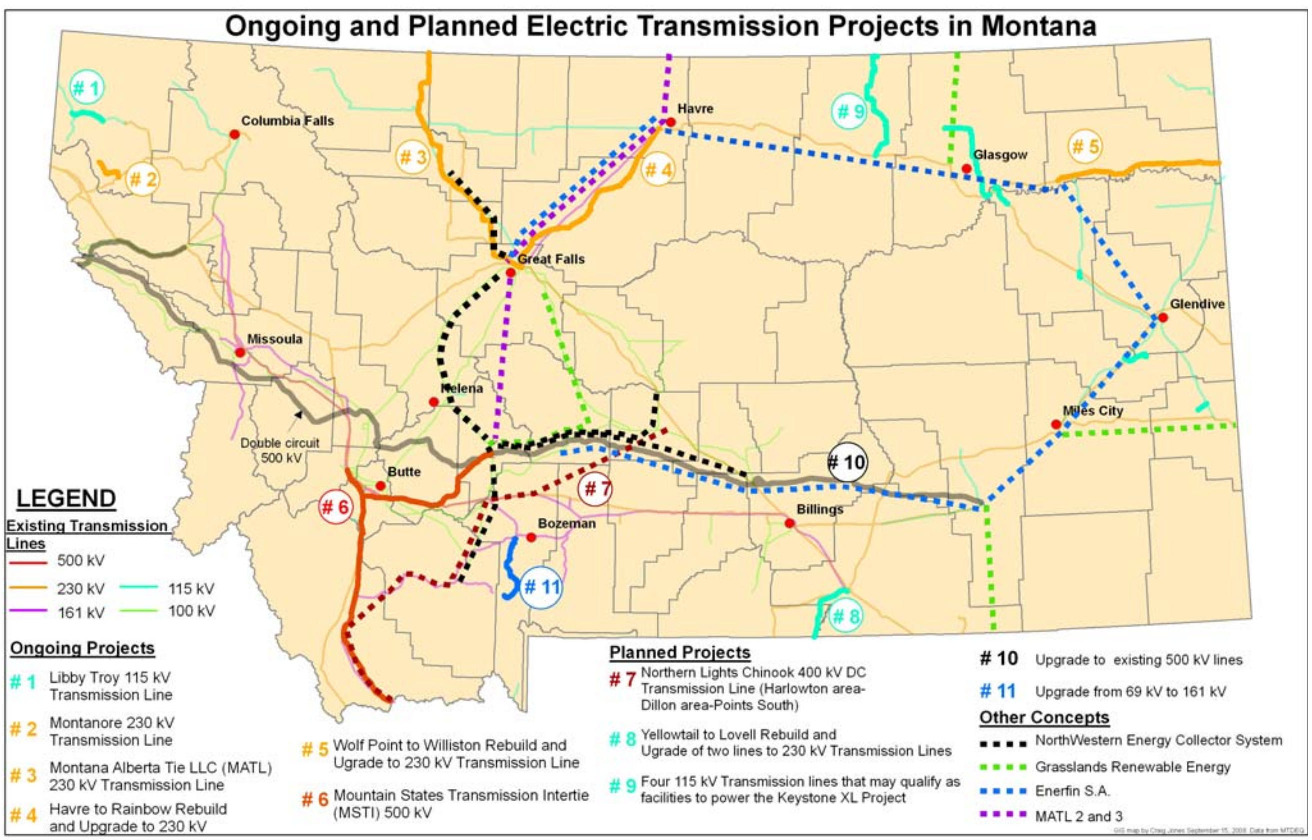


Figure 5-Ongoing and Planned Electric Transmission Projects in Montana (Montana DEQ)

Any new lines connecting Montana to the rest of the Western Grid could increase competition among Montana energy suppliers. Currently, the majority of Northwestern Energy's electricity supply comes from one supplier, PPL-Montana. Currently, PPL-Montana and NWE have agreed to an increasing default supply electricity rate over time. Increasing supplier competition in Montana's deregulated market could help lower or stabilize electricity prices to Montana ratepayers in the near and distant future, although the extent and significance of such savings is unknown. Some argue that new interstate lines out of Montana could increase electricity prices by opening up relative cheap Montana electricity generation to competing markets or by changing the configuration of the transmission system.

New 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 is away from the Interstate highway corridor, instead opening new corridors through forested areas with issues such as impacts to elk security areas and increased forest access. Lengthy detours around Boulder and Missoula added considerably to the cost of the line. Recent experience with the MATL and MSTI lines shows that Montana citizens and landowners are concerned about interference with farming practices, visual impacts, reductions in property values, general concerns about plants and animals in the area, potential human health effects, and use of private land rather than public land for public purposes.

Rural growth and residential construction in western Montana since the Colstrip lines were sited in the early 1980s can be expected to compound siting challenges for additional lines through the western portion of the state. Siting opportunities are limited by actual and contemplated wilderness areas and Glacier National Park in the western region. Indeed, siting and routing a new line out of the state in a westerly direction (especially near Missoula, the Flathead Indian Reservation, and along the Clark Fork River into Idaho) would likely prove extremely challenging today, due to geographical, wilderness and political issues. Due to these difficulties, the most likely routes for new transmission in and out of Montana are to the north into Canada, to the south via Monida Pass into Idaho, and possibly alongside existing transmission lines to the west.

8. 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 way reliability criteria are set, the limited number of hours the system is congested, the increasing costs of building new lines, ways to meet growing power needs without building new lines, and the problems involved in siting high voltage transmission lines. Other important issues include the cost of new capacity, making the commitment for new capacity, the alternatives for financing new transmission discussed in the Western Governors' Association Transmission Study, the follow-on work to the governors' study, and Section 368 of the Energy Policy Act of 2005 which establishes national energy corridors on federal lands.

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. These criteria do not reflect very well the probability or the consequences of the disruptive events being protected against. Since the system is quite reliable as currently built and operated, reliability concerns generally focus on very low probability events that may, depending on when they occur, have high costs. The criteria apply everywhere on the transmission grid despite the fact that in some areas and on some paths the consequences of an outage may be minimal while in other areas and other paths the same type of event may have large consequences. Path 15 in central California or the Jim Bridger West path in Idaho, are examples where a line outage can result in cascading failures and impact many millions of people. These segments 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 otherwise affect any load or affect very small loads.

Reliability criteria for the Western Interconnect are set by the Western Electricity Coordinating Council, which is part of the National Electric Reliability Council (NERC). WECC was formed in 2002 from a merger of the Western Systems Coordinating Council (WSCC) with several other transmission organizations. The WECC has much broader representation on its board than the WSCC did, and has stakeholder advisory committees.

Limited Hours of Congestion. As discussed previously, 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 transmission capacity (e.g. building new lines) is expensive and difficult. Yet it has been the preferred method to gain access for additional transactions and additional flows. If the costs of new construction were assigned to the congested hours only, it is very likely cheaper alternatives to new construction would be found. For example, some current transmission users with relatively low valued transactions or with ready alternatives might be willing, at some price, to sell their rights to new users who value that transmission at a higher level.

Cost. High voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may run to $1 million per mile. A double-circuit 500 kV line may cost $1.5 million or more per mile. A 500 kV substation costs around $50 million to $75 million each, depending on the 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. These prices seem to be increasing faster than inflation.

Direct current (DC) lines are cheaper still, but the equipment required to convert alternating current (AC) to direct current (DC) and back (in order to connect DC lines with the rest of the grid) is extremely expensive. Consequently, DC 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 Interconnect – 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. The proposed Chinook line through Montana, if built, would be a third DC line in the Western Interconnect.

<u>Alternatives to New Lines for Meeting an Increasing Electricity Demand</u>. With increasing costs and siting difficulties for new transmission lines, there may be other alternatives to building transmission that would keep the system robust. Some existing lines can be upgraded with new equipment to increase capacity without having to build new lines. Some lines can simply be re-built on existing rights of way, preventing the need to buy new land or enact eminent domain proceedings. In some cases, one new line built on the grid could allow higher ratings on other lines in the grid, just from its presence. The opposite could occur, too. Electricity consumers can voluntarily conserve their power usage to forestall the need for new lines (and this conservation can also prevent rolling blackouts during certain days). Also, generation plants can be located near their loads, eliminating some need for long transmissions of electricity. Also, the grid could potentially be run more efficiently by an RTO or other independent transmission operator, again forestalling the need for new transmission lines for at least a few years.

<u>Transmission Capacity to Accommodate New Generation in Montana</u>. As mentioned earlier, there is a "chicken and egg" problem in developing new transmission to facilitate economic development. If no transmission capacity is available to reach markets, generation developers may have a difficult time financing projects. Yet without financing, potential generators probably can't make firm commitments that would encourage utilities to invest on their own in new transmission capacity projects. Alternative approaches involve generation developers building for anticipated new load or construction of new merchant transmission capacity built in the hopes that generation will appear. These strategies still require financial markets to be convinced that the projects are viable. In any event, the regulatory structure in Montana (e.g., the Montana Major Facility Siting Act) requires a showing of need for new transmission projects. That may be a difficult requirement for transmission builders 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 yet another issue. Eminent

domain seizures could be at risk of successful court challenges if a landowner were to convince a court that the purposes behind a new transmission line were entirely or partially speculative.

The issues confronting proposed merchant generation plants (those built for profit by private companies who sell energy to the highest bidder) are different than those faced by traditional utility generators. The procedures for utilities typically entailed generation and transmission facilities that were planned, financed and built together. Private generation developers either must absorb the risk of building new transmission capacity or convince some other party to absorb the risk for them.

To give an illustrative example of the need for new transmission, there are thousands of MWs of proposed wind generation in central and eastern Montana at the extreme eastern edge of the Western Grid. If built, these plants would need new transmission just to connect their plants with major existing lines in Montana such as the two 500 kV lines starting at Colstrip. In fact, the stated purposed of MSTI is to connect Montana generation to outside markets. Generators would perhaps even need to pay for major upgrades to those existing lines in order to move their energy. In a more extreme case (such as if all remaining transmission space out of Montana is taken by other new plants), these plants might have to pay for some or all of a long high-voltage transmission line that would leave Montana directly from their plant towards a distant load. Such a cost would make some of these generation projects uneconomical.

Western Governors' Association Transmission Study. In the spring of 2001 the Western Governor's Association 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 in the U.S. West was coal-fired generation or wind generation (in many cases far away from loads). 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 ("Conceptual Plants for Electricity Expansion in the West", http://www.westgov.org/wga/initiatives/energy/transmission_rpt.pdf, August 2001).

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 (Financing Electricity Transmission Expansion in the West: A Report to the Western Governors, Feb. 2002, http://www.westgov.org/wga/initiatives/energy/final_rpt.pdf.

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, this approach 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. Moreover, the interstate highway approach could also result in overbuilding the transmission system, for example to alleviate congestion that may prove minimal or that could be more cheaply addressed in other ways.

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

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

Montana participated actively in this study. RMATS defined two levels of projects. "Recommendation 1" projects include a moderate upgrade of the existing Montana-Northwest transmission system, an upgrade to the existing two 500 kV lines, and installation of capacitors at various points and construction of a new substation at Ringling, but no new transmission lines. The recommendation would expand capacity on that line by approximately 500-700 MW. Recommendation 1 also includes a transmission line from Wyoming to Colorado, from Wyoming to Utah, and expansions on the Bridger transmission line ("Rocky Mountain Area Transmission Study", Sept. 2004, http://psc.state.wy.us/htdocs/subregional/FinalReport/reportcover.pdf).

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

National Energy Bill and Transmission Line Corridors. The omnibus National Energy Bill introduced in 2003 included a provision to enable the Department of Energy (DOE) to designate transmission lines of national interest to overcome significant congestion. This provision also allowed FERC to authorize construction and the use of federal eminent domain authority for such lines. No federal funding was provided. In 2005, the National Energy Bill passed which included that corridor language. Section 368 of the Energy Policy Act of 2005, entitled "Energy Right-of-Way Corridors on Federal Land," enacted August 8, 2005, directed the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate under their respective authorities corridors on federal land in 11 Western States for oil, gas and hydrogen pipelines and electricity transmission and distribution facilities. It stated that these corridors should be designated taking into account the "need for upgraded and new electricity transmission and distribution facilities" in order to "improve reliability," "relieve congestion," and "enhance the capability of the national grid to deliver electricity."

On the Energy Corridor PEIS webpage at http://www.corridoreis.anl.gov/, an energy corridor is defined as a parcel of land (often linear in character) that has been identified through the land use planning process as being a preferred location for existing and future utility rights-of-way, and that is suitable to accommodate one or more rights-of-way which are similar, identical or compatible. In the 2005 Energy Bill, lawmakers decided that designating specific energy corridors for future development would help minimize the time it takes to site and approve projects, as well as reducing environmental effects and conflicts with other uses of federal lands.

Expected benefits of energy corridor designation under the Energy Corridor PEIS (found on the web page) include the following:

- Streamlining and expediting the processing of energy-related permits and projects;
- Providing applicants for individual rights-of-way within designated corridors with a clear set of actions required by each of the agencies to implement projects in designated corridors;

- Reducing duplicative assessment of generic environmental impacts by focusing further impact assessment on site-specific (on-the-ground) environmental studies to determine route suitability and appropriate mitigation;
- Ensuring needed inter-agency coordination as part of the application process; and
- Encouraging new and innovative technologies to increase corridor capacity.

On June 9, 2006, four federal agencies released a draft map of potential energy corridors in several western US states for electricity transmission and oil, natural gas and hydrogen pipelines. This is found at http://www.corridoreis.anl.gov/eis/pdmap/index.cfm. The agencies -- the Energy Department, the Bureau of Land Management, the US Forest Service and the Department of Defense -- are preparing a draft programmatic environmental impact statement to identify the impacts of designating energy corridors on federal lands in 11 states, as directed by last year's Energy Policy Act. Montana's potential corridors basically follow the federal and state owned portions of the existing double circuit 500 kV line, the two lines that go south into Idaho near Dillon, and the line that goes southeast from Yellowtail Dam. However, the designated corridor parallel to the Colstrip lines does not appear to be wide enough to accommodate another 500 kV line and still meet WECC standards pertaining to reliability. Additionally, the corridor designation did not consider conflicting land uses on intervening private lands.

The transfer of transmission siting authority to the federal government raises mixed concerns for the state. Economic development interests see it as a way to speed construction of the infrastructure that would allow the state to develop its energy resources. Environmental interests see it as a loss of the state's ability to permit needed transmission lines and to site them to minimize environmental damage. Other parties question the need for a transfer of authority when there has been no history of difficulties in the West in permitting and siting transmission lines. Instead, they see it as a solution in search of a problem.

WREZ Study. The Western Governors' Association and U.S. Department of Energy launched the Western Renewable Energy Zones Project in May 2008 (This section is taken directly from http://www.westgov.org/wga/initiatives/wrez/). The goal of the WREZ project is to utilize those areas in the West with vast renewable resources to expedite the development and delivery of clean and renewable energy. Participating in the project are 11 states, two Canadian provinces, and areas in Mexico that are part of the Western Interconnect.

The WREZ project will generate:

- Reliable information for use by decision-makers that supports the cost-effective and environmentally sensitive development of renewable energy in specified zones, and

- Conceptual transmission plans for delivering that energy to load centers within the Western Interconnect. A number of factors will be considered, including the potential for development, timeframes, common transmission needs and costs. The project also will evaluate all feasible renewable resource technologies that are likely to contribute to the realization of the goal in WGA's policy resolution that calls for the development of 30,000 megawatts of clean and diversified energy by 2015.

Guiding this initiative is the WREZ Steering Committee, comprising governors, public utility commissioners and premiers. Officials from the Departments of Energy, Interior and Agriculture, as well as the Federal Energy Regulatory Commission, will participate as ex officio members.

9. Conclusion

The Western U.S. Grid is currently congested—there is little space left to carry further firm power transactions. Electricity demand is steadily rising for many regional loads on the grid. As deregulation begins to dominate the electricity industry, more customers are buying power from more distant suppliers. Furthermore, California and other states are looking for more 'green' electricity imports each year. The result of these trends is that new transmission lines and upgrades will be necessary in the next few years in order to accommodate an increased number of electrical transactions and an increasing number of remotely-located power generators such as in eastern Montana. The grid will also be managed differently and perhaps more economically efficiently as RTOs take over its operation. With transmission lines harder and more costly to build, and with federal control over the grid seeming to increase, private companies, government and citizens will need to coordinate more closely in order to determine how transmission will best meet the needs of customers and Montana citizens.

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

Natural gas is a major source of energy for Montana's homes, businesses, and industries. This paper discusses current natural gas trends in Montana, and what the state might expect in the coming years. It also discusses reasons for the unprecedented high natural gas prices experienced over the last several years, especially in late 2005 and early 2006 as well as in 2008.

Montana is part of the North American natural gas market, with gas prices and availability set more by events outside than inside Montana. Natural gas is burned at increasing rates for electricity generation around the country. As markets tighten, and as gas production from North American wells levels out or declines, the price and availability of natural gas has moved in ways Montanans have not experienced in previous decades.

1. Natural Gas Supplies for Montana and In-State Production

Montana currently produces more natural gas than it consumes. However, most of the production is exported and most of the consumption is imported. In 2006, Montana produced 112.8 billion cubic feet (bcf) of gas and consumed 73.9 bcf.[1] The bulk of Montana production is exported, leaving the state into Saskatchewan, North Dakota and Wyoming. Roughly half (or slightly more) of Montana consumption is imported, largely from Canada. These market patterns are driven by the trading structure of natural gas contracts as well as the actual configuration of pipelines throughout Montana.

Gas wells in Alberta and, to a much lesser extent, Montana provide most of the natural gas for Montana customers — a market condition unlikely to change in the foreseeable future. Reasons include our proximity to Alberta's large gas reserves and the configuration of pipelines within and outside of the state. Domestic gas wells are located mostly in the north-central portion of the state, although other regions are increasing production fairly rapidly. Supplies from the other Rocky Mountain states, mostly entering Montana from Wyoming, represent a small portion of total in-state usage and have declined from historic levels. The future direction of supplies from in-state development and from other Rocky Mountain states remains uncertain at this point. Coal bed natural gas production in Montana and from nearby Rocky Mountain states may increase, but the peak of that production is likely years away.

[1] U.S. EIA 2009, see Tables NG1 and NG2

Most gas produced in Montana comes from the north-central portion of the state, as defined in the Montana Board of Oil and Gas Conservation Annual Review, 2007. In 2007, the north-central portion accounted for 61 percent of total production, the northeastern portion 23 percent, and the south-central portion 15 percent. In-state gas production has been increasing in recent years (Figure 1, below). The south-central and northeastern portions of Montana have increased production levels since 1998, accounting for most of the recent increase in total statewide production, while production in the north-central portion of the state has remained fairly constant. Big Horn, Blaine, Fallon, Hill, Richland and Phillips Counties produce the greatest amount of natural gas in Montana at more than 10 bcf each. For 2007, the following counties produced these percentages of natural gas in Montana:

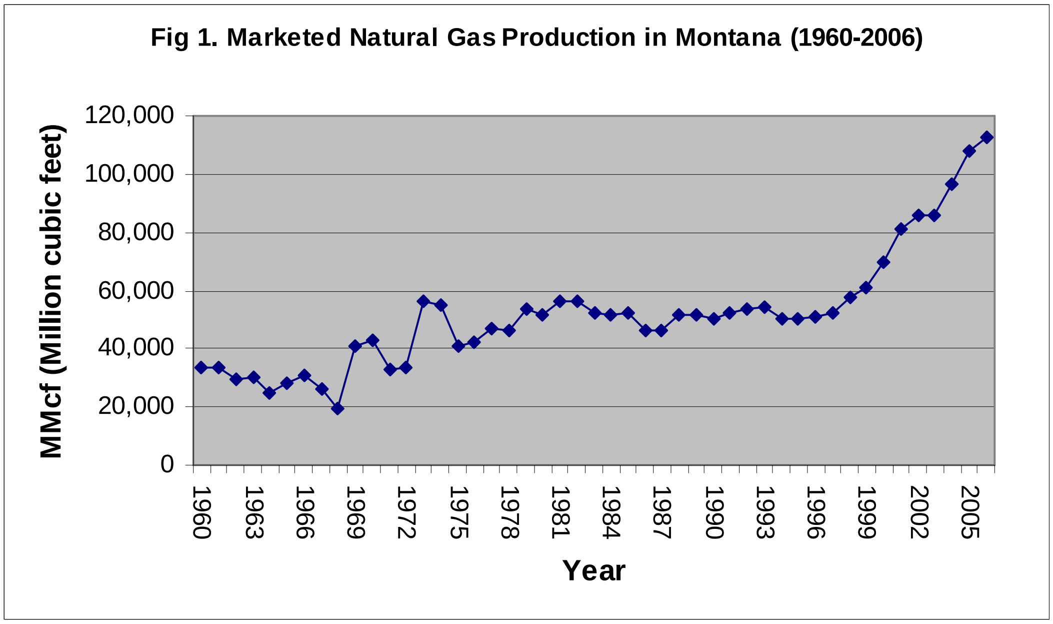
- Fallon — 22%,
- Phillips — 17%,
- Hill — 12%,
- Blaine — 11%,
- Big Horn — 11%,
- Richland — 14%

(Montana Board of Oil and Gas Conservation Annual Review, 2007)

Most of Big Horn County's production is coal bed natural gas, and that source may grow substantially in the next few years. Most of Richland County's production is "associated gas" that occurs as a byproduct of oil production.

Some of the gas produced in Hill and Blaine counties flows into NorthWestern Energy's gas pipeline. However, a significant amount of the gas produced in these counties flows into the Havre Pipeline system and to out-of-state markets. Gas produced in Fallon, Richland, and Phillips Counties flows into MDU's (Montana-Dakota Utilities) system and some of that flows east out of state.

Coal bed natural gas development in southeast Montana is just beginning to achieve significant production. Difficult environmental issues have slowed development over the past few years. With the Montana Environmental Impact Statement (EIS) on methane development completed and released to the public in the fall of 2003, and various lawsuits against the industry settled, in-state development is currently increasing. Two companies now operate near the town of Decker just north of the Wyoming border producing saleable gas. The total amount of coal bed natural gas development likely to occur in Montana has yet to be determined. A Bureau of Land Management (BLM) supplemental EIS was recently signed, so activity on federal lands may increase.



Source: U.S. EIA, Natural Gas Annual Reports, 1960-2006 (Table NG1).

2. Natural Gas Supplies for the United States

U.S. natural gas supplies are largely domestic, supplemented by imports mainly from Canada. A small amount of gas imports arrive from other countries, a portion of which is Liquefied Natural Gas (LNG). Currently, domestic gas production and imported gas are usually more than enough to satisfy customer needs during the summer, allowing a portion of supplies to be placed into storage facilities for withdrawal in the winter, when the additional requirements for space heating cause total demand to exceed production and import capabilities. Natural gas is injected into pipelines every day and transported to millions of consumers all over the country. Much of it travels long distances from production areas to population centers through interstate pipelines owned and operated by pipeline companies. Once the gas arrives at a population center, it is generally delivered to residential customers and other end-use consumers through the complex network of pipes owned and operated by local distribution companies (LDCs).

Total U.S marketed production of natural gas in 2006 was 19.38 trillion cubic feet (Tcf). This was up slightly from 2005 (18.95 Tcf) when Hurricane Katrina disrupted supplies, and was down from 2001 when production peaked at 20.57 Tcf. According to the U.S. Energy Information Administration, the top five natural gas producing states, including Texas, Oklahoma, New Mexico, Wyoming, and Louisiana, accounted for just over half of natural gas production in the United States in 2006. Marketed production from federal offshore wells in the Gulf of Mexico was 2.84 Tcf, or about 15 percent of total domestic production. This amount was sharply down from previous years when the average from the Gulf was usually around 4.0 Tcf. Major disruptions caused by Hurricane Katrina were behind the downturn. Texas, which comprises the largest producing area in the United States, accounted for nearly 29 percent of the marketed production, while Oklahoma, New Mexico, Wyoming, and Louisiana together accounted for about 33 percent. Growth in natural gas flows out of the prolific Rocky Mountain natural gas basins has continued modestly as increasing demand, particularly in Western markets, absorbed the increase. The other 27 producing states accounted for about 23 percent of marketed production.

The Rocky Mountain states are the most important domestic source of natural gas supply to the Pacific Northwest region, which includes Montana. Alaska's North Slope is potentially the largest domestic source of new natural gas resources for the nation as a whole, although no pipeline currently exists to transport it. According to the U.S. EIA, the Rocky Mountain and Alaska regions are projected to provide most of the increase in domestic natural gas production from 2004 to 2030. Because 60 percent of the projected growth in natural gas consumption occurs east of the Mississippi River, new natural gas pipelines are expected to be built from supply regions in the West to meet natural gas demand in the East, including a proposed North Slope Alaska pipeline.[2]

After declining during the 1990s, natural gas drilling in the U.S. picked up dramatically in early 2000 and 2001 in response to high gas prices, and has increased modestly since then as prices have remained relatively high. The lack of higher domestic production numbers in response to the increased natural gas drilling in recent years likely reflects the maturation of the natural gas resource base in the U.S. (especially the Lower-48 states), which results in declining returns to drilling activity.[3]

Gas production activity in the U.S. is expected to continually increase as long as demand keeps increasing and prices remain high. Actual production numbers are expected to increase only slightly. In the long run, if natural gas prices remain at their current high levels, domestic drilling activity will continue to grow, perhaps at higher rates than recently experienced. According to the U.S. EIA, domestic natural gas production is expected to modestly increase from 19.2 trillion cubic feet (tcf) in 2006 to a projected 20.8 tcf in 2020 to meet growing domestic demand. Domestic production is expected to level out during the decade between 2020 and 2030, reflecting decreasing domestic supplies from played out wells. An estimated 20.5 Tcf will be produced in 2030.[4] Future production would come primarily from Lower-48 onshore unconventional and conventional sources, with "unconventional production" expected to increase at a faster rate than other sources during that time. The definition of unconventional gas production

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[2] U.S. EIA
[3] Ibid.
[4] Ibid.

changes over time with technological advances, but currently includes deep gas, tight gas, gas-containing shales, and coalbed natural gas. Alaska and offshore natural gas are projected to also be significant future domestic sources.

Today, about 15-20 percent of the total natural gas consumed in the U.S. is imported from other countries, with most of that coming from Canada. In 2006, net imports to the United States were about 4.3 Tcf, an amount that has held steady since 2002. Aside from Canada, liquid natural gas (LNG) is the other significant source of natural gas imports. LNG imports into the U.S. have more than doubled since 2002 and stood at 0.58 Tcf in 2006 with Trinidad the major supplier. Net LNG imports today are about 14 percent of overall natural gas net imports, and are expected to grow significantly over time, eventually becoming the primary source of natural gas exports. Import levels of LNG in 2030 are expected to be 4.5 Tcf. This means a large increase in construction of U.S. LNG receiving terminals over the next 20 years. Imports from Canada have been holding steady since 2001, and stood at about 3.6 Tcf in 2006 out of the 4.2 Tcf total in imports. Imports from Canada are forecast to be only 1.2 Tcf by 2030 due to declining production of its fields. Net natural gas imports into the U.S. are expected to increase from 4.2 tcf in 2002 to almost 6.0 tcf in 2030, with imports making up an increasingly larger share of the total percentage consumed in the U.S. There were 394 natural gas storage sites in the United States at the end of 2005 with a combined total capacity of 8.26 Tcf.[5]

It is hard to predict how much natural gas is left in North American reserves that could go toward U.S. consumption. Reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. The Northwest Power and Conservation Council estimates between 2,100 and 2,650 tcf remaining of North American gas resources and about 290 tcf remaining in gas reserves (excluding Mexico).[6] Mexico used to send gas supplies to the U.S., but no longer does. Using these numbers and assuming that U.S. and Canadian consumption grows at 0.7 percent per year from current levels, estimated remaining North American resources would satisfy North American consumption for about 40 or 50 more years (not including imports and exports and unforeseen events). The entire world is estimated to contain about 13,000 tcf in natural gas reserves with much of that located in the Middle East.[7]

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[5] Ibid.

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

[7] Northwest Power and Conservation Council, Terry Morlan, 2007

In the last several years, some important trends in gas production have occurred with respect to North American supply. Several years ago, the government of Canada announced that it did not expect Alberta natural gas production to grow in the coming years as it has in the past, but instead to level off (Morlan, 2004). Also, Devon Energy, the largest U.S. independent producer of gas, is finding fewer reserves than predicted in new wells drilled in the U.S. and greater production decline rates in existing wells. Furthermore, the cost of finding natural gas in North America is rising. From 2001 through 2003, the three-year average finding cost for natural gas was $1.53/dkt, which was up 29 percent from the three-year average the year before. In 2003 alone, the average finding cost was $1.73/dkt[8]. Since 2004, those trends have not changed. It is therefore possible that gas production in North America in future years may not grow as quickly as historical trends and may not grow at all. In other words, gas markets could be tighter in future years than has been seen historically.

3. Natural Gas Consumption in Montana

Recent Montana natural gas consumption has averaged 60-70 billion cubic feet (bcf) per year with 73.8 bcf being consumed in 2006 (see figure 2). Future Montana natural gas consumption, excluding that used for any new electric generation built in-state or new large industry, is expected to increase slowly at less than 1 percent annually according to projections by Montana's largest gas utilities, Northwestern Energy (NWE) and Montana-Dakota Utilities Co. (MDU). Both residential and commercial gas consumption are growing slowly, and usage by industry is expected to stay fairly level over time. In the 1970's, Montana's industrial sector used much more natural gas than it does now, and as a result, total in-state consumption was higher than it is today. The closure of smelters in Anaconda, in particular, contributed to the drop in industrial usage that occurred in the 1980's. The Columbia Falls Aluminum Company has been using only a fraction of what did historically, which has been part of the reason for recent drops in industrial numbers, as well as fuel substitutions at Montana's refineries. Total in-state consumption is slowly creeping back up towards its levels in the 1970's, due mostly to increases in the state's population and commercial base over time.

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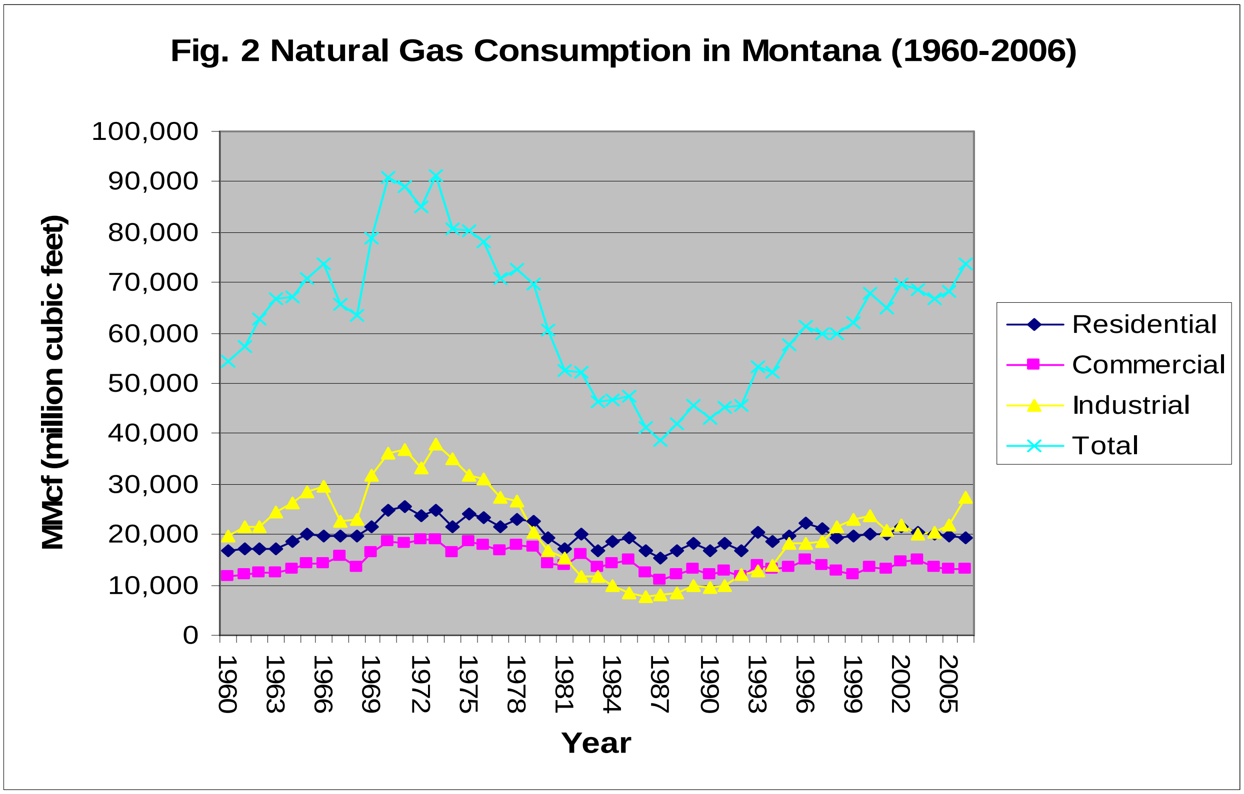
[8] Wall Street Journal, "Natural Gas is Likely to Stay Pricey". Monday, June 14, 2004. One dekatherm (dkt) is equal to a million British Thermal Units (BTUs). Often, natural gas prices will be reported either in dekatherms or in units of 'a thousand cubic feet' (Mcf's). Assuming an average BTU content for U.S. natural gas at standard conditions, 1.0 Mcf = 1.03 dkt according to the U.S. EIA (U.S. EIA, Natural Gas Annual, Table B2, 2002).



Source: U.S. EIA, Natural Gas Annual Report, 1950-2006 (Table NG2).

If new gas-fired electric generation plants get built in Montana, total gas consumption in Montana could significantly increase over current levels at a rate greater than the 1 percent growth rate projected by utilities. A proposed 500 MW Silver-Bow electrical generation plant near Butte, which was never built, would have consumed about 30 bcf per year of gas — equivalent to almost 50 percent of current total gas consumption in Montana. The Silver-Bow project would have also demanded a major upgrade in NorthWestern Energy's (NWE) gas pipeline system. The Basin Creek Generation plant near Butte at 51 MW capacity was up and running by late 2005. Natural gas usage at the Basin Creek plant only constitutes a small percentage of Montana's total usage right now, and did not require extensive upgrades to NWE's pipeline system (Waterman 2004). Proposed large natural gas plants in Montana include the Mill Creek Plant near Anaconda (200 MW) and Montgomery Energy Partners-Great Falls Energy Center (400 MW) near Great Falls. The later especially could significantly raise total Montana natural gas consumption.

4. Natural Gas Consumption in the U.S.

From the late 1970's to 2000, a number of changes in energy markets, policies, and technologies have combined to spur an increase in the total usage of natural gas in the U.S. (U.S. EIA 2001). These include:

- Deregulation of wellhead prices begun under the Natural Gas Policy Act of 1978 and accelerated under the Natural Gas Wellhead Decontrol Act of 1989;
- Deregulation of transmission pipelines by Federal Energy Regulatory Commission (FERC) Orders 436 (1985), 636 (1992), and 637 (2000). The FERC orders separated natural gas commodity purchases from transmission services so that pipelines transport gas on an equal basis. These orders were intended to ensure that all natural gas suppliers compete for gas purchasers on an equal footing, to enhance competition in the natural gas industry, to ensure that adequate and reliable service is maintained, to improve efficiency in the gas transportation marketplace, and to protect customers from the exercise of market power. Also, Order 636 allows gas customers to purchase natural gas from a supplier other than the utility that delivers their natural gas;
- Passage of the Clean Air Act Amendments of 1990 and subsequent regulations affecting air quality standards for industries and electricity generators in non-attainment areas, which favor natural gas since it burns relatively clean compared to coal;
- Upcoming legislation constraining carbon emissions would favor natural gas over coal as an electricity generation fuel;
- Gas turbine technology. High-efficiency combined cycle combustion turbine technology, coupled with historically low gas prices before 2002, 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 through 2020. Today's higher natural gas prices may slow down previously projected growth rates in natural gas electric generation, but more plants are still expected to be built along with an increase in wind generation.
- Improvements in exploration and production technologies, improving the return for exploration and production efforts;
- Investment in major pipeline construction expansion projects from 1991 through 2000 adding about 50 billion cubic feet per day of capacity; and
- Increased imports from Canada.

These factors created new markets and lowered the price of natural gas for existing markets in the 1980s and 1990s. It is important to note, however, that some of these trends have either leveled off or reversed as of today. For example, gas production in major producing areas like Alberta is leveling off (with Canadian imports to the U.S. falling off slightly in 2006), and gas prices are currently high relative to historical norms. This reversal in trends may or may not be temporary. While natural gas demand is expected to continue rising over time, it could grow less than expected or level off if recent trends continue. Indeed, U.S. gas consumption declined slightly from 2002 levels until 2007, despite a long-term increasing demand trend over time. The U.S. EIA has also revised forecasted natural gas consumption numbers down from previous estimates, while revising forecast gas prices up.

In 2002, according to the U.S. EIA, the U.S. consumed more than 23.0 trillion cubic feet (tcf) of natural gas, the highest level ever recorded. In 2003, it tapered off slightly to 22.3 tcf, went up slightly to 22.4 tcf in 2004, dropped to 22.2 tcf in 2005 and dropped again to 21.7 tcf in 2006, and then rose to 23.0 in 2007. Reasons for the slower growth in U.S. consumption include higher gas prices and milder winters in those years. Historically, U.S. natural gas consumption has increased at a healthy pace and the Pacific Northwest region is no exception. Two main reasons for historically rising use in the Pacific Northwest are strong regional economic growth, and increased gas-fired electrical generation in the region. In 2006, the use of gas for electricity generation was the second largest consuming sector in the U.S at 28.6 percent. That percentage is rising each year. Industrial use was just barely the largest consuming sector at 30.3 percent, but has been declining in absolute usage and as a share of the total market. Residential usage is the third largest category at 19.8 percent. The U.S. EIA forecasts that U.S. total natural gas consumption will increase from the current level of about 22.0 trillion cubic feet per year to nearly 25.0 Tcf in 2030. The U.S. EIA predicts that delivered and total natural gas consumption in the U.S. will increase by 0.7 percent annually through 2030. Earlier consumption growth rate estimates by the U.S. EIA were significantly higher, which suggests a general feeling among energy analysts that gas usage (and possibly production) will not grow as quickly as previously thought. It is unknown how the current economic recession will affect these numbers, but it may dampen further the demand growth for natural gas at both the U.S. and state level.

5. Montana's Natural Gas Pipeline System

On the U.S. EIA website, an information document entitled, "About U.S. Natural Gas Pipelines, Network Configuration and System Design" effectively describes gas systems: "A principal requirement of the natural gas transmission system is that it be capable of meeting the peak demand of its shippers who have contracts for firm service. To meet this requirement, the facilities developed by the natural gas transmission industry are a combination of transmission pipelines to bring the gas to the market areas and of underground natural gas storage sites and liquefied natural gas (LNG) peaking facilities located in the market areas.

"The design of natural gas transmission pipelines and integrated storage sites represents a balance of the most efficient and economical mix of delivery techniques given the operational requirements facing the pipeline company, the number and types of transportation customers, and available access to supplies from production areas or from underground storage. Many natural gas pipeline systems are configured principally for the long-distance transmission of natural gas from production regions to market areas. These long-distance systems are often referred to as trunklines. At the other extreme are the grid systems, which generally operate in and serve major market areas. Many of the grid systems can be categorized as regional distribution systems. For the most part, they receive their supplies of natural gas from the major trunklines or directly from local production areas. The grid systems transport natural gas to local distribution companies and large-volume consumers".

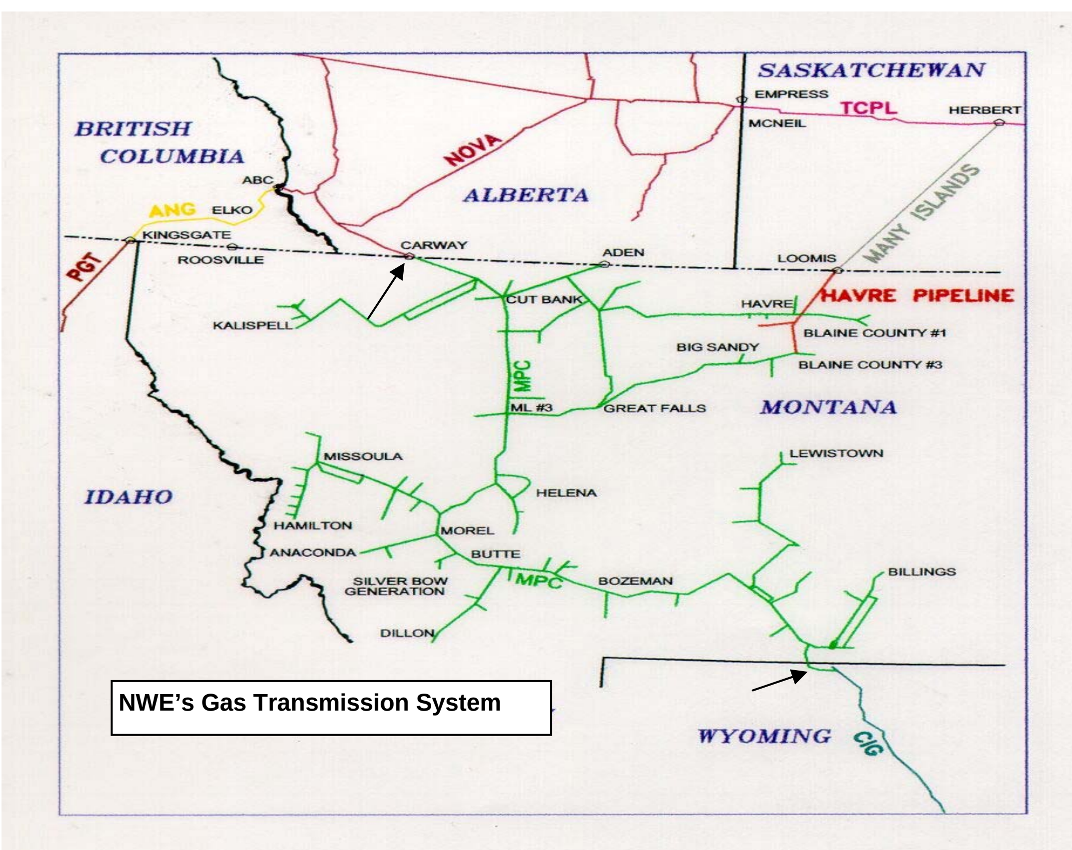
Three distribution utilities and two transmission pipeline systems handle over 99 percent of the natural gas consumed in Montana (Table NG5). The distribution utilities are NorthWestern Energy (NWE, previously the Montana Power Company), Montana-Dakota Utilities (MDU) and Energy West of Great Falls,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

Northwestern Energy (NWE) is the largest provider of natural gas in Montana, accounting for about 60 percent of all regulated sales in the state according to annual reports from Montana utilities (Table NG5). Northwestern Energy provides natural gas transmission and distribution services to about 165,000 natural gas customers in the western two-thirds of Montana (including the Conoco and Cenex oil refineries in Billings). These customers include residences, commercial businesses, municipalities, state and local governments and industry. NWE's gas transportation system, both long-distance pipeline transmission and local distribution, lies entirely within Montana. NWE's transmission system is regulated by the Montana Public Service Commission. The NWE system consists of more than 2,100 miles of transmission pipelines, 3,300 miles of distribution pipelines and three in-state storage facilities. NWE's system has pipeline interconnections with Alberta's NOVA Pipeline, the Havre Pipeline Company, the Williston Basin Interstate Pipeline Company and the Colorado Interstate Gas Company. The Havre pipeline also is regulated by the Montana Public Service Commission.

NWE supplies gas mostly from purchasing it on the market in contracts with various durations of three years or less. The NWE pipeline system receives gas from both Alberta and Wyoming. The price paid for gas in Montana on the northern end of NWE's system is generally tied to Alberta's AECO index. The price paid for gas coming in on the south end of Montana's system is generally tied to a Colorado Interstate Gas (CIG) index posted in Gas Daily (Griffin, 2006). Alberta sends natural gas to Montana primarily through NWE's pipeline at Carway and at Aden (both locations are north of Cut Bank) where it ties in with Alberta's NOVA Pipeline. Most gas exported on NWE's system is exported at Carway to Alberta.

Referring to the diagram below, NWE's pipeline system runs in a north-south direction from Carway (top arrow) and Aden at the Canadian border down through Cut Bank and south towards Helena approximately paralleling the Rocky Mountain Front. Near Helena, the main pipeline turns west and runs close to Highway 12 and then turns south again 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



NWE's Gas Transmission System

Missoula, Great Falls, the Flathead Valley, Dillon, Livingston and Billings. NWE's natural gas delivery system includes two main storage areas. The Cobb Storage is located north of Cut Bank near the Canadian border. The Dry Creek storage is located northwest of the Grizzly Interconnect, near the Wyoming border. Natural gas storage provides a critical supply component during the heating season, helps satisfy sudden shifts in demand and supply, and smoothes gas production throughout the year.

NEW's system delivers about 37 bcf of total gas per year to its customers on average compared with total annual Montana consumption of about 70 bcf. NWE's natural gas purchases come mostly from Alberta and in-state Montana wells. NWE purchases roughly 50 percent of its supply from Montana sources. Also, NWE imports more gas from Canada than it exports (Smith, 2008).

In 2006, NWE imported about 14.5 bcf from Canada, and about 6.0 bcf from other states including North Dakota and Wyoming. About 17.5 bcf on its system was from Montana wells. NWE used to obtain a larger percentage of its gas from Alberta. The NWE pipeline system has a daily peak capacity of 325 million cubic feet of gas (MMcf) (Griffin, 2007). About one half of the total gas throughput on NWE's system is used by "core" customers. This currently consists of 19 bcf in regulated sales from NWE to its consumers, who include residential and commercial business users. NWE has the obligation to meet all the supply needs of its core customers. The other half of gas throughput is used by non-core customers, including industry, local and state governments and by Energy West, which supplies Great Falls. NWE only provides delivery service for these non-core customers; they contract on their own for the gas supply. Peak gas usage occurs on cold weather days when daily demand is often close to peak pipeline capacity. Significantly smaller amounts are used when the weather is warm.

As of 2006, there is no unused firm capacity on the NWE pipeline transmission system. This means that no additional gas user of significant size, such as a large industrial company, can obtain guaranteed, uninterrupted gas delivery on the current system. At times of peak consumer usage, the pipeline is full and cannot deliver any more gas. As of mid-2007, customer peak daily demand on the system is an estimated 325 million cubic feet (MMcf), and thus the system's maximum daily capacity is currently matched by peak daily demand. The projected growth rate of maximum daily load and thus of required "daily pipeline delivery capacity" (excluding future electric generation plants) is 1.7 percent annually which translates to about 5 MMcf/day annually. This growth is expected to come almost solely from core customers. Meeting the demands of new gas-fired electric generation or a large new industrial facility would likely require additional upgrades on the system. The current recession may slow this predicted growth.

In 2004, NWE's main gas transmission system added two 'loops' to meet its projected increasing peak load in the coming years. Loops are new pipeline installed next to existing pipelines. One of those was built to provide additional gas transmission capacity to customers in the Flathead Valley. The second loop was built in order to increase capacity off of the main NWE pipeline (near Deer Lodge) to Missoula and the Bitterroot Valley. The Bitterroot Valley (fed by the Missoula line) and the Flathead Valley (fed by the Kalispell line) are two of the fastest growing areas in Montana. In 2006, NWE added additional looping pipelines to the Flathead Valley and Missoula area. These loops were needed to add capacity to the pipeline systems to keep up with load growth in these areas. NWE will also install a loop to the main 16 inch gas transmission line near Cut Bank. This loop is needed to increase the capacity of the system and keep up with load growth in the Missoula, Helena, and Bozeman areas. Also, a new compressor station is planned in the Cut Bank area. If the Mill Creek gas generation plant is built, it would be interruptible gas and therefore would not require major upgrades on the transmission system.

Montana-Dakota Utilities Co. (MDU) is the second largest natural gas utility in Montana and accounts for about 25-30 percent of all regulated natural gas sales in Montana. Currently, its sales in Montana are just over 8 bcf (Table NG5). It distributes natural gas to most of the eastern third of the state, including Billings. MDU primarily uses the Williston Basin Interstate (WBI) pipeline for the transmission of its purchased gas. The WBI gas pipeline provides service for other utilities and is regulated at the federal level by FERC. MDU buys its gas from more than 20 different suppliers. Most of its purchased gas is domestic with about 50 percent coming from Wyoming, various percentages coming from North Dakota and Montana, and about 10 percent coming from Canada. Periodically, MDU buys a certain amount of pipeline capacity on the WBI pipeline to match what it feels will be needed for the busiest usage day, based on the number of homes in its area. MDU expects less than 1 percent growth per year in its gas sales for the near future.[9]

Energy West (formerly Great Falls Gas Co.) is the third largest gas provider in Montana, accounting for about 10 percent of all regulated gas sales in Montana (Table NG5). Currently, its sales are about 3.0 bcf. It provides gas to the Great Falls area and a small amount to West Yellowstone through a propane vapor distribution system. The other Montana utilities currently operating account for about 1 percent of all gas sales and currently include the Cut Bank Gas Company and Havre Pipeline Company. The Northern Border pipeline (2.2 bcf/day capacity), which passes through the northeast part

[9] Montana-Dakota Utilities, Don Ball, 2007.

of Montana, is the largest pipeline in the state, but it has no injection points in Montana. It's terminus is the U.S. Midwest market.

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

Natural gas prices are measured in different ways at different points in the gas supply system. The "wellhead" price is the price of the gas itself right out of the ground. The wellhead price for natural gas (which varies a bit from region to region) is set in the national wholesale market, which was deregulated by the federal government in 1978. No state, including Montana, can regulate or really control this wholesale market. The wholesale gas prices on the major gas indices such as the Henry Hub and AECO Hub in Alberta reflect the wellhead price of gas plus a relatively small fee to transport the gas to the particular hub. 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 provides a nationwide price reference point. The difference between the Henry Hub price of natural gas and the average U.S. wellhead price from 1989 to late 2001 was about $0.12/dkt.[10] While the Henry Hub price appears to be a good approximation of average U.S. wellhead prices, other hubs located in relatively remote areas such as Wyoming can have significantly higher or lower prices than the Henry Hub due to their location, local pipeline constraints, and local markets.

The "citygate" gas price typically reflects the wellhead price plus pipeline transmission fees (to get the gas to a particular locale or distribution system). The "delivered" gas price we pay in our homes and businesses is the citygate price plus local distribution fees and other miscellaneous charges from the utility. Transmission and distribution fees are set by utilities and/or pipelines and are regulated by state and federal agencies.

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

[10] Northwest Power and Conservation Council, 2003

large price swings on the spot market. This helps keep the price paid for gas by customers relatively stable.

Because Montana continues to rely on Alberta for much of its natural gas, what happens with Alberta gas directly affects Montana. Alberta gas has a strong effect on the price for natural gas in Montana and in other parts of the U.S. that directly obtain supply from there. The wellhead price of Alberta natural gas is, in turn, determined largely by the North American free market, subject to the contract conditions agreed to by each buyer and seller. It is important to note that prices on Wyoming's hubs also affect Montana customers.

Prices in Alberta's main trading forums are determined by the AECO C/ Nova Inventory Transfer (NIT) index. This index, which is the common point on the Nova Gas Transmission system where gas is transferred, is very liquid for trading. The AECO C/ NIT index generally tracks the Henry Hub Index with some price differential. Due to its location in the Western Canada Sedimentary Basin, the AECO C/ NIT price is often US$0.60/MMBtu to US$1.50/MMBtu cheaper than the Henry Hub price.

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

Historically, the delivered price for natural gas to Montana customers was at least twice the average wellhead price. Typically, less than 50 percent of a customer's gas bill was for the actual gas itself. Transmission, delivery and other fees made up more than 50 percent of the total gas bill, with the exception of a few years in the 1980s. Today, with wellhead prices so high, that situation is no longer true. As discussed below, most of gas bill that consumers face today is for the gas itself. As of March 2009, for example, NWE residential customers pay an average delivered gas price of just over $10.00/dkt. About $6.50 of that is for the commodity itself, whereas about $3.50 is for transmission, distribution and other charges.[11]

[11] Northwestern Energy website.

7. Natural Gas Prices in the U.S.

Natural gas prices have been particularly sensitive to short-term supply and demand shifts in recent years because of the highly inelastic nature of this market.[12] Natural gas market prices respond to shifts in supply and demand. The degree of price response relates to the price elasticity of both supply and demand. In the short-term, consumers are limited in their ability to switch fuel sources, and production infrastructure is thought to be operating near capacity. Also, significant lead time is required in order to bring additional domestic or foreign natural gas supplies to market, as well as expand pipeline capacity to alleviate transmission bottlenecks. These conditions contribute to the inelastic nature of the market. Limited short-term price responsiveness means that natural gas prices will be highly sensitive to market factors such as weather swings or supply disruptions. Inelasticity is characteristic of many energy commodities. However, analyses of natural gas volatility relative to other commodities have ranked it among the highest. Electricity has been the only commodity group with price volatility consistently higher than those of natural gas.

Factors on the supply side that may affect natural gas prices, and hence volatility, include variation in natural gas storage, production, imports, or delivery constraints. Of these, storage levels receive a high amount of attention because of the physical hedge it provides during high demand periods. Also, working gas in storage often is viewed as a barometer of the supply and demand balance in the market. Disruptions caused by severe weather, operating mishaps, or planned maintenance can also cause short-term tightness in natural gas supply. In the summer of 2005, hurricanes along the U.S. Gulf Coast caused more than 800 billion cubic feet (bcf) of natural gas production to be shut down between August 2005 and June 2006. This is equivalent to about 5 percent of U.S. production over that period and about 22 percent of yearly natural gas production in the Federal Gulf of Mexico. As a result of these disruptions, natural gas spot prices at times exceeded $15 per million Btu (MMBtu) in many spot market locations and fluctuated significantly over the subsequent months, reflecting the uncertainty over supplies.

On the demand side, temperature changes tend to be one of the strongest short-term influences on gas prices. During cold months, residential and commercial end users consume more natural gas for heating needs, which places upward pressure on prices. If unexpected or severe weather occurs, the effect on prices intensifies because supply is often unable to react quickly to the short-term demand response, especially if the natural gas transportation system is operating at full capacity. Under these conditions, prices must rise high enough to reduce the demand for natural gas. Temperatures also have an effect on prices in the cooling season as many electric power-generating plants used to produce incremental supplies to meet air conditioning needs are fueled by natural gas. Therefore,

[12] Price inelasticity means that a small change in supply or demand leads to a large change in price.

hotter-than-normal temperatures during the summer can lead to more natural gas supplies feeding natural-gas-fired power generation. This effect may reduce natural gas available for storage and increase price pressure during the winter months when inventories are relied upon to meet heating demand.

The prices and market conditions for related fuels also have an effect on natural gas markets. In the United States, most baseload electricity generation is delivered from coal, nuclear, and hydroelectric power stations. Because natural gas tends to be a higher-cost fuel, natural-gas-fired power stations more typically are used to cover incremental power requirements that arise during times of peak demand or during sudden outages of baseload capacity. However, an increase in price or a disruption in supply in any one of the competing fuel markets can spark an increase in natural gas demand. For example, hydroelectric generation went through a relatively steep decline in the late 1990s owing to droughts in the West. The supply disruption led to a 40-percent decline in hydroelectric generation between 1997 and 2001. During the same period, natural-gas-fired generation increased 33 percent as there was spare capacity and these facilities were better positioned than coal-fired plants to respond to the deficit in electricity supply.

Lastly, economic activity is a major factor influencing natural gas markets. When the economy improves, the increased demand for goods and services from the commercial and industrial sectors generates an increase in natural gas demand. This is particularly prevalent in the industrial sector, which is the leading consumer of natural gas as both a plant fuel and as a feedstock for many products such as fertilizers and pharmaceuticals.

8. Natural Gas Prices in Montana

Natural gas customers in Montana and in the Pacific Northwest have historically paid relatively low gas rates compared to the rest of the U.S. In the past eight years, however, gas prices across this region have risen to be more in line with the rest of the nation. Even more significantly, national prices have significantly risen in this same time period and with them the prices paid in Montana. As a result of these two trends, Montana's gas prices have reached high levels rarely seen before and relatively low gas rates may be a thing of the past. There may also be more, large price variations over time as a result of increasingly higher prices.

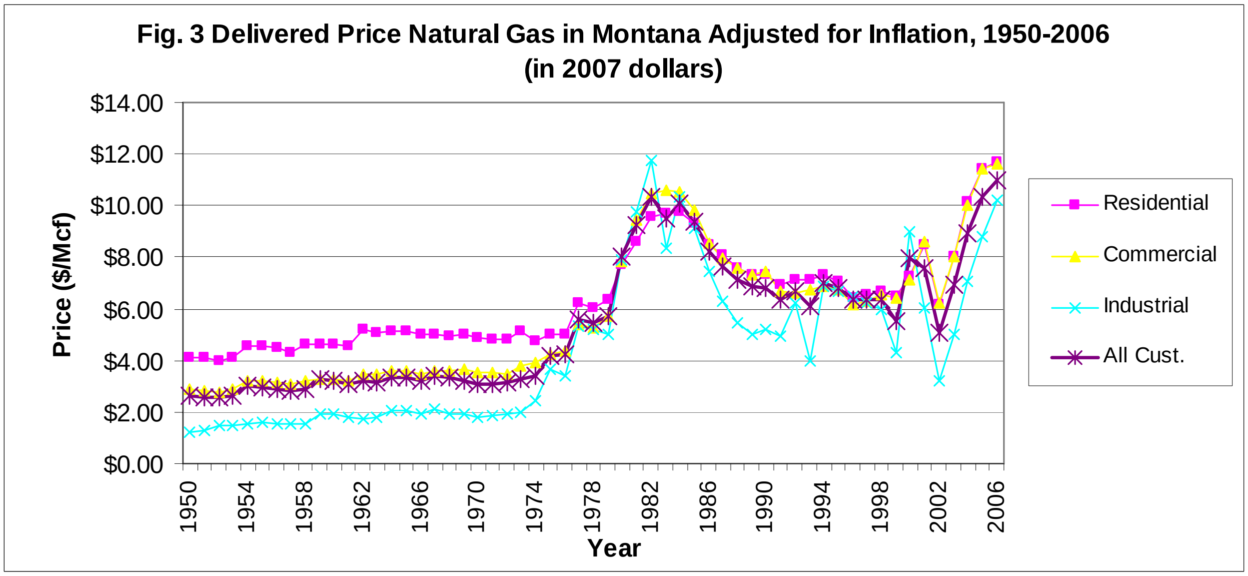
The main reason for increased gas prices in Montana is that the wellhead price nationwide for natural gas has greatly increased since 2002. A secondary reason is that the Pacific Northwest region now pays natural gas prices closer to the prices paid by the rest of the nation. This break from our historically lower prices is partially because more pipelines now connect gas supplies in western Canada and the western U.S. to buyers in the eastern U.S. This means that more customers compete with Montana for the same gas supplies. If demand for a commodity goes up, all else equal, prices also go up. Another reason for potentially higher long-term prices in this region is that the pipeline infrastructure of the Northwestern U.S. is less and less able over time to meet today's gas demand. This means that the regional gas market could more easily be upset by extreme events such as very cold weather.

The historical delivered gas prices (the final prices a customer sees on their bill) for all consumer classes in Montana, including residential, commercial and industrial, were relatively low (about $5/dkt) in today's dollars (actual dollars adjusted for inflation) until the late 1970s (see Table NG3). Delivered prices rose considerably through the mid-80s and mostly settled in the $6-10/dkt range using today's dollars. In the 1990s, the delivered prices came back down and hovered around $6-7/dkt. From 2000-2004, delivered gas prices started increasing and showing more variation, rising up to an average of $10/dkt for certain years in Montana. Then in 2005, prices really took off. Prices steadily rose over 2005, took a big jump after Hurricane Katrina, and peaked in January of 2006 at $13.50/dkt for NWE residential customers. Since then, prices have moderated. As of March 2009, NWE residential customers pay an average delivered gas price of just over $10.00/dkt.[13]

These recent large increases in delivered gas price have been felt nationwide and are due almost solely to the recent increases in the U.S. wellhead price of natural gas. There are three main reasons for the recent dramatic increase in U.S. natural gas prices. These include: 1) A tight North American natural gas market (increasing U.S. demand, and level or declining North American supply), 2) the continuing high price of oil (causing higher demand and prices for natural gas), and 3) the lingering after-effects of the Fall 2005 hurricane disruptions in U.S. supply.   Rapid growth by countries such as India and China also has increased world demand.

Figure 3 shows delivered natural gas prices in Montana adjusted for inflation and reported in constant 2007 dollars. The delivered prices graphed below are the prices that residents and businesses see in their final energy bill reflecting all charges.

[13] Northwestern Energy website.



Source: U.S. EIA, Natural Gas Annual Report, 1950-2006, U.S. EIA website (Table NG3).

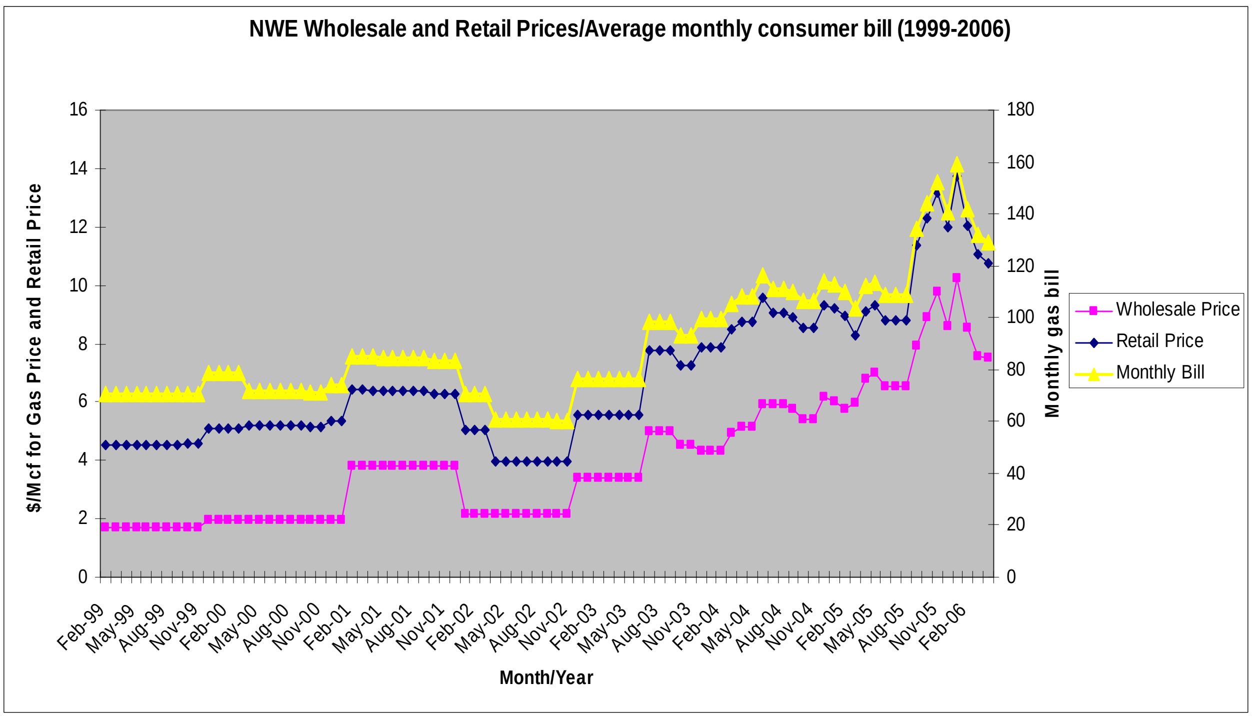
The average U.S. wellhead price of gas for the year 2000 was $3.68/dkt, for 2003 was $4.88/dkt and for 2006 was $6.42/dkt. This last price is well above historical norms and well above the long-term U.S. EIA forecast for wellhead price in 2030 of $5.80/dkt in today's dollars for some of the reasons discussed above.[14]

Transmission utilities in Montana, the two main ones being NorthWestern Energy (NWE) and Montana-Dakota Utilities (MDU), are prohibited from earning any profit on the cost of natural gas they purchase. Rather, they simply pass higher gas costs to consumers, and if gas prices go down they pass that savings on to customers. Utilities earn their profit through a return on capital investment, including the gas transmission and distribution systems, but don't earn a profit on their expenses, such as gas purchases. The average price of gas purchased by NWE, MDU and Energy West reflects current gas market conditions, and that price is constantly changing. Any price change requested by NWE must be approved by the Public Service Commission in what is called a "tracker" hearing. A tracker hearing covers only the cost of purchased gas, and not any of the other costs of the utility. Trackers usually are routine procedures, but can sometimes be contentious. NWE currently computes a new tracker each month to more accurately reflect the gas costs it incurs in order to supply its customers. In recent years, NWE has had to dramatically raise gas bills for its core customers — mostly residential and commercial users — due to the rising costs of gas. For Montanans as a whole, residential natural gas prices have more than doubled in just over five years, and virtually all of this increase is due to higher gas prices — not utility profits.

[14] U.S. EIA.

The following graph (Figure 4) shows the price of gas paid by NWE (before delivery to customers), the final delivery price paid by residential NWE customers, and the average monthly bill paid by residential NWE customers (assuming 10 dkt usage per month). The latest data possible was used covering a time period from 1999-2006. The two gas prices and monthly bills move in unison over time, demonstrating that the portion of a customer's bill where utilities make money — transmission and distribution — has remained relatively constant over time. In Figure 4, wholesale price is the price paid for the gas commodity itself (in dollars per Dekatherm) and retail price is the final delivered cost of gas per dkt to residential customers. The average residential monthly natural gas bill for both utilities is expressed in nominal dollars (not adjusted for inflation) based on 10 dkt consumption per month. Some figures are averaged over several months.

Figure 4: Northwestern Energy Gas Prices



Source: NWE, 2007

At a 10 dkt usage per month for the average family, 120 dkt would be consumed during the average year by the average household that uses natural gas. Using this average, the monthly gas bill for a NorthWestern Energy residential customer went from $70.89 in 2002 to $128.83 in April of 2006. This is an increase of 82 percent, $58 per month or $696 per year for the average NWE household. The monthly gas bill for an MDU customer went from $47.60 in January 2002 to $92.29 in April of 2006. This is an increase of 94 percent, $45 per month or $540 per year. Prices today would be about $100 per month, and thus have not risen much from 2006. These increases in natural gas prices from 2002-2006 were between 1 percent and 2 percent of median household income in Montana in 2006, which was $40,627.[15] The total annual gas bill for the average gas user on NWE's system as of 2006 was almost $1,550, or almost 4 percent of median household income in the state, and was $1,100 for the average MDU consumer (less than 3 percent of median household income). For those households that earned a lower than median household income and experienced average (or greater) natural gas usage, 4 percent or more of their income was spent on natural gas in 2005. The exception to this is those households in that category that received help on meeting their gas bills. Again, the high prices were due to high wellhead prices across the nation.

Due to natural gas deregulation, most large industrial customers in Montana contract for gas directly with MDU and Energy West or with other independent suppliers. Industry still uses the local utilities for distribution and transportation services. Despite typically paying lower gas rates than residents and commercial businesses (i.e. core customers), industry has also faced a major increase in gas bills as wholesale gas prices climb, although the prices paid by industry have fluctuated greatly from year to year (Figure 3 and Table NG3). The gas price for each industrial customer depends upon each specific contract, the gas supplier, and the ability of the given industry to switch from natural gas to some other fuel if prices get too high.

Today, five of the largest natural gas users in Montana are the four oil refineries in and near Billings and Great Falls and the Stone Container plant in Missoula. Plum Creek Manufacturing, REC near Butte, and Basin Creek Power Services are also large users in Montana (more than 500 million cubic feet used per year). The refineries in Billings have some flexibility in switching fuels to run their operations, so they have likely not been hit as hard by higher gas prices as other industries. Other large customers, such as Montana State University, probably have less flexibility to switch fuels, and have likely felt more of the cost of recent gas price increases. Large gas users who buy gas on the spot market, such as Montana State University-Billings, could be hurt more by recent high prices and price swings, whereas those industrial customers with longer-term contracts at lower prices are at least partially insulated until their contracts run out.

9. Future Price Increases and Price Volatility

As mentioned earlier, U.S. wellhead prices are the largest determinant of how much Montanans pay for gas. The wellhead price Montana utilities and their customers pay for gas is likely to remain fairly close (within a $0.30-$0.70 cent differential) to average U.S. prices on the national market. This is partially because of increased pipeline capacity from

[15] Montana CEIC, 2007

Alberta out to the U.S. Midwest and East Coast. Increased gas transmission capacity means that the wellhead price paid in Montana today is closely tied to wellhead prices paid nationwide. The price differential between prices Montanans face and the rest of the U.S. faces may also depend upon the amount of natural gas produced in Wyoming and other Rocky Mountain states in coming years.

The most recent long-term natural gas price forecast made by the U.S. EIA in its "Annual Energy Outlook 2007," released in February of 2007, is for an average annual U.S. wellhead price to be within the range of $4.80/dkt to $6.50/dkt from 2006-2030 in today's dollars with a price of $5.80/dkt in 2030. The delivered gas prices is forecast to be only modestly higher than today in Montana, $11.43/dkt for residential customers, $9.30/dkt for commercial customers, and $6.56/dkt for industrial customers using today's dollars. The Northwest Power and Conservation Council (NPCC) forecasts a natural gas wellhead price of $6.00/dkt in 2030 for its medium case, with a range of $4.00/dkt to $9.00/dkt. The forecast delivered gas prices in 2030 by the NPCC are $10.86/dkt for residential customers, $9.63/dkt for commercial customers, and $6.38/dkt for industrial customers.

It is important to note that natural gas prices have been volatile from time to time and will likely experience similar events in the coming years. That U.S. wellhead prices were over $10.35/dkt in October of 2005 after Hurricane Katrina and Montana delivered prices were over $13.00/dkt demonstrates how quickly today's gas market can change and how volatile gas prices are. Interestingly, recent analysis from the U.S. EIA has demonstrated that gas prices are not becoming more volatile over time. A paper entitled "An Analysis of Price Volatility in Natural Gas Markets" by Erin Mastrangelo of the U.S. EIA found no consistent increasing or decreasing trend in natural gas spot price volatility at the Henry Hub. The paper found that there is a seasonal pattern with colder months exhibiting considerably higher volatility levels when short term demand for gas peaks. Also, the analysis indicates that price volatility tends to vary between market locations (e.g., New York's gas hub is more volatile than the Henry Hub due in part to transportation constraints). Furthermore, the relative level of natural gas in storage has a significant impact on price volatility. When natural gas in storage is high or low compared with the five-year average level, price volatility at the Henry Hub increases. This effect is exacerbated during the months of the year surrounding the beginning and end of the heating season when storage levels are typically at the highest and lowest levels, suggesting that storage dynamics have a dominant role in influencing gas price volatility. Finally, this analysis shows that, even with relatively low levels of volatility, changes in the natural gas price level can have large impacts on the market as daily gas price movements expand.

Although gas prices are expected to increase slowly in the long run, Montanans may be subject to increasing gas price volatility from extreme or unexpected events such as the California energy crisis of 2000-2001 or Hurricane Katrina in 2005. One reason for potentially greater price volatility in Montana is that the integrated U.S. market means all of the U.S. feels the effects of unexpected events worldwide like cold snaps and political turmoil. Another factor in future gas prices paid by Montanans is the fact that domestic and Canadian supplies have leveled off at the present time (in part due to mature gas fields), while U.S. and world demand continue to climb with economic recovery and more natural gas fired electric generation on the horizon (U.S. EIA, 2007). Foreign supplies of natural gas could be harder to come by as India and China continue to grow rapidly, and the Middle East and former Soviet Union continue to experience political turmoil. This could raise the price of natural gas faster than some of the long-term forecasts included in this document might indicate. Also, as excess gas production capacity in the U.S. has moved towards zero, the gas markets are tight with demand equal to or greater than supply. In such market conditions, small changes in demand (from a cold snap) or in supply (from a hurricane) can cause huge short-term increases in gas price, as seen in the fall of 2005 after Hurricane Katrina. With an increasingly integrated North American gas system and a potentially permanent, tight gas market, events outside of Montana will affect our prices more than ever in coming years.

A final reason for expected continuing gas price volatility is that over the past 15 or so years, wholesale electric and natural gas prices have become intimately linked. Recently, most new electric generation built in the U.S. West has been gas fired, even with higher gas prices. Today, natural gas power plants still command a significant, though declining majority of installed capacity West-wide, followed at some distance by wind and coal-steam (King 2006). The Northwest Power and Conservation Council states that, "Fuel prices affect electricity planning in two primary ways. They influence electricity demand because they are substitute sources of energy for space and water heating and some other end-uses as well. They also influence electricity supply and price because they are potential fuels for electricity generation."[16] The increasing convergence of the electricity and natural gas markets means that extreme events are likely to affect both electricity and gas markets simultaneously.

Utilities and industry can reduce price risks by buying gas at fixed prices and using long-term and futures contracts. They can also store gas to prevent having to buy on the spot market. Residential and commercial customers can use budget billing to smooth out their gas bills over a given billing year, although this does not protect one from yearly

[16] *Revised Draft Fuel Price Forecasts for the Fifth Power Plan,* Council document 2003-7, April 22, 2003.

fluctuations. They can also use less gas through weatherizing, retrofits and behavior changes. There are also programs to help low-income users pay their energy bills. At this point, electricity efficiency improvements may be the "biggest bang for the buck" to reduce natural gas demand. Residential and commercial air conditioning is a big driver in the U.S. for marginal electricity demand and thus natural gas demand. Gas often powers peak electricity demands, up to 60 percent of margin in some areas, because gas-fired generation can be turned on and off relatively quickly (unlike coal plants). This might be an area to target for efficiency in the nation as a whole.

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

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

Table NG1. Montana Natural Gas Production and Average Wellhead Price, 1960-2007

Year	Gross Withdrawal[1] (MMcf)	Marketed Production[2] (MMcf)	Average Wellhead Price ($/Mcf)	Estimated Gross Value of Montana Production[3] (thousand $)
1960	37,792	33,235	0.07	2,360
1961	36,798	33,716	0.07	2,495
1962	32,621	29,791	0.07	2,205
1963	31,228	29,862	0.08	2,240
1964	26,653	25,050	0.08	1,954
1965	29,800	28,105	0.08	2,305
1966	36,048	30,685	0.08	2,547
1967	31,610	25,866	0.08	2,173
1968	32,229	19,313	0.09	1,757
1969	68,064	41,229	0.10	4,205
1970	48,302	42,705	0.10	4,399
1971	38,136	32,720	0.12	3,959
1972	38,137	33,474	0.12	4,117
1973	60,931	56,175	0.24	13,257
1974	59,524	54,873	0.25	13,883
1975	44,547	40,734	0.43	17,638
1976	45,097	42,563	0.45	18,941
1977	48,181	46,819	0.72	33,663
1978	48,497	46,522	0.85	39,404
1979	56,094	53,888	1.21	65,258
1980	53,802	51,867	1.45	75,415
1981	58,502	56,565	1.91	107,983
1982	58,184	56,517	2.15	121,229
1983	53,516	51,967	2.41	125,240
1984	52,930	51,474	2.46	126,626
1985	54,151	52,494	2.39	125,461
1986	48,246	46,592	2.05	95,514
1987	47,845	46,456	1.80	83,621
1988	53,014	51,654	1.70	87,812
1989	52,583	51,307	1.55	79,526
1990	51,537	50,429	1.79	90,268
1991	53,003	51,999	1.66	86,318
1992	54,810	53,867	1.62	87,265
1993	55,517	54,528	1.55	84,518
1994	51,072	50,416	1.46	73,607
1995	50,763	50,264	1.36	68,359
1996	51,668	50,996	1.41	71,904
1997	53,621	52,437	1.59	83,375
1998	59,506	57,645	1.53	88,197
1999	61,545	61,163	1.68	102,754
2000	70,424	69,936	2.84	198,618
2001	81,802	81,397	3.12	253,959
2002	86,424	86,075	2.39	205,719
2003	86,431	86,027	3.73	320,881
2004	97,838	96,762	4.51	436,397
2005	108,555	107,918	6.57	709,021
2006	114,037	112,845	5.53	624,033
2007	120,525	116,848	5.72	668,371

[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 was used for marketed production excluding nonhydrocarbon

[3] This number is an estimate. The gross value of gas production is computed by multiplying average wellhead price by the respective volume produced.

Sources: U.S. Department of Interior, Bureau of Mines, *Mineral Industry, Natural Gas Production and Consumption Annual Report* , 1960-75; 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* ,1980-2007 (EIA-0131), EIA website at http://www.eia.doe.gov/ --specifically EIA's natural gas navigator.

Table NG2. Montana Natural Gas Consumption by Customer Class, 1960-2007 (million cubic feet)

Year	Residential	Commercial[1,2]	Industrial[1,3]	Utilities	Total Consumption[4]
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	12,952	21,416	522	59,840
1999	19,676	12,088	23,036	291	62,129
2000	20,116	13,533	23,841	192	67,955
2001	20,147	13,245	20,923	161	65,051
2002	21,710	14,704	21,867	116	69,532
2003	20,436	15,119	20,194	259	68,473
2004	19,907	13,407	20,482	195	66,829
2005	19,834	13,136	22,013	213	68,355
2006	19,449	13,181	27,427	544	73,879
2007	19,622	13,155	26,810	729	73,822

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 additional uses, primarily pipeline and distribution fuel, along with lease and plant fuel and vehicle fuel.

Sources: U.S. Department of Interior, Bureau of Mines, *Mineral Industry Surveys, Natural Gas Production and Consumption*, annual reports for 1960-75; 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 1980-2007 (EIA-0131); EIA website at http://www.eia.doe.gov/ --Specifically EIA's Natural Gas Navigator.

Table NG3. Average Delivered Natural Gas Prices by Customer Class,[1] 1960-2007

Year	Price by Customer Class (dollars per thousand cubic feet) Residential	Commercial	Industrial	All Customers[2]
1960	0.66	0.46	0.27	0.45
1961	0.66	0.46	0.26	0.44
1962	0.75	0.51	0.25	0.46
1963	0.75	0.51	0.27	0.46
1964	0.76	0.53	0.30	0.50
1965	0.78	0.54	0.31	0.51
1966	0.78	0.54	0.30	0.50
1967	0.80	0.57	0.34	0.55
1968	0.82	0.60	0.33	0.55
1969	0.88	0.64	0.34	0.56
1970	0.91	0.66	0.34	0.57
1971	0.93	0.69	0.36	0.60
1972	0.97	0.69	0.38	0.63
1973	1.09	0.80	0.43	0.70
1974	1.12	0.93	0.58	0.80
1975	1.30	1.10	0.95	1.09
1976	1.36	1.19	0.93	1.16
1977	1.82	1.58	1.56	1.64
1978	1.89	1.65	1.64	1.72
1979	2.21	2.00	1.75	2.00
1980	3.05	3.12	3.14	3.18
1981	3.75	4.14	4.26	4.06
1982	4.46	4.87	5.49	4.83
1983	4.63	5.07	3.99	4.56
1984	4.86	5.24	5.17	5.03
1985	4.81	5.09	4.71	4.85
1986	4.45	4.48	3.91	4.31
1987	4.41	4.34	3.42	4.16
1988	4.30	4.30	3.08	4.04
1989	4.37	4.36	2.98	4.08
1990	4.59	4.64	3.27	4.26
1991	4.52	4.35	--	--
1992	4.80	4.46	--	--
1993	4.92	4.67	--	--
1994	5.23	4.91	--	--
1995	5.15	4.92	--	--
1996	4.86	4.64	--	--
1997	5.05	4.83	--	--
1998	5.25	5.13	--	--
1999	5.16	5.13	--	--
2000	6.03	5.90	--	--
2001	7.26	7.35	--	--
2002	5.30	5.37	--	--
2003	7.08	7.08	--	--
2004	9.19	9.15	--	--
2005	10.70	10.72	--	--
2006	11.26	11.12	--	--
2007	9.96	9.81	--	--

[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. Once Montana Power Company deregulated natural gas sales in 1991, most of the industrial customers left its system. Average price estimates for the remaining customers may not be representative of all industrial customers and therefore are not given for after 1990. For the same reason, estimates for All Customers are not made after 1990.

[2] The All Customers category includes all the consumers in Table NG2. The All Customers category is calculated by multiplying the consumption of each customer class (residential, commercial, industrial, utilities) by its corresponding consumer class price. These products are added up and the sum is divided by the total consumption of the four customer classes.

Sources: U.S. Department of the Interior, Bureau of Mines, Mineral Industry Surveys,*Natural Gas Production and Consumption*, annual reports for 1960-75; 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 1980-2007 (EIA-0131); EIA website at http://www.eia.doe.gov/ --Specifically EIA's Natural Gas Navigator.

Table NG4. Average Natural Gas Consumption and Annual Cost per Consumer, 1980-2007[1]

Year	Residential[2] Average Consumption (Mcf)	Residential[2] Average Annual Cost (dollars)	Commercial[2] Average Consumption (Mcf)	Commercial[2] Average Annual Cost (dollars)	Industrial[3] Average Consumption (Mcf)	Industrial[3] Annual Cost (dollars)
1980	117	356	670	2,089	32,841	103,218
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
1988	98	423	541	2,329	19,219	59,195
1989	106	464	591	2,579	23,138	68,951
1990	97	444	521	2,419	20,622	67,434
1991	104	468	554	2,411	21,842	70,331
1992	91	439	490	2,185	--	--
1993	108	531	569	2,657	--	--
1994	96	502	512	2,514	--	--
1995	97	500	512	2,519	--	--
1996	108	525	562	2,608	--	--
1997	100	505	507	2,449	--	--
1998	88	462	462	2,370	--	--
1999	89	459	425	2,180	--	--
2000	89	537	463	2,732	--	--
2001	89	646	450	3,308	--	--
2002	95	504	486	2,610	--	--
2003	88	623	491	3,476	--	--
2004	84	774	428	3,916	--	--
2005	82	882	420	4,502	--	--
2006	79	892	414	4,604	--	--
2007	80	796	407	3,993		

[1] Starting in 1993, DOE no longer provided figures for average cost. Thus, average cost to Residential and Commercial classes from 1993 forward is estimated by multiplying average consumption for the particular consumer class times average delivered price for that consumer class (table NG3). Thus, these numbers are estimates.

[2] From 1999-2007, average consumption for residential and commercial customers was calculated by dividing total consumption in Montana by the total number of consumers.

[3] For 1987-1990, industrial annual costs per consumer are estimated by DEQ using U.S. 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. From 1992 forward, no estimates are made for Industrial customers because many of those customers left the regulated utility and therefore no longer provide the information necessary to make the estimate.

Source: United States Department of Energy, Energy Information Administration, *Natural Gas Annual* , annual reports for 1980-2007 (EIA-0131). EIA website at http://www.eia.doe.gov/.

Table NG5. Regulated Sales[1] of Natural Gas by Gas Utilities,* 1960-2007 (million cubic feet)

Note: The gas sales numbers in this table are significantly lower than the total gas consumption numbers in Table NG2. As of 2007, they are about 50% lower than Montana's total consumption. This is the case 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. Perhaps most importantly, 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/NORTHWESTERN ENERGY[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
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	18,381	211	282	18,875	58.1%	9,301	NA	NA	9,301	28.6%
2001	18,460	236	299	18,995	59.2%	8,959	NA	NA	8,959	27.9%
2002	19,748	237	317	20,302	59.2%	9,925	NA	NA	9,925	28.9%
2003	18,538	214	277	19,029	59.2%	9,273	NA	NA	9,273	28.9%
2004	18,395	196	297	18,888	60.9%	8,347	5	NA	8,352	26.9%
2005	18,794	181	297	19,272	60.5%	8,969	2	NA	8,971	28.2%
2006	18,060	177	288	18,526	61.2%	8,350	NA	NA	8,350	27.6%
2007	18,191	169	295	18,656	60.2%	8,755	3	NA	8,758	28.3%

NA Not Available

* See notes on following page.

Table NG5. (continued)

	GREAT FALLS GAS COMPANY/ ENERGY WEST[4]					OTHER UTILITIES[5]		TOTAL SALES[6]			
Year	Residential and Commercial	Industrial	Other	Total	% of Total Montana Sales	Total for all Sectors	% of Total Montana Sales	Residential and Commercial	Industrial	Other	TOTAL
1960	4,048	388	566	5,002	11.0%	1,152	2.4%	28,129	19,122	858	48,109
1961	3,928	512	516	4,956	10.3%	1,045	2.1%	28,318	20,640	783	49,741
1962	4,067	380	606	5,053	10.2%	1,078	2.1%	29,451	21,502	855	51,808
1963	4,092	371	752	5,215	10.1%	945	1.8%	28,694	23,924	872	53,490
1964	4,030	396	793	5,219	9.8%	1,018	1.7%	31,937	26,125	902	58,964
1965	4,446	480	847	5,773	9.8%	1,160	1.8%	34,859	27,124	929	62,912
1966	4,767	499	868	6,134	9.8%	1,125	1.8%	33,863	27,804	901	62,568
1967	4,593	490	846	5,929	9.5%	1,160	1.9%	34,276	24,976	923	60,175
1968	4,505	397	856	5,758	9.6%	1,074	1.7%	35,488	26,597	917	63,002
1969	4,504	424	852	5,780	9.2%	1,118	1.6%	37,585	32,225	946	70,756
1970	5,042	412	891	6,345	9.0%	1,010	1.4%	37,833	34,966	1,004	73,803
1971	4,926	378	902	6,206	8.4%	1,048	1.4%	36,517	34,265	2,662	73,444
1972	4,901	367	895	6,163	8.4%	1,105	1.4%	38,710	34,699	2,975	76,384
1973	5,185	353	884	6,422	8.4%	982	1.3%	37,007	35,014	3,857	75,876
1974	4,729	414	864	6,007	7.9%	936	1.3%	35,601	35,168	2,803	73,572
1975	4,504	412	807	5,723	7.8%	1,000	1.3%	39,686	32,258	2,368	74,312
1976	5,145	354	845	6,344	8.5%	762	1.1%	36,640	28,000	2,297	66,936
1977	4,875	237	892	6,004	9.0%	715	1.2%	35,343	24,270	2,185	61,798
1978	4,317	246	734	5,297	8.6%	824	1.3%	38,122	21,457	2,324	61,904
1979	4,818	196	826	5,840	9.4%	804	1.3%	37,958	19,847	3,487	61,294
1980	4,512	249	750	5,512	9.0%	669	1.2%	32,980	16,548	5,675	55,203
1981	3,888	266	689	4,842	8.8%	573	1.2%	29,358	15,234	3,373	47,962
1982	3,257	169	619	4,044	8.4%	596	1.3%	33,145	11,460	1,944	46,549
1983	3,289	188	627	4,104	8.8%	446	1.1%	28,553	10,809	1,820	41,182
1984	3,320	206	636	4,162	10.1%	487	1.2%	30,837	8,674	1,827	41,338
1985	3,531	256	530	4,317	10.4%	474	1.1%	32,203	7,560	1,826	41,589
1986	3,719	181	536	4,436	10.7%	465	1.3%	27,655	6,100	1,706	35,461
1987	3,538	285	592	4,415	12.5%	388	1.2%	25,254	5,805	1,205	32,264
1988	3.064	193	442	3,699	11.5%	386	1.1%	26,887	7,296	1,247	35,431
1989	3,189	170	499	3,858	10.9%	427	1.1%	29,834	7,371	1,199	38,404
1990	3,567	160	411	4,138	10.8%	392	1.1%	27,879	6,189	1,162	35,230
1991	3,381	78	401	3,860	11.0%	400	1.1%	29,430	5,156	1,083	35,669
1992	3,435	164	389	3,988	11.2%	373	1.2%	31,443	676	234	32,353
1993	4,139	0	NA	4,139	12.8%	432	1.1%	36,053	768	1,979	38,800
1994	4,478	0	490	4,968	12.8%	443	1.3%	33,352	606	987	34,945
1995	3,971	0	478	4,449	12.7%	447	1.2%	34,634	616	981	36,231
1996	3,942	0	464	4,406	12.2%	498	1.2%	39,165	681	599	40,445
1997	4,362	0	NA	4,362	10.8%	504	1.3%	37,613	619	802	39,034
1998	4,496	0	314	4,810	12.3%	418	1.2%	33,118	309	1,625	34,091
1999	3,535	0	1331	4,866	14.3%	427	1.3%	31,145	281	1,240	32,532
2000	2,356	802	0	3,158	13.5%	239	0.7%	30,277	1,013	1,291	32,581
2001	2,798	1056	0	3,854	12.5%	301	0.9%	30,518	1,292	299	32,109
2002	2,694	1068	0	3,762	11.0%	303	0.9%	32,670	1,305	317	34,292
2003	2,531	1006	0	3,537	11.0%	270	0.8%	30,612	1,220	297	32,129
2004	2,520	992	0	3,512	11.3%	267	0.9%	29,529	1,188	297	31,014
2005	2,382	964	0	3,346	10.5%	243	0.8%	30,388	1,145	297	31,830
2006	2,247	932	0	3,179	10.5%	232	0.8%	28,889	1,109	288	30,286
2007	2,382	973	0	3,355	10.8%	236	0.8%	29,564	1,142	295	31,001

NA Not Available

* See notes on following page.

Table NG5. (continued)

[1] Gas sales to other utilities for resale and sales of natural gas to Canada are not included in these numbers.

[2] From 1950 to 1970, government and municipal sales were reported in the "Residential and Commercial" sector.

In 2001, the Montana Power Company was purchased by Northwestern Energy.

Starting in 2001, numbers are reported in Dekatherms.

"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.

MPC's Gas Utility started deregulating its service in 1991. 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 are 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 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 Sidney, 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 use 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 forward, amount sold is reported in Dekatherms rather than Mcf. From 1995 on, amounts for industrial and other usage are not reported or rarely reported by MDU.

[4] Starting in 1999, the Montana Public Service Commission started reporting figures for Energy West-West Yellowstone, so those West Yellowstone numbers are included in these Energy West figures. "Other" included sales to Malmstrom Air Force Base and other public authorities up until 1999. Starting in 2000, those numbers were no longer reported. In 1993, Great Falls Gas became Energy West.

Energy West's reporting year ends June 30th of each year. As an example, for 2006, the period being reported is July 1, 2005 through June 30, 2006.

From 1992-1998, figures were not given for Industrial usage. It is assumed those numbers are included in with residential and commercial numbers.

[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 NorthWestern Energy. The Cut Bank Gas Company's reporting year ends June 30th of each year. As an example, for 2006, the period being reported is July 1, 2005 through June 30, 2006.
Shelby Gas Association:	Supplies natural gas to Shelby; gas is purchased from Gas Marketers and transported by NorthWestern Energy.
Saco Municipal Gas Service:	Supplied natural gas to Saco from the town's own wells.
Consumers Gas Company:	Supplied natural gas to Sunburst and Sweetgrass; gas was purchased from NorthWestern Energy 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. Thus, after 1991, 'other utilities' includes the Cut Bank Gas Company and Shelby Gas Association only. Shelby Gas did not report in any year after 2000. Starting in 2000, Havre Pipeline Company has been included so that since 2000, "other utilities" totals included only Cut Bank Gas and the Havre Pipeline Company.

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

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

NOTE: Source documents from the Public Service Commission 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/Energy West 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 for Energy West 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 (1950-2007), supplemented by information obtained directly from the utilities. After 1993, schedule 35 of the annual reports of each utility was used. These annual reports are found on the Montana PSC website.

Table NG6. Largest Natural Gas Users in Montana as of 2009

Company	Industry	Location
Note: These figures represent annual average usage over the past 2-3 years.		
Over 500 Million Cubic Feet (MMcf) Average Usage Annually		
Conoco-Phillips	Oil refinery	Billings
Stone Container	Pulp/paper mill	Missoula
Exxon Mobile Co. USA	Oil refinery	Billings
Cenex Harvest States	Oil refinery	Laurel
Plum Creek Manufacturing	Sawmills, wood products	Columbia Falls
Basin Creek Power Services	Electric Generation	Butte
Renewable Energy Corporation[1]	Industrial manufacturing	West of Butte
Montana Refining Company	Oil refinery	Great Falls
200-500 MMcf Average Usage Annually		
Montana State University	Heating Plant-University	Bozeman
University of Montana	Heating Plant-University	Missoula
Barretts Minerals Inc.	Talc processing	Dillon
Roseburg Forest Products	Wood Processing	Missoula
Montana Resources Inc.	Mine	Butte
Columbia Falls Aluminum Co.	Aluminum manufacturing	Columbia Falls
American Chemet Corp.	Industrial manufacturing	East Helena
Sidney Sugars	Sugar production	Sidney
MDU Glendive turbines	Electrical generation	Glendive
50-200 MMcf Average Usage Annually		
Western Sugar Cooperative	Sugar production	Billings
Deaconess Billings Clinic	Hospital	Billings
St. Vincent Hospital	Hospital	Billings
MSU Billings	Heating Plant-University	Billings
Malmstrom AFB	Air Force Base	Great Falls
MDU Miles City turbine	Electrical generation	Miles City
C H S Inc.	Asphalt and asphalt products	Hardin
Montana Sulphur and Chemical	Sulphur production	Billings
Montana State Prison	Heating Plant-Prison	Deer Lodge
St. Patrick's Hospital	Hospital	Missoula

[1] The Renewable Energy Corporation purchased Advanced Silicon Materials (ASiMi) in 2005.

NOTE: Due to the difficulties of reporting exact or even approximate usage numbers for large individual gas users, DEQ has attempted to identify the current largest natural gas users in Montana and determine what range of average annual usage they likely fall under. Data for estimating consumption ranges was taken from personal communication with utilities, State of Montana gas contracts, and from the DEQ Air and Waste Management Bureau, Emissions Inventory Report. Note that these ranges represent average annual usage over the past 2 to 3 years and that actual usage can greatly vary from year to year--especially for the refineries. Estimated gas usage for some of these entities is based upon the annual process rate of particular industrial components that use gas within each listed company. Some of the listed facilities report their use rates of various fuels including natural gas, and those numbers are entered into the DEQ Emissions Inventory Reports. Also, the reports contained the rare error. Thus, best professional judgment was used for those DEQ Emissions Inventory Reports that were unclear or contained an error.

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), James Hughes, Montana DEQ in Billings (personal communication, Oct. 2008); U.S. Department of Energy, Energy Information Administration, Form 906 database (2000-2004), NorthWestern Energy (personal communication, Feb. 2006), Northwestern Energy (personal communication with Tom Vivian, Sept. and Oct 2008), Ed Kacer, Energy West (personal communication, Oct. 2008), Montana Department of Administration, State Procurement Board/State of Montana Term Contract FY2008-FY2010, Ken Phillips, DEQ.

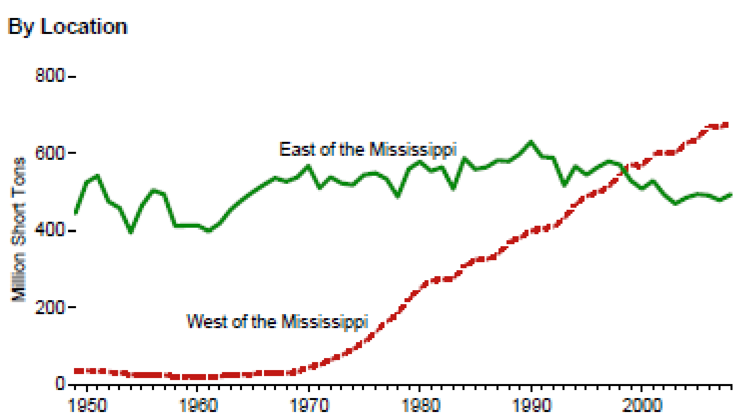
Coal in Montana

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. Montana's electricity market is dominated by coal-fired power plants, accounting for about two-thirds of the state's electricity generation. Slightly less than three-quarters of the coal mined in the state is exported, primarily to Midwestern utilities. Montana coal is exported to more than a dozen states, with Minnesota and Michigan being the largest recipients. Even though new generating stations built around the country in recent years have relied on natural gas or wind, coal continues to provide half of the nation's electricity.

1. Production

Montana is the fifth largest producer of coal in the United States, with over 43 million tons mined in 2007 (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 Savage, Montana production is entirely low-sulfur subbituminous coal, with 17-18 million Btu per ton. Like most Western coal, Montana coal is cleaner but lower in heat content than coal mined in the East. Over the last decade, coal produced west of the Mississippi has surpassed coal produced east of the Mississippi. (Figure 1)

Figure 1. Historical coal production in the U.S.

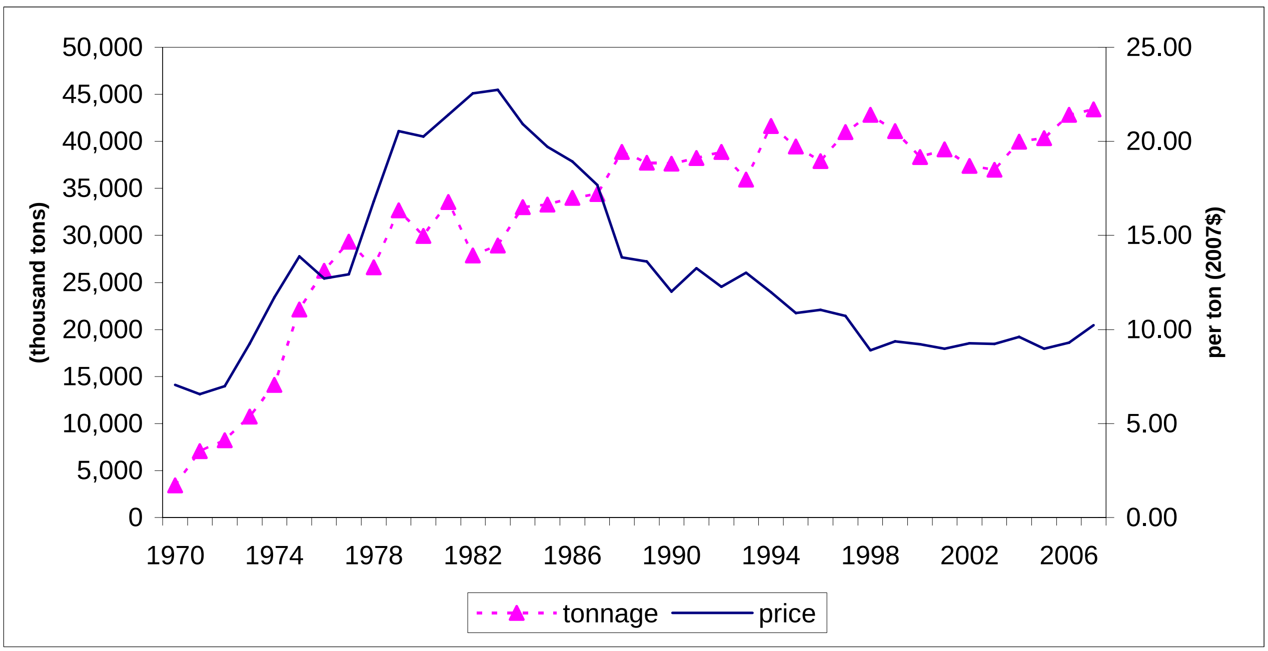


Source: U.S. Department of Energy, Energy Information Administration

Coal has been mined in Montana since territorial days. Early production was for heating fuel. Some coal was converted to coke for smelting, but most was used for steam power. Production initially peaked in the 1940s at around 5 million tons per year. As diesel replaced steam locomotives, production declined, bottoming in 1958 (Table C2). 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 as Colstrip Units 1 and 2 cam online and export markets developed. Since the end of the 1970's, production increased gradually to almost 43 million tons in 1998 and then dropped off (Table C2; see Figure 2). Over the last decade, production has steadily climbed, again reaching more than 43 million tons in 2007. Over the past decade Montana has accounted for about 4 percent of the coal mined each year in the U.S. Montana has more or less maintained its share of the U.S. market. Western states other than Wyoming followed a path similar to Montana, more or less maintaining market share.

Figure 2. Montana production and average price (2007 $)

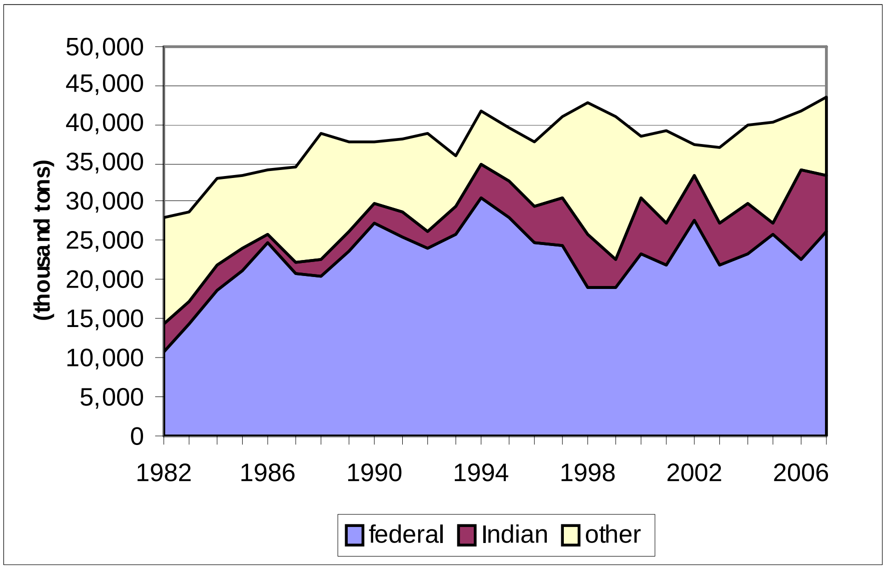


Source: Table C2.

The price of Montana coal averaged $11.79 per ton at the mine in 2007 (Table C2); this includes taxes and royalties. The average price of coal peaked at $14.22 per ton ($22.67 in 2002 dollars) in the early 1980s and began a downward trend that lasted into the turn of the century. By 2002 that price had fallen 60 percent in real terms. Since 2002 the price has gradually increased because the price of electricity has risen. Increased demand during the California energy crisis contributed to rising prices. Higher natural gas prices and a drop in hydropower because of prolonged drought in the Pacific Northwest have also been contributing factors.

Most coal in Montana is mined on federal lands (Table C3; see Figure 3). A significant portion also comes from Indian reservations. In 2007, the most recent year for which data is available, more than 60 percent of Montana coal came from federal lands and slightly less than 35 percent from reservation lands.

Figure 3. Production by land ownership type



Source: Table C3

There are currently six major coal mines in Montana, operating in Big Horn, Musselshell, Richland, and Rosebud counties (Table C4). Westmoreland Mining LLC controls three mines in Montana, accounting for more than 20 million tons in 2007. In 2007 Westmoreland gained 100 percent ownership of the Absaloka Mine in Big Horn County. During the 1990's, the last Montana mine producing less than 100,000 tons annually closed. A new mine at that site, near Roundup, opened in 2003.

Changes in ownership and expansions at the new mine in the Bull Mountains near Roundup, are expected to bring a 35 percent increase in Montana's total current coal output. The underground long-wall operation has seen a $400 to $450 million expansion over the past two years. A 35-mile rail spur has been added to the Burlington Northern Santa Fe (BNSF) line near Broadview. With the expansion, the mine is expected to ramp up production to about 15 million tons per year.

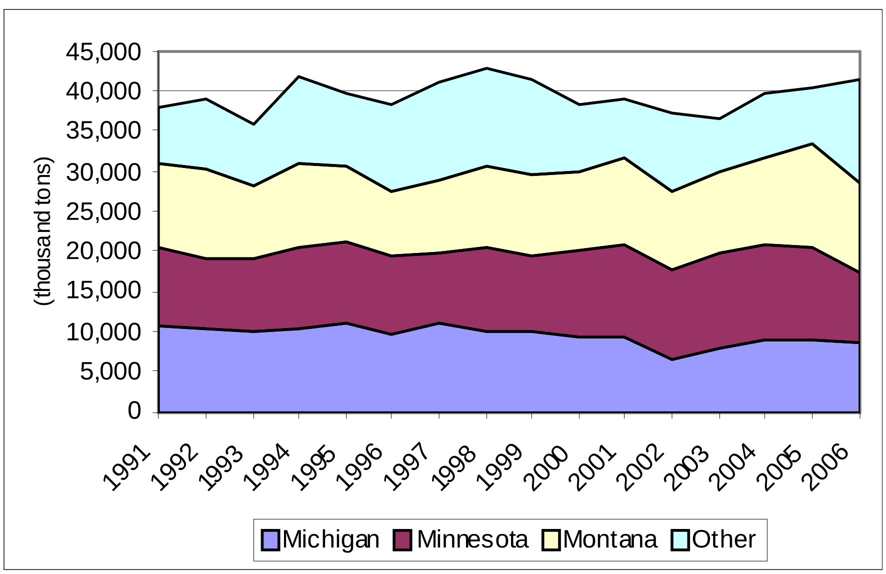
The West Decker and Spring Creek mines also have expanded significantly. Spring Creek, owned by Rio Tinto Energy America, was the largest producing mine in Montana in 2007, accounting for about 36 percent of production, or about 16 million tons. Western Energy Company (a subsidiary of Westmoreland) operates the Rosebud Mine and is the second largest producer, accounting for 29 percent of coal production in 2007. Montana coalfields continue to thrive. Spring Creek was the 11th largest producer in the country in 2007 and the Rosebud Mine was the 13th largest producer.

2. Consumption

Almost all coal produced in Montana generates electricity (Table C6). In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities. The remaining quarter is consumed in Montana. About 90 percent of what is consumed in Montana is burned to produce electricity, primarily at Colstrip. Minor amounts of residential and commercial heating and some industrial use account for the remainder. Montana coal consumption has been more or less stable since the late 1980's, after the Colstrip 4 generating unit came on line (Table C5).

Prior to deregulation, about 40 percent of the electricity generated in Montana with coal went to Montana customers, and 60 percent was shipped by wire to out-of-state utilities. No public data are available now, but it's likely that the majority of coal burned in Montana still produces electricity for export. Over the last decade, Michigan, Minnesota and Montana used about three quarters or more of all the coal produced in Montana (Table C7; see Figure 4). The remaining quarter now goes to 12 other states and other countries. After 2002, data on what other countries was not available, however, historically, Montana has shipped to Canada.

Figure 4. Destination for Montana coal



Source: Table C7.

3. Coal Economics

Since 2002, the Montana coal industry, has become more productive. The average price of coal has risen and the amount of coal mined has increased along with the number of employees (Table C8; see Figure 5). Taxes on coal -- despite decreases from historical highs -- remain a major source of revenue for Montana, with $45.3 million collected in coal severance tax in state fiscal year 2007 (July 2006-June 2007).[1] That is about half, in nominal terms, the amount collected in fiscal year 1984. Collections dropped as tax laws changed, beginning with the 1987 Legislature, and due to the declining price of coal. While the tax rates vary, 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 coal prices. The new tax structure's impact on coal production is less clear. Production has risen modestly since the cut in taxes, and Montana has been able to retain most of its share of the national market.

In addition to severance taxes, gross proceeds taxes are also paid to support the counties where mines are located. The 2009 Legislature altered a series of tax laws applicable to coal producers. Strip mines that recover coal using auger techniques can reduce their severance tax rate. And county commissioners have been granted authority to provide a 50 percent local abatement of coal gross proceeds taxes – up to 10 years -- at new or expanding underground mines.

Montana coal producers also pay a Resource Indemnity Trust tax, federal taxes and royalties. Federal leasing laws mandate that 50 percent of the royalties collected from development of federal leases be returned to the state. A royalty is also paid on coal-producing land leased from the state. In Montana, tract counts have remained constant since 2006, with about 29 leases on 13,841 acres. Coal production on state trust lands increased 63.7 percent in fiscal year 2008 to 4,720,487 tons mined, compared to 2,883,432 tons mined the previous year. The production totals were the highest recorded on state trust lands over the past decade.

Montana's coal resources have received a great deal of attention over the past year. The Otter Creek Project area in southeast Montana near Ashland is of particular interest. The State's ownership totals more than 9,500 acres, or roughly half of the Otter Creek area. The state's ownership is in a "checkerboard" pattern, and Great Northern Properties owns most of the other half of the coal estate. Surface ownership is a combination of state, federal, and fee. State recoverable coal totals 616 million tons at Otter Creek, or about one-half of the total 1.3 billion ton reserve. A lease appraisal that covers the state's ownership of the area has been completed, and the Land Board is reviewing the appraisal. In the coming year, the Land Board will consider offering the state tracts for lease.

While significant, Montana's output is dwarfed by Wyoming, which produced close to 40 percent of the country's output in 2007. This is ten times as much coal as Montana produced in 2007. The gap is due in part to a combination of physical factors that make Montana coal less attractive than coal from Wyoming. First, Montana coal generally is more

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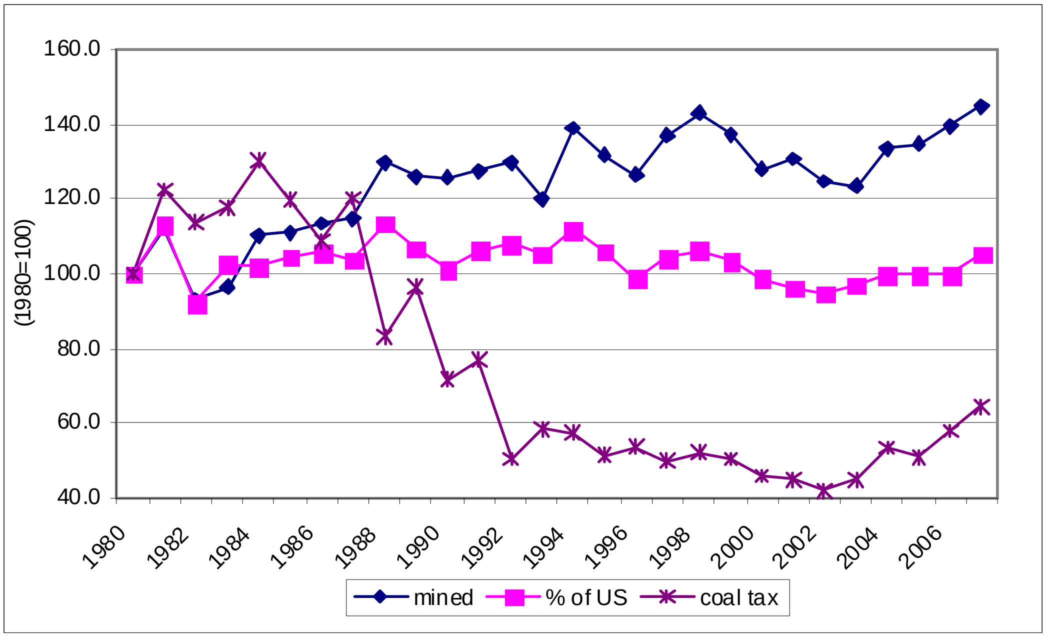
[1] Also, a gross proceeds tax of 5% goes to the county where the coal was mined. Another 0.4% goes for the Resource Indemnity and Groundwater Assessment Tax that, among other things, pays for reclamation of old unreclaimed mined areas.

costly to mine. Coal seams tend to be thinner—though still thick in comparison to eastern coal—and buried under more overburden than seams in Wyoming. Moreover, Wyoming coal tends to have slightly lower average ash and sulfur content than Montana coal. Coal from the Decker area does have the highest Btu in the entire Powder River Basin and about the same sulfur as Wyoming coal, but it has the disadvantage of having a high sodium content, which can cause problems in combustion.

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



Source: Table C8.

The cost of transportation to distant markets may also affect the competitiveness of Montana coal. Nearly all coal exported from Montana leaves on BNSF lines. Some is later transshipped by barge. Transportation costs can double, to more than triple, the delivered cost of Montana coal to out-of-state generating plants. Though transportation costs have fallen over the last fifteen years, the mine-mouth cost of coal has fallen faster, making transportation a larger component of final cost. Coal shipped from the Powder River Basin (Wyoming and Montana) in 2000 had the highest ratio of transportation cost to delivered price, on a per ton basis, for U.S. coalfields. (U.S. Department of Energy, Energy Information Administration *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation,* 2000). While the transportation report has not been updated, these figures have likely changed very little over the last nine years. 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.

Coal remains the least expensive fossil fuel to generate electricity. However, increasing the use of coal-fired generation for electricity may be closely linked to potential federal climate change activities and restraints on CO_2 emissions. The impact of potential climate change activities on the future price of coal-fired generation is uncertain at this time. The state has advocated clean coal technologies in the past, and a number of projects are in the preliminary stages. If carbon regulations move forward, these efforts may be of critical importance in promoting the consumption of Montana's vast coal resources.

Montana is one of only a few states that has taken steps to implement carbon sequestration legislation. While state law does not mandate the sequestration of CO_2 generated from sources, such as power plants, the law provides regulatory certainty to those interested in pursuing such technology. The Legislature, in approving Senate Bill No. 498 during the 2009 session, also has made clear its intent to have jurisdiction over a sequestration program -- while recognizing its regulatory program will need to be in-line with federal guidelines.

Table C1. Coal Production by State and Coal Rank, 2007 (Thousand Short Tons)

Rank	State	Bituminous Production	Subbituminous Production	Lignite Production	Anthracite Production	Total Production	Percentage of U.S. TOTAL 2007	Percentage of U.S. TOTAL 2001[1]
1	Wyoming	120	453,448	-	-	453,568	39.6%	32.7%
2	West Virginia	153,480	-	-	-	153,480	13.4%	14.4%
3	Kentucky	115,280	-	-	-	115,280	10.1%	11.8%
4	Pennsylvania	63,484	-	-	1,564	65,048	5.7%	6.6%
5	Montana	-	43,031	358	-	43,390	3.8%	3.5%
6	Texas	-	-	41,948	-	41,948	3.7%	4.0%
7	Colorado	28,016	8,368	-	-	36,384	3.2%	3.0%
8	Indiana	35,003	-	-	-	35,003	3.1%	3.3%
9	Illinois	32,445	-	-	-	32,445	2.8%	3.0%
10	North Dakota	-	-	29,606	-	29,606	2.6%	2.7%
11	Virginia	25,346	-	-	-	25,346	2.2%	2.9%
12	New Mexico	6,898	17,553	-	-	24,451	2.1%	2.6%
13	Utah	24,307	-	-	-	24,307	2.1%	2.4%
14	Ohio	22,575	-	-	-	22,575	2.0%	2.2%
15	Alabama	19,327	-	-	-	19,327	1.7%	1.7%
16	Arizona	7,983	-	-	-	7,983	0.7%	1.2%
17	Mississippi	-	-	3,545	-	3,545	0.3%	0.1%
18	Louisiana	-	-	3,127	-	3,127	0.3%	0.3%
19	Tennessee	2,654	-	-	-	2,654	0.2%	0.3%
20	Maryland	2,301	-	-	-	2,301	0.2%	0.4%
21	Oklahoma	1,648	-	-	-	1,648	0.1%	0.2%
22	Alaska	-	1,324	-	-	1,324	0.1%	0.1%
23	Kansas	420	-	-	-	420	0.0%	0.0%
24	Missouri	236	-	-	-	236	0.0%	0.0%
25	Arkansas	83	-	-	-	83	0.0%	0.0%
	Washington	-	-	-	-	-		0.4%
	East of Miss. River	**471,897**	**-**	**3,545**	**1,564**	**477,006**	41.6%	47.0%
	West of Miss. River	**69,710**	**523,724**	**75,040**	**-**	**668,474**	58.3%	52.8%
	U.S. Subtotal	**541,607**	**523,724**	**78,585**	**1,564**	**1,145,480**	99.9%	99.8%
	Refuse Recovery	**1,151**	**-**	**-**	**4**	**1,156**	0.1%	0.2%
	U.S. Total	**542,758**	**523,724**	**78,585**	**1,568**	**1,146,635**	100.0%	100.0%

- = No data are reported.

[1] Total U.S. production in 2001 was 1,127,689 tons.

Note: Total U.S. coal production increased 5.1% between 1997 and 2007.

Sources: U.S. Department of Energy, Energy Information Administration Form EIA-7A, "Coal Production Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report," as reported in U.S. Department of Energy, Energy Information Administration *Annual Coal Report 2007* (http://www.eia.doe.gov/cneaf/coal/page/acr/table6.html) and Annual Coal Report 2001 (http://tonto.eia.doe.gov/FTPROOT/coal/05842001.pdf).

Table C2. Montana Coal Production and Average Mine Price by Rank of Coal, 1950-2007

Year	PRODUCTION (thousand short tons)			AVERAGE MINE PRICE (dollars/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**
2001	38,802	340	**39,143**	w	w	**8.83**
2002	37,058	328	**37,386**	w	w	**9.27**
2003	36,625	369	**36,994**	w	w	**9.42**
2004	39,607	382	**39,989**	w	w	**10.09**
2005	40,024	330	**40,354**	9.74	-	**9.74**
2006	41,445	378	**41,823**	10.42	-	**10.42**
2007	43,031	358	**43,390**	w	w	**11.79**

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. Since 1998, an average open market sales price is calculated by dividing the total free on board (f.o.b) rail/barge value of the open market coal sold by the total open market coal sold. (Open market includes all coal sold on the open market to other coal companies or consumers.) Excludes mines producing less than 10,000 short tons, which are not required to provide data. Excludes silt, culm, refuse bank, slurry dam, and dredge operations. Totals may not equal sum of components because of independent rounding.

COMPARISON WITH TABLES C4 and C7. Total production in this table is slightly different than in Table C-4 (by less than +/- 1%) and in Table 7 (which usually is lower by <1%).

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); U.S. Department of Energy, Energy Information Administration,*Annual Coal Report* 2001-2007, Tables 6 and 31 (http://www.eia.doe.gov/cneaf/coal/page/acr/acr_sum.html), based on Energy Information Administration Form EIA-7A,*Coal Production Report*, and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2,*Quarterly Mine Employment and Coal Production Report*.

Table C3. Coal Mining Acreage,[1] Production and Royalties from Federal and American Indian Leases in Montana, 1982-2007

Year	Federal Leases			American Indian Leases		
	Acres Leased	Production (thousand short tons)	Royalties (thousand dollars)	Acres Leased	Production (thousand short tons)	Royalties (thousand dollars)
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
2001	29,408	21,937	$24,539	14,746	5,367	$2,571
2002	NA	27,696	$31,452	14,746	5,795	$2,730
2003	NA	21,782	$34,918	14,746	5,425	$2,568
2004	NA	23,171	$31,027	14,746	6,609	$3,174
2005[2]	NA	25,880	$32,205	14,746	1,518	$691
2006[2]	NA	22,786	$28,331	14,746	11,488	$6,364
2007	NA	26,168	$35,084	14,746	7,216	$4,835

NA = Not available

Notes: 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. The US Mineral Management Service does not accept reported royalty lines until they have passed systematic edits and have been processed in the Mineral Revenue Management Support System. Therefore, some of the year to year fluctuation may represent reporting patterns rather than production.

[1] Following 2001, acreage leased for coal was no longer available publicly. DEQ was able to obtain information from US Minerals Management Service indicating that the acreage of leases on tribal lands had remained unchanged since 2001 and that the active leases on federal lands had risen to 35,142 acres in 2008.

[2] According to correspondence between DEQ and the US Minerals Management Service, the amount of coal produced on Indian lands actually was roughly equivalent in FY2005 and FY2006. However, nine months of FY2005 production for Indian Coal were not successfully reported to MMS until FY2006.

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); United States Department of Energy, Energy Information Administration, *Annual Coal Report 2001;* Minerals Management Service *2001-Forward MRM Statistical Information* , http://www.mrm.mms.gov/MRMWebStats/Home.aspx.

Table C4. Coal Production by Company, 1980-2007 (short tons)

	Beartooth Coal Co.[1]	Blaine Warburton (owner)	Bull Mountain Coal Mining[2]	Coal Creek Mining Co.	Decker Coal[3]		Spring Creek Coal[4]	Big Sky Coal (owned by Peabody Coal Co.)	Red Lodge Coal Co.	Storm King Coal Mining Co.[5]	Westmoreland Savage[6]	Westmoreland[7]	Western Energy Co.[8]	TOTAL
					East Decker Mine	West Decker Mine								
County	Carbon	Blaine	Musselshell	Powder River	Big Horn	Big Horn	Big Horn	Rosebud	Carbon	Musselshell	Richland	Big Horn	Rosebud	
1980	7,321		11,189	64,398	5,576,607	5,616,695	118,660	2,964,359		8,571	305,578	4,905,262	10,401,972	29,980,612
1981			7,404	64,142	5,350,113	5,331,626	4,368,885	3,193,570		8,165	204,492	4,450,296	10,352,966	33,331,659
1982			15,141	16,608	4,914,970	4,884,920	1,352,181	2,891,428		8,062	171,556	4,158,578	9,424,857	27,838,301
1983			11,655		5,040,018	5,308,799	2,102,606	2,571,861		5,896	206,543	3,868,844	9,544,062	28,660,284
1984			15,865		5,019,186	5,278,365	2,962,008	3,945,865		16,379	236,954	3,621,544	11,957,724	33,053,890
1985			21,400		5,191,701	6,149,987	2,837,037	3,336,907		3,251	212,654	3,112,595	12,275,351	33,140,883
1986		276	23,915		5,397,476	6,706,592	4,664,238	2,594,306			252,754	2,028,595	12,074,698	33,742,850
1987		305	14,495		4,042,597	6,355,523	6,557,228	3,234,538	900		290,264	1,858,315	12,022,894	34,377,059
1988		248	15,542		3,655,067	7,068,653	4,704,442	3,788,137			227,603	3,304,822	16,155,867	38,920,381
1989		96	15,760		3,582,885	6,495,027	5,979,405	3,715,325			295,089	4,011,156	13,677,234	37,771,977
1990			14,307		2,595,829	6,602,744	7,133,285	3,602,851			234,010	4,471,345	12,800,898	37,455,269
1991			12,202		2,408,968	7,576,380	6,740,401	3,104,829			282,641	4,101,847	13,802,840	38,030,108
1992			9,235		2,621,326	9,323,561	6,641,332	2,212,071			247,155	3,490,797	14,347,159	38,892,636
1993			11,182		2,864,005	7,940,085	7,175,434	2,518,117			290,928	3,224,143	11,909,423	35,933,317
1994			2,600		2,787,908	7,726,969	9,934,305	3,053,125			323,381	4,363,500	13,390,492	41,582,280
1995			4,128		1,802,249	8,475,335	8,512,520	4,708,970			297,290	4,425,759	11,260,339	39,486,590
1996			151,024		601,544	10,388,948	9,015,361	4,984,352			256,476	4,668,021	7,775,391	37,841,117
1997			24,023		1,911,702	9,961,746	8,306,306	4,334,750			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
2002					746,967	9,281,431	8,905,368	2,805,392			312,037	5,160,921	10,061,856	37,273,972
2003			13,446		611,984	7,480,364	8,894,014	2,596,262			368,867	6,016,678	11,002,723	36,984,338
2004			208,755		355,142	7,886,137	12,001,290				380,042	6,588,633	12,654,765	40,074,764
2005			168,063			6,915,690	13,113,486				323,536	6,663,499	13,376,501	40,560,775
2006			269,397			7,044,226	14,561,848				378,601	6,782,935	12,731,703	41,768,710
2007			137,300			6,972,909	15,773,724				358,395	7,347,794	12,582,785	43,172,907

[1] Underground mine.

[2] This site has been operated by different companies, most recently Bull Mountain Coal Properties, and before that, P.M. Coal Co. and Mountain, Inc; RBM Mining Inc. did contract mining here from 1991 to 1994. Underground and strip mining both have been done at this site.

[3] Decker Coal Co. is a joint venture between KCP, Inc (previously Peter Kiewit Sons) and Western Minerals, Inc (previously held by Kennecott Energy Company). Kennecott purchased the share held by NERCO, a PacifiCorp subsidiary, in 1993.

[4] Rio Tinto, through its subsidiary Kennecott Energy Co., purchased NERCO, a Pacific Power and Light subsidiary and owner of Spring Creek Coal, in 1993.

[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) was operated by Washington Group International (formerly Morrison-Knudsen), which held a minority interest until 2007, when Westmoreland assumed full control of the mine.

[8] Westmoreland Resources purchased Western Energy from Montana Power Company in 2001. Since 1990, production volume includes in the low to mid-200,000 range of tons per year of waste coal sold to CELP generation plant.

Note: Total production is slightly different (usually higher by <0.5%) than in Table C-2. The data come from a state, rather than federal, source.

Source: Montana Department of Labor and Industry, Employment Relations Division (previously, Workers' Compensation Division) (1980-2007).

Table C5. Distribution of Coal for Use In Montana, 1974-2006

(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**
2001	11,045	3	307	**11,355**
2002	10,305	3	114	**10,422**
2003	10,903	117	2	**11,022**
2004	10,995	153	108	**11,256**
2005[1]	13,341	87	145	**13,574**
2006[2]	11,505	140	92	**12,098**

[1] Through correspondence with EIA and review of electric generation data, DEQ determined that the figure for electric utility consumption is high, by up to 2 million tons.

[2] Total includes 361,160 tons for which the sector is unknown.

Note: This data series consistently shows the amount of coal distributed to Electric Utilities to be slightly different than the amount received at Electric Utility Plants shown in Table C6 through 1997. Differences in distribution and receipt data are due to the time lag between distribution and receipt of coal shipments and to the use of Energy Information Administration, Form EIA-906, *Power Plant Report* to gather data reported in Table 6.

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); *Domestic Distribution of U.S. Coal by Destination State, Consumer, Destination and Method of Transportation, 2001-2006* (http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/coal_distributions.html).

Table C6. Receipts of Montana Coal at Electric Utility Plants[1] 1973-2006

(thousand short tons)

Year	Received at Montana Utilities: Subbituminous	Received at Montana Utilities: Lignite	Received at Montana Utilities: Montana Total	Received at Out-of-State Utilities	TOTAL
1973	NA	NA	882	9,741	**10,623**
1974	NA	NA	822	13,114	**13,936**
1975	NA	NA	1,197	20,180	**21,377**
1976	NA	NA	2,316	22,642	**24,958**
1977	NA	NA	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	**35,627**
1991	10,173	225	10,398	26,091	**36,489**
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]	9,915	277	10,192	30,243	**40,435**
1999[2]	9,646	215	9,861	29,803	**39,664**
2000[2]	8,899	317	9,216	27,579	**36,795**
2001[2]	10,074	307	10,381	37,018	**37,018**
2002[2]	9,285	283	9,568	35,497	**35,497**
2003[2]	9,791	318	10,109	24,465	**34,574**
2004[2]	10,056	321	10,377	26,891	**37,268**
2005[2,3,4]	NA	NA	12,692	24,851	**37,543**
2006[2]	10,347	323	10,670	28,749	**39,419**

NA - Not available

[1] Plants of 25-megawatt capacity or larger (1973-82); plants of 50-megawatt capacity or larger (1983-1997); all plants supplied by companies distributing 50,000 tons of coal or more per year (1998-2006). The change in definition in 1998 increased the size of the universe being covered.

[2] Since January 1998, some regulated utilities have sold off their generating plants. Once divestiture was complete, data were no longer required to be filed on the FERC Form 423 survey. Therefore, Montana Total, Received at Out-of-State Utilities and TOTAL from 1998 forward actually are EIA Form 6 survey data (Distribution of Coal Originating in Montana) . Subbituminous data for 1998 forward are numbers calculated by DEQ by subtracting Form 423 data on Lignite from Montana Total.

[3] Lignite consumption data for October was missing.

[4] Through correspondence with EIA and review of electric generation data, DEQ determined that the 2005 shipment figure to Montana is high, by up to 2 million tons and shipments to out of state plants low by a corresponding amount.

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 1978-2006 (EIA-0191; based on FERC Form 423); U.S. Department of Energy, Energy Information Administration, *Coal Industry Annual* , 1998-2000 (EIA-0584; based on EIA Form 6); U.S. Department of Energy, Energy Information Administration, *Domestic Distribution of U.S. Coal by Origin State, Consumer, Destination and Method of Transportation* 2001-2006 (http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/coaldistrib.html; based on EIA Form 6).

Table C7. Distribution of Montana Coal by Destination, 1991-2006 **(thousand short tons)**

Destination	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Alabama																4291
Arizona								94	69	198	275	81	48	71	361	458
Colorado	101	106	86	89	63	26										
Illinois	3,203	3,013	3,295	4,338	2,713	2,162	1,545	1,679	1,769	2,552	2,362	3,125	488	15		
Indiana	725	451	433	749	720	869	1,259	126	1,308	1,011	1,608	1,441	1,600	1,711	1,126	2,226
Iowa			1		2		105	136					29		34	29
Kansas							104	379	1,319	1,464			1,573	1,974	31	
Kentucky														44	795	
Michigan	10,838	10,376	10,055	10,481	11,014	9,806	10,866	9,861	9,952	9,239	9,435	6,542	7,752	9,089	8,978	8,770
Minnesota[1]	9,668	8,566	8,852	10,038	10,199	9,791	8,847	10,477	9,429	10,771	11,510	11,248	11,865	11,864	11,380	8,594
Mississippi	105	82	178	1,314	1,234	2,226	3,235	2,833	1,926	151						
Missouri					6									14		
Montana[1]	10,578	11,159	9,115	10,581	9,477	7,844	9,019	10,360	10,346	9,723	10,610	9,625	10,172	10,587	12,924	11,263
Nebraska	150	142	136	71	205	113	47	81								
Nevada											1	1	1	1	1	2
New Hampshire											10					
New Mexico																
North Dakota	425	444	422	559	469	417	402	517	877	145	618	487	617	964	1,454	1,228
Ohio						26	42		168	153	*			14		194
Oregon		1,835	355						1,507			675	232			
Pennsylvania															57	422
South Dakota					457	1,301	1,867	1,698	1,496							84
Tennessee		2												367		
Utah														3		
Washington		715	753	1,097	583	113	333	1,503		1,685	1,452	847	1,034	930	1,262	2,242
West Virginia															*	
Wisconsin	2,005	1,878	2,057	2,307	2,135	2,950	2,649	2,053	482	578	511	2,922	699	924	953	1,237
Wyoming	8	11	31	49	71	125	34	62		64	67	58	64	67	71	83
Unknown State												-1	6	56	185	
Domestic Total	37,812	38,804	35,795	41,672	39,362	37,770	40,363	41,860	40,649	37,735	38,459	37,050	36,181	38,694	39,612	41,123
Export - Canada[2]	10		54	90	259	316	438	814	682	608	485	180	541	1,142	653	447
Export - Overseas[2]	297	62	67	153		202	141									
TOTAL	38,119	38,866	35,916	41,915	39,621	38,288	40,942	42,674	41,331	38,343	38,944	37,230	36,721	39,836	40,265	41,570

* Less than 500 short tons

[1] Through correspondence with EIA and review of electric generation data, DEQ determined that the 2005 shipment figure to Montana is high, by up to 2 million tons. Some portion of this amount appears to have been shipped to Minnesota.

[2] After 2002, data were not available by country of destination.

Source: U.S. Department of Energy, Energy Information Administration *Coal Industry Annual* 1993-2000 (EIA-0584); U.S. Department of Energy, Energy Information Administration *Coal Distribution* 2001-2006 (foreign and domestic) (http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/coal_distributions.html, based on EIA Form 6).

Table C8. Montana Coal Production, Employment and Severance Tax, 1980-2007

YEAR	Coal Produced (thousand tons)[1]	Percentage of U.S. production	Number of miners[2]	Average cost per ton[1]	Coal Severance Tax[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
2001	39,143	3.5%	843	$8.83	$31,614,049
2002	37,386	3.4%	806	$9.27	$29,423,546
2003	36,994	3.5%	757	$9.42	$31,544,681
2004	39,989	3.6%	722	$10.09	$37,634,510
2005	40,354	3.6%	835	$9.74	$35,821,524
2006	41,823	3.6%	942	$10.42	$40,758,738
2007	43,390	3.8%	986	$11.79	$45,331,870

[1] Coal production and average cost from Table C2. 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 starting July 1 of the calendar year listed; thus, FY2003 starts in the middle of calendar year 2002. Includes all interest, penalties and accruals. Does not include temporary Coal Stabilization Tax in FY1993-94, which totaled $2,712,696. The amount of coal mined during a given fiscal year is not the same as during that calendar year. About 80-85% of the coal mined is taxed. Tax rates on coal were significantly reduced in the period 1989-1991.

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); U.S. Department of Energy, Energy Information Administration, *Annual Coal Report*, 2001-2007; Montana Department of Revenue *Biennial Report* (1980-2006); Montana Department of Revenue files (FY2006 and FY2007).

Petroleum and Petroleum Products in Montana

Montana Petroleum Quick Facts
(2007 data in round numbers)

Recent production: 35 million barrels per year

Amount of crude production exported: 96 percent

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

Total refinery capacity: 182,500 barrels/day

Crude oil receipts at refineries: 60 million barrels per year

Source of crude oil refined in state in recent years:
Montana – 2 percent
Alberta – 85 percent
Wyoming – 13 percent

Amount of liquid fuel refined products exported: 54 percent (2008)

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

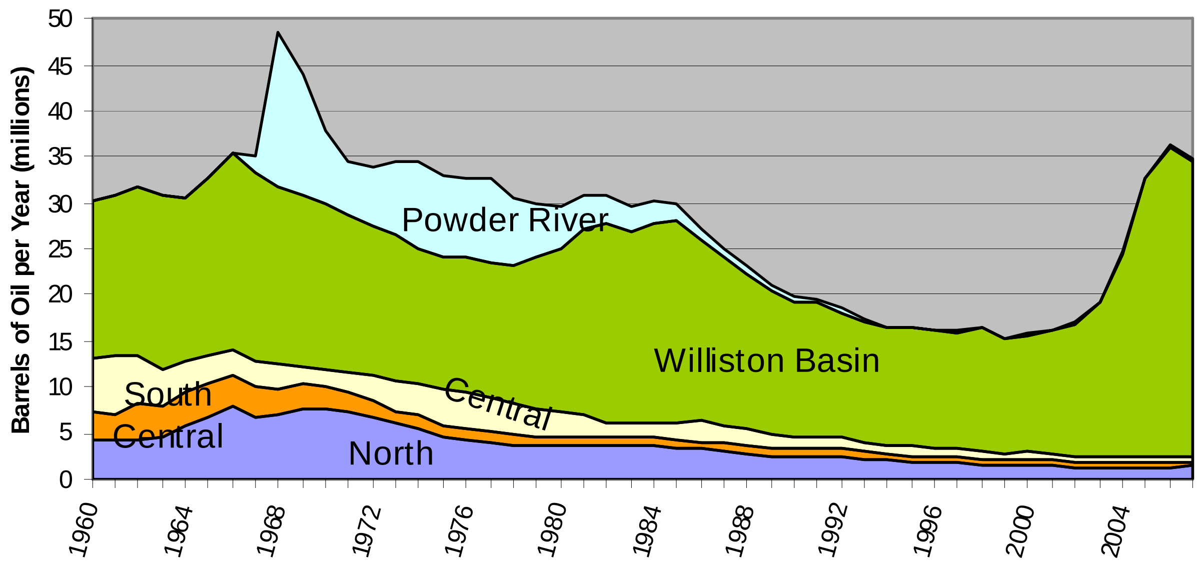
Montana consumption of petroleum products: 36 million barrels (includes refinery usage)

1. Production History

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

Montana's petroleum production peaked in 1968 at 48.5 million barrels (1 barrel = 42 gallons), the result of cresting Williston Basin production combined with a surge of production from the newly discovered Bell Creek field in the Powder River Basin (Table P1 and Figure P1). Production then declined quickly until 1971, when a series of world oil supply shocks began to push prices upward, stimulating more drilling. Production remained relatively stable between 1971 and 1974 as Powder River Basin output increased to match a decline in Williston Basin output. After 1974 production began to decline, despite the continued escalation of oil prices (Table P2).

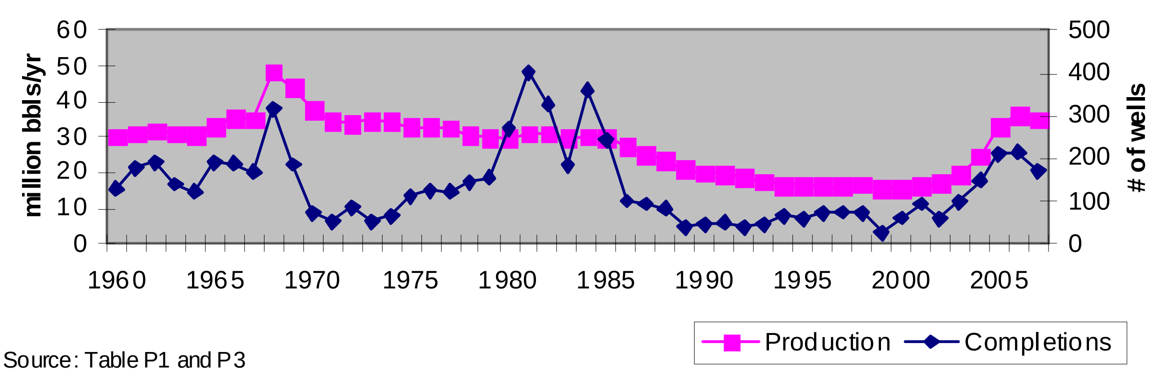
Figure P1. Historical Oil Production



Source: Table P1.

World oil price shocks following the Iran crisis in 1979 sparked a drilling boom, which peaked at 1,149 new wells of all types in 1981 (Table P3). That year, the average price of Montana crude climbed to almost $35 per barrel. While the increase in the price of oil encouraged more drilling, it did little to increase Montana production (Figure P2). The drilling produced a high percentage of dry holes and was unable to slow the decline in statewide production (Figure P4).

Figure P2. Oil Production and Well Completions, 1960-2007

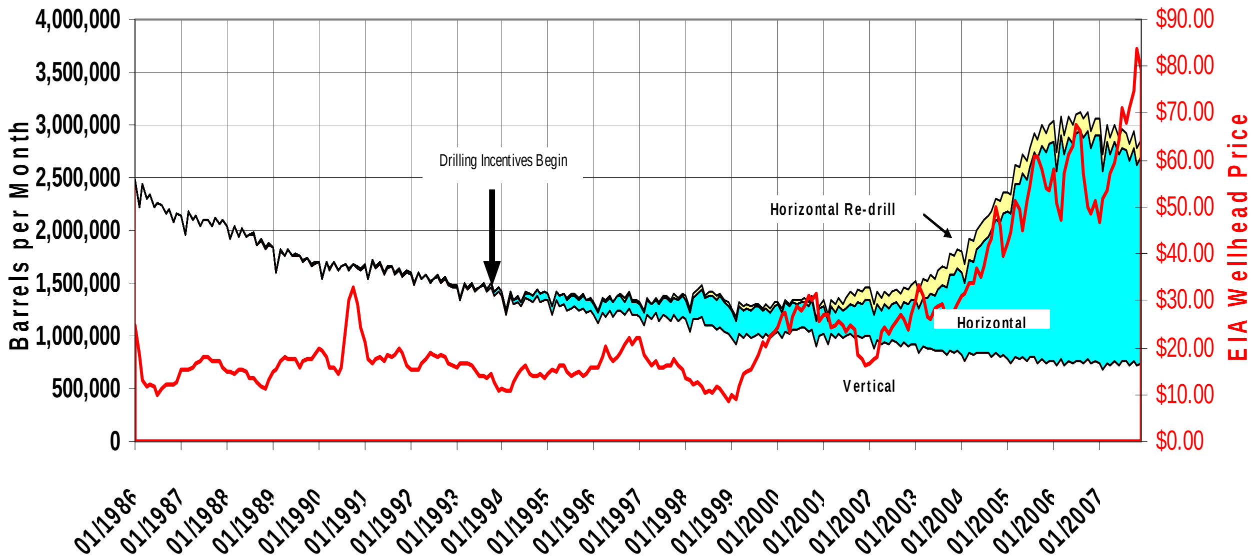


Source: Table P1 and P3

Output increased in the Williston Basin during the early 1980s and again in 2000, but this was matched by a steep decline in output from other areas. Production declined significantly following the drop in world oil prices in 1985, stabilizing around 16 million barrels per year in the mid-1990's, before staring to climb back in the early 2000s – pushed largely by new drilling techniques and prices that pushed demand.

In recent years, Montana oil production peaked during 2006 with approximately 36 million barrels of oil produced during the year. This was up from a recent historical low of approximately15 million barrels of oil produced during 1999 (Figure P3). Over 50% of the 2006 oil production was from the Bakken Formation in Elm Coulee Field in Richland County. Elm Coulee Field has produced 71.5 million barrels of oil since its discovery in 2000. While the reserves in the area were well known, a drilling technique called horizonal drilling, a method that includes drilling a vertical well and then "kicking out" horizonatlly, accompanied by a spike in oil prices has driven production in the area.

Figure P3 **Montana Monthly Oil Production, Vertical vs. Horizontal Wells January 1986 through December 2007**



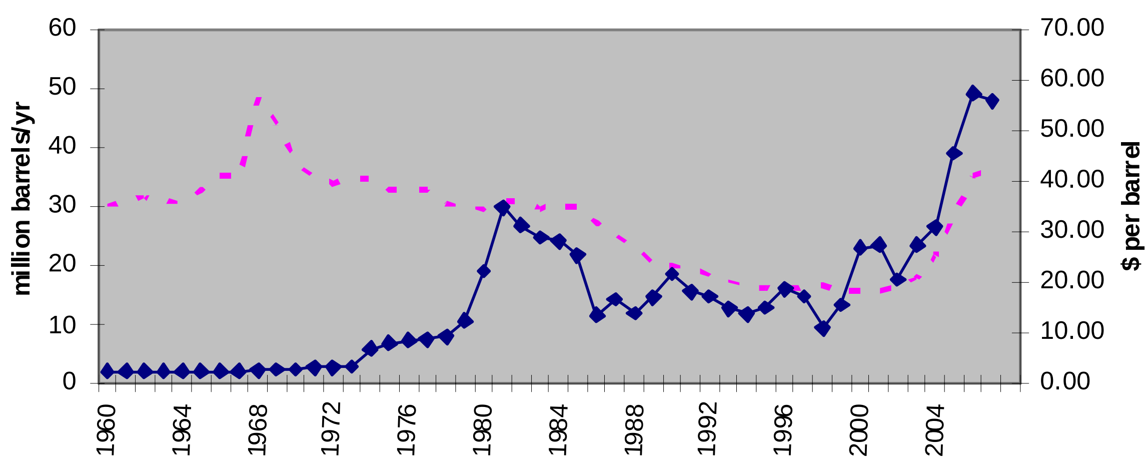
The Williston Basin, which covers parts of eastern Montana, North Dakota, and Saskatchewan, and includes the Bakken is America's largest inland oil field discovery over the last half century. About two-thirds of the acreage is in western North Dakota and in recent years, the big finds have been in North Dakota. In April 2008 the U.S. Geologic Service released a report, which estimated the amount of technically recoverable, undiscovered oil in the Bakken Formation at 3.0 to 4.3 billion barrels.

In Montana statewide production, however, has declined at a rate of approximately 6 percent per year since mid-2006. Oil production for the first eight months of 2008 was down more than 10 percent from the same period in 2007. Wells in Montana also are averaging 26-28 barrels per day in recent years (Table P1).

2. Refineries and Pipelines

Petroleum pipelines serving Montana consist of three separate systems (see Map, below). One bridges the Williston and Powder River Basins in the east and the other two link the Sweetgrass Arch, Big Snowy and Big Horn producing areas in central Montana. All these systems also move crude oil from Canada to Montana and Wyoming. (A fourth—Express—primarily carries Canadian crude through Montana.) In recent years, around 96 percent of

Figure P4. Production vs. Price, 1960-2007



Source: Table P2

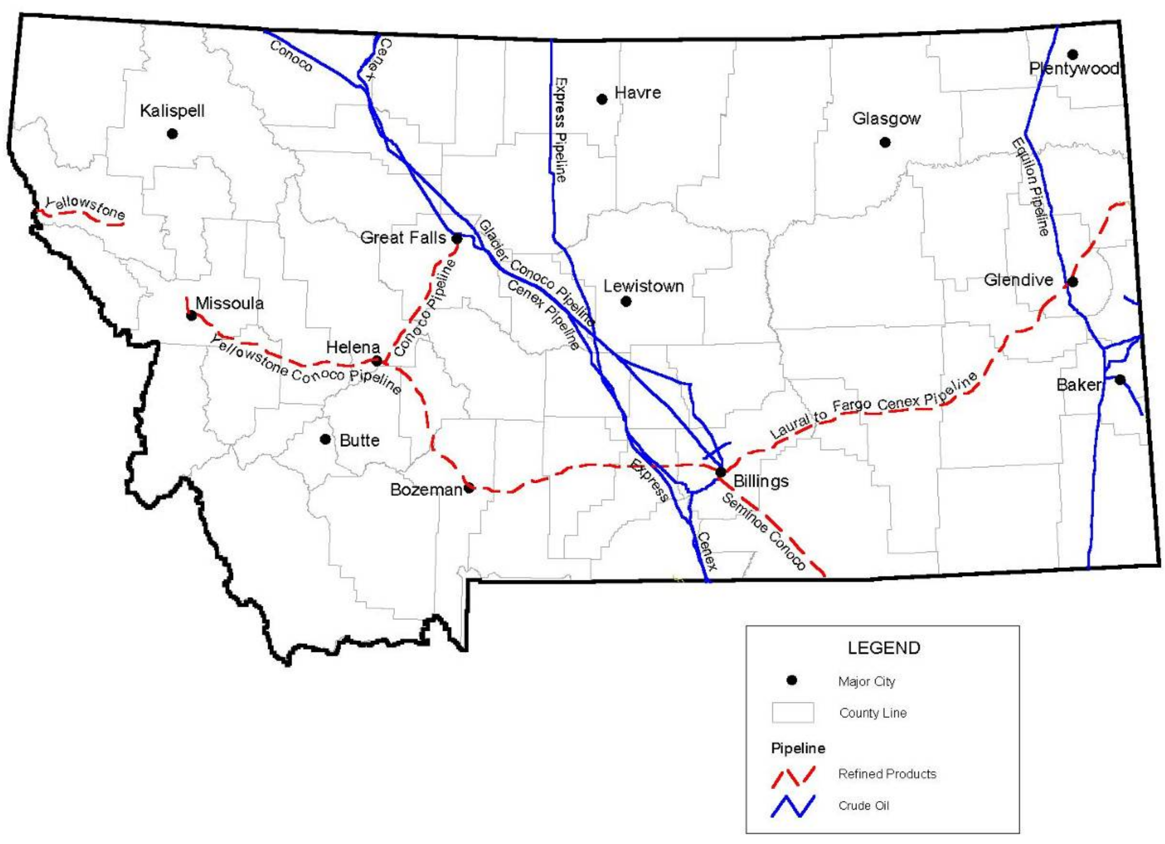
oil production has been exported from the state, mostly to Wyoming and beyond through the eastern pipeline system. This pipeline system is not connected to any of the Montana refineries, which limits the amount of Montana crude they can use.

Montana has four refineries, with a combined capacity of 182,500 barrels/day: ConocoPhillips (60,000 bbl/day) and ExxonMobil (58,000 bbl/day) in Billings, Cenex (55,000 bbl/day) in Laurel, and Montana Refining (9,500 bbl/day) in Great Falls. Montana refineries now use around 60-63 million barrels of crude a year (Table P5).

A $400 million upgrade at the CHS refinery completed in May 2008 increased the Laurel refinery's gasoline and diesel fuel by 20 percent, even though the refinery continues to process the same amount of crude oil. The Conoco Phillips refinery has undergone $500 million in improvements since November 2006, and the company indicates that additional improvements are underway and planned for the near future. According to company officials $90 million has been spent on the refinery since 2005. Connacher Oil and Gas of Calgary Alberta, purchased the Montana Refining Company in Great Falls in 2006.

In the last decade, less than 2 percent of the crude processed at Montana refineries was Montana crude. Oil fields in the Sweetgrass Arch, Big Snowy and Big Horn areas provided crude to the Montana refineries. Collectively, around 85 percent of the refinery crude inputs came from Alberta, Canada and around 13 percent came from Wyoming. The shipments from Canada have increased since the late 1960s, as Montana oil production and imports of Wyoming crude declined. (Figure P5, below)

MAP: Petroleum Pipelines in Montana



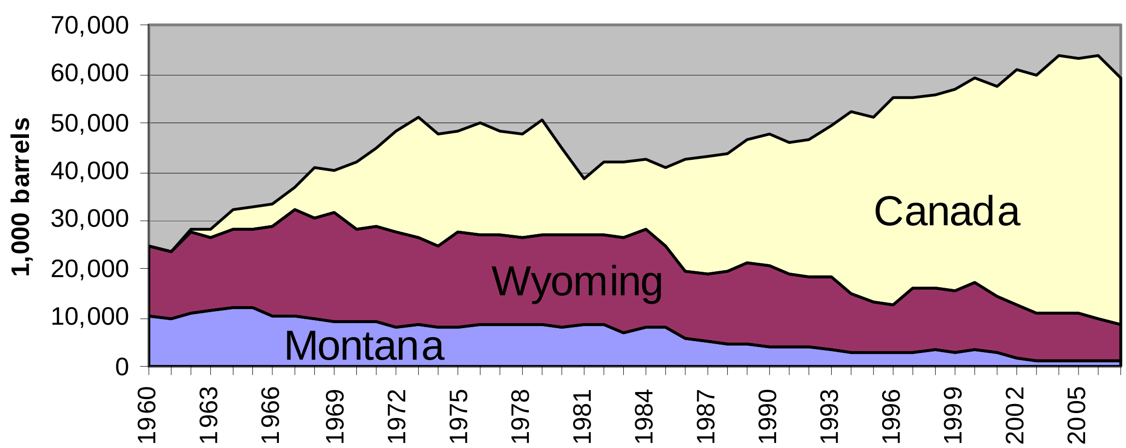
The refineries vary in their sources of crude inputs (Table P5). ConocoPhillips is the most dependent on Canadian crude, taking an average (2002-2007) of 97 percent of its total receipts from Canada. ExxonMobil is the least dependent on Canadian crude (56 percent of receipts) but by far the most dependent on Wyoming (43 percent of receipts).
Almost all of refinery output is moved by pipeline. The Billings area refineries ship their products to Montana cities and east to Fargo, North Dakota (Cenex pipeline), to Wyo-

ming and further south (Conoco Seminoe pipeline) and west to Spokane and Moses Lake, Washington (Conoco Yellowstone pipeline). Montana refineries provide almost one-quarter of North Dakota's gasoline and distillate use and almost one-tenth of Washington's gasoline and distillate use

Most of the petroleum from Richland County and northern North Dakota is delivered via the Enbridge North Dakota pipeline system. In 2005, Enbridge began a number of improvements and expansions to increase capacity on its system, which covers eastern Montana and interconnects in northwestern Minnesota. In response to the increased production in the Bakken and to better serve North Dakota and Montana, Enbridge added 30,000 barrels per day of delivery capacity to its North Dakota system in 2007. Additional expansions are expected to be in service by 2010.

In 2008 TransCanada Corp. announced plans to build the Keystone XL pipeline through eastern Montana and five other states to transport Canadian oil to U.S. refineries along the Gulf Coast of Texas. The 280-mile portion of the pipeline in Montana will be part of the 1,980-mile project, which begins in Hardisty, Alberta. While Montana refineries have their supplies contracted, they would not be prevented from bidding on access from the new pipeline.

Figure P5. Refinery Receipts by Source of Oil, 1960-2007

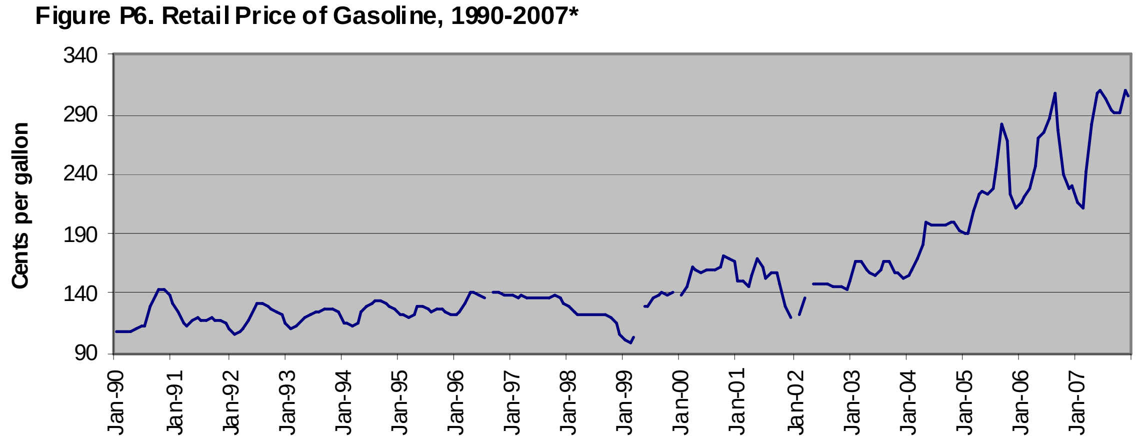


Source: Table P4

3. Petroleum Products Consumption

Petroleum product consumption in Montana continues to increase. It initially peaked at 33 million barrels in 1979 (Table P6). It then drifted lower, settling in the mid-1980's around 24 million barrels per year. After that, consumption began a slow climb, hitting a new high of nearly 36 million barrels in 2006.

The transportation sector is the single largest user of petroleum and the second largest user



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

Source: EIA 782a database

of all forms of energy in Montana. In 2006, 34 percent of petroleum consumption was in the form of motor gasoline and 34 percent was distillate, mostly diesel fuel. Around 17 percent was consumed in petroleum industry operations (Table P6).

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

The fluctuations in demand for gasoline and diesel fuel since 1970 reflect changes in the state and national economy and the international price of oil. The embargo by the Organization of Petroleum Exporting Countries (OPEC) in 1973-1974 and the Iranian crisis of 1979-1980 drove prices up and demand down. The increase in prices prompted advances in vehicle efficiency and a fuel switch by heavy-duty trucks from gasoline to diesel. The crash in international prices in 1985, the economic growth of the 1980's and 1990's, along with the decline in vehicle fleet fuel efficiency pushed gasoline and diesel demand up.

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

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

To say the least, crude oil prices have been volatile over the last four years. The average price of a barrel of oil produced by the Organization of the Petroleum Exporting Countries doubled from 2001 to 2005. Fueled by world events and weather, by January 2008, for the first time, oil prices reached $100 a barrel. A few months later prices crept past $135 a barrel. By the summer of 2008 a tank of gas costs nearly twice what it did at the start of 2007, with many paying more than $4-a-gallon. The price of West Texas Intermediate (WTI) crude oil is expected to stay roughly flat in 2009 at about $70 per barrel. The Energy Information Administration expects the annual average regular-grade gasoline retail price to be about $2.34 per gallon in 2009.[1]

4. Petroleum production and state revenue

There are various tax rates for oil and gas production in Montana based on the type of well, type of production, working or non-working interest, date when production began, and price of West Texas Intermediate crude oil. Over the last few years, oil and gas tax rates have changed several times. The increased price of oil and increased production has had a substantial impact on Montana's tax coffers.

Sustained high prices for oil and natural gas spurred drilling activity in Montana during the last five years, which has brough increased resource tax revenue to the state. At the end of fiscal year 2008, collections from oil and gas hit a record $324 million. Since reaching that highpoint (Table 1) oil and gas production collections have declined because of a significant reduction in commodity prices and production levels – specifically for oil.

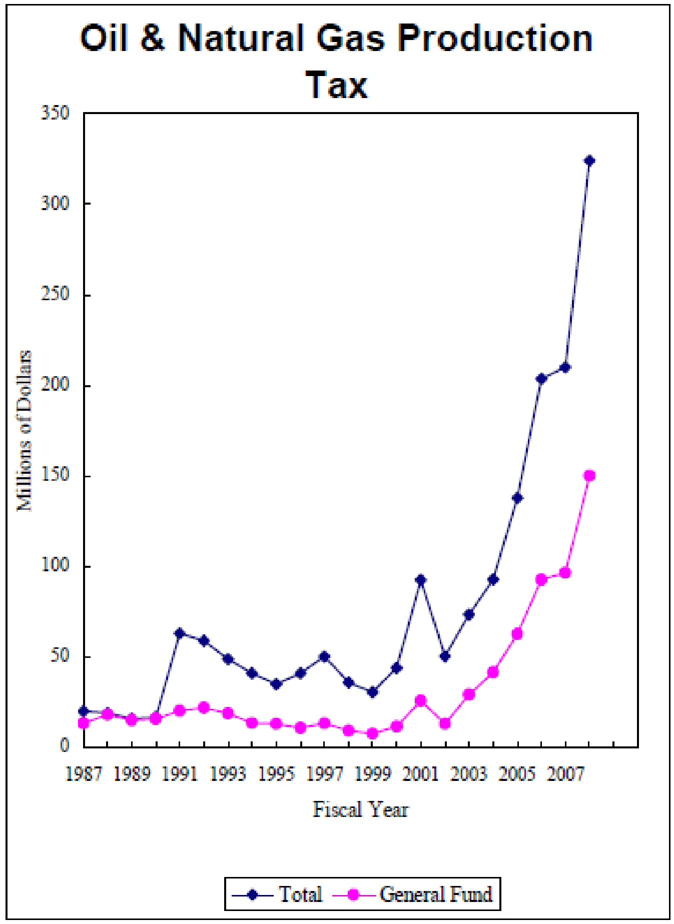
At the end of fiscal year 2009, total oil and gas production tax collections were $49.5 million (33.0 percent) below last year. A decrease in oil and gas production tax was expected because prices have plummeted from the highs of last summer. Montana oil prices averaged $82.34 per barrel for the first ten months of FY 2008 versus $60.73 per barrel for the first ten months of FY 2009.[2]

[1] http://www.eia.doe.gov/steo

[2] http://leg.mt.gov/content/Publications/fiscal/rev_transp/Gen_Fund_Update_July.pdf

Table I

	Fiscal Year	Total Collections Millions	General Fund Collections Millions	GF Percent Change
A	1987	19.904239	13.254877	Not App.
A	1988	18.913097	17.975582	35.61%
A	1989	15.748241	14.959251	-16.78%
A	1990	16.486405	15.567426	4.07%
A	1991	62.879742	20.163269	29.52%
A	1992	58.892324	21.822893	8.23%
A	1993	48.650604	18.676586	-14.42%
A	1994	40.871318	13.403408	-28.23%
A	1995	34.704332	12.963887	-3.28%
A	1996	40.826475	10.665986	-17.73%
A	1997	50.150068	13.283093	24.54%
A	1998	35.709042	9.120152	-31.34%
A	1999	30.446634	7.505617	-17.70%
A	2000	43.772950	11.362741	51.39%
A	2001	92.395790	25.791723	126.99%
A	2002	50.303610	12.902439	-49.97%
A	2003	73.389376	29.086038	125.43%
A	2004	92.676050	41.323718	42.07%
A	2005	137.754331	62.625939	51.55%
A	2006	203.681078	92.562800	47.80%
A	2007	209.946350	96.334992	4.08%
A	2008	324.311270	149.993826	55.70%



Comments on the data

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

Table P1. Average Daily Oil Production per Well and Annual Production by Region, 1960-2007

	Average Daily Production per Well (barrels)						Oil Production by Region (barrels)					
Year	North	South Central	Central	Northeastern	Southeastern	STATE AVERAGE	North	South Central	Central	Northeastern	Southeastern	TOTAL
1960	4.2	88.1	52.3	93.9		22.3	4,332,218	3,087,871	5,780,420	17,039,406		30,239,915
1961	4.7	97.9	53.8	89.3		25.0	4,211,017	2,895,587	6,367,524	17,431,916		30,906,044
1962	4.5	119.9	43.4	76.3		23.5	4,252,304	3,851,672	5,279,163	18,264,368		31,647,507
1963	4.9	113.4	34.8	74.4		23.2	4,530,510	3,383,587	3,950,490	19,005,066		30,869,653
1964	7.4	115.1	28.8	65.7		25.2	5,705,948	3,699,927	3,269,768	17,971,855		30,647,498
1965	7.1	97.6	25.5	70.9		23.6	6,826,261	3,597,647	2,849,923	19,504,287		32,778,118
1966	9.5	87.7	24.7	73.6		27.6	7,991,302	3,392,890	2,710,194	21,285,732		35,380,118
1967	8.8	90.7	27.5	69.9	70.6	28.2	6,758,280	3,181,132	2,872,604	20,475,733	1,671,277	34,959,026
1968	9.9	79.6	26.4	67.6	138.0	39.0	6,883,493	2,885,272	2,728,357	19,390,652	16,572,472	48,460,246
1969	11.3	69.5	22.6	66.4	91.4	36.1	7,557,966	2,739,346	2,011,445	18,396,618	13,248,737	43,954,112
1970	11.6	69.3	26.2	66.8	57.9	32.3	7,680,831	2,329,187	1,915,273	18,110,147	7,843,259	37,878,697
1971	11.3	57.9	29.4	62.4	50.9	30.1	7,292,476	2,028,304	2,274,124	17,042,703	5,961,116	34,598,723
1972	9.8	57.4	34.4	63.3	65.3	29.6	6,646,908	1,742,749	2,817,045	16,361,771	6,335,666	33,904,139
1973	9.5	50.0	36.2	60.8	90.4	31.7	5,948,826	1,515,088	3,238,967	15,735,703	8,181,598	34,620,182
1974	8.3	45.6	34.2	57.4	110.3	30.5	5,464,319	1,432,528	3,334,759	14,939,292	9,383,064	34,553,962
1975	6.0	36.1	35.8	53.4	103.2	26.2	4,551,324	1,318,779	3,954,024	14,312,685	8,706,862	32,843,674
1976	5.8	35.1	35.2	53.8	133.3	27.1	4,200,539	1,246,005	4,063,897	14,496,380	8,807,439	32,814,260
1977	5.6	30.4	29.4	50.8	140.2	26.2	4,060,957	1,210,064	3,677,361	14,621,635	9,110,037	32,680,054
1978	4.9	26.1	26.4	48.9	117.6	23.5	3,671,322	1,095,737	3,343,556	15,103,853	7,252,869	30,467,337
1979	4.6	27.7	24.4	51.2	94.9	22.9	3,536,296	1,131,798	3,029,397	16,546,576	5,713,032	29,957,099
1980	4.3	23.2	19.9	48.7	86.0	21.1	3,516,807	1,055,105	2,612,091	17,739,142	4,660,659	29,583,804
1981	4.3	18.9	20.0	50.6	59.2	21.0	3,605,207	910,595	2,583,690	19,954,159	3,759,760	30,813,411
1982	4.1	16.0	16.5	44.2	38.8	19.2	3,680,043	806,366	1,496,895	21,934,760	2,999,247	30,917,311
1983	3.7	14.4	14.0	39.6	35.1	16.9	3,682,130	790,150	1,467,855	20,877,527	2,847,618	29,665,280
1984	3.9	15.8	15.9	37.9	30.4	17.0	3,708,185	829,090	1,709,653	21,449,415	2,383,476	30,079,819
1985	3.3	16.3	12.3	39.1	22.1	16.0	3,419,300	838,817	1,868,780	21,979,087	1,744,433	29,850,417
1986	2.9	24.7	14.4	35.4	19.5	14.2	3,220,769	722,118	2,387,266	19,520,103	1,314,374	27,164,630
1987	2.9	17.4	13.9	35.1	26.2	14.1	3,040,941	827,229	1,847,551	18,319,149	1,069,179	25,104,049
1988	2.7	18.9	13.0	32.6	23.3	13.2	2,779,524	884,954	1,684,853	17,089,238	878,887	23,317,456
1989	2.6	16.2	12.8	30.8	16.8	12.5	2,488,169	773,372	1,544,989	15,476,534	686,228	20,969,292
1990	2.6	16.4	12.3	29.5	12.8	12.0	2,432,506	805,807	1,454,066	14,592,497	550,211	19,835,087
1991	2.7	17.9	12.3	29.4	16.9	12.2	2,510,130	804,003	1,393,046	14,380,288	485,881	19,573,348
1992	2.6	16.5	11.7	27.8	14.1	11.5	2,426,783	832,580	1,227,475	13,637,695	355,139	18,479,672
1993	2.4	17.4	10.1	27.9	13.3	11.4	2,143,943	772,668	1,095,551	13,110,882	272,517	17,395,561
1994	2.4	14.8	9.6	26.6	3.5	11.0	2,003,272	733,965	955,703	12,747,075	90,965	16,530,980
1995	2.3	14.5	11.4	26.9	12.4	11.9	1,783,331	698,537	1,040,127	12,877,305	126,524	16,525,824
1996	3.2	17.6	13.7	31.8	15.5	15.3	1,740,057	657,135	955,626	12,696,542	125,797	16,175,157
1997	3.2	15.9	13.5	31.4	12.0	15.2	1,691,832	603,422	991,714	12,667,200	180,245	16,134,413
1998	3.1	15.4	12.7	33.6	13.3	16.2	1,590,425	582,568	828,028	13,382,441	239,255	16,622,717
1999	3.1	17.7	11.5	31.6	11.7	15.5	1,511,361	606,812	638,239	12,373,436	208,707	15,338,555
2000	2.9	18.9	11.2	30.4	11.2	14.8	1,556,127	696,340	725,437	12,559,879	213,671	15,751,454
2001	2.7	16.3	10.4	30.9	10.0	15.1	1,430,087	656,160	650,982	13,369,437	173,567	16,280,233
2002	2.6	14.5	10.7	31.9	9.1	16.0	1,313,159	603,383	630,368	14,277,806	157,118	16,981,834
2003	2.6	14.3	9.5	36.7	8.4	18.1	1,275,084	572,145	598,971	16,823,588	141,033	19,410,821
2004	2.5	14.0	9.0	45.8	9.5	22.1	1,266,790	555,662	565,150	22,164,424	158,632	24,710,658
2005	2.4	13.7	8.6	56.8	9.3	27.7	1,254,747	534,180	535,904	30,296,287	158,002	32,779,120
2006	2.4	12.9	8.2	56.3	8.4	28.4	1,314,007	555,731	501,704	33,695,855	175,332	36,242,629
2007	2.5	12.8	8.2	49.2	18.1	26.0	1,399,836	530,323	468,604	32,103,869	350,564	34,853,196

NOTE: DNRC *Annual Review* provide data for the current year and the four previous years. Starting with 1996 data, DNRC does a rolling update and correction of previous year data each annual report. Thus, the final official data for 1996 was published in the 2000 report. From 1996 forward, the data in this table are from the most recent update of a year's data. Corrections caused final total annual production data to increase over the initial report from 0.03% to 1.5%, for an average increase of 54,000 bbls per year, in the years 1996-2003. These revisions had little or no impact on average daily production figures.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Division, *Annual Review, 1960-2007*

Table P2. Crude Oil Production and Average Wellhead Prices[1], 1960-2008

DNRC Statistics

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

DoR Statistics

Fiscal Year[3]	Crude Oil Production (Mbbls)	Average Wellhead Price ($/bbl)	Gross Value of Production (million $)
FY1995	16,448	14.60	240.1
FY1996	15,695	15.60	244.8
FY1997			
FY1998			
FY1999			
FY2000			
FY2001	15,736	27.40	431.2
FY2002	16,603	20.56	341.4
FY2003	17,742	27.27	483.8
FY2004	21,755	30.84	671.0
FY2005	28,643	45.56	1,304.9
FY2006	35,095	57.33	2,012.0
FY2007	36,202	55.82	2,020.9
FY2008	33,895	87.18	2,955.1

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

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

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

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division, *Annual Review*, 1960-2001; Montana Department of Revenue, Biennial Report 1994-1996 and DoR files for FY01-08.

Table P3. Number of Producing Oil Wells by Region and Number of Oil and Gas Wells Completed by Type, 1955-2007

	Number of Producing Oil Wells						Number of Wells Completed										
							Development					Exploratory					
Year	North	Central	South Central	North-eastern	South-eastern	TOTAL	Oil	Gas	Dry Holes	Service Wells	Sub-Total	Oil	Gas	Dry Holes	T.A.[1]	Sub-Total	TOTAL
1955	2,950	176	94	194		3,414	158	21	69		248	11	4	145		160	408
1956	2,969	213	96	306		3,584	229	6	75		310	12	0	171		183	493
1957	3,130	214	103	376		3,823	182	17	57		256	12	2	162		176	432
1958	3,120	248	102	446		3,916	159	7	46		212	12	2	109		123	335
1959	3,067	266	100	455		3,888	156	12	71		239	7	6	101		114	353
1960	2,811	303	96	497		3,707	114	4	58		176	14	3	150		167	343
1961	2,447	324	81	535		3,387	169	6	60		235	7	2	173		182	417
1962	2,615	333	88	656		3,692	182	16	57		255	8	2	154		164	419
1963	2,550	310	82	700		3,642	131	6	60		197	8	5	152		165	362
1964	2,216	317	88	708		3,329	100	7	109		216	22	3	150		175	391
1965	2,649	306	101	754		3,810	177	9	107		293	14	1	199		214	507
1966	2,308	301	106	792		3,507	179	9	96		284	10	3	185		198	482
1967	2,097	286	96	802	109	3,390	162	14	104		280	7	5	191		203	483
1968	1,898	282	99	784	328	3,391	300	14	89		403	15	13	509		537	940
1969	1,827	244	108	759	397	3,335	171	44	105		320	15	5	466		486	806
1970	1,806	200	92	743	371	3,212	60	30	63		153	12	11	272		295	448
1971	1,768	212	96	748	321	3,145	49	36	34		119	3	22	323		348	467
1972	1,856	224	83	706	265	3,134	79	97	87		263	7	19	435		461	724
1973	1,708	245	83	709	248	2,993	46	165	100		311	6	36	366		408	719
1974	1,802	267	86	712	233	3,100	58	179	212		449	7	21	265		293	742
1975	2,067	303	100	734	231	3,435	105	261	222		588	6	15	236		257	845
1976	1,978	316	97	737	181	3,309	106	264	169		539	17	8	223		248	787
1977	1,999	343	109	789	178	3,418	98	220	188		506	24	19	129		172	678
1978	2,052	347	115	863	169	3,546	123	223	232		578	21	15	179		215	793
1979	2,089	340	112	886	165	3,592	120	235	182		537	35	20	211		266	803
1980	2,212	358	124	996	148	3,838	241	203	206		650	30	12	260		302	952
1981	2,280	354	132	1,080	174	4,020	276	133	188		597	126	85	341		552	1,149
1982	2,455	249	138	1,360	212	4,414	263	145	120	19	547	64	46	248		358	905
1983	2,693	287	150	1,446	222	4,798	160	55	88	10	313	25	16	156	23	220	533
1984	2,610	294	144	1,577	214	4,839	327	99	87	20	533	33	21	189	25	268	801
1985	2,803	417	141	1,540	216	5,117	227	84	90	18	419	16	2	192	11	221	640
1986	3,017	453	80	1,509	184	5,243	90	81	69	4	244	11	10	130	10	161	405
1987	2,850	363	130	1,430	112	4,885	86	75	39	21	221	7	9	100	11	127	348
1988	2,821	355	128	1,434	103	4,841	72	54	46	12	184	10	19	100	9	138	322
1989	2,644	331	131	1,377	112	4,595	32	115	29	8	184	8	12	38	0	58	242

Year	North	Central	South Central	North-eastern	South-eastern	TOTAL	Oil	Gas	CBM[2]	Storage	EOR[3] Injection	Disposal	Dry	Other	Total
1990	2,579	323	135	1,356	118	4,514	42	191	0	2	6	2	91	0	334
1991	2,534	310	123	1,338	79	4,384	47	154	4	2	5	0	63	1	276
1992	2,568	287	138	1,338	69	4,400	38	151	0	3	0	2	65	6	265
1993	2,408	298	122	1,287	56	4,171	40	77	0	1	8	2	46	0	174
1994	2,324	272	136	1,311	71	4,114	62	102	0	7	7	2	77	4	261
1995	2,093	249	132	1,310	28	3,812	56	88	0	2	3	3	54	5	211
1996	2,023	242	120	1,271	49	3,705	70	64	0	2	9	2	49	1	197
1997	1,967	235	117	1,298	73	3,690	73	223	10	0	8	4	73	1	392
1998	1,912	236	118	1,292	83	3,641	63	144	21	0	18	1	66	3	316
1999	1,854	225	118	1,265	72	3,534	25	235	111	3	21	0	63	1	459
2000	1,891	229	125	1,305	77	3,627	54	288	77	6	7	2	56	1	491
2001	1,854	220	131	1,344	62	3,611	95	297	48	1	13	2	81	4	541
2002	1,765	215	130	1,394	57	3,561	58	314	8	6	7	0	71	1	465
2003	1,769	224	128	1,434	52	3,607	97	306	194	0	14	4	70	1	686
2004	1,798	221	125	1,546	54	3,744	148	375	43	0	1	2	54	5	628
2005	1,827	220	131	1,707	67	3,952	211	369	163	0	4	1	75	1	824
2006	1,874	214	130	1,878	70	4,166	214	348	317	0	5	6	61	4	955
2007	1,901	215	128	2,004	68	4,316	171	385	63	0	2	6	59	3	689

[1] T.A. - Temporarily abandoned. [2] CBM - Coalbed Methane [3] EOR - Enhanced Oil Recovery

NOTE: The data for wells drilled since 1990 supersede those in the previous Annual Reviews. After 1990, the number of wells drilled no longer is broken out by "Development" and "Exploratory." DNRC's *Annual Review* provides data for the current year and the four previous years. Starting with 1996 data, DNRC does a rolling update and correction of previous year data each annual report. Thus, the final official data for 1996 was published in the 2000 report. From 1996 forward, the data in this table are from the most recent update of a year's data.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Division, *Annual Review,* 1955-2007.
Permit Data 1990-2007: Board of Oil and Gas Live Data Access, October 14, 2008, http://bogc.dnrc.state.mt.us/OnlineData.htm.

Table P4. Receipts at Montana Refineries by Source of Crude Oil, 1960-2007 (thousand barrels)

	MONTANA		WYOMING		CANADA		NORTH DAKOTA		
Year	Crude Oil	Percent of Total	Crude Oil	Percent of Total	Crude Oil	Percent of Total	Crude Oil	Percent of Total	TOTAL
1960	10,531	42.3	14,383	57.7	21	0.1			24,935
1961	9,797	41.0	14,038	58.8	33	0.1			23,869
1962	11,175	39.7	16,708	59.4	266	0.9			28,149
1963	11,798	42.0	14,745	52.5	1,553	5.5			28,097
1964	12,292	38.4	15,714	49.1	4,002	12.5			32,007
1965	11,971	36.2	16,416	49.7	4,654	14.1			33,041
1966	10,626	31.8	18,120	54.2	4,684	14.0			33,429
1967	10,632	28.7	21,393	57.7	5,052	13.6			37,078
1968	9,690	23.7	20,915	51.0	10,347	25.2			40,951
1969	9,465	23.4	22,130	54.7	8,843	21.9			40,438
1970	9,080	21.5	19,342	45.7	13,908	32.8			42,330
1971	9,262	20.6	19,732	43.8	16,003	35.6			42,997
1972	8,194	16.9	19,241	39.6	21,156	43.5			48,591
1973	8,437	16.6	18,235	35.8	24,295	47.7			50,967
1974	7,989	16.6	16,949	35.3	23,115	48.1			48,053
1975	8,002	16.6	19,465	40.4	20,690	43.0			48,157
1976	8,517	16.9	18,311	36.4	23,494	46.7			50,322
1977	8,928	18.5	18,248	37.8	20,921	43.3	200	0.4	48,297
1978	8,848	18.5	17,513	36.6	21,369	44.7	69	0.1	47,739
1979	8,668	17.1	18,368	36.3	23,578	46.6	6	0.0	50,620
1980	8,016	17.9	19,050	42.6	17,627	39.4	25	0.1	44,719
1981	8,691	22.4	18,298	47.2	11,797	30.4	14	0.0	38,801
1982	8,653	20.5	18,178	43.0	15,402	36.5		0.0	42,234
1983	7,120	16.9	19,183	45.7	15,584	37.2	45	0.1	41,932
1984	7,821	18.2	20,552	47.9	14,516	33.8	55	0.0	42,945
1985	7,804	19.0	17,258	41.9	16,075	39.1	10	0.0	41,149
1986	6,019	14.1	13,795	32.4	22,778	53.5			42,593
1987	4,993	11.6	13,758	31.9	24,396	56.5			43,147
1988	4,607	10.5	14,907	34.0	24,306	55.5			43,820
1989	4,475	9.6	16,675	35.8	25,480	54.6			46,630
1990	4,057	8.5	16,431	34.4	27,271	57.1			47,760
1991	4,272	9.2	15,031	32.5	26,991	58.3			46,294
1992	3,907	8.3	14,820	31.6	28,110	60.0			46,837
1993	3,395	6.9	15,116	30.5	30,977	62.6			49,489
1994	3,109	5.9	11,865	22.7	37,383	71.4			52,357
1995	3,042	5.9	10,074	19.6	38,266	74.5			51,381
1996	3,033	5.5	9,686	17.5	42,549	77.0			55,269
1997	3,178	5.7	12,840	23.2	39,296	71.0			55,314
1998	3,203	5.7	13,067	23.5	39,449	70.8			55,719
1999	3,162	5.6	12,623	22.2	40,986	72.2			56,772
2000	3,520	5.9	13,579	22.9	42,281	71.2			59,380
2001	2,702	4.7	11,947	20.7	42,950	74.6			57,599
2002	1,733	2.8	11,100	18.2	48,130	78.9			60,963
2003	1,332	2.2	9,550	16.0	48,957	81.8			59,838
2004	1,258	2.0	9,581	15.0	52,965	83.0			63,805
2005	1,378	2.2	9,373	14.8	52,545	83.0			63,295
2006	1,229	1.9	8,626	13.5	54,043	84.6			63,899
2007	1,246	2.1	7,633	12.9	50,279	85.0			59,158

NOTE: Some data originally reported by the Montana Oil and Gas Conservation Division have been revised on the basis of further information received from individual refineries. The Oil and Gas Conservation Division data originally understated Canadian inputs and overstated Wyoming inputs to the Continental Oil refinery, at least for the years 1968-75. Canadian inputs to the Big West Oil and Westco refineries were apparently not reported to the Oil and Gas Conservation Division. Revised data are available only for the years 1972-75, but it is likely that Canadian inputs to these two refineries were significant before 1972.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division, *Annual Review*, 1960-2007.

Table P5. Receipts at Montana Refineries by Source of Oil, 2002-2007 (barrels)

Average (2002-2007)	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,037,283	5%	144,387	1%	55,558	0%	125,458	4%	1,362,686	2%
Wyoming	484,085	2%	554,250	3%	8,272,180	43%	-	-	9,310,515	15%
Canada	18,206,711	92%	19,487,912	97%	10,736,633	56%	2,721,790	96%	51,153,046	83%
Total Received	19,728,079	100%	20,186,549	100%	19,064,370	100%	2,847,248	100%	61,826,247	100%

2007	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,149,706	6%	96,065	0%	0	0%	0	0%	1,245,771	2%
Wyoming	596,486	3%	256,045	1%	6,780,663	39%	-	-	7,633,194	13%
Canada	17,112,058	91%	19,016,364	98%	10,684,276	61%	3,466,003	100%	50,278,701	85%
Total Received	18,858,250	100%	19,368,474	100%	17,464,939	100%	3,466,003	100%	59,157,666	100%

2006	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,113,647	5%	112,470	1%	0	0%	3,237	0%	1,229,354	2%
Wyoming	803,508	4%	273,267	1%	7,549,617	42%	0	-	8,626,392	14%
Canada	19,762,607	91%	20,838,356	98%	10,310,296	58%	3,131,724	100%	54,042,983	85%
Total Received	21,679,762	100%	21,224,093	100%	17,859,913	100%	3,134,961	100%	63,898,729	100%

2005	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,107,803	6%	110,195	1%	0	0%	159,683	6%	1,377,681	2%
Wyoming	316,611	2%	292,646	1%	8,763,255	41%	0	-	9,372,512	15%
Canada	17,857,334	93%	19,373,220	98%	12,601,354	59%	2,713,056	94%	52,544,964	83%
Total Received	19,281,748	100%	19,776,061	100%	21,364,609	100%	2,872,739	100%	63,295,157	100%

2004	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	936,276	5%	126,185	1%	0	0%	195,678	7%	1,258,139	2%
Wyoming	376,745	2%	803,810	4%	8,400,888	43%	0	-	9,581,443	15%
Canada	18,987,319	94%	20,292,895	96%	11,126,536	57%	2,558,218	93%	52,964,968	83%
Total Received	20,300,340	100%	21,222,890	100%	19,527,424	100%	2,753,896	100%	63,804,550	100%

2003	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	889,294	5%	302,072	2%	-	-	140,380	6%	1,331,746	2%
Wyoming	408,712	2%	674,758	4%	8,466,132	43%	-	-	9,549,602	16%
Canada	17,827,042	93%	17,715,443	95%	11,129,578	57%	2,284,724	94%	48,956,787	82%
Total Received	19,125,048	100%	18,692,273	100%	19,595,710	100%	2,425,104	100%	59,838,135	100%

2002	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,026,972	5%	119,337	1%	333,345	2%	253,772	10%	1,733,426	3%
Wyoming	402,446	2%	1,024,976	5%	9,672,522	52%	-	-	11,099,944	18%
Canada	17,693,908	93%	19,691,191	95%	8,567,758	46%	2,177,015	90%	48,129,872	79%
Total Received	19,123,326	100%	20,835,504	100%	18,573,625	100%	2,430,787	100%	60,963,242	100%

Source: Montana Department of Natural Resources and Conservation *Montana Oil and Gas Annual Review* (2002-2007)

Table P6. Petroleum Product Consumption Estimates, 1960-2006 (thousand barrels)

Year	Asphalt & Road Oil	Aviation Gasoline	Distillate Fuel	Jet Fuel	Kerosene	LPG	Lubricants	Motor Gasoline	Residual Fuel	Other[1]	TOTAL
1960	865	1,006	4,898	265	477	737	161	6,922	1,725	2,063	19,118
1961	823	1,427	5,278	280	366	859	157	6,979	2,112	2,580	20,861
1962	786	473	5,549	311	265	819	171	7,553	2,320	3,052	21,298
1963	900	499	5,393	340	359	766	171	7,481	2,704	2,852	21,465
1964	1,328	340	5,702	360	679	925	179	7,374	2,654	2,300	21,842
1965	1,003	312	4,962	384	248	926	189	7,709	2,835	1,241	19,809
1966	974	198	5,695	441	118	1,167	196	7,953	2,977	1,459	21,177
1967	1,066	131	3,394	574	859	1,585	175	8,104	3,092	1,231	20,211
1968	1,221	65	4,113	697	815	1,689	192	8,585	3,540	1,509	22,427
1969	1,189	38	4,641	806	657	1,690	196	8,737	3,739	1,556	23,250
1970	1,347	43	4,827	649	376	1,326	200	9,262	3,372	1,268	22,670
1971	1,337	42	5,715	767	362	1,402	188	9,494	3,356	1,262	23,926
1972	1,489	94	6,206	762	383	1,705	201	10,137	3,864	1,469	26,308
1973	1,397	110	6,989	757	405	1,503	219	10,883	4,018	1,765	28,048
1974	1,222	105	7,840	780	174	1,466	210	10,550	3,708	2,262	28,316
1975	924	79	7,586	818	122	1,370	208	10,630	3,772	2,178	27,687
1976	1,283	94	8,411	753	79	1,421	231	11,605	3,440	2,525	29,843
1977	1,133	92	8,258	772	93	1,368	247	11,100	3,700	2,506	29,270
1978	942	87	8,232	699	95	1,662	266	12,809	3,705	2,502	30,999
1979	1,054	122	9,037	907	17	1,094	278	11,162	3,424	5,773	32,869
1980	1,020	159	7,509	920	0	1,806	247	10,416	3,159	4,025	29,262
1981	1,035	177	6,469	800	26	1,027	237	10,797	2,623	2,494	25,686
1982	884	92	5,828	625	0	1,446	216	10,429	2,398	1,608	23,525
1983	1,130	102	8,863	652	18	1,497	227	10,525	2,328	1,306	26,648
1984	1,215	77	8,161	642	8	1,032	242	10,451	2,639	798	25,277
1985	1,463	91	10,444	678	10	1,576	225	10,188	2,512	133	27,320
1986	1,989	105	6,621	867	22	1,505	220	10,158	2,507	47	24,041
1987	1,642	82	6,223	718	8	1,716	249	10,258	3,236	23	24,156
1988	1,473	107	6,078	809	4	1,515	240	10,441	3,624	221	24,513
1989	1,749	95	7,336	750	3	1,608	246	10,310	3,615	180	25,893
1990	1,487	111	7,280	708	8	1,740	253	10,328	3,659	218	25,792
1991	1,350	108	7,220	615	3	1,053	227	10,360	3,203	145	24,284
1992	1,309	75	6,836	864	1	1,018	231	10,727	4,007	88	25,156
1993	1,707	64	7,315	901	8	2,200	235	10,999	3,157	680	27,267
1994	1,964	75	7,381	855	7	1,055	246	11,097	3,594	369	26,643
1995	1,293	78	8,049	1,052	1	918	242	11,328	4,811	236	28,008
1996	1,702	99	8,070	999	1	1,618	235	11,753	5,376	181	30,032
1997	1,448	71	9,037	792	2	277	248	11,480	5,013	162	28,529
1998	1,594	102	7,863	797	3	271	259	11,596	5,739	106	28,331
1999	2,625	121	7,921	836	2	527	262	11,768	6,530	20	30,614
2000	2,151	134	8,069	747	1	1,324	258	11,559	5,466	1	29,709
2001	903	109	8,476	756	12	1,400	237	11,640	4,953	2	28,488
2002	1,040	115	8,145	768	10	1,502	234	11,871	5,554	39	29,278
2003	319	101	7,721	832	8	2,151	216	11,846	5,365	6	28,566
2004	929	42	9,988	1,008	6	2,384	219	11,991	5,577	42	32,187
2005	730	47	11,465	1,112	9	2,455	218	11,770	5,613	106	33,527
2006	1,486	87	12,232	1,045	1	2,500	212	11,960	5,953	125	35,601

1 In Montana "Other Petroleum Products" are primarily still gas used as refinery fuel and petroleum coke used in electrical generation.

NOTE: DOE models provide the best consumption estimates publicly available; however, in some cases these estimates are disaggregated from national data. The continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_use/notes/use_petrol.pdf).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2006 (http://www.eia.doe.gov/emeu/states/sep_use/total/csv/use_mt.csv).

Table P7. Residential Petroleum Product Consumption Estimates, 1960-2006 (thousand barrels)

Year	Distillate Fuel	LPG[1]
1960	262	506
1961	335	616
1962	335	560
1963	328	499
1964	312	655
1965	277	636
1966	286	758
1967	196	994
1968	250	1,068
1969	289	1,072
1970	249	887
1971	397	905
1972	436	1,094
1973	495	965
1974	542	1,026
1975	589	973
1976	646	993
1977	616	993
1978	657	1,276
1979	675	606
1980	421	829
1981	273	503
1982	352	736
1983	449	901
1984	380	428
1985	309	604
1986	325	641
1987	220	709
1988	213	715
1989	345	831
1990	291	813
1991	287	703
1992	180	598
1993	234	548
1994	159	541
1995	218	473
1996	325	519
1997	685	152
1998	404	86
1999	225	342
2000	170	922
2001	170	940
2002	122	963
2003	190	1,637
2004	187	1,865
2005	169	1,824
2006	196	1,791

[1] DOE has numerous caveats on its allocation of liquified petroleum gas (LPG) consumption to the various sectors.

NOTE: This table excludes a small amount of kerosene consumption, which could not be estimated accurately by DOE models.

NOTE: DOE models provide the best consumption estimates publicly available; however, in some cases these estimates are disaggregated from national data. The continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_use/notes/use_petrol.pdf).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2006 (http://www.eia.doe.gov/emeu/states/sep_use/total/csv/use_mt.csv).

Table P8. Commercial Petroleum Product Consumption Estimates, 1960-2006 (thousand barrels)

Year	Distillate Fuel	LPG[1]	Motor Gasoline[2]	Residual Fuel
1960	297	89	135	2
1961	380	109	146	3
1962	380	99	121	4
1963	372	88	141	4
1964	354	116	127	3
1965	315	112	144	1
1966	324	134	123	1
1967	223	175	135	1
1968	284	188	133	1
1969	329	189	107	1
1970	283	157	220	1
1971	451	160	127	1
1972	496	193	168	1
1973	562	170	136	1
1974	616	181	125	2
1975	668	172	174	2
1976	734	175	163	3
1977	699	175	157	3
1978	746	225	167	4
1979	766	107	179	11
1980	346	146	92	7
1981	380	89	110	0
1982	183	130	127	5
1983	1,104	159	76	172
1984	935	75	61	105
1985	772	107	72	126
1986	373	113	76	37
1987	272	125	80	13
1988	181	126	76	9
1989	192	147	77	13
1990	154	143	84	11
1991	164	124	63	3
1992	140	106	55	4
1993	170	97	12	5
1994	159	95	15	3
1995	102	83	13	3
1996	229	92	19	2
1997	162	27	12	1
1998	114	15	14	1
1999	142	60	14	2
2000	143	163	14	1
2001	197	166	14	0
2002	137	170	15	0
2003	167	289	15	1
2004	294	329	15	0
2005	163	322	15	0
2006	215	316	16	0

[1] DOE has numerous caveats on its allocation of liquified petroleum gas (LPG) consumption to the various sectors.
[2] Includes miscellaneous (including unclassified) and public nonhighway sales of motor gasoline.

NOTE: DOE models provide the best consumption estimates publicly available; however, in some cases these estimates are disaggregated from national data. The continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_use/notes/use_petrol.pdf).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2006 (http://www.eia.doe.gov/emeu/states/sep_use/total/csv/use_mt.csv).

Table P9. Industrial Petroleum Product Consumption Estimates, 1960-2006 (thousand barrels)

Year	Distillate Fuel[1]	LPG[2]	Lubricants	Motor Gasoline[3]	Residual Fuel[4]
1960	1,500	112	23	816	1,684
1961	1,841	104	23	923	1,960
1962	2,159	125	30	685	2,575
1963	2,174	145	30	796	2,438
1964	2,331	128	31	746	1,986
1965	1,693	164	41	887	914
1966	2,123	254	43	681	980
1967	1,033	356	40	791	882
1968	1,222	359	44	745	1,242
1969	1,373	361	45	476	1,212
1970	1,274	246	46	635	1,123
1971	1,750	282	43	570	1,174
1972	1,863	339	46	702	1,390
1973	2,073	302	60	568	1,577
1974	2,413	206	58	503	2,126
1975	2,494	174	46	774	1,963
1976	2,926	202	51	774	2,303
1977	2,890	162	51	703	2,176
1978	2,375	115	55	578	2,270
1979	2,787	364	57	663	5,609
1980	1,925	786	51	619	4,018
1981	1,943	382	49	663	2,494
1982	1,396	551	45	632	1,603
1983	3,173	383	47	509	1,132
1984	2,686	461	50	558	692
1985	5,192	814	46	677	7
1986	1,968	696	45	637	10
1987	1,607	844	51	574	10
1988	1,473	626	50	575	212
1989	2,623	578	51	631	168
1990	2,778	717	52	615	207
1991	2,868	178	47	611	142
1992	2,141	279	48	572	85
1993	2,404	1,513	49	567	675
1994	1,917	360	51	603	365
1995	2,283	333	50	646	233
1996	2,569	991	48	663	178
1997	2,422	90	51	686	161
1998	1,955	108	54	437	106
1999	1,982	112	54	420	18
2000	1,904	227	53	406	0
2001	1,907	275	49	546	2
2002	1,842	358	48	566	39
2003	2,433	213	45	585	6
2004	3,237	164	45	681	42
2005	3,519	287	45	638	106
2006	3,673	375	44	694	95

1 Includes deliveries for industrial use (including industrial space heating and farm use), oil company use, off-highway use, and "other" uses Does not include use at electric utilities.

2 DOE has numerous caveats on its allocation of liquified petroleum gas (LPG) consumption to the various sectors.

3 Includes sales for agricultural use, construction use, and industrial and commercial use.

4 Includes industrial use, oil company use, and "other" uses.

NOTE: This table does not show the categories "asphalt and road oil" and "other petroleum products," which are consumed solely in the industrial sector and already are reported in Table P6. It also does not include kerosene, since the consumption has been minimal in recent years.

NOTE: DOE models provide the best consumption estimates publicly available; however, in some cases these estimates are disaggregated from nationa data. The continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_use/notes/use_petrol.pdf).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2006 (http://www.eia.doe.gov/emeu/states/sep_use/total/csv/use_mt.csv).

Table P10. Transportation Petroleum Product Consumption Estimates, 1960-2006 (thousand barrels)

Year	Aviation Gasoline[1]	Distillate Fuel[2]	Jet Fuel[3]	LPG[4]	Lubricants	Motor Gasoline[5]	Residual Fuel[6]
1960	1,006	2,839	265	29	137	5,972	377
1961	1,427	2,721	280	31	134	5,910	617
1962	473	2,675	311	35	141	6,747	471
1963	499	2,520	340	34	141	6,544	410
1964	340	2,705	360	26	148	6,501	307
1965	312	2,676	384	13	148	6,678	325
1966	198	2,961	441	21	153	7,148	396
1967	131	1,941	574	60	135	7,178	342
1968	65	2,356	697	73	148	7,708	243
1969	38	2,649	806	68	151	8,155	238
1970	43	3,020	649	36	154	8,407	119
1971	42	3,116	767	56	145	8,797	87
1972	94	3,408	762	78	155	9,267	63
1973	110	3,834	757	65	159	10,179	44
1974	105	4,266	780	53	152	9,922	122
1975	79	3,835	818	50	162	9,682	160
1976	94	4,101	753	50	180	10,668	141
1977	92	4,049	772	37	196	10,240	136
1978	87	4,451	699	46	211	12,064	134
1979	122	4,791	907	18	220	10,320	24
1980	159	4,759	920	45	196	9,705	0
1981	177	3,834	800	52	188	10,024	0
1982	92	3,866	625	29	172	9,671	0
1983	102	4,106	652	54	180	9,940	3
1984	77	4,082	642	69	192	9,831	2
1985	91	4,132	678	51	179	9,439	*
1986	105	3,930	867	55	175	9,445	0
1987	82	4,080	718	39	197	9,604	0
1988	107	4,149	809	48	190	9,789	0
1989	95	4,115	750	53	195	9,602	0
1990	111	3,993	708	67	201	9,630	0
1991	108	3,856	615	48	180	9,687	0
1992	75	4,339	864	35	183	10,100	0
1993	64	4,457	901	43	187	10,421	0
1994	75	5,100	855	58	195	10,479	0
1995	78	5,390	1,052	28	192	10,669	0
1996	99	4,886	999	16	186	11,070	0
1997	71	5,718	792	8	197	10,782	0
1998	102	5,350	797	62	206	11,145	0
1999	121	5,536	836	12	208	11,334	0
2000	134	5,812	747	11	205	11,139	0
2001	109	6,200	756	20	188	11,079	0
2002	115	6,018	768	11	185	11,290	0
2003	101	4,903	832	12	171	11,246	0
2004	42	6,237	1,008	26	174	11,295	0
2005	47	7,597	1,112	22	173	11,117	0
2006	87	8,122	1,045	18	168	11,251	30

* Less than 0.5.

1 Includes military and non-military use.

2 Includes deliveries for military use, railroad use and highway use.

3 Non-military use only of kerosene-type jet fuel.

4 DOE has numerous caveats on its allocation of liquified petroleum gas (LPG) consumption to the various sectors.

5 This table does not cover all uses of gasoline included in "Highway Use of Motor Fuel" in Table P11

6 Includes military use and railroad use.

NOTE: DOE models provide the best consumption estimates publicly available; however, in some cases these estimates are disaggregated from national data. The continuity of these data series estimates may be affected by changing data sources and estimation methodologies, which may account for some of the more dramatic year-to-year variation in consumption levels. See the "Additional Notes" under each type of energy in Technical Notes (http://www.eia.doe.gov/emeu/states/sep_use/notes/use_petrol.pdf).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data Consumption* tables (formerly *State Energy Data Report*), 1960-2006 (http://www.eia.doe.gov/emeu/states/sep_use/total/csv/use_mt.csv).

Table P11. Motor Fuel Use, 1960-2006 (thousand gallons)

Year	Highway Use of Motor Fuel: Gasoline	Highway Use of Motor Fuel: Diesel	Highway Use of Motor Fuel: Subtotal	Nonhighway Use of Motor Fuel (gasoline)	Losses Due to Evaporation, Handling, etc.	TOTAL Consumption of Motor Fuel
1960	242,430	27,216	269,646	69,974	3,150	342,770
1961	240,490	31,255	271,745	89,218	3,360	364,323
1962	274,043	30,311	304,354	41,413	3,654	349,421
1963	267,671	33,447	301,118	46,958	3,738	351,814
1964	273,144	35,294	308,438	42,657	3,612	354,707
1965	280,705	38,879	319,584	48,872	3,906	372,362
1966	269,659	43,253	312,912	40,736	3,780	357,428
1967	300,192	40,668	340,860	44,078	3,990	388,928
1968	321,429	45,756	367,185	40,607	4,032	411,824
1969	342,954	49,868	392,822	27,902	4,074	424,798
1970	352,654	58,136	410,790	39,654	4,242	454,686
1971	372,174	61,295	433,469	33,345	4,242	471,056
1972	394,482	69,145	463,627	42,185	4,368	510,180
1973	432,272	76,954	509,226	35,933	4,662	549,821
1974	412,004	72,955	484,959	31,842	4,452	521,253
1975	404,957	72,682	477,639	45,256	4,494	527,389
1976	449,092	87,051	536,143	46,148	4,998	587,289
1977	431,617	89,381	520,998	42,667	4,452	568,117
1978	511,119	100,375	611,494	38,123	5,208	654,825
1979	443,580	103,756	547,336	44,112	5,250	596,698
1980	416,511	98,615	515,126	40,788	4,662	560,576
1981	423,780	108,849	532,629	44,001	4,704	581,334
1982	406,462	110,864	517,326	40,371	4,410	562,107
1983	418,919	105,234	524,153	33,306	4,494	561,953
1984	416,324	117,012	533,336	34,828	-	568,164
1985	403,929	109,043	512,972	37,675	-	550,647
1986	404,386	107,192	511,578	36,006	-	547,584
1987	407,673	108,341	516,014	33,187	-	549,201
1988	412,126	117,389	529,515	33,710	-	563,225
1989	408,306	120,917	529,223	35,714	-	564,937
1990	410,718	125,346	536,064	36,646	-	572,710
1991	409,896	116,176	526,072	36,365	-	562,437
1992	432,413	133,926	566,339	32,650	-	598,989
1993	441,553	139,443	580,996	29,807	-	610,803
1994	444,618	156,703	601,321	32,358	-	633,679
1995	447,134	159,632	606,766	34,258	-	641,024
1996	466,331	146,177	612,508	36,169	-	648,677
1997	454,226	175,736	629,962	35,250	-	665,212
1998	469,369	172,711	642,080	26,862	-	668,942
1999	480,754	185,212	665,966	26,486	-	692,452
2000	469,683	190,450	660,133	26,394	-	686,527
2001	467,567	198,232	665,799	32,041	-	697,840
2002	476,027	202,477	678,504	33,151	-	711,655
2003	476,160	210,712	686,872	33,451	-	720,323
2004	474,580	223,636	698,216	31,564	-	729,780
2005	460,947	246,433	707,380	32,999	-	740,379
2006	460,703	259,569	720,272	37,640	-	757,912

NOTE: Motor fuel is defined by the US Department of Transportation as all gasoline covered by state motor fuel tax laws plus diesel fuel and LPG used in the propulsion of motor vehicles. (The Montana data do not include any LPG.) Gasohol is included with gasoline. Military use of motor fuel and aviation jet fuel use are excluded from DOT data. Figures for highway use of fuels may be understated because of refunds given on fuel for nonhighway use such as agriculture. Data have been adjusted to make them comparable to data from other states.

NOTE: Starting in 1984, losses due to evaporation and handling are no longer calculated by FHWA. Total consumption of motor fuel from 1984-2006, therefore, does not include this figure. To compare the total for these years to the total for the previous years, the losses should be subtracted from the 1960-83 total consumption column.

SOURCE: U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics* , annual reports, Table MF-21, 1960-2006.

Table P12a. Monthly Deliveries of Gasoline 1998-2008 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL (1,000 gal.)
1998	1,076	1,122	1,201	1,273	1,354	1,496	1,753	1,633	1,443	1,321	1,232	1,224	1,346
1999	1,071	1,148	1,317	1,235	1,343	1,533	1,735	1,654	1,473	1,326	1,330	1,326	1,376
2000	1,029	1,184	1,231	1,200	1,419	1,559	1,647	1,632	1,383	1,328	1,272	1,192	1,340
2001	1,115	1,162	1,212	1,293	1,385	1,452	1,665	1,693	1,372	1,363	1,293	1,230	1,354
2002	1,145	1,193	1,239	1,254	1,416	1,516	1,752	1,690	1,475	1,405	1,300	1,242	1,387
2003	1,171	1,183	1,130	1,251	1,436	1,570	1,754	1,666	1,418	1,500	1,179	1,246	1,377
2004	1,164	1,188	1,277	1,322	1,324	1,527	1,815	1,616	1,469	1,360	1,312	1,142	1,377
2005	1,139	1,205	1,251	1,253	1,282	1,543	1,669	1,663	1,366	1,258	1,271	1,253	1,347
2006	1,135	1,198	1,225	1,298	1,377	1,548	1,677	1,545	1,378	1,370	1,340	1,223	1,360
2007	1,167	1,231	1,253	1,267	1,370	1,522	1,680	1,611	1,401	1,394	1,304	1,183	1,366
2008	1,152	1,198	1,209	1,233	1,343	1,412							
avg.	1,124	1,183	1,231	1,262	1,368	1,516	1,715	1,640	1,418	1,362	1,283	1,226	1,363

[1]These data are from motor fuel tax collections and are supposed to cover all gasoline delivered for any purpose in Montana. The volumes come from distributors' bills of lading and therefore do not correlate exactly with consumption; this may explain some of the extremes in month to month variation. These are actual, unadjusted data, different from the data in P11, which come from the FHWA and were manipulated so data from all states would be comparable.

Source: Montana Department of Transportation motor fuel tax data base, December 2008

Table 12b. Monthly Deliveries of On-Road Diesel 1998-2008 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL (1,000 gal.)
1998	441	365	429	515	451	493	560	552	529	574	416	364	475
1999	456	426	500	554	519	526	577	619	580	597	541	496	533
2000	469	478	492	555	532	480	596	621	580	612	544	448	534
2001	522	495	413	564	601	633	667	627	552	662	514	475	561
2002	528	462	473	502	485	543	699	654	616	661	540	458	553
2003	575	446	430	570	526	599	741	677	599	715	580	504	581
2004	560	502	539	629	560	606	761	685	670	755	509	577	613
2005	589	656	617	660	640	638	771	763	653	775	725	622	676
2006	678	618	617	701	754	794	820	807	727	779	733	616	721
2007	654	667	674	623	689	774	867	848	750	840	748	580	727
2008	629	707	619	676	727	721							
avg.	555	529	528	595	589	619	706	685	626	697	585	514	597

[1]These data are from motor fuel tax collections and are supposed to cover all undyed diesel, excluding railroad use. Undyed diesel is for on-road use. The volumes come from distributors' bills of lading and therefore do not correlate exactly with consumption; this may explain some of the extremes in month to month variation. These are actual, unadjusted data, different from the data in P11, which come from the FHWA and were manipulated so data from all states would be comparable.

Source: Montana Department of Transportation motor fuel tax data base, December 2008.

Table 12c. Monthly Deliveries of Off-Road Diesel 2003-2008 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL (1,000 gal.)
2003	253	257	210	271	296	296	327	319	271	288	253	245	274
2004	279	297	333	346	274	314	354	409	386	305	389	306	332
2005	277	318	366	305	280	312	372	428	368	271	283	311	324
2006	314	285	306	339	325	320	386	344	259	316	323	275	316
2007	313	367	329	501	301	310	368	379	308	292	277	243	332
2008	281	313	323	213	339	246							
avg.	286	306	311	329	302	300	361	376	318	294	305	276	316

[1]These data are from motor fuel tax collections and are supposed to cover all dyed diesel, excluding railroad use. Dyed diesel is for off-road use, such as in agriculture or heavy construction. The volumes come from distributors' bills of lading and therefore do not correlate exactly with consumption; this may explain some of the extremes in month to month variation.

Source: Montana Department of Transportation motor fuel tax data base, December 2008.

Table 12d. Monthly Deliveries of Railroad Diesel 2003-2008 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL (1,000 gal.)
2003	319	198	415	259	390	287	298	280	310	402	296	265	311
2004	335	309	301	373	332	312	335	307	324	225	315	263	311
2005	278	269	364	317	310	339	217	259	309	261	235	258	285
2006	256	280	267	248	289	222	271	272	263	187	225	182	247
2007	314	386	309	348	401	376	341	364	331	353	379	356	355
2008	612	359	308	690	357	362							
avg.	352	300	327	372	346	316	292	296	307	286	290	265	302

[1]These data are from motor fuel tax collections and are supposed to cover all railroad use. The volumes come from distributors' bills of lading and therefor do not correlate exactly with consumption; this may explain some of the extremes in month to month variation.

Source: Montana Department of Transportation motor fuel tax data base, December 2008.

Table P13. Average Retail Price of Gasoline, 1990-2008 (cents/gallon)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1990	110.2	108.7	109.5	110.4	111.9	113.2	113.6	131.0	139.2	145.1	143.8	140.5
1991	133.2	127.0	115.3	115.1	118.2	119.9	119.5	119.5	120.0	119.3	118.8	115.9
1992	110.4	106.0	108.1	111.5	119.6	128.1	132.1	131.9	130.0	128.2	126.4	122.0
1993	115.7	112.2	113.0	115.6	120.6	122.8	125.4	125.3	127.0	129.1	128.9	124.7
1994	117.3	115.4	115.0	116.9	125.2	129.3	133.8	134.0	134.9	133.1	130.5	128.1
1995	123.4	122.8	121.0	123.7	130.2	129.8	127.8	126.5	128.1	127.8	124.6	122.9
1996	122.5	126.1	131.6	140.9	141.9	140.4	138.5		142.9	142.9	140.7	139.3
1997	139.2	138.1	138.9	138.3	138.2	137.4	136.5	137.7	138.5	139.7	138.2	133.8
1998	129.9	125.3	122.1	122.9	122.7	122.1	122.6	122.3	122.2	119.8	115.6	107.5
1999	101.0	100.2	105.2		130.9	131.1	137.6	139.6	141.5	139.8	142.5	
2000	140.3	147.8	162.0	160.3	159.7	160.2	160.4	160.4	164.3	173.5	169.7	167.0
2001	151.9	151.3	148.0	155.6	170.1	162.0	154.8	158.5	158.4	148.3	129.7	120.0
2002		122.6	138.1		148.4	148.7	149.3	148.4	146.4	145.7	146.8	143.2
2003	150.5	165.6	169.1	161.4	158.1	157.0	161.8	168.1	168.2	159.4	158.1	153.8
2004	155.2	160.0	169.4	182.2	199.1	196.8	198.4	198.7	196.6	200.3	200.0	191.8
2005	189.9	191.2	208.5	224.0	225.4	222.9	228.9	244.3	281.4	269.1	224.2	211.2
2006	217.1	220.6	228.0	248.2	270.9	275.5	287.0	308.1	276.9	239.8	228.3	231.5
2007	215.6	211.3	241.3	283.1	308.5	309.6	302.5	294.9	291.6	292.4	311.5	306.8
2008	295.4	302.8	315.8	339.0	365.8	397.6	410.6	394.5	373.8			
Average[2]	142.5	141.7	146.9	156.8	161.0	161.4	162.8	167.6	167.1	164.0	159.9	156.4
Median[2]	133.2	126.5	134.8	139.6	140.0	138.9	138.0	139.6	142.2	144.0	141.6	139.3

[1]State-wide average price of sales to end users through retail outlets, in nominal dollars.

[2]Excludes 2008 data.

Source: U.S. Department of Energy, Energy Information Agency, Energy Information Administration, Forms EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report" and EIA-782B, "Resellers'/Retailers' Monthly Petroleum Product Sales Report," http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_c_SMT_EPM0_cpgal_m.htm as of December 2008.

Table P14. Estimated Price of Motor Fuel and Motor Fuel Taxes, 1970-2008[1]

YEAR	Motor Gasoline ($/gallon)	State Tax (¢/gallon)	Date Changed	Federal Tax (¢/gallon)	Date Changed	Diesel ($/gallon)	State Tax (¢/gallon)	Date Changed	Federal Tax (¢/gallon)	Date Changed	Gasohol State Tax (¢/gallon)	Date Changed	Gasohol Fed. Tax (¢/gallon)[2]	Date Changed
1970	0.36	7		4		0.21	9		4					
1971	0.37	7		4		0.22	9		4					
1972	0.35	7		4		0.22	9		4					
1973	0.40	7		4		0.25	9		4					
1974	0.54	7		4		0.40	9		4					
1975	0.60	7.75	June 1	4		0.41	9.75	June 1	4					
1976	0.61	7.75		4		0.43	9.75		4					
1977	0.66	8	July 1	4		0.48	10	July 1	4					
1978	0.69	8		4		0.50	10		4					
1979	0.88	9	July 1	4		0.71	11	July 1	4		2	April 1	0	Jan. 1
1980	1.07	9		4		1.03	11		4		2		0	
1981	1.31	9		4		1.20	11		4		2		0	
1982	1.30	9		4		1.17	11		4		2		0	
1983	1.15	15	July 1	9	April 1	0.99	17	July 1	9	April 1	15	July 1	4	Apr. 1
1984	1.17	15		9		1.00	17		15	Aug. 1	15		4	
1985	1.16	15		9		0.94	17		15		15		3	Jan. 1
1986	0.90	17	Aug. 1	9		0.95	17		15		17	Aug. 1	3	
1987	0.97	20	July 1	9.1	Jan. 1	0.98	20	July 1	15.1	Jan. 1	20	July 1	3.1	Jan. 1
1988	1.10	20		9.1		1.01	20		15.1		20		3.1	
1989	1.22	21	July 1	9.1		1.13	20		15.1		20	July 1	3.1	
1990	1.16	21		14.1	Dec. 1	1.27	20		20.1	Dec. 1	20		8.7[3]	Dec. 1
1991	1.21	20.75	July 1	14.1		1.24	20		20.1		20.75	July 1	8.7[3]	
1992	1.18	21.75	July 1	14.1		1.23	21.8	July 1	20.1		21.75	July 1	8.7[3]	
1993	1.21	24.75	July 1	18.4	Oct. 1	1.25	24.8	July 1	24.4	Oct. 1	24.75	July 1	13[3]	Oct. 1
1994	1.25	27.75	July 1	18.4		1.25	28.5	July 1	24.4		27.75	July 1	13[3]	
1995	1.27	27.75		18.4		1.26	28.5		24.4		27.75		13[3]	
1996	1.38	27.75		18.3	Jan. 1	1.41	28.5		24.3	Jan. 1	27.75		12.9[3]	Jan. 1
1997	1.38	27.75		18.4	Oct. 1	1.21	28.5		24.4	Oct. 1	27.75		13[3]	Oct. 1
1998	1.21	27.75		18.4		1.32	28.5		24.4		27.75		13[3]	
1999	1.31	27.75		18.4		1.30	28.5		24.4		27.75		13[3]	
2000	1.60	27.75		18.4		1.64	28.5		24.4		27.75		13[3]	
2001	1.52	27.75		18.4		1.50	28.5		24.4		27.75		13.1[3]	Jan. 1
2002	1.41	27.75		18.4		1.39	28.5		24.4		27.75		13.1[3]	
2003	1.61	27.75		18.4		1.58	28.5		24.4		27.75		13.1[3]	Jan. 1
2004	1.88	27.75		18.4		1.91	28.5		24.4		27.75		13.1[3]	
2005	2.28	27.75		18.4		2.49	28.5		24.4		23.7	April 28	18.4	Jan. 1
2006	2.56	27.75		18.4		2.79	28.5		24.4		23.7		18.4	
2007	2.83	27.75		18.4		NA	28.5		24.4		23.7		18.4	
2008	NA	27.75		18.4		NA	28.5		24.4		23.7		18.4	

[1] Starting in 1989, a petroleum storage tank cleanup fee was levied on each gallon of fuel sold, at the rate of 1 cent for each gallon of gasoline (and ethanol blended with gasoline) distributed from July 1, 1989, through June 30, 1991 and 0.75 cent thereafter. The fee for diesel was 0.75 cent for each gallon distributed from July 1, 1993.

[2] Gasohol was not defined in federal tax law until 1979. Products later defined as gasohol (10 percent ethanol by volume) were taxable as gasoline prior to 1979. From 1979 to 1983, gasohol was exempt from gasolin tax.

[3] Blends using methanol, and amounts of ethanol between 5.7 and 10 percent, were taxed at lower rates.

NOTES: Price is average of all grades, in nominal dollars, including state and federal fuel taxes and petroleum storage tank cleanup fees. All prices except 1984-2007 gasoline prices are derived from the *State Energy Price and Expenditure Report*, which reports prices in $/million Btu. The source database for gasoline prices 1984-2007 omits all fuel taxes; therefore, DEQ added those taxes into the figures presented here. The source document omits federal diesel fuel tax from 1970-82; therefore, the federal tax has been added and is included in the 1970-82 diesel prices listed above. See *State Energy Data 2006 Price and Expenditure Data* for information on changes over time in the data sources and in the estimation methods used. In particular, note that diesel prices from 1984 forward are estimated as the ratio of the PAD IV diesel fuel price to the PAD IV motor gasoline price times the State motor gasoline price, plus federal and state per gallon taxes. PAD IV includes Colorado, Idaho, Montana, Utah and Wyoming.

SOURCES: Gasoline prices for 1984-2007 are from U.S. Department of Energy, Energy Information Administration, *Petroleum Marketing Annual,* Refiner/Reseller Motor Gasoline Prices by Grade, Sales to End Users Through Company Outlets, annual reports, 1985-2007(EIA-0487)(http://tonto.eia.doe.gov/dnav/pet/hist/d100640302a.htm). All other fuel prices are from U.S. Department of Energy, Energy Information Administration, *State Energy Data 2006 Price and Expenditure Data* (formerly, *State Energy Price and Expenditure Report*, annual reports 1970-2006 (EIA-0376)(http://www.eia.doe.gov/emeu/states/sep_prices/total/csv/pr_mt.csv). Pre-1986 diesel fuel prices may include some non-highway diesel costs. Fuel tax rates are from U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics*, annual reports, Table MF-121T 1970-2007, with corrections as provided by Montana Department of Transportation.