UNDERSTANDING ENERGY IN MONTANA

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

DEQ Report updated for ETIC 2013-2014

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Photo courtesy of PPL Montana

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 (NWE), dramatic changes in the price of natural gas, hundred dollar barrels of oil, serious talk of new markets and new transmission lines for Montana, growth in renewable energy resources, and discussions of climate change and energy independence. The Environmental Quality Council first prepared this guide in 2002. It was revised again in 2004 and 2010. The Energy and Telecommunications Interim Committee (ETIC) in 2013 agreed to revise the document to provide the most up-to-date background information available to policymakers and citizens alike. For the 2013-2014 guide a new, Renewable Energy in Montana section has been added. Special thanks should be extended to the DEQ, particularly Jeff Blend and Garrett Martin, who were instrumental in the preparation of the information that provides the backbone of this document.

This guide focuses on historical and current patterns of energy supply and demand. It is divided into six 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 intertwined with the electricity industry. The fourth section covers the Montana coal industry, which fuels the generation of electricity, is an important export, and whose future is dependent upon changes in the electric industry and world markets. The fifth section addresses petroleum, the sector most directly affected by international events. The final section discusses renewable energy development in Montana and the potential for that sector to grow in the future.

The guide, with its focus on historical and current patterns, deals primarily with conventional energy resources. Energy efficiency and energy conservation are given brief treatment, simply because such limited data is available. Public agencies, private businesses, and individual citizens need to keep the issues of efficiency and conservation in mind as they review the conventional resources included in this document.

Comments on the data

Data for this guide comes from a variety of sources, which don't always agree. 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.

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).

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

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

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.

Commercial Sector: Energy consumed by service-providing facilities and business equipment. It includes federal, state, and local governments; other private and public organizations, such as religious, social, or fraternal groups; and institutional living quarters.

Industrial Sector: Energy consumed by facilities and equipment used for producing, processing, or assembling goods. It encompasses manufacturing, agriculture, forestry, fishing and hunting, mining, including oil and gas extraction, and construction.

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

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

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.

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.

Renewable Energy: Energy obtained from sources that are essentially sustainable (unlike, for example, the fossil fuels, of which there is a finite supply). Sources of renewable 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 guide are in short tons.

Coal

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 coal rank (anthracite, bituminous, subbituminous, and lignite) is determined by its heating value.

Anthracite: Hard and jet black with a high luster; it is the highest coal rank 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 to 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 (aMW): 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 that 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.

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

Net Electric Generation: 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.)

Hydroelectric Power Station: 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.

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.

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.

PURPA: Public Utility Regulatory Policies Act of 1978 -- the 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.

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 rated total transfer capacity.

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

Distribution: The process of using relatively small, low-voltage wires for delivering power from the transmission system to local electric substations and to electric consumers.

ERCOT: The Electric Reliability Council of Texas, a separate synchronous grid connected 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 or above 69 kilovolts (kV). 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, in roughly 1998-1999, to form an organization that would have taken over operation of the Northwest transmission system. The effort was revived and superseded by the Regional Transmission Organization discussions.

Loop Flow: A characteristic of mass power flows across the Western Interconnection in which seasonal flows go over different paths from what was contractually scheduled. For example, power 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 counterclockwise through the same sections of the grid.

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. 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: The process of using high-voltage electric wires for bulk movement of large volumes of power across relatively long distances. Compare with **Distribution**.

Unscheduled Flows: See **Inadvertent Flows**.

West of Hatwai Path: 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.

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 western part of Texas.

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 1 Mcf.

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

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.

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 cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

Aviation Fuel: All special grades of gasoline for use in aviation reciprocating engines, as given in ASTM Specification D910 and Military Specification. Aviation fuel 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.

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

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-type 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 to 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.

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 from either 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, natural gasoline and isopentane, plant condensate, unfractionated stream, liquefied petroleum gases, aviation gasoline, motor gasoline, naphtha-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, naphtha less than 400 degrees F end-point, other oils over 400 degrees 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.

Renewable Energy

Biomass Energy System: A system that derives energy from organic material such as forest, agricultural, or food byproducts, typically through combustion to generate heat or electricity.

Cellulosic Biofuels: Fuels generated from the conversion of lignocellulose, the primary structural material in most plants, into liquid fuels such as ethanol. Cellulosic biofuels can utilize residual agricultural products such as corn stover, wheat straw, and wood chips, as well as perennial grasses like switchgrass as their feedstock.

Geothermal Energy System: A system that utilizes the thermal energy stored in the Earth to generate electricity or to provide heating, cooling, or both.

Large Hydro: Definitions vary but customarily includes hydroelectric dams with a nameplate capacity greater than 30 MW. Large hydro is not typically defined as an eligible renewable resource for RPS programs. Montana's RPS defines capacity expansions installed after April 2013 at existing hydroelectric dams as an eligible renewable resource.

Micro Hydro: A hydroelectric project with a nameplate capacity less than 100 kW.

Net Metered: A billing mechanism that credits distributed electricity generators for the electricity they add to the local electricity grid. Customers are only billed for net electricity consumption; the amount of electricity consumed minus the amount of electricity generated.

Renewable Portfolio Standard (RPS): A regulatory mandate that requires electricity providers to meet a portion of their retail sales of electricity with generation from eligible renewable resources.

Small Hydro: Definitions vary but customarily includes projects that have an electricity capacity of 10 MW or less. Small hydro is typically defined as an eligible renewable resource for RPS programs. Montana's RPS defines an eligible small hydroelectric project as one that has a nameplate capacity of 10 MW or less and does not require a new water appropriation, diversion, or impoundment or 15 MW or less and is installed at an existing reservoir or irrigation system.

Solar Energy System: A system that harnesses the radiant light, heat, or both from the sun to generate electricity or provide thermal heat or cooling.

Solar Photovoltaic (PV): A method of generating electricity by converting solar radiation into direct current electricity. Solar PV systems utilize panels of solar cells that contain a photovoltaic material that will generate electricity when struck by rays of sunlight.

Wind Energy System: A system that converts the kinetic energy of the wind into rotational energy, typically in order to generate electricity.

Summary

Summary Points:

These points summarize by topic the guide prepared for the Energy and Telecommunications Interim Committee. They cover the status of electricity, natural gas, coal, petroleum, renewable energy, and the 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 Points:
Electricity Supply and Demand in Montana

- As of 2014, Montana generating plants have the capacity to produce about 6,300 MW of electricity in the summer with a total nameplate generation capacity of 6,460 MW.

- In 2012, Montana consumed an estimated 1,582 aMW or about 1,700 aMW assuming 8 percent line losses, and produced 3,411 aMW in 2011. The other half of Montana electricity production is mostly exported west to Washington and Oregon.

- PPL Montana-owned plants produce the largest amount of electricity in Montana. PPL Montana's facilities accounted for just under 30 percent of the total generation in Montana in the period 2006-2011. The company owns major hydroelectric facilities in the state and is in negotiations to sell those facilities to NorthWestern Energy (NWE). PPL Montana also owns 25 percent of the Colstrip generating facility.

- NWE is the largest utility in Montana and is regulated by the Montana Public Service Commission (PSC). It provides generation and transmission to a majority of customers in the western two-thirds of Montana, although many large industrial companies purchase electricity supply elsewhere.

- Montana generation is powered primarily by coal (60 percent of total for 2006-2011) and hydroelectricity (35 percent of total from 2006-2011). Over the last 15 years, about a quarter of Montana coal production has gone to generate electricity in Montana.

- Montanans are served by 31 distribution utilities: 2 investor-owned utilities, 25 rural electric cooperatives, 3 federal agencies, and 1 municipality. Two additional investor-owned utilities and four cooperatives are based in other states but serve a handful of Montanans. In 2011, investor-owned utilities were responsible for 49 percent of the electricity sales in Montana, cooperatives 29 percent, federal agencies 3 percent, and power marketers 19 percent.

- Electricity in Montana costs less than the national average. In 2011, the Montana electricity price averaged 8.23 cents/kWh compared to 9.9 cents/kWh nationally. This is about 1.7 cents/kWh below the national average. In 1997 before electricity deregulation, Montana's average price of 5.2 cents/kWh was also 1.7 cents below the national average of 6.85 cents/ kWh.

- To be economically viable, any addition to generation resources in Montana likely will need contracts in out-of-state markets or will need to displace existing resources for in-state consumption.

Summary Points:

Montana's Electric Transmission Grid

- There are three primary electric transmission paths that connect Montana to the rest of the Western Interconnect and larger markets in the West. These paths are: Montana to Northwest – Path 8, Montana-Idaho – Path 18, Montana Southeast – Path 80.

- Most of Montana is integrally tied into the Western Grid or Western Interconnection. The easternmost part of the state is part of the Eastern Interconnection and receives its power from generators located in that grid.

- Electricity prices are impacted by the cost of transmission service to move power from one area to another. For example, a generator in Montana who wishes to sell to the Mid-Columbia (Mid-C) market, the major electricity trading hub closest to Montana and located in Washington, pays transmission charges on the NWE system and then on either the BPA or Avista system.

- Transmission congestion prevents low-cost power from reaching the areas where it is most needed. Low-cost power has little value if it cannot be transmitted to a location where energy is needed. For example, because most existing Montana transmission is fully contracted, future generators in Montana may be prevented from selling their power into a number of wholesale markets except by using nonfirm rights.

- A large portion of the electric load in the U.S. is procured through market transactions overseen by various Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). These organizations are independent entities that emerged as a result of guidelines prescribed by the Federal Energy Regulatory Commission (FERC), which sought to introduce competition and efficiency into electricity markets.

- There has been a strong interest in developing additional transmission to export Montana's generation potential to other markets.

- In the last decade, a few rebuilds of existing lines have taken place, including a WAPA 115 kV line between Great Falls and Havre built to 230 kV specifications and the rebuild of BPA's 115 kV line from Libby to Troy.

- 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, problems involved in siting high-voltage transmission lines, and the California RPS.

<u>Summary Points:</u>
Natural Gas in Montana

- While Montana produces about as much natural gas as it consumes, most in-state production is exported, and the majority of Montana's consumption is from imports. In 2011, Montana produced 74.6 billion cubic feet (Bcf) of gas and consumed 78.2 Bcf.

- In 2012 the northern portion of Montana accounted for 69 percent of total in-state production, the northeastern portion 23 percent, and the southcentral portion 10 percent. In-state gas production had been increasing in recent years through 2007 and then saw sharp declines in the years since.

- The Rocky Mountain states are the most important domestic source of natural gas supply to the Pacific Northwest region, which includes Montana. Alberta is the other important source for the region.

- Recent Montana natural gas consumption has averaged 70-80 Bcf per year with 78.2 Bcf being consumed in 2011. Both residential and commercial gas consumption are slowly growing.

- Three distribution utilities and two transmission pipeline systems handle more than 99 percent of the natural gas consumed in Montana. NWE is the largest provider of natural gas in Montana, accounting for almost 60 percent of all regulated sales in the state according to annual reports from Montana utilities.

- In late 2013, natural gas prices remained low in the U.S., hovering around $3.50/MMBtu at the Henry Hub. Prices are edging higher due to increased natural gas demand and low prices that discourage additional drilling.

- The average monthly gas bill for a NWE residential customer went from $70.89 in 2002 to $128.83 in April 2006. In 2013, the monthly bill was about $90. The monthly gas bill for a Montana-Dakota Utilities customer went from $47.60 in January 2002 to $92.29 in April of 2006. It was about $69 in 2013.

- Natural gas production has greatly increased in Richland County bordering North Dakota. This has been from associated gas that is produced as a byproduct of oil production. Richland County is on the edge of the Bakken boom in North Dakota, and oil production, as well as associated gas production, has grown in the past few years, although not nearly as fast as in North Dakota.

<u>Summary Points:</u>
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 is eventually converted to electricity.

- Montana is the fifth largest producer of coal in the U.S., with 42 million tons mined in 2011. The majority of mining occurs in the Powder River Basin south and east of Billings.

- The price of Montana coal averaged $16.02 per ton at the mine in 2011 and $18.11 per ton in 2012, sharply up from 2007, and up from the previous 20 years where it steadily hovered around $10.00 per ton.

- Most coal in Montana is mined on federal land. A significant portion also comes from Indian reservation land and private land. In 2009, the last year this data was available, 24 million tons of Montana coal came from leased federal land and slightly less than 7 million from leased reservation land.

- There are currently six major coal mines in Montana operating in Big Horn, Musselshell, Richland, and Rosebud counties. Westmoreland Mining LLC controls three mines in Montana, accounting for more than 11 million tons of coal in 2012.

- Taxes on coal, despite decreases from historical highs, remain a major source of revenue for Montana, with $52.7 million collected in coal severance tax in state fiscal year 2012.

- While significant, Montana's coal output is dwarfed by Wyoming, which produced close to 40 percent of the country's coal in 2011. This is slightly more than 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.

- Coal remains the least expensive fossil fuel used to generate electricity, although not as significantly as in the past. When natural gas was near $2/dkt in early 2013, it was momentarily cheaper than coal. Increasingly, the use of coal-fired generation for electricity is also closely linked to potential federal activities and restraints on greenhouse gases. The impact of potential greenhouse gas regulations on the future price and viability of coal-fired generation is uncertain at this time.

- In the past few years various business interests (mining, transportation, ports) have proposed shipping coal from the Powder River Basin area in southeastern Montana and Wyoming to the west Coast. Several coal export terminals have been proposed on the coasts of Washington and Oregon, including one inland on the Columbia River. These terminals, if built, would ship coal overseas, mostly to Asia.

<u>Summary Points:</u>
Petroleum and Petroleum Products in Montana

- During the 2013 fiscal year, Montana produced about 28.8 million barrels of crude oil, worth more than $2.4 billion in gross value. In 2012 Montana's four petroleum refineries exported 47 percent of their refined liquid products to Washington, North Dakota, Wyoming, and additional points east and south.

- Montana's recent oil production boom peaked in 2006 when oil production in the state exceeded 36 million barrels. This was up from a recent historical low of 15 million barrels of oil produced during 1999.

- Beginning in 2014, the Williston Basin is expected to produce more than 1 million barrels of oil per day; however, Montana's Bakken oil production represents less than 10 percent of the recent oil production in the Bakken. Most of the focus of drilling in the Bakken has been in North Dakota, beginning in 2007 after Montana's Elm Coulee field production peaked.

- Three crude oil pipeline networks serve Montana's petroleum production regions. 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.

- Plans exist for additional crude oil pipelines to traverse eastern Montana to increase the crude oil transportation capacity out of both the Athabasca oil sands region of Canada and the Williston Basin region of North Dakota and Montana. Most notably, 280 miles of the proposed 1,980-mile Keystone XL pipeline would pass through northeastern Montana as part of its route from Hardisty, Alberta, to Steele City, Nebraska.

- Montana's four petroleum refineries have a combined refining capacity of 188,600 bbl/day: ExxonMobil (60,000 bbl/day) and Phillips 66 (59,000 bbl/day) in Billings, CHS (59,600 bbl/day) in Laurel, and Calumet Montana Refining (10,000 bbl/day) in Great Falls. Montana refineries typically refine 60-63 million barrels of crude oil a year.

- After peaking in 2007, Montana's consumption of petroleum products declined by more than 18 percent between 2007 and 2010 before growing once more in 2011. Montana's annual petroleum consumption initially peaked at 33 million barrels in 1979. It then drifted lower, settling in the mid-1980s at around 24 million bbl/year.

- In 2011, 97 percent of Montana motor gasoline consumption was for highway vehicle use, while most of the remaining 3 percent was consumed by nonhighway vehicles.

- At the end of fiscal year 2013, total oil and gas production tax collections were $206 million, $94 million of which went to the state's general fund.

<u>Summary Points:</u>
Renewable Energy in Montana

- Beginning with the Black Eagle Dam in 1890, Montana has, for over a century, utilized renewable energy to power its major industries and later its homes and businesses.

- In 2005 two events jumpstarted the development of renewable electricity generation in Montana. First, the Montana Legislature passed a Renewable Portfolio Standard (RPS), mandating that regulated utilities and electricity suppliers meet 15 percent of their retail electricity sales with renewable energy by 2015 with intermediate requirements in 2008 and in 2010. Second, Invenergy completed the construction of the 135 MW Judith Gap wind farm in central Montana.

- Altogether the 665 MW of new renewable electricity generation facilities generated more than 2 million MWh in 2013, which is equal to 14 percent of Montana's retail electricity sales and 7 percent of the state's total electricity generation.

- The state’s current 645 MW of installed wind energy capacity represents less than a tenth of one percent of the state’s total wind energy potential. Developing just 1 percent of the states wind energy potential (9,440 MW) would generate more than twice the electricity consumed by Montana annually.

- Because Montana's electricity providers are already contracted to buy most of the renewable electricity they need to meet their 2015 renewable electricity requirements, the main market for new, large renewable electricity generation projects is likely to be out-of-state.

- Energy consumers also utilize renewable energy to provide direct heating and cooling of residential, commercial, community and government buildings. There are currently nine wood manufacturers, nine schools, two hospitals, two state buildings, and one university campus that generate space heat and domestic hot water with woody biomass.

- Between 2006 and 2012, 1,500 Montana homes and small businesses reported installing geothermal energy systems and claiming the applicable state tax credit for doing so. In addition, more than 40 facilities in Montana, including pools, spas, and greenhouses, utilize hot water and steam from the state’s many natural hot springs.

- Active and passive solar energy are also increasingly common in Montana. Active solar heating systems have typically been used to provide heat for domestic hot water systems as well as for hydronic heating systems with Montana commonly seeing more than 100 solar thermal systems installed annually.

Electricity Supply and Demand in Montana

Montana's electricity supply, or total electric generation, continues to develop, with new natural gas and wind generation coming online in recent years. However, electricity demand in Montana declined in recent years, due to a higher penetration of energy efficiency and to the exit of a number of large, industrial customers.

As Montana's electricity sector evolves, electricity supply and demand in the state is also increasingly influenced by complex world markets. In recent years, the deregulation of wholesale electricity markets through the federal Energy Policy Act of 1992 and the legislatively driven deregulation of Montana's retail market (Chapter 505, Laws of 1997) have largely been turned back.

NorthWestern Energy (NWE), Montana's dominant electric utility serving about 340,000 Montana electric customers, emerged from bankruptcy in late 2004. In late 2013, NWE announced plans to buy back the 11 in-state dams currently owned by PPL Montana and owned by the Montana Power Company (MPC) prior to that. NWE continues to transition into a vertically integrated utility, owning more generation to meet its customers' needs.

The first new electric generation in Montana in recent years came online in 2003. Additional plants followed, including a number of wind farms. By 2011 wind generation supplied about 4.2 percent of the state's net electricity generation. In addition, Montana is home to a portion of the Bakken shale development, one of the largest accumulations of crude oil in the country. In 2011 Montana was the sixth largest coal producing state, supplying about 3.8 percent of U.S. coal, with most of that be used for electricity production. In addition, Montana is home to four refineries. All of these topics, as well as electric transmission, which affect access to Montana's electricity supply and its customers, are discussed in more detail in other chapters of this publication. Electricity supply and demand, however, serve as an umbrella to many of these topics and provides the necessary background for the details offered in other chapters.

Montana in Perspective

Throughout this chapter, measurements of electricity, kilowatt-hours (kWh) or megawatt-hours (MWh) are used to describe supply and demand. One MWh is produced when a 1-MW generator runs for 1 hour. A 1-MW generator running for all 8,760 hours in a year produces 1 average megawatt (aMW). To put this in context, residential customers who do not use electricity for heating typically use 10 to 30 kWh per day. Helena and the Helena valley in 2012 used around 80 aMW total (700,000 MWh), with a peak usage of around 128 MW.[1]

[1] David Fine, NWE, Dec 10, 2013.

Montana generates more electricity than it consumes. Even so, it is a small player in the western electricity market. As of 2014, Montana generating plants have the capacity to produce about 6,300 MW of electricity in the summer with a total nameplate capacity of 6,460 MW. This number is constantly evolving as new plants are added and others, occasionally, shut down. Plants do not run all the time, nor do they produce exactly the same amount of electricity from year to year. For example, the output from hydroelectric generators depends on the rise and fall of river flows, and any type of plant needs downtime for refurbishing and repairs. Montana generators produced 2,977 aMW from 2001-2005 and 3,342 aMW from 2006-2011. Montana usage and transmission losses account for about half of total in-state production, or about 1,700 aMW. In 2012, Montana consumed an estimated 1,582 aMW or about 1,700 aMW assuming 8 percent line losses, and produced 3,411 aMW in 2011. The other half of Montana electricity production is mostly exported west to Washington and Oregon via the Colstrip transmission lines. The Colstrip coal generation plant and a few of the larger dams in northwestern Montana account for the vast majority of contracted Montana electricity exports.

<u>Electricity Facts for Montana</u>
Generation capability -- 6,460 MW
Average generation -- 3,400 aMW
Average load (2012) -- 1,582 aMW

Montana straddles the two major electric interconnections in the country. Most of Montana is in the Western Interconnection, which covers all or most of 11 states and two Canadian provinces; it also includes small portions of one Mexican state and three other U.S. states. Less than 10 percent of Montana's load, and about 4 percent of the electricity generated in Montana, occurs in the Eastern Interconnection. The 2012 Montana load (sales plus transmission losses) was equivalent to less than 2 percent of the 99,608 aMW load in the Western Interconnection.[2]

Generation

There are more than 50 major generating facilities in Montana. Montana's 10 largest electric generation plants are listed below by capacity and output (**Charts E1 and E2**). Small commercial and residential wind turbines are also in operation but are not considered major facilities. The oldest operating generating facility in Montana is Madison Dam near Ennis, built in 1906. The newest is NorthWestern Energy's Spion Kop wind farm, which came online in 2013. The largest facility is the four privately owned coal-fired generating units at Colstrip, which have a combined capability of 2,094 MW, or about 30 percent of Montana's total generation capacity. The largest hydroelectric plant in Montana is Avista's Noxon Rapids Dam, recently upgraded to 562 MW in capability.

[2] Layne Brown, Western Electricity Coordinating Council.

Chart E1. Ten Largest Plants by Generation Output, 2011			
Plant	**Primary Energy Source or Technology**	**Operating Company**	**2011 Output (MWh)**
1. Colstrip	Coal	PPL Montana LLC	13,012,250
2. Libby	Hydroelectric	USCE-North Pacific Division	2,450,665
3. Noxon Rapids	Hydroelectric	Avista Corp	2,109,683
4. Hungry Horse	Hydroelectric	U S Bureau of Reclamation	1,378,437
5. Kerr	Hydroelectric	PPL Montana LLC	1,262,600
6. Fort Peck	Hydroelectric	USCE-Missouri River District	1,224,036
7. Yellowtail	Hydroelectric	U S Bureau of Reclamation	1,123,986
8. J.E. Corette Plant	Coal	PPL Montana LLC	829,601
9. Hardin Generator Project	Coal	Rocky Mountain Power Inc.	645,637
10. Glacier Wind Farm	Wind	NaturEner	630,390

Source: Department of Commerce, Energy Promotion and Development Division, U.S. EIA data.

Chart E2. Ten Largest Plants by Generation Capacity, 2013**			
Plant	**Primary Energy Source or Technology**	**Operating Company**	**Net Summer Capacity (MW)**
1. Colstrip*	Coal	PPL Montana LLC	2,094
2. Noxon Rapids	Hydroelectric	Avista Corp	562
3. Libby	Hydroelectric	USCE-North Pacific Division	525
4. Hungry Horse	Hydroelectric	U S Bureau of Reclamation	428
5. Yellowtail	Hydroelectric	U S Bureau of Reclamation	287
6. Kerr	Hydroelectric	PPL Montana LLC	206
7. Fort Peck	Hydroelectric	USCE-Missouri River District	180
8. J E Corette Plant	Coal	PPL Montana LLC	153
9. Hardin Generator Project	Coal	Rocky Mountain Power Inc.	107
10. Thompson Falls	Hydroelectric	PPL Montana LLC	94

*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 capacity (typically 30%-40%) because wind is an intermittent resource. That is why Judith Gap and NaturEner are not on this list.

PPL Montana-owned plants (previously owned by MPC) produce the largest amount of electricity in Montana (**Figure 1**). PPL Montana's facilities accounted for just under 30 percent of the total generation in Montana in the period 2006-2011. The company owns major hydroelectric facilities in the state and is in negotiations to sell those facilities to NWE. PPL Montana owns 25 percent of the Colstrip generating facility and is the operating partner for the four Colstrip power plants. (PPL owns 50 percent of Units 1 and 2 and a 30 percent interest in Unit 3.) PPL Montana's electricity is sold by its marketing operation in Butte, PPL EnergyPlus, to wholesale customers such as NWE, large industrial customers, and electricity cooperatives.

Figure 1. Average Generation by Company, 2006-2011

Company	aMW	Percent
PPL Montana[1,2]	941	28.2%
Puget Sound Energy[2]	548	16.4
Avista[2]	377	11.3
Bonneville Power Administration[3]	348	10.4
Portland General Electric[2]	240	7.2
NorthWestern Energy[2,4]	218	6.5
Western Area Power Administration[3]	207	6.2
PacifiCorp[2]	123	3.7
Rocky Mountain	77	2.3
Invenergy	53	1.6
Yellowstone	49	1.5
NaturEner	47	1.4
MDU	44	1.3
Other	70	2.1
TOTAL	3,342	100.0%

[1] PPL Montana plants were owned by MPC until mid-December 1999.
[2] Public data on output for Colstrip 1-4 is 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.

Puget Sound Energy (PSE) is the second largest electricity producer in Montana, with 16.4 percent of total Montana generation in the period 2006-2011. This is due to its financial stake in the Colstrip plants (50 percent of Units 1 and 2; 25 percent of Units 3 and 4). PSE also holds partial ownership in the transmission lines that run from Colstrip west out of state, as do the other owners of Colstrip. This ownership extends from Colstrip to Townsend, where BPA takes over ownership. PSE is a federally regulated utility, providing electric and natural gas service to the Puget Sound region of Washington.

Avista, with its 15 percent interest in Colstrip Units 3 and 4 and its full ownership of the five-generator Noxon Rapids hydroelectric plant on the Clark Fork River (rated at 510 MW nameplate capacity), is also a major producer of electricity in Montana (about 11.3 percent of the state's total generation). PacifiCorp is another major owner in Colstrip.

Federal agencies–Bonneville Power Administration (BPA) and Western Area Power Administration (WAPA)–collectively distributed 16.6 percent of the electricity generated in Montana from 2006-2011. This generation is owned by the federal government. Two of Montana's largest energy generation facilities, Libby Dam on the Kootenai River (U.S. Army

Corp of Engineers) and Hungry Horse on the South Fork of the Flathead (U.S. Bureau of Reclamation), provide power for BPA. Headquartered in Portland, Oregon, BPA transmits and sells wholesale electricity in Washington, Oregon, Idaho, and western Montana. BPA is the marketing agent for power from all of the federally owned hydroelectric projects in the Pacific Northwest and is one of four federal marketing agents within the U.S. BPA is a large player in northwestern Montana for both electric supply and transmission line operations. WAPA, like BPA, is a power marketing agency. It markets power for federal hydroelectric facilities in the region east of the Continental Divide in Montana. WAPA operates three hydroelectric facilities in Montana: Yellowtail on the Bighorn River (U.S. Bureau of Reclamation), Canyon Ferry near Helena, and Fort Peck (U.S. Army Corp of Engineers) on the Missouri River. Fort Peck Dam is configured to deliver electricity to both the Western and Eastern Interconnections.

NWE is the largest utility in Montana and is regulated by the Montana Public Service Commission (PSC). NWE is headquartered in Butte for its Montana operations and Sioux Falls, South Dakota, for the parent company. It provides generation and transmission to a majority of customers in the western two-thirds of Montana, although many large industrial companies and electric cooperatives purchase electricity supply elsewhere.

NWE owned very little generation in Montana in 2002, but has slowly been acquiring facilities. NWE owns a 30 percent interest in Colstrip Unit 4 (about 6 percent of the state's total generation capacity) and purchases electricity from a number of small qualifying power production facilities (QFs) that include natural gas, waste coal, small hydroelectric, and wind generation. In 2011, NWE commissioned the Dave Gates natural gas turbine facility near Anaconda (150 MW) to provide regulation services for NWE's balancing area.

NWE's share of Colstrip, plus its ownership of Dave Gates and Spion Kop, now accounts for 6.5 percent of the total generation in the state. Adding PPL's dams would greatly increase its percentage of total generation in Montana and a corresponding decline in PPL's ownership percentage. NWE also retained MPC's QF contracts and has expanded those contracts. To note a few, those contracts include contracts with Colstrip Energy Limited Partnership (CELP), Montana Department of Natural Resources and Conservation, Hydrodynamics, Two Dot Wind, and Yellowstone Energy Limited Partnership (YELP). NWE also has contracts for the output from the Basin Creek natural gas plant, Judith Gap Wind Farm, and Tiber Dam.

Montana generation is powered primarily by coal (60 percent of total for 2006-2011) and hydropower (35 percent of total from 2006-2011). Over the last 15 years, about a quarter of Montana's total coal production has gone to generate electricity in Montana. The rest has been exported out-of-state, primarily for electric generation elsewhere. Until 1986, when Colstrip 4 was completed, hydropower was the dominant source of net electric generation in Montana. Most of the small amount of petroleum used for electric generation (1.5 percent of total generation in 2011) is actually petroleum coke from the refineries in Billings. Small amounts of natural gas (1.4 percent of total generation in 2011) and increasing amounts of wind (3.8 percent of total generation in 2011) round out the in-state generation picture. It is likely that wind will make up a larger percentage of Montana's total generation in the future as more wind farms are built and as Montana's generation portfolio continues to diversify. Coal will make up between 50 and 60 percent of total generation going into the future if the Corette coal plant in Billings shuts down. Hydroelectric generation produces about 30 to 40 percent of total generation, and that percentage is expected to remain in that range.

During spring runoff, utilities operate their systems to take advantage of cheap hydroelectric power, both on their own systems and on the wholesale 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 hydroelectric power availability is low.

Consumption

Montana electric consumers are served by 31 distribution utilities: 2 investor-owned utilities, 25 rural electric cooperatives, 3 federal agencies, and 1 municipality. Two additional investor-owned utilities and four cooperatives are based in other states but serve a handful of Montanans. In 2011, investor-owned utilities were responsible for 49 percent of the electricity sales in Montana, cooperatives 29 percent, federal agencies 3 percent, and power marketers 19 percent (**Figure 2**).

Reported sales of electricity in Montana in 2011 were 13.8 billion kWh. This is down from 15.5 billion kWh in 2007, due mostly to decreased industrial use (at least two large companies scaled back or shut down during this time and the economic recession of 2008 also slightly lowered consumption). The residential and commercial sectors in 2011 each accounted for about 35 percent of electricity sales, and the industrial sector accounted for just under 30 percent. In 2007, the industrial sector accounted for 45 percent of sales. Total Montana electricity sales tripled between 1960 and 2000, then dropped by more than 15 percent as industrial loads tumbled following the electricity crisis of 2000-2001. Sales have risen since then (**Figure 3**).

Since 1990, sales to the commercial sector have grown the most, followed by sales to the residential sector. Industrial sales fluctuated over this time period. Residential growth tends to track population growth, while commercial growth tends to track economic activity. Growth in both sectors may slow if electricity prices continue to rise and energy efficiency technology continues to permeate the market. There are no statewide forecasts for future electricity consumption.

Consumption patterns continually shift as existing electricity-consuming equipment and appliances become more efficient, while conversely, new electricity-consuming inventions gain market share in U.S. homes and jobs. Consumption patterns in the state and nation may change, if electric vehicles become a significant part of new vehicle sales.

Electricity in Montana costs less than the national average. In 2011, the Montana electricity price averaged 8.23 cents/kWh compared to 9.9 cents/kWh nationally. This is about 1.7 cents/kWh below the national average. Interestingly, in 1997 before electricity deregulation, Montana's average price of 5.2 cents/kWh was also 1.7 cents below the national average of 6.85 cents/ kWh. For both Montana and the U.S., electricity prices have risen moderately faster than inflation since 1997 (58 percent and 45 percent respectively, versus a 40 percent rise in U.S. Consumer Price Index).

Figure 2. Distribution of Montana 2011 Sales by Type of Utility (aMW)

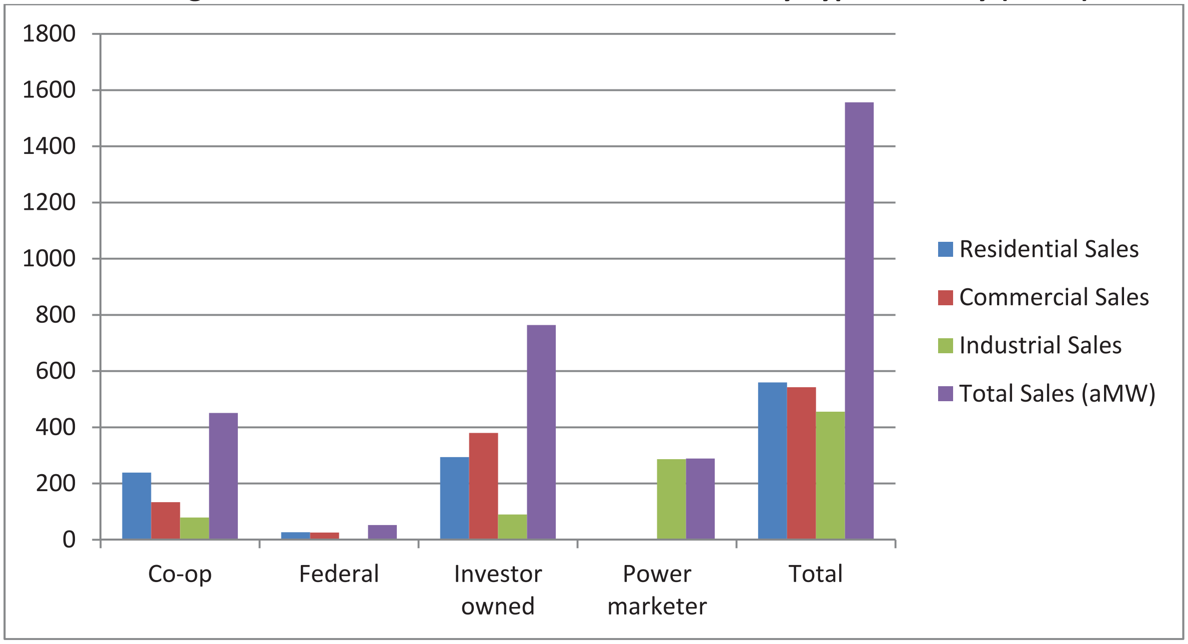
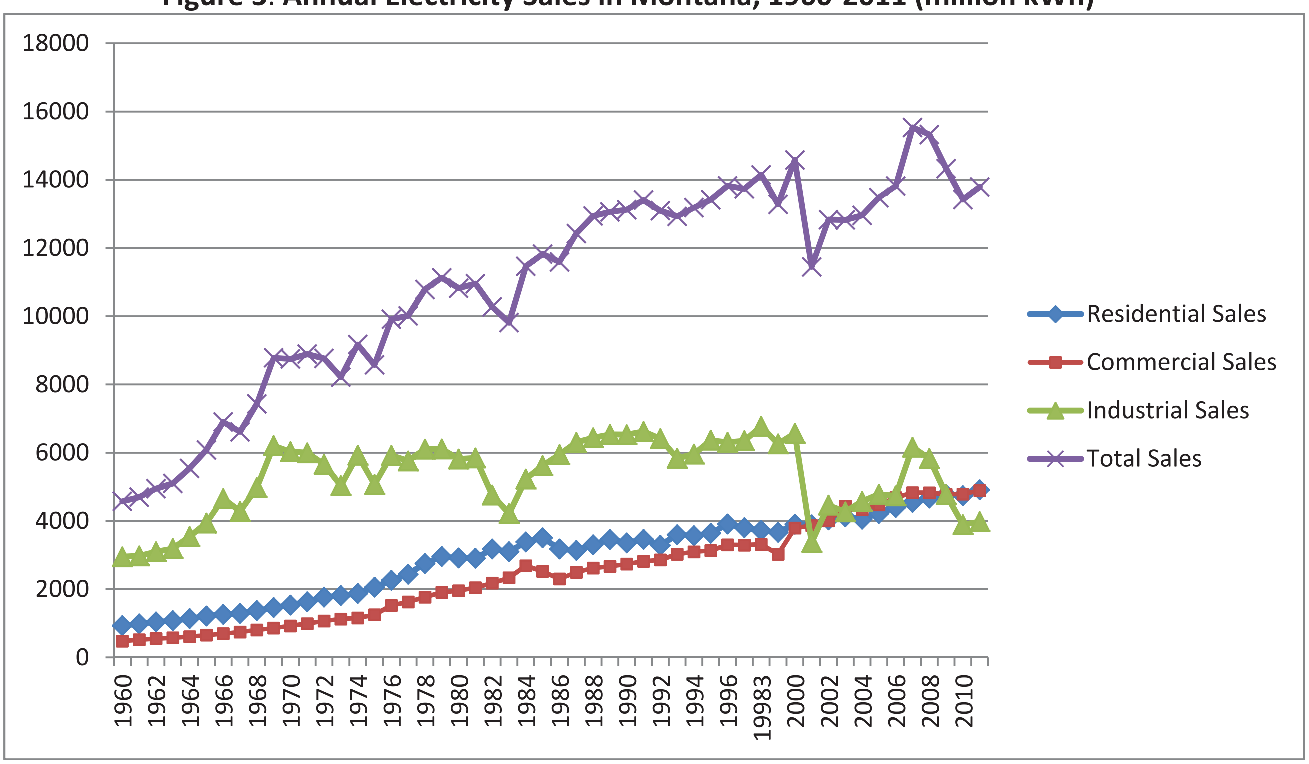


Figure 3. Annual Electricity Sales in Montana, 1960-2011 (million kWh)



Montana average residential consumption averaged 872 kWh/month in 2011, or about 1.2 akW annually, slightly higher than 1.1 akW in 2007. This average covers a wide range of usage patterns. Households without electric heat can use 200 kWh to 1,000 kWh per month (0.3-1.4 akW annually) depending on the size of the housing unit and number of appliances. Use in electrically heated houses can easily range between 1,800 kWh and 3,000 kWh per month (2.5 and 4.1 akW annually).[3]

Commercial accounts averaged about 3,920 kWh/month or 5.37 akW per year in 2011, showing no change since 2009. Because so many different types of buildings and operations are included in the commercial sector, it is difficult to describe a typical usage pattern.

Montana's largest electricity consumers are large industrial customers, including metal mines, the four in-state oil refineries, large petroleum pipelines, forestry products companies, a silicon manufacturer, and two cement plants. These customers use NWE, MDU, or WAPA as their electricity transmission provider, but most buy their power from nonutility suppliers, such as power marketers. These are generally privately negotiated contracts.

Future Supply and Demand

Nine large generation plants in Montana have come online during the past few years, including:

- The Basin Electric Cooperative Culbertson natural gas plant outside Culbertson (91 MW)
- NaturEner 's Glacier wind farm (210 MW) and Rimrock wind farm (189 MW) near Shelby
- NWE's Dave Gates natural gas plant (150 MW) located near Anaconda and used largely for regulating reserves
- The Turnbull Hydroelectric plant located on the Bureau of Reclamation's Sun River Irrigation project west of Great Falls (13 MW)
- Goldwind America's Musselshell I and 2 wind farms near Harlowton (20 MW)
- Oversight Resource's Gordon Butte wind farm near Martinsdale (10 MW)
- NWE's Spion Kop wind farm near Geyser (40 MW)
- MDU's Diamond Willow wind farms near Baker (30 MW).

Other wind and natural gas facilities went online in the last 10 years, including the 135- MW Judith Gap wind farm and the Basin Creek 53 MW natural gas plant south of Butte. Before the 2008 recession, there were as many as 50 wind power projects in various stages of development in Montana, but today only a few of those projects are still viable. Reasons for the decline include the economic recession and its corresponding drop in electricity demand, as well as an uncertain renewable portfolio standard (RPS) in California that might limit demand for remote Montana wind power (California's renewable portfolio standard is discussed further in the Transmission chapter). With the construction of the 230-kilovolt Montana-Alberta Tie Line (MATL), completed in September 2013, a new market has opened up to transfer electricity to and from Alberta. At the present time, power is likely flowing mostly north on MATL because there are transmission constraints south out of Great Falls.

[3] David Fine, NWE, Dec 10, 2013.

In the 1990's, the only sizeable generation 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, nonutility generators (QFs) could sell power to utilities on a more competitive basis. The Montana One waste-coal plant, now referred to as CELP and sized at 41.5 MW, was built near Colstrip in 1990, and the BGI petroleum coke-fired plant, now referred to as YELP at 65 MW, was built in Billings in 1995. These two plants account for about 92 percent of the average total production of all QFs in Montana. QFs continue to be the source of much discussion before Montana's PSC. As of 2014, QFs up to 3 MW can qualify for avoided cost rates from a PURPA-bound utility, as opposed to the previous limit of 10 MW.[4]

To be economically viable, any new generation resources in Montana likely will need contracts in out-of-state markets or will need to displace existing resources for in-state consumption. Therefore, new generation must: offer a competitive wholesale price and have the transmission access necessary to compete in out-of-state markets; or offer a better package of prices and conditions than those resources currently supplying Montana loads. Transmission access is limited out of Montana and is also a critical issue.

Potential for Efficiency and Conservation

Energy conservation refers to activities that reduce the amount of electricity used by a consumer, such as turning a light off when leaving the room. Energy efficiency results from technologies that are more efficient or use less energy, like a compact fluorescent light bulb versus an incandescent bulb. Demand response occurs 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 or an industrial customer shutting down for several hours during and electricity shortage. These three types of behaviors (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 demand-side management.

Montana ranked 29th overall among the 50 states on the 2013 State Energy Efficiency Scorecard produced by the American Council on Energy Efficiency Economy in terms of energy efficiency efforts.

The Northwest Power and Conservation Council provides estimates of the amount of energy efficiency 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 5 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 Pacific Northwest's new demand for power.

[4] Otherwise, plants have to enter a competitive solicitation under a bidding process with NorthWestern Energy rather than receive a preset 'avoided cost price', which is calculated by the Montana Public Service Commission.

The Universal System Benefits (USB) program requires Montana electric utilities, investor-owned and electric cooperatives, to spend money on activities related to energy conservation, renewable energy projects, market transformation, research and development, and low-income energy assistance. In March 2013, NWE provided an annual USB program report showing about $1.41 million focused on energy conservation programs, which compares to about $3.4 million directed to low-income activities. NWE, for example, provides an energy audit program for residential customers. In 2012 more than 3,000 onsite audits were funded.[5] In a similar report MDU reported $2,700 directed to energy conservation program rebates in Montana in 2012.[6] Some western Montana cooperatives are served by the BPA. That means they are included in the demand-side management activities of the Northwest Power and Conservation Council and the Northwest Energy Efficiency Alliance.

NorthWestern Energy 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 2013 plan, an annual demand-side management goal of 6 MW per year is in place. NorthWestern is in the fourth year of its DSM acquisition plan set forth in the 2009 Electric Supply Resource Procurement Plan. As of 2009, the amount of remaining achievable, cost-effective electric DSM was estimated to be 84.3 MW.

There are no statewide estimates of 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.

Early History

The early history of electricity development in Montana is tied to the servicing of mining and the industrial processing of ores and minerals. The development of large hydroelectric facilities dominated the three decades following 1900. Industrial demand for electricity expanded in the mid-20th Century as oil refineries and both crude and refined pipelines arrived. Small scale thermal generation of electricity dates to Montana's territorial era. As hydroelectric opportunities diminished in the mid-20th Century, utilities looked to eastern Montana's coal deposits. The transmission of electricity in the region first developed to carry electricity from the hydroelectric facilities to the industrial centers.

Electric lighting was the earliest commercial application in Montana. Above-ground operations at a copper mine in the Butte mining district were illuminated by arc lights as early as 1880.[7] These bulbless, direct current dynamos and lamps soon gave way to Edison-style enclosed bulb lighting. Both Butte and Helena had coal-fired electric works plants by the late 1880s, mostly for municipal and commercial lighting. By 1890, Butte had two competing electric lighting companies and two modern coal-fired steam generation plants.

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[5] David Fine, NWE, Dec 10, 2013.

[6] Larry Oswald, MDU, Dec. 11, 2013.

[7] The Butte Daily Miner, November, 1880.

The explorer William Clark performed a rough survey of the Great Falls of the Missouri as the expedition passed through in 1805. His journal entry notes, “from this survey, the Missouri experiences a descent of 360 feet 2 inches” over roughly 13 miles. Ninety years later the state’s first hydroelectric dam would be built at Black Eagle Falls. The electric plants were commissioned in 1891 and 1892. Black Eagle Dam was entirely reconstructed in 1926, and the original dam is now under the impoundment of the new facility. Another early hydroelectric project was a dam on the Missouri River 17 miles east of Helena near Canyon Ferry. The structure provided 30 feet of head to four, 550-kilowatt generators. The plant began operation in 1898 and initially furnished electricity to the Capitol over a double circuit power line. The plant was upgraded in 1901 and two-pole transmission lines were built to Butte and Anaconda in 1902.

As more industrial applications arrived to consume electricity, local electric companies in Helena, Butte, and Great Falls rushed to build new dams and to improve existing dams. Five main players emerged by 1905 from the many small power companies of previous decades. Helena-based Missouri River Power Company seemed poised to break out as the major player in Montana electricity generation and transmission. However, its new Hauser Dam on the Missouri collapsed in the spring of 1908. The financial fallout of dam failure led indirectly to the forming of the Montana Power Company.[8] John D. Ryan, an executive of the Anaconda Company, moved aggressively to consolidate the various regional interests. By 1911, he had formulated control over all Missouri River development rights, as well as the remnants of the failed Missouri River Power Company. In 1912 and 1913, Ryan brokered a merger with the remaining electric companies that would form MPC. Ryan served as MPC’s first president following the consolidation.[9]

MPC moved to build Volta Dam (later named Ryan Dam) outside of Great Falls, which was completed in 1915. The company also worked to complete Thompson Falls Dam on the Clark Fork River, which also came online in 1915. An upgrade to Rainbow Dam was implemented in 1918. Holter Dam on the Missouri was completed in 1918.[10] MPC began construction at the Kerr Dam site downstream of Flathead Lake as the Great Depression was gaining traction. Work stopped in 1931 and resumed in 1936. The project was completed in 1938. Additional generation was added in 1949 and 1954 after completion of the federal Hungry Horse Dam project on the South Fork of the Flathead River above Flathead Lake.

Hydroelectricity wasn’t the only player in Montana’s early energy history. The city of Billings grew from roughly 10,000 people in 1910 to almost 32,000 in 1950, in part due to development of the area’s natural gas and oil fields and oil refineries. Three large oil refineries in the Billings

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[8] *Early Steel Towers and Energy for Montana’s Copper Industry*, Montana the Magazine of Western History, F. Quivik, 1988.

[9] *Energy-Power, Copper, and John D. Ryan*, Montana the Magazine of Western History, C. Johnson, 1988.

[10] *Early Steel Towers and Energy for Montana’s Copper Industry*, Montana the Magazine of Western History, F. Quivik, 1988.

area became a new market for electricity. By the late 1960s these refineries used about 25 MW, up from 3.5 MW in 1950. The Yellowstone Pipeline from Billings to Spokane used about 7.5 MW to power five pumps during this period and a crude oil line running from Alberta into Wyoming used more than 11 MW to power a dozen pump stations. MPC needed more generation in the area to meet the growing load. In his *History of the Montana Power Company*, author Cecil Kirk, writing in the late 1960s, noted: "There were several reasons for building the steam plant in Billings. First the Billings area needed more generation and steam was the only answer there. Secondly, a good source of fuel oil was available from the Billings refineries, and a source of gas was available in the Dry Creek Field. Third, cooling water was available from the Yellowstone River. And finally, [the Montana Power Company] needed a back-up source of power for its hydro-plants in case of low water or sudden freeze-ups. Billings seemed the ideal location."

A 70-MW thermal plant designed to run on either natural gas or oil was completed in late 1951 and named for the MPC president of the time, Frank Bird. An 8-inch crude oil pipeline from the Dry Creek field near Red Lodge was converted to carry natural gas to the new plant. A second single-boiler thermal plant would follow in 1968–the Corette Plant–engineered to fire by coal. The J.E. Corette Steam Plant remains operational today at about 180 megawatts; the Bird plant was taken out of service in the 1980s after a number of years of intermittent use.

Current Topics

NWE buyback of dams

In 2013, the Montana era of deregulation was rolled back one step further to the days of vertically integrated utilities. In September 2013, NWE announced it had entered into an agreement with PPL Montana to buy 11 hydroelectric dams in Montana totaling 633 MW of capacity. The announced price is about $900 million. One of these dams, the Kerr dam, is expected to be sold to the Salish-Kootenai tribe in 2015. The overall sale of the PPL dams to NWE is subject to approval by the PSC, a process which will take place in 2014. These purchases would allow NWE to cover all of its electricity demand during low peak periods (light usage periods) and to rely less on market purchases during heavier demand periods.

Southern Montana Electric

In late 2011, the Southern Montana Electric Generation and Transmission Cooperative (SME) filed for bankruptcy with more than $440 million in debt. SME formerly supplied electricity to six cooperatives in central and southern Montana as well as a few large customers in Great Falls. The financial problems that led to the bankruptcy were mostly a result of a failed attempt to build a 250-MW coal-fired power plant and to sell the electricity it generated on the wholesale market. The project was later scaled back to a 40-MW gas plant that has sat dormant since its completion. In addition, SME signed a contract with PPL Montana in 2009 that obligated the cooperative to buy more power than it needed, further degrading its financial position. Two former members of SME, Yellowstone Valley Electric and Electric City Power of Great Falls, broke away in 2013 in separate settlements. This greatly raised the rates for the four remaining cooperatives under SME. The remaining cooperative members want to leave

SME and liquidate the assets in order to avoid being saddled with SME's debts.[11] As of early 2014, the case is ongoing.

In response to the problems faced by SME, the 2011-2012 Energy and Telecommunications Interim Committee spent much of its time examining the regulatory structure surrounding rural electric cooperatives in Montana. The result was the passage and approval of Senate Bill No. 90 (Chapter 55, Laws of 2013) by the 2013 Legislature. The legislation established new transparency and voting requirements for cooperatives. The law includes voting requirements for distribution cooperatives and generation and transmission cooperatives that enter into agreements for the construction of certain electric generating facilities or that enter into certain energy contracts.

Clean Air Act 111(d) Legislation

The Environmental Protection Agency (EPA) under the Clean Air Act (CAA) is crafting greenhouse gas regulations for new and existing major stationary sources, including power plants, under Section 111 of the CAA. Section 111 performance standards, like much of the CAA, are designed and promulgated through a federal-state partnership. EPA is authorized to approve a minimum federal "backstop" for regulations, and then allow states to control greenhouse gas emissions above and beyond that backstop. The rules are expected to be released in 2014.

Depending on the final rules, greenhouse gas-intensive coal generation could be forced to develop a number of retrofits, likely making generation more expensive over time. As a result, utilities across the nation are closely watching the rulemaking and evaluating the use of new and existing coal plants. Both NWE and MDU, in their respective resource plans and in recent portfolio purchases, evaluate these issues. Both also have favored acquisitions of natural gas and wind power in the last 2 years. MDU has taken advantage of market purchases from Midwest Independent Transmission System Operator (MISO), while NWE continues to purchase energy on the wholesale market with a mix of long-term and shorter-term purchases.

[11] http://billingsgazette.com/news/state-and-regional/montana/judge-removes-power-co-op-trustee-in-surprise-move/article_415ff041-61f0-532d-8790-38f00e558ed0.html#ixzz2nHmb5mzn

Table E1. Electric Power Generating Capacity by Company and Plant as of May 2013[1] (Megawatts-MW)

COMPANY	PLANT	COUNTY	ENERGY SOURCE	INITIAL OPERATION (First Unit)	CAPACITY (MW) GENERATOR NAMEPLATE	NET SUMMER	NET WINTER
Avista	Noxon Rapids 1-5	Sanders	Water	1959	562.4	562.4	562.4
Basin Electric Power Cooperative	Culbertson Generation Station	Richland	Natural Gas	2010	91.0	90.8	95.8
Flathead Electric Cooperative	Landfill Gas To Energy[2]	Flathead	Landfill Methane	2009	1.6	1.2	1.2
Mission Valley Power Co.	Hellroaring[7]	Lake	Water	1916	0.4	0.4	0.4
Montana-Dakota Utilities	Diamond Willow	Fallon	Wind	2007	30.0	30.0	30.0
Montana-Dakota Utilities[8]	Glendive #1	Dawson	Natural Gas/#2 Fuel Oil	1979	34.8	34.0	--
Montana-Dakota Utilities[8]	Glendive #2	Dawson	Natural Gas/#2 Fuel Oil	2003	40.7	40.3	--
Montana-Dakota Utilities[8]	Lewis & Clark	Richland	Lignite Coal/Natural Gas	1958	44.0	52.3	--
Montana-Dakota Utilities[8]	Miles City	Custer	Natural Gas/#2 Fuel Oil	1972	23.2	21.6	--
NaturEner	Glacier 1 & 2	Toole	Wind	2008	210.0	204.2	204.2
NaturEner	Rimrock	Toole	Wind	2012	189.0	180.0	180.0
Northern Lights Cooperative	Lake Creek A&B	Lincoln	Water	1917	4.5	4.5	4.5
NorthWestern Energy (NWE)	Dave Gates Generating Station	Deer Lodge	Natural Gas	2011	150.0	150.0	150.0
NorthWestern Energy (NWE)	Spion Kop	Judith Basin	Wind	2012	40.0	40.0	40.0
NWE Portfolio - Basin Creek Power	Basin Creek 1-9	Silver Bow	Natural Gas	2006	52.5	53.1	53.1
NWE Portfolio - Invenergy Wind	Judith Gap	Wheatland	Wind	2005	135.0	135.0	135.0
NWE Portfolio (winter) - Tiber Montana, LLC	Tiber Dam	Liberty	Water	2004	7.5	7.0	5.5
NWE Portfolio - Turnbull Hydro LLC	Turnbull Hydro[3]	Teton	Water	2011	13.0	11.0	--
NWE QF - Colstrip Energy Partnership	Montana One	Rosebud	Waste Coal	1990	41.5	37.9	39.5
NWE QF - Granite County	Flint Creek Dam	Granite	Water	1901	2.0	2.0	2.0
NWE QF - Hydrodynamics	South Dry Creek[3, 4]	Carbon	Water	1985	2.0	2.1	--
NWE QF - Montana DNRC	Broadwater	Broadwater	Water	1989	9.7	9.7	9.7
NWE QF - Goldwind Global	Mussellshell 1 & 2	Wheatland	Wind	2013	20.0	20.0	20.0
NWE QF - other hydro	Various	Various	Water	Various	3.7	4.4	1.4
NWE QF - other wind	Various[4]	Various	Wind	Various	2.0	2.0	2.0
NWE QF - Oversight Resources	Gordon Butte	Meagher	Wind	2012	9.6	9.6	9.6
NWE QF - Two Dot Wind	Martinsdale Colony S.[4]	Wheatland	Wind	2006	2.0	1.6	1.6
NWE QF - Yellowstone Partnership	BGI	Yellowstone	Petroleum Coke	1995	65.0	57.7	60.7
Ormat (Basin Electric Cooperative portfolio)	Culbertson Waste Heat	Richland	Recovered Heat	2010	5.5	5.5	5.5
PacifiCorp	Bigfork 1-3	Flathead	Water	1910	4.2	4.6	4.6
PPL Montana	Black Eagle 1-3	Cascade	Water	1927	16.8	21.0	21.0
PPL Montana	Cochrane 1-2	Cascade	Water	1958	60.4	64.0	64.0
PPL Montana (50%) Puget Sound Energy (50%)	Colstrip 1	Rosebud	Subbituminous Coal	1975	358.0	307.0	307.0
PPL Montana (50%) Puget Sound Energy (50%)	Colstrip 2	Rosebud	Subbituminous Coal	1976	358.0	307.0	307.0
PPL Montana (30%) Avista (15%), PacifiCorp (10%) Puget Sound Energy (25%) Portland General Electric (20%)	Colstrip 3	Rosebud	Subbituminous Coal	1984	778.0	740.0	740.0
PPL (operator); Avista (15%) NorthWestern Energy (30%), Portland General Electric (20%) Puget Sound Energy (25%), PacifiCorp (10%)	Colstrip 4	Rosebud	Subbituminous Coal	1986	778.0	740.0	740.0
PPL Montana	Hauser 1-6	Lewis-Clark	Water	1911	17.0	19.0	19.0
PPL Montana	Holter 1-4	Lewis-Clark	Water	1918	38.4	48.0	48.0
PPL Montana	J. E. Corette	Yellowstone	Subbituminous Coal	1968	172.8	153.0	153.0
PPL Montana	Kerr 1-3	Lake	Water	1938	207.6	206.0	206.0
PPL Montana	Madison 1-4	Madison	Water	1906	8.8	8.0	8.0
PPL Montana	Morony 1-2	Cascade	Water	1930	45.0	48.0	48.0
PPL Montana	Mystic 1-2	Stillwater	Water	1925	10.0	12.0	7.0
PPL Montana	Rainbow	Cascade	Water	1910	60.0	60.0	60.0
PPL Montana	Ryan 1-6	Cascade	Water	1915	48.0	60.0	60.0
PPL Montana	Thompson Falls 1-7	Sanders	Water	1915	87.1	94.0	94.0
Rocky Mountain Power	Hardin	Big Horn	Subbituminous Coal	2006	115.7	107.0	107.0
Salish - Kootenai Tribe	Boulder Creek	Lake	Water	1984	0.4	0.4	0.4
Southern Montana G&T Cooperative	Highwood Generating Station	Cascade	Natural Gas	2011	42.6	40.5	42.5
Thompson River Co-gen	Thompson River[5]	Sanders	Coal/wood	2004	16.0	0.0	0.0
United Materials (Idaho QF/NWE QF)	Horseshoe Bend	Cascade	Wind	2006	9.0	9.0	9.0
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	Big Horn	Water	1966	250.0	287.2	287.2
US BurRec - Pacific Northwest Region	Hungry Horse 1-4	Flathead	Water	1952	428.0	428.0	428.0
US Corps of Engineers - Missouri River Division	Fort Peck 1-5[6]	McCone	Water	1943	185.3	179.5	179.5
US Corps of Engineers - North Pacific Division	Libby 1-5	Lincoln	Water	1975	525.0	525.0	525.0
TOTAL MONTANA CAPACITY (MW)					**6462.4**	**6296.1**	**6136.9**

[1] Does not include units, mostly small, that are net-metered or that are located behind the meter of an industrial facility.
[2] Numbers for capabilities actually are highest monthly output to date.
[3] Only operates during summer.
[4] Capabilities are maximum monthly capacity 2006-2011, as reported by NWE.
[5] Currently idle.
[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).
[7] Currently shut down for maintenance but planning on coming on-line again in 2013
[8] MDU no longer calculates a winter rating since MISO uses a single annual assessment for their summer peak.

Sources: On-line date and nameplate are primarily from two sources (except where otherwise noted) - U.S. DOE Energy Information Administration "Form EIA-860 Database Annual Electric Generator Report 2011" http://www.eia.gov/electricity/data/eia860/index.html and the WECC "LRTA 2012" list of existing generation; Landfill Gas to Energy-Flathead coop, Martinsdale Colony South from NWE, MDU facilities from MDU, Noxon from Patrick Maher at Avista; Thompson Falls - Owner; Gordon Butte - NWE; Culbertson Waste Heat - Basin Electric Coop; Dave Fine, NWE for Basin Creek, BGI, and CELP; Dave Hoffman-PPL for Ryan. Summer and Winter capacity are from two primary sources (unless otherwise noted) which are U.S. DOE Energy Information Administration "Form EIA-860 Database Annual Electric Generator Report 2011" http://www.eia.gov/electricity/data/eia860/index.html and the WECC "LRTA 2012" list of existing generation; Boulder Creek, Fort Peck, Hellroaring, Flathead Landfill Gas to Energy, Libby, and MDU facilities - owner; Gordon Butte, Martinsdale Colony South, NWE QF - other hydro, NWE QF - other wind, and South Dry Creek – NWE; Ryan Dam, Dave Hoffman of PPL; Culbertson Waste Heat – Basin Electric Coop; MDU facilities update-Brian Giggee and Darcy Neigum; Hellroaring-Mission Valley Power; Patrick Maher, Avista; Dave Fine of NWE for CELP and BGI.

Table E2. Net Electric Generation By Plant and Ownership, 2006-2011[1] (MWh)

COMPANY / PLANT	2006	2007	2008	2009	2010	2011	Average Generation[2] (aMW) 2006-2011	Average Generation[2] (aMW) 2001-2005	2006-2011 as % of 2001-2005
Avista									
Noxon Rapids	1,823,945	1,590,451	1,696,459	1,673,251	1,503,127	2,109,683	197.8	172.7	115%
Basin Creek Power Services LLC									
Basin Creek Plant (NWE portfolio)	40,587	80,267	49,108	66,127	18,760	10,305	5.0	--	--
Basin Electric Cooperative									
Culbertson Generation Station[3]	--	--	--	--	5,938	62,944	3.9	--	--
Bonneville Power Administration									
Hungry Horse[4]	1,055,468	931,620	1,119,403	742,284	834,213	1,378,437	115.3	89.6	129%
Libby	2,190,677	2,344,156	1,950,437	1,574,357	1,701,918	2,450,665	232.3	220.2	106%
Clark Fork and Blackfoot LLC (NWE)									
Milltown	2,326	--	--	--	--	--	0.3	1.4	19%
Colstrip Energy Partnership									
Montana One (NWE QF)	305,830	303,650	293,305	286,606	330,796	260,758	33.9	31.7	107%
Flathead Electric Cooperative									
Landfill Gas To Energy	--	--	--	3,072	7,285	8,572	0.7	--	--
Gordon Butte, LLC									
Gordon Butte (NWE QF)	--	--	--	--	--	1,241	0.1	--	--
Hydrodynamics									
South Dry Creek (NWE QF)	6,262	6,605	7,598	7,343	8,614	6,026	0.8	0.6	134%
Strawberry Creek (NWE QF)	1,410	1,519	1,292	1,448	1,551	1,447	0.2	0.1	110%
Invenergy Services LLC									
Judith Gap (NWE portfolio)[5]	439,727	486,847	500,828	456,985	414,002	511,361	53.5	--	--
Mission Valley Power									
Hellroaring	1,929	1,767	2,498	1,817	2,084	1,155	0.2	0.2	105%
Montana-Dakota Utilities									
Diamond Willow	--	16	64,997	67,691	67,902	98,867	6.8	--	--
Glendive	6,512	12,687	3,218	1,949	6,978	15,402	0.9	1.1	84%
Lewis-Clark	336,937	314,675	331,504	316,534	315,371	300,792	36.5	35.5	103%
Miles City	1,648	2,623	369	-28	1,021	218	0.1	0.3	44%
MT Dept of Nat. Res. and Con.									
Broadwater Power Project (NWE QF)	48,249	44,982	46,134	52,730	52,843	53,536	5.7	4.8	118%
NaturEner									
NaturEner Glacier Wind Energy 1 LLC[6]	--	--	27,689	257,187	231,374	308,543	23.5	--	--
NaturEner Glacier Wind Energy 2 LLC[6]	--	--	--	56,332	227,020	321,846	23.0	--	--
Northern Lights Cooperative									
Lake Creek[7]	27,073	27,406	23,102	21,888	22,636	30,822	2.9	2.8	105%
NorthWestern Energy (portfolio)									
Dave Gates Generating Station	--	--	--	--	--	329,266	37.6	--	
Northwestern Qualifying Facilities									
Other hydro	8,419	7,072	7,094	9,423	9,353	7,788	0.9	0.8	116%
Wind (excluding Two Dot LLC plants)	--	6	72	62	53	52	0.0	0.0	204%
Ormat									
Culbertson Waste Heat (Basin portfolio)[3]	--	--	--	--	27,557	57,155	4.8	--	--
PacifiCorp									
Bigfork	31,391	24,435	27,562	28,977	32,262	34,671	3.4	2.8	120%
PPL Montana									
Black Eagle	136,211	124,084	126,199	142,590	141,584	147,040	15.6	13.2	118%
Cochrane	276,795	233,765	270,680	298,387	296,861	284,974	31.6	25.2	125%
Colstrip[8]	14,764,749	15,840,087	16,086,750	13,154,978	16,211,861	13,025,219	1,694.9	1,737.6	98%
Hauser Lake	127,815	118,972	129,812	135,336	132,325	133,275	14.8	12.5	118%
Holter	279,655	223,234	267,506	319,805	303,864	348,297	33.1	25.4	131%
J E Corette	1,204,206	1,186,136	1,024,555	1,075,253	961,177	831,047	119.5	128.0	93%
Kerr	1,076,089	1,088,593	1,069,901	993,385	1,033,265	1,262,600	124.1	108.6	114%
Madison	67,595	60,099	57,078	62,452	61,727	65,131	7.1	7.0	101%
Morony	273,198	241,470	256,017	307,166	299,245	199,410	30.0	25.7	117%
Mystic Lake	43,252	48,577	53,487	54,439	46,138	50,609	5.6	4.8	117%
Rainbow	238,164	228,869	239,938	268,072	252,528	230,631	27.7	24.2	115%
Ryan	411,025	384,540	390,576	441,426	423,204	440,545	47.4	41.1	115%
Thompson Falls	493,070	509,373	474,349	482,044	465,209	534,298	56.3	52.1	108%
Rocky Mountain Power									
Hardin Generating Station	489,442	728,486	610,938	790,037	793,895	645,637	77.2	--	--
Salish-Kootenai									
Boulder Creek	1,263	1,042	1,225	1,026	1,352	1,637	0.1	0.1	180%
Tiber Montana, LLC									
Tiber (NWE portfolio)[9]	42,986	38,901	43,402	50,830	41,868	58,260	5.3	3.5	150%
Turnbull Hydro, LLC									
Turnbull Hydro						22,319	2.5	--	--
Two Dot Wind (NWE QF)									
Martinsdale Colony	1,277	1,319	1,442	1,117	959	1,218	0.1	0.1	110%
Martinsdale Colony South	0.1	533	991	931	1,968	2,015	0.1	--	--
Mission	168	131	174	86	65	89	0.0	0.0	74%
Moe Wind	144	598	745	606	623	708	0.1	--	--
Montana Marginal	447	376	291	288	204	125	0.0	0.0	67%
Sheep Valley	878	923	1,044	890	807	1,018	0.1	0.1	130%
United Materials of Great Falls Inc									
Horseshoe Bend (NWE QF)[10]	23,528	24,481	27,311	23,095	21,055	24,550	2.7	--	--
Western Area Power Administration									
Canyon Ferry	329,710	285,725	332,402	388,180	368,871	418,733	40.4	30.6	132%
Fort Peck	704,920	609,731	573,386	584,252	584,252	1,224,036	81.4	79.8	102%
Yellowtail	475,182	380,434	769,281	898,516	830,746	1,123,986	85.2	47.2	180%
Yellowstone Energy Partnership									
Billings Generation Inc. (NWE QF)	424,898	428,640	405,715	449,482	403,000	444,292	48.6	45.6	107%
TOTALS	28,215,057	28,969,903	29,367,862	26,550,700	29,501,313	29,883,251	3,342.2	2,977.2	112%

Note: aMW = average megawatt, or 8,760 megawatt hours in a year.

1 Net generation equals gross generation minus plant use.
2 aMW = average megawatt, or 8,760 megawatt hours in a year. Average is for a period shorter than 5 years if the plant came on line during the 5-year period.
3 Data provided by Basin Electric Cooperative, as EIA data appear to be incorrect.
4 Data for 2007 and 2008 from the U.S. Corps of Engineers, as EIA data appear to be incorrect.
5 Data for 2006-2009 provided by NorthWestern Energy, as EIA data appear to be incorrect.
6 Data provided by Naturener, as EIA data appear to be incorrect; averages exclude months in the first year of commercial operation.
7 Gross generation; plant use has not been subtracted out.
8 Operated by PPL; actual ownership shared with five other utilities.
9 Data for 2004-2006 provided by Tiber LLC.
10 NWE QF for summer months; in the other 9 months the output goes to Idaho Power.

Source: U.S. Department of Energy, Energy Information Administration, Form 906 and 920 databases (http://www.eia.gov/electricity/data/eia923/index.html), except as follows: Landfill Gas to Energy - Flathead Electric Cooperative; Milltown Dam, Strawberry Creek, NWE QFs and Two Dot - NorthWestern Energy; Hellroaring Creek - Mission Valley Power; Lake Creek - Northern Lights Cooperative; and Boulder Creek - S&K Holdings. Additional sources listed in footnotes 4, 5 and 9.

Table E3. Average Generation by Company, 2001-2005 and 2006-2011

Company	aMW[1] 2001-2005	aMW[1] 2006-2011
Avista[2]	356.9	377.5
Basin Creek Power Services	--	5.0
Basin Electric Cooperative	--	3.9
Bonneville Power Administration[3]	309.8	347.7
Colstrip Energy Partnership	31.7	33.9
Flathead Electric Cooperative	--	0.7
Hydrodynamics	0.8	1.0
Invenergy	--	53.5
Mission Valley Power	0.2	0.2
Montana-Dakota Utilities	36.8	44.3
MT Dept of Natural Resources and Conservation	4.8	5.7
Naturener	--	46.6
Northern Lights Cooperative	2.8	2.9
NorthWestern Energy[2]	185.6	217.5
NWE QF - other hydro	0.8	0.9
NWE QF- other wind	0.0	0.1
Ormat	--	4.8
PacificCorp[2]	125.7	123.2
Portland General Electric[2]	245.6	239.6
PPL Montana[2]	906.8	941.1
Puget Sound Energy[2]	561.8	548.0
Rocky Mountain Power	--	77.2
Salish-Kootenai Tribes	0.1	0.1
Southern Montana G&T Cooperative[3]	--	--
Tiber LLC	3.5	5.3
Turnbull Hydro LLC	--	2.5
Two Dot Wind	0.3	0.5
United Building Materials	--	2.7
Western Area Power Administration[4]	157.7	207.0
Yellowstone Energy Partnership	45.6	48.6
TOTAL	2,977.2	3,342.2

Montana Generation by Plant Owner

	2001-2005 aMW[1]	2001-2005 Percent	2006-2011 aMW[1]	2006-2011 Percent
PPL	907	30.5%	941	28.2%
Puget	562	18.9%	548	16.4%
Avista	357	12.0%	377	11.3%
BPA	310	10.4%	348	10.4%
PGE	246	8.3%	240	7.2%
NWE	186	6.2%	218	6.5%
WAPA	158	5.3%	207	6.2%
Pacific	126	4.2%	123	3.7%
Rocky Mt	--	--	77	2.3%
Naturener	--	--	47	1.4%
Invenergy	--	--	53	1.6%
Yellowstone	46	1.5%	49	1.5%
MDU	37	1.2%	44	1.3%
Other	45	1.5%	70	2.1%
TOTAL	2,977	100.0%	3,342	100.0%

Colstrip Ownership Percentages, 2013 (based on capability)

	MW	Percent
Avista	222	11%
NorthWestern	222	11%
PacifiCorp	148	7%
PPL	529	25%
Portland	296	14%
Puget	677	32%
TOTAL	2094	100%

MW in Colstrip Units:

I & II	III & IV
614	1480

[1] aMW = average megawatt, or 8,760 megawatt hours in a year. Average Megawatts may include fewer years than the column range given such as for Ormat which started in 2010

[2] 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.

[3] Southern Montana G&T Cooperative started running the Highwood Generating Station in 2011. It has only run a few times in 2011 and 2012 for testing purposes only.

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

Source: U.S. Department of Energy, Energy Information Administration, Form 906 and 920 databases (http://www.eia.gov/electricity/data/eia923/index.html), with additional data from Basin Electric Cooperative, Flathead Electric Cooperative, Mission Valley Power, Naturener, Northern Lights Cooperative, NorthWestern Energy for QFs, Milltown and corrected Judith Gap data, S&K Holdings, and Tiber LLC, Troy Dalgren, Southern Montana G&T, personal communication, Dave Hoffman, PPL, personal communication.

Table E4. Annual Consumption of Fuels for Electric Generation, 1960-2011[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	11,929	824	1,045
2008	12,012	809	573
2009	10,151	928	772
2010	12,005	778	727
2011[4]	9,772	878	4,681

* 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.

[4] The Dave Gates Generating Station, which began production in 2011, accounts for the significant uptick in natural gas usage for 2011. This increase in natural gas usage, combined with an enormous runoff year and corresponding high hydroelectric production, is the reason for lower coal usage in 2011.

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, Form EIA906 data, (1990-2011). 2011 data found at http://www.eia.gov/electricity/data/state/.

Table E5. Net Electric Generation by Type of Fuel Unit, 1960-2011 (million kWh)[1,2]

YEAR	HYDROELECTRIC (million kWh)	%	COAL (million kWh)	%	PETROLEUM [3] (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	*			25,921
1991	11,970	42	16,433	58	20	*	32	*			28,455
1992	8,271	32	17,454	68	17	*	35	*			25,776
1993	9,614	40	14,083	59	22	*	35	*			23,754
1994	8,150	33	16,809	67	20	*	73	*			25,052
1995	10,746	41	14,934	58	168	1	49	*			25,897
1996	13,795	52	12,463	47	445	2	55	*			26,758
1997	13,406	47	14,616	51	437	2	49	*			28,508
1998	11,118	39	16,785	59	427	2	56	*			28,385
1999[4]	11,879	44	16,993	54	487	2	37	*			29,476
2000	9,623	36	16,201	61	520	2	27	*			26,371
2001	6,613	27	17,036	70	498	2	20	*			24,167
2002	9,567	38	15,338	60	470	2	17	*			25,391
2003	8,702	33	17,049	65	402	2	25	*			26,178
2004	8,856	33	17,380	65	439	2	28	*			26,703
2005	9,587	34	17,823	64	415	1	27	*			27,853
2006	10,130	36	17,085	61	419	1	68	*	436	2	28,138
2007	9,364	33	18,357	64	479	2	106	*	496	2	28,802
2008	10,000	34	18,332	62	419	1	66	*	593	2	29,409
2009	9,506	36	15,611	59	490	2	78	*	821	3	26,506
2010	9,415	32	18,601	63	409	1	57	*	930	3	29,791
2011	12,596	42	15,056	50	461	2	418	1	1,166	4	30,129

NA = Not available *Less than 0.5 percent. The Total column may include other fuels not listed in the fist five columns

[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 nonutility plants selling into the grid is included. From 1990 forward, TOTAL includes minor amounts of generation from sources not listed in the table. This table is useful for long-term trends; Table E3 is more detailed for recent production figures. For more information on this data, go to http://www.eia.gov/electricity/annual/pdf/tech_notes.pdf

[2] Outputs from certain hydro and wind facilities, most notably Lake (1996-2010) and Tiber (2004-2005), aren't included in the EIA database; the sum of these exclusions is around 65-75 million kWh (~8 aMW) at its highest and much less otherwise. Further, there are several known errors (see Footnotes 3-6 in Table 2) and probably additional errors not known to DEQ. Because the net error in the EIA data is not known, DEQ has not made any corrections in these data except as noted in Footnote 4.

[3] Primarily petroleum coke and some fuel oil.

[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 - 2011 Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923) found at* http://www.eia.gov/electricity/data/state/.

Table E6. Annual Sales of Electricity, 1960-2011 (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[1]	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]	4,669	4,826	5,831	NA	15,326	3,732,962
2009[3]	4,774	4,779	4,773	NA	14,326	3,596,865
2010[3]	4,743	4,789	3,891	NA	13,423	3,754,493
2011[3]	4,913	4,892	3,983	NA	13,788	3,282,882

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 interdepartmental 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 and is believed to be minimal in recent years.

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 (2000-2011, sales_annual.xls, http://www.eia.gov/electricity/data.cfm#sales, as of 4-21-13); updated information on 1997 sales provided by Bonneville Power Administration (1997).

Table E7. Average Annual Prices for Electricity Sold, 1960-2011 (cents per kilowatt-hour)[1]

Year	MONTANA								U.S.
	Residential	Commercial	Industrial	Street & Highway Lighting	Other Public Authorities	Railroads & Railways	Intra-Company Sales	All Montana 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
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	3.19	14.09	NA	--	NA	4.80	6.74
1999[2]	6.78	6.35	2.74	14.36	NA	--	NA	4.77	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]	9.13	8.54	5.90	NA	NA	--	NA	7.72	9.74
2009[2]	8.93	8.32	5.45	NA	NA	--	NA	7.57	9.82
2010[2]	9.16	8.55	5.49	NA	NA	--	NA	7.88	9.83
2011[2]	9.75	9.12	5.27	NA	NA	--	NA	8.23	9.90

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 including 'All Montana Sales' 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 (2000-2011).

[2] Calculation of prices is 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 is believed to be minimal in recent years. Errors in price, where they exist, are most likely to occur in industrial prices.

Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* , 1961-2000; U.S. Department of Energy, Energy Information Administration, Form 861 Database (2000-2011, avgprice_annual.xls, http://www.eia.gov/electricity/data.cfm#sales as of 4-21-13).

Table E8. Utility Revenue, Retail Sales, Consumers and Average Price per Kilowatt-hour, 2011 (with comparison to 2005 price)

	RESIDENTIAL			Average price (cents/kWh)[2]		COMMERCIAL			Average price (cents/kWh)[3]		INDUSTRIAL			Average price (cents/kWh)[3]		TOTAL			Average price (cents/kWh)[3]	
UTILITY NAME	Revenue ('000s)	Sales (aMW)[1]	Consumers	2011	2005	Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	2011	2005	Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	2011	2005	Revenue ('000s)	Sales (aMW)[1]	Consumers[2]	2011	2005
Cooperative	$195,865	238.5	163,722	9.4	7.7	$93,530	133.9	24,542	8.0	6.9	$46,318	78.7	4,246	6.7	5.3	$335,713	451.1	192,510	8.5	7.0
Beartooth Electric Coop, Inc	$8,522	6.2	5,274	15.7	8.7	$1,075	0.9	346	13.8	7.7	$0	0.0	-	0.0	6.5	$9,597	7.1	5,620	15.4	8.5
Big Flat Electric Coop Inc	$2,159	2.1	1,652	11.6	9.4	$429	0.4	201	11.1	9.6	$703	0.6	33	13.6	10.3	$3,291	3.2	1,886	11.9	9.6
Big Horn County Elec Coop, Inc	$3,683	4.2	3,090	9.9	8.4	$1,996	2.2	541	10.2	8.1	--	--	--	--	--	$5,678	6.5	3,631	10.0	8.3
Big Horn Rural Electric Co	$45	0.0	37	12.6	9.5	$200	0.2	29	12.5	9.1	$1,526	1.4	1	12.8	8.4	$1,771	1.6	67	12.8	8.5
Fall River Rural Elec Coop Inc	$1,704	1.8	1,343	10.6	9.7	$2,133	3.5	511	7.0	7.1	--	--	--	--	--	$3,837	5.3	1,854	8.3	8.0
Fergus Electric Coop, Inc	$8,917	6.8	5,804	14.9	10.2	$12,854	15.0	239	9.8	5.6	$242	0.2	94	16.3	10.2	$22,013	22.0	6,137	11.4	8.0
Flathead Electric Coop Inc	$53,772	80.8	51,848	7.6	7.5	$27,044	49.0	9,526	6.3	7.2	$10,533	23.9	82	5.0	4.8	$91,349	153.7	61,456	6.8	6.7
Glacier Electric Coop, Inc	$6,669	8.1	5,788	9.4	8.9	$5,669	9.1	1,658	7.1	6.4	$1,165	2.3	4	5.9	5.2	$13,503	19.5	7,450	7.9	7.2
Goldenwest Electric Coop, Inc	$708	0.7	697	12.4	10.4	$101	0.1	9	13.4	8.4	--	--	--	--	--	$809	0.7	706	12.5	9.9
Grand Electric Coop, Inc	$11	0.0	16	8.7	6.9	--	--	--	--	--	--	--	--	--	--	$11	0.0	16	8.7	6.9
Hill County Electric Coop, Inc	$4,866	4.5	3,541	12.2	9.9	$2,439	2.9	185	9.6	7.3	$3,750	6.0	3	7.2	3.4	$11,056	13.4	3,729	9.4	5.9
Lincoln Electric Coop, Inc	$5,931	8.6	4,611	7.9	5.3	$1,845	3.1	690	6.9	5.1	$743	1.1	4	7.6	5.1	$8,519	12.8	5,305	7.6	5.2
Lower Yellowstone R E A, Inc	$2,657	4.0	2,682	7.5	7.5	$2,334	2.9	722	9.2	9.1	$7,588	9.0	888	9.6	8.1	$12,579	15.9	4,292	9.0	8.0
Marias River Electric Coop Inc	$2,340	3.7	2,491	7.3	4.9	$4,145	6.4	1,314	7.4	5.4	--	--	--	--	--	$6,485	10.1	3,805	7.3	5.2
McCone Electric Coop Inc	$5,387	5.3	4,496	11.6	9.4	$2,303	2.7	578	9.8	7.5	--	--	--	--	--	$7,690	8.0	5,074	11.0	8.8
McKenzie Electric Coop Inc	$71	0.1	124	10.5	7.7	$0	0.0	1	30.0	6.3	--	--	--	--	--	$71	0.1	125	10.5	7.6
Mid-Yellowstone Elec Coop, Inc	$2,120	1.7	1,018	14.3	9.2	$460	0.4	202	12.7	8.4	$894	0.7	723	15.4	--	$3,474	2.8	1,943	14.3	9.1
Missoula Electric Coop, Inc	$14,230	17.6	12,393	9.2	7.6	$3,327	4.6	1,270	8.2	6.6	$1,214	2.2	280	6.4	6.1	$18,771	24.4	13,943	8.8	7.3
Northern Lights, Inc	$4,098	5.0	3,692	9.3	8.9	$642	0.9	258	8.5	7.9	$2,303	5.9	5	4.5	4.4	$7,043	11.8	3,955	6.8	6.9
NorVal Electric Cooperative, Inc	$3,403	3.4	1,895	11.5	8.5	$2,617	2.0	1,308	15.0	11.5	$522	0.6	4	9.7	9.7	$6,542	6.0	3,207	12.5	9.3
Park Electric Coop Inc	$6,330	7.7	5,151	9.3	8.4	$596	1.0	84	7.0	6.4	$4,650	8.2	278	6.5	4.2	$11,576	16.9	5,513	7.8	6.2
Powder River Energy Corporation	$41	0.1	43	7.7	6.4	$2,355	2.8	176	9.6	5.9	$4,620	10.7	63	4.9	6.6	$7,016	13.6	282	5.9	6.5
Ravalli County Elec Coop, Inc	$10,248	15.5	9,377	7.6	6.7	$702	1.1	362	7.2	6.3	$165	0.3	1	5.7	5.0	$11,115	16.9	9,740	7.5	6.6
Sheridan Electric Coop, Inc	$2,936	4.0	2,731	8.4	7.4	$6,103	7.1	781	9.9	7.7	$262	0.2	601	12.4	13.0	$9,300	11.3	4,113	9.4	7.7
Southeast Electric Coop, Inc	$2,198	1.8	1,960	13.8	11.2	$87	0.1	18	11.2	8.5	$853	1.0	2	9.4	4.9	$3,138	2.9	1,980	12.2	6.8
Sun River Electric Coop, Inc	$5,519	5.4	4,421	11.7	8.4	$1,188	1.7	267	8.2	5.6	$2,110	2.3	862	10.4	6.7	$8,817	9.4	5,550	10.8	7.5
Tongue River Electric Coop Inc	$7,421	6.3	4,264	13.4	7.5	$1,521	1.5	519	11.6	7.8	$1,854	1.7	132	12.6	6.2	$10,796	9.5	4,915	13.0	7.3
Vigilante Electric Coop, Inc	$6,783	11.2	7,745	6.9	6.4	$3,313	6.3	1,323	6.0	5.6	--	--	--	--	--	$10,096	17.5	9,068	6.6	6.1
Yellowstone Valley Elec Co-op Inc.	$23,096	21.8	15,538	12.1	7.6	$6,053	6.1	1,424	11.3	7.2	$622	0.57123	186	12.4	--	$29,771	28.5	17,148	11.9	7.5
Federal	$14,119	26.9	14,547	6.0	5.3	$10,025	25.6	6,204	4.5	3.7	$0	0.0	-	0.0	3.3	$24,144	52.6	20,751	5.2	3.8
Mission Valley Power	$14,119	26.9	14,547	6.0	5.3	$7,752	15.7	6,182	5.6	5.8	--	--	--	--	4.7	$21,871	42.6	20,729	5.9	5.5
Western Area Power Administration	--	--	--	--	--	$2,273	9.9	22	2.6	1.3	--	--	--	--	--	$2,273	9.9	22	2.6	1.3
Municipal[3]																				
City of Troy	$715	1.4	840	6.0	5.5	$279	0.6	123	5.3	5.1	$6	0.0	5	8.8	9.1	$1,000	2.0	968	5.8	5.4
Investor-Owned	$268,455	294.0	290,839	10.4	8.6	$331,981	379.8	70,191	10.0	8.0	$52,655	90.2	1,585	6.7	5.6	$653,091	764.0	362,615	9.8	7.9
Avista Corp	$11	0.0	9	6.6	4.6	$27	0.0	12	7.5	6.3	$0	0.0	-	--		$38	0.1	21	7.2	5.4
Black Hills Power	$7	0.0	13	8.2	7.6	$42	0.0	20	10.1	9.2	$2,403	5.7	2	4.8	4.8	$2,452	5.8	35	4.8	4.8
Montana-Dakota Utilities Co	$15,238	20.9	18,879	8.3	7.3	$16,726	27.6	5,315	6.9	5.6	$16,459	36.4	147	5.2	4.3	$48,423	84.9	24,341	6.5	5.5
NorthWestern Corporation	$253,199	273.1	271,938	10.6	8.7	$315,186	352.1	64,844	10.2	8.2	$33,793	48.1	1,436	8.0	6.3	$602,179	673.2	338,218	10.2	8.2
Power Marketers[4]	--	--	--	--	--	$978	2.7	3	--	3.3	$98,508	286.5	17	3.9	3.9	$99,485	289.3	20	3.9	3.9
ConocoPhillips Company	--	--	--	--	--	--	--	--	--	--	$14,845	47.4	4	3.6	6.3	$14,845	47.4	4	3.6	6.3
Hinson Power Company LLC[5]	--	--	--	--	NA	--	--	--	--	NA	$503	1.0	1	5.7	NA	$503	1.0	1	5.7	NA
PPL EnergyPlus LLC	--	--	--	--	--	$978	2.7	3	--	--	$83,159	238.1	12	4.0	3.5	$84,137	240.9	15	4.0	3.5
STATE TOTALS [8]	**$479,153**	**560.8**	**469,948**	**9.8**	**8.1**	**$436,793**	**542.7**	**101,063**	**9.2**	**7.6**	**$197,487**	**455.4**	**5,853**	**4.9**	**4.4**	**$1,113,434**	**1559.0**	**576,864**	**8.2**	**6.5**

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

[2] 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.

[3] DOE did not have data on sales by Electric City Power, Inc, owned by the City of Great Falls. Total 2011 sales by ECP were 12.4 aMW. ECP still gets its supply from SME, who gets it from an energy trading firm (and formerly from PPL under a contract that was rejected in the bankruptcy contract from 2012).

[4] Revenues don't include all transmission and distribution costs. These costs add approximately 1- 3 cents to the delivered price of electricity in most cases.

[5] In 2005, Bonneville Power Administration, instead of Hinson Power Company, supplied CFAC. Therefore, no price data are given for 2005.

[8] 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. These reported state totals are a net of 15 aMW below that reported in Table E6 or about a 1% difference.

Source: U.S. Department of Energy, Energy Information Administration, Form EIA-861 database 2011, file 2_2011.xls, http://www.eia.gov/electricity/data/eia861/.

Table E9. Percent Of Utility Sales To End Users in Montana and Elsewhere, 2011

Utility	Percentage in Montana	Other States					
		State	Percent	State	Percent	State	Percent
Avista Corp	0%	WA	62%	ID	38%		
Beartooth Electric Coop	94%	WY	6%				
Big Flat Electric Coop	100%						
Big Horn County Elec Coop	93%	WY	7%				
Big Horn Rural Electric Co	11%	WY	89%				
Black Hills Power	3%	SD	87%	WY	10%		
ConocoPhillips	18%	IL	52%	TX	14%	PA	16%
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	28%	ND	72%				
Grand Electric Coop	0%	SD	100%				
Hill County Electric Coop	100%						
Hinson Power Company	100%						
Lincoln Electric Coop	100%						
Lower Yellowstone R E A	87%	ND	13%				
Marias River Electric Coop	100%						
McCone Electric Coop	100%						
McKenzie Electric Coop	0%	ND	100%				
Montana-Dakota Utilities Co	26%	ND	59%	SD	5%	WY	10%
Mid-Yellowstone Elec Coop	100%						
Mission Valley Power	100%						
Missoula Electric Coop	100%	ID	0%				
NorVal Electric Coop	100%						
Northern Lights	31%	ID	69%	WA	0%		
NorthWestern Energy	79%	SD	20%	WY	0%		
Park Electric Coop	100%						
Powder River Energy Corporation	4%	WY	96%				
PPL EnergyPlus	24%	PA	74%	NJ	2%		
Ravalli County Elec Coop	100%						
Sheridan Electric Coop	94%	ND	6%				
Southeast Electric Coop	98%	SD	1%	WY	0%		
Sun River Electric Coop	100%						
Tongue River Electric Coop	100%						
City of Troy	100%						
Vigilante Electric Coop	100%	ID	0%				
WAPA	2%	CA	57%	AZ	16%	Others	26%
Yellowstone Valley Elec Coop	100%						

Source: U.S. Department of Energy, Energy Information Administration, Form EIA-861 database 2011, file 2_2011.xls, http://www.eia.gov/electricity/data/eia861/.

Montana's Electric Transmission Grid

The transmission grid serves the vital function of moving power from generating plants to customers and their electric loads. It robustly and reliably provides this service even though individual elements of the transmission grid may be knocked out of service or taken down for maintenance. The ownership of and rights to use the transmission system are complex matters. This use is further complicated by line congestion on in-state and interstate lines. Electric transmission is quickly changing, with increased regulation at the national level and increasing amounts of variable generation on the system. The construction of new in-state and out-of-state transmission lines to expand the capacity of the current grid and to make new Montana power generation possible is also a challenging topic, raising questions about property rights and economic development.

Historic Development and Current Status of Transmission in Montana

The transmission network in Montana, as in most places, initially 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 hydroelectric 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 in 1901 from the Madison dam plant, near Ennis, to Butte. Improvements to insulators and tower design soon allowed for the transmission of higher voltages. A major transmission project of the time shipped power from the newly-constructed Rainbow Dam on the Missouri River near Great Falls to the Butte-Anaconda area. Completed in 1910 using metal lattice towers, the 100-KV high-tension twin lines featured modern suspension insulators. At the time of construction, it was the longest high voltage transmission line in the country. The Rainbow Line remains in service more than a century later.[1]

The MPC presided over Montana's first integrated transmission system. As the transmission system grew, MPC expanded its network to include 161 kV lines and ultimately a 230 kV backbone of lines. The federal WAPA electric transmission system in Montana began to transport electricity to Fort Peck in the 1930s during construction of the dam there and then to move power to markets following construction of the generators at the dam in the early 1940s. WAPA's system continued to grow as its needs to serve rural electric cooperatives expanded and the Big Horn Hydroelectric Project came online in the late 1960s.

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[1] *Early Steel Towers and Energy for Montana's Copper Industry*, Montana the Magazine of Western History, F. Quivik, 1988.

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, BPA extended its high-voltage system into the Flathead Valley to interconnect with Hungry Horse Dam and to serve the now-defunct aluminum plant at Columbia Falls. In the mid-1980s, 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. 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 assets were purchased by NWE and most of its generation was sold to PPL Montana.[2]

Most intrastate (in-state) electric transmission in Montana is currently owned by NWE and WAPA. BPA has major interstate lines in Montana and PacifiCorp owns a few smaller interstate lines. WAPA lines in northern and eastern Montana cross into North Dakota and serve local Montana loads. In most cases, MDU uses WAPA lines and in a few instances co-owns lines. About 25 electric distribution cooperatives in Montana use the NWE, MDU, BPA, and WAPA lines for transmission.

Montana's strongest transmission interconnections with other regions include: two 500 kV lines (on the same towers and owned by several large utilities) leading from Colstrip into Idaho and Spokane; BPA's 230 kV lines and 500 kV line running west from Hot Springs; PacifiCorp's interconnection from Yellowtail Dam south to Wyoming; WAPA's direct current (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 lines from Yellowtail Dam to Wyoming; and NWE's AMPS line (a multiparty line that runs from northwestern Montana to southeastern Idaho) running south from Anaconda parallel to the Grace Line into Idaho (**Figure 4**).

Montana is an electricity export state. Currently, the state's net electricity exports are almost equal to the amount of electricity consumed in the state each year. For example, in 2010 Montana generated about 29,791 GWh and consumed just 13,423 GWh.[3] There are three primary electric transmission paths that connect Montana to the rest of the Western Interconnect and larger markets in the West.[4] These paths are:

- Montana to Northwest–Path 8
- Montana-Idaho–Path 18
- Montana Southeast–Path 80[5]

Typically, power flows from east to west over Path 8 and north to south over Paths 18 and 80. Directionally, energy on these transmission lines typically flows from Montana to out-of-state loads, although on occasion electricity flows into Montana on these same lines. A new path out

[2] As of late 2013 PPL Montana planned to sell its hydroelectric generation assets to NWE.

[3] *2010 Electric Power Annual*, State Data Tables, EIA, January 2012, http://www.eia.gov/electricity/state/.

[4] Transmission "paths" are groups of more or less parallel transmission lines that carry power within the same general areas.

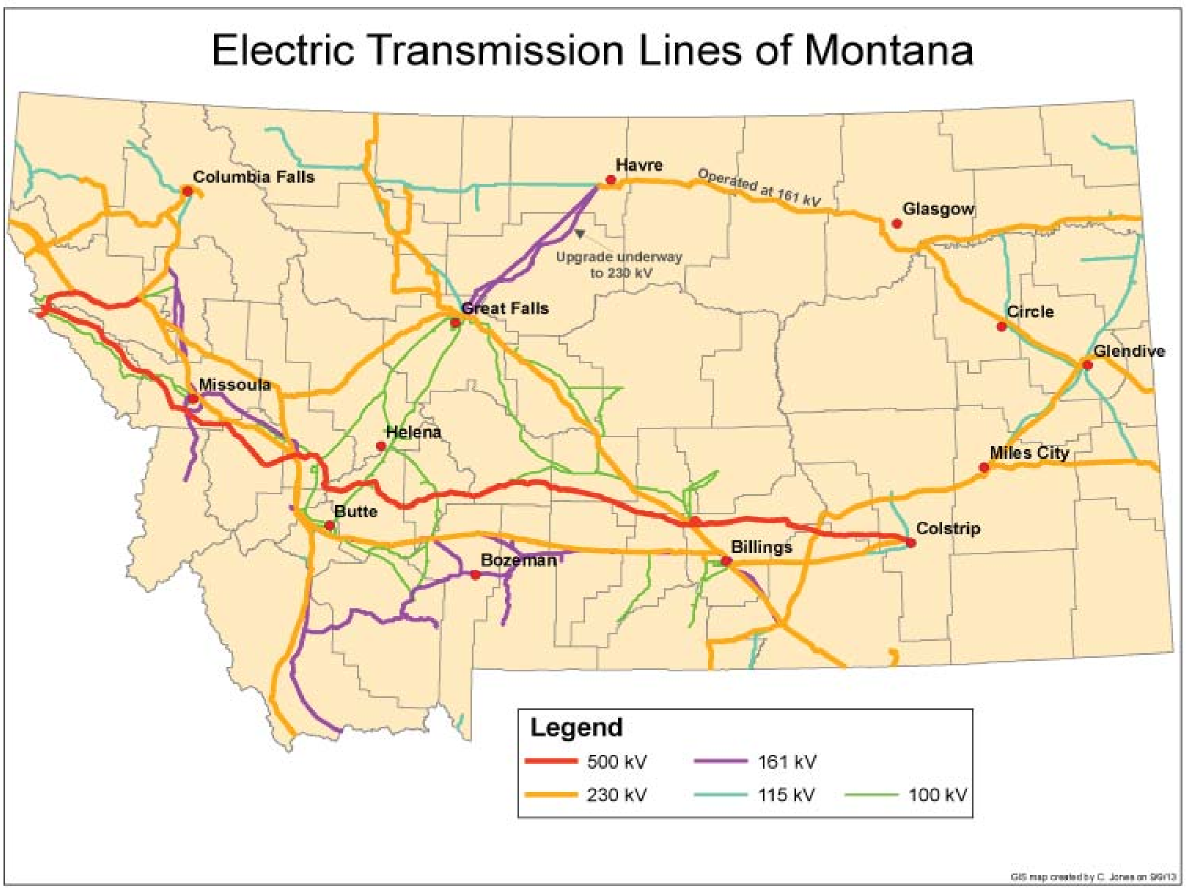
[5] WECC 2013 Path Rating Catalog, http://www.wecc.biz/library/Pages/Path%20Rating%20Catalog%202013.pdf.

of Montana, Path 83, has been created between Montana and Alberta with the recent completion of the Montana Alberta Tie Line (MATL). There is no official "path" leaving the most eastern portion of the state.

As U.S. and Canadian utilities have grown increasingly dependent 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 (**Figure 5**). 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 Eastern and Western 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

Figure 4. Electric Transmission lines of Montana as of 2013 (DEQ)



instantaneous flows across any such connection. Therefore, the two grids are only weakly tied to each other with converter stations. Eight converter stations across the U.S. currently connect (indirectly) the western and eastern grids with a combined capacity of 1,470 MW. One of these stations is located at Miles City. It is capable of transferring up to 200 MW of electricity in either direction.[6] Depending on transmission constraints, a limited amount of additional power can be moved from one grid to the other by shifting hydroelectric generation units at Fort Peck Dam.

Most of Montana is integrally tied into the Western Grid or Western Interconnection. However, the easternmost part of the state, with less than 10 percent of total Montana load, is part of the Eastern Interconnection and receives its power from generators located in that grid, including generators as far away as the east coast.

Certain transmission lines in Montana are regulated under the Montana Major Facility Siting Act (MFSA) administered by the Montana Department of Environmental Quality (DEQ). 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 are covered under MFSA if they meet certain criteria.

Figure 5. U.S. Western Interconnection – Major Lines

Historically, the Montana PSC has jurisdiction over cost recovery for new transmission projects that serve Montana retail customers, but not over siting decisions.

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 commercial operation and management. The flow of power on a transmission network (the charge of 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 power.

Transmission "paths" are generally 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

[6] Donald G. Davies, Chief Senior Engineer, Western Electricity Coordinating Council.

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 the Dillon area into Idaho, the Grace Line and the AMPS line, form what is called "Path 18".

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. 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 (the scheduled path) or even the shortest distance path. A 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. The resistance or impedance of a given transmission line depends on its voltage and current. Power flows generally cannot be constrained to any particular physical or contract path, but instead follow the laws of physics.

Electric power flows in opposite directions also 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 is shipped westbound on a given transmission line from point A to point B and 25 MW is sent simultaneously eastbound on that same line from point B to point A, the actual measured flow on the line is 75 MW in a westbound direction. If 100 MW is sent in each direction on the same line at the same time, the net measured flow is zero. In this situation, additional power could still physically flow in either direction up to the full capacity of the line in that particular direction.

Electric power also travels near the speed of light and is consumed at the same moment it is generated. Almost all generated power distributed over the grid must be consumed instantaneously off of the grid.[7] Unlike gas, oil, coal, and other energy sources, electricity cannot yet be stored as inventory in large quantities. Transmission operators constantly balance electricity supply (generation) and demand (consumption). This is a complicated process that involves significant manpower and technology, complicated balancing routines, numerous transmission jurisdictions, and federal and state oversight.[8] The fact that almost all power generated on the grid must be consumed instantaneously is the reason why steady generation sources fueled by coal and natural gas are often easier to manage than some renewable sources such as wind and solar, whose generation levels vary. Because of the constant need to balance supply and demand, the electric transmission system has, at times, been called the most complicated machine on the planet.

[7] With current technology, a small fraction of generated power can be stored in flywheels, in salt caverns (usually associated with wind power), in melted salts (solar farms), and in pumped storage.

[8] There are several high-tech and human mechanisms for balancing supplies and demand on the entire Western Grid and within individual operating areas, like NWE's balancing authority in Montana. There are also new technologies being developed to economically allow the storage of large quantities of electricity on the grid, but they are not available yet.

The actual physical flows on a grid are the net result of all generators and all loads (electricity demands) on the network at a given instant in time. 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 depend on the amounts and locations of electric generation and load as opposed to the contracted schedules in place at a given time. Actual path loads are also impacted by congestion of certain lines or paths on the grid and outages on the grid.

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, referred to as the contract path, 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 the entities holding rights to use those wires along that path. Purchasers also may include entities that want to use the grid on a short-term basis when there is room available. In a perfect world, these transactions flow on the contract path agreed to by the interested parties. Due to the laws of physics that ultimately govern the grid and grid conditions at any given time, however, portions of any contracted transaction flow along other paths aside from the contracted path. These are "unscheduled flows". An unscheduled flow is a result of the difference between the physics of the transmission system and the scheduling paradigm (contract rights). Inadvertent flows are also flows that are not scheduled but can be caused by a variety of events, including but not limited to unplanned loss of generators or load, data errors, and scheduling errors.[9]

On the Western Grid, major unscheduled flows occur around the entire interconnection at any given moment. For example, power sent from hydroelectric dams in Washington to California flows directly south over the contracted pathways, but also flows clockwise through Utah and Colorado into New Mexico and Arizona and then west to California. Power sent from Colstrip in eastern Montana to Los Angeles flows mostly west on Path 8 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, a small amount of Colstrip power also flows over other paths, including south through Wyoming on Path 80, on its way to California.

Unscheduled flows may interfere with the ability of transmission path owners to make full use of their contractual rights. The Western Electricity Coordinating Council (WECC) addresses unscheduled flows with an unscheduled flow mitigation plan. Utilities (or other transmission owners) whose wires are affected accommodate a certain amount of this unscheduled flow by reducing their available transmission capacity. If further reductions are necessary, the path owners can request an adjustment of flows throughout the interconnection. Path owners can also call for curtailment of schedules across other paths that affect their ability to use their own path.[10]

[9] Craig Williams, WECC, Market Interface Manager.

[10] Ibid.

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. Counterscheduling is allowed; however, counterscheduling does not "create" additional firm capacity. 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. Because of this, scheduling against reverse flows is not considered firm capacity because the power may not always be available.

If scheduled flows do not exhaust a path rating, the unused capacity may be released as "nonfirm" transmission capacity. Nonfirm capacity is available during only some hours of the year, not during all hours as with firm capacity. Nonfirm capacity is generally not purchased very far in advance. Owners of transmission capacity who do not plan to use extra room on their lines can in some instances release it early. Owners, however, are often reluctant to do so because of needs for flexibility or a desire to withhold access to markets from competitors.

Transmission adds monthly charges to our electricity bills and can result in different electricity costs across regions. Electricity prices are impacted by the cost of transmission service to move power from one area to another. For example, a generator in Montana who wishes to sell to the Mid-Columbia (Mid-C) market, the major electricity trading hub closest to Montana and located in Washington, pays transmission charges on the NWE system and then on either the BPA or Avista system. These charges are necessary to transmit, or "wheel", the power from the NWE system area to Mid-C. These additional costs mean that the wholesale-priced power from generation in NWE's territory for local Montana consumption is generally sold in Montana at a discount relative to the Mid-C market price for electricity because of the avoided transmission charges of sending that power into the Mid-C hub. In this manner, transmission pricing is integrally linked to electricity pricing throughout the region and the country.

Jurisdiction over transmission rates resides both with state utility regulators and with the Federal Energy Regulatory Commission (FERC), depending on circumstances. In the case of NWE, transmission rates for bundled retail customers are determined by the Montana PSC. Wholesale transactions that use NWE's transmission facilities pay the FERC-regulated transmission price. A standard feature of FERC-regulated transmission service is the Open Access Transmission Tariff (OATT). Each FERC-regulated transmission provider, including NWE, posts the terms and conditions of transmission service in its FERC-approved OATT. The OATT identifies various transmission product offerings, including network integration service, point to point (PTP) transmission service, and ancillary services.

PTP transmission service allows a transmission customer to wheel power to and from distinct locations. Ancillary services are services needed to support transmission service and maintain reliable operation of the transmission system. Each transmission provider's OATT includes terms and pricing for ancillary services that are required to support transmission service and maintain system balance. In general, FERC's treatment of these services is standardized across the country.

Grid Capacity and Reliability

The amount of power that a transmission line can carry is limited by several factors, including 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 to other objects. Arcing -- electricity traveling to the ground--may result. When that happens, the transmission line can fail, instantly stopping electricity flow and affecting the rest of the grid. Inductive characteristics on a line are associated with magnetic fields that constantly expand and contract in AC circuits wherever there are coils of wire, including transformers. This is not an issue for DC transmission lines.

The most important factor in determining the total amount of power that a line can carry is reliability. 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 failure. Causes include lightning, ice, pole collapse, animals shorting out transmission lines, falling trees, vandalism, and increasingly terrorism, including cyber-attacks. Reliability of the grid is ensured by building redundancy into it. The grid is designed to withstand the loss of key elements and still provide uninterrupted service to customers.

Reliability concerns limit the amount of power that can be carried over a line or path to the amount of load that can be served with key elements out of service on the grid. Within NWE's service area in Montana the reliability of the transmission system is evaluated by computer simulation and long-term transmission planning. 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 lines to higher capacities.

Another example of reliability limits relates to major transmission paths used to serve distant loads or to make wholesale transactions. 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 having two or more elements out of service. The Colstrip 500 kV lines west of Townsend are a double-circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service and because both circuits are on the same towers, which increases the potential of wildfire or other catastrophic event hindering both paths. At all times they carry significantly less power than their thermal limit in either direction.

The actual rating on a path can change hourly and depends on 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 toward the Idaho panhandle and Washington are called the Montana-Northwest path (Path 8). The Montana-Northwest path is generally limited 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 composed 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. The BPA is currently working on relatively low-cost improvements that would expand capacity by 500-700 MW on the Montana-Northwest path, specifically the double circuit 500 kV line. This proposed upgrade is called the Montana to Washington project (M2W) and would be used by new generators to access West Coast markets.

Ownership and Rights to Use the Transmission System

Rights to use the transmission system are 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 compose 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.

The FERC issued Order 888 in April 1996, which requires that transmission owners functionally separate their transmission operations and their power marketing operations. This means that all generators have the right to access utilities' transmission systems. If the transmission system in place does not have sufficient capacity to accommodate a bona fide request for transmission service, the utility must begin the process to build the needed upgrades, provided that the transmission customer pays for the incremental cost of the upgrades.

Power marketing occurs when transmission owners who 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 public website called Open Access Same-Time Information System (OASIS) on which available capacity is posted.

Available transmission capacity (ATC) is the available room on existing transmission lines to move power during 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 are rights to transfer power on a firm basis every hour of the year. The owners of transmission rights on rated paths may or may not actually schedule power during every hour. When they don't, the unused space may be available on a nonfirm basis. In 2014, 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 for the most part fully allocated and tightly held. Only new lines or purchased rights will allow a new market entrant to obtain ATC beyond what is available. ATC may change on an hourly basis depending on grid conditions.

In terms of ATC, incremental export capacity out of Montana is extremely limited. There is no incremental firm export capacity out of Montana to the Southwest (Path 18) and limited incremental export capacity out of Montana to the Northwest (Path 8). ATC is also constrained instate on NWE's system, especially in the area south of Great Falls. Where ATC is available in state, it is typically to move power within Montana or through Montana to interstate lines. Because of these transmission constraints, there is a need for a new transmission line or an upgrade to the existing system to accommodate transmission service requests to move existing and planned electricity generation from Montana into load centers in the Pacific Northwest and California. Even with some limited export capacity to the Northwest, there is only minimal capacity available west of Idaho.

In addition, from Mid-C south to California, there is no long-term firm ATC (export capability). For all practical purposes, there is very little current long-term firm ATC northwest out of Montana beyond Mid-C. There is, however, capacity to import power into Montana over the paths. Despite little ATC availability, most transmission paths on the Western Grid are fully scheduled for only a small portion of the year, and nonfirm space is often 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.[11] However, nonfirm access cannot be scheduled far in advance, and its access cannot be guaranteed. Nonfirm access is a workable way to market excess power for existing generators. Nonfirm availability may be a reasonable way to develop new firm power transactions if backup arrangements can be made to cover the contracts in the event that the nonfirm space becomes unavailable. Financing new generation may be difficult, however, unless the power can be shown to move to market via firm space.

Congestion

Transmission constraints are often referred to as transmission congestion. Transmission congestion raises the price of delivered power. It often prevents low-cost power from reaching the areas where it is needed. Low-cost power has little value if it cannot be transmitted to a location where energy is needed. For example, because most existing Montana transmission is fully contracted, future generators in Montana may be prevented from selling their power into a number of wholesale markets except by using nonfirm rights. When transmission congestion exists, generators may be forced to sell at other locations where buyers are only willing to pay less for power.

Broadly speaking, transmission congestion causes price variations between various locations on the power grid. Absent transmission congestion and line voltage losses, the price of electricity would not vary significantly between the points of origination and delivery. However, the transmission system has physical capacity constraints and is subject to congestion when supply exceeds demand. At that point, managing congestion becomes part of the economic reality of delivering electricity.

In general terms, additional transmission capacity allows more generators to access the grid, promoting competition and lowering prices. Conversely, limited capacity necessitates either transaction curtailment or redispatch from a generator that bypasses the bottleneck in the

[11] BPA's OASIS website, http://transmission.bpa.gov/Business/Operations/intertie/default.aspx.

system. Areas with consistently high electricity prices, like southern California, experience the greatest degrees of transmission congestion year-round due to factors including significant demand, huge peaking demands during hot weather, and the necessity of large imports from other states.

Transmission congestion can have several different meanings. A transmission path may be described as congested if no rights to use it are for sale. Congestion also may 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.

By the first definition, the paths through which generators in Montana send their power west, and that includes West of Hatwai, are mostly congested – and few firm rights are currently available for those paths. By the second definition, the paths west of Montana are congested during a few hours of the year – contract holders fully use their scheduling rights only a small fraction of the time; the rest of the time they use only portions of their rights.

By the third definition, the lines 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 from scheduled flows because of the difference between the physics and the management of the grid.

As mentioned above, schedules are contract-path-based. In contrast, actual loadings follow the laws of physics and are net-flow-based and include inadvertent flows. Actual flows on the paths west of Montana are almost always below scheduled flows because of the inadvertent flows and loop flows in that part of the grid. **Figure 6** shows that from September 2012 to August 2013 the highest actual loadings on the Montana-Northwest path (Path 8) were loaded at or above 90 percent of the path capacity for only a few hours. For most hours, the path was not heavily loaded.[12] On the other hand, the path was 60 percent loaded or more about 50 percent of all hours in that time period, indicating that Path 8 is actually one of the most heavily used in the Western Interconnection. Even a well-used line, however, usually has physical space available for more electrons. The West of Hatwai path is physically less utilized as a percentage of being fully loaded than Path 8 (**Figure 7**).

Transmission capacity from Montana to the Pacific Northwest is limited by the amount of space that is simultaneously available on both paths. Because both paths are almost never completely full to their physical limitations, it appears that there is almost always some physical room available on both paths, although often that amount is likely small.

Path 18 from Montana to Idaho consists of two transmission lines. According to WECC, Path 18 is not historically congested based on actual electricity flows over the line.[13] WECC concludes

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[12] http://transmission.bpa.gov/Business/Operations/intertie/cutplanes/Montana.aspx.

[13] 10-Year Regional Transmission Plan: WECC Path Reports, WECC, approved by the Board of Directors September 22, 2011.

that the path could become congested in the future, contingent on development of renewable energy in Montana. Although Path 18 is not congested based on actual flows on the lines, it is heavily utilized from a scheduling standpoint. Actual flows are not high relative to the path rating due to the path being scheduled in both directions.

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.

Figure 6. Montana-Northwest Cutplane cumulative loading curve Sept. 2012-Aug. 2013

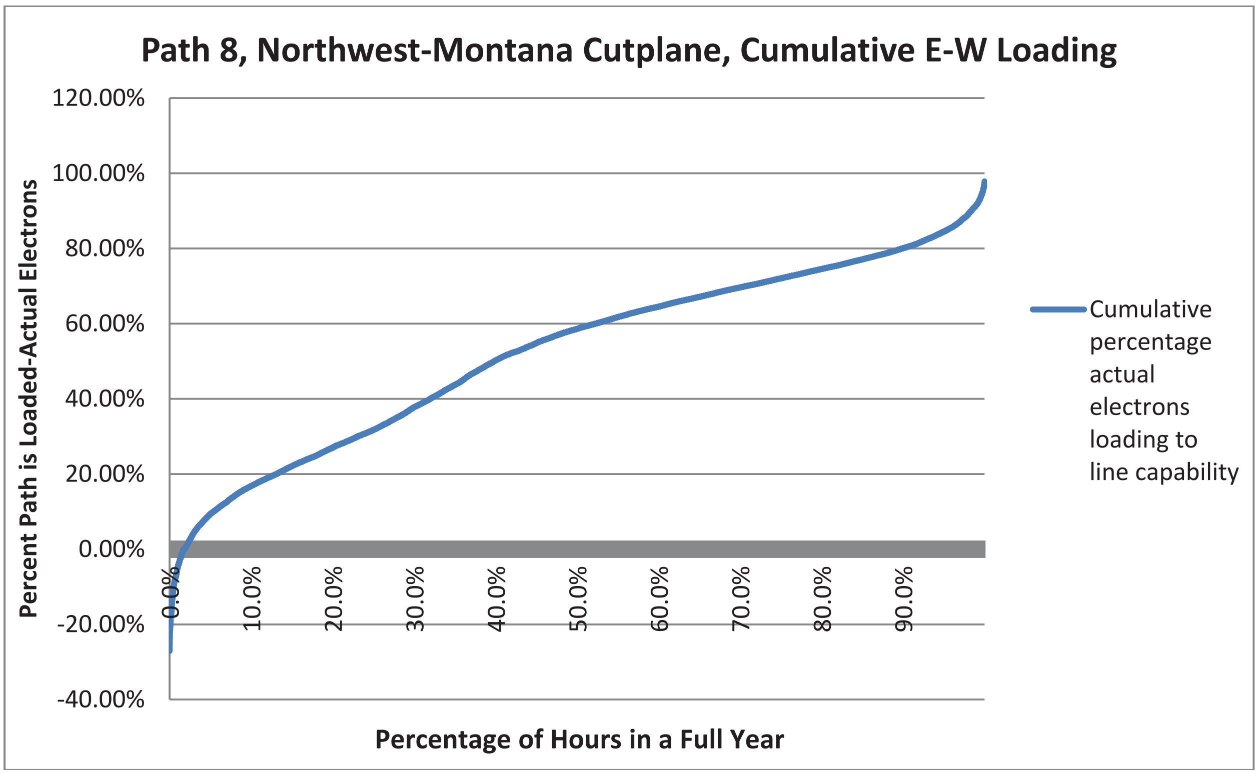
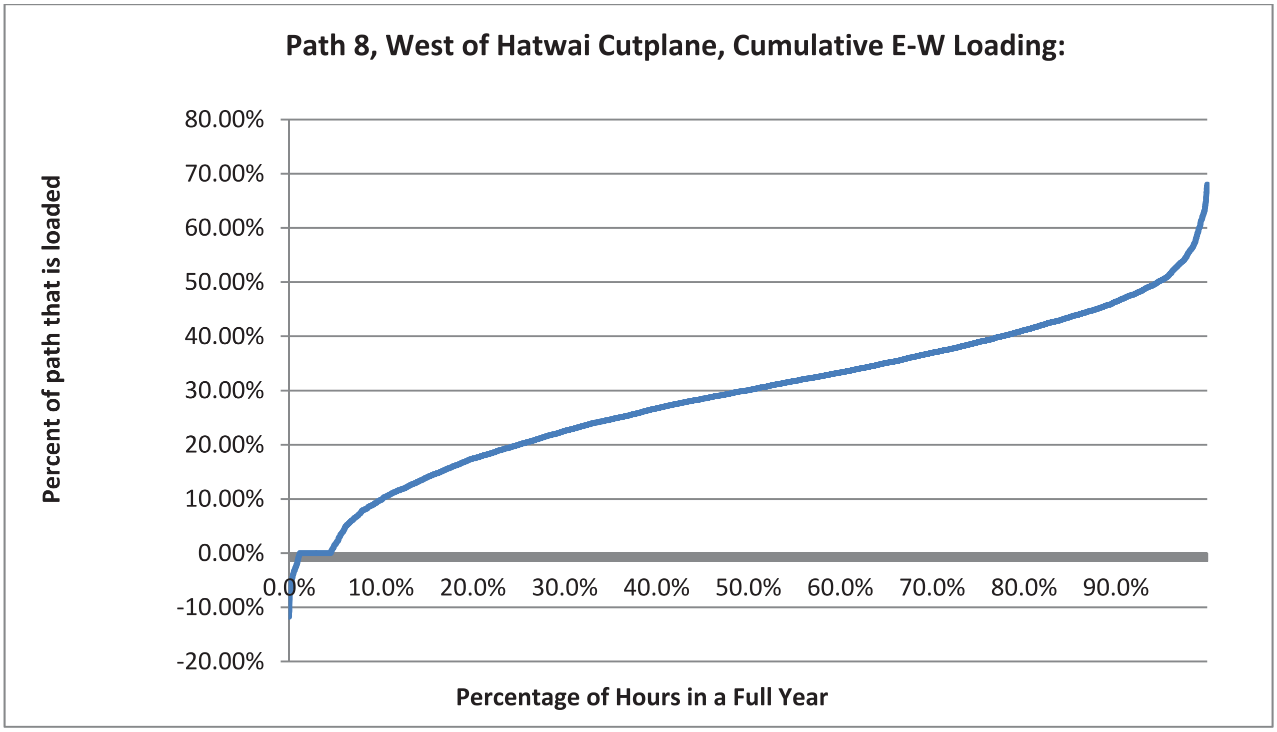


Figure 7. West of Hatwai Cutplane cumulative loading curve Sept. 2012-Aug. 2013



Grid Management by a Regional Transmission Organization (RTO)

A large portion of the electric load in the U.S. is procured through market transactions overseen by various RTOs and Independent System Operators (ISOs). These organizations are independent entities that emerged as a result of guidelines prescribed in FERC Orders 888 and 889 with which FERC sought to introduce competition and efficiency into electricity markets. RTOs/ISOs are charged under these orders with promoting nondiscriminatory access to transmission lines and fostering a competitive environment in restructured electricity markets. These organizations are responsible for developing a platform for the oversight of transmission capacity, transmission access scheduling, and congestion management.[14]

Most of Montana is not part of an RTO. RTO and ISO organizations in the U.S. include the Midwest Independent Transmission System Operator (MISO), which covers much of the Midwest including eastern Montana. Alberta, Canada, has Alberta Electric System Operator (AESO) as its version. PJM Interconnection is an RTO located in the eastern portion of the U.S. and California Independent System Operator (CAISO) is California's ISO.

Discussions about having an independent body take over operation and control of access for the transmission system have been underway since the mid-1990s among transmission owners and other stakeholders in the Pacific Northwest. Stakeholders include NWE and the BPA, among others. An RTO would allow all parties to signal their willingness to pay for transmission

[14] *Markets for Power in the United States*, Paul L. Joskow, The Energy Journal, Vol. 27, No. 1, 2006, page 17.

access and theoretically would make more efficient use of the grid. In addition, RTO management would result in congestion price signals that would encourage economy-based decisions on the location of new generation and on the expansion of capacity on congested transmission paths. Columbia Grid (consisting of BPA and Washington public and private utilities) and the Northern Tier Transmission Group (consisting of public utilities outside Washington and some Utah Cooperatives) continue to search for a solution to this issue.

Proposed Transmission Lines in Montana

In the past decade, there has been a strong interest in developing additional transmission to export Montana's generation potential to other markets. Montana's large energy resources and small in-state electricity demand make it a hot spot for proposed transmission projects to export power out of state. The largest electricity market in the Western Interconnection is California. In addition, substantial electricity sales growth is forecast for Arizona, Colorado, Utah, Washington, and Oregon. These markets will need substantial new resources in order to meet forecasted load growth. Renewable resource mandates also guarantee that a significant portion of newly built resources will be renewable.

The Montana Alberta Tie Line (MATL) came online in September 2013. It is the first direct interconnection between the Alberta and Montana balancing areas and is capable of carrying 300 MW in either direction.

In 2008, NWE applied for MFSA certification for the Mountain States Transmission Intertie, (MSTI) which would have been a 500 kV line running from Townsend to Midpoint, Idaho. This line would have been capable of carrying up to 900 MW south to north and 1,500 MW north to south. In 2012, the MSTI line was put on hold. At this time, MDU has indicated it has no major plans for electric transmission upgrades in Montana.

In the last decade, a few rebuilds of existing lines have taken place in Montana, including a WAPA 115 kV line between Great Falls and Havre built to 230 kV specifications and the rebuild of BPA's 115 kV line from Libby to Troy. NWE replaced a 50 kV line between Three Forks and the Four Corners area with a new 161 kV line. NWE also has started building the upgrade to a 161 kV line between Four Corners and Big Sky. The Montana to Washington project (M2W) is still in the planning stages and would increase the line rating of the Colstrip double-circuit 500kV lines by about 600 MW without the need for any new wires or towers. M2W would require a new substation located in Montana and additional work for 12 miles in Idaho.

New lines connecting Montana to the rest of the Western Grid could potentially increase competition among Montana energy suppliers. Increasing supplier competition in Montana's market could lower or stabilize electricity prices to Montana ratepayers in the near and distant future, although the extent and significance of such savings are unknown. On the flipside, some argue that new interstate lines out of Montana could increase electricity prices by opening up relatively cheap Montana electric 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. Siting the Colstrip double-circuit 500 kV lines in western Montana, particularly in the areas of Boulder, Rock Creek, and Missoula, required much work with a variety of entities.[15] As a result, the route is away from the interstate highway corridor, opening new corridors through forested areas.

Recent experience with the MATL and proposed MSTI lines shows that Montana citizens and landowners are concerned about interference with farming practices, visual impacts, reductions in property values, potential human health effects, and the use of private land rather than public land for electric transmission purposes.

Rural growth and residential construction in western Montana since the Colstrip lines were sited in the early 1980s may 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. Siting and routing a new line out of the state in a westerly direction would likely prove extremely challenging 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 into Wyoming and Idaho, and possibly alongside existing transmission lines to the west.

Regional Planning in the Western Interconnection

<u>NTTG</u>

The Northern Tier Transmission Group (NTTG) is a group of transmission providers and customers involved in the sale and purchase of transmission capacity on the power grid that delivers electricity to customers in the Northwest and Mountain states. The 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. NTTG is developing cost allocation methodology for FERC Order 1000 and working on its biennial report. The group's work establishes a plan for general transmission improvements needed for feasible system operation at times of transmission stress 10 years in the future. NWE is a member.

<u>FERC Order 1000</u>

In July 2011, FERC issued Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities. The order reforms the current transmission planning processes for new transmission lines and outlines new cost allocation principles for transmission lines approved in a transmission plan for purposes of cost allocation. Order 1000

[15] The original centerline proposed by the Colstrip partners crossing of the Confederated Salish and Kootenai Tribes would not be granted an easement by the tribe to get to the Hot Springs substation. The Colstrip partners got BPA to take over responsibility to build the line from Townsend west. BPA had originally planned to build the line on a right-of-way BPA already owned through the reservation. But during the NEPA process, it was determined that going to the Taft substation was preferable to the one at Hot Springs. These events made for the current route away from the interstate highway corridor, instead opening new corridors through forested areas and making for limited siting opportunities in the areas of Boulder, Rock Creek, and Missoula.

requires regional transmission planning groups to consider transmission that is necessary for reliability, economics, and achievement of federal or state laws and regulations when developing regional transmission plans. Order 1000 also requires interregional coordination on transmission planning. It requires that each region have coordinated procedures for the evaluation of transmission projects that span multiple regions.

Order 1000 addresses cost allocation for new transmission facilities. FERC set six basic principles for cost allocation and resolved that costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation should be allocated to those that benefit. Order 1000 introduced a degree of uncertainty into cost recovery for certain new transmission projects. Prior to the order, cost recovery for new transmission investments could be subject to FERC jurisdiction, rather than the jurisdiction of individual state commissions.

ACE Diversity Interchange Agreement

In 2006, five control areas or balancing authorities 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 WECC. ADI is the pooling of ACE to take advantage of control error diversity. As part of the ADI 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 on 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 to reduce generator wear and tear so that generator reliability increases.

Committee on Regional Electric Power Cooperation (CREPC)

CREPC is a joint committee of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners. CREPC is composed of the public utility commissions, energy agencies, and facility siting agencies in the western states and Canadian provinces in the western electricity grid. It works to improve the efficiency of the western electric power system.[16] CREPC's main issues are integrating more renewable energy into the system, FERC Order 1000, the energy imbalance market, future transmission plans, and current changes in the structure of WECC.

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, problems involved in siting high-voltage transmission lines, and the California Renewable Portfolio Standard (RPS).

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[16] http://www.westgov.org/wieb/site/crepcpage/.

Reliability Criteria

Reliability criteria for the Western Interconnection are set by the WECC. 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. Since the system is reliable as currently built and operated, reliability concerns generally focus on 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. Path 15 in central California or the Jim Bridger West path in Idaho are examples of paths where a line outage can result in cascading failures and impact many millions of people.

Others are concerned that WECC's governance of reliability criteria has been lax, especially given the large power outages that occurred on September 8, 2011 in the Southwest. In the wake of the Arizona-Southern California system disturbance that left 2.7 million customers without power, the NERC and the FERC issued a joint report identifying deficiencies in WECC's management of its reliability responsibilities and concluding that these contributed to the blackout. WECC's current responsibilities include serving as the regional entity for the Western Interconnection development and monitoring and enforcement of reliability standards for the bulk electric system in the Western Interconnection. It also serves as the single, centralized reliability coordinator for the Western Interconnection. There is concern that housing both the regional entity and reliability coordinator roles within WECC affects its ability to fulfill both responsibilities. In 2013 the WECC approved a resolution to bifurcate WECC. Under this new structure the reliability coordinator and interchange authority functions in the Western Interconnection will become a separate entity from WECC.[17]

Merchant lines

Efforts by FERC to open up electricity markets through approval of merchant transmission projects stimulate independent investment in transmission facilities, allowing for greater competition among power producers. Starting in 2000, FERC began approving applications by parties proposing market-based transmission rates known as merchant transmission projects. Merchant transmission is a model under which transmission costs are recovered through market-based or negotiated rates as opposed to traditional cost-based rates. Merchant transmission projects are a means to bring forward new capital investment to reduce transmission congestion and to link regional markets in situations in which the prospect of cost-based rate recovery proves to be insufficient to spur transmission development.

As a matter of basic economics, transmission congestion leads to disparate power prices. While these disparities may produce an incentive to construct new generation, it is plausible that new transmission priced at market rates would be a less expensive solution but would not necessarily be proposed under the traditional model of cost-based ratemaking. Regulators and developers realize that merchant transmission can meet this need.

[17] Northwest Power and Conservation Council, July 2, 2013, http://www.nwcouncil.org/media/6868113/p2.pdf.

The development of state renewable energy standards has given added impetus to merchant transmission, as parties seek to bring remote renewable energy to populated load centers. Generators and large customer loads are the parties most in need of this type of project.

Cost of Building Transmission

High-voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may cost up to $2 million per mile. A double-circuit 500 kV line may cost $3.1 million or more per mile. A 500 kV substation costs $50 million to $75 million, depending on the location on the network. If series compensation is required, 500 kV substations may cost up to $100 million. However, 230 kV lines are somewhat cheaper, about half the cost per mile of 500 kV lines, and substation costs run around $25 to $30 million each. These prices seem to be increasing faster than inflation, in part due to the increasing costs of metals.[18]

DC lines are cheaper still, but the equipment required to convert AC to DC 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 major DC lines in the Western Interconnection – the Pacific DC Intertie from Celilo in northern Oregon to Sylmar near Los Angeles and the IPP line from the Intermountain Power Project generating station in Utah to the Adelanto substation near Los Angeles. Neither line has any intermediate connections.

Financing Transmission Lines

The "beneficiary pays" model reflects the way transmission is financed for certain types of lines, like 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 benefits to Montana coal and wind developers unless they were willing to pay the costs of needed transmission. Proponents of the interstate highway model are skeptical that the beneficiary pays model will result in the timely construction of new transmission capacity.

The issues confronting proposed merchant generation plants are also different from those faced by traditional utilities. Utilities plan, finance, and build transmission and generation together and recover costs from ratepayers. Private generation developers must absorb the risk or convince another party to absorb that risk.

Alternatives to New Lines for Meeting an Increasing Electricity Demand

With increasing costs and siting difficulties for new transmission lines, there may be other alternatives to building transmission facilities that would keep the system robust. Some existing lines can be upgraded with new equipment to increase capacity. Some lines can be rebuilt on existing rights-of-way. One new line built on the grid could allow higher ratings on other lines in the grid just from its presence. The opposite also could occur. Electricity consumers also

[18] Craig Williams, WECC, Market Interface Manager.

could consider voluntarily conserving power usage to forestall the need for new lines. Many utilities have demand-side management programs, energy efficiency programs, and interruptible rates. Generation plants also could be located near their loads, eliminating some need for long transmissions of electricity. Finally, the grid could potentially be run more efficiently by an RTO or other independent transmission operator.

Transmission Capacity to Accommodate New Generation in Montana

There is a "chicken and egg" problem in developing new transmission projects 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 to 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. The regulatory structure in Montana requires a showing of need for new transmission projects. That may require more effort for transmission builders without firm commitments from generators.

Recent Issues in Transmission

Reduced Demand from 2008-2012 and Consequences

The recession that started in 2008 lowered electricity demand enough to stall proposed generation and transmission projects. The lack of demand for MSTI was likely partially due to the recession as well as uncertainty with the California RPS. In addition, credit markets tightened as a result of the recession, making it potentially harder for projects to be funded.

California RPS

While California is not the only renewable market in the West, California's RPS will require more renewable energy than the rest of the western states combined. It is likely that many wind developments proposed in Montana and other western states intend to sell into the California market. California has a statutory 33 percent RPS requirement by 2020 for all large utilities in the state. Recent changes to California's RPS rules place some additional burdens on out-of-state wind resources. These changes could negatively impact developers' interest in pursuing wind resources in Montana and could decrease interest in new transmission.

Starting in 2016, California utilities must procure at least 75 percent of their renewable resources signed after June 1, 2010, from generation directly connected to a California balancing authority area, transferred into a California balancing authority, or scheduled hourly or subhourly into a California balancing authority area without substituting electricity from another source. Utilities may only procure up to 25 percent of incremental renewable resources from other resource types, which are unbundled renewable energy credits. While there are ways Montana wind can be included for RPS compliance in California, the difficulty of demonstrating compliance may reduce California utilities' demand for these resources.

Montana Wind

New development in Montana includes NaturEner's Glacier and Rim Rock wind farms. These wind farms sell renewable energy credits to San Diego Gas and Electric. They are using both firm and nonfirm transmission to get power out of Montana. Currently, San Diego Gas and Electric is trying to cancel its purchase agreement with NaturEner.

Spion Kop in central Montana started operating in 2013 and is owned by NWE to meet RPS requirements. Other proposed wind projects are looking at the M2W transmission upgrade as a potential way to get power out of state. The status of the federal Production Tax Credit will be critical in this arena.

WECC Energy Imbalance Market

An Energy Imbalance Market (EIM) aggregates the variability of generation and load over balancing authorities and reduces the total amount of required reserves. An EIM more easily allows participants to use the lowest-cost generation in the market to balance loads and generation.

The EIM initiative is a comprehensive market-based proposal to address generator imbalances in the West. It is a regional economic dispatch tool that supplies imbalance energy within transmission and reliability constraints. The EIM would be a 5-minute, security-constrained economic dispatch model using locational marginal pricing for energy imbalances. The EIM could utilize physically available transmission space and would reduce the costs of integrating variable energy resources. The EIM would allow the deviations from electricity schedules to be resolved using the most cost-effective, physically deliverable resource. A variety of groups are currently exploring the possibility of implementing this market.

Western Governors' Association (WGA)

WGA convened a siting task force composed of state siting representatives, developers, nongovernmental organizations, and local community leaders. Established in October 2011, the task force is asked to develop tools and best practices for siting transmission, create an online toolkit to host information for comparing state processes, build Memorandum of Understanding templates, develop public outreach strategies, design best practices for mitigation and ongoing regional efforts, and promote collaboration and cooperation.

The WGA, Western Interstate Energy Board, and WECC are also working with stakeholders to analyze transmission requirements under a range of alternative energy futures. The joint effort will develop long-term, interconnection-wide transmission expansion plans. WGA has been actively engaged with the federal Interagency Rapid Response Transmission Team to coordinate state and federal siting and permitting requirements for new transmission lines. Draft recommendations targeted specific process management and policy issues aimed at shortening the length of time to site and permit without affecting the integrity of the process.

Smart Grid

A smart grid is a modernized electrical grid that uses information and communications technology to gather and act on information in an automated fashion to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity.[19] A smart grid can alert customers to real time prices in order to promote conservation and allow for tiered electricity pricing. This technology can also help the grid be managed from many places and sensors rather than one central location. Concerns about the smart grid include cost, cybersecurity concerns, and personal privacy.

The first deployments in the U.S. started around 2010. In 2014, NWE continued to participate in two smart grid test projects in Montana.

[19] http://energy.gov/oe/technology-development/smart-grid.

Natural Gas in Montana

Natural gas is a major source of energy for Montana's homes, businesses, and industries. Increasingly, it is also an important fuel for in-state electrical generation. 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 electrical generation in Montana and around the country. This trend is expected to continue with lower prices and increasing environmental regulation of coal generation plants. As natural gas markets become more complex and as fracking technology transforms the natural gas industry, the price and availability of natural gas will continue to move in ways Montanans have not experienced in previous decades.

Historic Development of Natural Gas in Montana

The historic discoveries and development of natural gas in Montana parallel that of petroleum. Natural gas has long been associated with production of crude oil and the term "associated gas", which is produced alongside crude oil. Even today natural gas at oil production sites may be flared for many months because of its comparatively low price and infrastructure needs to bring it to markets. Seamless, electric, welded steel pipe made long-range transportation of natural gas economical in the 1920s. Natural gas was known in Montana as early as 1913, but actual production drilling did not begin until 1926, as associated gas, and 1929, as a target commodity in fields near Cut Bank.

In 1930 a major oil company drilling in Carbon County near Bridger brought in a gas well that flowed 11 million cubic feet per day while yielding only a modest amount of oil. This area became known as the Dry Creek Field. Natural gas fields were also developed in the 1930s in the Kevin-Sunburst area and at the Bodoin Dome near Saco. The Big Coulee Field southeast of Harlowton came into production in the mid-1950s.

By early 1931 work began to connect a natural gas pipeline between the Cut Bank Field production area with the industrial centers of Butte and Anaconda. The 20-inch main line to Wolf Creek included a 16-inch line extending to the Butte-Anaconda junction. Branch lines were laid to Helena and Deer Lodge. The line was completed in the summer of 1931, with line pressure running at 330 pounds and a peak load of 20 million cubic feet per day. The line was pressurized from the gas fields until 1949 when a 1,200-horsepower compressor was installed near the absorption plant at the north end of the line. By 1950 a connection was made between Butte and Bozeman, which allowed access to the Dry Creek Field. A line also was brought into Great Falls for the copper refinery. Missoula's service began in 1956.

As MPC entered into arrangements for Canadian gas by the late 1950s, storage on the system was required and compressed injection systems were utilized in depleted gas fields at Box Elder, Shelby, and at the Cobb Storage Field in the Cut Bank production area.[1]

Natural Gas Supplies for Montana and In-State Production

Montana currently produces about as much natural gas as it consumes. However, most in-state production is exported, and the majority of Montana's consumption is from imports. In 2011, Montana produced 74.6 billion cubic feet (Bcf) of gas and consumed 78.2 Bcf.[2] The bulk of Montana production is exported, leaving the state for Saskatchewan, North Dakota, Alberta, and Wyoming. These market patterns are driven by the trading structure of natural gas contracts as well as the actual configuration of pipelines and wells throughout Montana.

Gas wells in Alberta and, to a lesser extent, Montana provide most of the natural gas for Montana customers, a market condition unlikely to change in the future. Reasons include Montana's 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 northcentral portion of the state, although other portions of the state have wells. Supplies from other Rocky Mountain states and from North Dakota also represent a portion of total in-state usage–mostly on MDU's system. Coal bed natural gas production in Montana and from nearby Rocky Mountain states may increase over time but has been a small percentage of Montana production over the past decade. With the recent NWE purchases of natural gas fields in northcentral Montana in 2010 and 2013, a larger percentage of gas consumed in Montana will likely be produced in-state than in recent years.

As noted in the Montana Board of Oil and Gas Conservation Annual Review for 2012, the northern portion of Montana accounted for 69 percent of total in-state production, the northeastern portion 23 percent, and the southcentral portion 10 percent. In-state gas production had been increasing in recent years through 2007 and then saw sharp declines in the years since (**Figure 8**). Blaine, Fallon, Hill, Richland, and Phillips counties produce the greatest amounts of natural gas in Montana at more than 5 Bcf each annually. Richland County has increased its percentage of the total amount, all of it in "associated gas", with the booming oil production in that county from the Bakken oil field.[3]

Some of the gas produced in Hill and Blaine Counties in northern Montana flows into NWE's gas pipeline system and some into the Havre Pipeline system. Havre Pipeline exports 2.0 Bcf out of 8.0 Bcf total from those wells, while the rest is consumed in-state on NWE's system.[4] Gas

[1] *A History of the Montana Power Company*, Cecil Kirk, 2008.

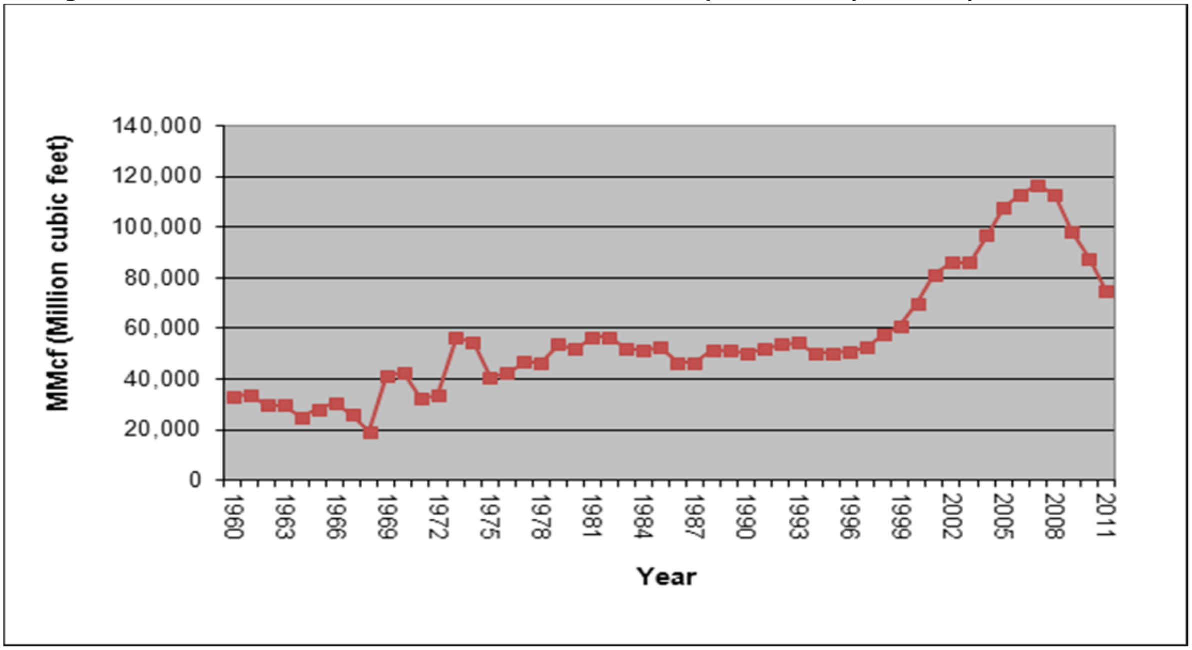
[2] U.S. EIA 2013, Tables NG1 and NG2.

[3] Associated gas is natural gas that is a byproduct from oil wells.

[4] The export on Havre Pipeline to Canada is shrinking with production declines and the Montana consumption is being held constant.

produced in Fallon, Richland, and Phillips Counties mostly flows into MDU's system, and much of that flows east out of the state into North Dakota.

Figure 8. Marketed Natural Gas Production in MT (1960-2011), MMcf (Million cubic feet)



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 arrives from other countries, a portion of which is liquefied natural gas (LNG). Domestic gas production and imported gas are usually 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 has risen sharply in recent years. In 2006 it was 19.38 trillion cubic feet (Tcf), and in 2012 it was up to 25.32 Tcf. This increase is mostly due to fracking technology. Hydraulic fracturing (commonly called fracking or fracing) is a technique in which water, chemicals, and sand are pumped into the well to unlock the hydrocarbons trapped in shale formations by opening cracks (fractures) in the rock and allowing natural gas to flow from the shale into the well. When used in conjunction with horizontal drilling, hydraulic fracturing enables gas producers to economically extract shale gas. Without these techniques, natural gas does not flow to the well rapidly, and commercial quantities cannot be produced from shale. Fracking is occurring in diverse areas across the U.S. and has raised environmental and landowner concerns in some areas.[5]

According to the U.S. Energy Information Administration (EIA), the top five states producing natural gas in 2012 were Texas (7.2 Tcf), Oklahoma (2.0 Tcf), New Mexico (1.3 Tcf), Wyoming (2.1 Tcf), and Louisiana (3.0 Tcf). These states accounted for about 60 percent of marketed natural gas production in the United States in 2012. Growth in natural gas flows out of the Rocky Mountain natural gas basins has continued modestly and increasing demand, particularly in U.S. western markets, has absorbed the increase.[6] Domestic production has been so high recently that plans are being developed for increased U.S. natural gas exports, which are presently quite small. The U.S. Department of Energy recently approved two export applications.[7]

Marketed production from federal offshore wells in the Gulf of Mexico was 1.5 Tcf in 2012, or about 6 percent of total domestic production. These amounts are sharply down from 10 years ago when the average annual natural gas production from the Gulf was around 4.0 Tcf. The reason for the change is that onshore fracking and onshore conventional and unconventional production are generally cheaper than offshore production.[8]

The Rocky Mountain states are the most important domestic source of natural gas supply to the Pacific Northwest region, which includes Montana. Alberta is the other important source for the region. Alaska's North Slope is potentially the largest domestic source of new natural gas resources for the nation as a whole, although no pipeline now exists to transport it. Natural gas production in the U.S. is expected to hold steady at around 25 Tcf through 2014, according to EIA projections. The EIA's 2013 Annual Energy Outlook estimates U.S. natural gas production to increase from 23 Tcf in 2011 to about 33 Tcf in 2040, a 44 percent increase. Almost all of the increase in domestic natural gas production is due to projected growth in shale gas production (using fracking technology), which is expected to increase from 7.8 Tcf in 2011 to 16.7 Tcf in 2040. Much of that increase would come from the Marcellus formation in the Northeast U.S. Onshore production is projected to increase over the forecast period, while federal Gulf of Mexico production from existing fields declines, as the current economics of onshore drilling remain more favorable and require lower marginal investments. The U.S. is projected to become a net exporter of natural gas over time, exporting more than 3.0 Tcf by 2040.[9] However, it is important to note that with the volatile nature of the natural gas market, it is hard to predict anything further than a few years out.

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[5] *What is Shale Gas and Why Is It Important*?
http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm.
[6] U.S. Energy Information Administration, http://www.eia.gov/naturalgas/.

[7] *U.S. Steps Up Natural Gas Exports*, CNN, June 4, 2013, http://money.cnn.com/2013/06/04/news/economy/natural-gas-exports/index.html.

[8] Jim Kendall, U.S. EIA.

[9] *U.S. Short Term Energy Outlook*, August 6, 2013. http://www.eia.gov/forecasts/steo/report/natgas.cfm.

About 12 percent of the total natural gas consumed in the U.S. is imported from other countries, with most of that coming from Canada. In 2012 net imports to the U.S. were 3.1 Tcf, down from 4.3 Tcf in 2006. Aside from Canada, LNG is the other significant source of natural gas imports. LNG imports into the U.S. have fallen sharply since 2006 and are only about 5 percent of overall natural gas net imports.[10] U.S. exports have ramped up from 0.8 Tcf in 2007 to 1.6 Tcf in 2012. Most of the increase has been through pipelines sending product to Canada and Mexico. The U.S. is expected to export more natural gas over time, if current supply trends continue. There were 410 natural gas storage sites in the United States in 2011 with a combined total capacity of 8.9 Tcf.[11]

It is difficult to predict how much natural gas is left in North American reserves that could go toward U.S. consumption. Reserves are constantly consumed and replaced.[12] The EIA estimates that in 2013, the U.S. had 305 Tcf of proven reserves (about 8 years of current U.S. consumption) and just over 2,000 Tcf of unproven reserves or about 80 years of consumption.[13] As of 2007, the entire world was estimated to contain about 13,000 Tcf in natural gas reserves, with much of that located in the Middle East.[14]

Natural Gas Consumption in Montana

Recent Montana natural gas consumption has averaged 70-80 Bcf per year with 78.2 Bcf being consumed in 2011 (**Figure 9**). Both residential and commercial gas consumption are growing slowly, and usage by industry is expected to stay fairly level over time unless a large new gas-consuming company enters or leaves the state.

In the 1970s, 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 a large copper smelter in Anaconda, in particular, contributed to the drop in industrial usage that took place in the 1980s. Other closed businesses, including the Columbia Falls Aluminum Company and Smurfit-Stone, no longer use natural gas, which is part of the reason for recent drops in industrial numbers, as well as fuel substitutions at Montana's oil refineries. On the other hand, two relatively new in-state electrical generation facilities are using increasing amounts of natural gas. Total in-state consumption is slowly creeping back up toward its peak levels in the 1970s, due to increases in the state's population and commercial base and to new natural gas electric generation.

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[10] U.S. EIA, http://www.eia.gov/naturalgas/.

[11] U.S. EIA, http://www.eia.gov/naturalgas/.

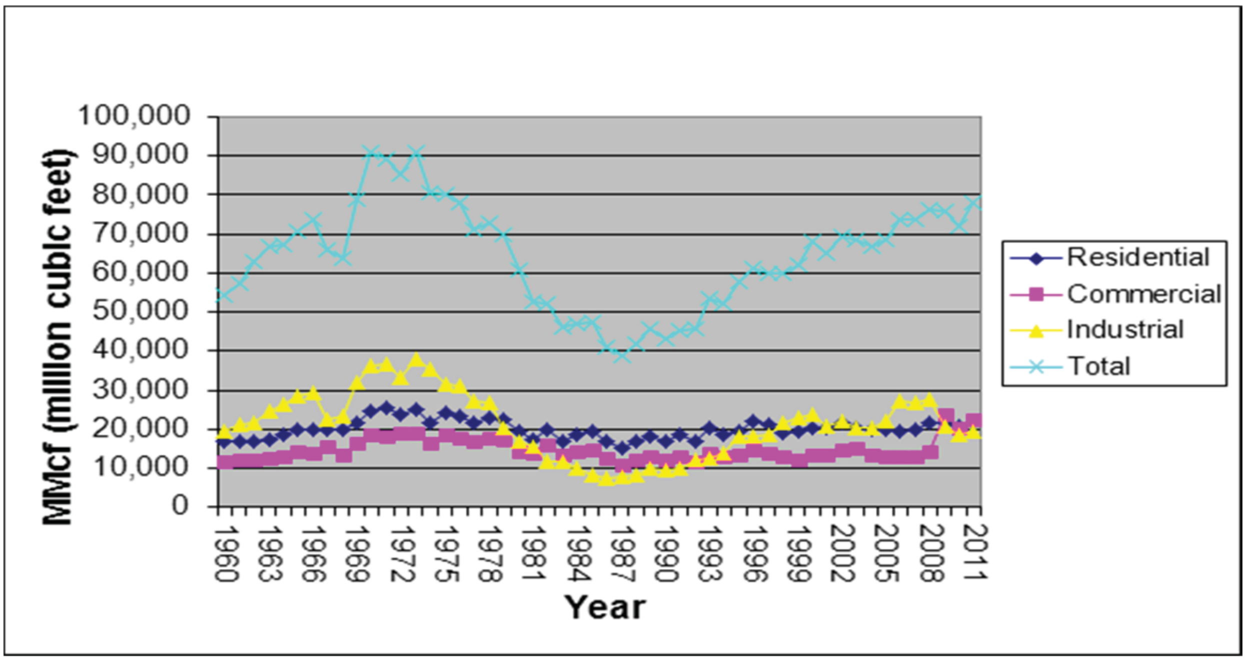
[12] "Reserves" refers to natural gas that has been discovered and proved producible given current technology and markets.

[13] *Oil and Gas Supply Module, Assumptions to the Annual Energy Outlook 2013*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

[14] Northwest Power and Conservation Council, Terry Morlan, 2007.

The Basin Creek generation plant near Butte at 51 MW became operational in late 2005. Natural gas usage at the plant constitutes a small percentage of Montana's total usage and did not require extensive upgrades to NWE's pipeline system. The 150-MW Dave Gates Generating Station (DGGS) near Anaconda started operating in 2011 and also uses a small percentage of Montana's total. Neither plant runs constantly as a baseload resource. DGGS and Basin Creek consumed roughly 4.5 Bcf of gas in 2012. DGGS recently had a mechanical outage for more than a month and likely consumes more gas now that it is fully operational. Basin Creek is operating more than in the past due to cheaper gas and an outage at the Colstrip Steam Electric Station in 2013. The Culbertson Generation Station at about 90 MW started operating in 2010 and is on the Eastern Electric Grid. The Culbertson Generation Station operates sporadically and not as baseload generation, so it doesn't use a sizeable amount of natural gas. A large baseload natural gas plant running at high capacity (500 MW baseload) could use half as much natural gas as Montana consumes in a year, but no such plant exists in Montana.

Figure 9. Natural Gas Consumption in Montana (1960-2011)



Natural Gas Consumption in the U.S.

In the last 40 years, changes in energy markets, policies, and technologies combined to spur an increase in the total usage of natural gas in the U.S. These changes included:

- Deregulation of wellhead prices under the Natural Gas Policy Act of 1978 and acceleration under the Natural Gas Wellhead Decontrol Act of 1989;
- Deregulation of transmission pipelines by 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. Order 636 allowed 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 nonattainment areas, which favor natural gas over other fossil fuels;
- Potential federal regulation that could constrain carbon emissions;
- Improvements in the efficiency and flexibility of natural gas generation and improvements in exploration and production technologies (fracking and coalbed methane technologies); and
- Investment in major pipeline construction expansion.

U.S. gas consumption declined slightly from 2002 levels until 2007, despite a long-term increasing demand trend over time. In 2002, according to the EIA, the U.S. consumed more than 23.0 Tcf of natural gas, the highest level ever recorded. That level stayed consistent through 2007 and then rose to 25.5 Tcf in 2012. This increase was due to low natural gas prices, economic recovery from the 2008 recession and increased use for electric generation. U.S. total natural gas consumption is projected to grow from 24.4 Tcf in 2011 to 29.5 Tcf in 2040, according to the EIA. Natural gas use will increase in all the end-use sectors except in residential, where consumption will decline as a result of improvements in appliance efficiency and falling demand for space heating, attributable in part to population shifts to warmer regions of the country.[15]

Historically, U.S. natural gas consumption has increased at a healthy pace. In 2012, the use of gas for electric generation was the largest consuming sector in the U.S at 36 percent, up from 28.6 percent in 2006. That percentage is rising each year. Industrial use of natural gas, the second largest category in the U.S., has been declining in usage and as a share of the total market, although it had increased recently due to low gas prices. Chemical and fertilizer industries, for example, have benefited from lower natural gas prices. Residential usage is the third largest category. Both electrical generation and industrial consumption of natural gas are projected to rise steadily through 2040, using about one-third each of total supply. Natural gas electrical generation is expected to increase relative to coal generation over this time period as a percentage of total electrical generation.[16] Although coal is expected to remain the top generation fuel, natural gas is expected to grow to 30 percent of total U.S. generation by 2040.

Montana's Natural Gas Pipeline System

Three distribution utilities and two transmission pipeline systems handle more than 99 percent of the natural gas consumed in Montana. The distribution utilities are NWE, MDU, and Energy West, 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.

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[15] *Annual Energy Outlook 2013*, http://www.eia.gov/forecasts/aeo/source_natural_gas_all.cfm#netexporter.

[16] Ibid.

NWE is the largest provider of natural gas in Montana, accounting for almost 60 percent of all regulated sales in the state according to annual reports from Montana utilities.[17] NWE provides natural gas transmission and distribution services to about 183,300 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.[18]

NWE's gas transmission system is regulated by the Montana PSC. The NWE system consists of more than 2,000 miles of transmission pipelines, 5,000 miles of distribution pipelines, and three major 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 is also regulated by the PSC.[19]

NWE supplies gas by purchasing it on the market in contracts with various durations of 3 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 prices in Alberta. The price paid for gas coming in on the southern end of Montana's system is generally tied to prices associated with the Colorado Interstate Gas. Alberta sends natural gas to Montana primarily through NWE's pipeline at Carway, which ties into TransCanada, and at Aden where it ties in with an independent producer. Most gas exported on NWE's system is exported to Alberta at Carway.

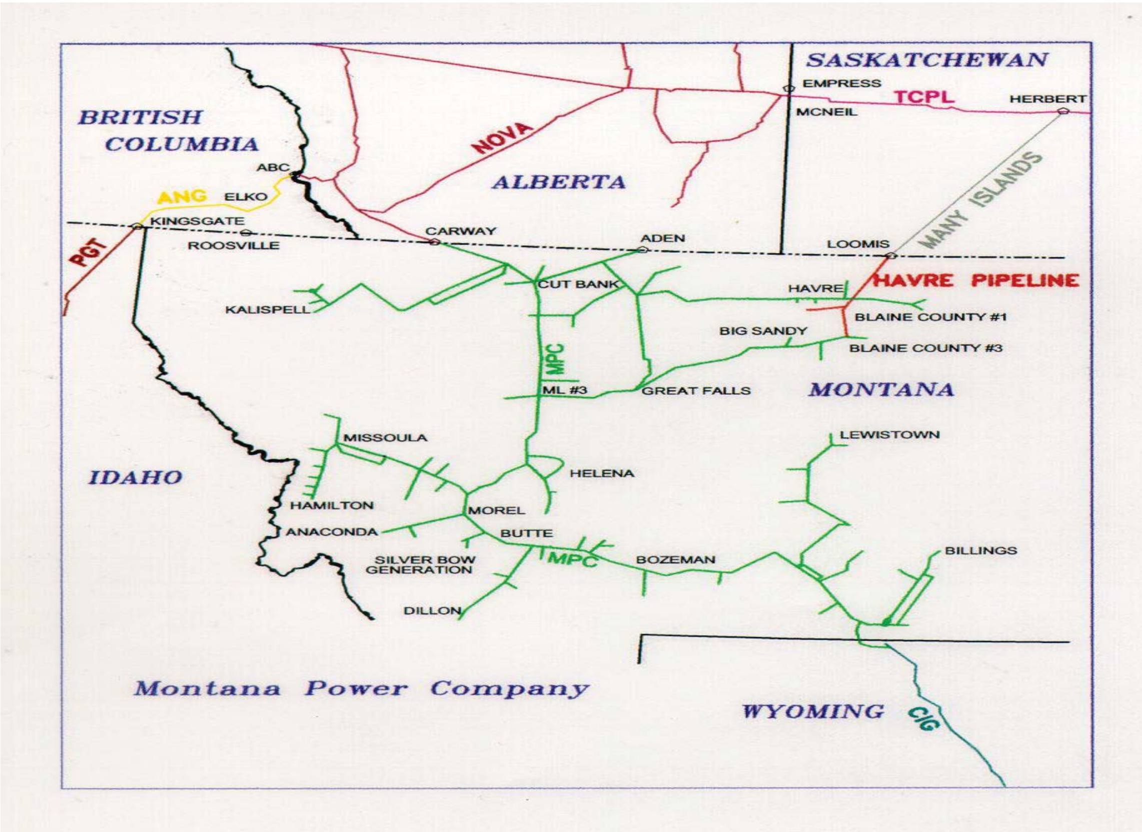
NWE's pipeline system runs in a north-south direction from Carway and Aden at the Canadian border down through Cut Bank and south toward Helena paralleling the Rocky Mountain Front (**Figure 10**). Near Helena, the main pipeline turns west and runs close to Highway 12 and then turns south again and runs close to I-90, passing near Anaconda. It then turns east toward Butte, still following I-90. From Butte, it runs east passing near Bozeman. At Big Timber it turns southeast and runs toward the Wyoming border, where it connects with the Colorado Interstate Gas line and the Williston Basin Interstate line. The NWE gas system branches out from the main pipeline at various locations and runs to Missoula, Great Falls, the Flathead Valley, Dillon, Livingston, and Billings. NWE's natural gas delivery system includes two main storage areas. The Cobb storage is located north of Cut Bank near the Canadian border. The Dry Creek storage is located 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 flattens out gas production throughout the year.

[17] Annual reports are filed with the Montana PSC by natural gas utilities (1950-2011). Regulated sales do not include most industrial consumption, because since 1991 and the time of deregulation, industrial consumption has not been reported due to different reporting requirements and processes used by utilities. Regulated sales also do not include gas used for pipeline transportation, gas sales to other utilities for resale in Montana, lease and plant fuel, or fuel used by utilities.

[18] Jim Griffin, August 2013.

[19] Jim Griffin, August 2013.

Figure 10. NWE's Natural Gas Transmission System



NWE's natural gas transmission system delivers about 40 Bcf of total gas per year to its customers on average, compared with total annual Montana consumption of about 80 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. NWE exports a small amount of natural gas.

In 2012 NWE imported 10.5 Bcf or 57 percent out of 18.5 Bcf of total regulated sales. That left 8.0 Bcf or 43 percent from Montana production. The recent Bear Paw natural gas field acquisition by NWE (located south of Havre) has changed the split slightly. For the 12-month period ending in June 2014, the forecast split is 54 percent Canadian gas and 46 percent Montana gas on a total of 19.7 Bcf. NWE used to obtain a larger percentage of its gas from Alberta, but with recent gas field purchases, most of NWE's Montana production is consumed in the state.[20]

The NWE pipeline system has a daily peak capacity of 325 MMcf of gas. About one-half of the total gas on NWE's system is used by "core" customers. This consists of 19 Bcf in regulated sales

[20] John Smith, Manager of Natural Gas Supply, NWE, August 2013.

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 is used by noncore customers, including industry and local and state governments, and by Energy West, which supplies Great Falls. NWE provides only delivery service for these noncore 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 during warm weather.

There is no unused firm capacity on the NWE pipeline transmission system. No additional gas user of significant size, like a large industrial company, could obtain guaranteed, uninterrupted gas delivery on the current system. At times of peak consumer usage, the pipeline is full and could not deliver more gas. Customer peak daily demand on the system is an estimated 325 MMcf, and the system's maximum daily capacity is matched by peak daily demand.[21] The projected growth rate of natural gas use on the system is expected to come from core customers. Over the past decade, NWE has expanded its gas transmission capacity by building loops on its current system, which is a second pipe running parallel along a main line. Meeting the demands of new gas-fired electrical generation or a large new industrial facility would likely require significant additional upgrades to the system.

MDU is the second largest natural gas utility in Montana and accounts for about 25 to 30 percent of all regulated natural gas sales in Montana. Its sales in Montana are just over 10 Bcf. It distributes natural gas to most of the eastern third of the state, including parts of Billings. MDU uses the Williston Basin Interstate line and NWE pipelines for the transmission of its purchased natural gas in the state. The Williston Basin Interstate line and NWE pipelines provide service for other utilities and are regulated at the federal level by FERC. MDU buys its gas from more than 20 different suppliers throughout the upper Midwest. Of its current gas, MDU is purchasing 15 to 20 percent from producing fields in Montana and about 40 to 50 percent of its supply from the North Dakota Bakken area. These percentages can change depending on seasonal demand. MDU expects future growth to be about 1 percent per year for the near future.[22]

Energy West is the third largest natural gas provider in Montana, accounting for about 10 percent of all regulated gas sales in Montana. Its annual sales are about 4.0 Bcf. It provides gas to the Great Falls area and a small amount to West Yellowstone through a propane vapor distribution system.

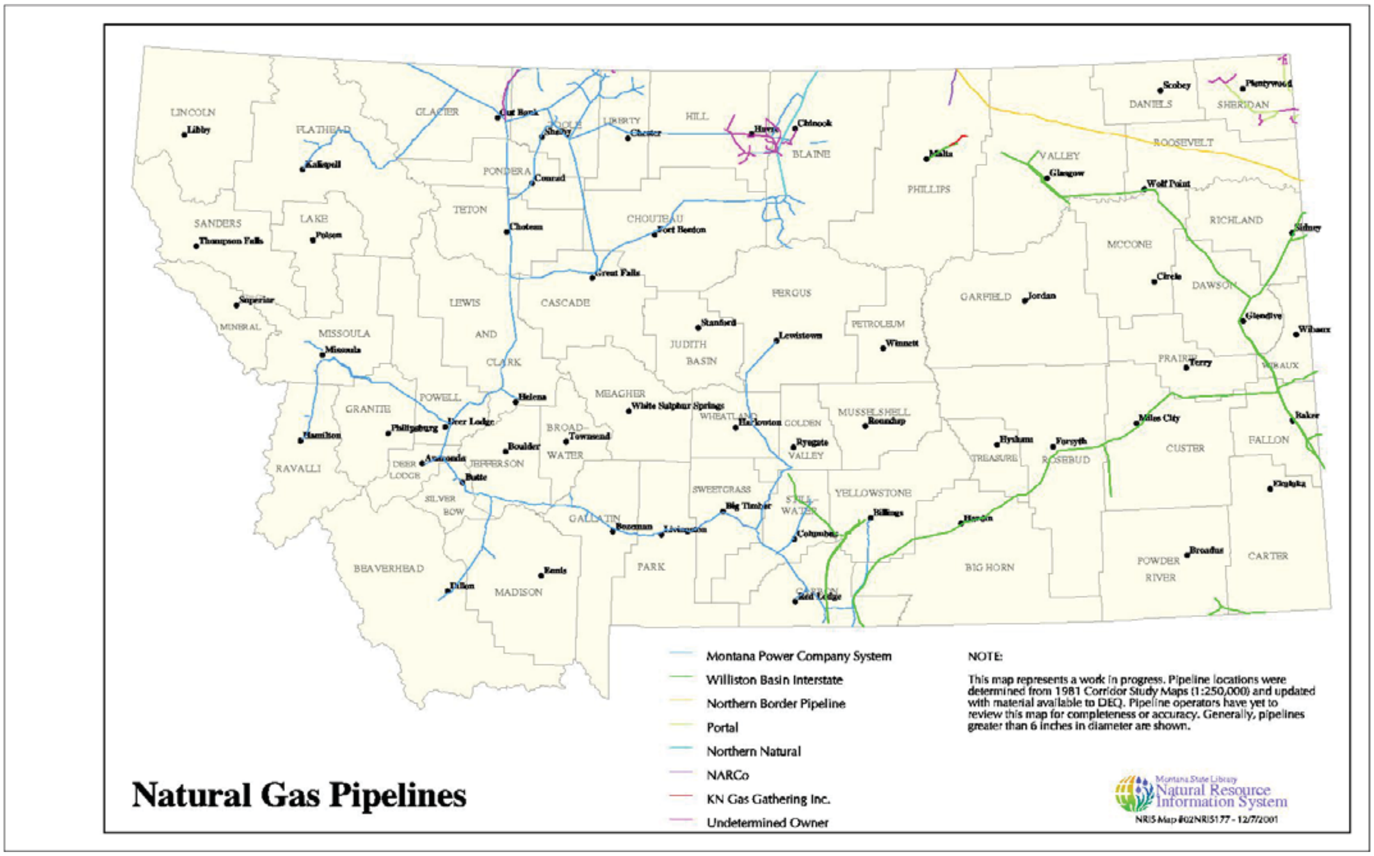
Other operating Montana utilities account for about 1 percent of all gas sales and currently include the Cut Bank Gas Company and Havre Pipeline Company. The Northern Border pipeline (2.2 Bcf/day capacity), which passes through the northeastern part of Montana, is the largest pipeline in the state, but it has no injection points in Montana. Northern Border feeds the

[21] Jim Griffin, August 2013.

[22] Bob Morman, MDU, August 2013.

Culbertson Generation Station and also feeds the Ormat Waste Heat station near Culbertson. Its terminus is the U.S. Midwest market. **Figure 11** provides an overview of natural gas pipelines in Montana. The blue lines show NWE's system and the green lines are the system serving MDU. Other lines are listed.

Figure 11. Map of Natural Gas Pipeline in Montana (NRIS)



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 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.

While the Henry Hub price appears to be a good approximation of average U.S. wellhead prices, other hubs located in relatively remote areas, like Wyoming and Alberta, can have significantly higher or lower prices than the Henry Hub due to their location, local pipeline constraints, and local markets. As another example, during the cold winter of 2014 in the northeastern U.S. where prices spiked, similar price spikes did not occur in the Henry Hub. This illustrates how price differentials also can occur between different populated areas in the U.S.

The city gate gas price reflects the wellhead price plus pipeline transmission fees (to get the gas to a particular locale or distribution system). The delivered gas price paid by customers is the city gate price plus local distribution fees and other miscellaneous charges from the utility. Transmission and distribution fees are set by utilities, pipelines, or both 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 can be volatile and represent a small portion of market sales. 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 generally used by larger buyers rather than spot prices. NWE, as an example, buys much of its natural gas for its core customers using long-term contracts (up to 3 years) to lock in an acceptable price and to avoid large price swings on the spot market. This helps keep the price paid by customers relatively stable in a market that can otherwise experience large price swings.

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 their supply from Alberta. 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 index. This index is very liquid for trading. The AECO C index generally tracks the Henry Hub Index with some price differential. Due to its location in the western Canada sedimentary basin, the AECO C price is often $0.60/MMBtu to $1.50/MMBtu cheaper than the Henry Hub price. This has kept Montana gas prices generally lower than the U.S. average.

Increases in demand for natural gas in the region tend to cause contracted gas prices to rise in Montana. While it is the interplay between the supply and demand of Alberta's gas that generally has the greatest effect on the gas prices paid in Montana, increased production from fracking has also brought prices down significantly. This interplay occurs both on a national level and regionally for both supply and demand.

Natural Gas Prices in the U.S.

In late 2013, natural gas prices remained low in the U.S., hovering around $3.50/MMBtu at the Henry Hub. As of April 2014, these prices increased to about $4.50. Manufacturing has benefited, including chemical companies and fertilizer companies that use large amounts of natural gas. Prices are edging higher back to normal prices due to increased natural gas demand and low prices that can discourage additional drilling. Future exports, especially of LNG, could raise prices.

Natural gas prices have been particularly sensitive to short-term supply and demand shifts in recent years because of the highly inelastic nature of the market.[23] 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 current production infrastructure is thought to be operating near capacity. Significant lead time is required to bring additional domestic or foreign natural gas supplies to market, as well as to expand pipeline capacity to alleviate bottlenecks. These conditions contribute to the inelastic nature of the market.

Factors on the supply side that may affect natural gas prices include variations in natural gas storage, production, imports, or delivery constraints. Storage levels receive the most attention because of the physical hedge that these levels provide during high-demand periods. Working gas in storage often is viewed as a barometer of the supply and demand balance in the market. Fracking technology has been the dominant price factor recently, increasing supply and lowering price and also preventing recent long-term price swings.

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 Bcf of natural gas production to be shut down between August 2005 and June 2006. This was equivalent to about 5 percent of U.S. production over that period and about 22 percent of yearly natural gas production in the Gulf of Mexico. As a result of these disruptions, natural gas spot prices at times exceeded $15 MMBtu in many 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, which places upward pressure on prices. Temperatures also have an effect on prices in the summer as usage increases to meet air-conditioning, so very hot summers also can raise natural gas prices.

The prices and market conditions for related fuels also have an effect on natural gas. Historically in the U.S., most baseload electricity is delivered from coal, nuclear, and hydroelectric generation. Because natural gas tends to be a higher-cost fuel, natural gas-fired power stations were used to cover mostly incremental power requirements during times of peak demand or sudden outages of baseload capacity. This is changing as an increasing amount of new baseload electricity is natural gas fired nationwide. The shift is due to lower gas prices, lower emissions from gas plants compared to coal, low initial capital cost for gas plants, a fast online time, and versatility to ramp electric output up and down.

Economic activity also 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. The trend is prevalent in the industrial

[23] Price inelasticity means that a small change in quantity supplied or quantity demanded leads to a large change in price.

sector, which uses natural gas as both a plant fuel and a feedstock for many products, like fertilizers and pharmaceuticals. The recent recession lowered natural gas prices, as industrial usage was down. Industrial usage has recently increased to a higher level than before the recession, and prices are slowly rising.

Natural Gas Prices in Montana

Until the late 1970s, delivered gas prices in Montana were relatively low (about $5/dkt) in today's dollars (actual dollars adjusted for inflation). Delivered prices rose considerably through the mid-80s and mostly settled in the $6-$10/dkt range using today's dollars (**Figure 12**). In the 1990s, the delivered prices came 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 rocketed. Prices steadily rose over 2005, increased after Hurricane Katrina, and peaked in January of 2006 at $13.50/dkt for NWE residential customers. Since then, prices have declined to historical lows. As of July 2013, NWE residential customers pay an average delivered gas price of $7.50/dkt.[24] **Figure 12** shows delivered natural gas prices in Montana adjusted for inflation through 2011 and reported in constant 2007 dollars. The delivered prices are the prices residents and businesses see in their final energy bill reflecting all charges.

The average U.S. wellhead price of gas in 2000 was $3.68/dkt. For 2003 the price was $4.88/dkt, and for 2006 it was $6.42/dkt. In 2012, it was $2.66/Mcf, but increased in the first half of 2013. The U.S. delivered price of natural gas averaged just over $10/dkt in 2012.[25]

The EIA forecast for wellhead price in 2030 is about $5/dkt in today's dollars.[26] The Northwest Power and Conservation Council (NPCC) forecasts a natural gas Henry Hub price of $5.80/dkt in 2030 for its medium case, with a range of $4.20/dkt to $7.70/dkt. The NPCC forecasts the AECO price to be around $4.95/dkt in 2030.[27]

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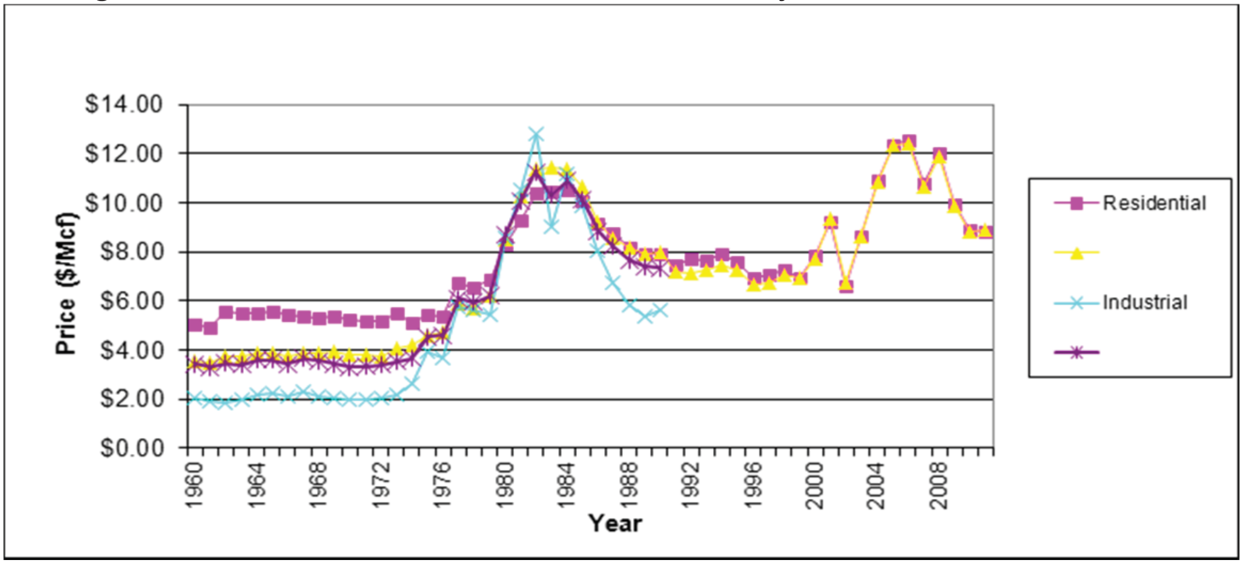
[24] NWE natural gas rates, http://www.northwesternenergy.com/documents/MT_Rates/Gas/gsummaries.htm.

[25] U.S. Energy Information Administration, http://www.eia.gov/naturalgas/.

[26] *Annual Energy Outlook 2013*, http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf and http://www.eia.gov/forecasts/aeo/source_natural_gas_all.cfm#netexporter

[27] Northwest Power and Conservation Council, *The Seventh Power Plan, Proposed Fuel Price Forecasts*, July, 2013. http://www.nwcouncil.org/media/6870894/FuelPriceForecast.pdf .

Figure 12. Delivered Price Natural Gas in Montana Adjusted for Inflation, 1950-2011



Transmission utilities in Montana, the major utilities being NWE and MDU, are prohibited from earning any profit on the cost of natural gas they purchase. The commodity cost of the gas is simply passed on to its customers. If gas costs increase, they are passed on to customers, and if gas prices go down, the savings are also passed 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 PSC 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 be contentious. NWE computes a new tracker each month to reflect the gas costs it incurs in order to supply its customers.

The average monthly gas bill for an NWE residential customer went from $70.89 in 2002 to $128.83 in April 2006. In 2013, the monthly bill was about $90. The monthly gas bill for an MDU customer went from $47.60 in January 2002 to $92.29 in April 2006. It was about $69 in 2013. Natural gas prices for a Montana consumer are in the middle range of historical prices.

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. The gas price for each industrial customer depends on each specific contract, the gas supplier, and the ability of the industry to switch from natural gas to some other fuel if prices get too high. Four of the largest natural gas users in Montana are the oil refineries in and near Billings and Great Falls. Plum Creek Manufacturing, REC near Butte, and Basin Creek Power Services are also large users in Montana. Several natural gas pipelines also use large amounts of natural gas to pump the product over long distances at appropriate pressures. The refineries in Billings have some flexibility in switching fuels to run operations, so they may not be hit as hard by higher gas prices as other industries. Other large customers, like Montana State University, have less flexibility to switch fuels. Large gas users who buy gas on the spot market, like Montana State University-Billings, could be hurt by high prices and price swings, while other industrial customers with longer-term contracts at lower prices are partially insulated.

Recent Developments

NWE Purchases

In 2013 NWE bought a large natural gas production field in northern Montana, expanding ownership of the gas it supplies to Montana customers to 37 percent. NWE bought the field from Devon Energy Production Co. and acquired Devon's interest in a gas pipeline that runs from north of Great Falls to the Canadian border. The purchase is part of the company's ongoing strategy to buy production assets that can lock in long-term supply at a stable price for its customers.

In the late 1990s, NWE's predecessor, MPC, sold its natural gas wells and began acquiring gas for its Montana customers entirely on the market. It had owned wells that provided about half the gas it needed for customers. Starting in 2010, NWE began buying gas production fields to help supply its Montana natural gas customers. NWE said the Devon gas field will produce 5.6 Bcf of gas annually and has proven reserves of an additional 65 Bcf.

Bakken Boom

It is difficult to determine what production from fracking will do to natural gas in the U.S., but it will likely keep prices relatively low in the short term and supply high. It may also increase domestic production and lower the amount of natural gas coming from the Gulf. It also will keep imports low in the near future and may continually increase U.S. exports.

Natural gas production has greatly increased in Richland County bordering North Dakota. This is from associated gas that is produced as a byproduct of oil production. Richland County is on the edge of the Bakken boom in North Dakota, and oil production, as well as associated gas production, has grown in the past few years, although not nearly as fast as growth in North Dakota. Over time, more natural gas is being captured and less is being flared into the atmosphere in that area.

Peaking Plants

DGGS is a peaking natural-gas fueled electric plant and regulated as a cost-based resource. The 150-MW unit is located near Anaconda. The plant, which began commercial operation in 2011, provides energy necessary to maintain NWE's high-voltage bulk transmission network in Montana. Electricity is a dynamic resource and demand fluctuates on a moment-by-moment basis. The electricity network needs to meet demand at all times while maintaining voltage and reliability requirements. The electricity generated at DGGS meets this demand around the clock, resulting in a stable, reliable transmission network and reducing NWE's reliance on outside providers for transmission regulation. DGGS provides additional flexibility to integrate Montana renewable power into the existing transmission system.

Future Price Increases and Price Volatility

U.S. wellhead prices generally determine how much Montanans pay for gas. The wellhead price that Montana utilities and their customers pay for gas is likely to remain close to average U.S. prices on the national market. This is partially because of increased pipeline capacity from Alberta to the Midwest and East Coast. Increased gas transmission capacity means the wellhead price paid in Montana is also closely tied to wellhead prices paid nationwide. The price differential between prices Montanans face and prices the rest of the U.S. face may also depend on the amount of natural gas produced in Wyoming and other Rocky Mountain states. It is important to note that natural gas prices are volatile and will fluctuate in the coming years.

The EIA has found that prices tend to be seasonally volatile and can be volatile based on location. 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 5-year average level, price volatility at the Henry Hub increases. This effect is exacerbated during the end of the heating season when storage levels are typically at the highest and lowest levels. Even with relatively low levels of volatility, changes in the natural gas price level can impact the market as daily gas prices expand.[28]

Although natural gas prices are expected to slowly increase, Montanans may be subject to increasing price volatility from extreme or unexpected events. 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. 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. The U.S. also is increasingly becoming self-sufficient in natural gas supply, and extreme price volatility has not been seen in the past few years.

Over the past 15 years, wholesale electricity and natural gas prices became intimately linked. Recently, most new electric generation built in the West has been gas-fired, even with volatile gas prices. Natural gas power plants command a significant majority of new electric installed capacity in the West, followed at some distance by wind. A recent analysis shows that natural gas transmission pipeline capacity in the West is sufficient to handle increasing natural-gas fired electricity, except under the most extreme weather and under pipeline failure conditions.[29] In the northeastern U.S. infrastructure is underbuilt and price fluctuations are often experienced during cold snaps. Throughout the U.S., the natural gas system will need to be operated with more flexibility to meet increasing demand and diverse end users. Fuel prices influence

[28] *An Analysis of Price Volatility in Natural Gas Markets*, EIA, Erin Mastrangelo, http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2007/ngprivolatility/ngprivolatility.pdf.

[29] *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electricity System Perspective, E3.* The study was done for the state-provincial steering committee and the Committee on Regional Electric Power Cooperation (CREPC). CREPC is a joint committee of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners. http://westernenergyboard.org/wp-content/uploads/2013/03/SPSC_Ph_1_Exec_Summ_West_Gas_Elect_Report_3-17-20141.pdf.

electricity demand because they are substitute sources of energy for space and water heating. They also are potential fuels for electrical generation.[30] The increasing convergence of the electricity and natural gas markets means that extreme events are likely to simultaneously affect both electricity and gas markets.

Utilities and industry can reduce price risks by buying natural 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 even out gas bills over a given billing year, although this does not protect a customer from yearly fluctuations. Customers can also use less gas through weatherizing and behavioral changes. Electricity efficiency improvements and demand-side management may be the biggest bang for the buck to reduce natural gas demand and alleviate price fluctuations.

The convergence of the electricity and natural gas markets has implications for regional electricity and natural gas utility systems. New electrical generation facilities that do not use natural gas, for example, will be more attractive options in terms of energy diversity. For example, most utilities in the Northwest have acquired wind generation, in part because of the hedge that fixed-priced wind power could provide against volatile natural gas prices.

High natural gas prices point out three lessons for Montana. First, natural gas prices are affected by a number of factors beyond the state's control. Second, the growing use of natural gas for electricity generation and tight gas markets has the potential to upset the traditional, seasonal patterns of natural gas storage and withdrawals 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.

[30] Northwest Power and Conservation Council. *Revised Draft Fuel Price Forecasts for the Fifth Power Plan*, April 22, 2003.

Table NG1. Montana Natural Gas Production and Average Wellhead Price, 1960-2011

Year	Gross Withdrawal[1] (MMcf)	Marketed Production[2] (MMcf)	Average Wellhead Price[3] ($/Mcf)	Estimated Gross Value of Montana Production[4] (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
2008	119,399	112,529	7.50	843,968
2009	105,251	98,245	3.16	310,454
2010	93,266	87,539	3.64	318,642
2011	79,506	74,624	NA	--

[1] Gross Withdrawal includes all natural gas plant liquids and all nonhydrocarbon gases but excludes lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations.

[2] Marketed Production represents Gross Withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. Includes all quantities of gas used in field and processing plant operations. 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 gases.

[3] Starting in 2011, the EIA discontinued the survey that gave them state-level wellhead prices due to data quality issues The reason for this is that the EIA wasn't able to get consistent and full information from the states on wellhead prices. Therefore, 2010 was the last year that the average wellhead price for Montana was reported.

[4] This number is an estimate. The gross value of gas production is computed by multiplying average wellhead price by the respective volume produced. Because wellhead prices were no longer available starting in 2011, 2010 was the last year this number was calculated. 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, EIA, Natural Gas Production and Consumption Annual Report, 1976-79 (EIA-0131); U.S. Department of Energy, EIA, Natural Gas Annual,1980-2011; EIA website at http://www.eia.gov/naturalgas/ under 'Data' and then 'Production'.

Table NG2. Montana Natural Gas Consumption by Customer Class, 1960-2011 (million cubic feet)

Year	Residential	Commercial[1,2]	Industrial[1,2,3]	Utilities for Electric Power	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	19,722	13,223	26,923	1,000	73,822
2008	21,585	14,340	27,800	513	76,422
2009	21,675	23,575	20,615	656	75,802
2010	20,875	20,459	18,478	705	72,026
2011	21,710	22,336	19,386	4,681	78,218

[1] Commercial consumption is defined as gas used by nonmanufacturing establishments or agencies primarily engaged in the sale of goods or services. Included are such establishments as hotels, restaurants, wholesale and retail stores, and other service enterprises; and gas used by local, state, and federal agencies engaged in nonmanufacturing activities.

[2] Amy Sweeney of the EIA indicated that in 2008, NorthWestern reclassified some consumption volumes from industrial to commercial to better align with EIA sector definitions.

[3] Natural gas used for heat, power, or chemical feedstock by manufacturing establishments or those engaged in mining or other mineral extraction as well as consumers in agriculture, forestry, and fisheries. Also included in industrial consumption are generators that produce electricity and/or useful thermal output primarily to support the above-mentioned industrial activities. Industrial use includes refinery use of gas but excludes pipeline fuel.

[4] Total Consumption includes other items aside from the first four columns; primarily pipeline and distribution fuel, along with lease and plant 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 1980-2011. EIA website at http://www.eia.gov/naturalgas/ under 'Data' and then 'Consumption'.

Table NG3. Average Delivered Natural Gas Prices by Customer Class, 1960-2011

Year	Price by Customer Class (dollars per thousand cubic feet)			
	Residential	Commercial	Industrial[1]	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	9.91	9.76	--	--
2008	11.52	11.37	--	--
2009	9.50	9.39	--	--
2010	8.64	8.54	--	--
2011	8.80	8.86		

[1]Once MPC 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, average price estimates for 'All Customers' are not made after 1990.

[2] Average prices for the 'All Customers' column through 1990 were computed by multiplying the consumption of each customer class (residential, commercial, industrial, utilities) by its corresponding consumer class price. These products were added up and the sum was divided by the total consumption of the four customer classes.

Source: 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 1980-2011; EIA website at http://www.eia.gov/naturalgas/ under 'Data' and then 'Prices'.

Table NG4. Total Number of Customers, Average Natural Gas Consumption, and Annual Cost per Consumer by Customer Class, 1980-2011

Year	Residential[1,2]			Commercial[1,2]			Industrial[2,3]		
	Total Number of Customers	Average Consumption (Mcf)	Average Annual Cost (dollars)	Total Number of Customers	Average Consumption (Mcf)	Average Annual Cost (dollars)	Total Number of Customers[4]	Average Consumption (Mcf)	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	167,883	91	$403	21,382	514	$2,231	435	18,072	$ 61,806
1988	171,785	98	$423	22,246	541	$2,329	435	19,219	$ 59,195
1989	171,156	106	$465	22,219	591	$2,579	428	23,138	$ 68,951
1990	174,384	97	$444	23,331	521	$2,419	457	20,622	$ 67,434
1991	177,726	104	$468	23,185	554	$2,411	452	21,842	$ 70,331
1992	182,641	91	$438	23,610	490	$2,185	459	26,619	--
1993	188,879	108	$530	24,373	569	$2,657	462	27,468	--
1994	194,357	96	$504	25,349	512	$2,514	453	30,773	--
1995	203,435	97	$497	26,329	512	$2,519	463	39,168	--
1996	205,199	108	$525	26,374	562	$2,608	466	38,848	--
1997	209,806	100	$506	27,457	507	$2,449	462	40,619	--
1998	218,851	88	$460	28,065	462	$2,370	454	47,172	--
1999	222,114	89	$457	28,424	425	$2,180	397	58,025	--
2000	224,784	89	$540	29,215	463	$2,732	71	335,789	--
2001	226,171	89	$647	29,429	450	$3,308	73	286,616	--
2002	229,015	95	$502	30,250	486	$2,610	439	49,811	--
2003	232,839	88	$621	30,814	491	$3,476	412	49,015	--
2004	236,511	84	$774	31,357	428	$3,916	593	34,540	--
2005	240,554	82	$882	31,304	420	$4,502	716	30,744	--
2006	245,883	79	$891	31,817	414	$4,604	711	38,575	--
2007	247,035	80	$791	32,472	407	$3,972	693	38,850	--
2008	253,122	85	$982	33,008	434	$4,940	693	40,116	--
2009	255,472	85	$809	33,731	699	$6,577	396	52,059	--
2010	257,322	81	$701	34,002	602	$5,139	384	48,121	--
2011	259,046	84	$738	34,305	651	$5,769	381	50,882	

[1] Starting in 1993, DOE no longer provided figures for average cost. 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 1999-2011, average consumption for residential customers was calculated by DEQ by dividing total residential consumption in Montana (Table NG2) by the total number of residential consumers. Average consumption per customer for commercial and industrial customers in Montana was calculated the same way by EIA. Total number of customers data for each customer class was retrievable as far back as 1987 from the EIA.

[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 available for Industrial customer prices because many of those customers left the regulated utility and therefore no longer provided the information necessary to make the price estimate. Accordingly, average cost to industrial customers cannot be calculated after 1991.

[4] In 2000 and 2001, many of the remaining industrial customers in Montana went out and chose their own supplier, possibly accounting for the low number of consumers reported in those years. In addition, a reporting error was probably made in those 2-years due to the size of the numerical anomaly. Investigations with the EIA (Amy Sweeney) and NorthWestern Energy (Glen Phelps) did not reconcile these numbers.

Source: United States Department of Energy, Energy Information Administration, Natural Gas Annual, annual reports for 1980-2011; EIA website at http://www.eia.gov/naturalgas/ under 'Data' and then 'Consumption' and then 'Number of Customers'. Data from Table NG2 and Table NG3 were used to make calculations in this table.

Table NG5. Regulated Sales[1] of Natural Gas by Gas Utilities, 1960-2011 (million cubic feet unless otherwise noted)

Note: The gas sales numbers in this table are significantly lower than the total gas consumption numbers in Table NG2. As of 2011, they are 50-60% lower than Montana's total consumption. These sales data are taken from annual reports filed by utilities to the Montana PSC. The way utilities report gas sales to the PSC is different from the way Table NG2 total consumption numbers are calculated by the U.S. Energy Information Administration. More 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 (Thousand Dkt from 2001-Present) [2]					MONTANA-DAKOTA UTILITIES (Thousand Dkt from 1992-Present)[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	59.3%	8,959	NA	NA	8,959	28.0%
2002	19,748	237	317	20,302	59.6%	9,925	NA	NA	9,925	29.1%
2003	18,538	214	277	19,029	59.3%	9,273	NA	NA	9,273	28.9%
2004	18,395	196	297	18,888	61.2%	8,352	NA	NA	8,352	27.1%
2005	18,794	181	297	19,272	60.9%	8,971	NA	NA	8,971	28.3%
2006	18,060	177	288	18,526	60.8%	8,350	NA	NA	8,350	27.4%
2007	18,191	169	295	18,656	60.3%	8,758	NA	NA	8,758	28.3%
2008	20,170	207	311	20,698	61.0%	9,386	NA	NA	9,386	27.7%
2009	20,024	170	314	20,509	59.5%	10,011	NA	NA	10,011	29.1%
2010	19,037	194	337	19,567	59.1%	9,712	NA	NA	9,712	29.4%
2011	19,956	162	372	20,490	58.7%	10,385	NA	NA	10,385	29.7%

Table NG5. (continued)

Year	GREAT FALLS GAS COMPANY/ ENERGY WEST[4]					OTHER UTILITIES[5]		TOTAL SALES[6]			
	Residential and Commercial	Industrial	Other	Total	% of Total Montana Sales	Total for all Sectors	% of Total Montana Sales	Residential and Commercial	Industrial	Other	TOTAL
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	2,797	1055	0	3,852	13.5%	239	0.7%	30,718	1,266	1,291	33,275
2001	2,694	1067	0	3,761	12.5%	301	0.9%	30,414	1,303	299	32,016
2002	2,530	1007	0	3,537	10.4%	303	0.9%	32,506	1,244	317	34,067
2003	2,520	993	0	3,513	10.9%	270	0.8%	30,601	1,207	297	32,105
2004	2,381	964	0	3,345	10.8%	267	0.9%	29,395	1,160	297	30,852
2005	2,248	932	0	3,180	10.0%	243	0.8%	30,256	1,113	297	31,666
2006	2,382	973	0	3,355	11.0%	232	0.8%	29,024	1,150	288	30,462
2007	2,352	946	0	3,298	10.7%	236	0.8%	29,537	1,115	295	30,947
2008	2,582	1007	0	3,590	10.6%	244	0.7%	32,382	1,214	311	33,907
2009	2,676	1027	0	3,703	10.7%	235	0.7%	32,946	1,197	314	34,457
2010	2,562	1017	0	3,578	10.8%	231	0.7%	31,542	1,211	337	33,090
2011	2,707	1083	0	3,790	10.9%	248	0.7%	33,296	1,245	372	34,913

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] Montana Power Company/NorthWestern Energy

From 1960 to 1970, government and municipal sales were reported in the "Residential and Commercial" sector.

In 2001, the MPC was purchased by NorthWestern Energy.

Starting in 2001, numbers are reported in Dekatherms (dkt).

"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 the 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 as it was in later years. In 1992, figures used are from Actual Billed Volumes supplied by Fran Balkovetz at MPC.

[3] Montana-Dakota Utilities

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 1975-1981 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 dkt rather than Mcf. From 1995 on, amounts for industrial and other usage are not reported or rarely reported by MDU, so everything is reported in the 'Residential and Commerical' category.

[4] Great Falls Gas Company/Energy West

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. Starting in 2009, Energy West Cascade Gas started reporting as a gas utility, so those numbers are included. "Other" included sales to Malmstrom Air Force Base and other public authorities until 1999. Starting in 2000, the numbers for the 'other' category were no longer reported as such. In 1993, Great Falls Gas became Energy West.

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

Energy West Gas reports from 2000-2008 use inconsistent dates within their reports, so best professional judgment was used to clean the data.

From 1992-1998, figures were not given for Industrial usage. It is assumed those numbers are included 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 30 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.
Havre Pipeline Gas:	Havre Pipeline Company LLC owns and operates a natural gas pipeline system located in Blaine, Hill, and Choteau Counties. This gas is sold to various entities both within and outside of Montana.

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, though it remains in business. Starting in 2000, Havre Pipeline Company has been included so that since 2000, "other utilities" totals include 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 in their definition 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 12-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 Consumers 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 12-month reporting period ending June 30.

The 1982 figures for Energy West were estimated by the sector averages from the 1981 and 1983 12-month reports. The 1983 figures and those for all subsequent years are based on 12-month reports ending June 30 of that year.

Source: Annual reports filed with the Montana Public Service Commission by the natural gas utilities (1950-2011), 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 Public Service Commission website at http://psc.mt.gov/electronicDocuments.asp#reports.

Table NG6. Largest Natural Gas Users in Montana as of 2011-2012		
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
Exxon Mobile Co. USA	Oil refinery	Billings
Cenex Harvest States	Oil refinery	Laurel
Montana Refining Company	Oil refinery	Great Falls
Plum Creek Manufacturing	Sawmills, wood products	Columbia Falls
Basin Creek Power Services	Electric Generation	Butte
Renewable Energy Corporation[1]	Industrial manufacturing	West of Butte
Williston Basin-Cabin Creek	Nat. Gas Pipeline (compressor stations)	Southern Montana
Northern Border Pipeline Company	Nat. Gas Pipeline (compressor stations)	Northeast Montana
Havre Pipeline Company	Nat. Gas Pipeline (compressor stations)	Northern Montana
NorthWestern Energy	Nat. Gas Pipeline (compressor stations)	State-wide
200-500 MMcf Average Usage Annually		
Montana State University	Heating Plant-University	Bozeman
University of Montana	Heating Plant-University	Missoula
Basin Creek Power Services	Electric Generation	Butte
Dave Gates Generating Facility	Electric Generation	Near Anaconda
Malmstrom AFB	Air Force Base	Great Falls
Barretts Minerals Inc.	Talc processing	Dillon
Roseburg Forest Products	Wood Processing	Missoula
Sidney Sugars	Sugar production	Sidney
Havre Pipeline Company	Nat. Gas Pipeline (compressor stations)	Northern Montana
Western Sugar Cooperative	Sugar production	Billings
50-200 MMcf Average Usage Annually		
Deaconess Billings Clinic	Hospital	Billings
St. Vincent Hospital	Hospital	Billings
MSU-Billings	Heating Plant-University	Billings
MDU-Glendive turbines	Electrical generation	Glendive
Montana Resources Inc.	Mine	Butte
American Chemet Corp.	Industrial manufacturing	East Helena
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 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 on 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 to 1999) taken from EPA's AIRS County Reports; DEQ Air Resources Management Bureau, Debbie Linkenbach, Emissions Inventory Detail (2000, 2001, 2008, and 2011), James Hughes, Montana DEQ in Billings (personal communication, Oct. 2008, Dec. 2009, Dec. 2010, Jan. 2012 and Jan 2013) with help from Rodger Godfry and Kathleen Doran of Montana DEQ (Jan. 2013); U.S. Department of Energy, Energy Information Administration, Form 906 database (2000-2004), NorthWestern Energy (personal communication with Tom Vivian, Feb. 2006, Sept. and Oct 2008, Dec. 2010, Jan 2012 and Dec. 2012), Bob Morman, MDU (personal communication, Dec. 2012), Ed Kacer, Energy West (personal communication, Oct. 2008, Jan. 2010, Jan. 2012), Nick J Bohr, Energy West (personal communication, Jan. 2013), Montana Department of Administration, State Procurement/State of Montana Term Contract, Ken Phillips, DEQ, accessing the EnergyCAP Enterprise System for the State of Montana, with help from David LeMieux, DEQ (Dec. 2010 and Jan 2012).

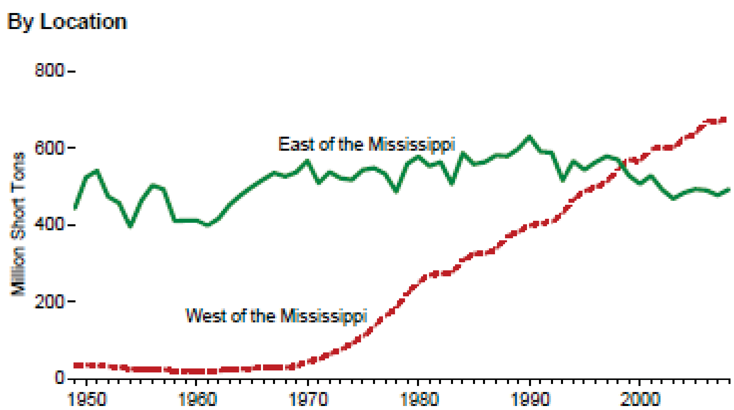
Coal in Montana

The Montana coal industry exists to support the generation of electricity. All but a tiny fraction of the coal mined in Montana is eventually converted to electricity, either in-state, out-of-state, or out-of-country. Montana's electricity market has until recently been dominated by coal-fired power plants, accounting for about two-thirds of the state's electric generation in the 2000s but only 50 percent in 2011. Slightly more than three-quarters of the coal mined in the state is exported, primarily to Midwestern utilities and foreign markets. The coal that remains in Montana fuels electric generating plants, with most used at the Colstrip facility. Montana coal is exported to more than a dozen states and increasingly to overseas markets. Coal's contribution to U.S. electrical generation continues to decline from its recent position of providing half of the nation's electricity, but still remains the top fuel for U.S. electric generation.

Production

Montana is the fifth largest producer of coal in the U.S., with 42 million tons mined in 2011. The majority of mining occurs in the Powder River Basin south and east of Billings. With the exception of the small lignite mine at Savage and the fast-growing Signal Peak mine north of Billings, production is low-sulfur subbituminous coal, with 17-18 million Btu per ton. Signal Peak also produces bituminous coal. Like most coal in the West, Montana coal is cleaner but lower in heat content than coal mined in the East. Information provided by the EIA shows that over the last decade, coal produced west of the Mississippi has surpassed coal produced east of the Mississippi in total tonnage (**Figure 13**).

Figure 13. Historical coal production in the U.S.



Coal has been mined in Montana since territorial days. Early production was primarily for heating fuel. Some coal was converted to coke for smelting, some 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, reaching its lowest point in 1958. 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 electric generating plant opened in Sidney in 1958 by MDU. Production began to grow again in 1968, when Western Energy Company began shipping coal mined from the Colstrip area to a generating plant in Billings owned by its parent company, MPC.

As Montana mines began supplying electric generating plants in Montana and the Midwest, coal production jumped. Production in 1969 was 1 million tons; 10 years later, it was 32.7 million tons as Colstrip Units 1 and 2 (electric generation) came online and export markets continue to develop. Production increased gradually to almost 43 million tons in 1998 and then declined. Over the past decade, production steadily climbed, again reaching more than 43 million tons in 2007. It declined to 37 million tons in 2012. 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. Wyoming's share has increasingly grown over time with the rich and productive fields located in the Powder River Basin south of Montana's major coal mines, which are in the northern portion of the basin.

In Montana in 2012 productivity declined by 12 percent, and the average mine price increased by 13 percent over the year.[1]

The price of Montana coal averaged $16.02 per ton at the mine in 2011 and $18.11 per ton in 2012, sharply up from 2007, and up from the previous 20 years where it steadily hovered around $10.00 per ton.[2] 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 fell 60 percent in real terms. Recent sharp price increases since 2007 have been the result of a variety of influences, and it is difficult to pinpoint one cause. The EIA suggests that higher recent reported prices are the result of several factors:

- All basins reported higher prices in part from higher commodity prices in general.
- Coal industry productivity was down in 2010-2011, possibly leading to higher prices. The year 2007 included the open market price only, while 2012 numbers are the total for all disposition types.
- Exports may play some role in the higher prices seen for Montana coal. However, even those Montana mines that do not appear to be exporting coal have seen dramatic increases in prices in this period.[3]

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[1] Reasons for the declining trend in productivity nationally include: less favorable stripping ratios, permitting challenges, shortages of skilled laborers, demographic shifts, and long-wall saturation, according to the EIA.

[2] 2012 EIA, http://www.eia.gov/coal/annual/pdf/table31.pdf.

[3] Diane Kearney, Operations Research Analyst, Coal and Uranium Team, Office of Electricity, Coal, Nuclear, and Renewables Analysis, EIA, December 27, 2013.

Most coal in Montana is mined on federal lands with most of the rest from Indian reservation land and private land. In 2009, the last year this data was available, 24 million tons of Montana coal came from leased federal lands and slightly less than 7 million from leased reservation lands.

There are currently six major coal mines in Montana operating in Big Horn, Musselshell, Richland, and Rosebud Counties. Westmoreland Mining LLC controls three mines in Montana, accounting for more than 11 million tons of coal in 2012. In 2007 Westmoreland gained 100 percent ownership of the Absaloka Mine in Big Horn County. During the 1990s, the last Montana mine producing less than 100,000 tons annually closed. A new mine at that site, Signal Peak near Roundup, opened in 2003.

Expansions at the Signal Peak mine are expected to bring a significant increase in Montana's total current coal output. The underground long-wall operation continues to see expansion. A 35-mile rail spur has been added to the BNSF (formerly Burlington Northern and Santa Fe) line near Broadview to deliver coal from Signal Peak to various markets. With the expansion, the mine is expected to ramp up production to about 15 million tons per year.

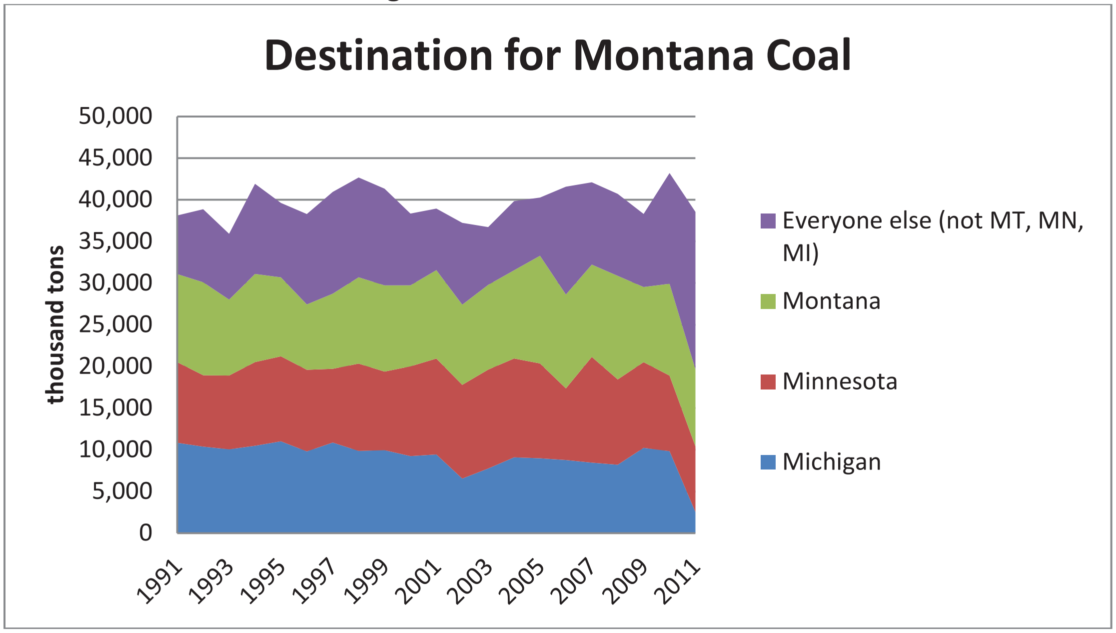
The West Decker and Spring Creek mines expanded significantly until 2008, when production from the West Decker mine fell to almost nothing. The Spring Creek mine, owned by Cloud Peak, was the largest producing mine in Montana in 2012, accounting for about 47 percent of production, or about 17 million tons. Western Energy Company (a subsidiary of Westmoreland) operates the Rosebud Mine and is the second largest producer at 8 million tons, accounting for 22 percent of coal production in 2012. Production has been down for coal in Montana, from about 45 million tons in 2008 down to 36.7 million tons in 2012. The future of Montana coal could depend in large part on greenhouse gas regulations for electric generation, the amount of U.S. coal-fired generation operating, natural gas prices, and coal exports.

Consumption

Almost all coal produced in Montana generates electricity. In recent years, about three-quarters of production has been shipped by rail to out-of-state utilities and, increasingly, foreign nations. 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 1980s, after the Colstrip 4 generating unit came online. Since 2011 less coal has been consumed, in part because of a heavy hydroelectric year in 2011 and a shutdown at one of the Colstrip units in 2013.

Prior to deregulation, about 40 percent of the electricity generated in Montana with coal went to Montana customers and 60 percent was transmitted to out-of-state utilities. No public data is available now, but it's likely that the majority of coal burned in Montana still produces electricity for export to Washington and Oregon. This is because the ownership structure of Colstrip by six different companies has remained largely the same over time. Over the last decade, Michigan, Minnesota, and Montana used about three-quarters or more of all the coal produced in Montana (**Figure 14**). Since 2010, the trend has changed dramatically, with about 25 percent still staying in Montana, much less going to Michigan and Minnesota, and more going to coal brokers who are sending much of it overseas. Almost half of Montana coal now goes to 12 other states and other countries, whereas the other half goes to Montana, Michigan, and Minnesota. After 2002, data on shipments to other countries was not available; however, historically, Montana has shipped some coal to Canada. Some exports are going to Europe and Asia, and most exports from Montana mines currently go through brokers first, who don't always accurately report the final destination for exports.

Figure 14. Destination for Montana coal



Coal Economics

Since 2002 the average price of coal has increased, and the amount of coal mined has increased along with the number of in-state mining employees (**Figure 15**). Taxes on coal, despite decreases from historical highs, remain a major source of revenue for Montana, with $52.7 million collected in coal severance tax in state fiscal year 2012.[4] That is just over half, in nominal terms, of the amount collected in fiscal year 1984, when collections peaked. Collections dropped in the 1980s and 1990s as tax laws changed, beginning with tax changes made by the 1987 Legislature. Revenues also dropped due to the declining price of coal over time. 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 larger impact on tax collections than the drop in coal prices. The tax structure's impact on coal production is less clear. Production has risen modestly since

[4] A gross proceeds tax of 5 percent goes to the county where the coal was mined. Another 0.4 percent goes for the Resource Indemnity and Ground Water Assessment Tax that, among other things, pays for reclamation of old, unreclaimed mined areas.

the cut in coal 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.[5] The 2009 Legislature altered a series of tax laws applicable to coal producers. Severance tax rates for strip mines that recover coal using auger techniques were reduced. County commissioners have been granted authority to provide up to a 50 percent local abatement of coal gross proceeds taxes for 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.[6] A royalty is also paid on coal-producing land leased from the state.

While significant, Montana's coal output is dwarfed by that of Wyoming, which produced close to 40 percent of the nation's coal in 2011. This is slightly more than 10 times as much coal as Montana produced. The gap is due in part to a combination of physical factors that make Montana coal less attractive than coal from Wyoming. Montana coal generally is more costly to mine. Coal seams tend to be thinner, though still thick in comparison to eastern coal, and buried under more overburden than seams in Wyoming. Wyoming coal also 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, however, and about the same sulfur as Wyoming coal. It has the disadvantage of having a high sodium content, which can cause problems in combustion.

The cost of transportation to distant markets may also affect the competitiveness of Montana coal. Nearly all coal exported from Montana leaves on BNSF rail lines. Some is later shipped by barge. Transportation costs can be double to triple the delivered cost of Montana coal shipped to out-of-state generating plants. 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.[7] 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 in Wyoming than in the northern end.

Coal remains the least expensive fossil fuel used to generate electricity, although not as significantly as in the past. When natural gas was near $2/dkt in early 2013, it was briefly cheaper than coal. By 2014 coal was again a much cheaper fuel for generating electricity. Increasingly, the use of coal-fired generation for electricity is also closely linked to potential federal activities and restraints on greenhouse gases. The impact of potential greenhouse gas regulations on the future price and viability of coal-fired generation is uncertain at this time.

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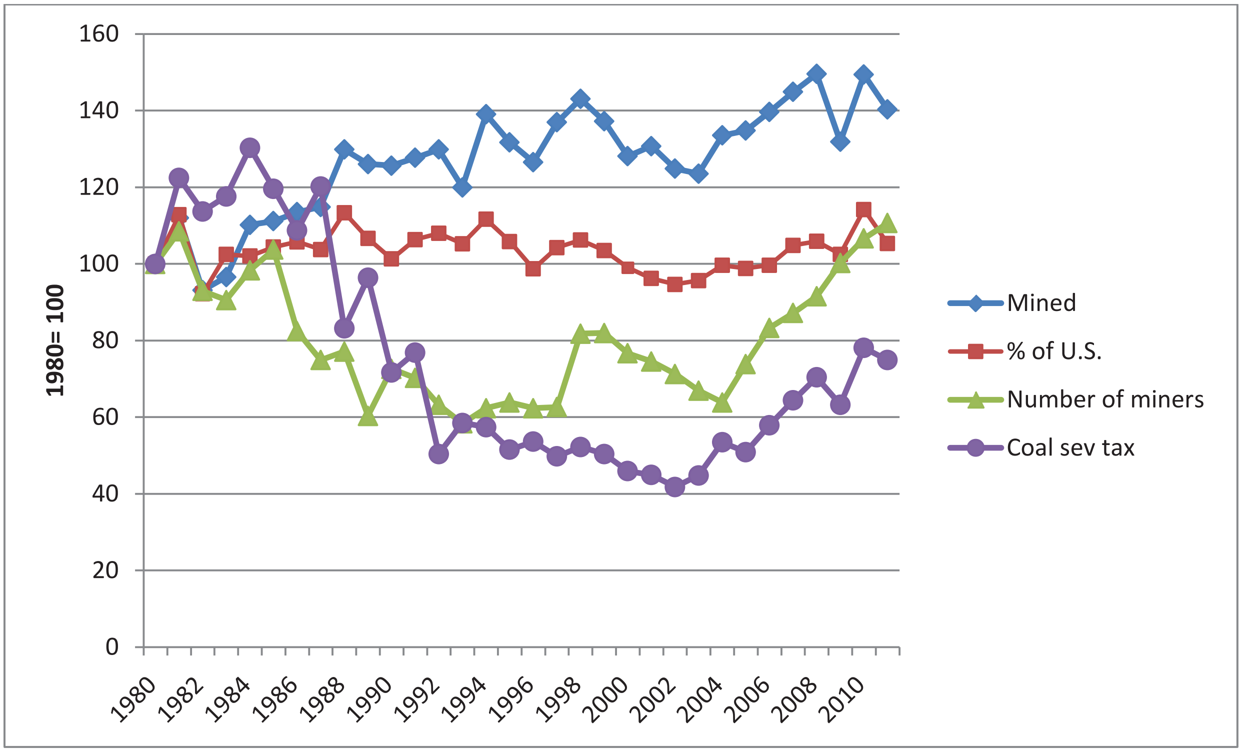
[5] Montana DOR, TPR, Rosemary Bender.

[6] Congressional budget discussions could impact this.

[7] *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation,* EIA, 2000.

The state has advocated clean coal technologies in the past, and a number of projects are in the preliminary stages. If greenhouse gas regulations move forward, these efforts may be of critical importance in promoting the consumption of Montana's vast coal resources.

Figure 15. Relative Changes in Montana production, share of U.S. market, number of miners, and severance tax collections, 1980 to 2011 (1980 = 1)



Early Observations

Not surprisingly, coal in present-day Montana was documented by the earliest white explorers of the region. Captain William Clark, on the return trip through what is now Montana, led half of the Lewis and Clark Expedition down the Yellowstone River, passing within perhaps 50 miles of the coal beds of what is now known as the Rosebud field, part of the larger Fort Union Formation in the Powder River Basin.

The following excerpt is from Clark's Yellowstone River journal from the summer of 1806:

> *In the evening I pass Starters of Coal in the banks on either side … bluffs about 30 feet above the water and in two vanes [veins] from 4 to 8 feet thick, in a horizontal position. This coal or carbonated wood is like that of the Missouri [River] of an inferior quality.*[8]

[8] *Journals of the Lewis & Clark Expedition*, R. Gold Thwaites, editor, 1905.

The annual federal Statistics of Mines and Mining compiled for the western states and territories for 1873 and 1875 indicated limited seasonal coal extraction in the Big Hole Valley, at Mullan Pass west of Helena, at Fort Benton, and at Belt along the Missouri River. During this time the coal was probably used principally to forge iron for blacksmithing in nearby towns.

Railroad planners became interested in local coal to build steam for locomotive power, and early surveys in Montana Territory often included geologists on the lookout for available deposits. In 1882 the geologists of the Northern Transcontinental Survey visited the region in the course of a general reconnaissance of the Northwest, a chief object of the exploration being to secure information concerning coal resources. The existence of valuable coal deposits in the Great Falls region was clearly recognized by the survey, as were lesser-quality deposits near present-day Lewistown and in the Bull Mountains.[9]

The narrow-gauge Utah & Northern (later Union Pacific) reached Montana from the South in 1880, connecting to Butte the following year.[10] Northern Pacific and to a lesser extent Union Pacific formed coal mining companies to exploit the deposits at Timberline on Bozeman Pass, and by 1885 more than 83,000 tons per year was mined there, mostly for rail transportation.[11] Great Northern launched a coal subsidiary in 1888 at Sand Coulee outside of Great Falls to provide for its Montana operations.[12]

By 1880, use of coal in Montana was growing to include more industrial uses–principally ore processing–in addition to commercial and domestic home heating. Nontransportation industrial use would grow significantly over the next quarter century with the rise of copper smelting and refining in the Butte-Anaconda district and at Great Falls. The use of coal for mineral reduction declined early in the twentieth century, at least partially as hydroelectric dams came online along the Missouri River.

Current Issues in Montana

<u>Otter Creek</u>

Montana's coal resources received a great deal of attention over the past few years. 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 private ownership. State recoverable coal totals 616 million tons at Otter Creek, or about one-half of the total 1.3-billion-ton reserve. In November 2009, Otter Creek entered into a coal lease agreement with Great Northern covering its privately owned coal resources on the Otter Creek Mine tracts. In March 2010, Ark Land Company was the successful bidder on Montana coal

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[9] *Geology of the Lewistown Coal Field, Montana*, U.S.G.S., 1909, Calvert, W.R.

[10] *Montana: A History of Two Centuries*, Malone, M., et al, 1976.

[11] Op cit, McDonald and Burlingame.

[12] *The Cascade County Album: Our History in Images*, Cascade County Historical Society, 1999.

interests on the intervening sections. These combined coal lease interests total approximately 17,900 contiguous acres.[13]

The Otter Creek Coal Mine would be located about 5 miles southeast of the town of Ashland, in southeastern Montana. On July 26, 2012, Otter Creek Coal, a wholly-owned subsidiary of Arch Coal, Inc., filed an application with the DEQ for a surface coal mining permit. An Environmental Impact Statement (EIS) is being prepared by DEQ and the Department of Natural Resources and Conservation to ensure agency decisions regarding the proposed project are in compliance with the Montana Environmental Policy Act. The proposed project would produce approximately 20 million tons of coal per year over a 20-year period.

<u>Impacts From Federal Greenhouse Gas Activities</u>

The Environmental Protection Agency (EPA) under the Clean Air Act (CAA) is crafting greenhouse gas regulations for new and existing major stationary sources, including power plants, under Section 111 of the CAA. Section 111 performance standards, like much of the CAA, are designed and promulgated through a federal-state partnership. EPA is authorized to approve a minimum federal “backstop” for regulations, and then allow states to control greenhouse gas emissions above and beyond that backstop. While portions of the proposed rules are out for public comment in early 2014, other rules, for example those for existing sources, aren’t expected until later in 2014.

Depending on the final rules, greenhouse gas-intensive coal generation could be forced to develop a number of retrofits, likely making generation more expensive over time. As a result, utilities across the nation are closely watching the rulemaking and evaluating the use of new and existing coal plants. Both NWE and MDU, in their respective resource plans and in recent portfolio purchases, evaluate these issues. Both also have favored acquisitions of natural gas and wind power in the last 2 years. MDU has taken advantage of market purchases from the regional transmission organization known as MISO, while NWE continues to purchase energy on the wholesale market with a mix of long-term and shorter-term purchases.

Montana is one of only a few states that have taken steps to implement carbon sequestration legislation (Chapter 474, Laws of 2009). While state law does not mandate the sequestration of carbon dioxide generated from sources, the law provides regulatory certainty to those interested in pursuing such technology. Montana also has stated its intent to have jurisdiction over a sequestration program, while recognizing that its regulatory program will need to be in line with federal guidelines.

<u>Coal Exports and Coal Trains and Coal Terminals</u>

In the past few years various business interests (mining, transportation, ports) have proposed shipping coal from the Powder River Basin area in southeastern Montana and Wyoming to the West Coast. Several coal export terminals have been proposed on the coasts of Washington and Oregon, including one inland on the Columbia River. These terminals, if built, would ship

[13] http://deq.mt.gov/ottercreek/default.mcpx and Kris Ponozzo of Montana DEQ, January 2, 2013.

coal overseas, mostly to Asia. Concerns have been raised about greenhouse gas emissions and impacts along railroad routes, including some Montana cities and towns, where coal would be shipped to the proposed ports. The U.S. coal industry sees exports as an opportunity to make up for declining domestic demand. The future of proposed coal exports remains in question but could likely have a significant effect on coal production in Montana.

Table C1. Coal Production by State and Coal Rank, 2011 (Thousand Short Tons)

Rank	State	Bituminous Production	Subbituminous Production	Lignite Production	Anthracite Production	Total Production	Percentage of U.S. TOTAL 2011	2007[1]	2001[1]
1	Wyoming	-	438,673	-	-	438,673	40.1%	39.6%	32.7%
2	West Virginia	134,662	-	-	-	134,662	12.3%	13.4%	14.4%
3	Kentucky	108,766	-	-	-	108,766	9.9%	10.1%	11.8%
4	Pennsylvania	57,051	-	-	2,131	59,182	5.4%	5.7%	6.6%
5	Texas	-	-	45,904	-	45,904	4.2%	3.7%	4.0%
6	Montana	5136	36,518	355	-	42,009	3.8%	3.8%	3.5%
7	Illinois	37,770	-	-	-	37,770	3.5%	2.8%	3.0%
8	Indiana	37,426	-	-	-	37,426	3.4%	3.1%	3.3%
9	North Dakota	-	-	28,231	-	28,231	2.6%	2.6%	2.7%
10	Ohio	28,166	-	-	-	28,166	2.6%	2.0%	2.2%
11	Colorado	21,868	5,022	-	-	26,890	2.5%	3.2%	3.0%
12	Virginia	22,523	-	-	-	22,523	2.1%	2.2%	2.9%
13	New Mexico[2]	17,989	3,933	-	-	21,922	2.0%	2.1%	2.6%
14	Utah	19,648	-	-	-	19,648	1.8%	2.1%	2.4%
15	Alabama	19,071	-	-	-	19,071	1.7%	1.7%	1.7%
16	Arizona	8,111	-	-	-	8,111	0.7%	0.7%	1.2%
17	Louisiana	-	-	3,865	-	3,865	0.4%	0.3%	0.3%
18	Maryland	2,937	-	-	-	2,937	0.3%	0.2%	0.4%
19	Mississippi	-	-	2,747	-	2,747	0.3%	0.3%	0.1%
20	Alaska	-	2,149	-	-	2,149	0.2%	0.1%	0.1%
21	Tennessee	1,547	-	-	-	1,547	0.1%	0.2%	0.3%
22	Oklahoma	1,145	-	-	-	1,145	0.1%	0.1%	0.2%
23	Missouri	465	-	-	-	465	0.0%	0.0%	0.0%
24	Arkansas	133	-	-	-	133	0.0%	0.0%	0.0%
25	Kansas	37	-	-	-	37	0.0%	0.0%	0.0%
	East of Miss. River	**449,918**	**-**	**2,747**	**2,131**	**454,796**	41.5%	41.6%	47.0%
	West of Miss. River	**74,531**	**486,295**	**78,355**	**-**	**639,181**	58.3%	58.3%	52.8%
	U.S. Subtotal	**524,449**	**486,295**	**81,102**	**2,131**	**1,093,977**	99.8%	99.9%	99.8%
	Refuse Recovery	**1,547**	**-**	**-**	**104**	**1,651**	0.2%	0.1%	0.2%
	U.S. Total	**525,996**	**486,295**	**81,102**	**2,235**	**1,095,628**	100.0%	100.0%	100.0%

- = No data are reported.

[1] Total U.S. production in 2001 was 1,127,689 tons and in 2007 was 1,145,480 tons.

[2] One mine in New Mexico periodically produces both bituminous and subbituminous coal. When this occurs, it is double counted as a subbituminous and bituminous mine but is not double counted in the total.

Sources: U.S. Department of Energy, Energy Information Adminstration, *Annual Energy Review 2011* , Table 6, Coal Production and Number of Mines by State and Coal Rank, (http://www.eia.gov/coal/data.cfm#production), original sources for Table 6 in 2011 report are U.S. Energy Information Administration Form EIA-7A, "Coal Production and Preparation Report," and U.S. Department of Labor, Mine Safety and Health Administration Form 7000-2, "Quarterly Mine Employment and Coal Production Report."; *Annual Coal Report 2007* http://www.eia.gov/coal/annual/archive/05842007.pdf) and *Annual Coal Report 2001,* http://www.eia.gov/coal/annual/archive/05842001.pdf).

Table C2. Montana Coal Production and Average Mine Price by Rank of Coal, 1950-2011

	PRODUCTION (thousand short tons)				AVERAGE MINE PRICE (dollars/short ton)		
Year	Subbituminous	Lignite	Bituminous[2]	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**
2008	44,431	355	-	**44,786**	w	w	**12.31**
2009	39,143	343	-	**39,486**	w	w	**13.53**
2010	44,381	352	-	**44,733**	w	w	**15.12**
2011	36,518	355	5,136	**42,009**	15.43	w	**16.02**

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.

[2]From the *Annual Coal Report, 2011* , and from conversations with Paulette Young at the U.S. EIA, it was discovered that for the second time in recent history, in 2011, a mine in Montana reported mining bituminous coal. It is believed that the 5,136 thousand ton number is either a reporting error by that mine, or that bituminous coal really was mined. The EIA checked the data several times over one month and contacted the mine in question, and the mine held firm that bituminous coal was mined, and thus the number holds. EIA Form 923 data incidates that the mine in question is Signal Peak. The average price of the bituminous coal was withheld.

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 coal sold by the total coal sold. This number excludes mines producing less than 25,000 short tons, which are not required to provide data and 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 C4 (by less than +/- 1%) and in Table C7 (which usually is lower). The main reason is the different data sources used for each table.

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* 2001-2011, Tables 6 and 31 (http://www.eia.gov/coal/data.cfm#production) and (http://www.eia.gov/coal/data.cfm#prices), 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, 1982-2009

Year[2]	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
FY 2002	NA	27,696	$31,452	14,746	5,795	$2,730
FY 2003	NA	21,782	$34,918	14,746	5,425	$2,568
FY 2004	NA	23,171	$31,027	14,746	6,609	$3,174
FY 2005[3]	NA	25,880	$32,205	14,746	1,518	$691
FY 2006[3]	NA	22,786	$28,331	14,746	11,488	$6,364
FY 2007	NA	26,168	$35,084	14,746	7,216	$4,835
FY 2008	NA	25,708	$34,201	NA	6,533	$4,998
FY 2009	NA	24,189	$31,366	NA	6,613	$5,424

NA = Not available

This table was discontinued in 2010 due to the difficulty in obtaining accurate information on coal leases and due to discontinued information on acres leased.

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 the 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]The Year is the Fiscal Year Accounting Year which starts on October 1st of the previous year and ends on September 30th of the named year. Reported Royalty Revenue by Accounting Year – This data set represents all royalty data accepted in the MRM Financial System including adjusted royalty line transactions. This data is static and will not change. The “Accounting Year” or “acceptance date” approach has been used by MRM since its inception in 1982, because it represents all reported royalty revenues for a given reporting period (including revenues reported for prior periods) consistent with MRM’s financial reporting requirements. The data set identifies MRM’s mineral revenue collections that could be disbursed to appropriate recipients. However, the Accounting Year approach can impact data and/or trending.

[3] 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;* Office of Natural Resources Revenue *(* formerly Minerals Management Service), *ONRR Statistical Information* , http://www.onrr.gov/ONRRWebStats/home.aspx (2001-Forward).

Table C4. Coal Production by Company, 1980-2012 (short tons)

	Beartooth Coal Co.[1]	Blaine Warburton (owner)	Signal Peak Energy[2]	Coal Creek Mining Co.	Decker Coal[3] East Decker Mine	Decker Coal[3] West Decker Mine	Spring Creek Mine[4] (owned by Cloud Peak Energy)	Big Sky Coal (owned by Peabody Coal Co.)	Red Lodge Coal Co.	Storm King Coal Mining Co.[5]	Westmoreland Savage Mine[6]	Westmoreland Absaloka Mine[7]	Westmoreland Rosebud Mine[8]	TOTAL
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
2008			186,750		581,306	6,411,896	17,947,506				356,344	6,617,070	12,826,742	44,927,614
2009			866,772		2,866,162	1,720,374	17,608,969				337,061	6,138,334	10,105,036	39,642,708
2010			4,388,851		2,699,951	228,006	19,345,161				351,502	5,467,954	12,230,346	44,711,771
2011			5,135,571		2,749,367	295,575	19,080,553				354,669	5,557,604	8,784,829	41,958,168
2012			5,707,623		2,247,873	484,570	17,200,109				296,454	2,714,063	8,010,495	36,661,187

[1] Underground mine.

[2] This site has been operated by different companies, most recently Signal Peak Energy, before that 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. Signal Peak Energy currently is the joint venture between the Boich Group LLC, FirstEnergy, an Ohio based utility company and Pinesdale LLC. Underground and strip mining both have been done at this site.

[3] Decker Coal Co. is a joint venture between Amber Energy and Cloud Peak Energy Inc., each of whom own 50% of the mine. In March of 2013, Amber Energy is expected to buy out Cloud Peak's share and own 100% of the mine. In January of 2010, Cloud Peak Energy Inc. announced an agreement that Decker Coal Company has accepted a buy-out offer from an eastern utility company for a coal supply contract originally scheduled through 2012. This likely accounts for the greatly declining numbers at the West Decker mine in 2009 and 2010. Ambre Energy, an Australian company, bought a 50% interest in Decker Coal Company in 2011.

[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. Cloud Peak Energy later was spun off of Rio Tinto and now owns the Spring Creek Mine.

[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: Sharon Meyer, Montana Department of Labor and Industry, Employment Relations Division, Safety and Health Bureau, Mining Section (1980-2012), (406) 444-3931. Delivered by mail to the desk of Jeff Blend, DEQ.

Table C5. Consumption of Coal In Montana, 1960-2009

(thousand short tons)

Year	Electric Utilities	Residential and Commercial	Industrial	TOTAL
1960	187	30	36	**253**
1961	262	28	45	**336**
1962	295	29	49	**373**
1963	285	27	44	**357**
1964	294	25	62	**381**
1965	296	22	52	**370**
1966	323	23	45	**392**
1967	326	24	31	**381**
1968	399	19	32	**450**
1969	577	18	25	**619**
1970	723	12	28	**763**
1971	672	19	40	**731**
1972	769	12	49	**830**
1973	893	14	44	**951**
1974	854	12	56	**923**
1975	1,089	11	50	**1,149**
1976	2,374	9	124	**2,507**
1977	3,197	2	186	**3,385**
1978	3,184	16	190	**3,390**
1979	3,461	11	213	**3,686**
1980	3,352	14	154	**3,520**
1981	3,338	8	276	**3,622**
1982	2,596	9	222	**2,826**
1983	2,356	8	169	**2,533**
1984	5,113	6	164	**5,283**
1985	5,480	8	225	**5,713**
1986	7,438	22	319	**7,780**
1987	7,530	8	192	**7,730**
1988	10,410	9	215	**10,634**
1989	10,208	53	197	**10,458**
1990	9,573	57	220	**9,850**
1991	10,460	45	281	**10,786**
1992	11,028	21	251	**11,300**
1993	9,121	11	367	**9,499**
1994	10,781	4	572	**11,357**
1995	9,641	10	622	**10,272**
1996	8,075	4	130	**8,210**
1997	9,465	83	105	**9,653**
1998	10,896	4	145	**11,046**
1999	10,903	3	168	**11,074**
2000	10,385	3	166	**10,554**
2001	10,838	3	159	**11,000**
2002	9,746	3	92	**9,841**
2003	11,032	2	93	**11,127**
2004	11,322	108	92	**11,522**
2005	11,588	145	89	**11,822**
2006	11,302	140	89	**11,531**
2007	11,929	2	110	**12,041**
2008	12,012	11	90	**12,113**
2009	10,151	10	60	**10,221**

Note: The number for the amount of coal used at electric utilities is different in Tables C5 and C6 due to coming from different data sets. The data in this table comes from the U.S. EIA *State Energy Data System (SEDS)* which relies on data from multiple sources, which vary over time. This SEDS data changed in 2008 enough that there no longer was any point in presenting new distribution data in this table.

Sources: Data are taken from US DOE's State Energy Data System (SEDS) found at http://www.eia.gov/state/seds/seds-data-complete.cfm#consumption. Data surveys/sources, estimation procedures, and assumptions are described in the Technical Notes for the State Energy Data System (SEDS) at http://www.eia.gov/state/seds/sep_use/notes/use_coal.pdf.

Table C6. Receipts of Montana Coal at Electric Utility Plants[1] 1973-2011

(thousand short tons)

Year	Received at Montana Utilities Subbituminous	Lignite	Montana Total	Received at Out-of-State Utilities	TOTAL
1973			882	9,741	**10,623**
1974			822	13,114	**13,936**
1975			1,197	20,180	**21,377**
1976			2,316	22,642	**24,958**
1977			3,223	22,730	**25,954**
1978	3,033	298	3,331	22,976	**26,307**
1979	3,207	304	3,511	24,613	**28,124**
1980	3,071	293	3,364	24,561	**27,925**
1981	3,129	210	3,339	26,634	**29,973**
1982	2,424	177	2,601	25,439	**28,040**
1983	1,804	206	2,010	25,756	**27,766**
1984	4,823	200	5,023	27,432	**32,455**
1985	5,292	168	5,460	25,975	**31,435**
1986	7,308	190	7,498	22,992	**30,490**
1987	7,376	220	7,596	24,607	**32,203**
1988	10,306	168	10,474	26,076	**36,550**
1989	9,989	235	10,224	25,858	**36,082**
1990	9,343	176	9,519	26,108	**35,627**
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**
2007[2]	10,669	301	10,970	29,393	**40,363**
2008	11,969	316	12,285	27,642	**39,927**
2009	8,647	307	8,954	26,074	**35,028**
2010	10,642	310	10,952	24,359	**35,311**
2011[5]	8,868	297	9,165	14,663	**23,828**

[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 sold off their generating plants. Once divestiture was complete, data for those plants 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 to 2007 are EIA Form 6 survey data (Distribution of Coal Originating in Montana). Subbituminous data for 1998 through 2007 are numbers calculated by DEQ by subtracting Form 423 data on Lignite from Montana Total. EIA introduced a new form (EIA-923) in 2008, which once again had complete data on receipts at utilities; that data base is used from 2008 forward.

[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.

[5] Starting in 2010, the EIA in its Annual Coal Distribution Report added the estimates of coal exports data by 'brokers/traders'. The coal exports by brokers/traders are estimated data. The data in EIA Form 923 indicate that starting in 2011, large amounts of Montana produced coal were exported out of the country, or exported by brokers to locations unknown. Information as to where this broker exported coal went is not available. Clearly, from Table C7, far less coal in 2011 went to out of state U.S. electric utilities and more went overseas.

Sources: Federal Energy Regulatory Commission (formerly the Federal Power Commission), Form 423 (1973-77); U.S. Department of Energy, Energy Information Administration, *Monthly Cost and Quality of Fuels for Electric Utility Plants,* annual reports for 1978-2007 (EIA-0191; based on FERC Form 423, http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html); 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* 2001-2007 (http://www.eia.gov/coal/distribution/annual/archive.cfm; based on EIA Form 6); U.S. Department of Energy, Energy Information Administration, *EIA-923 (Schedule 2) - Monthly Utility and Nonutility Fuel Receipts and Fuel Quality Data,* 2008-2010 (http://www.eia.gov/electricity/data/eia923/index.html), for 2011 data, 2011 December EIA-923, Schedule 2, Monthly Time Series File, Fuel Receipts and Cost, found at http://www.eia.gov/electricity/data/eia923/ on the right hand side with zip file named '2011: EIA-923'.

Table C7. Distribution of Montana Coal by Destination, 1991-2011 (thousand short tons)

Destination	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Alabama																4,291					
Arizona								94	69	198	275	81	48	71	361	458	584	720	634	683	761
Colorado	101	106	86	89	63	26													69		
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	1,631	1,571	794	168	238
Iowa			1		2		105	136					29		34	29		79	29	94	54
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	8,455	8,204	10,230	9,831	2,525
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	12,684	10,234	10,283	9,068	7,872
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	11,081	12,432	9,017	11,024	9,256
Nebraska	150	142	136	71	205	113	47	81													
Nevada											1	1	1	1	1	2					
New Hampshire											10										
New Mexico																		257			
New York																			198		
North Dakota	425	444	422	559	469	417	402	517	877	145	618	487	617	964	1,454	1,228	1,356	498	1,169	1,281	1,201
Ohio						26	42		168	153	*			14		194	56	130	387	1,242	370
Oklahoma																					14
Oregon		1,835	355						1,507			675	232						28	152	108
Pennsylvania															57	422	404	195	218	181	
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	3,427	4,118	2,588	2,495	2,438
West Virginia															*			202	68		
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	1,961	562	501	539	489
Wyoming	8	11	31	49	71	125	34	62		64	67	58	64	67	71	83	71	27	19	19	20
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	41,710	39,228	36,233	36,777	25,346
Export - Canada[2]	10		54	90	259	316	438	814	682	608	485	180	541	1,142	653	447	387	1,480	2,065	3,905	4,994
Export - Overseas[2]	297	62	67	153		202	141														
Export - brokers[3]																				2,526	8,205
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	42,097	40,707	38,299	43,209	38,545

* 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.

[3] Starting in 2010, the EIA in its Annual Coal Distribution Report added the estimates of coal exports data by brokers/traders. The coal exports by brokers/traders are estimated data. The data in this table indicate that starting in 2011, large amounts of Montana produced coal were exported out of the country, or exported by brokers. Information as to where this exported coal went is not available. Clearly, much of the coal that used to go to Michigan utilities is now either exported out of the country or unaccounted for in the data because it is handled by brokers.

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* 2001-2010 (foreign and domestic) at http://www.eia.gov/coal/distribution/annual/archive.cfm; using the files titled "Domestic distribution of U.S. coal by origin State, consumer..." and "Domestic and foreign distribution of U.S. coal by State of origin" using pdf files; for 2011, http://www.eia.gov/coal/distribution/annual/pdf/acdr_fullreport2011.pdf and http://www.eia.gov/coal/distribution/annual/pdf/o_11foreign.pdf.

Sources of these publications are: U.S. Energy Information Administration Form EIA-923, "Power Plant Operations Report," Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users," Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants," Form EIA-7A, "Coal Production and Preparation Report," and Bureau of the Census, U.S. Department of Commerce, "Monthly Report EM 545."

Table C8. Utilities Served by Montana Mines - 2011

Coal Mine	Utility Operator Name	Utility Plant Name	State	Received at Plant 2011 (thousand tons)
Absaloka Mine	Consumers Energy Co	B C Cobb	MI	308
	Consumers Energy Co	J C Weadock	MI	307
	Northern States Power Co - Minnesota	Sherburne County	MN	4730
	Rocky Mountain Power Inc	Hardin Generator Project	MT	462
Signal Peak (Bull Mountain Mine)	FirstEnergy Generation Corp	Bay Shore	OH	370
	Wisconsin Electric Power Co.	Valley	WI	14
	Global energy	CCT Terminal	IL	238
	C Riess	Syl Laskin	MN	24
	Dairyland Power Cooperative	Alma	WI	44
Decker Mine	Detroit Edison Co	BRSC Shared Storage	MI	127
Rosebud Mine	PPL Montana LLC	Colstrip	MT	8405
Savage Mine	Montana-Dakota Utilities Co	Lewis & Clark	MT	297
Spring Creek Mine	City of Marquette	Shiras	MI	188
	Detroit Edison Co	BRSC Shared Storage	MI	236
	City of Holland	James DeYoung	MI	28
	Great River Energy	Stanton	ND	752
	Minnesota Power Inc	Clay Boswell	MN	1763
	Minnesota Power Inc	Taconite Harbor Energy Center	MN	217
	Consumers Energy Co	BC Cobb	MI	267
	Otter Tail Power Co	Hoot Lake	MN	484
	Portland General Electric Co	Boardman	OR	108
	Rio Tinto	Cholla	AZ	43
	Salt River Project	Coronado	AZ	719
	AES	Shady Point	OK	14
	TransAlta Centralia Gen LLC	Transalta Centralia Generation	WA	2343
	Weyerhaeuser Co	Weyerhaeuser Longview WA	WA	94
	Wisconsin Electric Power Co	Presque Isle	MI	844
	Wisconsin Power & Light Co	Nelson Dewey	WI	382
	Wyandotte Municipal Serv Comm	Wyandotte	MI	20
Total				**23,828**

Source: U.S. Department of Energy, Energy Information Administration, EIA-923 (Schedule 2) - Monthly Utility and Nonutility Fuel Receipts and Fuel Quality Data, 2008-2011 (http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html)

Note: Starting in 2010, the EIA in its Annual Coal Distribution Report added the estimates of coal export data by brokers/traders. The coal exports by brokers/traders are estimated data. The data in EIA Form 923 indicate that starting in 2011, large amounts of Montana produced coal were exported out of the country, or exported by brokers. Information as to where this broker exported coal went is not available. Using data from Table C7, less Montana coal went to out of state U.S. electric utilities in 2011, especially to the state of Michigan. Foreign shipments of coal in Table C7 are not included in this table nor are brokered exports, accounting for the lower 2011 total number in this table compared to previous years when 35,311 and 35,028 thousand tons were reported for 2010 and 2009 respectively. Form EIA-923 used for this table is a monthly survey filled out by the power plants (rather than coal mines) which uses a sample survey of power plants (versus a census of all plants), and there are large reporting discrepencies from month to month that are reconciled once a year. Therefore, sometimes the EIA-923 data will not be final for a particular year or the timing of all form data will be off. Like the EIA Annual Coal Distribution Report, this number does not account for coal stockpiles.

Note: The largest discrepencies between coal production numbers in Table C4 and coal shipped to utilities in this table are the Spring Creek, Signal Peak, and Decker mines. It appears that much of the coal from Signal Peak is being exported out of the country, and that much of the coal from Spring Creek and Decker is either being exported out of the country or exported by brokers.

Table C9. Montana Coal Production, Employment and Severance Tax, 1980-2011

YEAR	Coal Produced (thousand tons)[1]	Percentage of U.S. production	Number of miners[2]	Average Mine Price per ton[1]	Coal Severance Tax (fiscal year)[3,4]
1980	29,948	3.6%	1,131	$10.50	$70,415,018
1981	33,545	4.1%	1,227	$12.14	$86,186,886
1982	27,882	3.3%	1,051	$13.57	$80,044,981
1983	28,924	3.7%	1,024	$14.22	$82,823,410
1984	33,000	3.7%	1,112	$13.57	$91,748,856
1985	33,286	3.8%	1,173	$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
2008	44,786	3.8%	1,035	$12.31	$49,564,120
2009	39,486	3.7%	1,133	$13.53	$44,529,619
2010	44,733	4.1%	1,206	$15.12	$54,970,717
2011	42,009	3.8%	1,251	$16.02	$52,742,627

[1] Coal production and average mine price 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] As of 2011, employees include the average number of employees working in a specific year at coal mines anc preparation plants. Includes maintenance, office, as well as production-related employees. Before 2011, employees include production, preparation, processing, development, maintenance, repair, ship or yard work a 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. Found at http://www.eia.gov/tools/glossary/?id=coal.

[3] This number is for the Coal Severance Tax including both state and local severance collections. This number represents the state Fiscal Year starting July 1 of the calendar year listed; thus, the number for 2009 actually represents FY 2010 which starts on July 1, 2009 and ends June 30, 2010.

[4] 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. More data on current coal severance tax is found in the Montana Department of Revenue *Biennial Report.*

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*, 2001-2011; Montana Department of Revenue *Biennial Report* (1980-2012); Montana Department of Revenue files (FY2008 and FY2009), Steve Cleverdon (MT DOR) for 2011 Severance Tax number.

PETROLEUM AND PETROLEUM PRODUCTS IN MONTANA

During the 2013 fiscal year, Montana produced about 28.8 million barrels of crude oil, worth more than $2.4 billion in gross value. This oil production accounted for the majority of the $206.4 million in oil and gas production tax revenue collected by Montana. Ninety-four percent of Montana's crude oil production is exported to other states, primarily North Dakota and Wyoming, while 85 percent of the crude oil refined in Montana is imported from Canada with another 12 percent coming from Wyoming.

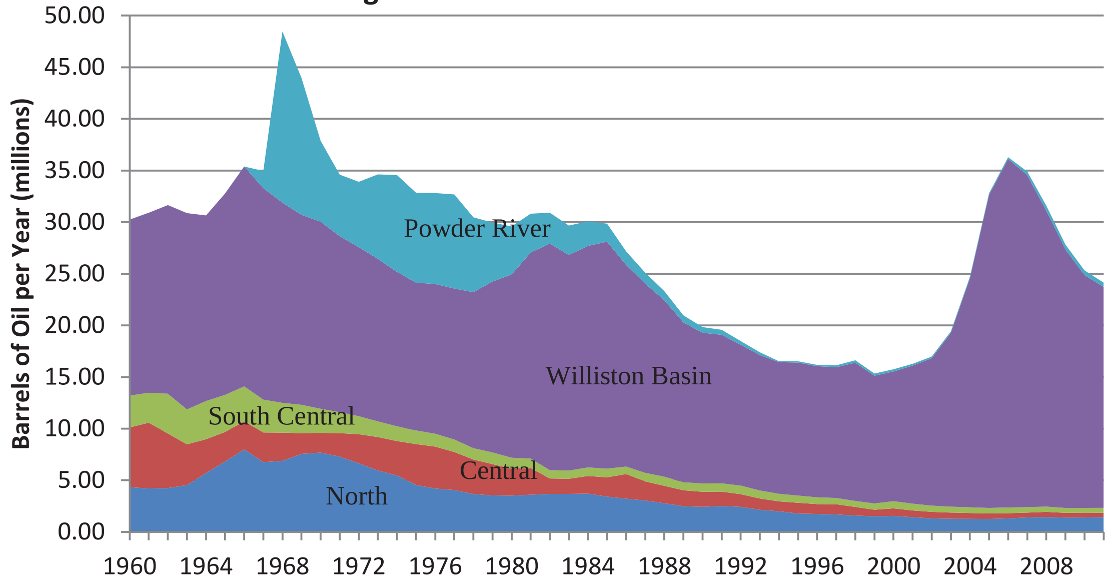
The state is home to four refineries, two in Billings, one in Laurel, and another in Great Falls. Those refineries have a total capacity of 188,600 barrels/day (bbl/day.) In 2012 Montana's four petroleum refineries exported 47 percent of their refined liquid products to Washington, North Dakota, Wyoming, and additional points east and south. Crude oil receipts at Montana's four refineries totaled 61 million barrels in 2012. Montana consumed about 32 million barrels of refined petroleum products in 2011, which included refinery usage.

Production History

Oil production in Montana arrived somewhat later than neighboring states. Probably the first oil wells drilled in Montana were in the Butcher Creek drainage between Roscoe and Red Lodge, beginning in 1889. Nonproducing wells were drilled within today's boundaries of Glacier National Park in the early 1890s. The state's first oil boom was a discovery in what geologists refer to as the Middle Mosby Dome at Cat Creek, a tributary of the Musselshell River east of Lewistown. Oil was drilled and collected there in early 1920. By 1921, 1.3 million barrels was produced at Cat Creek. That was soon followed by the Kevin Sunburst field discovery in 1922. That field would lead production from about 1925 through 1935. A bit west, the Cut Bank oil fields developed in the mid-1930s and led the state well into the 1950s when oil was discovered in the Williston Basin around 1955. Oil fields were developed in the Sweetgrass Arch in northern Montana, the Big Snowy Uplift in central Montana, the northern extensions of Wyoming's Big Horn Basin in southcentral Montana, and the Powder River Basin in southeastern Montana.

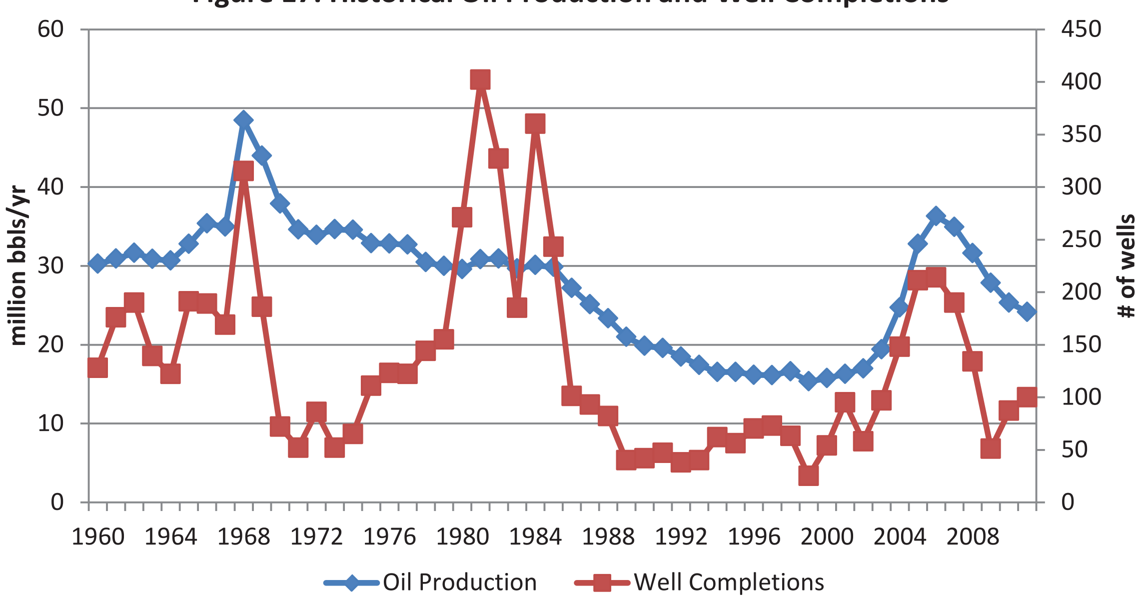
Montana's petroleum production peaked in 1968 at 48.5 million barrels (1 barrel = 42 gallons), the result of cresting Williston Basin production combined with a surge of production from the newly discovered Bell Creek field in the Powder River Basin (**Figure 16**). Production then declined quickly until 1971, when a series of world oil supply shocks began to push crude oil 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.

Figure 16. Historical Oil Production



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. 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 17**). The drilling boom of the early 1980s produced a high percentage of dry holes and was able only to delay the slow decline of statewide production (**Figure 19**).

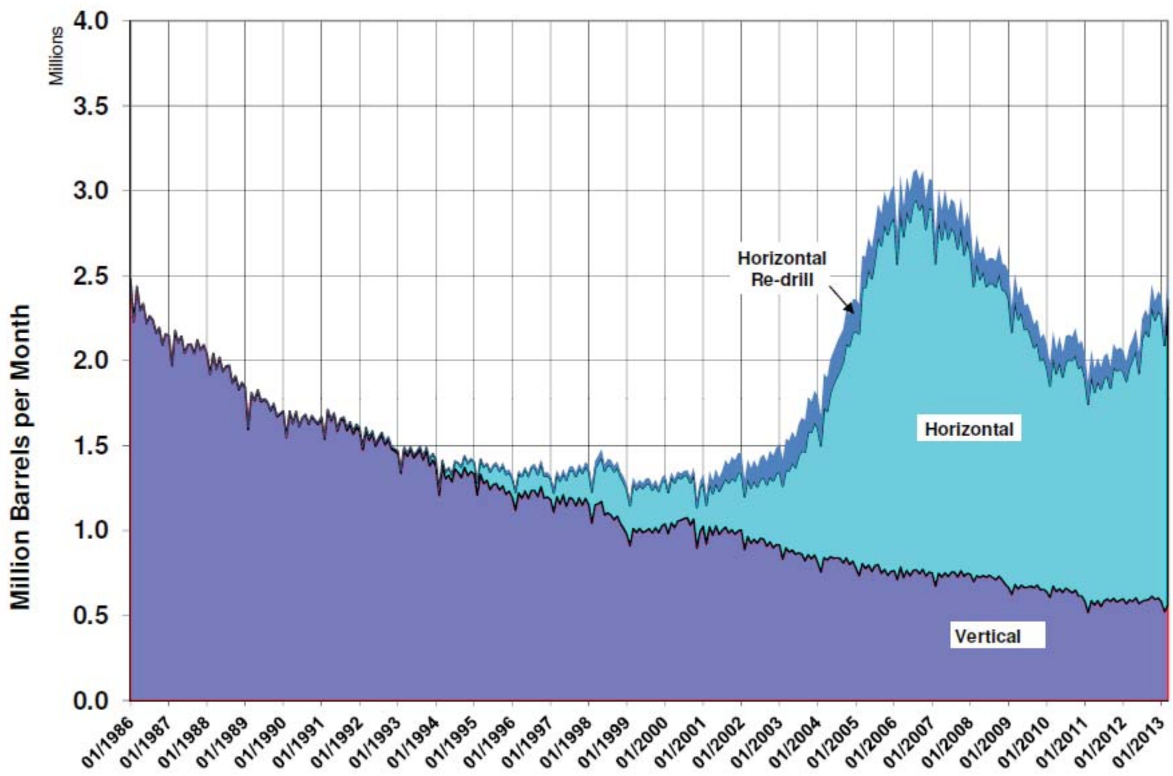
Figure 17. Historical Oil Production and Well Completions



Output increased in the Williston Basin during the early 1980s, but this was matched by a steep decline in output from other areas. Production declined significantly following the drop in world oil prices in 1985, stabilizing at about 16 million bbl/year in the mid-1990s. After 1999, oil production increased sharply as horizontal drilling and hydraulic fracturing techniques began to be implemented more widely in the Williston Basin (**Figure 18**).

Montana's recent oil production boom peaked in 2006 when production exceeded 36 million barrels. This was up from a recent historical low of 15 million barrels of oil produced during 1999. More than 50 percent of the 2006 oil production was from the Elm Coulee field in Richland County, part of the larger Bakken formation. Through 2012, the Elm Coulee Field has produced 131 million barrels of oil since its discovery in 2000. While reserves in the area were well known, horizontal drilling techniques, a method that includes drilling a vertical well and then "kicking out" horizontally through the oil-bearing rock formation, were critical in making the field economical to develop, along with the recent spike in oil prices.

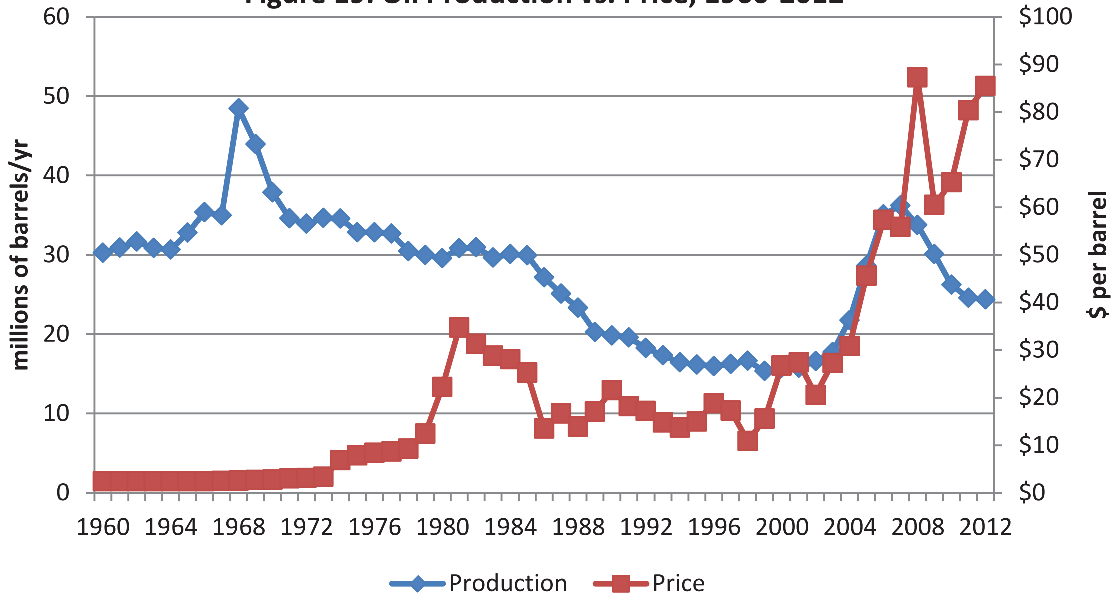
Figure 18. Montana Monthly Oil Production - Vertical vs. Horizontal Wells, 1986-2012



The Williston Basin, which covers parts of eastern Montana, North Dakota, South Dakota, and Saskatchewan and includes the Bakken and Three Forks formations, is one of the newest large oil-producing regions in the country to produce hundreds of millions of barrels of oil annually. Beginning in 2014, the Williston Basin is expected to produce more than 1 million barrels of oil per day; however, Montana's Bakken oil production represents less than 10 percent of the recent oil production from the larger formation. Most of the focus of drilling in the Bakken has been in North Dakota, beginning in 2007 after Montana's Elm Coulee field production peaked. Monthly oil production in Montana's Bakken region began to rise once more beginning in 2011, and more significantly in 2012, as drilling activity began to pick up as incremental drilling activity shifted away from North Dakota where drilling activities have run up against the infrastructure limits of the surrounding region.

In total, the U.S. Geological Survey (USGS) estimated in April 2013 that the Williston Basin has technically recoverable oil reserves of 7.4 billion barrels, up from the USGS's prior estimate of 3.65 billion barrels in 2008. The upward revision was largely driven by a reassessment of the technical potential of the Three Forks formation, which lies beneath the Bakken formation, as a result of technology and drilling developments between 2008 and 2013.

Figure 19. Oil Production vs. Price, 1960-2012



After declining by a third between 2006 and 2011, Montana annual oil production rose once more in 2012 to 26.5 million barrels and 28.8 million barrels for fiscal year 2013. In addition to increased drilling rig activity in Montana's portion of the Bakken formation, exploratory wells have also been drilled in central and northern Montana as additional geologic formations that might lend themselves to horizontal drilling and hydraulic fracturing techniques are explored. While these potential oil fields are not expected to hold the immense potential of the Bakken formation, they have the potential, if successful, to more than offset ongoing production declines from Montana's older, conventional oil-producing wells. In addition, a production increase from the Bell Creek field in the Powder River Basin region is expected in the near future as enhanced oil recovery techniques are implemented.

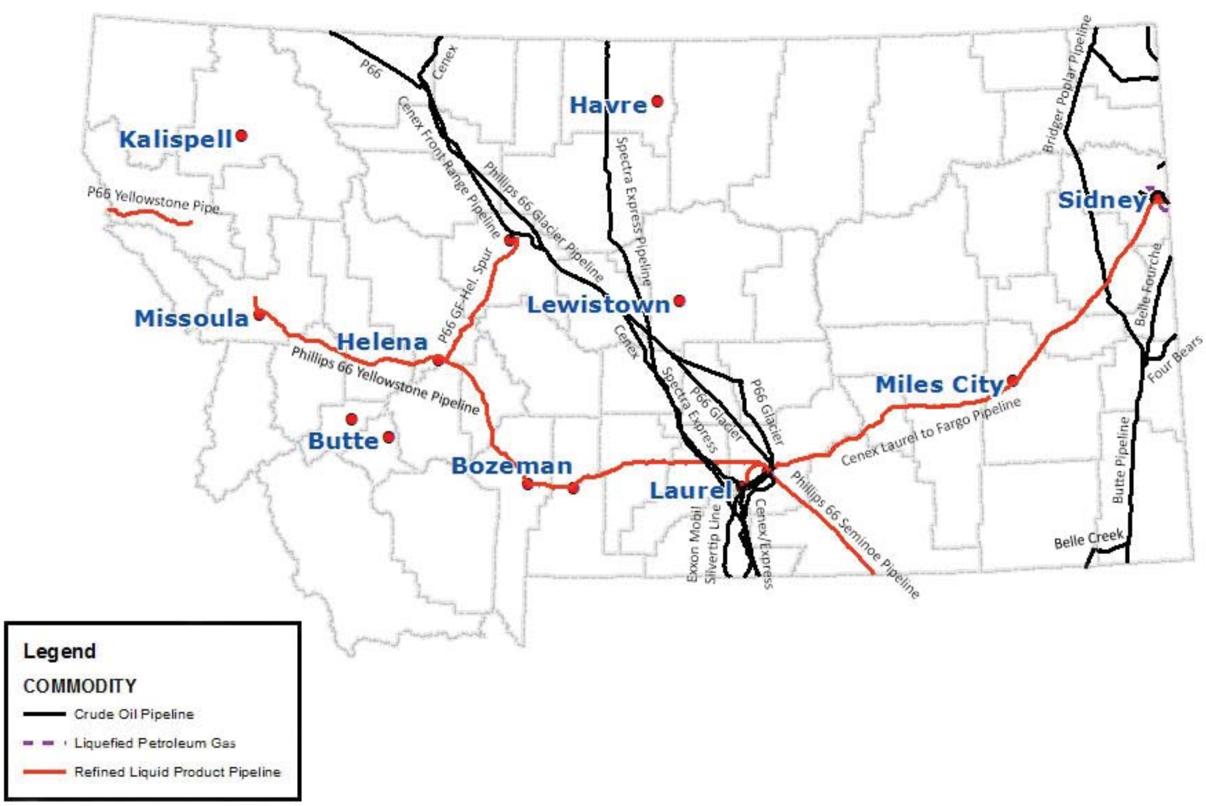
Pipelines

Three crude oil pipeline networks serve Montana's petroleum production regions (**Figure 20**). 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 three systems also move crude oil from Canada to Montana and Wyoming. A fourth crude oil pipeline, the Express Pipeline, transports western Canadian crude through central Montana to Casper, Wyoming. In addition to the state's four crude oil pipelines, three refined petroleum product pipelines operate in the state, delivering refined petroleum products to many of Montana's larger cities as well as exporting products for use in neighboring states.

As shown in **Figure 16**, the majority of oil production in Montana occurs in the Williston Basin of eastern Montana, which is not connected by pipeline to Montana's four refineries. As a result, in 2012, more than 94 percent of Montana oil production was exported from the state, mostly to Wyoming and the Dakotas, through the eastern Montana pipeline system or through the increasing use of unit train shipments.

Figure 20. Map of Montana Petroleum Pipelines



Most of the petroleum produced from the Elm Coulee field in Richland County is transported east and joins North Dakota Bakken oil production, where it is transported through Enbridge's North Dakota pipeline system. In 2013, in order to expand pipeline transport capacity out of the Bakken region, Enbridge completed a 145,000 bbl/day pipeline expansion connecting its North Dakota pipeline system to its main pipeline system transporting western Canada oil production to the Great Lakes region. Enbridge has additional plans to expand pipeline capacity east from the Bakken region through its proposed 225,000 bbl/day Sandpiper Pipeline Project.

Plans also exist for additional crude oil pipelines to traverse eastern Montana in order to increase the crude oil transportation capacity out of both the Athabasca oil sands region of Canada and the Williston Basin region of North Dakota and Montana. Most notably, 280 miles of the proposed 1,980-mile Keystone XL Pipeline would pass through northeastern Montana as part of its route from Hardisty, Alberta, to Steele City, Nebraska. If built, the Keystone XL pipeline is expected to have an on-ramp for Bakken oil production near Baker. Additional pipelines have been proposed to transport oil production from the Williston Basin south through southeastern Montana to Wyoming.

The rapid increase in Bakken oil production within North Dakota has resulted in oil companies significantly increasing their use of the region's railways to transport Bakken oil. Beginning in 2013 a majority of Bakken oil production was transported by rail rather than pipeline, with most heading south and east toward Gulf Coast and Mid-Atlantic oil refineries. However in 2013, 50,000 bbl/day of Bakken crude oil was shipped by rail to the Tesoro oil refinery in Anacortes, Washington, and several other West Coast refineries have plans to develop the necessary rail infrastructure to utilize Bakken crude oil. While all the current and planned rail terminals for loading Bakken crude oil are located in North Dakota, the majority of the westbound crude oil unit trains are likely to traverse the length of Montana on their way to West Coast refineries.

While tens of millions of barrels of crude and refined petroleum products are transported across Montana in a given year, this transportation does not always occur without incident. Between 2002 and 2013, the state's petroleum pipelines had 11 significant incidents in which petroleum was spilled, totaling 6,236 gross barrels of petroleum spilled and a total of $143 million in property damage.[1]

The most significant oil spill over the 2002-2013 period was the 2011 spill from ExxonMobil's Silvertip Pipeline at Laurel. While the 1,509 barrels of crude oil spilled represents only the second largest spill during the 12-year period (in terms of gross barrels spilled), the pipeline break occurred underneath the Yellowstone River, contaminating an 85-mile stretch of the river and resulting in $137 million of property damage. In October 2013, state and federal officials announced they were going to seek additional compensation for environmental damages caused by the spill, which may increase the ultimate price tag of the spill for ExxonMobil.[2]

Less significant pipeline spills can still disrupt the Montana petroleum industry. The 2013 pipeline spill on Phillips 66's Seminoe pipeline that runs between Billings and Wyoming resulted in the loss of 400 barrels of refined petroleum products and $2 million in property damage but also shut the pipeline down for 10 days while repairs and testing were conducted. This halt in

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[1] http://primis.phmsa.dot.gov/comm/reports/safety/IncDetSt_st_MT_flt_sig.html?nocache=5024#_liquidall.

[2] http://fuelfix.com/blog/2013/10/31/montana-feds-to-seek-damages-from-exxon-mobil-spill/.

the Seminoe pipeline's operation delayed the transportation of more than 200,000 barrels of refined product from Billings to various locations in Wyoming.

Through 2013 there have not been any significant incidents involving a crude oil unit train in Montana. However the dramatic increase in the amount of petroleum products transported by rail across North America since 2010 and increased potential in the coming years within Montana has raised concerns about the impact from potential train derailments involving petroleum unit trains.

History of Oil Refineries

Montana's earliest oil refining followed production. The first oil refinery was a small facility built in the Cat Creek area out of parts scavenged from large steam-powered tractors. Two formal refineries were soon constructed at Winnett near the Cat Creek strike. One operated intermittently into the early 1930s. An astounding number of oil refineries were built in Montana during the early decades of oil development and largely followed development of oil fields, beginning with Cat Creek and the larger Mosby Dome in the 1920s. These "tea kettle" refineries were installed close in to the oil strikes. Even by the standards of the day they were inefficient, skimming gasoline off the light oils that sometimes yielded 50 percent. Remaining kerosene-type fuel oil was sold to the railroad with some residual tars marketed locally.[3]

Lewistown had two refineries by the early 1920s, both operating until the early 1940s. Two Kevin-Sunburst refineries and two near Cut Bank were built in the 1930s. Construction of refineries along transportation corridors outside of oil fields included ones in Great Falls, Butte, Missoula, and Kalispell. Yale Oil started a refinery in Billings and the Laurel Oil and Refining Company built one there, both dating from about 1930. These refineries processed oil from fields in northern Wyoming.

The war years further consolidated refining, as Standard Oil purchased a large Cut Bank refinery in 1942. Farmers Union Central Exchange out of St. Paul (the predecessor of Cenex) purchased the Laurel refinery in 1943. MPC exited the oil business and sold its interests in the Glacier Refinery in Cut Bank to Union Oil of California in 1944. Carter Oil purchased the Yale Refinery in Billings around the same time. According to the U.S. Bureau of Mines, 28 refineries operated in Montana at the outset of World War II in 1941; by 1947 there were 11. In 1961, nine refineries operated at least seasonally in the state. Big West closed in Sunburst in 1977. In 1987 the last refinery in Cut Bank, then owned by Flying J out of Utah, closed.

Continental built completed building a modern facility in Billings in 1949. Carter Oil also built a replacement plant in Billings. The development of Billings as a refining center saw the rise of refined pipelines to export product out of Montana. The Yellowstone Pipeline from the Billings refineries west to the Spokane area was completed in 1954. The 425-mile Oil Basin Pipeline (now Cenex) from Laurel to Minot was also built around this time.

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[3] *A History of Petroleum County*, 1989.

Oil Refineries

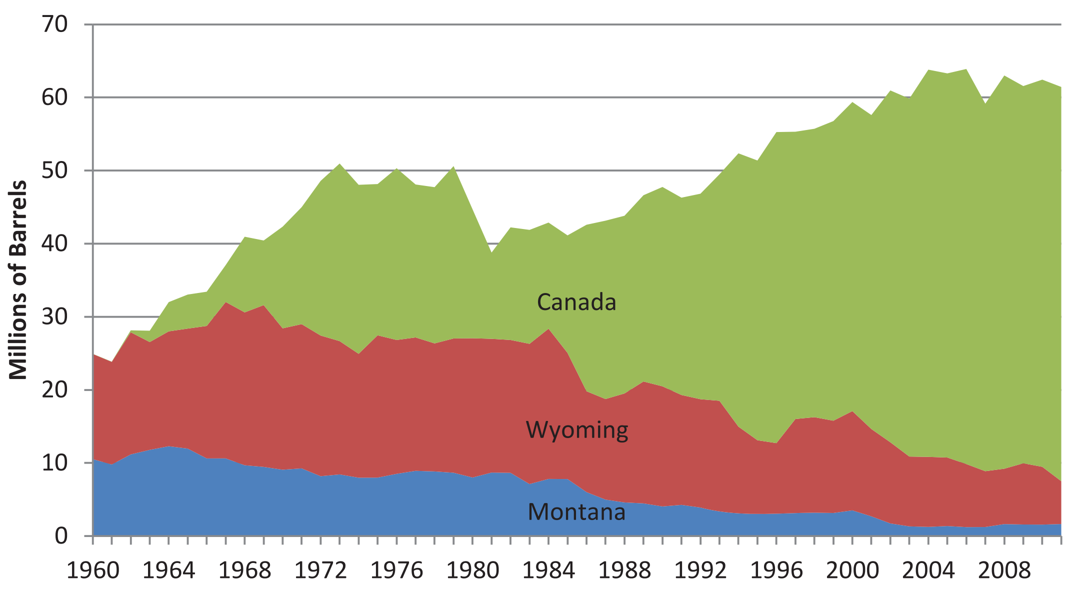
Four petroleum refineries currently operate in Montana with a combined refining capacity of 188,600 bbl/day: ExxonMobil (60,000 bbl/day) and Phillips 66 (59,000 bbl/day) in Billings, CHS (59,600 bbl/day) in Laurel, and Calumet Montana Refining (10,000 bbl/day) in Great Falls. Montana refineries typically refine 60-63 million barrels of crude oil a year.

A decade after the merger of Conoco Inc. and Phillips Petroleum Co. in 2002, ConocoPhillips spun off its downstream assets (refining and distribution) in 2012 by creating the Phillips 66 holding company. Phillips 66 now operates the Billings refinery previously operated by ConocoPhillips, as well as the Seminoe and Yellowstone refined product pipelines that deliver refined petroleum products south and west from Billings.

Also in 2012, Calumet Specialty Products Partners purchased the Montana Refining Company in Great Falls from Connacher Oil and Gas Limited of Canada. Calumet plans to invest $275 million in the Montana refinery to increase its refining capacity to 20,000 bbl/day. CHS, ExxonMobil, and ConocoPhillips/Phillips 66 have all invested hundreds of millions of dollars over the last decade in improving the efficiency and performance of their respective refineries in Montana in order to increase their output of high-value refined products without increasing crude oil consumption.

Between 2008 and 2012, 2.6 percent of the crude oil 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, 85 percent of the refinery crude inputs came from Alberta, Canada, and 12 percent came from Wyoming. The shipments from Canada have increased since the late 1960s as Montana oil production and imports of Wyoming crude have declined (**Figure 21**).

Figure 21. Refinery Receipts by Source of Oil, 1960-2011



The refineries vary in their sources of crude inputs. The Phillips 66 Refinery in Billings and Calumet Montana refinery in Great Falls are the most dependent on Canadian crude, respectively taking an average of 99 and 100 percent of their total receipts from Canada (2007-2011). The Billings ExxonMobil refinery is the least dependent on Canadian crude, with two-thirds of its crude oil receipts coming from Canada while the remaining third came from Wyoming (2007-2011).

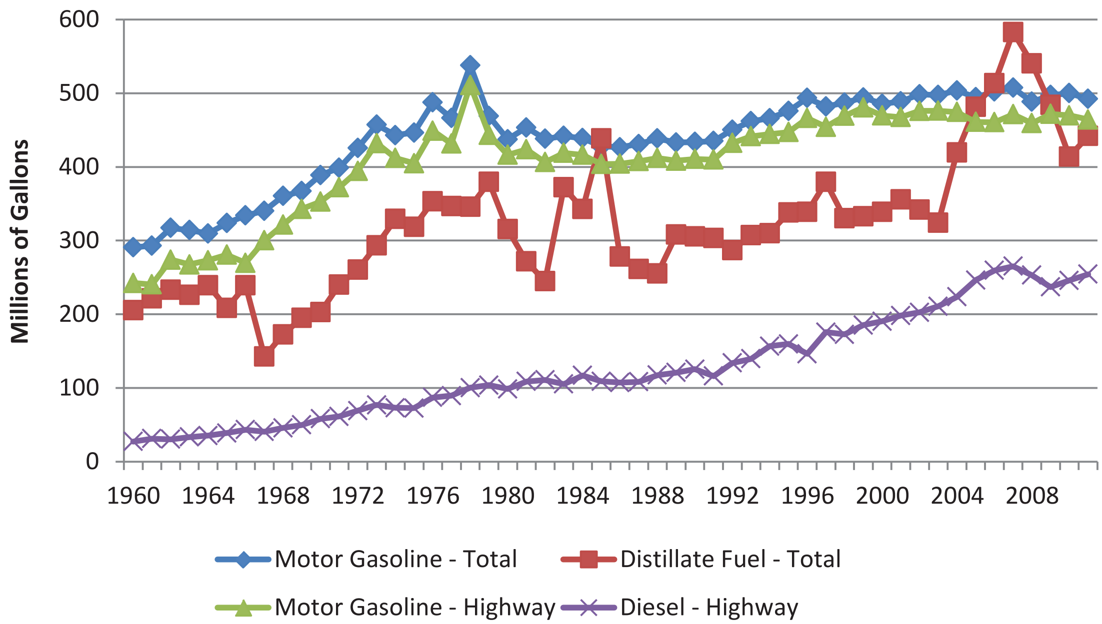
Almost all refined output from Montana's four refineries is moved by pipeline. The Billings area refineries ship their products to Montana cities and east to Fargo, North Dakota (Cenex Pipeline), to Wyoming and further south (Phillips 66 Seminoe Pipeline), and west to Spokane and Moses Lake, Washington (Phillips 66 Yellowstone Pipeline). Montana refineries' exports of refined petroleum products into neighboring states are sufficient to meet a third of Wyoming's gasoline and distillate fuel consumption, a quarter of North Dakota's, and a tenth of Washington's.

Petroleum Products Consumption

After peaking in 2007, Montana's consumption of petroleum products declined by more than 18 percent between 2007 and 2010 before growing once more in 2011. Montana's annual petroleum consumption initially peaked at 33 million barrels in 1979. It then drifted lower, settling in the mid-1980s at around 24 million bbl/year. Beginning in the 1990s consumption began to slowly climb once more, hitting a new high of nearly 38 million barrels in 2007. The decline in petroleum consumption since 2007 is a result of both the economic recession and broader national economic trends, including declining use of personal vehicles and improved fuel economy for new vehicle purchases (**Figure 22**).

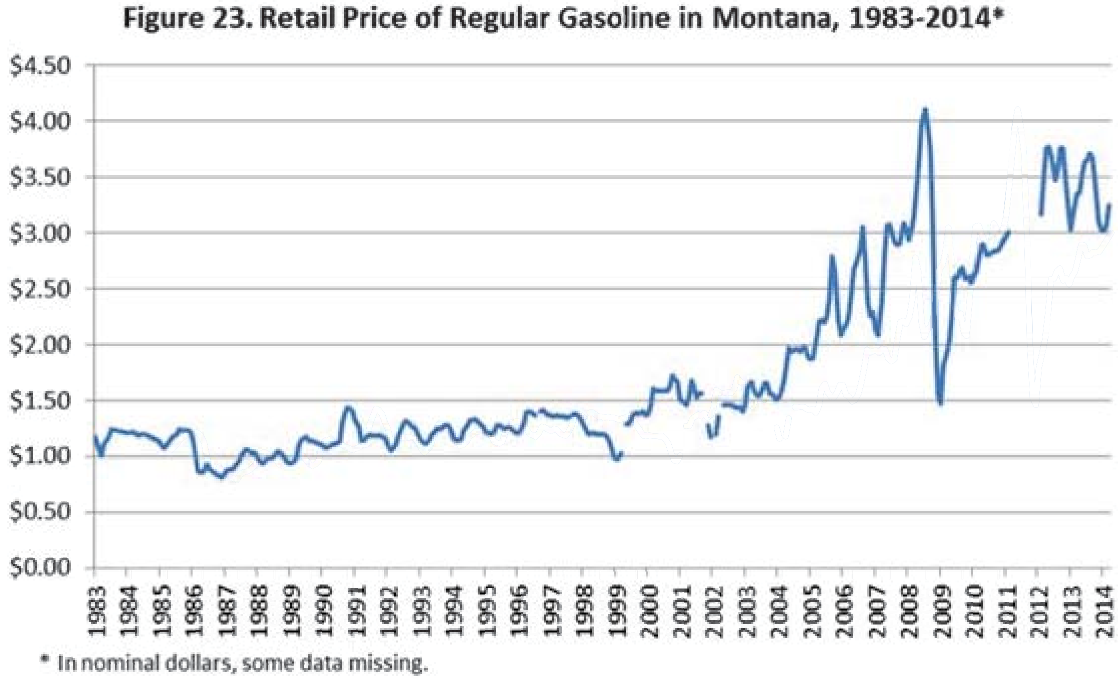
The transportation sector is the single largest user of petroleum and the second largest user of all forms of energy in Montana. In 2011, 37 percent of petroleum consumption was in the form of motor gasoline and 33 percent was distillate, mostly diesel fuel. Around 17 percent was consumed in petroleum industry operations.

Figure 22. Montana Petroleum Product Consumption, 1960-2011



Despite the recent peak in overall petroleum consumption, Montana gasoline consumption actually peaked in 1978 at more than half a billion gallons before declining in response to the 1979 oil crisis. Flat through most of the 1980s, Montana gasoline consumption began to rise once more in the 1990s, peaking a second time above a half a billion gallons of gasoline consumed in 2007 before the recent economic recession once again caused gasoline consumption to drop. In 2011, 97 percent of Montana motor gasoline consumption was for highway vehicle use, while most of the remaining 3 percent was consumed by nonhighway vehicles. In contrast, diesel use has steadily increased since the 1960s, peaking in 2007 before the recent economic recession. While motor gasoline consumption growth has been stagnant over the last 15 years, diesel consumption has increase by 74 percent over the same period.

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 oil crises of the 1970s drove prices up and demand down, prompting the implementation of the Corporate Average Fuel Economy (CAFE) standards, advances in vehicle efficiency, and a fuel switch by heavy-duty trucks from gasoline to diesel. The crash in international prices in 1985 and the economic growth of the 1980s and 1990s, along with the decline in vehicle fleet fuel efficiency, pushed gasoline and diesel demand upward. High gasoline and diesel prices over the last decade have likely acted as an overall drag on the national economy and been a key factor in the overall trend toward reduced gasoline consumption in recent years (**Figure 23**).

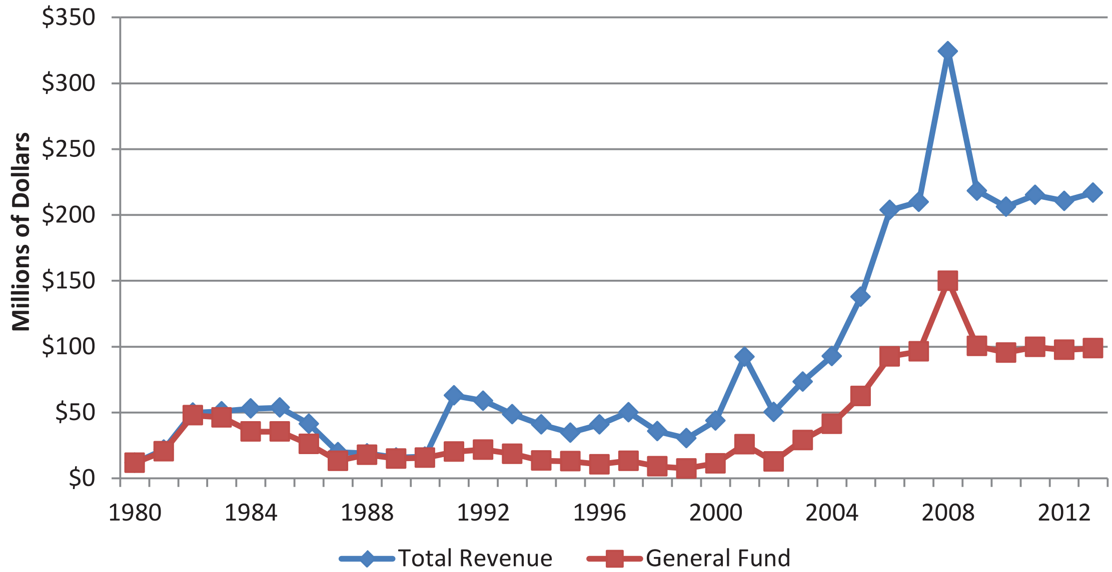


Between 1999 and 2010, national crude oil prices remained highly volatile, rising from an annual average of $15.56 per barrel in 1999 to a prerecession annual average peak of $94.04 per barrel in 2008.[4] At its peak in July 2008, crude oil was trading at $145 per barrel before the economic recession caused global crude oil prices to plummet below $35 per barrel in February 2009. Since 2010 global crude oil prices have remained relatively stable, hovering around $100 per barrel. As noted in **Figure 23**, all these market fluctuations have had a significant impact on the prices being paid at Montana gas pumps.

Fuel use shows a cyclical rise and fall through the year. Use tends to rise during the summer months and taper off during the winter. The winter trough in fuel use is a third lower than the summer peak. This seasonal pattern is caused by variations in the use of Montana’s 1 million vehicles, by the increase in tourist traffic during the summer, and by seasonal agricultural uses.

[4] http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=f000000__3&f=m

Figure 24. Oil & Natural Gas Production Tax Revenue, 1980-2013



The price of gasoline can vary significantly around the state, a fact that is masked by the data, which is available only as statewide averages. (Complete data on the Montana price of diesel was not available.) The price of gasoline has a cyclical rise and fall, just like demand for gasoline; however, price lags behind demand, with peak prices tending to appear after the peak driving season.

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 nonworking interest, date when production began, and the price for which the crude oil is sold. This last point is important because crude oil from the northern Rockies and upper Midwest, including the Bakken region, frequently trades at a significant discount ($5-$25 per barrel) to West Texas Intermediate (WTI) prices because of limited pipeline capacity and higher rail costs to transport the oil production to key trading hubs. However, despite the discounted price for Montana oil production, overall increases in oil production and crude oil prices have still provided the state with substantial tax revenues (**Figure 24**).

Since fiscal year 2006, Montana has been able to rely on about $200 million in oil and gas production tax revenue, with an average of 46 percent of the revenue returning to the local county governments where the revenue was generated. Most of the remaining revenue is directed to the state's general fund. Small percentages of oil and gas production revenue are directed to specific state accounts to help fund particular interests, like natural resource protection and the state university system. The one recent exception to the recent trend of steady oil and gas production tax revenue was fiscal year 2008, when increased oil and natural gas production combined with high oil and natural gas prices, resulting in a record

$324 million in tax revenue being collected from oil and natural gas production, $150 million of which went to the state's general fund.

At the end of fiscal year 2013, total oil and gas production tax collections were $206 million, $94 million of which went to the state's general fund. This is roughly in line with fiscal year 2012 and previous years. The stability of oil and natural gas production tax revenues from fiscal years 2009 through 2013 has occurred despite overall production declines since 2006 because the price of oil has steadily rebounded since the economic recession. Expected natural gas price increases after the market price hit bottom in April 2012, combined with stabilizing oil production beginning in 2011, is likely to keep Montana's oil and gas tax revenue stable in the near future even if oil prices decline somewhat. Tax revenues may increase in the future if the region's oil transportation constraints can be alleviated, allowing Bakken oil production to be sold closer to WTI hub prices.

Table P1. Average Daily Oil Production per Well and Annual Production by Region, 1960-2011

	Average Daily Production per Well (barrels)						Oil Production by Region (barrels)					
Year	North	Central	South Central	Northeastern	Southeastern	STATE AVERAGE	North	Central	South Central	Northeastern	Southeastern	TOTAL
1960	4.2	52.3	88.1	93.9		22.3	4,332,218	5,780,420	3,087,871	17,039,406		30,239,915
1961	4.7	53.8	97.9	89.3		25.0	4,211,017	6,367,524	2,895,587	17,431,916		30,906,044
1962	4.5	43.4	119.9	76.3		23.5	4,252,304	5,279,163	3,851,672	18,264,368		31,647,507
1963	4.9	34.8	113.4	74.4		23.2	4,530,510	3,950,490	3,383,587	19,005,066		30,869,653
1964	7.4	28.8	115.1	65.7		25.2	5,705,948	3,269,768	3,699,927	17,971,855		30,647,498
1965	7.1	25.5	97.6	70.9		23.6	6,826,261	2,849,923	3,597,647	19,504,287		32,778,118
1966	9.5	24.7	87.7	73.6		27.6	7,991,302	2,710,194	3,392,890	21,285,732		35,380,118
1967	8.8	27.5	90.7	69.9	70.6	28.2	6,758,280	2,872,604	3,181,132	20,475,733	1,671,277	34,959,026
1968	9.9	26.4	79.6	67.6	138.0	39.0	6,883,493	2,728,357	2,885,272	19,390,652	16,572,472	48,460,246
1969	11.3	22.6	69.5	66.4	91.4	36.1	7,557,966	2,011,445	2,739,346	18,396,618	13,248,737	43,954,112
1970	11.6	26.2	69.3	66.8	57.9	32.3	7,680,831	1,915,273	2,329,187	18,110,147	7,843,259	37,878,697
1971	11.3	29.4	57.9	62.4	50.9	30.1	7,292,476	2,274,124	2,028,304	17,042,703	5,961,116	34,598,723
1972	9.8	34.4	57.4	63.3	65.3	29.6	6,646,908	2,817,045	1,742,749	16,361,771	6,335,666	33,904,139
1973	9.5	36.2	50.0	60.8	90.4	31.7	5,948,826	3,238,967	1,515,088	15,735,703	8,181,598	34,620,182
1974	8.3	34.2	45.6	57.4	110.3	30.5	5,464,319	3,334,759	1,432,528	14,939,292	9,383,064	34,553,962
1975	6.0	35.8	36.1	53.4	103.2	26.2	4,551,324	3,954,024	1,318,779	14,312,685	8,706,862	32,843,674
1976	5.8	35.2	35.1	53.8	133.3	27.1	4,200,539	4,063,897	1,246,005	14,496,380	8,807,439	32,814,260
1977	5.6	29.4	30.4	50.8	140.2	26.2	4,060,957	3,677,361	1,210,064	14,621,635	9,110,037	32,680,054
1978	4.9	26.4	26.1	48.9	117.6	23.5	3,671,322	3,343,556	1,095,737	15,103,853	7,252,869	30,467,337
1979	4.6	24.4	27.7	51.2	94.9	22.9	3,536,296	3,029,397	1,131,798	16,546,576	5,713,032	29,957,099
1980	4.3	19.9	23.2	48.7	86.0	21.1	3,516,807	2,612,091	1,055,105	17,739,142	4,660,659	29,583,804
1981	4.3	20.0	18.9	50.6	59.2	21.0	3,605,207	2,583,690	910,595	19,954,159	3,759,760	30,813,411
1982	4.1	16.5	16.0	44.2	38.8	19.2	3,680,043	1,496,895	806,366	21,934,760	2,999,247	30,917,311
1983	3.7	14.0	14.4	39.6	35.1	16.9	3,682,130	1,467,855	790,150	20,877,527	2,847,618	29,665,280
1984	3.9	15.9	15.8	37.9	30.4	17.0	3,708,185	1,709,653	829,090	21,449,415	2,383,476	30,079,819
1985	3.3	12.3	16.3	39.1	22.1	16.0	3,419,300	1,868,780	838,817	21,979,087	1,744,433	29,850,417
1986	2.9	14.4	24.7	35.4	19.5	14.2	3,220,769	2,387,266	722,118	19,520,103	1,314,374	27,164,630
1987	2.9	13.9	17.4	35.1	26.2	14.1	3,040,941	1,847,551	827,229	18,319,149	1,069,179	25,104,049
1988	2.7	13.0	18.9	32.6	23.3	13.2	2,779,524	1,684,853	884,954	17,089,238	878,887	23,317,456
1989	2.6	12.8	16.2	30.8	16.8	12.5	2,488,169	1,544,989	773,372	15,476,534	686,228	20,969,292
1990	2.6	12.3	16.4	29.5	12.8	12.0	2,432,506	1,454,066	805,807	14,592,497	550,211	19,835,087
1991	2.7	12.3	17.9	29.4	16.9	12.2	2,510,130	1,393,046	804,003	14,380,288	485,881	19,573,348
1992	2.6	11.7	16.5	27.8	14.1	11.5	2,426,783	1,227,475	832,580	13,637,695	355,139	18,479,672
1993	2.4	10.1	17.4	27.9	13.3	11.4	2,143,943	1,095,551	772,668	13,110,882	272,517	17,395,561
1994	2.4	9.6	14.8	26.6	3.5	11.0	2,003,272	955,703	733,965	12,747,075	90,965	16,530,980
1995	2.3	11.4	14.5	26.9	12.4	11.9	1,783,331	1,040,127	698,537	12,877,305	126,524	16,525,824
1996	3.2	13.7	17.6	31.8	15.5	15.3	1,740,057	955,626	657,135	12,696,542	125,797	16,175,157
1997	3.2	13.5	15.9	31.4	12.0	15.2	1,691,832	991,714	603,422	12,667,200	180,245	16,134,413
1998	3.1	12.7	15.4	33.6	13.3	16.2	1,590,425	828,028	582,568	13,382,441	239,255	16,622,717
1999	3.1	11.5	17.7	31.6	11.7	15.5	1,511,361	638,239	606,812	12,373,436	208,707	15,338,555
2000	2.9	11.2	18.9	30.4	11.2	14.8	1,556,127	725,437	696,340	12,559,879	213,671	15,751,454
2001	2.7	10.4	16.3	30.9	10.0	15.1	1,430,087	650,982	656,160	13,369,437	173,567	16,280,233
2002	2.6	10.7	14.5	31.9	9.1	16.0	1,313,159	630,368	603,383	14,277,806	157,118	16,981,834
2003	2.6	9.5	14.3	36.7	8.4	18.1	1,275,084	598,971	572,145	16,823,588	141,033	19,410,821
2004	2.5	9.0	14.1	45.8	9.5	22.1	1,266,627	565,150	555,166	22,164,424	158,632	24,709,999
2005	2.4	8.6	13.8	56.7	9.3	27.6	1,254,295	535,904	533,805	30,298,141	158,002	32,780,147
2006	2.4	8.2	13.0	56.1	8.4	28.4	1,313,478	501,704	555,562	33,740,058	175,332	36,286,134
2007	2.5	8.2	12.9	49.2	18.1	26.1	1,401,762	468,604	529,991	32,148,738	350,564	34,899,659
2008	2.4	8.1	11.6	41.9	25.8	22.6	1,442,557	502,308	507,847	28,653,476	483,006	31,589,194
2009	2.3	8.5	10.9	36.9	31.4	20.1	1,391,914	458,195	473,063	25,033,377	471,373	27,827,922
2010	2.3	8.6	10.3	33.0	33.7	18.1	1,398,400	470,016	455,778	22,543,608	456,880	25,324,682
2011	2.4	8.1	10.8	32.0	33.5	17.4	1,434,003	419,647	478,635	21,401,777	410,104	24,144,166

NOTE: DNRC *Annual Review* provides data for the current year and the 4 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 2007 were published in the 2011 report. From 2008 forward, the data in this table are from the most recent update of a year's data; prior data are final. Corrections have caused final total annual production data to increase over the initial report by less than 0.5 percent, often by much less, with most of the changes, if any, occurring in the year or two after the initial report. These revisions have had little or no impact on average daily production figures.

SOURCE: Montana Department of Natural Resources and Conservation, Oil and Gas Division, *Annual Review, 1960-2011* http://bogc.dnrc.mt.gov/annualreviews.asp.

Table P2. Crude Oil Production and Average Wellhead Prices[1], 1960-2012

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	33,766	87.28	2,947.1
FY2009	30,083	60.47	1,819.0
FY2010	26,212	65.27	1,710.9
FY2011	24,587	80.38	1,976.2
FY2012	24,378	85.43	2,082.7

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, FY2001 began July 1, 2000 and ended June 30, 2001. Information from earlier years could not 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 FY01-12. FY08-FY11 numbers reflect updates and amended returns.

Table P3. Number of Producing Oil Wells by Region and Number of Oil and Gas Wells Completed by Type, 1960-2011

	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
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
							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	1,797	221	124	1,550	54	3,746	148	375	43	0	1	2	54	5	628		
2005	1,826	220	130	1,713	67	5,961	211	369	163	0	4	1	75	1	824		
2006	1,873	214	129	1,877	70	4,163	214	348	317	0	6	9	65	3	962		
2007	1,899	215	128	2,007	68	4,317	190	399	62	0	2	10	64	3	730		
2008	1,972	227	128	2,065	76	4,468	134	307	42	0	3	2	45	3	536		
2009	2,004	208	127	2,053	57	4,449	51	160	11	0	0	3	26	0	251		
2010	1,999	204	138	2,079	43	4,463	87	154	2	0	0	0	19	0	262		
2011	2,022	203	135	2,114	41	4,515	100	32	1	6	1	5	17	1	163		

[1] T.A. - Temporarily abandoned. [2] CBM - Coal bed 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 2007 was published in the 2011 report. From 2008 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,* 1960-2011 http://bogc.dnrc.mt.gov/annualreviews.asp.

Table P4. Receipts at Montana Refineries by Source of Crude Oil, 1960-2011 (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
2008	1,644	2.6	7,576	12.0	53,789	85.4			63,009
2009	1,589	2.6	8,374	13.6	51,599	83.8	11	0.0	61,573
2010	1,574	2.5	7,905	12.6	52,960	84.7			62,440
2011	1,653	2.7	5,859	9.5	53,927	87.8			61,439

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* , 1960-2011, http://bogc.dnrc.mt.gov/annualreviews.asp.

Table P5. Receipts at Montana Refineries by Source of Crude Oil, 2002-2011 (thousand barrels)

Average (2007-2011)	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,422,043	7%	119,224	1%	-	-	-	-	1,541,267	3%
North Dakota	-	-	-	-	-	-	2,136	0%	2,136	0%
Wyoming	1,351,653	7%	150,871	1%	5,966,997	33%	-	-	7,469,520	12%
Canada	16,582,296	86%	20,477,557	99%	12,086,161	67%	3,364,793	100%	52,510,807	85%
Total Received	19,355,992	100%	20,677,257	100%	17,972,089	100%	3,366,929	100%	61,523,730	100%

2011	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,524,393	8%	128,801	1%	-	-	-	-	1,653,194	3%
Wyoming	1,390,369	7%	101,513	0%	4,366,870	25%	-	-	5,858,752	10%
Canada	16,123,335	85%	20,827,456	99%	13,363,216	75%	3,613,492	100%	53,927,499	88%
Total Received	19,038,097	100%	21,057,770	100%	17,730,086	100%	3,613,492	100%	61,439,445	100%

2010	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,468,482	8%	105,880	0%	-	-	-	-	1,574,362	3%
Wyoming	2,144,378	11%	54,872	0%	5,706,014	31%	-	-	7,905,264	14%
Canada	15,446,095	81%	21,415,316	99%	12,559,241	69%	3,539,657	100%	52,960,309	84%
Total Received	19,058,955	100%	21,576,068	100%	18,265,255	100%	3,539,657	100%	62,439,935	100%

2009	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,473,524	8%	115,573	1%	-	-	-	-	1,589,097	3%
North Dakota	-	-	-	-	-	-	10,680	0%	10,680	0%
Wyoming	1,903,112	10%	140,596	1%	6,330,412	33%	-	-	8,374,120	14%
Canada	16,151,406	83%	19,854,526	99%	12,751,345	67%	2,841,575	100%	51,598,852	84%
Total Received	19,528,042	100%	20,110,695	100%	19,081,757	100%	2,852,255	100%	61,572,749	100%

2008	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,494,109	7%	149,800	1%	-	-	-	-	1,643,909	3%
Wyoming	723,920	4%	201,327	1%	6,651,025	38%	-	-	7,576,272	12%
Canada	18,078,585	89%	21,274,125	98%	11,072,727	62%	3,363,236	100%	53,788,673	85%
Total Received	20,296,614	100%	21,625,252	100%	17,723,752	100%	3,363,236	100%	63,008,854	100%

2007	Cenex		Conoco		Exxon		Montana Refining		TOTALS	
Montana	1,149,706	6%	96,065	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%	-	-	3,237	0%	1,229,354	2%
Wyoming	803,508	4%	273,267	1%	7,549,617	42%	-	-	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%	-	-	159,683	6%	1,377,681	2%
Wyoming	316,611	2%	292,646	1%	8,763,255	41%	-	-	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%	-	-	195,678	7%	1,258,139	2%
Wyoming	376,745	2%	803,810	4%	8,400,888	43%	-	-	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 (2002-2011), http://bogc.dnrc.mt.gov/annualreviews.asp.

Table P6. Petroleum Product Consumption Estimates, 1960-2010 (thousand barrels)

Year	Asphalt & Road Oil	Aviation Gasoline	Distillate Fuel	Jet Fuel	Kerosene	LPG	Lubricants	Motor Gasoline	Residual Fuel	Other[1]	TOTAL	Fuel Ethanol
1960	865	1,006	4,898	265	477	737	161	6,922	2,063	1,725	19,118	0
1961	823	1,427	5,278	280	366	859	157	6,979	2,580	2,112	20,861	0
1962	786	473	5,549	311	265	819	171	7,553	3,052	2,320	21,298	0
1963	900	499	5,393	340	359	766	171	7,481	2,852	2,704	21,465	0
1964	1,328	340	5,702	360	679	925	179	7,374	2,300	2,654	21,842	0
1965	1,003	312	4,962	384	248	926	189	7,709	1,241	2,835	19,809	0
1966	974	198	5,695	441	118	1,167	196	7,953	1,459	2,977	21,177	0
1967	1,066	131	3,394	574	859	1,585	175	8,104	1,231	3,092	20,211	0
1968	1,221	65	4,113	697	815	1,689	192	8,585	1,509	3,540	22,427	0
1969	1,189	38	4,641	806	657	1,690	196	8,737	1,556	3,739	23,250	0
1970	1,347	43	4,827	649	376	1,326	200	9,262	1,268	3,372	22,670	0
1971	1,337	42	5,715	767	362	1,402	188	9,494	1,262	3,356	23,926	0
1972	1,489	94	6,206	762	383	1,705	201	10,137	1,469	3,864	26,308	0
1973	1,397	110	6,989	757	405	1,503	219	10,883	1,765	4,018	28,048	0
1974	1,222	105	7,840	780	174	1,466	210	10,550	2,262	3,708	28,316	0
1975	924	79	7,586	818	122	1,370	208	10,630	2,178	3,772	27,687	0
1976	1,283	94	8,411	753	79	1,420	231	11,605	2,525	3,440	29,843	0
1977	1,133	92	8,258	772	93	1,368	247	11,100	2,506	3,700	29,270	0
1978	942	87	8,232	699	95	1,662	266	12,809	2,502	3,705	30,999	0
1979	1,054	122	9,037	907	17	1,094	278	11,162	5,773	3,424	32,869	0
1980	1,020	159	7,509	920	0	1,806	247	10,416	4,025	3,159	29,262	0
1981	1,035	177	6,469	800	26	1,027	237	10,797	2,494	2,623	25,686	1
1982	884	92	5,828	625	0	1,446	216	10,429	1,608	2,398	23,525	24
1983	1,130	102	8,863	652	18	1,497	227	10,525	1,306	2,328	26,648	26
1984	1,215	77	8,161	642	8	1,032	242	10,451	798	2,639	25,266	23
1985	1,463	91	10,444	678	10	1,576	225	10,188	133	2,512	27,320	15
1986	1,989	105	6,621	867	22	1,505	220	10,158	47	2,507	24,041	8
1987	1,642	82	6,223	718	8	1,716	249	10,258	23	3,236	24,156	6
1988	1,473	107	6,078	809	4	1,515	240	10,441	221	3,624	24,513	1
1989	1,749	95	7,336	750	3	1,608	246	10,310	180	3,615	25,893	0
1990	1,487	111	7,280	708	8	1,740	253	10,328	218	3,659	25,792	3
1991	1,350	108	7,220	615	3	1,053	227	10,360	145	3,203	24,284	13
1992	1,309	75	6,836	864	1	1,018	231	10,727	88	4,007	25,156	13
1993	1,707	64	7,315	901	8	2,200	235	10,999	680	3,198	27,308	15
1994	1,964	75	7,381	855	7	1,054	246	11,097	369	3,638	26,687	0
1995	1,293	78	8,049	1,052	1	918	242	11,328	236	4,815	28,011	17
1996	1,702	99	8,070	999	1	1,618	235	11,753	181	5,384	30,041	0
1997	1,448	71	9,037	793	2	277	248	11,480	162	5,012	28,528	0
1998	1,594	102	7,863	798	3	271	259	11,596	106	5,740	28,333	10
1999	2,625	121	7,921	836	2	527	262	11,768	20	6,540	30,624	11
2000	2,151	134	8,069	747	1	1,324	258	11,559	1	5,409	29,652	13
2001	903	109	8,476	756	12	1,400	237	11,640	2	4,830	28,365	35
2002	1,040	115	8,145	768	10	1,502	234	11,871	39	5,549	29,274	35
2003	319	101	7,721	832	8	2,151	216	11,846	6	5,402	28,603	30
2004	929	42	9,988	1,008	6	2,384	219	11,991	42	5,564	32,173	38
2005	730	47	11,465	1,112	9	2,455	218	11,770	106	5,597	33,511	261
2006	1,486	87	12,232	1,045	1	2,409	212	11,960	125	5,885	35,443	311
2007	937	69	13,880	1,026	1	2,993	219	12,079	0	6,929	38,133	525
2008	818	90	10,673	832	4	3,076	203	11,626	0	6,385	33,707	660
2009	706	75	10,242	792	0	2,683	183	11,844	61	5,369	31,956	762
2010	710	45	8,911	928	1	2,464	203	11,954	1,032	4,905	31,154	863

1 In Montana "Other Petroleum Products" primarily are 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.gov/state/seds/seds-technical-notes-complete.cfm#undefined).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data System* file "All Consumption in Physical Units," 1960-2010. (http://www.eia.gov/beta/state/seds/seds-data-complete.cfm?sid=MT#Consumption).

Table P7. Residential Petroleum Product Consumption Estimates, 1960-2010 (thousand barrels)

Year	Distillate Fuel	LPG[1]
1960	262	488
1961	335	594
1962	335	541
1963	328	482
1964	312	632
1965	277	614
1966	286	731
1967	196	959
1968	250	1,030
1969	289	1,034
1970	249	856
1971	397	873
1972	436	1,056
1973	495	931
1974	542	990
1975	589	939
1976	646	958
1977	616	958
1978	657	1,231
1979	675	584
1980	421	799
1981	273	486
1982	352	710
1983	449	869
1984	380	413
1985	309	583
1986	325	618
1987	220	684
1988	213	689
1989	345	801
1990	291	784
1991	287	678
1992	180	577
1993	234	528
1994	159	522
1995	218	456
1996	325	501
1997	685	146
1998	404	83
1999	225	330
2000	170	890
2001	170	907
2002	122	929
2003	190	1,398
2004	187	1,863
2005	169	1,732
2006	196	1,726
2007	197	1,990
2008	162	2,230
2009	118	2,362
2010	112	1,969

[1] DOE has numerous caveats on its allocation of liquefied 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.gov/state/seds/seds-technical-notes-complete.cfm#undefined).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data System* Table CT4. Residential Sector Energy Consumption Estimates, Selected Years, 1960-2010, Montana (http://www.eia.gov/beta/state/seds/data.cfm?incfile=/state/seds/sep_use/res/use_res_MT.html&sid=MT).

Table P8. Commercial Petroleum Product Consumption Estimates, 1960-2010 (thousand barrels)

Year	Distillate Fuel	LPG[1]	Motor Gasoline[2]	Residual Fuel
1960	297	107	135	2
1961	380	130	146	3
1962	380	119	121	4
1963	372	106	141	4
1964	354	139	127	3
1965	315	135	144	1
1966	324	160	123	1
1967	223	211	135	1
1968	284	226	133	1
1969	329	227	107	1
1970	283	188	220	1
1971	451	192	127	1
1972	496	232	168	1
1973	562	204	136	1
1974	616	217	125	2
1975	668	206	174	2
1976	734	210	163	3
1977	699	210	157	3
1978	746	270	167	4
1979	766	128	179	11
1980	346	175	92	7
1981	380	107	110	0
1982	183	156	127	5
1983	1,104	191	76	172
1984	935	91	61	105
1985	772	128	72	126
1986	373	136	76	37
1987	272	150	80	13
1988	181	151	76	9
1989	192	176	77	13
1990	154	172	84	11
1991	164	149	63	3
1992	140	127	55	4
1993	170	116	12	5
1994	159	115	15	3
1995	102	100	13	3
1996	229	110	19	2
1997	162	32	12	1
1998	114	18	14	1
1999	142	73	14	2
2000	143	195	14	1
2001	197	199	14	0
2002	137	204	15	0
2003	167	528	15	1
2004	294	331	15	0
2005	163	414	15	0
2006	215	344	16	0
2007	175	316	15	0
2008	198	428	17	0
2009	151	183	15	33
2010	108	292	15	23

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

[2] Includes miscellaneous (including unclassified) and public nonhighway sales of motor gasoline.

NOTE: This table excludes a small amount of kerosene and ethanol consumption, less than 1,000 bbl each in recent years.

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.gov/state/seds/seds-technical-notes-complete.cfm#undefined).

SOURCE: U.S. Department of Energy, Energy Information Administration, *Table CT5. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2010, Montana.* (http://www.eia.gov/beta/state/seds/data.cfm?incfile=/state/seds/sep_use/com/use_com_MT.html&sid=MT).

Table P9. Industrial Petroleum Product Consumption Estimates, 1960-2010 (thousand barrels)[1]

Year	Asphalt and road oil	Distillate Fuel[2]	LPG[3]	Lubricants	Motor Gasoline[4]	Petroleum coke	Residual Fuel[5]	Still gas
1960	865	1,500	112	23	816	626	1,684	1,099
1961	823	1,841	104	23	923	965	1,960	1,147
1962	786	2,159	125	30	685	1,111	2,575	1,210
1963	900	2,174	145	30	796	1,179	2,438	1,438
1964	1,328	2,331	128	31	746	1,134	1,986	1,436
1965	1,003	1,693	164	41	887	1,224	914	1,512
1966	974	2,123	254	43	681	1,382	980	1,485
1967	1,066	1,033	356	40	791	1,455	882	1,533
1968	1,221	1,222	359	44	745	1,809	1,242	1,624
1969	1,189	1,373	361	45	476	1,945	1,212	1,688
1970	1,347	1,274	246	46	635	1,633	1,123	1,615
1971	1,337	1,750	282	43	570	1,690	1,174	1,511
1972	1,489	1,863	339	46	702	1,917	1,390	1,794
1973	1,397	2,073	302	60	568	1,914	1,577	1,966
1974	1,222	2,413	206	58	503	1,671	2,126	1,882
1975	924	2,494	174	46	774	1,851	1,963	1,762
1960	865	1,500	112	23	816	626	1,684	1,099
1961	823	1,841	104	23	923	965	1,960	1,147
1964	1,328	2,331	128	31	746	1,134	1,986	1,436
1965	1,003	1,693	164	41	887	1,224	914	1,512
1967	1,066	1,033	356	40	791	1,455	882	1,533
1968	1,221	1,222	359	44	745	1,809	1,242	1,624
1969	1,189	1,373	361	45	476	1,945	1,212	1,688
1970	1,347	1,274	246	46	635	1,633	1,123	1,615
1984	1,215	2,686	461	50	558	1,352	692	1,818
1985	1,463	5,192	814	46	677	1,466	7	1,787
1986	1,989	1,968	696	45	637	1,464	10	2,043
1987	1,642	1,607	844	51	574	1,952	10	2,037
1988	1,473	1,473	626	50	575	2,003	212	2,135
1989	1,749	2,623	578	51	631	1,821	168	2,305
1990	1,487	2,778	717	52	615	1,862	207	2,292
1991	1,350	2,868	178	47	611	1,752	142	2,219
1992	1,309	2,141	279	48	572	2,167	85	2,279
1993	1,707	2,404	1,513	49	567	1,578	675	2,267
1994	1,964	1,917	360	51	603	1,820	365	2,258
1995	1,293	2,283	333	50	646	1,878	233	2,223
1996	1,702	2,569	991	48	663	2,120	178	2,313
1997	1,448	2,422	90	51	686	1,719	161	2,289
1998	1,594	1,955	108	54	437	2,801	106	2,266
1999	2,625	1,982	112	54	420	3,312	18	2,380
2000	2,151	1,904	227	53	406	2,285	0	2,464
2001	903	1,907	275	49	546	823	2	2,708
2002	1,040	1,842	358	48	566	1,883	39	2,659
2003	319	2,433	213	45	585	1,525	6	2,768
2004	929	3,237	164	45	681	1,600	42	2,746
2005	730	3,519	287	45	638	1,563	106	2,753
2006	1,486	3,673	322	44	694	1,696	95	2,780
2007	937	4,474	676	45	501	2,796	0	2,764
2008	818	3,875	383	42	359	2,672	0	2,648
2009	706	3,895	128	38	357	1,471	28	2,700
2010	710	2,210	186	42	407	998	1,009	2,717

1 Does not include use at electric utilities or the small amounts of ethanol used.

2 Includes deliveries for industrial use (including industrial space heating and farm use), oil company use, off-highway use, and "other" uses.

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

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

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

NOTE: This table does not include blending components or 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 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.gov/state/seds/seds-technical-notes-complete.cfm#undefined).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data System* table "Consumption in Physical Units," 1960-2010 (formerly State Energy Data Report). (http://www.eia.gov/beta/state/seds/seds-data-complete.cfm?sid=MT#Consumption).

Table P10. Transportation Petroleum Product Consumption Estimates, 1960-2010 (thousand barrels)

Year	Aviation Gasoline[1]	Distillate Fuel[2]	Jet Fuel[3]	LPG[4]	Lubricants	Motor Gasoline[5]	Residual Fuel[6]	Fuel Ethanol
1960	1,006	2,839	265	29	137	5,972	377	0
1961	1,427	2,721	280	31	134	5,910	617	0
1962	473	2,675	311	35	141	6,747	471	0
1963	499	2,520	340	34	141	6,544	410	0
1964	340	2,705	360	26	148	6,501	307	0
1965	312	2,676	384	13	148	6,678	325	0
1966	198	2,961	441	21	153	7,148	396	0
1967	131	1,941	574	60	135	7,178	342	0
1968	65	2,356	697	73	148	7,708	243	0
1969	38	2,649	806	68	151	8,155	238	0
1970	43	3,020	649	36	154	8,407	119	0
1971	42	3,116	767	56	145	8,797	87	0
1972	94	3,408	762	78	155	9,267	63	0
1973	110	3,834	757	65	159	10,179	44	0
1974	105	4,266	780	53	152	9,922	122	0
1975	79	3,835	818	50	162	9,682	160	0
1976	94	4,101	753	50	180	10,668	141	0
1977	92	4,049	772	37	196	10,240	136	0
1978	87	4,451	699	46	211	12,064	134	0
1979	122	4,791	907	18	220	10,320	24	0
1980	159	4,759	920	45	196	9,705	0	0
1981	177	3,834	800	52	188	10,024	0	1
1982	92	3,866	625	29	172	9,671	0	22
1983	102	4,106	652	54	180	9,940	3	25
1984	77	4,082	642	69	192	9,831	2	21
1985	91	4,132	678	51	179	9,439	*	14
1986	105	3,930	867	55	175	9,445	0	7
1987	82	4,080	718	39	197	9,604	0	6
1988	107	4,149	809	48	190	9,789	0	1
1989	95	4,115	750	53	195	9,602	0	0
1990	111	3,993	708	67	201	9,630	0	3
1991	108	3,856	615	48	180	9,687	0	13
1992	75	4,339	864	35	183	10,100	0	13
1993	64	4,457	901	43	187	10,421	0	14
1994	75	5,100	855	58	195	10,479	0	0
1995	78	5,390	1,052	28	192	10,669	0	16
1996	99	4,886	999	16	186	11,070	0	0
1997	71	5,718	793	8	197	10,782	0	0
1998	102	5,350	798	62	206	11,145	0	10
1999	121	5,536	836	12	208	11,334	0	11
2000	134	5,812	747	11	205	11,139	0	13
2001	109	6,200	756	20	188	11,079	0	34
2002	115	6,018	768	11	185	11,290	0	34
2003	101	4,903	832	12	171	11,246	0	29
2004	42	6,237	1,008	26	174	11,295	0	36
2005	47	7,597	1,112	22	173	11,117	0	246
2006	87	8,122	1,045	18	168	11,251	30	293
2007	69	9,013	1,026	12	174	11,563	0	503
2008	90	6,423	832	35	161	11,250	0	639
2009	75	6,061	792	10	145	11,471	0	739
2010	45	6,464	928	17	161	11,531	0	833

* Less than 0.5.

1 Contains military and non-military use.

2 Contains deliveries for military use, railroad use and on-highway use.

3 Data prior to 1984 only covers non-military use of kerosene-type jet fuel.

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

5 This column contains uses of gasoline not included in "Highway Use of Motor Fuel" in Table P11.

6 Contains 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.gov/state/seds/seds-technical-notes-complete.cfm#undefined).

SOURCE: U.S. Department of Energy, Energy Information Administration, *State Energy Data System* file "All Consumption in Physical Units," 1960-2010. (http://www.eia.gov/beta/state/seds/seds-data-complete.cfm?sid=MT#Consumption).

Table P11. Motor Fuel Use, 1960-2011 (thousand gallons)

Year	Highway Use of Motor Fuel: Gasoline	Diesel	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
2007	471,532	265,261	736,793	29,650	-	766,443
2008	459,218	252,978	712,196	24,999	-	737,195
2009	471,907	237,130	709,037	24,589	-	733,626
2010	469,964	245,823	715,787	20,090	-	746,558
2011	464,325	254,254	718,579	19,699	-	749,076

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 1984-2011, 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, 1960-2011 (http://www.fhwa.dot.gov/policy/ohpi/hss/hsspubs.cfm) and (http://www.fhwa.dot.gov/policyinformation/statistics/2011/) under the 'Motor Fuel' category.

Table P12a. Average Daily Delivery Rates of Gasoline (per month) to Outlets 1998-2012 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Daily Average (1000 gallons/day)
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	1,556	1,515	1,339	1,293	1,255	1,291	1,317
2009	1,202	1,182	1,184	1,252	1,390	1,499	1,653	1,580	1,442	1,345	1,255	1,278	1,356
2010	1,075	1,195	1,252	1,280	1,320	1,543	1,719	1,643	1,462	1,364	1,303	1,236	1,367
2011	1,131	1,215	1,232	1,238	1,300	1,482	1,655	1,638	1,451	1,350	1,280	1,240	1,352
2012	1,167	1,302	1,226	1,254	1,366	1,514	1,737	1,686	1,430	1,365	1,293	1,229	1,381
avg.	1,129	1,194	1,229	1,260	1,362	1,514	1,698	1,631	1,420	1,356	1,281	1,236	1,360

[1]These data are from motor fuel tax collections, which are supposed to cover all gasoline delivered for any purpose in Montana. The volumes come from distributors' bills of lading and the monthly date represents actual periods that gallons of fuel were distributed within the state. Accordingly, they 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 which were manipulated so data from all states would be comparable.

Source: Montana Department of Transportation motor fuel tax data base, January 2013.

Table 12b. Average Daily Delivery Rates of Diesel (per month) to Outlets 1998-2012 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Daily Average (1000 gallons/day)
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	746	736	725	746	649	613	691
2009	578	595	578	607	639	689	749	753	745	752	676	628	666
2010	706	614	592	676	644	757	789	790	758	751	628	615	694
2011	572	569	681	635	608	754	832	813	788	776	688	637	697
2012	633	621	679	702	657	729	868	935	847	842	767	667	746
avg.	573	548	556	611	602	649	736	725	675	722	617	553	631

[1]These data are from motor fuel tax collections, which 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 the monthly date represents actual periods that gallons of fuel were distributed within the state. Accordingly, they 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 which were manipulated so data from all states would be comparable.

Source: Montana Department of Transportation motor fuel tax data base, January 2013.

Table 12c. Average Daily Delivery Rates of Off-Road Diesel (per month) to Outlets 2003-2012 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Daily Average (1000 gallons/day)
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	314	327	163	276	244	256	275
2009	354	268	255	230	227	244	254	276	269	246	228	232	257
2010	216	252	302	303	225	250	296	363	312	309	273	262	281
2011	288	336	325	241	227	233	317	372	304	288	263	256	288
2012	304	381	276	260	258	259	364	364	260	273	260	257	293
avg.	288	308	303	301	275	278	335	358	290	286	279	264	297

[1]These data are from motor fuel tax collections, which 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 the monthly date represents actual periods that gallons of fuel were distributed within the state. Accordingly, they 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, January 2013.

Table 12d. Average Daily Delivery Rates of Railroad Diesel (per month) 2003-2012 (1000 gallons/day)[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Daily Average (1000 gallons/day)
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	451	324	213	236	154	215	357
2009	277	247	252	257	196	219	243	266	244	246	201	266	243
2010	217	248	250	236	207	255	218	250	238	236	262	276	241
2011	244	252	279	234	220	200	201	202	209	243	257	233	231
2012	260	236	216	199	243	220	212	232	223	246	260	223	231
avg.	311	278	296	316	294	279	279	276	266	263	258	254	281

[1]These data are from motor fuel tax collections, which are supposed to cover all railroad use. The volumes come from distributors' bills of lading and the monthly date represents actual periods that gallons of fuel were distributed within the state. Accordingly, they 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, January 2013.

Table P13. Average Retail Price of Regular Gasoline, 1990-2011 (dollars/gallon)[1,2]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1990	1.093	1.073	1.083	1.093	1.108	1.122	1.125	1.302	1.380	1.441	1.429	1.397
1991	1.323	1.260	1.143	1.141	1.172	1.188	1.184	1.186	1.189	1.182	1.177	1.146
1992	1.093	1.051	1.071	1.104	1.184	1.269	1.309	1.306	1.289	1.271	1.252	1.210
1993	1.148	1.113	1.123	1.145	1.193	1.214	1.239	1.239	1.255	1.275	1.274	1.232
1994	1.158	1.140	1.136	1.151	1.236	1.277	1.321	1.324	1.333	1.315	1.289	1.265
1995	1.217	1.209	1.194	1.220	1.282	1.277	1.260	1.245	1.259	1.257	1.226	1.208
1996	1.206	1.238	1.293	1.387	1.404	1.387	1.365		1.407	1.408	1.387	1.372
1997	1.370	1.360	1.370	1.362	1.362	1.353	1.342	1.359	1.365	1.378	1.362	1.318
1998	1.278	1.232	1.199	1.207	1.203	1.199	1.200	1.196	1.196	1.174	1.131	1.048
1999	0.985	0.974	1.026		1.288	1.290	1.353	1.374	1.390	1.377	1.405	1.364
2000	1.385	1.446	1.609	1.588	1.581	1.585	1.587	1.588	1.623	1.722	1.682	1.666
2001	1.499	1.494	1.459	1.529	1.676	1.605	1.526	1.559	1.563		1.274	1.174
2002		1.197	1.356		1.455	1.456	1.459	1.458	1.438	1.432	1.439	1.407
2003	1.469	1.628	1.665	1.586	1.551	1.541	1.586	1.652	1.652	1.564	1.549	1.507
2004	1.521	1.570	1.666	1.796	1.968	1.942	1.956	1.959	1.940	1.976	1.972	1.891
2005	1.867	1.882	2.057	2.215	2.223	2.200	2.258	2.416	2.789	2.665	2.216	2.082
2006	2.144	2.176	2.252	2.455	2.680	2.730	2.845	3.057	2.745	2.374	2.259	2.290
2007	2.129	2.090	2.388	2.806	3.065	3.073	2.998	2.922	2.890	2.900	3.093	3.044
2008	2.941	3.022	3.147	3.387	3.649	3.974	4.108	3.945	3.738	3.002	2.034	1.537
2009	1.475	1.807	1.934	2.050	2.300	2.598	2.601	2.670	2.692	2.585	2.606	2.548
2010	2.624	2.663	2.777	2.899	2.898	2.806	2.811	2.839	2.838	2.843	2.880	2.925
2011	2.966	3.010										
Average	1.613	1.619	1.616	1.743	1.784	1.813	1.830	1.879	1.855	1.807	1.711	1.649
Median	1.385	1.403	1.370	1.529	1.455	1.456	1.459	1.508	1.438	1.436	1.429	1.397

[1]State-wide average price of sales to end users through retail outlets, in nominal dollars. Average price of all gasoline would be slightly higher, about three cents per gallon annual average in recent years.

[2] Due to budget cuts, EIA suspended publishing these data; the February 2011 price is the last in this series.

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." Regular gasoline only, through retail outlets (http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMA_EPMR_PTC_SMT_DPG&f=M). DEQ has added the relevant taxes to the EIA data; see Table P14 for taxes.

Table P14. Estimated Price of Motor Fuel and Motor Fuel Taxes, 1970-2012[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		1.63	28.5		24.4		27.75		13[3]	
2001	1.52	27.75		18.4		1.49	28.5		24.4		27.75		13.1[3]	Jan. 1
2002	1.41	27.75		18.4		1.38	28.5		24.4		27.75		13.1[3]	
2003	1.61	27.75		18.4		1.57	28.5		24.4		27.75		13.2[3]	Jan. 1
2004	1.88	27.75		18.4		1.90	28.5		24.4		27.75		13.2[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		2.80	28.5		24.4		23.7		18.4	
2007	2.83	27.75		18.4		3.02	28.5		24.4		23.7		18.4	
2008	3.27	27.75		18.4		3.89	28.5		24.4		23.7		18.4	
2009	2.37	27.75		18.4		2.55	28.5		24.4		27.75	July 1	18.4	
2010	2.85	27.75		18.4		NA	28.5		24.4		27.75		18.4	
2011	NA[4]	27.75		18.4		NA[4]	28.5		24.4		27.75		18.4	
2012	NA[4]	27.75		18.4		NA[4]	28.5		24.4		27.75		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 gasoline tax.

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

[4] Due to budget cuts, EIA suspended publishing gasoline and diesel price data for Montana and other individual states; the February 2011 price is the last in this series, and thus 2010 is the last full year in the series when prices are available for gasoline.

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 1984-2010 gasoline prices are derived from the *State Energy Price and Expenditure Report*, which reports prices in $/million Btu. The source database for gasoline prices 1984-2010 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 2008 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 1984-2010 are from U.S. Department of Energy, Energy Information Administration, Total Gasoline Retail Sales by All Sellers, (http://www.eia.gov/dnav/pet/pet_pri_allmg_c_SMT_EPM0_dpgal_a.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 1970-2008 (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 1970-2009, (http://www.fhwa.dot.gov/policyinformation/statistics/2009/fe101a.cfm) and 2011 (http://www.fhwa.dot.gov/policyinformation/statistics/2011/), with corrections as provided by Montana Department of Transportation.

Renewable Energy in Montana

Beginning with the Black Eagle Dam in the early 1890s, Montana has, for over a century, utilized renewable energy to power its major industries and later its homes and businesses. Between 1890 and 1975, successively larger dams were constructed to provide electricity to the state of Montana and beyond, along with providing water storage and flood control. In addition to hydroelectricity, biomass in the form of wood, has also provided a key energy resource for heating Montana homes, businesses, and public facilities since the state's founding and continues to be an important heating source today.

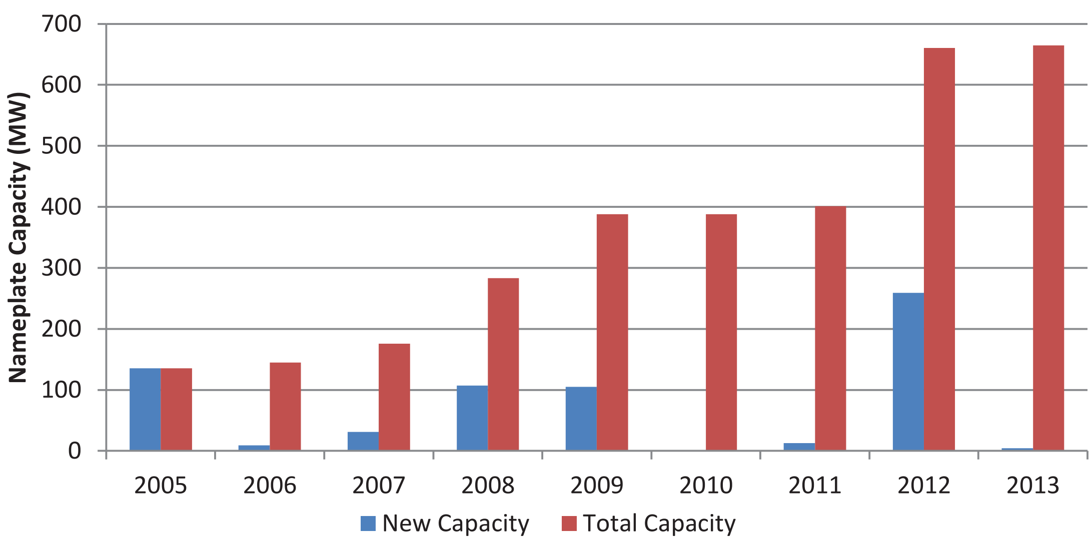
Since 1975 when the Libby Dam was completed, Montana has not seen the construction of any further large hydroelectric dams. The next 30 years saw little renewable electricity development in Montana, mainly smaller hydroelectric projects that contracted to sell power to MPC and later NWE as small qualifying power producer facilities (QFs). In 2005 two separate events jumpstarted the development of renewable electricity generation in Montana. First, the Montana Legislature passed a Renewable Portfolio Standard (RPS), mandating that regulated utilities and electricity suppliers in the state meet 15 percent of their retail electricity sales with renewable energy by 2015 with intermediate requirements for 5 percent renewable energy by 2008 and 10 percent by 2010. Second, Invenergy completed the construction of the 135 MW Judith Gap wind farm in central Montana, supplying renewable electricity to NWE as part of a long-term power purchase agreement. Judith Gap continues to be the single largest contributor of renewable energy used by NWE to achieve compliance with Montana's RPS.

In 2005 Montana became the 19th state in the country to adopt an RPS. Since then, another 11 states have adopted RPS programs along with the District of Columbia, while another 8 states have established voluntary renewable energy goals. Montana's RPS legislation applies to the state's two large public utilities (NWE and MDU) and larger competitive electricity suppliers, which together account for about half the retail sales of electricity in the state. Montana's RPS does not require renewable energy purchases by the state's rural electric cooperatives, public utilities with 50 or fewer retail customers, competitive electricity suppliers with four or fewer retail customers, or electricity customers that generate their own electricity. The RPS does note that it is the responsibility of electric cooperatives with more than 5,000 Montana customers to meet the Legislature's intent to encourage renewable energy generation.

The Montana RPS defines eligible renewable energy resources for use in meeting RPS obligations as electricity generating facilities that commenced commercial operation after January 1, 2005 that generate electricity from renewable resources, including: wind; solar; geothermal; landfill or farm-based methane gas; wastewater treatment gas; certain kinds of biomass; new hydroelectricity facilities less than 10 MW in capacity that do not require a new appropriation, diversion, or impoundment of water; and fuel cell power derived from a renewable fuel. Subsequently, the Montana Legislature has revised its definition of eligible renewable energy resources to include new hydroelectric generation up to 15 MW at existing reservoirs or irrigation systems, electricity generated from capacity expansions at existing hydroelectric dams, various forms of electricity storage, and additional biomass resources. To date, only wind and hydroelectric resources are used to comply with the state's RPS program, although the Wastewater Treatment Facility in Great Falls registered as an eligible renewable resource.

Completed in 2005, the 135 MW Judith Gap wind farm became the first development to qualify for use in compliance with Montana's RPS program. Judith Gap opened the door for additional large wind energy developments in the state (**Figure 25**). Judith Gap was followed by the 30 MW Diamond Willow Wind Farm completed in 2007 outside Baker, the 210 MW Glacier Wind Farm completed in two phases between 2008 and 2009 west of Shelby, the 189 MW Rim Rock Wind Farm completed in 2012 north of Cut Bank, and the 40 MW Spion Kop Wind Farm completed in 2012 northwest of Geyser. In addition to the larger wind energy developments, a number of smaller wind energy developments, using both modern and refurbished wind turbines, successfully obtained power purchase contracts to sell renewable electricity to NWE as QFs. These developments included the 9 MW Horseshoe Bend Wind Farm completed in 2006 outside Great Falls, the 10 MW Gordon Butte Wind Farm completed in 2012 outside Martinsdale, and the 20 MW Musselshell I & II Wind Farms completed in 2012 south of Shawmut.

Figure 25. Montana New Renewable Electricity Capacity, 2005-2013

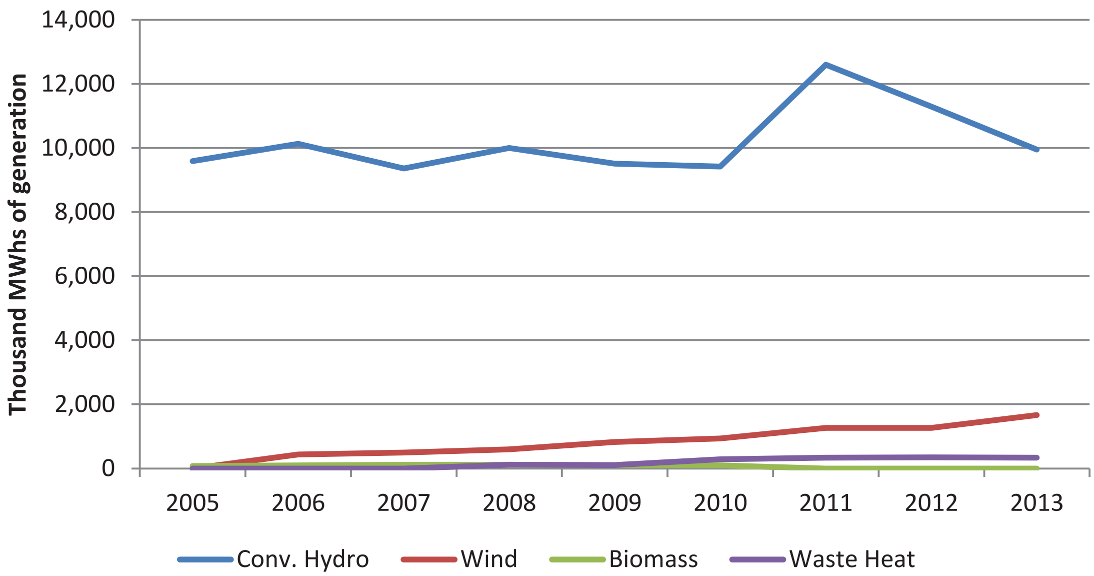


In addition to wind energy development the last decade has also seen the addition of three hydroelectric facilities, including the 13 MW Turnbull Hydro Generation Project outside Augusta (which uses a modified existing irrigation canal), and several biomass, biogas, and cogeneration facilities in Montana. Most recently, in 2013 the F.H. Stoltze Land and Lumber mill in Columbia Falls began operation of a new 2.5 MW biomass-fueled combined heat and power plant that is generating heat for their manufacturing process and selling electricity to the local electric cooperative, in addition to selling renewable energy credits to the state of Washington.

Altogether the 665 MW of new renewable electricity generation facilities generated more than 2 million MWh in 2013, which is equal to 14 percent of Montana's retail electricity sales and 7 percent of the state's total electricity generation (**Figure 26**). However, only a third of the renewable electricity generation in Montana is ultimately purchased by Montana electricity providers for compliance with Montana's RPS program. Most of the remaining renewable electricity generation is sold to out-of-state utilities for use and compliance with other state RPS programs.

Montana's RPS program also includes a provision for community renewable energy projects (CREPs). That provision requires electricity providers to procure a portion of their renewable electricity obligation from renewable electricity developments in which local owners have a controlling interest and that is less than 5 MW in total nameplate capacity. In 2009 the Montana RPS was revised to allow local public utilities to own CREPs, to increase the maximum size of a CREP from 5 MW to 25 MW, and to delay the initial compliance year from 2010 to 2012. For years 2012 through 2014, the RPS program requires 50 MW of CREPs followed by 75 MW of CREPs for 2015 and beyond. To date, MDU has achieved compliance with its portion of the RPS CREPs requirement, while NWE has fallen short and received exemptions from the PSC while it pursues additional CREP-compliant projects.

Figure 26. Renewable and Alternative Energy Generation by Year



As is noted in the Electricity and Transmission sections of this handbook, before the recent economic recession, dozens of additional renewable energy projects, primarily wind energy projects, were planned for development in Montana along with additional transmission projects to export the resulting electricity generation to out-of-state markets, primarily on the West Coast. However, the economic recession and its corresponding reduction in electricity demand, along with changes in California's RPS program to prioritize in-state renewable electricity generation, reduced demand for additional renewable electricity generation across the West, as well as the transmission projects necessary to export additional electricity generation out-of-state. As a result, most of the recently planned renewable energy and transmission projects for Montana have been shelved. In 2014, only two small utility-scale renewable energy developments, totaling 20 MW in capacity, are expected to be commissioned. Both developments, the Fairfield and Two Dot wind farms, are QF wind developments that signed contracts with NWE.

Because Montana's electricity providers are already contracted to buy most of the renewable electricity they need to meet their 2015 renewable electricity requirements, the main market for new, large renewable electricity generation projects is likely to be out-of-state. However, without additional firm transmission capacity to better connect Montana to major areas of electricity demand, it may be difficult for any new renewable electricity projects to develop in Montana. As noted in the Transmission section, the Montana-to-Washington (M2W) transmission upgrade project is an interstate transmission project that is still moving forward and could create the potential to export an additional 600 MW of Montana-generated electricity to West Coast markets.

In addition to utility-scale renewable electricity developments, Montana also has seen the installation of a significant number of small, distributed renewable electricity generation systems over the past decade. Most of these systems have been net metered, meaning that they are connected to the larger electricity grid. Any excess electricity generated by the renewable electricity systems that can't be immediately consumed by the system owners on-site is put onto the larger electricity distribution system, spinning the electricity customers' electricity meter backward. Through the end of 2012, NWE, which serves a majority of Montana's residential and commercial electricity customers, had 1,040 net metered renewable electricity systems installed, accounting for a total capacity of slightly more than 4 MW. Solar PV systems accounted for 936 of the 1,040 installed systems with an average capacity rating of 3.5 kW. One-hundred-and-one of the remaining 104 net metered systems were wind energy systems averaging 8.1 kW in capacity while the final three systems were small hydroelectric systems averaging 4.2 kW in capacity.

Beyond the renewable electricity generated from Montana's renewable resources, energy consumers also utilize renewable energy to provide direct heating and cooling of residential, commercial, community and government buildings. There are currently nine wood manufacturers, nine schools, two hospitals, two state buildings, and one university campus that generate space heat and domestic hot water with woody biomass. For residential homes, heating with wood and pellet stoves and fireplaces is common in the state, either as a primary source of heating or as a supplemental heating source. The 2012 American Community Survey (ACS) estimated that 9 percent, or 37,500, of Montana homes used wood as a primary source of heating. The ACS does not track secondary sources of heating but it's likely that a much larger percentage of Montana homes utilize wood or other biomass resources as supplemental fuels for heating.

Other important renewable energy fuels for heating and cooling Montana homes and businesses include geothermal energy, which typically takes the form of ground-source heat pumps, and solar energy. Ground-source heat pumps utilize the consistent temperature of the ground to provide heating in colder months and cooling in warmer months. In 2012, at least 298 Montana taxpayers installed geothermal energy systems based on the number of reported geothermal energy tax credits claimed in the state. Between 2006 and 2012, 1,500 Montana homes and small businesses reported installing geothermal energy systems and claiming the applicable state tax credit for doing so. In addition, more than 40 facilities in Montana, including pools, spas, and greenhouses, utilize hot water and steam from the state's many natural hot springs.[1]

Active and passive solar energy are also increasingly common in Montana. Active solar heating systems have typically been used to provide heat for domestic hot water systems as well as for hydronic heating systems with Montana commonly seeing more than 100 solar thermal systems installed annually. Solar water heating systems are also common for small commercial applications, such as car washes and laundries that have relatively large hot water demands. Recent technology improvements have also resulted in increased use of solar air systems for heating homes. Passive solar heating, where the architecture of homes is used to absorb radiant heat during colder months, is also used by some homeowners to reduce fall through spring heating bills.

Montana is also using the state's ample biomass resources to generate small amounts of biofuels as well. For instance, Earl Fisher Biofuels in Chester produces 250,000 gallons of biodiesel a year from Montana-grown oilseeds and sells its fuel to local farms for equipment, as well as to a retail station in Havre, with plans to expand its operations to 1 million gallons. Smaller operations exist throughout the state, generating small amounts of biofuels for personal or local consumption.

Renewable Energy Potential
Thanks to its large size and geographic diversity, Montana is rich in renewable energy potential. Montana has an abundance of wind energy. The National Renewable Energy Laboratory estimates Montana's wind potential at 80 meters above ground is 944,004 MW, ranking Montana third nationally in total wind energy potential. While economic, infrastructure, environmental, and legal constraints limit feasibility to a small percentage, the state's current 645 MW of installed wind energy capacity represents less than a tenth of one percent of the state's total wind energy potential. Developing just 1 percent of the states wind energy potential (9,440 MW) would generate more than twice the electricity consumed by Montana annually.

As noted in **Figure 27**, much of the wind energy potential in the state is in central and eastern Montana, although the ridgelines of western Montana also present strong wind energy potential.

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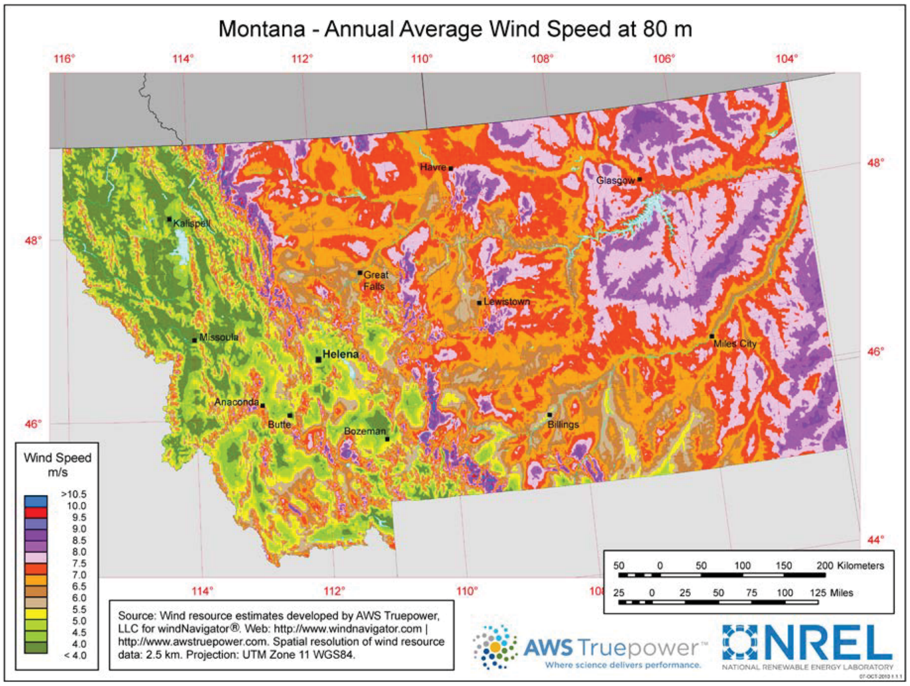
[1] *"A Clean Energy Economy for Montana",* Natural Resource Defense Council, 2010. http://www.nrdc.org/energy/cleanmt/files/cleanmt.pdf.

Figure 27. Montana Wind Energy Resources. Source: NREL



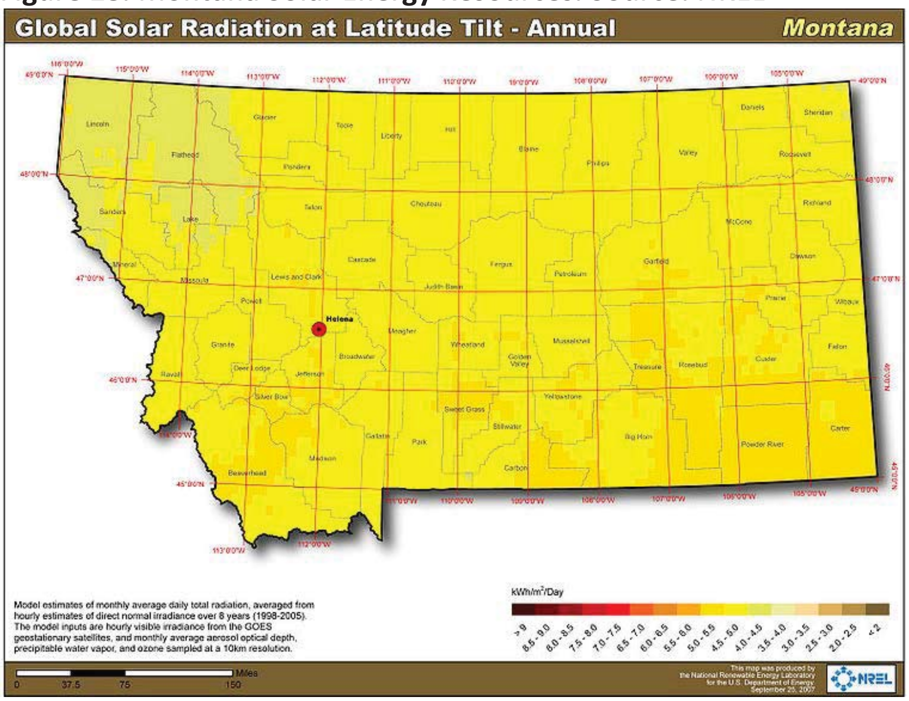
Being a northern state, Montana does not have the solar energy resources found in the desert Southwest states of California, Nevada, Arizona, and New Mexico, which have seen dramatic increases in solar energy in recent years, including the installation of large, utility-scale solar energy facilities. Nevertheless, Montana has respectable solar energy potential--between 4.5 and 5.5 kWh/m^2/day in most regions of the state thanks to the number of sunny or partly sunny days experienced throughout most of the state (**Figure 28**). Montana's more temperate summer climate also reduces efficiency losses that occur with PV systems as temperatures increase. While utility-scale solar energy facilities can't be ruled out in Montana, it's more likely that the bulk of solar energy development in Montana will remain of the smaller, residential and commercial rooftop variety.

Because decent solar resources fall across most of the state, gauging Montana's solar potential is largely a question of economics. Recent years have seen the price of solar PV systems decline precipitously, with residential systems falling below $5 per watt of installed capacity in 2013 while non-residential systems fell below $3.75 per watt and utility-scale systems dropped below $2 per watt by the fourth quarter of 2013.[2] However, some 2014 applications to Montana's alternative energy loan program show bids for larger residential PV systems as low as $2.50 per watt before utility, state, and federal incentives are considered, further emphasizing that the recent trend of cost decreases are continuing. At current national average prices for residential and commercial solar PV systems and utility-supplied electricity, residential and commercial solar PV owners are still paying a cost premium for consuming

[2] *"Solar Industry Data"*, Solar Energy Industries Association, 2014. http://www.seia.org/research-resources/solar-industry-data.

renewable electricity, but as solar PV prices continue to fall and utility electricity prices rise, the disparity is narrowing. If these trends continue and solar PV bids in Montana continue to fall at the low end of the cost range, rooftop solar PV may be a more cost-effective investment for residential and commercial customers.

Figure 28. Montana Solar Energy Resources. Source: NREL

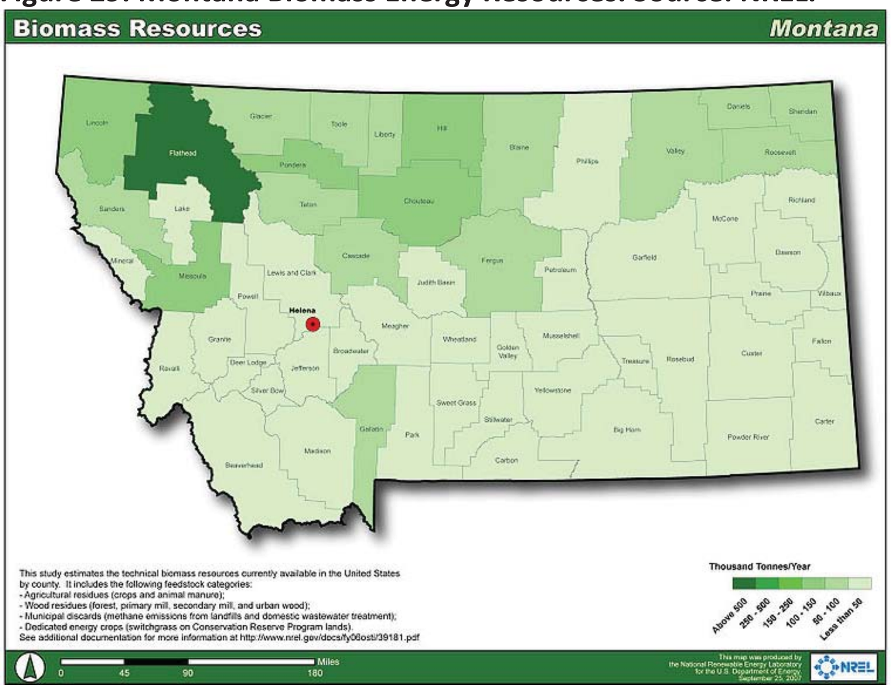


However, the high upfront cost of solar PV systems, cost-effective or not, is still the largest barrier to greater implementation in Montana, as it is elsewhere. In response to these high upfront costs, third-party solar financing companies, which install and own solar PV systems on residential and commercial roofs, are increasing in popularity. These companies sell the resulting electricity generation to the property owner. Montanans access to third-party or other readily available financing may be the determining factor in how much solar PV is installed in the state over the next decade.

Montana also has significant biomass, biofuel, and biogas energy resources from a variety of sources. The greatest market potential for biomass energy from wood is in thermal energy generation and combined heat and power. Wood biomass fuels are being used in the form of chips, pellets, and cordwood derived from forests and mill and urban wood residues. Montana's forest resources provide a substantial resource base for wood biomass fuels. There are volumes of overstocked forests, dead or dying trees affected by insects and disease, and low-value small diameter trees harvested in hazardous fuel reduction, forest restoration treatments, and as forest slash. By utilizing wood for energy, Montana also creates a market value and greater economic return on the costs of forest management to sustain healthy and productive forest and to protect watersheds from the risks of catastrophic wildfire.

Agricultural wastes, like wheat straw, could be used as a biomass energy resource or as a feedstock for creating cellulosic biofuels. Marginal agricultural lands in eastern Montana could be used to grow biofuel crops, like camelina, while marginal agricultural lands in western Montana are ideal for biomass and biofuel crops, like switchgrass, poplar, and willow. As noted in **Figure 29**, Montana has the potential to use a substantial amount of biomass to generate electricity and biofuels. Montana's northern counties, particularly the northwestern counties like Flathead and Lincoln, have significant amounts of potential biomass available for use. In addition, Montana's wastewater treatment plants, landfills, and cow and swine farms are prime biogas resources, capable of capturing methane emissions for combustion to generate electricity, many of which already are doing so. For instance, Huls Dairy in Ravalli County uses the manure waste from its cows and runs it through an anaerobic digester to capture and burn the resulting methane to run a 50 kW generator that is net metered to the grid.

Figure 29. Montana Biomass Energy Resources. Source: NREL.

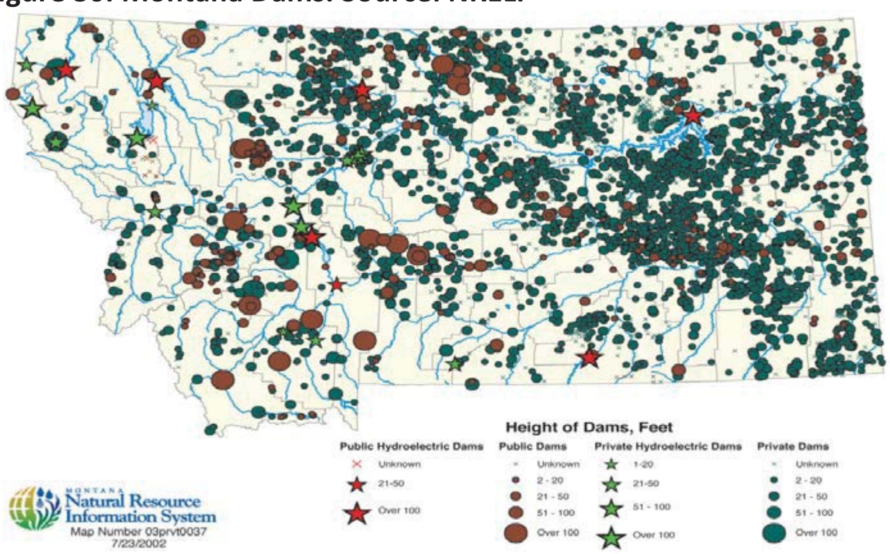


Montana is using only a fraction of its biomass resources because of economic, technological, and social constraints. The costs of harvesting and transporting biomass can be a major hurdle. As with conventional fossil fuel resources that are burned, combusting biomass resources can have negative air quality impacts, potentially limiting development. However, as the F.H. Stoltze combined heat and power facility demonstrates, biomass facilities that replace older fossil fuel-based facilities can deliver air quality benefits. Many promising biofuel production technologies, like those used to create cellulosic biofuels from agricultural wastes, are in the early stages of development and have not yet demonstrated clear economic viability. If these technologies prove capable and competitive with conventional resources, Montana, with its ample and varied agricultural and forestry lands, may see increased interest for biofuels development. Montana State University-Northern in Havre also operates a Bio-Energy Research

Center to conduct comprehensive studies on all aspects of biofuel production and usage, operating its own biodiesel pilot plant to produce biofuels for analysis and testing.

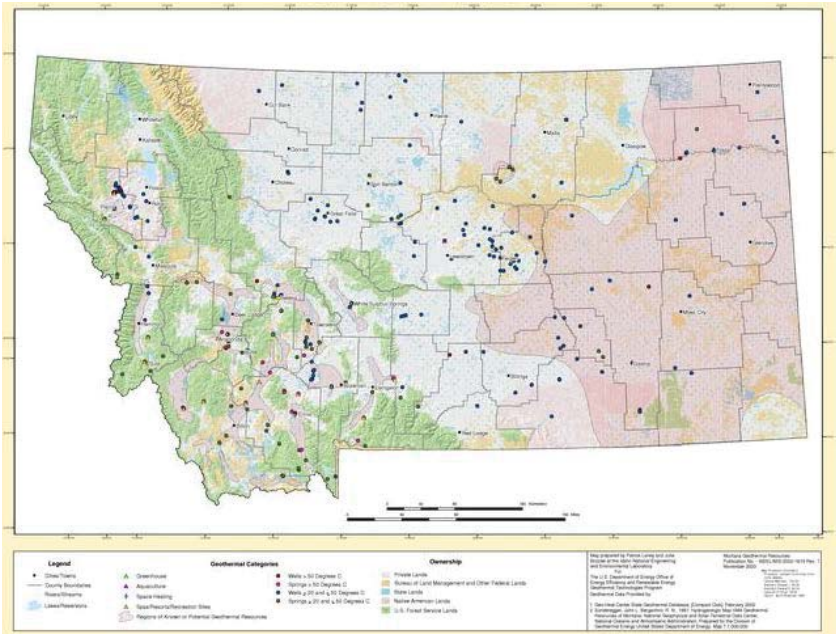
Montana is home to hundreds of dams, most of which serve agricultural and livestock purposes or are used for flood control (**Figure 30**). Most of the state's largest dams include facilities for generating electricity, although there are examples, such as Gibson Reservoir Dam west of Augusta, where small utility-scale hydroelectric systems could be installed as a stand-alone project or as part of a larger dam retrofit. In addition to these larger projects, there is also the potential to implement small- and micro-hydroelectric projects at smaller dams throughout the state. The majority of Montana's impoundments, however, likely aren't suitable for installing electricity generating equipment because of short expected future lifespans of the impoundments, seasonal outflows, unfavorable economics, or inability to acquire the necessary water rights. Nevertheless, small projects like the 2 MW Flint Creek Dam and 455 kW Lower South Fork project show it is feasible to develop these resources under the right circumstances.

Figure 30. Montana Dams. Source: NREL.



Montana's geothermal energy resources are a largely untapped resource to date. While the area directly neighboring Yellowstone National Park, with its famous geothermal features, cannot be utilized because of the need to preserve the park's natural features, many other regions of the state have the potential to yield geothermal energy resources. As noted in **Figure 31**, Montana's southwestern valleys and much of the eastern third of the state have temperatures that could be developed for direct uses or electricity generation. To date these resources have been untapped because of low electricity prices and the abundance of other more cost-effective resources. The development of enhanced geothermal systems and lower temperature generation technologies may change the economic climate for geothermal generation in Montana. Similar to oil and natural gas drilling, the environmental impacts from geothermal energy development must also be considered, including potential impacts on local groundwater and increased seismicity from drilling activity.

Figure 31. Montana Geothermal Resources. Source: DOE.



Conclusions

As Montana comes to the end of the first decade since enactment of the state's RPS program, the renewable energy industry has seen significant growth. There is dramatic growth in wind energy development across central and northern Montana and increased use of distributed forms of renewable energy, like rooftop solar, small wind, and ground-source heat pumps. Montana has only tapped a fraction of its ample renewable energy, but it is unclear what portion of these resources will be economically viable to develop in the future. Further advances in technology will likely reduce development costs. However, further development is limited by Montana's relatively small population and limited electricity demand. Developing further capacity for Montana to export renewable energy resources will be key if Montana hopes to significantly increase existing renewable energy industries and to develop new ones.