APPENDIX B
ALTERNATIVE GENERATION TECHNOLOGIES

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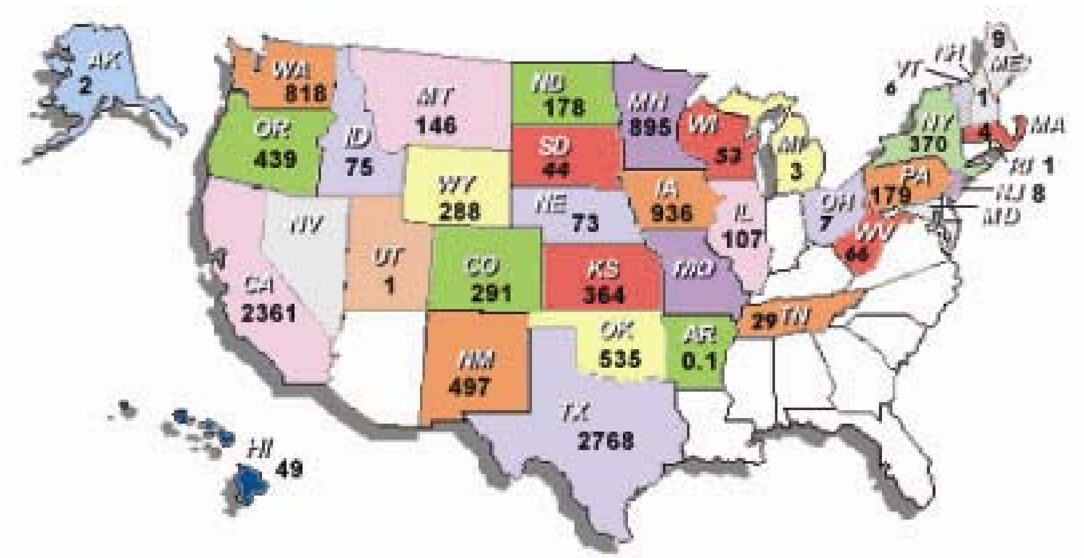
B1.0 RENEWABLE NON-COMBUSTIBLE ENERGY GENERATING SOURCES EVALUATED (WIND, SOLAR, HYDROELECTRIC, AND GEOTHERMAL)

B1.1 Wind Energy

Wind turbines convert the power in the wind into electricity by extracting the kinetic energy in the wind, and utilizing the wind turbine to generate mechanical power. Wind energy is the fastest-growing renewable energy source in the world. However, it still accounts for just 0.25 percent of U.S. power output (Figure B1).



(Source: American Wind Energy Association, 2007)

Figure B1 – Installed Wind Power-Generating Capacity by State, in MW, as of December 31, 2006

Wind power must compete with conventional generation sources on a cost basis. Wind energy is one of the lowest-priced renewable energy technologies available today. State-of-the-art wind power plants can generate electricity for less than 5 cents/kWh with the Production Tax Credit in many parts of the U.S. (AWEA 2004). Technological advances have improved the performance of wind turbines and driven down their cost. In locations where the wind blows steadily, the cost of wind power has been shown to compete favorably with coal and natural gas fired power plants (if the full cost including "firming" is not considered). Even though the cost of wind power has decreased dramatically in the past 10 years, the technology requires a higher initial investment than fossil-fueled generators.

Fixed, investment-related costs are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs to approximately $800 to $1,100/kW. Not including the cost of firming, the Energy Information Administration (EIA) projects the levelized cost of wind power to be approximately $50.6/MWh. The U.S. Department of Energy (DOE) National Renewable Energy Laboratory projects the levelized cost of wind power to be between $40 and $55/MWh.

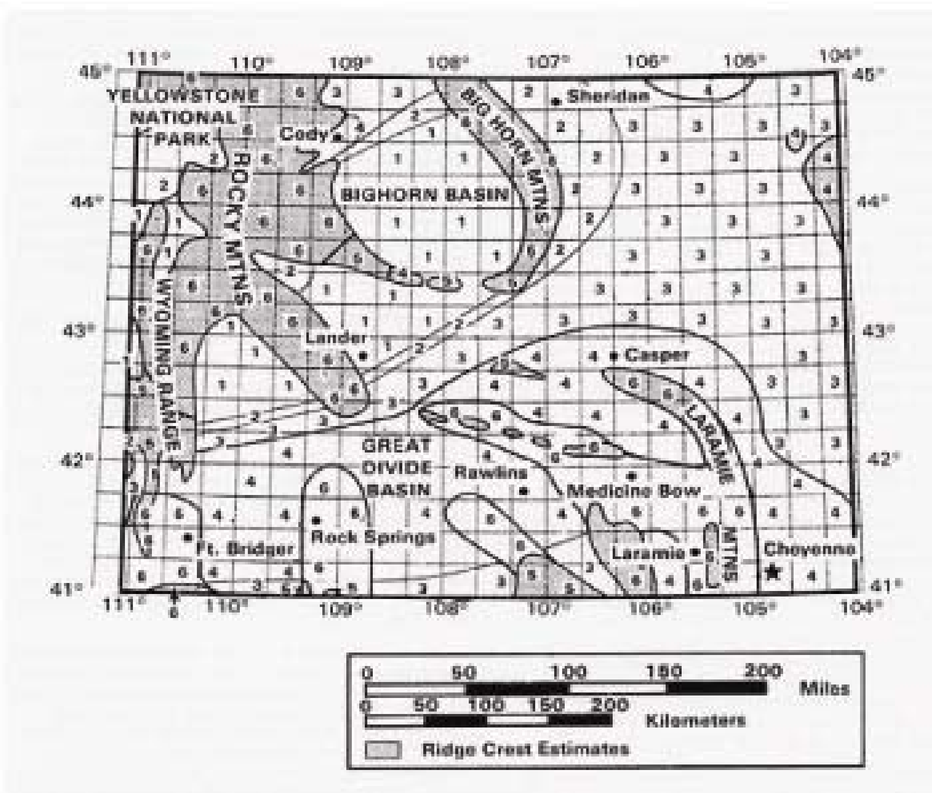
Another major issue regarding wind is its intermittence, in that wind power can offer energy, but not an on-demand capacity. With wind's unpredictable nature, forecasting how the wind is going to blow and accurately scheduling the generation is rather difficult. Thus, it is not considered a "firm" resource because not all winds can be harnessed to meet the timing of electricity demands. Due to the intermittent nature of wind, a wind power plant's economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of a wind turbine's productivity. Estimates of capacity factors range from 30 to 40 percent.

As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (the lowest) to class 7 (the highest). In general, wind power class 4 or higher can be useful for generating wind power with large (utility-scale) turbines, and small turbines can be used at any wind speed. Class 4 and above are considered good resources. Figure B2 is a map showing the general wind power classes across Wyoming. It indicates that northeastern Wyoming has primarily a wind power class 3 with only a small portion a class 4. This indicates that the area of northeastern Wyoming needing additional electrical capacity will not be best served by wind power. Although Wyoming residents heartily agree that the wind always blows in Wyoming, the northeastern portion of the state is not, ironically, a preferred location for wind generation

In addition to a less suitable wind power class, building both wind and new natural gas resources for Basin Electric members that could provide 385 MW of baseload power needed will be more costly than building a single coal resource of 385 MW, and require considerably more land area. For example, a 385-MW wind farm will require approximately 29 square miles (18,560 acres or 7,511 hectares) of area based on an average power output of 13.47 MW/square mile for wind power class 4 resources. Because of the intermittent nature of wind power, large land requirements, difficulty in scheduling the generation in a class 3 area, and average annual capacity factors of only 30 to 40 percent, wind power cannot fulfill the need of a long-term, cost-effective, and competitive generation of energy to meet the need for 385 MW of highly reliable baseload capacity for Basin Electric members in northeastern Wyoming and western South Dakota. For these reasons, RUS has determined that this alternative does not meet the purpose and need for the project.

B1.2 Solar Energy

The sun is an infinite source of energy. Current technologies allow for the harness of solar energy for heating, lighting, cooling, and electricity. The sun's energy can be converted to electricity directly through photovoltaic cells (solar cells). However, solar energy varies by location and by the time of year. Solar resources are expressed in watt-hours per square meter per day (Wh/m^2/day). This is roughly a measure of how much energy falls on a square meter over the course of an average day.



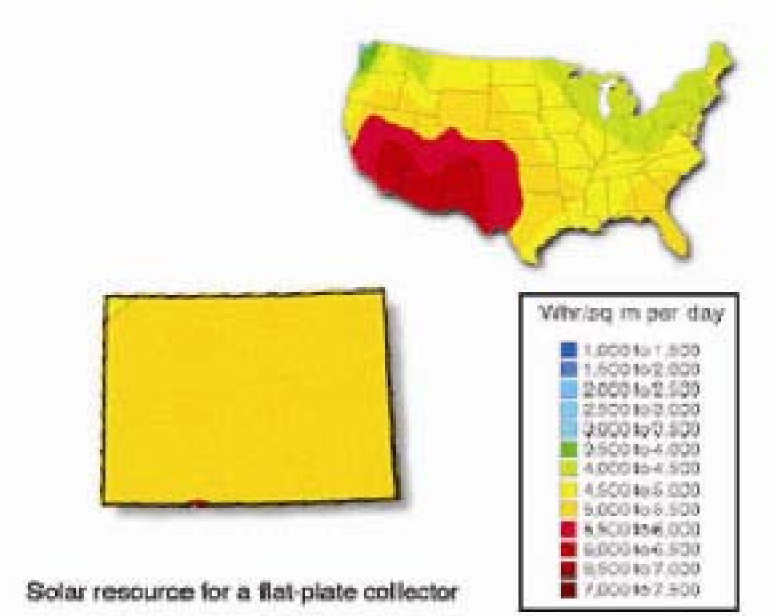
(Source: National Renewable Energy Laboratory, 2007)

Figure B2 – Classes of Wind Power in Wyoming

There are two types of solar collectors. Flat-plate collectors are generally fixed in a single position, but can be mounted on structures that tilt toward the sun on a seasonal basis, or on structures that roll east to west over the course of the day. Concentrator collectors focus direct sunlight onto solar cells for conversion to electricity. These collectors are on a tracker, so they always face the sun directly and because these collectors focus the sun's rays, they only use the direct rays coming straight from the sun.

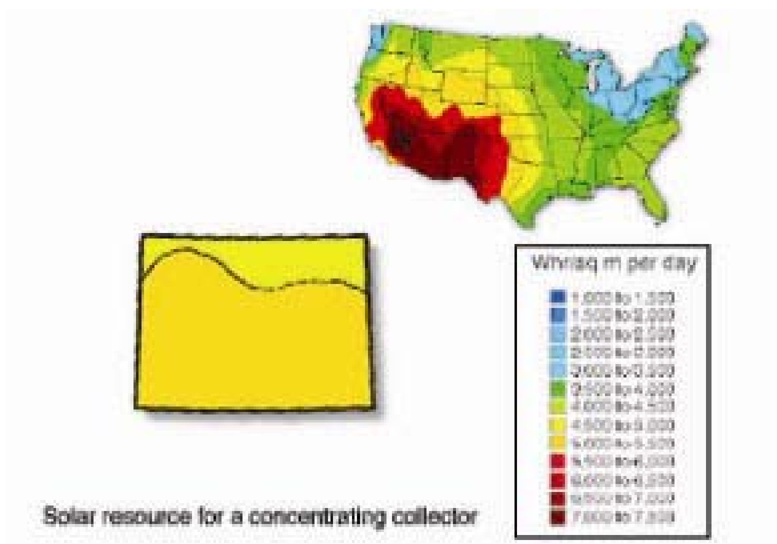
Figure B3 shows a map of the United States and the amount of solar resource capability with a flat-plate collector in an area. Wyoming has a good useful resource throughout the state. If a PV array were installed with a collector area equal to the size of a football field, in one of the state's better locations, it will produce around 1,098,000 kWh per year. Assuming 35 percent capacity factor, the 1,098,000 kWh per year will result with about a peak of 3.85 MW.

Figure B4 shows a map of the United States and the amount of solar resource capability with a concentrator collector in the area. A solar trough electricity system with a collector area of 200,000 square meters – a system that will cover roughly 150 acres – would produce about 46,574,000 kWh per year. Assuming 35 percent capacity factor, the 46,574,000 kWh per year will provide a peak of about 15 MW.



(Source: U.S. DOE EERE State Energy Alternatives Website [Ref. 7])

Figure B3 – Solar Resources for a Flat-Plate Collector in Wyoming and the United States



(Source: U.S. DOE EERE State Energy Alternatives Website [(Ref. 7])

Figure B4 – Solar Resources for a Concentrating Collector in Wyoming and the United States

The Western Governors Association (WGA) estimates that, with a longer-term federal investment tax credit and state-based incentives, the western United States could install as much as eight gigawatts (8,000 MW) of solar electric generating capacity by 2015, enough to power four million homes (REA 2005). According to the WGA, deployment on this scale could also reduce solar costs to a point where they are competitive with power produced from fossil fuels. A WGA task force in 2005 envisioned half of solar deployment developed in central concentrating solar power plants and half developed in distributed PV generation. According to the U.S. DOE however, Wyoming's climate and northern latitude render it a marginal resource for solar concentrators (DOE 2005b). The most promising role for solar energy in Wyoming may not be in centralized, utility-operated power plants, but rather in distributed applications such as hot water and space heating, as well as electricity generation in residences, commercial buildings, farms, and ranches. Photovoltaic systems are expected to be used in the United States for both residential and commercial buildings. Other uses include grid support for distributed utility systems, Hydrogen gas (H_2) production for portable fuel, peak power shaving, and intermediate daytime load following. Photovoltaic systems could also be used for dispatchable electricity with electric storage and improved transmission.

Solar energy is both renewable and sustainable. There are no major water discharge issues and no major direct air emissions related to the installation of a solar facility. Carbon emissions are avoided, as are SO_2 and NO_x emissions. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators. The fact that the structures associated with solar energy installations are generally not nearly as tall as modern wind turbines means that they have not generated the same concern and controversy over aesthetic impacts as wind farms. Likewise, solar energy facilities have not been implicated in bird and bat kills, as have some wind facilities. However, within the confined footprint of development, centralized solar energy facilities virtually eliminate native habitat.

Due to the intermittent nature of solar power, economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of solar power productivity. Estimates of capacity factors range from 20 to 35 percent (Basin Electric 2005a).

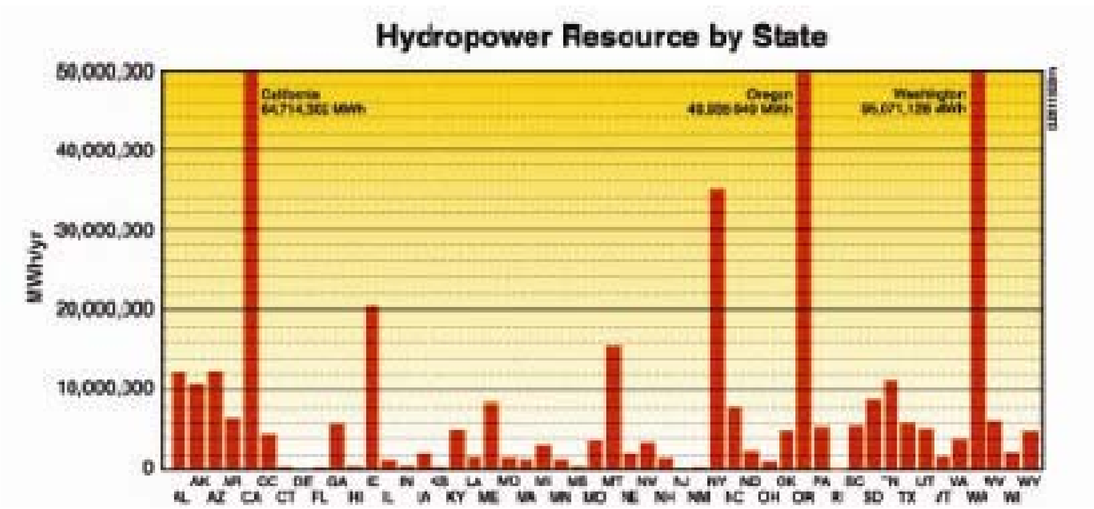
Fixed, investment-related charges are the largest component of solar-based electricity costs. Capital costs for PV systems range from $5,000 to $12,000 per kilowatt and are off set by low operating costs, i.e. no fuel. The 20-year lifecycle costs range from $200/MWh to $500/MWh (Basin Electric 2005a).

Solar power cannot fulfill the need of a long-term, cost-effective, and competitive generation of 385 MW baseload capacity in northeastern Wyoming and western South Dakota for Basin Electric due to fact that the power is intermittent, weather-dependent, and will probably have an average capacity factor in the range of 20 to 35 percent while also be very costly for that capacity factor (Basin Electric 2005a). For these reasons, RUS has determined that this alternative does not meet purpose and need for the project.

B1.3 Hydroelectricity

Hydroelectric power (Hydropower) is the kinetic energy of flowing energy. Hydropower is captured and used to power machinery or converted to electricity. Hydropower plants will typically dam a river or stream to store water in a reservoir. The water is released from the reservoir and it flows through a turbine causing it to spin and activating a generator to produce electricity. Hydropower is the nation's leading renewable energy source. It accounts for 81 percent of the nation's total renewable electricity generation.

The amount of hydropower resource varies widely among states (Figure B5). To have a viable hydropower resource, a state must have both a large volume of water and a significant change in elevation. The data in Figure 2-19 includes both current hydropower generation as well as an estimate of potential additional resources and factors in the many legal, social, and environmental constraints on hydropower development. Wyoming could produce approximately 4,934,273 MWh of electricity annually from hydropower (Basin Electric 2005a), which will be equivalent to approximately 1408 MW of installed capacity, assuming a 40 percent average annual capacity factor. Wyoming has relatively low use of hydropower based on the percentage of the state electricity generation, which is around 2-3 percent.



(Source: Energy Information Agency and the Idaho National Engineering and Environmental Laboratory)

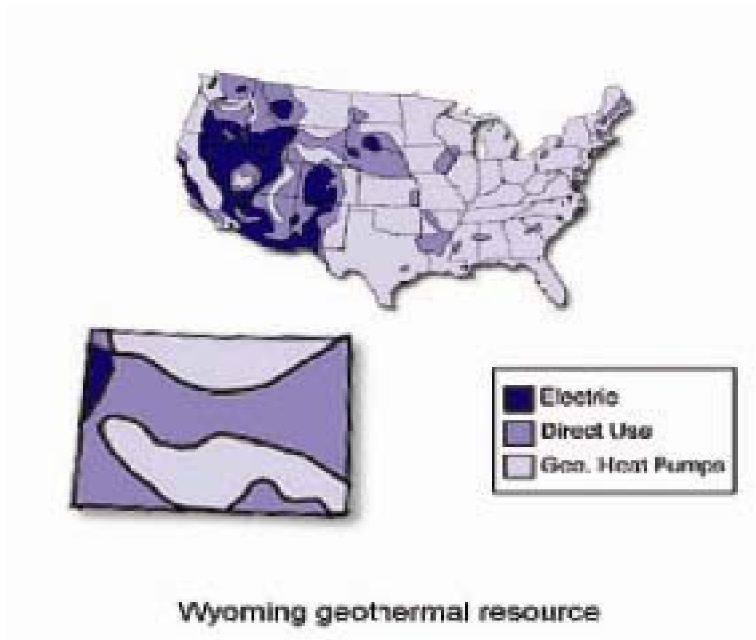
Figure B5 – Hydropower Resource by State

Given the limited availability of resources for developing hydropower in Wyoming, it is unlikely that this technology could fulfill the need of a long-term, cost-effective, and competitive generation of baseload capacity for Basin Electric. Due to the limited availability of potential hydropower in northeastern Wyoming, RUS has determined that this alternative is not technically feasible.

B1.4 Geothermal Energy

Around the world, geothermal energy – "heat from the earth" – is a proven resource both for direct heat and power generation. This energy source is contained in underground reservoirs of steam, hot water, and hot dry rocks. Two types of geothermal resources are being tapped commercially: hydrothermal fluid resources and earth energy. Hydrothermal fluid resources, which are reservoirs of steam or very hot water, are well suited for electricity generation. Due to the remote locations of many geothermal resources, the cost of transmission may make development of these energy sources more expensive than a facility that is closer to an identified interconnection point. Earth energy, the heat contained in soil and rocks at shallow depths, is excellent for direct use and geothermal heat pumps but not as a source of electric power generation.

There are three types of geothermal energy. The first is power generation (or electric), which utilizes steam turbines using natural steam or hot water flashed to steam, and binary turbines produce mechanical power that is converted to electricity. The second is a direct use application where a well brings heated water to the surface; a mechanical system delivers the heat to the space or process; and a disposal system either injects the cooled geothermal fluid under ground or disposes of it on the surface. The third and most rapidly growing use for geothermal energy is geothermal heat pumps, which use the earth or groundwater as a heat source in winter and a heat sink in summer, in essence a device which transfers heat from the soil to the house in winter and from the house to the soil in summer. Figure B6 shows geothermal resources throughout the United States.



(Source: U.S. DOE EERE State Energy Alternatives Website [(Ref. 7])

Figure B6 – Geothermal Resources in Wyoming and the United States

As shown on Figure B6, northeastern Wyoming does not have sufficient geothermal resources to provide large scale electric generation. Geothermal electric power cannot, therefore, fulfill the need of a reliable, long-term, cost-effective, and competitive generation of baseload capacity for Basin Electric due to fact that commercial geothermal resources for generation of electric power are not generally available in northeastern Wyoming and western South Dakota. RUS has determined that this alternative is not technically feasible.

B2.0 RENEWABLE COMBUSTIBLE ENERGY GENERATING SOURCE EVALUATED (BIOMASS, BIOGAS, AND MUNICIPAL SOLID WASTE)

B2.1 Biomass Power

The term "biomass" means any plant-derived organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes, and other waste materials. Biomass can be used to provide heat, make fuels, chemicals and other products, and generate electricity. Bio-energy ranks second (to hydropower) in renewable U.S. primary energy production and accounts for three percent of the primary energy production in the United States (DOE 2005d). However, on an equivalent heat basis, biomass actually ranks first among renewable energy sources. Biomass is the second most widely utilized renewable energy behind hydroelectricity.

Biomass power (Biopower) is the generation of electric power from biomass resources; these resources include urban waste wood, crop and forest residues; and, in the future, crops grown specifically for energy production. Biopower technologies are proven electricity generation options in the United States, with 10 gigawatts (10,000 MW) of installed capacity. All of today's capacity is based on mature, direct combustion technology. Direct combustion involves the burning of biomass with excess air, producing hot flue gases that are used to produce steam in the heat exchange sections of boilers. The steam is used to produce electricity in steam turbine generators (DOE 2005f).

Heat can be used to chemically convert biomass into a fuel oil, which can be burned like petroleum to generate electricity. Biomass can also be burned directly to produce steam for electricity production or manufacturing processes. In a power plant, a turbine utilizes the steam to turn a generator that converts the energy into electricity. Some coal-fired power plants use biomass as a supplemental energy source in high-efficiency boilers to significantly reduce emissions (DOE 2005d).

Biomass can also produce gas for generating electricity. Gasification systems use high temperatures to convert biomass into a gaseous mixture of hydrogen, carbon monoxide, and methane. The gas then fuels a combustion turbine, which is very much like a jet engine, except that it turns an electric generator instead of propelling a jet. The decay of biomass in landfills also produces a gas – methane (CH_4) – that can be burned in a boiler to produce steam for electricity generation or for industrial processes (DOE 2005d).

Wood is the most commonly used biomass fuel for heat and power, and is an available biomass resource in Wyoming, though less available in South Dakota. Biomass resource supply includes the use of five general categories of biomass: urban residues, mill residues, forest residues, agricultural residues, and energy crops. Of these potential biomass supplies, most forest residues, agricultural residues, and energy crops are not presently cost-effective for energy use. New tax credits or incentives, increased monetary valuation of environmental benefits, or sustained high prices for fossil fuels could make these fuel sources more economic in the future. Forest fires in the past several years in western states have generated increased stimulus to initiate forest thinning programs, and several biomass plants are being proposed in the west to use forest thinning as a major fuel source. (Basin Electric 2005c).

Biomass reduces most emissions compared with fossil fuel-based electricity. Biomass results in very low carbon dioxide (CO_2) emissions due to the absorption of CO_2 during the biomass cycle of growing, converting to electricity, and re-growing biomass. Nearly all current biomass generation is based on direct combustion in small, biomass-only plants with relatively low electric efficiency. Most biomass direct combustion generation facilities utilize the basic Rankine cycle for electric power generation, which burns biomass fuel in a boiler to produce steam that is expanded in a Rankine Cycle prime mover to produce power. Currently, co-firing is the most cost-effective technology for biomass. Co-firing substitutes biomass for coal or other fossil fuels in existing coal-fired boilers.

The primary pollution issue in utilizing biomass to generate electricity is the control of air emissions. Co-firing of biomass fuels in a coal-fired boiler is advantageous from a renewable energy point of view as well as an alternative to land disposal of biomass as a solid waste. Biomass used as 5-15 percent of the fuel input in the co-firing of a coal-fired boiler will have similar air emissions and control requirements as those for a conventional pulverized coal or circulating fluidized bed boiler discussed later in this chapter. A 250 MW biomass-only fired boiler will have estimated air emissions shown in Table B1. While a biomass-fired boiler will have relatively low emissions of sulfur dioxide (SO_2), emissions of nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM), and hazardous air pollutants (HAPs) will typically be higher than conventional coal-fired boilers or natural gas-fired combustion turbines.

Table B1 – Estimated Annual Air Emissions (Tons/Year) For a 250 MW Generating Station Using Biomass or Municipal Solid Waste1

Technology	SO_2	NO_x	CO	PM_{10}	Hazardous Air Pollutants (HAPs)	Hg	GHGs[2]
Biomass	274	2,409	6,570	810	427	0.038	342[3]
Municipal Solid Waste	439	4,886	1,911	132	54	0.29	2,668,000

Source: SME 2006
Notes:
[1]For biomass, based on 250-MW wood-fired boiler with low-NO_X burners and fabric filter; average fuel heating value of 6,500 British thermal units (Btu) per pound (lb). For municipal solid waste, based on mass burn water well combustor, 4,500 Btu/lb; 2,443,000 tons refuse derived fuel per year (RDF/yr); Lime Spray Drier, Fabric Filter, and Selective Catalytic Reduction (at 80 percent control); AP-42, Section 2.1 emission factors.
[2]Greenhouse Gases
[3]CO_2 emitted from this source is generally not counted as greenhouse gas emissions because it is considered part of the short-term CO_2 cycle of the biosphere (Basin Electric 2006a).

The current biomass sector is comprised mainly of direct combustion plants and a small amount of co-firing. Plant size averages 20 MW, and the biomass-to-electricity conversion efficiency is about 20 percent. The price of electricity from biomass is generally in the range of $80 to $120/MWh, depending on the type of technology used, the size of the power plant and the cost of the biomass fuel supply. For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation; thereby reducing transportation costs. The preferred system has transportation distances below 100 miles. The most economical conditions exist when the energy use is located at the site where biomass residues are generated (i.e., at a paper mill or sawmill). These conditions do not exist for Basin Electric because biomass transportation distances coupled with the higher levelized cost compared to a conventional coal-fired power plant hamper the ability to fulfill the need for long-term, cost-effective, and competitive generation of Basin Electric baseload capacity in northeastern Wyoming and western South Dakota. For these reasons, RUS has determined that this alternative does not meet the purpose and need for the project.

B2.2 Biogas

Environmental concerns and rising energy costs for energy and for wastewater treatment have led to a resurgence of interest in anaerobic treatment and new interest in using biogas produced during this treatment of organic wastes. Biomass gasification for power production involves heating biomass in an oxygen-starved environment to produce a medium or low calorific gas. This biogas is then used as fuel in a combined cycle power generation plant that includes a gas turbine topping cycle and a steam turbine bottoming cycle (DOE 2005).

The same types of anaerobic bacteria that produced natural gas also produce methane rich biogas today. Anaerobic digestion by anaerobic bacteria (whose survival requires an environment devoid of oxygen) is a naturally-occurring process (CanREN 2003). Anaerobic bacteria break down, or digest, organic material in the absence of oxygen and produce biogas as a waste product (Basin Electric 2005c). By contrast, aerobic decomposition, or composting, requires large amounts of oxygen and produces heat. “Swamp gas,” which contains methane, is produced by the anaerobic decomposition of wetland vegetation that has settled to the bottom of a marsh, swamp or other wetland.

The second stage of the process is environmentally sensitive to changes in temperature and pH and must be free of oxygen to produce biogas as a waste product. The anaerobic processes can be managed in a "digester" (an airtight tank) or a covered lagoon (a pond used to store manure) for waste treatment. The primary benefits of anaerobic digestion are nutrient recycling, waste treatment, and odor control. Except in very large systems, biogas production is considered a secondary benefit (Basin Electric 2005c).

In most cases, the methane produced by the digester is well-concentrated. Because methane is the principal component of natural gas, it is an excellent source of energy for use either in cogeneration on the electrical grid or simply for fueling boilers at the wastewater treatment plant. The methane captured from an anaerobic digester will naturally contain some impurities, chiefly sulfur, which should be scrubbed prior to pressurization and combustion. Anaerobic digesters are used in municipal wastewater treatment plants and on large farm, dairy, and ranch operations for disposal of animal waste.

Landfill biogas (LFG) is created when organic waste in a landfill naturally decomposes. This gas consists of about 50 percent methane, about 50 percent carbon dioxide, and a small amount of non-methane organic compounds. Instead of allowing LFG to escape into the air, it can be captured, converted, and used as an energy source. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and it helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change.

The various types of biogas can be collected and used as a fuel source to generate electricity using conventional generating technology. Production of electric power from both digester gas and landfill gas has been demonstrated commercially for many years (Renewable Energy Technologies 2002). The DOE Energy Information Administration projects the capital cost component of the levelized cost of biogas power to be approximately $37/MWh in 2009. The total levelized cost of biogas power is projected to be approximately $46/MWh.

Using digester or landfill gas as a fuel in a turbine is environmentally beneficial because biogas is a renewable resource. Pretreatment of the digester or landfill gas is very important to the longterm viability of the engines or turbines. The gas is typically treated to remove hydrogen sulfide, siloxanes, moisture, and particulates prior to combustion. The primary environmental compatibility issue is the air emissions produced by combustion. Air emissions for a turbine firing digester or landfill gas are similar to those of a natural gas-fired combustion turbine. The use of Selective Catalytic Reduction (SCR) for nitrogen oxide (NOx) control and catalytic oxidation for carbon monoxide (CO) control may be required. There are no major issues with biogas concerning water discharge or solid waste/hazardous waste generation. A 20-MW biogas facility will require approximately three acres (1.2 ha). Therefore, 13 of these plants having a total output of 250 MW will require a total area of approximately 39 acres (16 ha).

The current USEPA Landfill Methane Outreach Program landfill and project database lists one landfill site in Wyoming and nine landfill sites in South Dakota that are either candidates or have the potential for landfill gas to produce electric power project (EPA 2006). All of the landfills are located within Basin Electric service territory. One is located in Cheyenne, Wyoming (owned and operated by the City of Cheyenne), and the other located in South Dakota include the Sioux Falls, Rapid City, Brookings, Brown County, Mitchell, Pierre, Vermillion, and Watertown municipal landfills; and the Tri-County Landfill (owned and operated by the Tri-County Landfill Association). No landfills in Wyoming or South Dakota are currently using landfill gas for energy production.

The ability of a landfill to use the LFG for power generation is based on the rate of gas production. Gas production is dependent on the volume of waste in place, the age of the waste, and the moisture content of the waste. Landfills in Wyoming and South Dakota are dry and produce less gas than landfills in other parts of the country. Because of its low population, the total volume of waste produced in Wyoming and South Dakota is less than about 42 other states.

For Basin Electric, the key issues for biogas facilities are the dispersed locations and insufficient quantities of the fuel source. Therefore, the amounts of digester gas and landfill gas resources are limited within the Basin Electric service area. And it is unlikely that biogas power can fulfill the need for 385 MW of highly reliable baseload capacity. Due to the limited availability of the fuel source, RUS has determined that this alternative is not technically feasible.

B2.3 Solid Waste

The municipal solid waste industry includes four components: recycling, composting, landfilling, and waste-to-energy via incineration. MSW is total waste excluding industrial waste, agricultural waste, and sewage sludge. Medical wastes from hospitals and items that can be recycled are also generally excluded from MSW used to generate electricity. As defined by the U.S. EPA, MSW includes durable goods, non-durable goods, containers and packaging, food wastes, yard wastes, and miscellaneous inorganic wastes from residential, commercial, institutional, and industrial sources. Examples from these categories include: appliances, newspapers, clothing, food scraps, boxes, disposable tableware, office and classroom paper, wood pallets, rubber tires, and cafeteria wastes. Waste-to-energy combustion and landfill gas are byproducts of municipal solid waste (EIA 2005).

MSW can be directly combusted in waste-to-energy facilities to generate electricity. Because no new fuel sources are used other than the waste that will otherwise be sent to landfills, MSW is often considered a renewable power source. Although MSW consists mainly of renewable resources such as food, paper, and wood products, it also includes nonrenewable materials derived from fossil fuels, such as tires and plastics (EPA 2005b).

At the power plant, MSW will be unloaded from collection trucks and shredded or processed to ease handling. Recyclable materials will be set aside, and the remaining waste will be fed into a combustion chamber to be burned. The heat released from burning the MSW will be utilized to produce steam, which turns a steam turbine to generate electricity.

Burning MSW produces nitrogen oxides, CO_2, and SO_2 as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Variability in the composition of MSW affects the emissions produced. For example, if MSW containing batteries and tires are burned, toxic materials can be released into the air. A variety of air pollution control technologies are used to reduce toxic air pollutants from MSW power plants (EPA, 2005b). Estimated emissions of criteria air pollutants from a 250-MW MSW electric-generation facility are comparable or lower than a coal-fired resource, however, the emissions of hazardous air pollutants including mercury, cadmium, and toxic organics are considerably higher (SME 2004a).

Power plants that burn MSW are normally smaller than fossil fuel power plants but typically require a similar amount of water per unit of electricity generated. Similar to many older fossil fuel power plants, MSW power plants discharge used water. Pollutants build up in the water used in the MSW power plant boiler and cooling system. In addition, the cooling water from the MSW boiler is considerably warmer when it is discharged than when it was taken. This discharge will require a permit and will have to be monitored (EPA 2005b).

MSW power plants reduce the need for landfill capacity because disposal of ash created by MSW combustion requires less volume and land area as compared to unprocessed MSW. However, because ash and other residues from MSW operations may contain toxic materials, the power plant wastes must be disposed of in an environmentally safe manner to prevent toxic substances from migrating (leaching) into ground-water supplies. Current regulations require MSW ash sampling on a regular basis to determine its hazardous status. Hazardous ash must be managed and disposed of as hazardous waste. Depending on state and local restrictions, nonhazardous ash may be disposed of in a MSW landfill or recycled for use in roads, parking lots, or daily covering for sanitary landfills (EPA 2005b).

The United States has approximately 90 operational MSW-fired power generation plants, generating approximately 2,500 megawatts, or about 0.3 percent of total national power generation. However, because construction costs of new plants have increased, economic factors have limited new construction (EPA 2005b). The capital cost of an MSW power project is approximately $3,500 to $4,000/kW. The total levelized cost of MSW power is projected to be approximately $85/MWh (see Table 2-5). Typically, MSW power plants become economical only when landfills for MSW disposal are not available near the collection area and hauling costs become excessive. The MSW power plants can command a tipping fee to offset the high cost of power production, but these need to be in the $50 to $60/ton range in order for the plant to be competitive. These conditions exist in populous areas such as New York City. Except for small, localized areas, the potential for economical power to be generated in northeastern Wyoming and western South Dakota from MSW does not exist. Basin Electric serves rural areas and does not have a municipal customer base large enough to support a municipal solid waste-to-energy project. There are currently no MSW incinerators operating in the State of Wyoming or South Dakota. For these reasons, RUS has determined that this alternative does not meet the purpose and need for the project.

B3.0 NON-RENEWABLE COMBUSTIBLE ENERGY SOURCES (NATURAL GAS COMBINED CYCLE, MICROTURBINES, PULVERIZED COAL, AND INTEGRATED GASIFICATION COMBINED CYCLE)

B3.1 Natural Gas Simple Cycle Combustion Turbine

Natural Gas Simple Cycle (NGSC) is a type of combustion turbine generator (CTG) application. In simple cycle operation, gas turbines are operated alone, without any recovery of the energy in the hot exhaust gases. Simple cycle gas turbine generators are typically used for peaking or reserve utility power application, which primarily are operated during the peak summer month at less than a total of 2,000 hours per year. Simple cycle applications are rarely used in baseload applications because of the lower heat rate efficiencies. However, CTGs could be used in baseload operation if it was economical to do so.

There are two types of combustion gas turbines: heavy industrial “frame” machines and aeroderivative machines, which are limited in maximum size to about 50 MW. This study looked at two different machines, the General Electric (GE) PG7121EA, which is a “frame” machine, and the GE LM6000, which is an aero-derivative machine. Gas turbine powered plants are preassembled at the factory, skid or baseplate mounted, and shipped to the site along with other major components including the generator, cooling, lube oil, and electrical modules. Because of the pre-assembled modular approach, field erection hours are significantly reduced, particularly as compared to a coal-fired plant.

The capital cost component of the levelized cost of NGSC (LM6000) power is approximately $23/MWh for a plant that runs about 20 percent annual capacity factor. The total levelized cost of NGSC power is projected to be relatively high at approximately $99/MWh for about 1,750 hours of operation in a year or about 20 percent annual capacity factor. If a NGSC were operated at 80 percent annual capacity factor, the levelized cost of power will be about $74/MWh. Most of the power-generation cost for NGSC is from the variable/fuel cost at approximately $66/MWh, assuming the cost of fuel is about $5.50/MMBtu. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Weather and demand are large factors that affect gas prices and are very unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation’s power increasingly being generated by natural gas, demand also spikes in summer, when companies fire up peaking plants to provide more power for cooling needs.

NGSC cannot meet Basin Electric's need for long-term, cost-effective, and competitive energy generation due to the higher levelized cost and instability in the fuel cost. For these reasons, RUS has determined that this alternative will not be evaluated in detail.

B3.2 Natural Gas Combined Cycle

Natural Gas Combined Cycle (NCCC) is a type of combustion turbine generator (CTG) application. Combined cycle operation consists of one or more CTGs exhausting to one or more heat recovery steam generators (HRSG). The resulting steam generated by the HRSG is then used to power a steam turbine generator (STG).

The capital cost component of the levelized cost of NGCC power is approximately $16/MWh for a plant that runs about 60% annual capacity factor. The total levelized cost of NGCC power is projected to be approximately $60/MWh for about 5,250 hours of operation in a year or about 60% annual capacity factor (Basin Electric 2005a). If a NGCC were operated at 80% annual capacity factor, the levelized cost of power will be about $55/MWh. Most of the power-generation cost for NGCC is from the variable/fuel cost at approximately $41/MWh, assuming the cost of fuel is about $5.50/MMBtu. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Weather and demand are large factors that affect gas prices and are very unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation's power increasingly being generated by natural gas, demand also spikes in summer, when companies fire up peaking plants to provide more power for cooling needs (Basin Electric 2005a).

NGSC cannot meet Basin Electric's need for long-term, cost-effective, and competitive energy generation due to the higher levelized cost and instability in the fuel cost. For these reasons, RUS has determined that this alternative will not be evaluated in detail.

B3.3 Microturbines

Microturbines are small gas turbines that burn gaseous and liquid fuels to create high-speed rotation that turns an electrical generator. Microturbines entered field-testing around 1997 and began initial commercial service in 2000. The size range for microturbines available and under development is from 30-350 kW, compared to conventional gas turbine sizes that range from approximately 1 MW to 500 MW (Basin Electric 2005a). They are able to operate on a variety of fuels, including natural gas, sour gas (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene and diesel fuel/heating oil. The design life of microturbines is estimated to be in the 40,000 to 80,000 hour range. While units have demonstrated reliability, they have not been in commercial service long enough to provide definitive performance and operating life data (Basin Electric 2005a).

The total installed cost of a 30 kW microturbine is approximately $2500/kW, while a 350 kW microturbine is expected to have a total installed cost of $1300/kW. Microturbines are still on a learning curve in terms of maintenance, as initial commercial units have seen only a few years of service so far. Most manufacturers offer service contracts for specialized maintenance priced at about $0.01/kWh. This cost information was based on information gathered by Energy Nexus

Group for the USEPA. With the small number of units in commercial service, information is not yet sufficient to draw conclusions about reliability and availability of microturbines. The basic design and low number of moving parts hold the potential for systems of high availability; manufacturers have targeted availabilities of 98 to 99% (Basin Electric 2005a).

Microturbines cannot fulfill Basin Electric's long-term energy needs due to high installed cost, the large number of microturbines be needed to fulfill the capacity requirement, and the instability in the cost of fuel (Basin Electric 2005a). For these reasons, RUS has determined that this alternative will not be evaluated in detail.

B3.4 Pulverized Coal

PC plants represent the most mature of coal-based power generation technologies considered in this assessment. Modern PC plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Units operate at close to atmospheric pressure, simplifying the passage of materials through the plant, reducing vessel construction cost, and allowing onsite fabrication of boilers. A typical process flow diagram for a PC unit is shown in Figure B7.

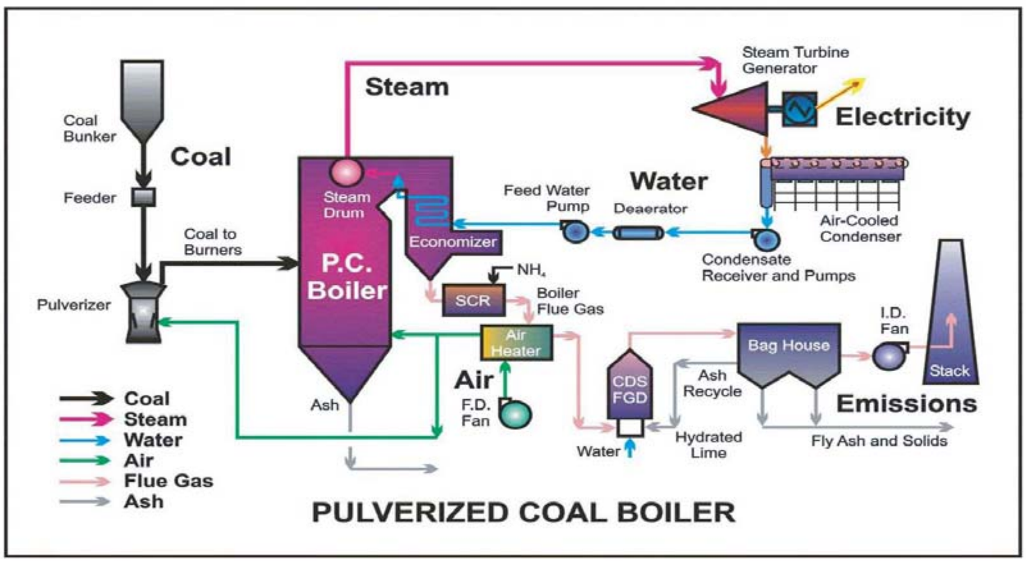


Figure B7 – Pulverized Coal Unit Process Flow Diagram

The concept of burning coal that has been pulverized into a fine powder stems from the fact that if the coal is made fine enough it will burn almost as easily and efficiently as a gas. Crushed coal from the silos is fed into the pulverizers along with air preheated to about 580°F. The hot air dries the fine coal powder and conveys it to the burners in the boiler. The burners mix the powdered coal in the air suspension with additional preheated combustion air and force it out of nozzles similar in action to fuel being atomized by fuel injectors. Combustion takes place at 2400°F to 3100°F, depending largely on coal rank. Steam is generated, driving a steam turbine-generator. Steam generated in the boiler is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

The boiler produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, nitrogen oxide (NOx), and sulfur dioxide (SO_2). The pollution control equipment includes either a fabric filter or electrostatic precipitator for particulate control (fly ash), selective catalytic reduction (SCR) for removal of NOx, and a flue gas desulfurization (FGD) system for removal of SO_2. Limestone is required as the reagent for the most common wet FGD process, limestone-forced oxidation desulfurization. Dry FDG processes are more commonly used on lower sulfur western coal, using lime as the reagent and providing significant savings in water consumption over wet FGD systems. A lime or limestone storage and handling system is a required design consideration with this system.

Most of the PRB coal used for electricity generation is burned in PC plants. Initially, PC units encountered many problems burning this coal. Over time, PC boiler designs have been refined based on the specific characteristics of the fuel, such as moisture content, ash composition and softening temperature, and sulfur content allowing PC boilers to now successfully burn PRB coal.

PC has been used for large utility units for more than 50 years. The technology has evolved in areas such as distributed control systems and emissions control to improve performance. A description of both subcritical and supercritical PC boilers is provided below.

Subcritical Pulverized Coal Boilers

The typical coal units of 250 MW and above that have been built in the U.S. since 1960 are subcritical PC designs using a 2,400 pounds per square inch gauge (psig)/1000°F/1000°F single reheat steam power cycle, providing a net plant efficiency (higher heating value [HHV])1 of approximately 36 percent based on a bituminous coal fuel. Occasionally, a 2,400 psig/1050°F/1050°F steam cycle has been employed.

Supercritical Pulverized Coal Boilers

A typical commercial supercritical PC design uses a 3,500 psig/1050°F/1050°F single reheat steam power cycle, providing an HHV of approximately 39 percent.

In Europe, the once-through boiler is traditionally used. This type of boiler does not require differentials between water and steam phases to operate. It was therefore logical for steam pressures to continue to be increased above 2,400 psig in the quest for greater unit efficiency. In Japan, the Ministry of Trade and Industry encouraged a relatively early and universal change to supercritical steam conditions, and now virtually all steam boiler/turbine units above 350 MW operating in Japan use supercritical steam conditions.

While the majority of coal-fired units in the U.S. have used subcritical drum boilers, some supercritical units have also been built. Early supercritical units experienced various reliability problems, but these have generally been attributed to design practices used to reduce capital costs during that era. American Electric Power of Columbus, Ohio, an electrical utility provider to 11 states, demonstrated the first commercial use of supercritical technology in 1956. Between 1956 and the mid-1970s, substantial experience was accumulated. Most of the supercritical units built in this period continue to operate today, and many now have good availability records.

[1] Net Plant Efficiency is defined as the net electrical output of the plant divided by the higher heating value (HHV) fuel consumption of the plant.

Ameren, an electric utility provider in Missouri and Illinois, continues to operate 1,000-MW supercritical units built in 1966 and 1968. American Electric Power has units of 600, 800, and 1,300 MW that entered service between 1968 and 1990.

B3.5 Circulating Fluidized Bed

The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to produce a coarser material. A typical process flow diagram for a CFB unit is shown in FigureB8. The plant fuel handling system unloads and stacks out the fuel, crushes or otherwise prepares it for combustion, and then reclaims the fuel, as required. In the CFB, the fuel is combusted to produce steam. The steam is then conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

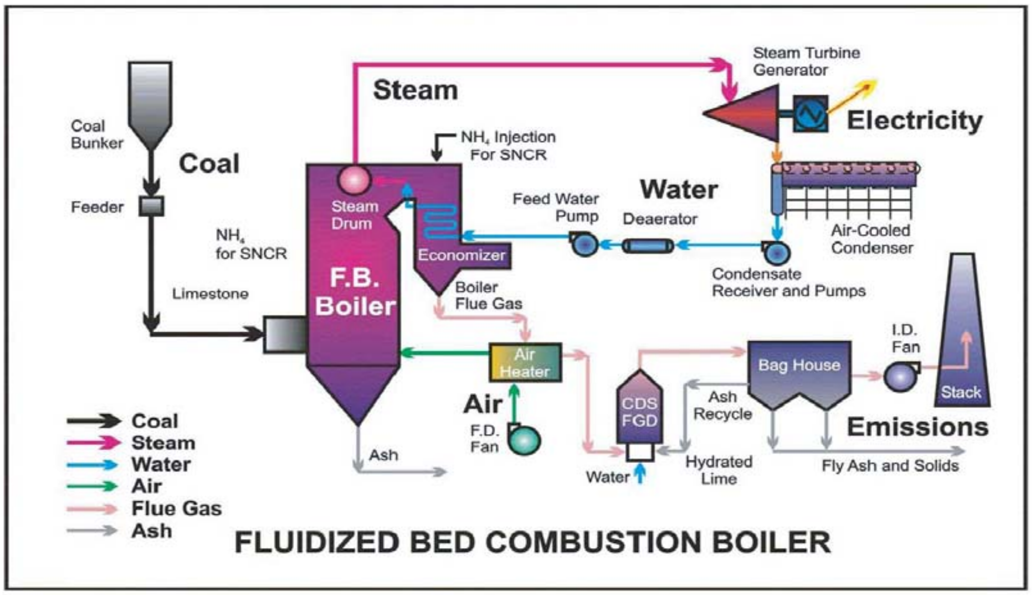


Figure B8 – Circulating Fluidized Bed Unit Process Flow Diagram

CFBs are designed for the particular coal to be used. The method is principally of value for low-grade, high-ash coals that are difficult to pulverize and that may have variable combustion characteristics. It is also suitable for co-firing coal with low-grade fuels, including some waste materials. The advantage of fuel flexibility often mentioned in connection with CFB units can be misleading. The combustion portion of the process is inherently more flexible than PC, but material-handling systems must be designed to handle larger quantities associated with lower quality fuels. Once built, the unit operates most efficiently with whatever design fuel is specified.

Most existing utility CFB units burn bituminous coal, anthracite coal waste, or lignite coal. The operating history of utility CFB boilers burning PRB or other types of sub-bituminous coal is limited. CFB technology typically has an economic advantage only when used with high ash and/or high-sulfur fuels. Therefore, bituminous coal, petroleum coke, coal waste, lignite, and biomass fuels are the typical applications for CFB technology.

PRB coals may also have a tendency to produce small particle size (fine) fly ash that makes it more difficult to maintain the required bed volume in a CFB unit. Therefore, additional quantities of inert materials, such as sand and limestone, may be required for a CFB unit burning low- sulfur/low-ash PRB coals.

CFB power plants have demonstrated technical feasibility in commercial utility applications for approximately 20 years. The technology has evolved during that time to improve its technical performance; however, an economic analysis determined that CFB was not the technology best suited for the Fork Station.

B3.6 Integrated Gasification Combined Cycle

IGCC is used in coal-based power generation where coal reacts with steam, oxygen or air at high temperature to produce a gaseous mixture consisting primarily of hydrogen (H_2) and CO. A typical process flow diagram for an IGCC unit is shown in Figure B9.

To produce a synthesis gas suitable for use in the combustion turbine portion of a combined-cycle unit, the gaseous mixture requires cooling and cleanup to remove contaminants and pollutants. The combined-cycle portion of the plant is similar to a conventional combined cycle. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 200 to 400 Btu gas, and use of steam produced via heat recovery from the raw gas and from the combustion turbine exhaust heat recovery steam generator. Specifics of a plant design are influenced by the gasification process and matching coal supply, degree of heat recovery, and methods to clean up the gas.

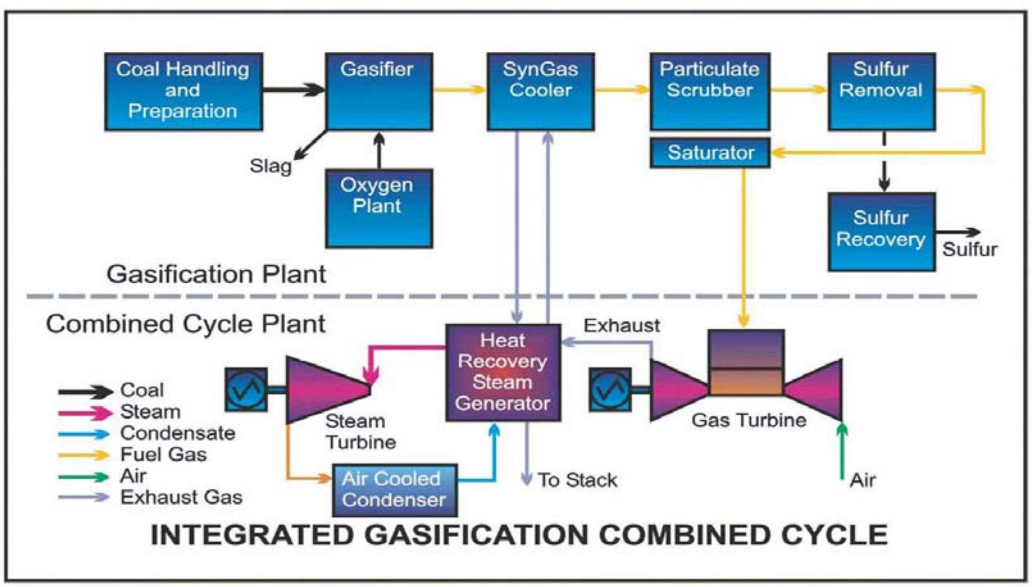


Figure B9 – Integrated Gasification Combined-Cycle Process Flow Diagram

Coal gasification takes place in the presence of a controlled "shortage" of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurized reactor, and the product is a mixture of CO, H_2, and CO_2 (called synthesis gas, syngas, or fuel gas). The sulfur present in the fuel mainly forms hydrogen sulfide (H_2S), but there is also a small amount of carbonyl sulfide (COS). The H_2S can be more readily removed than COS in gas cleanup processes; therefore, a hydrolysis process is typically used to convert COS to H_2S. Although there is no NO_x formed during gasification, some is formed when the fuel gas or syngas is subsequently burned in the combustion turbines. The product gas is cleaned and then burned with air, generating combustion products at high temperatures and pressures.

IGCC has been demonstrated in a few commercial-scale facilities. A variety of coals have been gasified, the resulting gases have been cleaned up to allow use in combustion turbines, and electricity has been generated. However, capital cost and performance in a number of areas including high-temperature heat recovery and hot-gas cleanup, have proven problematic.

An important part of achieving an attractive heat rate is generation of high-pressure and temperature steam from the high-temperature raw gas generated by gasifying coal. The temperature of the raw gas is dependent on the gasification process and the coal. Slagging gasifiers, such as the Texaco process, typically generate gases in the 2500°F to 2800°F range. These high-temperature gases containing corrosive compounds such as H_2S create a very demanding environment for the generation of high-pressure and high-temperature steam. The alternative of not recovering the heat in the raw gas, such as direct quenching of the gas, results in lower efficiencies.

It is also attractive from an efficiency perspective to provide clean gas to the combustion turbine at an elevated temperature without cooling and reheating; hence, the desire to use hot-gas cleanup. This demanding service has not been reliably demonstrated in a commercial application, resulting in less efficient approaches being used for current plants.

The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies than PC plants and may be able to match the environmental performance of gas-fired plants. However, the thermal efficiencies of new PC plants using superheated steam have also increased, as has their environmental performance.

The U.S. plants are part of the DOE Clean Coal Program, and the European plants are part of the Thermie Programme. The DOE has partially funded the design and construction of the U.S. plants, as well as the operating costs for the first few years. The Wabash River plant was a repowering project, but from the point of view of demonstrating the viability of various systems, it is effectively a new plant, even though tied to an existing steam turbine. The Cool Water and Louisiana Gasification Technology, Inc. (LGTI) projects were the first commercial-scale IGCC projects constructed in the U.S. Both were constructed with guaranteed price support from the U.S. Synthetic Fuels Corporation but were closed once the duration of the price guarantee period expired.

The only commercial size IGCC demonstration plant that has operated with PRB coal fuel was the 160-MW Dow Chemical LGTI plant in Plaquemine, Louisiana. This plant used an oxygenblown E-Gas entrained flow gasifier and was reported to have operated successfully from 1987 to 1995 when the plant closed.

Current development of IGCC focuses on achieving high thermal efficiencies with low levels of emissions. The goal with IGCC is to reach efficiencies of more than 40 percent and possibly as high as 45 percent. Higher efficiencies are possible when high gas inlet temperatures to the gas turbine can be achieved. At the moment, the gas cleaning stages for particulates and sulfur removal can be carried out only at relatively low temperatures, which restrict the overall efficiency obtainable.

An IGCC plant has the potential for reduced emissions of SO_2, NO_x, mercury (Hg), and particulates, compared to levels produced by conventional PC and CFB units. SO_2 removal of up to 99 percent and Hg removal of approximately 90 percent is possible in the gas treatment system downstream from the gasifier. Particulates are removed to levels approaching natural gas-fired combustion turbines. NO_x emissions from the gas turbines are anticipated to be similar to emissions from natural gas-fired combustion turbines. Based on a BACT analysis, additional controls may be required, including SCR for NO_x reduction, and catalytic oxidation for CO reduction synthesis gas during plant startups, shutdowns, and upsets; and from miscellaneous support equipment such as diesel or natural gas emergency generators and fire pumps.

Table B2 compares the proposed Dry Fork Station Project PC emission rates with the current annual emission rates from existing CFB commercial plants and from existing U.S. IGCC demonstration plants.

TABLE B2 – Comparison of Coal Combustion Technology Emission Rates

Pollutant	Emission Rates for Coal Combustion Technologies (Lb/MMBtu)		
	PC (Proposed Dry Fork Station)	**CFB (Existing U.S. Commercial Plants)**	**IGCC (Existing U.S. Demonstration Plants)***
SO_2	0.10	0.10	0.17
NO_x	0.07	0.09	0.09
PM_{10}**	0.017	0.019	0.011
CO	0.15	0.15	0.045
VOC	0.0037	0.0037	0.0021

Notes:
*Public Service Company of Indiana (PSI) Energy Wabash River Station and Tampa Electric Company, Polk Power Station Existing IGCC Demonstration Plants
**PM_{10} includes filterable and condensable portions.

An IGCC unit for the Dry Fork Station Project will have two primary liquid effluents: blowdown from the BFW purification system and water blowdown. Less blowdown occurs from the BFW purification system compared to a PC or CFB unit because the steam cycle in an IGCC plant typically produces less than 40 percent of the plant's power. However, BFW makeup may be the same as, or even larger, than a PC- or CFB-based plant of comparable output, even if it is well designed, operated, and maintained. A coal gasification process may consume significant quantities of BFW in tap purges, pump seals, intermittent equipment flushes, synthesis gas saturation for NO_x control, and direct steam injection into the gasifier as a reactant and/or temperature moderator.

Water blowdown is typically high in dissolved solids and gases, along with the various ionic species, such as sulfide, chloride, ammonium, and cyanide, washed from the synthesis gas. The Wabash River IGCC plant installed an add-on mechanical vapor recompression system in 2001 to better control arsenic, cyanide, and selenium in the wastewater stream.

As with the PC and CFB power units, dry cooling and zero liquid discharge systems could be used to reduce overall water consumption and discharge. The Tampa Electric Polk IGCC plant treats process water blowdown with ammonia stripping, vapor compression concentration, and crystallization to completely eliminate process water discharge.

Liquid wastes will also include auxiliary cooling tower blowdown and chemicals associated with water treatment. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Storm water discharge permits and an SWPPP will also be required as a condition of approval.