

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 11 – Electricity Producing Options

This chapter outlines potential systems for producing electricity at ethanol plants. It was primarily prepared by project participants at RMT Inc.

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants Report for Task 11, “Electricity-Producing Options”

Background of the Task

This project concerns the use of biomass as the proximate energy source for producing electricity. Electricity-producing technologies based on a proximate energy source other than biomass, such as photovoltaics, geothermal, hydro, wind, etc., are therefore not within the scope of this project, and will not be evaluated.

There are, at present, two applicable technologies for using biomass to produce electricity on a commercial scale: rotating generators and fuel cells. By far the predominant means of producing commercial-scale electricity is with rotating generators. The generators are similar in operation (although differing in design details and control systems), regardless of the motive force used to spin them (steam turbines, combustion turbines, wind turbines, water turbines, etc.). The primary differences in the electricity-producing systems are thus in the components used to supply and support the rotating generator. Likewise, fuel cells are similar in operation (although differing in design details, especially regarding fuel pretreatment), regardless of the source of the fuel. It is primarily the supply and support systems that differ. Because the electricity-producing component of the energy systems is essentially independent of the motive force and/or fuel, this chapter examines the relevant details of the different supply/support systems as they relate to generating electricity using biomass fuel at ethanol plants.

Steam Turbine–Based Systems

In a steam turbine–based system, high-pressure steam is used to power a turbine, which is in turn connected to an electric generator. There are two primary means of producing the steam for such systems (direct-fired or heat recovery), and two major modes of operation of steam turbines (letdown and condensing). All of these means are applicable to the use of biomass fuel in ethanol plants.

The steam-producing units can be either of the direct-fired or of the heat recovery type. In a direct-fired unit (whether it is conventional or fluidized bed), fuel is combusted within the unit, and the steam-generating components are integral with the combustion unit. Direct-fired units may be of the “fire tube” or “water tube” configuration. In the fire tube configuration, the hot combustion gases pass through a series of tubes immersed in a vessel of water. In the water tube configuration, water passes through a series of tubes, located inside the combustion chamber and/or in an adjacent chamber directly connected to the combustion chamber. Especially for larger units, the water tube configuration is more efficient and can produce higher steam pressures and temperatures, and is by far the predominant configuration. Direct-

fired units are widely used in fuel ethanol plants, for both steam generation and for pollutant incineration.

In a heat recovery type steam-producing unit, usually referred to as a heat recovery steam generator, or an “HRSG”, the steam generation unit is separate from the combustion unit, although usually located in proximity to it. HRSGs are almost always of the water tube design. While an HRSG can be designed to meet essentially any steam-producing need, in practice, they are often used to recover somewhat lower grade heat from systems in which higher grade heat has been used for some other purpose (such as turning a combustion turbine or incinerating pollutants). HRSGs are therefore more common in lower (up to 150 psi or so) to medium (several hundred psi) pressure applications. HRSGs are widely used in fuel ethanol plants.

While steam turbines are of a similar basic design, with details dependent on specifics of the system being served, there are two basic operational modes. In a “letdown” steam turbine, only a portion of the available steam pressure is used to rotate the turbine (and thus generate electricity for the purposes of this project), with steam exiting the turbine at sufficient pressure to perform some other function. In a typical fuel ethanol plant, process steam is generated at around 150 psi. If a letdown turbine were used to generate electricity, the steam might enter the turbine at 600 psi and leave it at 150 psi, with the pressure reduction used to generate electricity.

The second basic turbine operational mode is “condensing,” where the maximum pressure drop is achieved across the turbine by condensing the exiting steam. This mode of operation is more efficient than the letdown mode because, by condensing the exiting steam, an actual vacuum can be created at the discharge side of the turbine, thus maximizing the differential pressure drop across the turbine. In addition, because the pressure on the exiting side of the turbine is as low as possible and is uniform, and because this mode of operation can readily handle varying conditions, the condensing turbine can enhance the stability of the entire steam system, can aid in handling transient loads, and can help avoid process disruptions. However, to achieve the condensing requires considerable amounts of cooling water, and the lower the temperature of the cooling water, the better the system works. If a facility cannot be located near a large supply of clean, low-temperature water, an evaporative cooling tower may be needed. Although most fuel ethanol plants have cooling towers, the cooling towers are probably not sized to provide cooling for a condensing turbine, and additions or changes in operation of the cooling tower may be needed to accommodate the condensing turbine.

The most efficient overall system design may be to use both a letdown and a condensing turbine. Steam feed to the letdown turbine would be constant, resulting in a constant stream of process steam out of the letdown turbine, and a constant generation of electricity. This also allows for a uniform and highly efficient use of the steam-generating unit. Steam exiting the letdown turbine would go to both process and the condensing turbine, with any excess process steam going to the condensing turbine. Variations in the use of process steam would be

handled by the condensing turbine, helping the management of the process. Figures EPO-1 and EPO-2 show conceptual fluidized bed combustion and gasification systems with both letdown and condensing turbines.

Combustion Turbine–Based Systems

In a combustion turbine system, the combustion unit and the rotating turbine are a single unit. Combustion of fuel inside the unit produces the power needed to operate and rotate the turbine. The turbine is connected to an electric generator through a speed reducer. The typical large combustion turbine is similar to the jet engines that power aircraft.

Only gaseous or liquid fuels can be used in combustion turbines. The fuels must be free of particulates, agglomerative materials, and any component that would cause undue wear on system components, especially turbine blades. Liquid fuels can be injected into the combustion chambers, whereas gaseous fuels must be compressed before injection. Compression of the gaseous fuels can require considerable energy, especially if the heat content of the fuel is low.

In a simple-cycle system, the exhaust gases from the combustion turbine are discharged to a stack. This is a common configuration for electric “peaking” plants that operate intermittently, for short periods. For continuous operations, much higher efficiency is achieved if the combustion turbine is combined with an HRSG, as described in the next section. Such a configuration also produces process steam.

Combined Combustion Turbine and Steam Turbine Systems

The hot exhaust gases from the combustion turbine can be directed into an HRSG to generate steam. Such a system is called a combined-cycle system. Once the steam is generated in the HRSG, the rest of the steam turbine and electric generator systems are the same as for the steam turbine systems described above. If more energy is needed from the HRSG (for example, if it is desired to generate larger quantities of high-pressure steam), the system can be designed to introduce additional fuel into the HRSG. Figure EPO-3 shows a conceptual fluidized bed gasification system with a combined-cycle system.

The overall efficiency of combined-cycle systems is much higher than that of simple-cycle systems. In addition, the combined-cycle system generates process steam that the plant needs.

Sterling Engine – Based Technology

Sterling engines produce energy from external heat based on temperature differences causing the expansion and contraction of gases. The external heat source could be generated from a variety of fuel sources, including biomass. Sterling engines have proved effective for small-scale energy production (up to 150 kw). However, because of their high capital costs and size, sterling engines are not suitable for large-scale industrial applications.

Water Considerations

Water is consumed in the ethanol production process, both as a chemical component and as cooling water for various processes. These production processes are essentially independent of the plant energy center, and are not included in this analysis.

The simple-cycle combustion turbine uses little water, and is not considered further in this analysis of water use. Likewise, the electricity generators do not use water.

All of the steam-based energy systems use water for boiler feed. The boiler feed water is treated to remove as much sediment and problematic dissolved solids as possible by using industrial feed water pretreatment systems. These processes generate a wastewater stream containing the removed material and any water treatment chemicals. This wastewater stream is either discharged from the plant or returned to the ethanol production process. The treated boiler feed water becomes steam in the steam generator. After being used in the process (primarily for low-level process heat and for distillation), most of the steam is returned to the steam generator in the form of condensate. The buildup of sediment and dissolved solids in the boiler water limits the number of times the sequence of water-steam-water (called a “cycle”) can continue. To maintain acceptable levels of sediment and dissolved solids in the boiler, there is a purge (called blowdown) of boiler water from the boiler, and an equal input of pretreated boiler feed water into the boiler. All else being equal, the purer the boiler feed water, the greater the number of cycles that can be maintained. Because the blowdown is hot, energy can be saved if the blowdown can be recycled to the production process or sometimes additional heat recovery is implemented.

The amount of water used to produce boiler feed water is primarily a function of the amount of steam used, the quality of the available raw water supply, and the ethanol production process details. The type of steam generator used will have little impact on the amount of boiler feed water needed.

For one of the technologies included in this project, fluidized bed gasification, the syngas conditioning step may include syngas cooling. As much as possible, the syngas cooling would be done in a manner promoting the maximum recovery of heat from the raw syngas. If additional cooling is needed, or if maximization of heat recovery from the raw syngas is not feasible, cooling water may be needed to achieve the desired degree of cooling. The cooling water would likely be taken as a side stream from the main plant cooling tower, although additional capacity may have to be added to the cooling tower to accommodate the syngas heat load. Since the cooling tower uses evaporation as the means of cooling, such a heat load would result in consumptive use of water.

Of the two types of steam turbines considered in this project, the letdown turbine does not use cooling water. The steam discharging from the letdown turbine enters the production process,

from which it is returned to the steam generator as condensate. Cooling water is used for the production process, the same as if there was no letdown turbine in the system. If excess steam entered the letdown turbine (such as to attempt to generate an amount of electricity greater than the amount corresponding to the process steam needs of the plant), the resultant excess steam discharging from the letdown turbine would either have to be vented or routed to the process. In the latter event, however, since the amount of steam needed for the production process is carefully balanced, and since most plants do not have significant excess production cooling capacity or excess production condensate handling capacity, a serious imbalance, or even a process shutdown, would occur.

The second type of steam turbine, the condensing turbine, requires substantial quantities of cooling water to achieve condensation of the steam discharging from the turbine, and thus provide the maximum pressure drop across the turbine. Most ethanol plants would not have sufficient excess cooling capacity to accommodate the condensing turbine. Additional cooling capacity would need to be added, by either once-through (if the plant had access to a suitable source of cooling water) or recirculating evaporative cooling (cooling tower) systems. To offset the disadvantage of needing this additional cooling water, and as described above, the condensing turbine offers significant advantages to a combined heat and power (CHP) system by providing both highly efficient operation and the ability to smoothly handle variations in steam load. This in turn allows for stable, efficient operation of the remainder of the system.

Ash Considerations

The ash from the combustion or gasification units is not affected by the type of steam turbine used, or by the electricity generator. The ash (or total residue) from the gasification system will be affected by the type of steam generator used. If the syngas is directly burned in a boiler, little if any pretreatment will be needed, and little if any residue will be generated in the pretreatment step. The ash from the boiler will be essentially the same chemically as the ash from the gasification unit itself, although the particle size distribution will likely be affected, with the ash from the boiler likely being finer.

For use in a combustion turbine, or for use as a general replacement for natural gas in various systems in the plant, the syngas will need to be pretreated, and the pretreatment will produce additional and different residues. Typical pretreatment begins with cooling. The cooling helps remove moisture, and allows for additional pretreatment using lower cost, conventional devices such as fabric filters. The cooling step may produce tarry condensates and potentially, depending on the degree of cooling, a liquid waste stream containing organic condensables, water, and water-soluble components. This material would need to be processed before either reintroduction into the gasifier (for the organics phase) or discharge from the plant (for the aqueous phase). The material captured in the post-cooling step, such as in the fabric filter, would be expected to differ chemically from the ash from the gasifier itself, in that the captured

material would likely be only partially oxidized. Managing this material would depend on the detailed design of the overall system.

Maintenance Considerations

As a general rule, the simpler the system and the fewer the components, the lower the maintenance. A simple boiler, fueled with natural gas, and generating only medium-pressure (about 150 psi) process steam usually requires little maintenance, and will be used as the base case for this project.

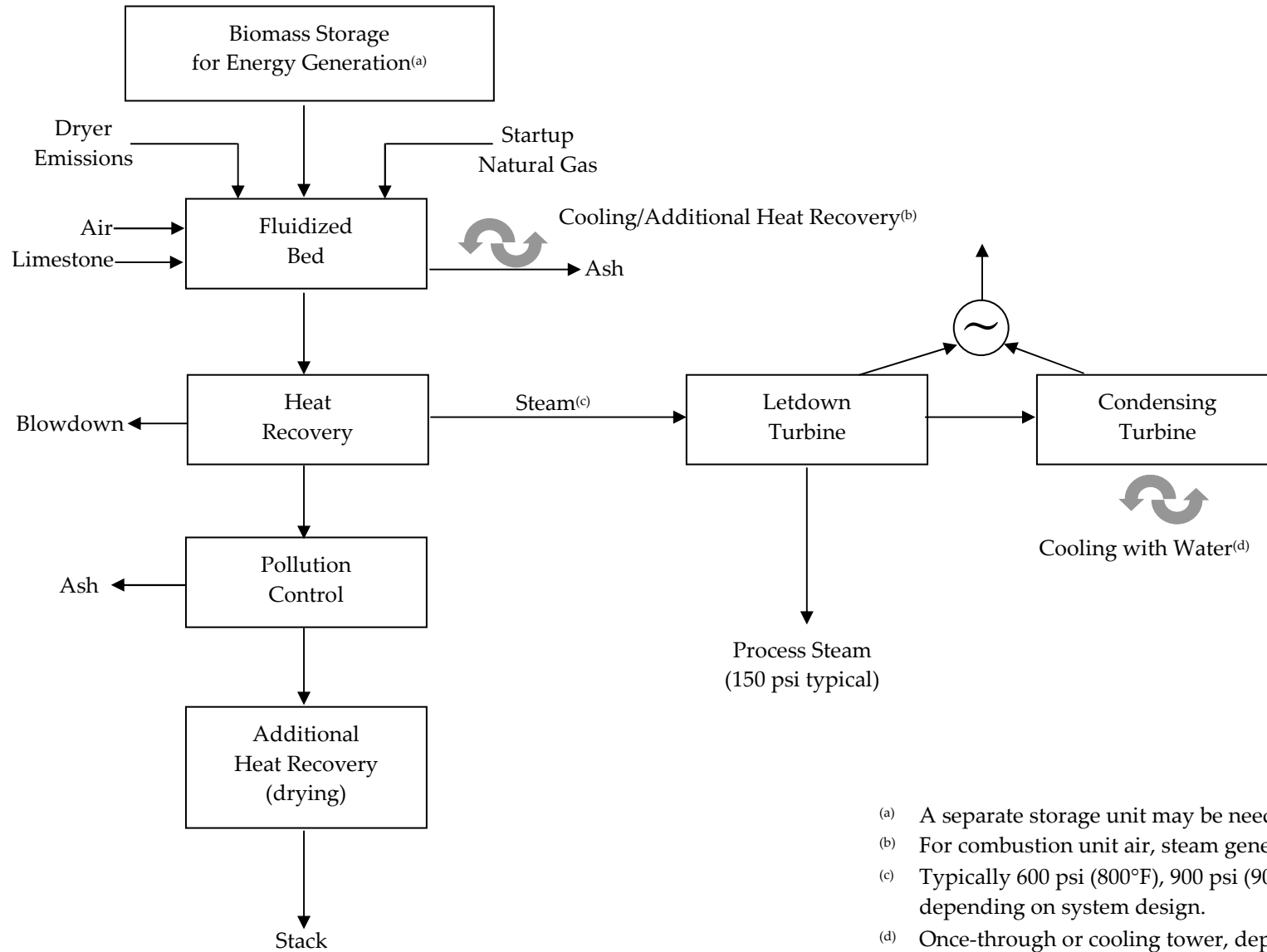
The types of electricity generators that will likely be used for the CHP systems considered in this project require very little maintenance, and will not be considered further in this analysis of maintenance considerations. Likewise, assuming proper boiler feed water and condensate treatment, the types of steam turbines that will likely be used for the CHP systems considered in this project require little but routine maintenance of a type that can likely be performed by plant maintenance staff, and therefore will not be considered further in this analysis of maintenance considerations.

Because of the physical characteristics of the biomass fuels, their biodegradability, and their being subject to freezing, the biomass fuel storage, handling, and feed systems may be quite complex, and will likely require considerable maintenance. A severe incident, such as freezing up of feed materials, with associated damage to piping, pumps, and other system components, could be very costly. And, the indirect cost of the interruption of plant operations, and possibly the need to discard batches, could result in even higher costs. Such costs could be lowered somewhat if an alternative fuel supply (likely natural gas) was readily available and if the CHP systems could be rapidly switched to the alternative fuel, but the possible demand charges for such alternative fuels could be substantial. Also, if plant systems were set up for near “real-time” use of the biomass materials as fuels, the limited storage capacity for the coproducts would limit the amount of production the plant could continue. Additional biomass storage may not be feasible, both because of cost and because of the material handling challenges. The design of individual plant systems would have to take these considerations into account.

Fluidized bed systems require additional maintenance, with gasification systems requiring somewhat more maintenance than combustion systems.

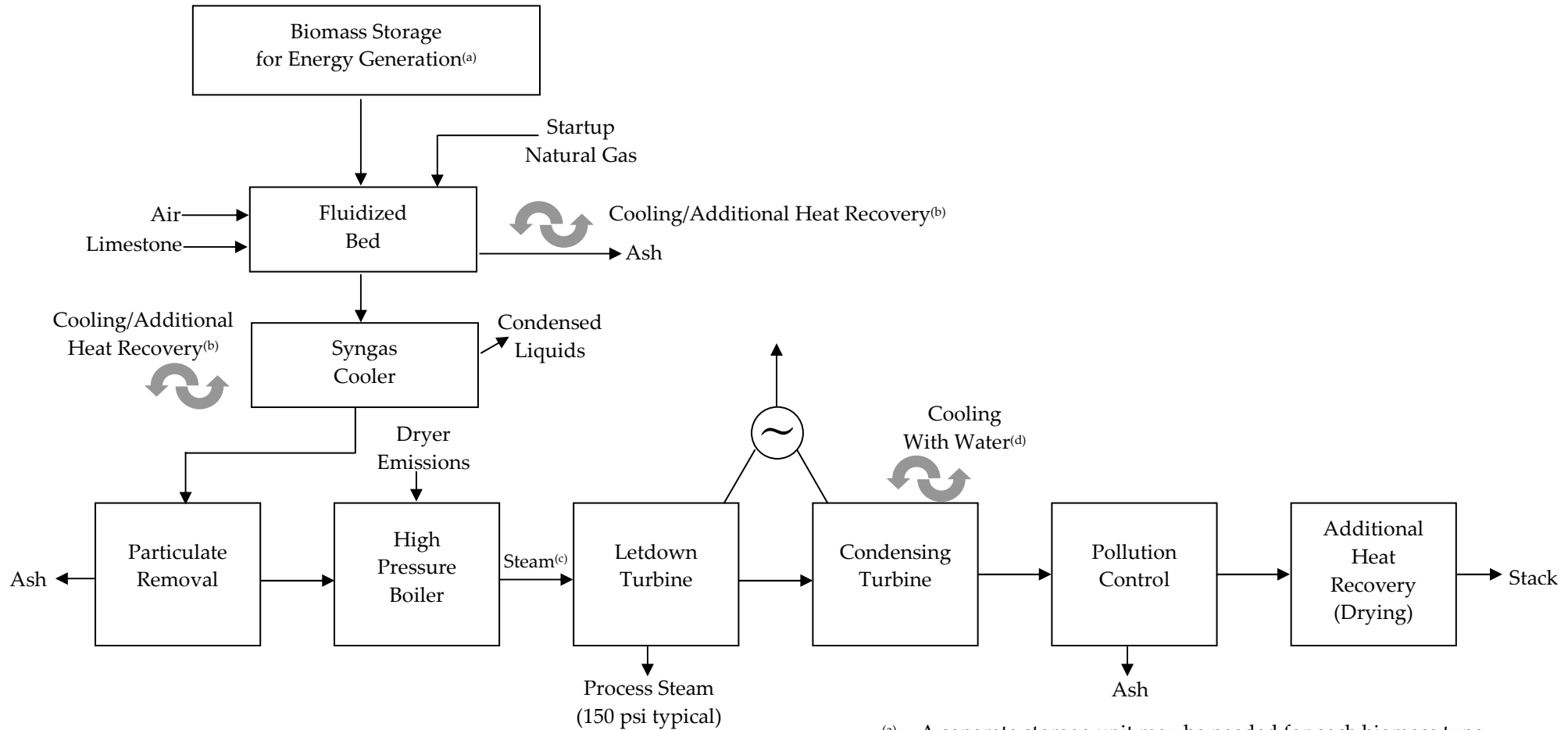
Figures

**Figure EPO-1
Fluidized Bed Combustion with Electricity Generation
and Process Heat**



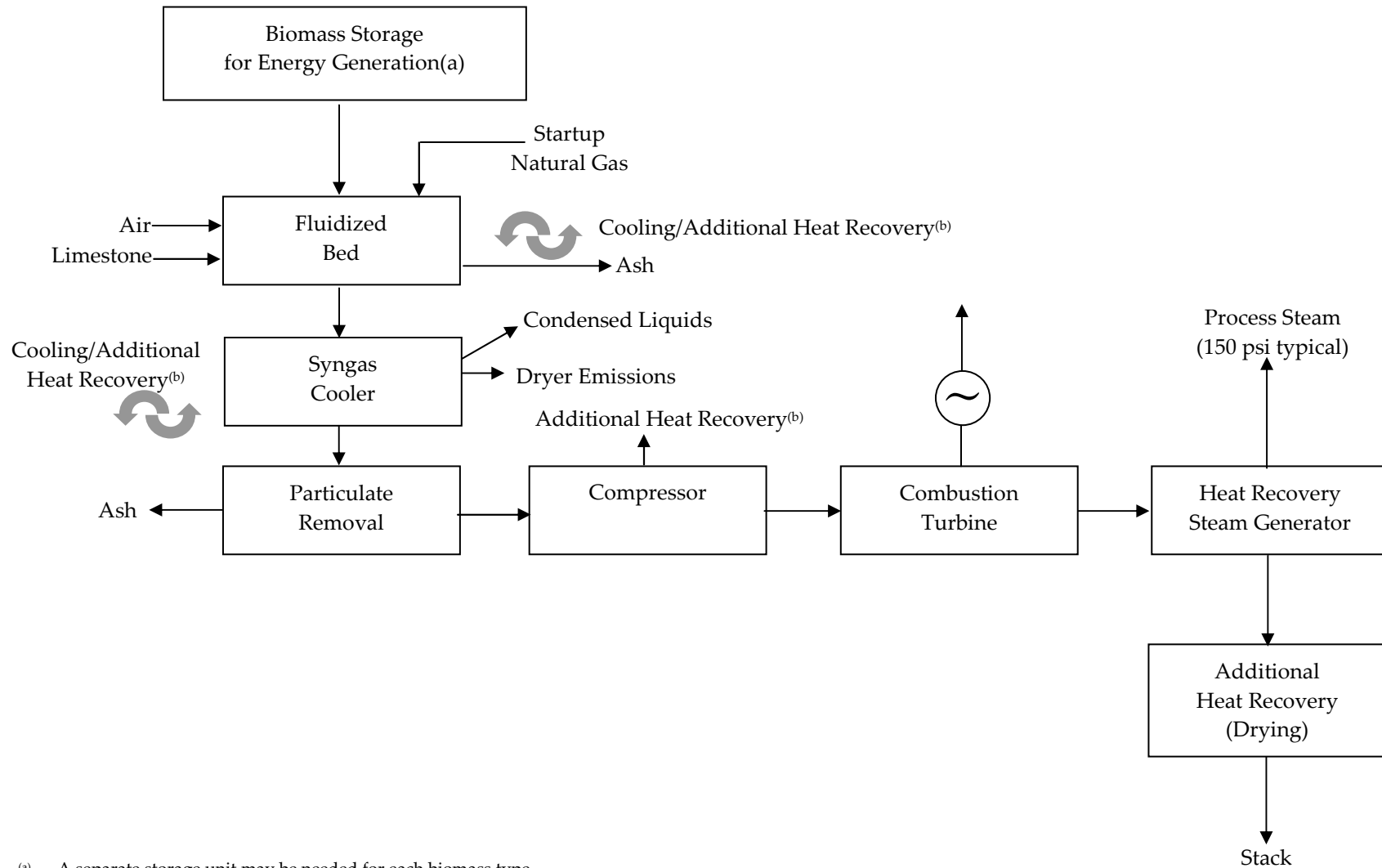
- (a) A separate storage unit may be needed for each biomass type.
- (b) For combustion unit air, steam generator feed water, or drying.
- (c) Typically 600 psi (800°F), 900 psi (900°F), or 1,500 psi (950°F), depending on system design.
- (d) Once-through or cooling tower, depending on site conditions and system design.

**Figure EPO-2
Fluidized Bed Gasification with Electricity Generation and Process Heat
(Steam Turbine)**



- (a) A separate storage unit may be needed for each biomass type.
- (b) For combustion unit air, steam generator feed water, or drying.
- (c) Typically 600 psi (800°F), 900 psi (900°F), or 1,500 psi (950°F), depending on system design.

Figure EPO-3
Fluidized Bed Gasification with Electricity Generation and Process Heat
(Combustion Turbine)



(a) A separate storage unit may be needed for each biomass type.
 (b) For combustion unit air, steam generator feed water, or drying.