

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 12 – Compatibility with Existing Plant Combustion Systems

This chapter outlines potential advantages as well as disadvantages of incorporating biomass energy generation in existing 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 12, “Compatibility with Existing Plant Combustion Systems”

Background of the Task

An important element of this project is the evaluation of the potential for use of the co-product and corn stover fuels with existing ethanol plant infrastructure. Utilizing existing plant infrastructure could substantially lessen the capital requirements for using the co-product and corn stover fuels, could speed the processing of necessary construction and environmental permits, and could minimize the amount of new operations and maintenance (O&M) experience needed by plant staff. On the other hand, existing plant energy systems have generally been carefully designed to be optimal for the particular plant needs, and modifying the systems can be costly and problematic, including potentially increasing O&M costs and lowering energy utilization efficiencies.

All fuel ethanol plants use steam in the ethanol production and refining process, and some plants use steam in DDGS driers. Smaller amounts of steam may be used for space heating, line tracing, and other ancillary purposes. Few plants currently generate their own base load electricity for process use, although some plants have motor-generator sets (gensets) for emergency use or for electricity peak shaving. Because all ethanol plants require steam, of growing interest are systems that generate both process steam (heat) and electricity (power), referred to as combined heat and power (CHP) systems. Increasing applications of CHP systems are anticipated in the future, especially systems incorporating co-products and biomass fuels. This chapter examines some key considerations regarding the use of co-product streams and corn stover for CHP with existing plant energy infrastructure.

Electricity Generation

As described in other chapters of this report, current practical electricity production at fuel ethanol plants will use rotating generators, driven by either a combustion turbine or a steam turbine. The electric generator is not directly impacted by the fuel used to generate the steam for the steam turbine or to fire the combustion turbine. However, the reliability and stability of the electricity supply is critical for plant operations and economics. The fuel source will impact the plant electricity system to the extent that the combustion systems, and their thermal or mechanical feeds to the electricity generators, are effected by the fuel sources.

The steam generation systems for existing ethanol plants are designed with sufficient capacity to operate the plant, with perhaps some extra capacity to accommodate system maintenance

and perhaps modest production increases. The steam systems generally do not have sufficient capacity to generate base load electricity for the plant and also to supply the plant steam operating needs. Of course, a combustion turbine would not be in use at the plant unless the combustion turbine was already being used for generating electricity for the plant, and any combustion turbine would be in conjunction with a heat recovery steam generator. For plants without a combustion turbine, generating electricity would therefore necessitate adding new or additional equipment. Many ethanol plants are designed and built with expansion in mind. Space and infrastructure are often provided in anticipation of additional steam production, and perhaps for also generating base load electricity. Providing such space and infrastructure during initial plant design and construction can significantly reduce both the time and cost of future expansion.

Considering in general the use of co-product fuels or corn stover in existing plant systems, an ethanol plant needs both steam and electricity to operate. Variability in the fuel supply, such as varying moisture levels and varying proportions of component fuels, may result in variability in the steam production or pressure, or, in the case of gasification, in the syngas supply and composition. This in turn may effect the amount or quality of electricity produced. From a practical standpoint, the ethanol plant may be able to supplement the electricity supply via a genset, or via drawing from the grid, although such electricity supplementation may be costly and technically challenging. Such alternatives likely will not exist for the plant steam supply. On the other hand, the plant can likely tolerate more short term variability in the steam supply than in the electricity supply. Indeed, owing to increased use of electronics and to integrated operating control systems, the more modern plants may be more sensitive to power interruptions and to power quality than some of the older plants.

Biomass-fueled systems will likely require additional maintenance and/or extended periods of outage compared to systems fueled with natural gas. Plants using natural gas may be designed to have multiple boilers, or multiple combustion turbines, to ensure continuity of steam supply during maintenance of one boiler or turbine. The capital cost and space requirements for most biomass fueled systems make redundancy in the form of additional duplicate systems a challenge. As described above, replacement electricity may be available from gensets or from the grid, but replacement steam is likely unavailable from outside the plant. Rental boilers and rental electric generation systems may be arranged for extended, planned outages. A possible installed alternative is a modest-sized natural gas fired boiler as a supplement to the biomass fueled system, to be used to maintain minimum plant operations, and to prevent freezing, during maintenance or extended outage of the biomass fueled system. Such a backup system would probably not have sufficient capacity to generate base load electricity.

Compatibility with existing CHP systems therefore depends both on the fuel-utilizing component and on the electricity supply system. Modifications may be needed in the plant

electricity supply systems unless acceptable stability is designed into the fuel-utilizing components. The stability of the fuel-utilizing components in turn depends on well designed hardware, careful O&M, and close attention to the uniformity and predictability of the fuel supply.

Considering all of the above, ethanol plant co-products are nearly ideal biofuel sources for eventual in-plant electricity production because of their availability, uniformity, ease of use, and modest O&M challenges, and because the plant can exercise direct control over their production and quality.

An important consideration related to electricity generation in existing plants (as well as for new plants) is the water balance associated with the generation. As described elsewhere in this report, generating base load electricity for an ethanol plant would involve one of three turbine types. A combustion turbine could be used to directly drive the electricity generator, with steam generated in a heat recovery steam generator (HRSG). Cooling water is needed for both the combustion turbine and the electricity generator, but the cooling water would be incorporated into the overall heat recovery design of the energy system and of the plant. Most of the heat would be recovered via the HRSG in the form of preheated feed water, although some low level heat could be used for other plant uses. There would be little net additional to plant water demand.

The other two turbine types are steam turbines, that in turn drive electricity generators. In a letdown turbine, steam enters the turbine at high pressure and leaves at a pressure suitable for process use, usually 60-150 pounds per square inch (psi). The energy to drive the electricity generator is derived from the pressure differential across the turbine. A letdown turbine adds virtually no water demand to the plant. In a condensing turbine, the pressure differential across the turbine is maximized by condensing the discharging steam. A partial vacuum is created on the discharge side of the condensing turbine, making a condensing turbine inherently more efficient than a letdown turbine. However, to achieve this efficiency requires a continuous flow of cooling water to condense the steam. The heat added to the cooling water is low level, meaning that it cannot be practically recovered for other uses. The colder the cooling water, the less cooling water is needed. Many ethanol plants use groundwater, which generally has a temperature of around 55°F-60°F, ideal for condensing. However, much groundwater also contains high levels of hardness, that can foul heat exchangers. To help address this problem, the quantity of cooling water can be increased to minimize the temperature rise across the condenser, and so minimize deposition of hardness. This raises both pumping costs and water use. Condensing turbines can use a considerable quantity of water. As a general rule, a condensing turbine serving an electricity generator producing 1 MW of electricity requires

around XXXXXXXX gallons per minute of cooling water. This can amount to around XXXX% of the total water use of the ethanol plant absent the condensing turbine.

Thus, where water quantity or quality is a concern (and it is a concern nearly everywhere), careful consideration needs to be given to the overall system design for generating base load electricity at an ethanol plant. A letdown turbine or a combustion turbine will use less water, whereas a condensing turbine is efficient, and, as described elsewhere in this report, has operational advantages. A system incorporating both a letdown turbine and a small condensing turbine, or a combustion turbine and a small condensing turbine, may be optimal for some plants.

Existing Combustion and Gasification Systems

Dry grind fuel ethanol plants utilize a variety of combustion equipment. Some plants are also considering gasification systems, and several such systems are under design or construction. The applicability of the co-products and corn stover to such existing and planned equipment is discussed below.

Almost all dry grind fuel ethanol facilities have some type of on-site combustion system for steam generation. (A few plants receive steam from a different source, such as a nearby electric utility steam plant or large industrial steam generator primarily serving another facility.) Most early ethanol plants, and many new plants, rely on conventional natural gas fired boilers. As emission control requirements for VOCs, odor, and particulate matter became more stringent, especially related to co-products drying, a potential solution to the excessive emissions was to modify the boilers to allow introduction of pollutant-containing emission streams into the boilers, where the pollutants would be destroyed during the fuel combustion process. However, it is difficult to optimize both emission control and energy efficiency into a single such system, especially considering the quantity and schedule variability in both steam demand and raw emissions from co-products drying. Also, the high moisture content and potential particulate matter content of the exhaust from typical distillers wet grains dryers can result in increased maintenance and downtime for the steam generator. To address these problems, many ethanol plants have separate systems for steam generation and dryer emission control.

Natural gas fired steam generation units, either stand-alone or as part of a system incorporating a heat recovery steam generator, are still the dominant method of steam generation for most dry grind fuel ethanol plants. Some of these plants have propane in bulk storage tanks as backup for the natural gas supply. As described for coal fired combustion units below, natural gas fired units are optimized for the particular fuel and steam demand of the ethanol plant they serve. Introducing new fuel, especially if its physical and chemical characteristics differ

substantially from natural gas (as all biomass fuels will), will require careful engineering and system modifications. O&M cost will increase, and efficiency will likely decrease. Considering typical natural gas fired boilers, introduction of the co-products or corn stover can be regarded as infeasible.

A few newer ethanol plants plan to burn coal to generate steam, and possibly electricity. These plants are generally in reasonable proximity to other large users of coal, such as electric utility generating stations or large industrial coal users. This allows the ethanol plant to realize savings in transportation and storage of coal, and helps ensure a reliable coal supply. The higher capital, operating, waste management, and emission control costs of using coal as compared to natural gas are felt to be more than offset by the savings in fuel cost. On a Btu basis, the cost of coal is only about $\frac{1}{4}$ - $\frac{1}{2}$ the cost of natural gas for long term contracts, and the savings are even more pronounced when compared to recent experience with the spot price of natural gas. However, the cost of utilizing coal may escalate substantially if a CO₂ tax is imposed, or if CO₂ sequestration is required. Also, the ethanol plant's potential for realizing revenue from sale of renewable energy credits could be substantially lowered if coal is used as fuel.

It is often assumed that a steam generator system designed to burn coal can also burn biomass, including ethanol plant co-products and corn stover. This is generally not the case. A system burning solid fuel is designed to optimize burning of a particular type of fuel with particular physical and chemical characteristics. Burning other solid fuels may be possible, but usually requires hardware and operating system modifications and results in lower system efficiency, higher O&M expense, greater downtime, and higher cost per delivered Btu. As a minimum, significant pretreatment of the biomass may be needed prior to introduction into the steam generator, further raising costs. Successful introduction of substantial quantities of co-products or corn stover into a steam generator system designed for other solid fuels will require considerable capital investment, careful reengineering, and substantial operating system modifications. Even then, optimum performance may not be achieved.

Several plants are considering biomass gasification, and several are considering fluidized bed combustion systems. (Fluidized beds can also be designed for gasification systems.) As with natural gas and coal, the anticipated physical and chemical characteristics of the planned fuel will need to be considered in the system design. Introducing fuel with substantially different characteristics could be problematic. As described elsewhere in this report, the moisture content of the biomass fuel is a critical component in system design and operation. Other important fuel components include nitrogen, sulfur, and alkali metals content; density; handling characteristics (flowability, stickiness, freezing point, etc.); and the effects of aging. Some of the biomass fueled systems are anticipated to use wood chips as the primary fuel, and have been designed accordingly. If the biomass fueled systems have not been designed to accommodate the ethanol plant co-products and/or corn stover, their effective and efficient

incorporation into the fuel stream may be challenging. This will be especially true for syrup, and for the co-products containing high nitrogen and sulfur.

Many plants control dryer emissions with some type of efficient dedicated emission combustion system, typically a regenerative thermal oxidizer (RTO). RTOs use alternating beds of ceramic media to thermally oxidize VOCs, and to recapture the heat of combustion to sustain the process. The RTO needs to initially be raised to oxidizing temperature by heating, usually with natural gas, and an ongoing natural gas feed to a burner in the RTO is needed to compensate for system thermal losses. Modern RTOs are designed to have thermal efficiency of 95% or greater.

Most ethanol plants have a natural gas fired flare to control emissions from tank truck and/or tank car loading. The flares may have a continuously operating natural gas fired pilot light, although designs without a continuous pilot light are available. Since the flame may be self-sustaining once initiated, and since product loading is not continuous, natural gas use for the flare is relatively low compared to other natural gas uses in the plant. Nevertheless, the cost of natural gas for the flare may reach thousands of dollars per month. Also, the ethanol and denaturant combusted is lost, not recovered. Whether syngas from the gasification of biomass could replace the natural gas in the flares is beyond the scope of this project. However, since the plant would likely want to be able to load product even when ethanol production was temporarily down (such as for steam or electricity system maintenance), having the flare solely dependent on the plant's biomass gasification system is probably inadvisable.

Some plants have emergency standby engine-generator sets (gensets). The generators are usually diesel powered, although some may use natural gas for fuel. Typical operation would be only a few hundred hours per year, or less. Whether syngas from the gasification of biomass could replace the natural gas for the genset is beyond the scope of this project. However, the genset would most likely be needed when plant electricity supply has been interrupted, and at such times the biomass gasifier would likely be down. It is therefore likely inadvisable to have the emergency genset dependent on the plant's biomass gasification system.

The remainder of this chapter focuses on the applicability of the generation of electricity using existing facility combustion systems, modified for biomass combustion. Using at least portions of existing facility combustion systems has the potential to reduce capital costs and operational disruption as compared with the installation of new systems in the same locations as the existing systems. This potential benefit is largely eliminated if the plant space and configuration allow construction of new systems separate from existing systems. However, as described above, efficiency and operating cost should also be carefully evaluated, since specially designed systems are often more efficient and cost effective over the long run than retrofit systems.

Plant Combustion Systems to be Evaluated

In a previous chapter, “Combustion Options,” the following four combustion/gasification systems targeted in this project are described:

- Combustion in fluidized bed units
- Gasification in fluidized bed units
- Combustion of syrup using an injection nozzle in a standard boiler design
- Combustion of a combination of syrup and DWG, DDG, or DDGS using an injection nozzle in a standard boiler design

The compatibility of each of these four options for using biomass fuel in existing systems is discussed below. Also included is some discussion regarding combustion in coal-fired steam generators.

Combustion in Fluidized Beds

At the time this report is being prepared, only one dry grind fuel ethanol plant in the United States, Corn Plus in Winnebago, Minnesota, has a fluidized bed combustion system capable of using co-products. The system was not designed to combust corn stover. Although Corn Plus is a partner plant in this project, a patent is pending on the fluidized bed combustion application, and details of the fluidized bed combustion system design and operation are not publicly available at this time. The discussion here is therefore based on information that is publicly available, and on the evaluation performed as part of this project.

The Corn Plus fluidized bed combustion system was designed to combust syrup as produced at the plant at that time, with about 30% solids, and possibly to combust DWG. The system produces only steam. The system design incorporates supplemental feed of natural gas. Computational fluid dynamic (CFD) modeling performed by RMT as part of this project shows that syrup with a solids content of less than about 50% will not support stable and self-sustaining combustion. CFD modeling shows a similar result for DWG.

Whether the Corn Plus fluidized bed combustion system would support syrup or DWG with solids content of 50% or greater, or would support combustion of DDG or DDGS, could not be determined as part of this project.

The configuration and components of a fluidized bed combustion system are substantially different from a natural gas fired boiler. Although some components of the fluidized bed system could potentially be housed in the structures housing a natural gas fired boiler, a more likely scenario is construction of a completely new system at a location as near as possible to the existing connections of the feed water, steam, gas, and electricity lines, and convenient for the

storage and supply of the co-products and/or corn stover. This would also allow for continued plant operation during construction of the new system.

Gasification in Fluidized Beds

At the time this report is being prepared, there is no fluidized bed gasification system at a dry grind fuel ethanol plant in the United States. Other types of gasification systems are under design or construction at a number of plants. The systems are planned to use biomass as a fuel source, and the biomass may include DDG or DDGS. Computational fluid dynamic (CFD) modeling performed by RMT as part of this project (albeit on fluidized bed gasification units) indicates that feed materials with a high moisture content are not good candidates for gasification systems at ethanol plants. A preliminary drying step will be required for many feed materials.

As with fluidized bed combustion systems, the configuration and components of a fluidized bed gasification system are substantially different from conventional steam generation or CHP units. In addition, depending on the configuration and system details, the fluidized bed gasification system doesn't generate steam (like a fluidized bed or conventional combustion boiler) or drive a generator shaft (like a combustion turbine) itself. The syngas produced must be used in some other device to produce steam or generate electricity, and the syngas may need to be cleaned up before such use. Thus, to serve an existing plant, a new gasification and syngas cleaning system would be needed, and existing gas combustion units would require appropriate modifications. As described above, some existing plant components, such as loadout flares and gensets, may not be good candidates for syngas. Additional safety procedures and equipment would also be needed owing to the different chemical makeup of the syngas (that has a large proportion of carbon monoxide (CO) and hydrogen) as compared with natural gas (primarily methane).

The gasification systems planned or under construction at several ethanol plants reportedly do not use a fluidized bed. Such systems have lower capital and operating costs than fluidized bed systems, but tend to be larger in size for a given output, and to have lower throughput per area. Determining what is the optimum system for a large fuel ethanol plant is beyond the scope of this project.

As discussed earlier in this report, gasification systems may have advantages over combustion systems for use of biomass in existing plants. Gasification produces a gaseous energy source that may be able to be used, with appropriate equipment modification, in some of the existing plant systems currently using natural gas. Temperatures needed for gasification are lower (typically 200-400°F [93-204°C] lower) than for fluidized bed combustion systems, potentially reducing the generation of NO_x. With proper pretreatment, the syngas can be used in a

combustion turbine for generating electricity, followed by a heat recovery steam generator (HRSG) to generate steam.

Injection Via Nozzle Into a Conventional (Non-Fluidized) Boiler

As discussed in previous chapters, generation of electricity and steam by injection of either syrup or syrup and solids-containing portions (DWG, DDG, and DDGS) into current plant natural gas fired boilers is projected to not be feasible from a practical standpoint. Injecting the co-products into a coal fired boiler may be feasible, although may result in lowered efficiency, increased O&M cost, and worsened emissions. Based on the analyses performed as part of this project, and on the literature, the ethanol plant biomass solids are of a size necessary for injection into a combustion unit through a nozzle, and can be mixed with syrup or with other liquid or gaseous fuel for injection into an appropriate steam generator. However, the moisture content of the syrup and DWG, as received, are too high for stable, self-sustaining combustion. A substantial reduction of the moisture content, with associated costs and energy use, would be needed prior to combustion unless the syrup and/or DWG comprises only a small proportion of the overall feed material. A new potential technology application to accomplish this moisture reduction for syrup is described below.

A new modular evaporation technology application has recently been developed and is reportedly in operation at some ethanol plants to increase the solids content of the syrup to over 50 percent, and possibly to 70% or more. CFD modeling described in a previous chapter of this report and information from the operating partner ethanol plant combusting syrup indicate that syrup with a reduced moisture content (near 50 percent moisture) may achieve stable, self-sustaining combustion, at least in a fluidized bed.

As discussed in previous chapters, liquid or slurry injection into appropriate boiler systems of all sizes is a long established technology. Details of the injection vary, depending on the feed material and the type of boiler. Heavier feeds may require augmentation to achieve adequate dispersion. The augmentation may be accomplished by a combination of heating the feed material, by mechanical dispersion, and by using special nozzles supplemented with compressed air, steam, or gaseous fuel.

There are several disadvantages to using liquid injection via nozzles into a conventional combustion unit. As discussed above, the moisture content of the syrup and DWG would need to be substantially reduced to allow for stable, self-sustaining combustion. Feeding of co-products through pressure nozzles intended for other materials might result in additional O&M expense. Ethanol co-products contains complex carbon compounds that would not be expected to burn as cleanly as natural gas. Particulates would be generated, some of which might cause fouling of the combustion or steam system. The relatively high levels of alkaline metals in the

co-products may cause problems with slagging and ash fusion. A steam generator designed for natural gas will likely not be able to handle such particulates and ash. The sulfur content of the co-products might pose an emission problem, and, unlike a fluidized bed, adding chemicals to sequester the sulfur may be much more difficult, or may even be infeasible. System modifications to allow for the combustion of co-products might limit the capabilities for the combustion of conventional solids, so that the potential for burning of other biomass might be compromised.

For a plant with a coal fired steam generator, unless the system was designed to handle the co-products, their introduction via injection would likely result in lowered efficiency, operational problems, and higher cost. If the plant had already born the additional capital cost to burn coal, had secured the necessary permits, and had arranged for a coal supply, there would appear to be little if any direct advantage to introducing the co-products as fuel. The plant could choose to utilize the co-products or corn stover for reasons of indirect advantages, such as marketing considerations, inability to handle all of the co-products produced, or carbon offsets. Thus, although the use of the co-products in a coal-fired system may be technically feasible, it is likely not practical except for plant-specific, non-technical reasons.

Conclusions

Existing plant energy systems are generally optimized for particular fuel composition and characteristics, and the particular energy needs of the ethanol plant. Unless the existing system is designed to handle co-products or corn stover, introduction of the materials, even if technically feasible, is probably directly disadvantageous. Indirect advantages may exist, and would have to be evaluated on a plant-specific basis. Using existing infrastructure to speed the construction of and to lower the cost of new energy systems using co-products and corn stover is potentially a better alternative.