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Integrating Biomass to Produce Heat and Power at Ethanol Plants

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Abstract. Dry-grind ethanol process co-products and corn stover can be used to provide electricity (both for the plant and sale to the grid) and process heat. These biomass fuels can reduce process energy costs and increase the renewable energy balance for fuel ethanol production. An Aspen Plus model of the dry-grind ethanol process was used as a basis for the integration of biomass-fueled combined heat and power systems. Several combinations of combustion and gasification systems, power production cycles, biomass fuel combinations, and air emission control technologies are evaluated. Suitable configurations for incorporating biomass to produce heat and power at typical 190 million liters (50 million gallons) per year dry-grind ethanol facilities are analyzed.

Keywords. Biomass, Renewable, Sustainable, Model, Gasification, Combustion, Emissions, Ethanol production, Combined heat and power

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Introduction

The energy required to produce ethanol continues to be an important topic in the bio-fuel industry. Process energy in the form of heat and electricity is the largest energy input into the ethanol production process (Shapouri et al., 2002). Ethanol plants have a choice as to which fuel they will use to supply this energy. The most common source is currently natural gas. Some plants are being designed to use coal. Biomass is an alternative, renewable source of energy for ethanol plants. Dry-grind corn ethanol plants produce biomass co-products which contain a significant amount of energy when used as a fuel. These ethanol plants also are typically located near corn producing areas which have a large amount of corn stover available for use as a fuel. These biomass powered dry-grind ethanol plants could generate the electricity they need for processing as well as surplus electricity to sell to the grid. Using biomass as a fuel replaces a large fossil fuel input with a renewable fuel input which will significantly improve the renewable energy balance of dry-grind corn ethanol (Morey et al., 2006b).

Objectives

The main objective of this analysis was to model the technical integration of several biomass energy conversion systems into the dry-grind corn ethanol process. The conceptual system designs must provide the necessary process heat while meeting prevailing air emissions standards.

Methods

The analysis was performed primarily using Aspen Plus process simulation software. An Aspen Plus model of the dry-grind ethanol process was obtained from the USDA Agricultural Research Service (McAloon et al., 2004) and was used as the basis for the energy conversion system models that followed. This model contains a feature that allows it to be scaled to different annual ethanol outputs. For the purposes of this study all cases were set to produce 190 million liters (50 million gallons) per year of denatured ethanol. The primary components of the process such as fermentation, distillation, and evaporation were not changed. Only those components impacted by using biomass fuel were modified. They included steam generation (biomass combustion or gasification), thermal oxidation, and co-product drying. Process data from several ethanol plants participating in the project were also taken into account in the modeling process. Several sensitivity analyses were performed on each simulation to ensure good performance.

Biomass Property Data

A typical dry-grind corn ethanol plant produces distiller's dried grains with solubles (DDGS) as a co-product. DDGS is a mixture of two process streams called distiller's wet grains (DWG) and concentrated distiller's solubles (also known as "syrup"). The DWG and syrup are mixed and dried together to become DDGS. Property data for these process streams and corn stover was needed in order to build an accurate model. Morey et al. (2006a) provides an analysis of the fuel properties of these streams based on data taken from five dry-grind ethanol plants, as well as a fuel characterization of corn stover. Table 1 provides a summary of some of the important biomass property data.

Table 1. Selected biomass property data.¹

Fuel	Moisture content, % wet basis	HHV, MJ/kg dry matter	Nitrogen, % dry matter	Sulfur, % dry matter
Corn Stover	13%	17.9	0.7%	0.04%
Syrup	67%	19.7	2.6%	1.0%
DDGS	10%	21.8	4.8%	0.8%
DWG	64%	22.0	5.4%	0.7%

¹. Morey et al. (2006a)

In the Aspen Plus modeling environment the ultimate and proximate analysis data for each fuel was used to characterize its composition. The heat of combustion data were also entered for each material. An internal Aspen Plus specific heat model was used for each material which calculates specific heat based on composition. These specific heat models were then validated by comparing them to data presented in a report on a biofuel component physical property database for Aspen Plus from NREL (Wooley and Putsche, 1996).

Emissions Estimates

We worked with RMT, Inc., an engineering consulting firm, to generate predictive emissions estimates from the various thermal conversion technologies and fuel combinations. Computational fluid dynamics modeling was performed for several scenarios with the results focusing mainly on emissions of oxides of nitrogen (NO_x) and oxides of sulfur (SO_x). An equilibrium model (minimization of the Gibbs function) is used to simulate the combustion reaction in Aspen Plus. The computational fluid dynamics emissions estimates were used to adjust the emissions output of the Aspen Plus models.

Definition of Technology Combinations

Defining technology combinations was an iterative process of gathering industry data from vendors, ethanol plants, literature, and engineering firms, then modeling certain scenarios to determine their feasibility. We worked with the engineering consulting firms (AMEC and RMT Inc.) to put together suitable technology combinations.

Thermal conversion

Fluidized bed combustion and gasification were the main thermal conversion options evaluated in the modeling. Fluidized bed combustion was a good candidate because of its capacity to utilize high moisture fuels and the option of adding limestone as a bed material to control SO_x emissions. Fluidized bed gasification has the added benefits of lower operating temperatures which was important because of the low ash fusion temperatures of DDGS. Gasification also permits greater control of the conversion process through the option of producer gas cleanup before subsequent combustion.

Drying and Thermal Oxidation

Conventional dry-grind ethanol plants generally use natural gas direct fired dryers (rotary, or ring type) to dry the DDGS. In a plant powered by solid fuel, a common option is to use steam tube (indirect heat) rotary dryers. In this setup steam from the boiler provides heat to the wet material and air in the dryer through a series of tubes arranged inside the rotating dryer cylinder. One advantage of this method is that less air is required to carry away the moisture than would be used in a direct fired dryer resulting in a lower volume of dryer exhaust needing to be thermally oxidized.

An alternative option that we have observed in practice is the use of hot flue gas from the boiler directed into a rotary dryer to provide the drying energy. This option takes advantage of low grade energy that may have otherwise been vented to the stack, but produces amounts of dryer exhaust similar to direct fired dryers. Depending on the details of the combustion process, the use of hot flue gases for drying DDGS may affect the quality of the dried material.

When gasification is used as the thermal conversion process the option exists to modify a natural gas fired dryer to utilize producer gas as a fuel. This method requires some producer gas cleanup processes.

An additional alternative is superheated steam drying. In this method superheated steam comes into direct contact with the wet material and absorbs moisture. Then, the resulting saturated steam is used to provide heat to another process component. This method has the advantage of being highly energy efficient, and condensing all water vapor produced in the dryer.

All the modeling done to date uses steam tube dryers with the dryer exhaust being routed to the combustion unit where thermal oxidation occurs. The assumption made for modeling purposes in terms of thermal oxidation was that the combustion reactor average temperature had to be greater than 816 °C (1500 °F) (Lewandowski, 2000). Future analyses may include several alternative dryer options.

Emissions Control

The emissions estimates and technology specifications were made using data from the literature on emissions control technology and suggestions from the partner engineering firms. Combustion modeling results from RMT and our own calculations indicated that for the chosen system sizes most cases would need to be classified as a major source due to the emissions of NO_x and/or SO_x (EPA, 2006). The approach used was to benchmark existing solid fuel consuming facilities in terms of the “Best Available Control Technology” (BACT) determinations in their air quality permits. This resulted in emissions control equipment specifications for each case. We are currently working with RMT, Inc. to finalize some of the emissions estimates for SO_x in the fluidized bed combustion cases. For the purposes of this paper SO_x emission potential was calculated based on the amount of sulfur in the fuel. Destruction efficiencies for each control technology were estimated and used to calculate the resulting air emissions data.

As mentioned before, fluidized bed combustors allow for the use of limestone as a bed material which helps to reduce SO_x emissions. In the DDGS gasification cases flue gas desulfurization semi-dry scrubbers were used to reduce SO_x emissions.

Emissions of NO_x were controlled using selective catalytic reduction (SCR) technology, or selective non-catalytic reduction (SNCR), depending upon the level of destruction efficiency required. SCR can achieve higher destruction efficiencies, but it has a higher capital cost and requires the flue gas to exit the boiler at fairly high temperatures (the modeling assumed a minimum SCR temperature of 302 °C (575 °F)). Alternative methods of NO_x reduction may be

possible in the case of gasification if the ammonia produced during gasification is removed catalytically from the producer gas (Stevens, 2001). It may also be possible to utilize this ammonia for NO_x reduction if the producer gas is burned in a carefully designed staged combustion reactor. Due to limited demonstration, these alternatives were not included in the analysis.

Emissions of particulate matter were not simulated in the analysis although the necessary particulate removal equipment was specified in each case. The particulate removal equipment (cyclones, baghouse, etc.) was specified using estimates from similar processes.

Steam Cycle and Electricity Production

Several variations of steam turbine power cycles were used to generate electricity in this analysis. Each fuel combination and technology scenario was analyzed on three levels of electricity production.

At the first level, the system simply provides the process heat needed to produce ethanol and dry the co-product. No electricity is generated.

The second level system generates steam at an elevated temperature and pressure and uses a backpressure turbine to produce electricity. The limiting factor for electricity production in this case is that all the outlet steam from the turbine needs to be used for ethanol production and co-product drying. Under these constraints the actual amount of electricity produced is very close to meeting the ethanol plant requirements. Because of this, the second level of electricity production will be referred to as CHP (Combined Heat and Power).

At the third level a surplus of steam is generated at high temperature and pressure and is used to drive extraction type turbines. The steam necessary for ethanol production and co-product drying is extracted after the high pressure turbine stage and the excess steam is sent through the low pressure turbine stage then condensed. The amount of fuel used in this third level is limited to the amount of energy available if all the ethanol co-products at the plant were used as fuel. At this level a portion of the electricity generated is used to meet the plant needs, and a significant amount of electricity is also sold to the grid.

For each case it was assumed that the steam used for ethanol production and co-product drying needed to be 1.1 MPa (150 psig) saturated steam. This assumption was made based on suggestions from our partner engineering firms, assumptions made in the recent EPA study on CHP for the ethanol industry (EPA, 2005), and discussions with ethanol process design firms. However, it should be noted that, depending on the particular plant design, portions of the steam requirement are actually at lower pressures in operating plants. This may allow for a small amount of additional electricity generation where steam is extracted from the turbine at the various required pressures.

Results

Three combinations of fuel and thermal conversion technology were analyzed, each at the three different levels of electricity generation. For each case system performance results are presented.

Corn Stover Combustion

The first option analyzed was the direct combustion of corn stover in a fluidized bed. The corn stover was assumed to be densified at an off-site facility. Figure 1 shows a simplified process flow diagram of this case. At the heart of the process is the bubbling fluidized bed boiler. The

dryer exhaust stream is routed through the combustor to accomplish thermal oxidation of the volatile organic compounds it contains. Oxides of nitrogen are controlled using SNCR at the boiler. Particulate matter is removed from the flue gas by cyclones and a baghouse.

At the first level no electricity is generated. Saturated steam is produced in the boiler at 1.1 MPa (150 psig) for use in ethanol processing and co-product drying (see Figure 1).

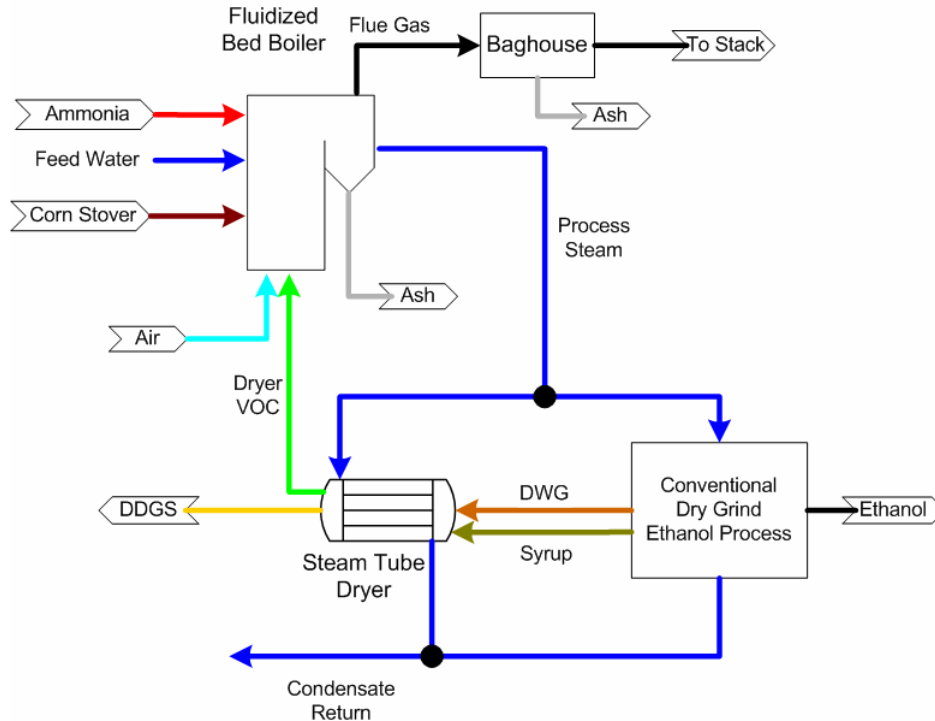


Figure 1. Corn stover combustion, level 1: process heat only.

At the second level electricity is generated using a backpressure turbine. Steam is produced at 6.3 MPa (900 psig) and 482° C (900° F), then expanded through a backpressure turbine to 1.1 MPa (150 psig) (see Figure 2). Some de-superheating is then necessary to provide saturated steam to the ethanol process and the co-product dryer.

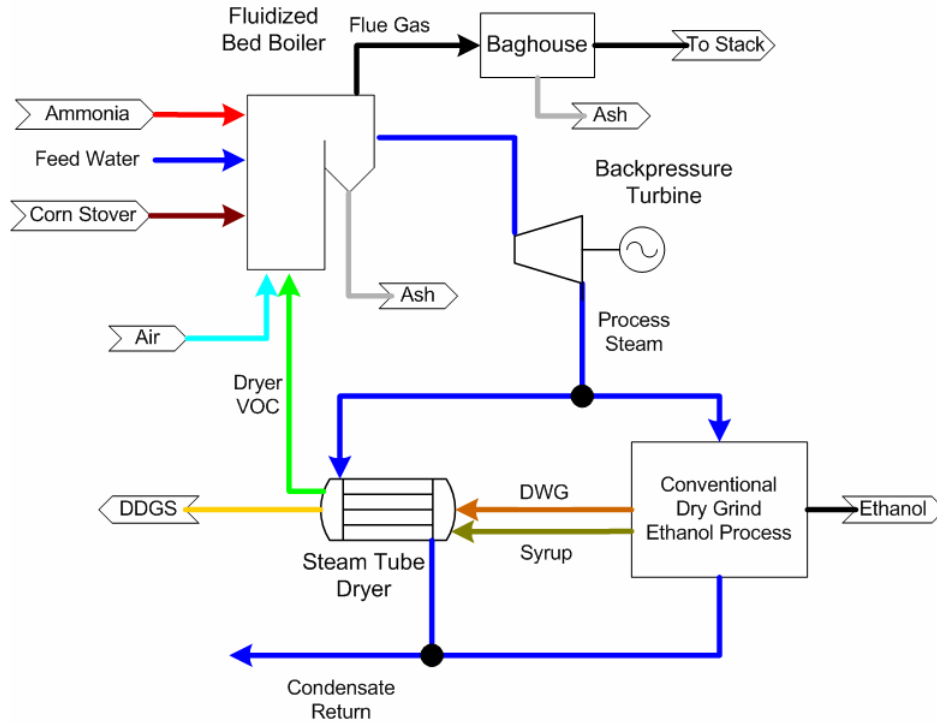


Figure 2. Corn stover combustion, level 2: CHP.

The third level of electricity production uses an extraction turbine. A surplus of steam is generated in the boiler at 6.3 MPa (900 psig) and 482° C (900° F). Process steam is extracted from the turbine at 1.1 MPa (150 psig) (see Figure 3). The remaining steam continues through the low pressure stage of the turbine and is condensed.

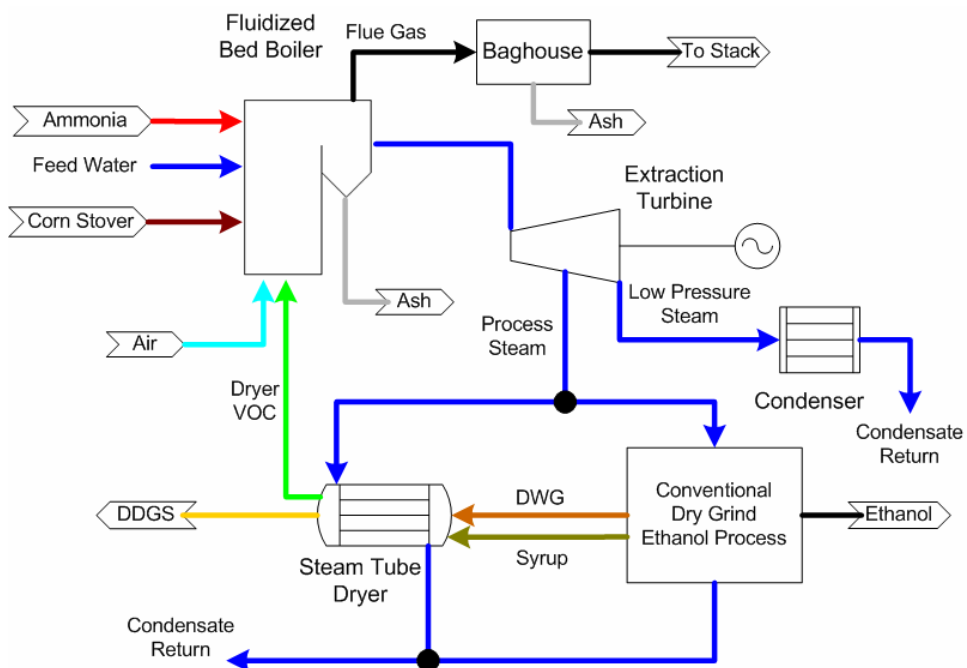


Figure 3. Corn stover combustion, level 3: CHP and electricity to the grid.

Syrup and Corn Stover Combustion

The next option analyzed was combustion of the syrup co-product supplemented with corn stover. The process flow diagram for this system (shown in Figure 4) is essentially the same as the corn stover combustion case except that the syrup co-product is not dried, but rather combusted in the fluidized bed boiler along with corn stover. Limestone is used as the bed material in the combustor to reduce emissions of SO_x . The drying operation in this case is much smaller because only the DWG co-product must be dried. This makes the overall process steam load smaller as well.

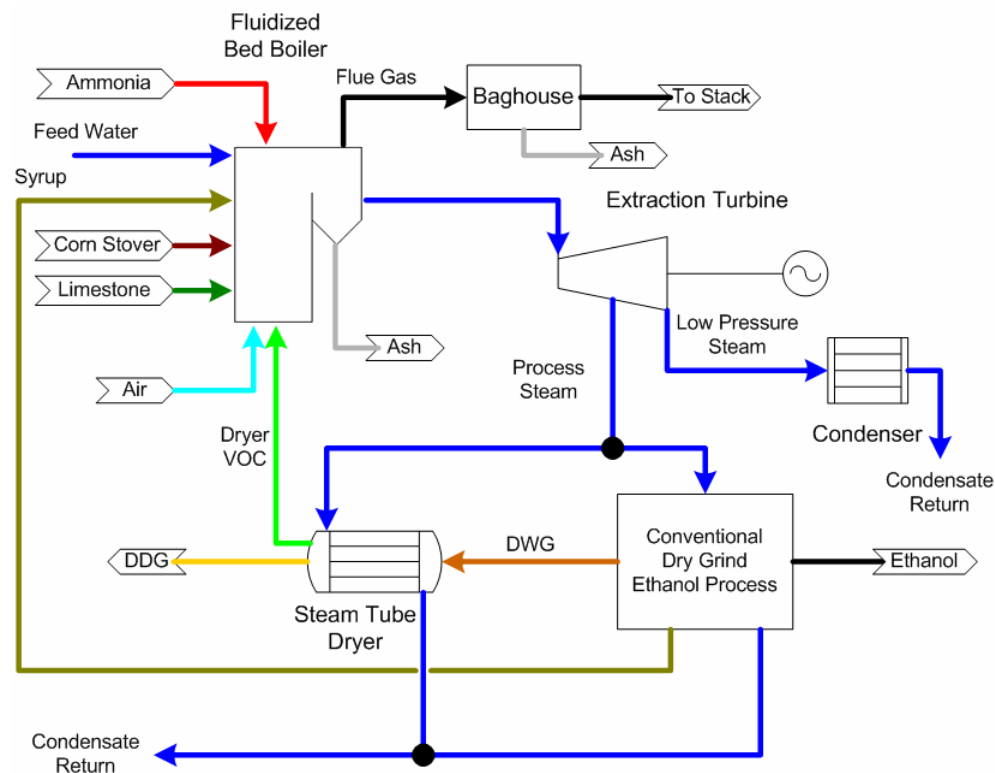


Figure 4. Syrup and corn stover combustion, level 3: CHP and electricity to the grid.

The three levels of electricity production for this fuel combination follow the same iterations as the corn stover combustion cases discussed previously. Figure 4 shows a process flow diagram for the third level of electricity production. For all three levels all of the syrup produced at the plant was used as fuel. Figure 5 shows fuel energy input from syrup and corn stover for each level. The amount of fuel used is shown in Figure 6. The average moisture content of the fuel mixture for the process heat, CHP, and CHP + grid scenarios was 56%, 53%, and 44%, respectively.

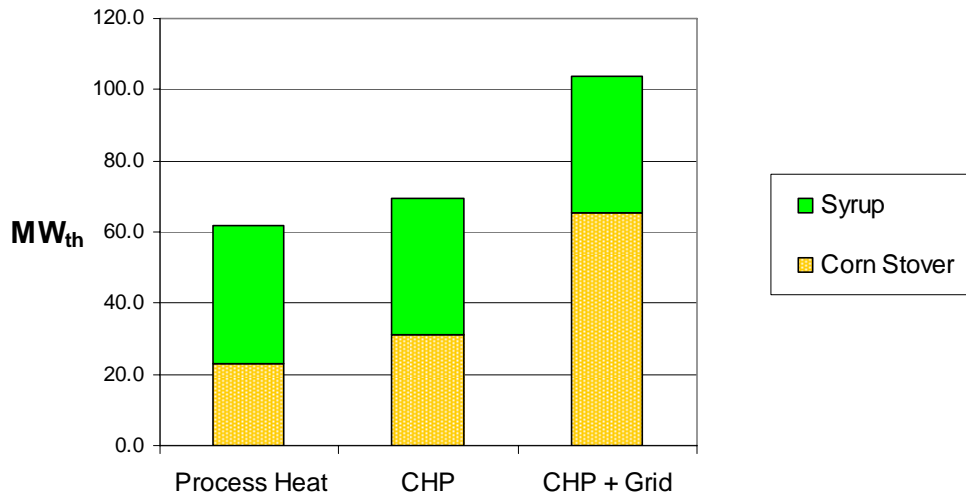


Figure 5. Syrup and corn stover combustion: fuel energy input rate contribution (HHV).

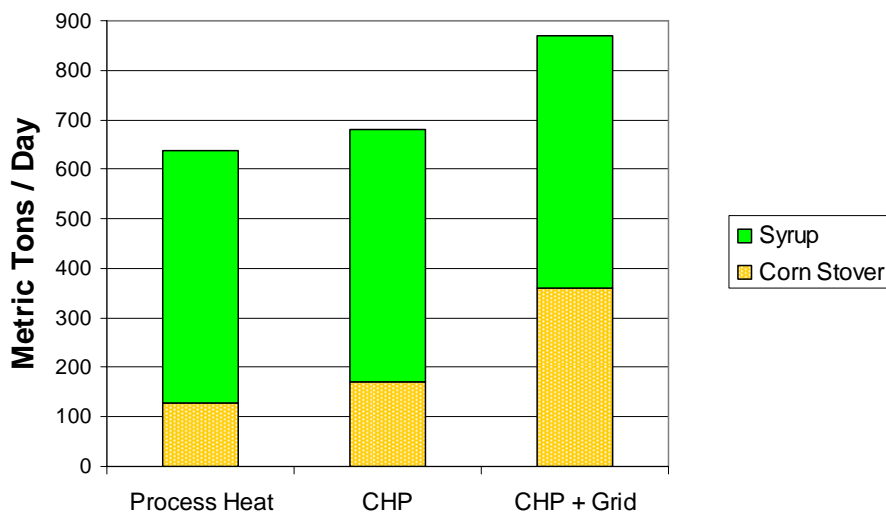


Figure 6. Syrup and corn stover combustion: fuel use.

DDGS Gasification

The last option analyzed was the gasification of DDGS (see Figure 7). The system chosen uses an air-blown fluidized bed gasifier to convert the DDGS into producer gas. Particulates are removed from the gas stream in high-temperature cyclones. The producer gas is not allowed to cool significantly in order to avoid condensation of tars. A staged combustion reactor is used to combust the producer gas. Ambient air and exhaust from the DDGS dryer are added at separate stages. This combustion reactor acts as a thermal oxidizer for the dryer exhaust stream and eliminates that capital expense. Immediately following the combustor is a heat recovery steam generator (HRSG) where steam is produced for the ethanol process, co-product

drying, and electricity production depending on the specific case. The flue gas exiting the HRSG enters an SCR unit where NO_x emissions are reduced. A semi-dry scrubber using a lime slurry is then utilized to reduce the emissions of SO_x.

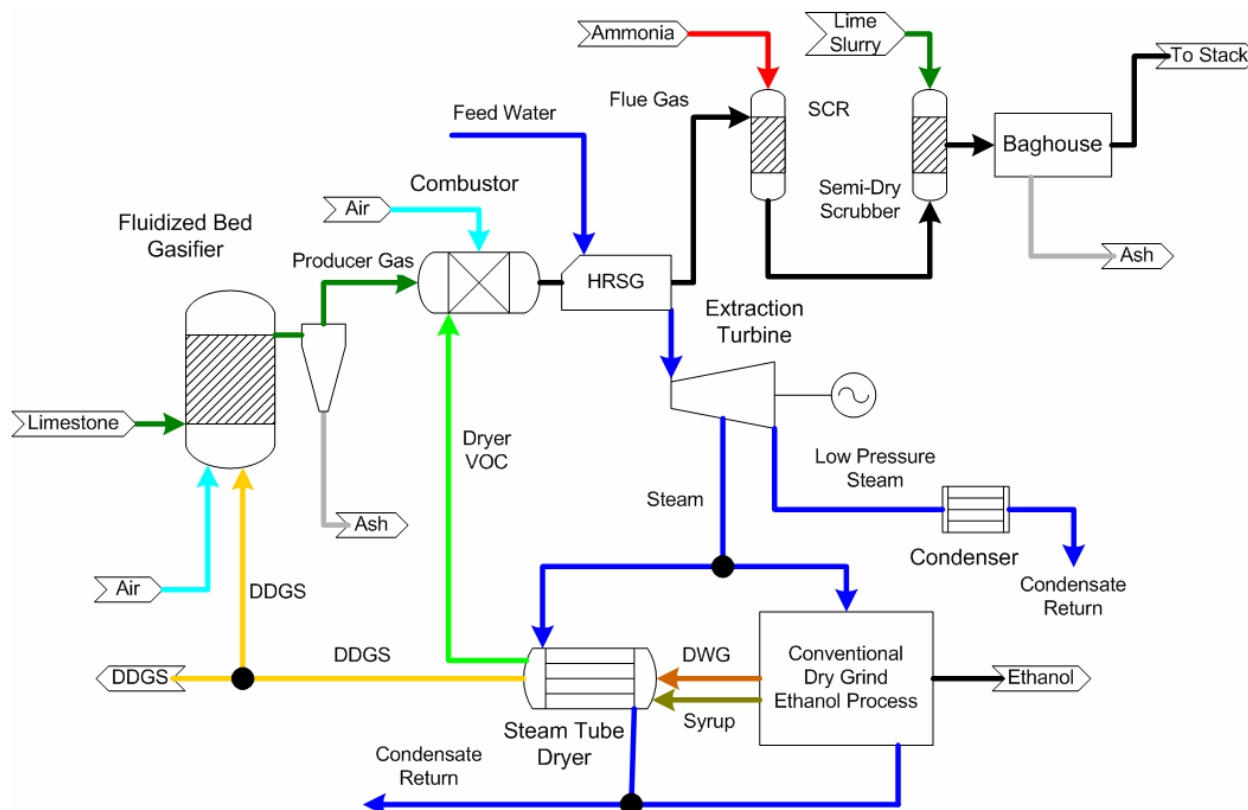


Figure 7. DDGS gasification, level three: CHP and electricity to the grid.

The third level of electricity production for the DDGS gasification option is shown in Figure 7. The other levels of electricity production have system changes similar to the previously mentioned cases of corn stover combustion.

Gasification of DDGS is an attractive option because of relatively low temperature ash fusion characteristics of DDGS. The gasification reaction occurs at lower temperature than combustion and much of the ash is removed before the gas is combusted. This decreases the chance of fouling the boiler tubes with alkali deposits.

System Performance Comparison

Table 2 presents some of the performance data of interest from each case. In general the combustion of corn stover makes most efficient use of the fuel energy input due to its simplicity and relatively low fuel moisture content. However, in the syrup and corn stover combustion cases the energy for drying the syrup co-product is effectively hidden in the lower system thermal efficiency. This is because the syrup moisture is vaporized in the combustor where it decreases the boiler efficiency rather than being evaporated in the dryer via process steam where the energy would be counted as a useful output of the system. This dynamic also explains why less electricity is generated in level 2 of the syrup and corn stover combustion cases. Less process steam is required for drying the co-product since only DWG is being dried. This limits the amount of steam flowing through the backpressure turbine since all of the output steam must be used to meet process needs.

Table 2. System performance results for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.¹

	Biomass Fuel Use ² (Wet Basis) t/day	Fuel Energy Input Rate MW _{th}	Power Generated (Gross) MW _e	Power To Grid (Net) ³ MW _e	Power Generation Efficiency	System Thermal Efficiency ⁴
<i>Corn Stover Combustion</i>						
Level 1: Process Heat Only	363	66	0	-6.0	-	80.5%
Level 2: CHP	416	75	6.6	0.4	8.8%	78.9%
Level 3: CHP & Elec. to Grid	575	104	13.0	6.8	12.5%	63.1%
<i>Syrup & Corn Stover Combustion</i>						
Level 1: Process Heat Only	637	62	0	-6.2	-	70.1%
Level 2: CHP	680	70	5.4	-0.7	7.8%	69.7%
Level 3: CHP & Elec. to Grid	870	104	12.9	6.7	12.4%	53.8%
<i>DDGS Gasification</i>						
Level 1: Process Heat Only	318	72	0	-6.2	-	73.3%
Level 2: CHP	365	83	7.0	0.8	8.5%	72.2%
Level 3: CHP & Elec. to Grid	459	104	11.5	5.2	11.1%	61.6%

¹ All energy and power values in this table are based on the fuel Higher Heating Value (HHV).

² Moisture contents: Corn stover – 13%; Syrup & corn stover – 56%, 53%, 44% for levels 1, 2, 3, respectively; DDGS – 10%.

³ Negative values refer to power purchased from the grid by the ethanol facility.

⁴ Efficiency of converting fuel energy into other useful forms of energy (process heat and electricity).

Stack emissions results with control technology in place for NO_x and SO_x are presented in Tables 3 and 4 respectively. Most of the cases emit a pollutant at a rate above the current regulatory threshold of 227 metric tons (250 tons) per year which puts them in the major source category. Some of the cases involving corn stover are close to or below this threshold which would make it possible for them to be permitted as synthetic minor sources. The relatively high nitrogen content of DDGS contributes to the higher NO_x emissions in the gasification cases. The sulfur content of syrup is also something that needs to be taken care of in those cases. These results show that the emissions from using ethanol co-products as a fuel will need to be addressed. However, it should be noted that the emissions from installed and optimized systems may be significantly lower depending on the process design and operational characteristics.

Table 3. Emissions of NO_x after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.¹

	NO _x Emissions Control Technology	NO _x Emissions Destruction Efficiency	NO _x Emissions Rate ²		NO _x Annual Emissions	
			g/MJ	(lb/MMBtu)	t/yr	tn/yr
Corn Stover Combustion						
Level 1: Process Heat Only	SNCR	60%	0.10	(0.22)	199	(219)
Level 2: CHP	SNCR	60%	0.10	(0.22)	228	(251)
Level 3: CHP & Elec. to Grid	SNCR	60%	0.10	(0.22)	315	(348)
Syrup & Corn Stover Combustion						
Level 1: Process Heat Only	SNCR	60%	0.06	(0.14)	117	(129)
Level 2: CHP	SNCR	60%	0.06	(0.13)	127	(139)
Level 3: CHP & Elec. to Grid	SNCR	60%	0.05	(0.12)	169	(187)
DDGS Gasification						
Level 1: Process Heat Only	SCR	90%	0.17	(0.39)	377	(415)
Level 2: CHP	SCR	90%	0.17	(0.39)	432	(476)
Level 3: CHP & Elec. to Grid	SCR	90%	0.17	(0.39)	543	(599)

¹ All NO_x emissions are calculated as NO₂.

² Values are based on the fuel Higher Heating Value (HHV).

Table 4. Emissions of SO_x after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.¹

	SO _x Emissions Control Technology	SO _x Emissions Destruction Efficiency	SO _x Emissions Rate ²		SO _x Annual Emissions	
			g/MJ	(lb/MMBtu)	t/yr	tn/yr
Corn Stover Combustion						
Level 1: Process Heat Only	(none)	0%	0.04	(0.10)	92	(102)
Level 2: CHP	(none)	0%	0.04	(0.10)	106	(117)
Level 3: CHP & Elec. to Grid	(none)	0%	0.04	(0.10)	146	(161)
Syrup & Corn Stover Combustion						
Level 1: Process Heat Only	Limestone Sorbent	70%	0.19	(0.44)	365	(402)
Level 2: CHP	Limestone Sorbent	70%	0.17	(0.39)	368	(406)
Level 3: CHP & Elec. to Grid	Limestone Sorbent	70%	0.12	(0.27)	382	(422)
DDGS Gasification						
Level 1: Process Heat Only	Semi-Dry Scrubber	80%	0.14	(0.33)	321	(354)
Level 2: CHP	Semi-Dry Scrubber	80%	0.14	(0.33)	368	(406)
Level 3: CHP & Elec. to Grid	Semi-Dry Scrubber	80%	0.14	(0.33)	463	(511)

¹ All SO_x emissions are calculated as SO₂.

² Values are based on the fuel Higher Heating Value (HHV).

The renewable energy ratio for each case was calculated following the assumptions presented in a previous study (Morey et. al. 2006b). The renewable energy ratio is defined as follows:

$$(\text{Energy in Ethanol} + \text{Co-product Energy} + \text{Electricity to Grid Energy}) \div \text{Fossil Energy Input}$$

The energy use and credit assumptions made by Morey et. al. (2006b) use data from Shapouri et al. (2002) as a basis for these calculations. Some slight changes have been made to the electricity use assumptions for the purposes of this report. An updated value of 0.2 kWh/L of ethanol produced (0.75 kWh/gal) was used for the electricity demand in the conventional natural gas ethanol plant calculations. We estimated the electricity demand of the biomass fueled ethanol facilities to be higher at 0.25 kWh/L (0.95 kWh/gal) due to added equipment. Also, some of the equipment contributing to the parasitic electric load was modeled. These loads were subtracted from the gross electricity production for each case.

Figure 8 shows the comparison of renewable energy ratio between the modeled cases and a conventional dry-grind corn ethanol plant. It can be seen that using biomass as a fuel can greatly increase the renewable energy balance of ethanol production.

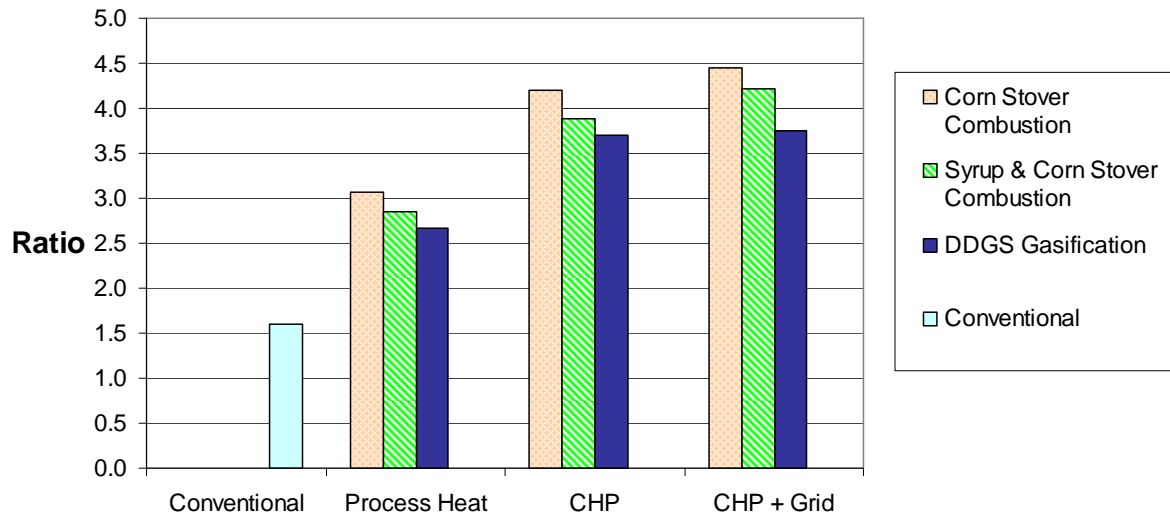


Figure 8. Renewable Energy Ratio (LHV)

Conclusion

The results show that there are several methods which could be used to generate electricity and process heat using biomass at ethanol plants. These technologies can produce renewable electricity for the grid and improve the renewable energy balance of ethanol. These systems will need to be designed with close attention to the ash fusion characteristics of the biomass fuels and with appropriate emissions technology in place.

There is opportunity for much future study on this subject. Several alternative co-product drying scenarios could be modeled. A system utilizing superheated steam drying holds promise for increased efficiency and decreased water use. Electricity production could be increased with the use of biomass integrated gasification combined cycle (BIGCC) technology. A full study on the application of BIGCC in the ethanol industry would be useful.

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