Biomass Integrated Gasification Combined Cycle for Heat and Power at Ethanol Plants

Matthew J. De Kam, Graduate Student

Department of Bioproducts and Biosystems Engineering, University of Minnesota, 1390 Eckles Ave, St. Paul, MN 55108 USA, deka0017@umn.edu

R. Vance Morey, Professor* (corresponding author)

Department of Bioproducts and Biosystems Engineering, University of Minnesota, 1390 Eckles Ave, St. Paul, MN 55108 USA, rvmorey@umn.edu, ph 612.625.8775, fax 612.624.3005

Douglas G. Tiffany, Research Fellow

Department of Applied Economics, University of Minnesota, 1994 Buford Avenue St. Paul, MN 55108 USA, tiffa002@umn.edu

Abstract.

Biomass integrated gasification combined cycle (BIGCC) technology can be used to generate process heat and significant amounts of electricity at dry-grind ethanol facilities by utilizing the ethanol process coproducts and other biomass sources. These systems can reduce fuel costs for ethanol plants, improve the renewable energy balance of dry-grind ethanol production, and provide reliable renewable electricity for process use and for sale to the local utility. An Aspen Plus model of the dry-grind ethanol process is used as the basis for a subsequent gasification system model. A twin fluidized bed steam gasification configuration based on the SilvaGas process is used to generate synthesis gas. The results show that a dry-grind ethanol facility with a capacity of 190 million liters per year could produce 30.4 MW_e of power while supplying all its process heat needs using ethanol coproducts and corn cobs. This configuration results in a three fold improvement in the amount of renewable energy produced per unit of fossil energy used compared to a conventional ethanol production process using natural gas.

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

1. Introduction

Recently there has been increased scrutiny into the sustainability of liquid biofuels, especially in the case of corn ethanol. The long term viability of these fuels will depend upon the methods used to produce them. Many look forward to second generation cellulosic biofuels which promise a more favorable energy balance. But some of the technologies proposed for the production of cellulosic biofuels can also be applied to the current corn ethanol process, specifically the production of heat and power from biomass coproducts.

Process energy in the form of heat and electricity is the largest energy input into the ethanol production process [1]. Currently the most common fuel used to provide process heat is natural gas, and some plants now burn coal. Biomass is an alternative, renewable source of energy for ethanol plants. Dry-grind corn ethanol plants produce biomass coproducts which contain a significant amount of energy when used as a fuel. These ethanol plants also are typically located near agricultural areas which may have biomass residues available for use as fuels. 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 replaces a large fossil fuel input with a renewable source which will significantly improve the renewable energy balance of dry-grind corn ethanol [2].

Several studies have explored the possibilities of producing electricity at ethanol plants, but Biomass Integrated Gasification Combined Cycle (BIGCC) technology has not been evaluated [3–5]. BIGCC technology has the potential to produce electricity at a higher efficiency through the use of combustion turbines and steam turbines. This technology has already been evaluated for paper mills and the sugarcane ethanol industry [6, 7]. In this research BIGCC technology is applied to the dry-grind corn ethanol process.

2. Methodology

2.1 Ethanol process model

This study focuses on providing the process heat and electricity needs for dry-grind ethanol facilities. Having an accurate model for the conventional dry-grind ethanol process operating parameters is an important element of this research. To meet these needs a model of the dry-grind ethanol process was obtained from the USDA Agricultural Research Service (ARS) [8, 9]. The ARS model was developed using Aspen Plus process simulation software to simulate the dry-grind ethanol process. The ARS model is set to an output of 190 million liters per year for use in this study and all analysis is based on a dry-grind corn ethanol plant of this size.

The ARS model lists five main places where process steam is used in the conventional ethanol process. First the process water is heated in a large heat exchanger just before mixing with the ground corn. Next, the cooking process requires some additional process steam. The distillation process demands significant amounts of heat via process steam in the beer column re-boiler and the stripper column re-boiler. The molecular sieve package also uses a small amount of process steam. No steam requirement is listed for the multiple effect evaporators used to reduce the moisture content of the distiller’s solubles. The heat requirement for the evaporators is met using the hot vapors from the top of the distillation columns. The amount of steam energy required by each process step is shown in Table 1.

In the ARS model the total steam energy demand shown in Table 1 corresponds to 45,670 kg/hr of saturated process steam at a pressure of 446 kPa. In a typical dry-grind ethanol plant natural gas boilers generate this steam. Natural gas is also normally used to dry the ethanol coproducts, and to thermally oxidize the Volitile Organic Compounds (VOCs) from the dryer exhaust stream. An analysis that accompanies the ARS model estimates the amount of natural gas needed to operate the plant. This baseline process energy demand for a conventional natural gas fired plant is 9.09 MJ/L HHV.

The primary components of the ARS process model such as fermentation, distillation, and evaporation are not changed for use in this study. Only those components impacted by using biomass fuel are modified. The modified areas include steam generation, thermal oxidation, and co-product drying. An additional process steam heat loss of 655 kW_{th} is assumed for the biomass steam generation case to account for losses during steam distribution. This corresponds to 1% of the fuel energy input for a conventional plant bringing the process steam energy demands to a total of 27,890 kW_{th}. This process steam energy demand value is used in all modeling presented in this research.

2.2 Renewable Energy Balance

An important objective of this research is to evaluate the renewable energy ratio of ethanol production under the new system configuration. The renewable energy ratio refers to the ratio of useful energy produced relative to the fossil energy used in the production process [2]. The assumptions used for calculating the energy ratio are shown in Table 2.

The same fossil energy input estimate is used for both corn stover and corn cobs. When electricity is produced from a biomass fuel and sold to the grid it is assumed that this renewable electricity will displace fossil sources of electricity. It is assumed that on average fossil based electricity is generated at an efficiency of 35% on a Lower Heating Value (LHV) basis.

2.3 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 normally mixed and dried together to become DDGS. Property data for these process streams as well as corn cobs is needed in order to build an accurate model. Morey et al. [12] provides an analysis of the fuel properties of ethanol coproducts based on data taken from five dry-grind ethanol plants. Table 3 provides a summary of some of the important biomass property data used in the modeling.

Aspen Plus process simulation software is used to model the systems evaluated in this research. Aspen Plus is chosen because of its capabilities in simulating processes involving solid components characterized by an ultimate analysis and because the ARS dry-grind ethanol process model is also modeled using this software. All processes are modeled under steady state and steady flow conditions.

In Aspen Plus the biomass fuels are represented as solid non-conventional components. The ultimate analysis of each fuel is used to provide the necessary data for the General Enthalpy and General Density property models in Aspen Plus which allow the user to enter density, heat capacity, and enthalpy of formation values for each component. The higher heating value (HHV) is used to calculate the enthalpy of formation for each biomass fuel according to equation 1.

$$h^{\circ}_{f,biomass} = \Delta h_{comb} + h^{\circ}_{f,prod} \quad (1)$$

The enthalpy of combustion (Δh_{comb}) corresponds to the HHV, and the enthalpy of formation of the combustion products is given by equation 2:

$$h^{\circ}_{f,prod} = \sum_{prod} h^{\circ}_{f,i} y_i \quad (2)$$

In equation 2, y_i represents the mass fraction, and $h^{\circ}_{f,i}$ is the enthalpy of formation of each species in the combustion products at the reference state of 1 atm and 298.15 K. The data used for the general enthalpy model in Aspen Plus is shown in Table 4.

A general biomass heat capacity value from an Aspen Plus property database created by NREL is used in this modeling [15]. The heat capacity of ash is calculated based on ash compositions reported in Morey et al. [12] according to equation 3.

$$C_p = \sum_i y_i C_{p,i} \quad (3)$$

The ash heat capacity is calculated as the sum of the component mass fractions (y_i) multiplied by their respective heat capacities ($C_{p,i}$).

Aspen Plus offers a wide array of thermodynamic property methods for use in process simulation. The Redlich-Kwong-Soave equation of state with the Boston Mathias alpha function (RKS-BM) is used to calculate thermodynamic data in this study [16].

2.4 Drying

Conventional dry-grind ethanol plants typically use natural gas fired dryers (rotary or ring type) to dry the coproducts. For systems using solid fuels it is common to use steam tube rotary dryers. Steam tube dryers are used in the system evaluated in this study. Data on dryer performance and drying ethanol coproducts is provided by Davenport Dryer Company (www.davenportdryer.com). A diagram of the dryer model in Aspen Plus is shown in Fig. 1.

The wet biomass materials enter mixed together at 67°C. Part of the moisture portion of the non-conventional component representing the biomass materials in Aspen is converted to conventional liquid H_2O in a stoichiometric reaction (RSTOIC) block. Ambient air at 100 kPa, 25°C, and 50% relative humidity enters the dryer. The amount of ambient air required is calculated based on the assumption that the exiting dryer exhaust has a humidity ratio of 0.75 kg water/ kg dry air as suggested by Davenport Dryer Co. The water is evaporated in a countercurrent heat exchanger block using process steam as a heat source. The heat exchanger is specified so that the biomass and exhaust exit at a temperature of 91°C. A small heat loss is modeled in the condensate return line and is assumed as 2% of the dryer thermal load. A FLASH2 block is used to separate the exhaust vapors from the biomass material. Dried product exits the dryer at 10% moisture.

2.5 Twin Fluidized Bed Gasification

The gasification technology used is based on the SilvaGas process which was developed by Batelle, and commercialized by Future Energy Resources Corporation (FERCO) [17, 18]. This process uses two-stage atmospheric pressure gasification to convert biomass to a medium heating value synthesis gas. A basic schematic of this process is shown in Fig. 2.

Biomass enters the near-atmospheric pressure gasifier and reacts with steam and hot recycled sand to produce synthesis gas. Some unreacted char and sand exits the gasifier with the synthesis gas, and is captured in a cyclone separator. This char and sand then moves to a fluidized bed combustor where the burning char heats the sand to high temperatures. The high temperature sand then returns to the gasifier to provide the heat necessary for converting the biomass into synthesis gas. The resulting synthesis gas can have a heating value near 17 $MJ/N.m^3$ depending on process conditions [18, 19]. This medium heating value synthesis gas can be cooled, cleaned, and compressed for use in a combustion turbine generator.

The goal in modeling this BIGCC system is to provide mass and energy balance calculations which show how much electricity could be produced at ethanol plants. Emissions estimates are not calculated for this process. Some alterations are made to adapt the SilvaGas process for use in an ethanol plant. Depending on which biomass fuel is being used it may need to be dried before gasification. In the case of using ethanol coproducts this means having an additional dryer with an exhaust stream that needs to be thermally oxidized. The exhaust stream from both the ethanol process dryer, and the biomass fuel dryer are routed into the fluidized bed combustor for thermal oxidation. The combustor is operated at $990^{\circ}C$ which is well above the general guideline of $816^{\circ}C$ suggested by Lewandowski [20] for thermal oxidation. Adding these humid streams to the combustor absorbs significant heat, and decreases the heat provided to the gasifier. To accommodate for this, some of the biomass fuel is allowed to bypass the gasifier and be directly combusted to provide more heat. A diagram of this model is presented in Fig. 3.

The Aspen Plus model for this process shown in Fig. 3 reflects the adaptations made for integration into an ethanol plant. Biomass fuel is decomposed into its basic components simulating instantaneous devolatilization in an RYIELD block similar to the approach taken by Nikoo and Mahinpey [21]. This process happens first since it is common to both gasification and combustion. The devolatilized biomass is then divided between the gasifier and combustor. In the gasifier section the gas distribution is shifted in an RSTOIC block according to the assumptions that all fuel sulfur will initially produce H_2S, all fuel chlorine will initially produce HCl, and all fuel nitrogen will produce NH_3. The gasification reactions occur in an equilibrium reactor according to the reaction set shown in Table 5.

The detailed reaction mechanisms that occur during gasification are complex and the kinetic parameters are still being explored by many researchers [18, 22, 23]. In many cases an equilibrium model of the gasification process can provide a reasonable representation [18, 24, 25]. An equilibrium model is used in this case modeled with an RGIBBS reactor in Aspen Plus. Each equilibrium reaction is specified according to the reaction set in Table 5. Temperature approaches to equilibrium are specified for certain reactions, and the production of certain species is set based on the amount of fuel being used. Some carbon may be partially oxidized as in reaction 4. Reaction 5 is sometimes referred to as the water gas reaction where water reacts with carbon at high temperatures to produce combustible gas [18]. Steam methane reforming is represented by reaction 6, and the production of methane is set as a ratio of the fuel being gasified [18, 26]. Reaction 7 is the water gas shift reaction and is specified with a temperature approach [18]. The major hydrocarbon reactions (8 through 10) are specified based on the amount of fuel being gasified so that the amount produced conforms to industry data for this process. Tar is modeled as phenol (C_6H_6O). Reactions 11 through 13 represent the calcination of limestone and subsequent absorption of HCl and H_2S [27–29].

A significant amount of carbon passes through the gasifier as char. In this case the amount is set at 19.7% of the incoming carbon. This number was set based on balancing the heat needs for the overall process. Steam is introduced into the gasifier at rate based on the amount of biomass being used. Limestone is used as the bed material. The gasification reactor operates at a specified temperature of 870° C as suggested in Paisley and Welch [17], and the heat energy required is supplied by the combustor.

The char and ash are removed in a cyclone at the outlet of the gasifier and recycled to the combustor. The char combustor calculations are modeled by a minimization of the Gibbs free energy method. In Aspen Plus the possible products of combustion are specified, but specific chemical equations are not needed. The atoms are rearranged based on the criteria of minimizing the total Gibbs free energy (*G*) for the system according to the following equation.

$$G = \sum_{i=1}^{c} n_i \overline{G_i} \qquad (4)$$

In equation 4 n_i is the mole number of component *i*, *c* is the number of components, and $\overline{G_i}$ is the partial molar Gibbs energy of component *i* [30, 31]. The combustion reaction is operated at a set temperature of 990° C [17]. Rather than modeling a large amount of recirculating bed material a heat stream is used in Aspen Plus to transfer energy from the combustion unit to the gasification unit. Heat streams are shown as dotted lines in Fig. 3. This method simulates the concept behind the twin reactor design, but eliminates the need for multiple feedback loops and decreases unnecessary modeling complexity. Because of this assumption the solid material removed in the cyclone separator on the combustion unit equals the amount of material that would need to be removed from the system under steady state conditions. This material is therefore removed rather than being recycled to the gasifier.

2.6 Synthesis Gas Conditioning

After the synthesis gas leaves the gasifier it must be processed for use in a combustion turbine. Fig. 4 shows a diagram of this system which follows the same basic steps suggested by [17]. First the synthesis gas passes through a gas cooling heat exchanger which generates process steam. Next, the gas passes through a wet scrubber to remove particulate matter. This scrubber is modeled as a flash vessel in Aspen Plus. The next stage in gas processing is the selective removal of harmful components such as acid gases. The gasification of these biomass fuels will produce components such as H_2S, HCl, and NH_3 which can be harmful to equipment and produce pollutants during synthesis gas combustion. There are many options available for acid gas removal, and the system chosen will depend on the process conditions. In a commercial application a system such as the Selexol process could be used to remove these components [18]. For the purposes of this study the treatment process is not modeled in detail, instead a simple separation unit is used in Aspen Plus to remove the problematic components.

After treatment the synthesis gas must be compressed. A two stage compressor model with intercooling is used. The first compression stage increases the pressure from near atmospheric to 316 kPa and is modeled with an isentropic efficiency of 80% and a 95% mechanical efficiency for the drive motor. The intercooler decreases the temperature of the gas down to 127°C. The second stage increases the pressure to 1000 kPa with the same assumptions for efficiency.

2.7 Combined Cycle Power Generation

The synthesis gas is then combusted in a combustion gas turbine. The turbine is modeled following specifications in Paisley and Welch [17] which are based on an ALSTOM Power Systems gas turbine generator (Fig. 5). The entering ambient air is compressed in an adiabatic process with an isentropic efficiency of 85% and a 3% mechanical loss. The turbine has a pressure ratio of 10:1. The synthesis gas is combusted using a minimization of the Gibbs free energy reactor block as discussed earlier and presented in equation 4. The combustion temperature is 1070°C. The expansion process is considered to have an isentropic efficiency of 90% with 2% mechanical loss.

The exhaust gas from the combustion turbine is routed to a heat recovery steam generator along with the flue gas from the fluidized bed combustor. A simplified diagram of the power generation system for this case is shown in Fig. 6.

The synthesis gas passes through a gas cooler which generates some process steam. The gas is then cleaned, compressed and combusted in a gas turbine as described earlier. The hot combustion products from the gas turbine and the fluidized bed combustor are used to provide heat to the steam generator. The stack gas exits the steam generator at 176°

C. Superheated steam at 482° C and 6,300 kPa exits the steam generator and is piped to a backpressure steam turbine losing 5° C along the way. A backpressure steam turbine with an outlet pressure of 446 kPa is used to generate electricity. The turbine is modeled as an adiabatic expansion process with an isentropic efficiency of 75% and a mechanical efficiency of 97% for the generator.

The turbine exhaust is still superheated steam at a temperature of 208° C. De-superheating is done by adding water before the steam is used in the ethanol process. After desuperheating process steam is then supplied at 446 kPa to the ethanol process, the ethanol co-product dryer, and the gasifier fuel dryer. The condensate from the dryer and ethanol process are combined with makeup water in a deaerator to remove dissolved gases. The deaerator operates at 446 kPa and uses some process steam to heat the condensate to near saturation temperature (148° C). The main feed pump for the steam generator increases the pressure to 1,480 kPa and is modeled with an efficiency of 75%.

3. Results

BIGCC technology is integrated into the dry-grind ethanol process using a mixture of the syrup co-product and corn cobs as biomass fuel. Fig. 7 shows a diagram of the resulting overall system configuration. The syrup and cob mixture is dried to 10% moisture content in a steam tube dryer before being gasified. The amount of fuel used is based on meeting the process heat demands while also accomplishing thermal oxidation of the dryer exhaust in the fluidized bed combustor.

Performance results for this system are shown in Table 6. This system uses a combination of the ethanol co-product syrup which is available at the plant, and corn cobs which must be brought in from nearby sources. The amount of fuel used on an energy basis is slightly more than what is available in only the ethanol coproducts. If all the ethanol coproducts were used as fuel it would represent an energy input rate of 104 MW_{th}, but the results show that this system has an energy input rate of 110 MW_{th}. This is the amount of fuel needed to provide process heat and accomplish thermal oxidation while generating electricity in this configuration. All of the syrup produced is used as fuel, and corn cobs are brought in to provide the additional energy. Corn cobs are chosen because they should be available nearby and machinery exists for their collection. Using only the cob portion allows the remaining corn stover to remain in the field to help maintain soil organic matter.

For comparison data from a group of biomass CHP systems evaluated by De Kam [32] are presented in Table 7. These additional systems operate using only steam turbines to generate power. The power generation and system thermal efficiencies of the BIGCC system are higher than the steam cycle systems in Table 7.

Fig. 8 shows a breakdown of the renewable energy balance for both a conventional natural gas fired ethanol plant and an ethanol plant powered by BIGCC. The co-product energy credit is smaller in the BIGCC case because the syrup portion of the coproducts is being used as fuel for the plant. It is clear that the amount of fossil fuel used has decreased greatly, and new credit from renewable electricity helps improve the energy outputs.

The renewable energy ratio is calculated for each case by dividing the renewable energy output by the fossil energy input. This results in a ratio of 1.7 for the conventional natural gas fired ethanol process and a ratio of 5.1 for the BIGCC system. This shows that integrating BIGCC into the ethanol process improves the renewable energy ratio of ethanol production three fold. This ratio is also an improvement over the biomass CHP systems evaluated in De Kam [32] which resulted in renewable energy ratios ranging from 4.0 to 4.7.

4. Conclusions

There are technologies available which can significantly decrease the amount of fossil fuels needed to produce ethanol. 30.4 MW_e of renewable power can be produced at a dry-grind ethanol facility with a capacity of 190 million liters per year while also supplying all the process heat needs using ethanol coproducts and corn cobs. The renewable energy ratio of ethanol production could be improved from a typical value of 1.7 up to 5.1 at plants using BIGCC technology.

A key to the feasibility of these systems will be the cost to build and operate them. Future work is needed to evaluate the economic realities associated with BIGCC technology applied to the ethanol industry. In states where the utilities are mandated use renewable sources of electricity perhaps partnerships between ethanol plants and utilities could be made. The heat and power generation system could be located at a separate, but nearby site and operated by the utility. Future work in the area of public policy is needed to understand what incentives would be necessary to help the ethanol industry proceed in the direction of improved sustainability

Acknowledgements

We would like to thank Davenport Dryer Company for providing steam tube dryer information. Thanks also to Frank Taylor and Andy McAloon of USDA ARS for their help with the Aspen Plus ethanol process model. This work was supported by a grant from the

Xcel Energy Renewable Development Fund as well as funds from the Minnesota Agricultural Experiment Station.

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Figure Captions

Fig. 1. Steam tube dryer model in Aspen Plus

Fig. 2. SilvaGas gasification process [18]

Fig. 3. Aspen Plus model of twin fluidized bed steam gasification

Fig. 4. Gas cleanup and compression model

Fig. 5. Combustion turbine model

Fig. 6. Integrated gasification combined cycle diagram

Fig. 7. BIGCC system configuration

Fig. 8. Renewable energy balance

Figures

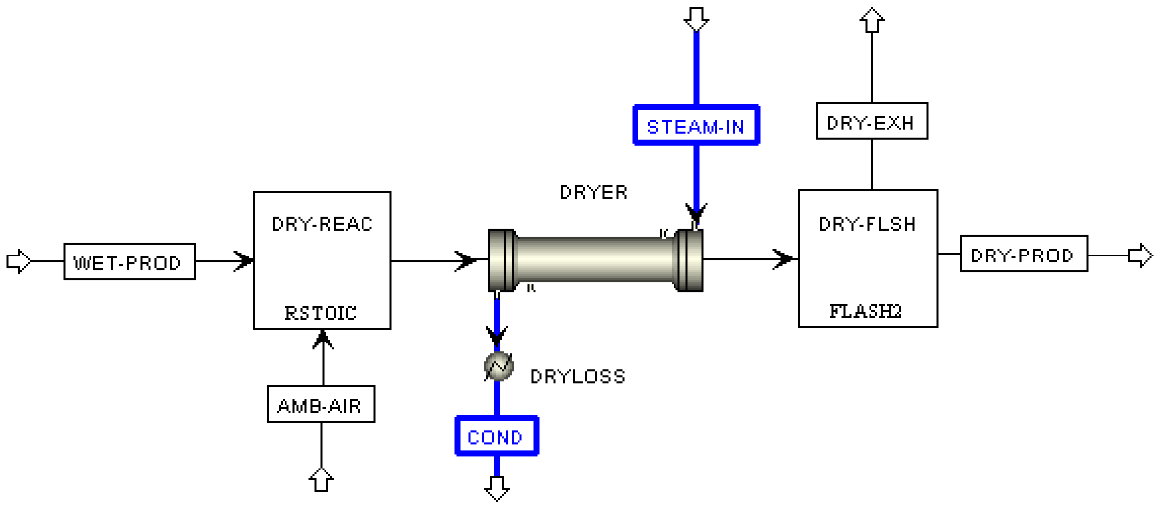

Fig. 1. Steam tube dryer model in Aspen Plus

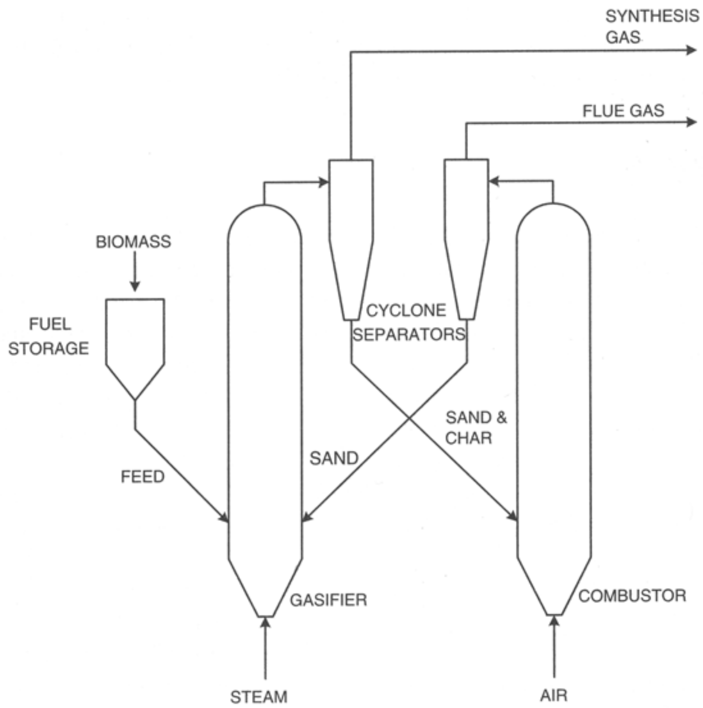

Fig. 2. SilvaGas gasification process [18]

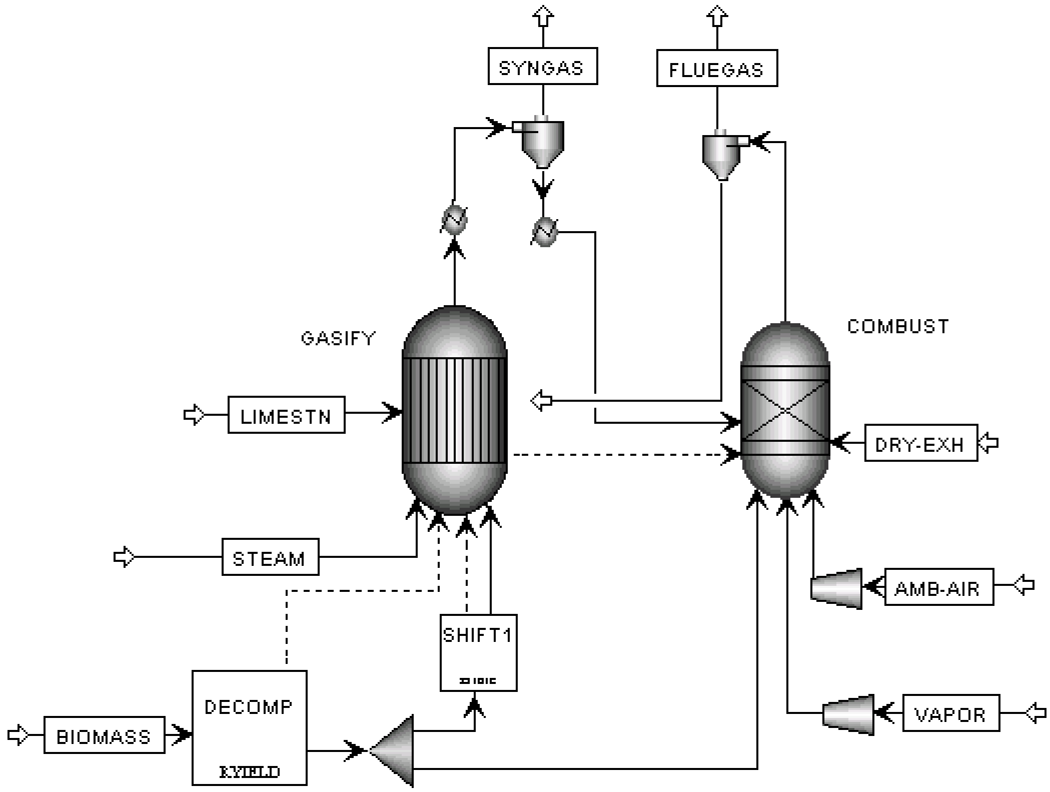

Fig. 3. Aspen Plus model of twin fluidized bed steam gasification

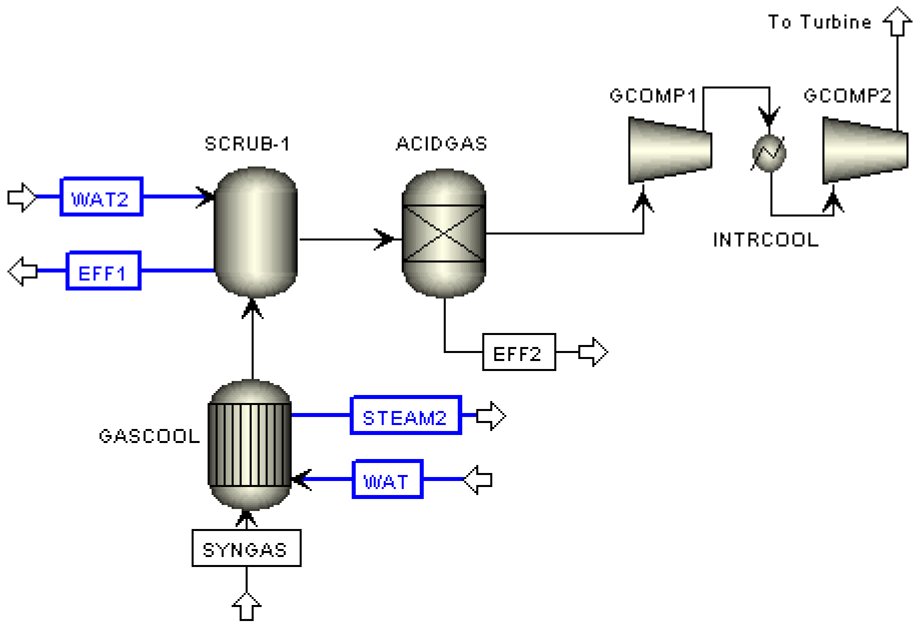

Fig. 4. Gas cleanup and compression model

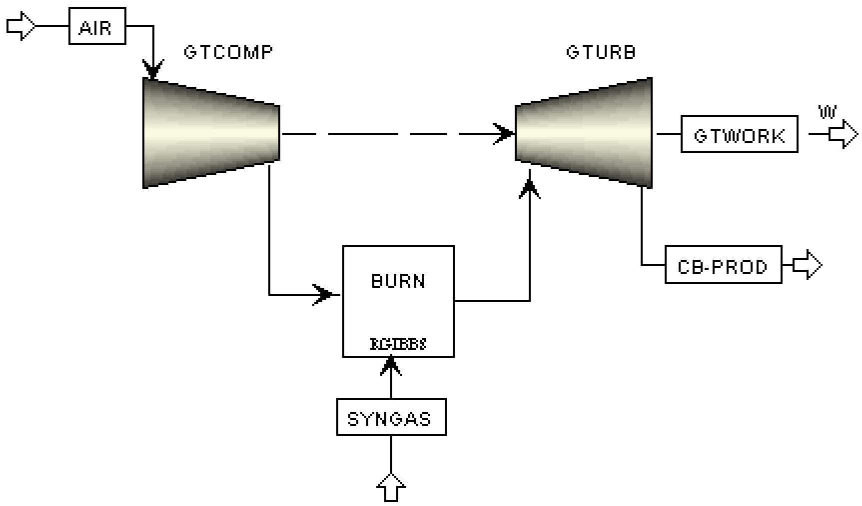

Fig. 5. Combustion turbine model

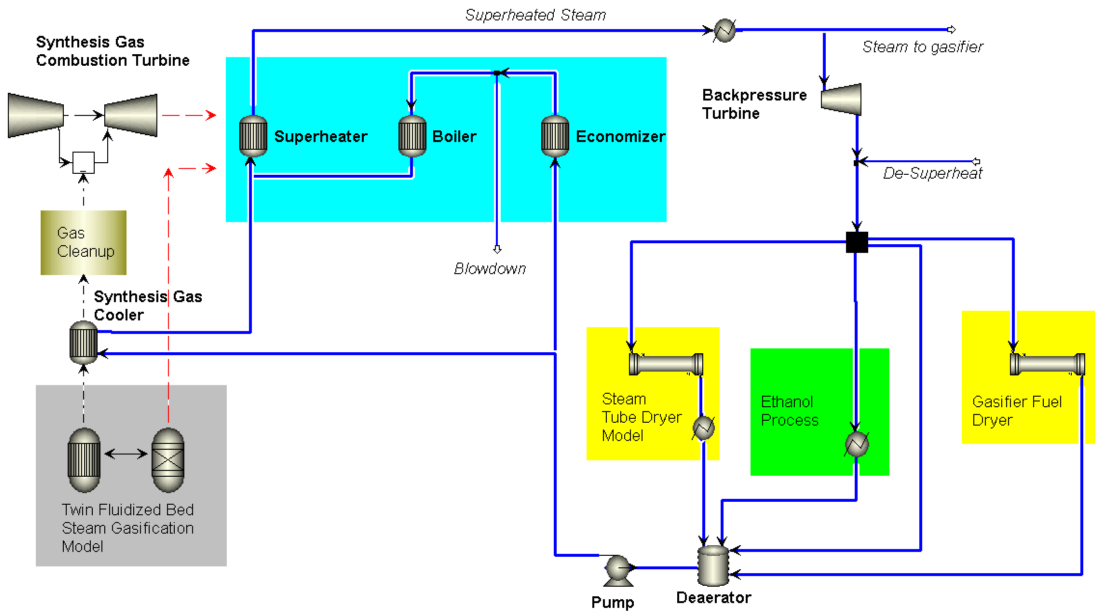

Fig. 6. Integrated gasification combined cycle diagram

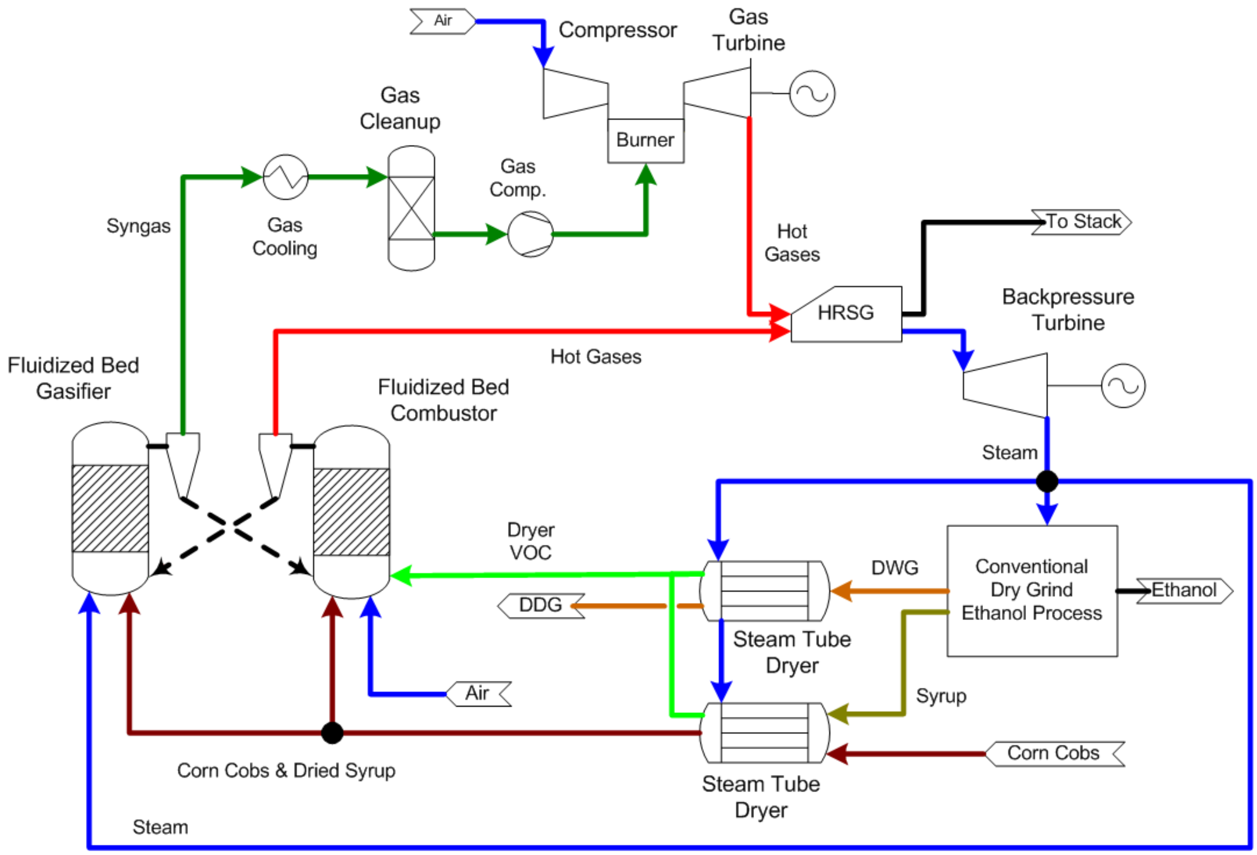

Fig. 7. BIGCC system configuration

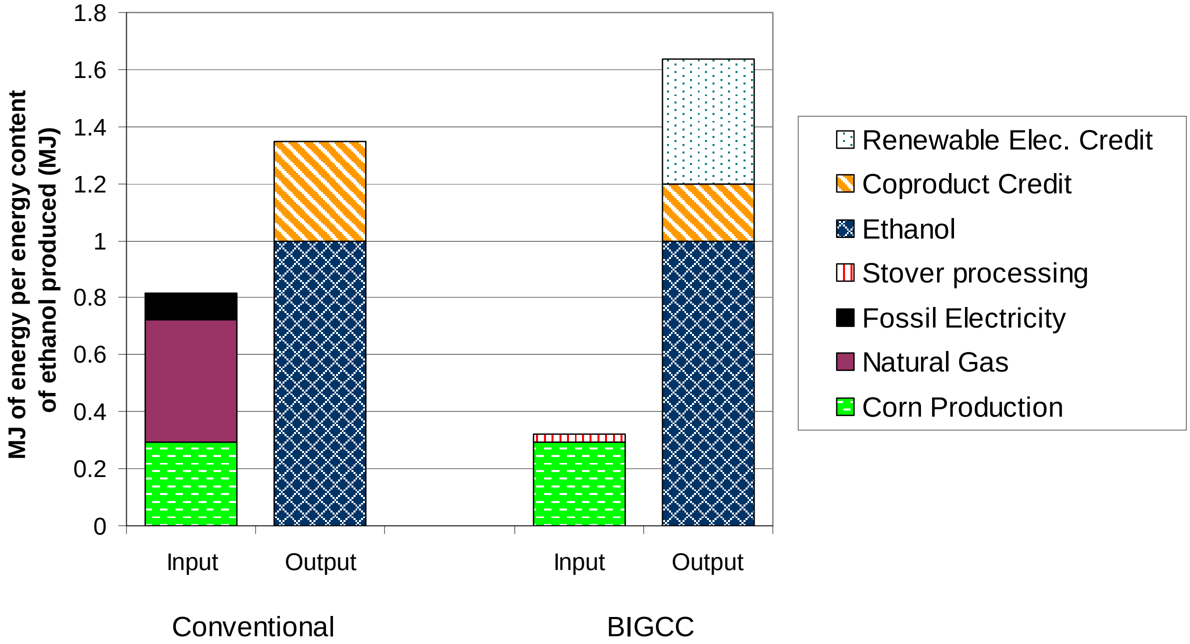

Fig. 8. Renewable energy balance

Tables

Table 1.
Steam energy demands of the conventional ethanol production process for a 190 ML per year plant excluding the energy needed for co-product drying.

Process steam point of use	**Heat duty (kW)**	**% of total**
Process condensate exchanger	6,446	24%
Cook heat exchanger	1,634	6%
Beer column re-boiler	15,709	58%
Stripper column re-boiler	3,054	11%
Molecular sieve	392	1%
Totals:	**27,235**	**100%**

Table 2.
Technical assumptions for energy use in the dry-grind ethanol process [a].

Fossil energy for corn production	6.27 MJ/L	Shapouri et al. [10]
Natural gas for process heat	8.26 MJ/L	ARS Model
Ethanol process electricity demand	2.04 MJ/L	EPA [11]
Fossil energy for corn stover production and processing	0.82 MJ/kg	Morey et al. [2]
Energy in Ethanol	21.3 MJ/L	Shapouri et al. [10]
Ethanol co-product energy credit	7.38 MJ/L	Shapouri et al. [10]

[a] Energy values in this table are based on the Lower Heating Value (LHV)

Table 3.
Biomass property data [a].

	DDGS	Syrup	Corn Stover	Corn Cobs [b]
Moisture (% wt., wet)	10.1	66.8 [c]	13.0 [d]	13.0 [d]
HHV (dry), MJ/kg	21.75	19.73	17.93	18.30 [e]
Ultimate (% wt., dry)				
Carbon	50.15	42.97	45.44	46.58
Hydrogen	6.87	7.04	5.52	5.87
Nitrogen	4.78	2.62	0.69	0.47
Oxygen	33.36	39.07	41.49	45.46
Sulfur	0.77	0.96	0.04	0.01
Chlorine	0.18	0.35	0.1	0.21
Ash	3.89	6.99	6.72	1.4

[a.] Data adapted from Morey et al. [12] unless otherwise noted
[b.] Corn Cob data from Brown [13] unless otherwise noted
[c.] Calculated from ARS Aspen Plus ethanol plant model
[d.] Estimated moisture content necessary for storage
[e.] Butuk and Morey [14]

Table 4.
Biomass thermodynamic data (moisture free)

	DDGS	Syrup	Corn Stover	Corn Cobs
Enthalpy of formation (kJ/kg)	-4497.5	-4533.5	-4869.4	-5376.2
Heat capacity [a] (J/kg K)	1545.3	1545.3	1545.3	1545.3
Ash heat capacity [b] (J/kg K)	1080.5	1080.5	1869.1	1869.1

[a.] Wooley and Putsche [15].

[b.] Calculated based on ash composition given in Morey et al. [12]

Table 5.
Steam gasification reaction set.

Reaction	**No.**
$C + O_2 \Leftrightarrow CO$	4
$C + H_2O \Leftrightarrow CO + H_2$	5
$CO + 3H_2 \Leftrightarrow CH_4 + H_2O$	6
$CO + H_2O \Leftrightarrow CO_2 + H_2$	7
$\frac{1}{2}CO + H_2 \Leftrightarrow C_2H_4 + \frac{1}{2}H_2O$	8
$CO + \frac{5}{2}H_2 \Leftrightarrow \frac{1}{2}C_2H_6 + H_2O$	9
$C + \frac{1}{2}H_2 + \frac{1}{12}O_2 \Leftrightarrow \frac{1}{6}C_6H_6O$	10
$CaCO_3 \Leftrightarrow CaO + CO_2$	11
$CaO + H_2S \Leftrightarrow CaS + H_2O$	12
$CaO + 2HCl \Leftrightarrow CaCl_2 + H_2O$	13

4-7: Higman and van der Burgt [18]
11, 12: Yrjas et al. [28]
13: Weinell et al. [29]

Table 6.
BIGCC system performance results for a 190 million liters per year dry-grind ethanol plant.[a]

Biomass fuel use (wet basis)		
Cobs	Tonnes/day (metric)	384
Syrup	Tonnes/day (metric)	509
Total	Tonnes/day (metric)	893
Fuel energy input rate		
Cobs	MW_{th}	71
Syrup	MW_{th}	39
Total	MW_{th}	110
Ethanol process heat demand	MW_{th}	27.9
Co-product dryer load	MW_{th}	12.8
Fuel dryer load	MW_{th}	10.6
Turbine output		
Gas Turbine	MW_e	18.9
Steam Turbine	MW_e	11.5
Total	MW_e	30.4
Power used by BIGCC system [b]	MW_e	4.0
Power used by ethanol process	MW_e	4.7
Power to grid (net)	MW_e	21.7
Power generation efficiency		28%
System thermal efficiency [c]		71%

[a] All energy and power values in this table are based on the fuel Higher Heating Value (HHV)
[b] Parasitic load including gas compressors, pumps, and blowers
[c] Efficiency of converting fuel energy into other useful forms of energy (process heat and electricity), excludes BIGCC parasitic load

Table 7.
Steam cycle CHP system performance data for comparison.[a,b]

		Corn stover combustion	**Syrup & corn stover combustion**	**DDGS gasification**
Fuel energy input rate	MW_{th}	104	104	104
Steam turbine output	MW_e	17.4	16.0	15.4
Power to grid (net)	MW_e	10.7	9.6	9.6
Power generation efficiency		16.7%	12.4%	14.8%
System thermal efficiency [c]		63.6%	53.0%	62.5%

[a] Data from steam cycle CHP systems evaluated in De Kam [32]
[b] All energy and power values in this table are based on the fuel Higher Heating Value (HHV)
[c] Efficiency of converting fuel energy into other useful forms of energy (process heat and electricity), excludes parasitic load