Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants

D. G. Tiffany, R. V. Morey, M. J. De Kam

Abstract. *Dry-grind ethanol plants have the potential to reduce their operating costs and improve their net energy balances by using biomass as the source of process heat and electricity. We modeled various technology bundles of equipment, fuels, and operating activities that are capable of supplying energy and satisfying emissions requirements for dry-grind ethanol plants of 190 and 380 million L (50 and 100 million gal) per year capacity using corn stover, distillers dried grains with solubles (DDGS), or a mixture of corn stover and syrup (the solubles portion of DDGS). Results showed favorable rates of return on investment for biomass alternatives compared to conventional plants using natural gas and purchased electricity over a range of conditions. The mixture of corn stover and syrup provided the highest rates of return in general. Factors favoring biomass included a higher premium for low carbon footprint ethanol, higher natural gas prices, lower DDGS prices, lower ethanol prices, and higher corn prices.*

Keywords. *Ethanol, Biomass, Economics, CHP, Emissions, Process heat, Electricity production.*

Production of fuel ethanol by the dry-grind process is expanding rapidly in the United States, and annual production capacity is expected to exceed 12 billion gal per year by the end of 2008 (Renewable Fuels Association, 2007). Natural gas has been the fuel typically used to produce process heat at these plants, while coal has sometimes been used for fuel, especially in plants greater than 380 million L (100 million gal) per year of capacity. Dry-grind ethanol plants typically yield 0.41 L of anhydrous ethanol per kg of corn (2.75 gal/bu) and 8.2 kg (18 lb) of DDGS. Drying of DDGS typically requires over one-third of the natural gas used by the plant. Consideration of the co-product DDGS as a biomass fuel reveals that there is sufficient energy to supply all needed process heat and electricity for the facility with additional energy available for electrical power generation for sale to the grid.

We have identified the leading methods of thermal conversion of ethanol co-products or field residues that would be technically feasible and financially prudent under a range of economic conditions. We have collected and analyzed technical data related to characteristics of DDGS, syrup, and corn stover in order to model the conversion of energy derived from these biomass fuels (Morey et al., 2009). We have modeled combustion and gasification performance to help predict emissions of NO_x and SO_x from the biomass fuels. In addition, issues of ash fusion caused by the alkali metals in the biomass have been studied to help identify combustion/gasification strategies that will have operational reliability. Further details of the systems we modeled are presented in De Kam et al. (2009).

Submitted for review in August 2008 as manuscript number FPE 7640; approved for publication by the Food & Process Engineering Institute Division of ASABE in February 2009. Presented at the 2007 ASABE Annual Meeting as Paper No. 076233.

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Key Economic Drivers for Adopting Biomass

Natural gas costs are the second largest operating cost for dry-grind ethanol plants, following only the cost of the corn as an operating expense. At this time of expansion of dry-grind ethanol production in the U.S. Corn Belt, demands for natural gas are also expanding rapidly, which exacerbates supply issues on natural gas lines of limited capacity in certain rural areas. Figure 1 shows the history of natural gas prices in Iowa, the heart of the U.S. Corn Belt, with the price effects of damage to natural gas infrastructure caused by Hurricane Katrina becoming evident in August of 2005.

Electricity costs are not as important to ethanol plant economics in magnitude, but plants have a self-interest in producing enough power on-site in order to maintain uninterrupted operation of computers, process controls, and other vital systems such as pumps and agitators. In some areas, local power providers would welcome the ability of newly established ethanol plants to provide their own power in order to avoid heavy investments to upgrade distribution capacity. In addition, there are improving incentives available to ethanol plants and other facilities to produce power for the grid from biomass as individual states establish goals that increase the renewable percentage of the power used within their borders.

In the years before 2006, revenues from sales of distillers dried grains with solubles (DDGS) often represented 20% of the total revenue stream of dry-grind plants; however, since that time the percent of total revenues from this co-product has fallen to about half of that amount. Given the rapid expansion of ethanol capacity that is underway in the United States, it will be improbable for U.S. livestock populations to consume the burgeoning production of this co-product. One of the reasons why U.S. livestock cannot consume the

  ISSN 0883-8542

increased production of DDGS stems from the maximum potential inclusion rates for this mid-level protein feed when fed to certain classes of livestock. DDGS contain nutritional energy, but contain a form of fat that some species of animals do not tolerate at high intake rates while achieving favorable performance. Dairy cows experience milk fat depression when fed diets too high in the fats found in DDGS (Hippen et al., 2007). Swine and poultry have lower abilities to utilize DDGS in their diets due to adverse effects of the dietary fat on carcass quality and due to the poor balance of amino acids, respectively.

As a feedstuff, DDGS have been hampered by issues of variability due to differences in corn quality (year to year) as well as ethanol plant operational issues involving the amount of concentrated solubles (syrup) dried with the dry portions of the stillage. Operators report that control and management of the DDGS dryers can cause a problem in feed quality when syrup balls are formed in DDGS. The composition of solubles in the DDGS and the manner in which they are dried or handled can also affect issues such as caking when the DDGS are shipped. Figure 2 shows a history of DDGS prices, which have historically been correlated highly with and similar in magnitude to corn prices on a per ton basis. Table 1 demonstrates the challenge of feeding the production of U.S. DDGS projected to be produced by 2009 at maximum dietary inclusion rates to the 2006 U.S. livestock population. Based on this table, it will require maximum dietary inclusion rates fed to 75% of the livestock populations to approach consumption of the expected amount of DDGS produced in 2009.

Figure 1. Industrial natural gas prices in Iowa from 2001-2008 (Energy Information Agency, 2008).

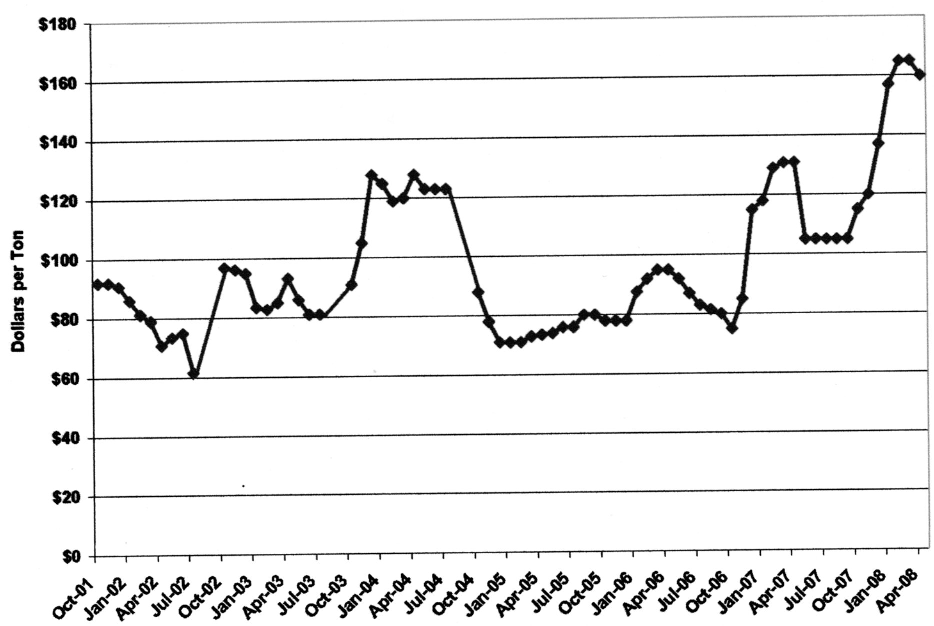

Figure 2. Historical prices of distillers dried grains at Lawrenceburg, Indiana (USDA-ERS, 2008).

Table 1. Consumption of available DDGS (28 million metric tons) by percent of market penetration based on annual ethanol production of 38 billion L (10 billion gal) (Cooper, 2006).

Species	Millions of Grain-Consuming Animal Units	Maximum Rate of Inclusion (%)	Millions of Metric Tons Market Penetration Percent		
			50%	75%	100%
Dairy	10.2	20	1.9	2.8	3.8
Beef	24.8	40	9.2	13.8	18.4
Pork	23.8	20	4.3	6.5	8.7
Poultry	31.1	10	2.9	4.3	5.8
Total	89.9		18.3	27.4	36.6

The efforts of California and growing interests on the national level to reduce the carbon footprint of the transportation fuel supply should establish higher prices for ethanol produced by methods that result in lower emissions of greenhouse gases. California's goal is to reduce greenhouse gases from the transportation sector by 10% by 2020. As California's AB-32 Legislation is implemented, firms selling fuels in that state should be willing to pay more for ethanol produced with a low-carbon footprint whether due to the feedstock used, the source of the imbedded energy in the fertilizer used or other factors affecting imbedded energy usage.

Well to wheels studies by Wang et al. (2007) of Argonne National Laboratory reveal that use of biomass as a source of process heat and power in ethanol plants results in nearly a three-fold reduction in greenhouse gas emissions compared to using the typical energy sources of natural gas and purchased electricity (fig. 3). This data implies that a California fuel supplier would need to purchase and transport one-third as much ethanol to blend in order to achieve equivalent GHG reductions if the ethanol were produced at a plant using biomass for process heat and electricity. Ethanol produced at plants using biomass fuels, with a lower carbon footprint than ethanol produced at plants using natural gas and purchased electricity, should command a price premium in the market related to savings in freight required to move ethanol from the Corn Belt to California.

Objectives

The objective of this article was to perform an economic analysis for several biomass energy conversion systems integrated into the dry-grind corn ethanol process as described by De Kam et al. (2009). The economic drivers described above will be reflected in the assumptions related to prices.

Methods

The technical analysis for integrating biomass energy into the dry-grind ethanol process is described in detail in De Kam et al. (2009). Some of the important features are summarized here. 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., 2000; McAloon et al., 2004; Kwiatowski et al., 2006), and was used as the basis for the energy conversion system models that followed. Biomass systems that produce 190 million L (50 million gal) per year of denatured ethanol were modeled. 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, co-product drying, and emissions control. Process data from several ethanol plants participating in the project were also taken into account in the

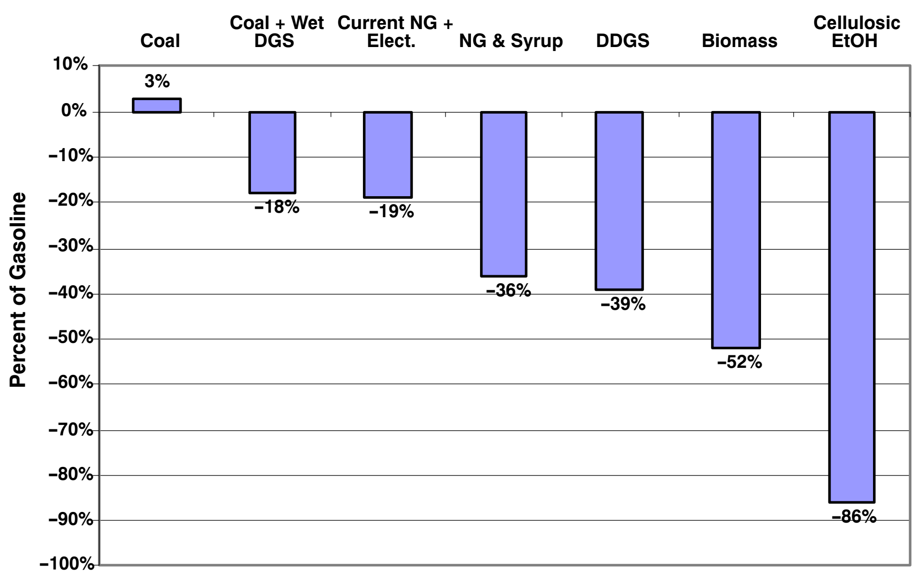

Figure 3. Well to wheels greenhouse gas emissions changes from fuel ethanol produced using various fuels and conversion assumptions at the plant relative to gasoline (Wang et al., 2007).

modeling process. Several sensitivity analyses were performed on each simulation to ensure good performance.

Three biomass fuels were included in the analysis – distillers dried grains with solubles (DDGS), corn stover, and a mixture of corn stover and syrup (the solubles portion of DDGS). Three levels of technology were analyzed for providing energy at dry-grind plants. They included 1) process heat only, 2) process heat and electricity for the plant – combined heat and power (CHP), and 3) CHP plus additional electricity for the grid. The limit for the third case was defined in terms of the maximum energy available if all of the DDGS were used to provide process heat and electricity. A conventional ethanol plant using natural gas and electricity was also modeled to provide comparison information for the economic analysis.

Fluidized bed combustion was used for corn stover and the mixture of corn stover and syrup. Fluidized bed gasification was used for DDGS to overcome problems of slagging that occur with low ash fusion temperatures of certain biomass fuels. Appropriate drying modifications were made to accommodate each configuration. The necessary emissions control technologies, primarily for oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and chlorine (HCl), were also modeled for each configuration.

Estimating Capital Costs

The Aspen Plus model estimates important material and energy flows which allowed us to specify the capacities of the required capital equipment. Using these capacities, we worked with a consulting engineering firm to specify equipment to meet these requirements. The consulting engineering firm (AMEC E&C Services, Inc., Minneapolis, Minn.) then estimated equipment costs using data from previous projects and by soliciting bids from potential vendors for some items. Cost estimates were categorized according to new equipment and the equipment that would be replaced (avoided cost) compared to a conventional dry-grind plant. We focused on the net change in equipment cost required to construct a dry grind ethanol plant to use biomass rather than natural gas and purchased electricity as energy sources.

In the biomass scenarios, we assumed that a package natural gas boiler would be included for backup and also perhaps to phase in biomass as a fuel source over time, so the cost of that equipment was not deducted from the conventional base case of a natural gas powered plant. However, because the dryer exhaust was routed to the combustion unit in the biomass systems, we were able to eliminate the capital costs of the thermal oxidizer that would be required in the natural gas-fired conventional plants.

Equipment costs for new items were first estimated, and then other costs associated with the project were added. Among these were installation, building, electrical, contractor costs and fees, engineering, contingency, and escalation to arrive at the total project cost for new items. The resulting capital costs for new items for all fuel and technology combinations are shown in table 2. Total project costs for new items were divided by total equipment costs for new items to yield a project cost/equipment cost factor. The resulting factors ranged from 3.31 to 3.33 for the nine fuel/technology combinations in table 2.

Avoided equipment costs and corresponding total project costs were also estimated and included in table 2 for each fuel/technology combination. Recent estimates of total project costs (including operating capital) for conventional (natural gas) dry-grind plants obtained from design-build firms and bankers (Eidman, 2007) also are included in table 2. Net (new – avoided) project costs for biomass systems are added to the cost of conventional plants to obtain total capital cost estimates for 190 million L (50 million gal) per year biomass fueled plants.

Cost estimates for the 380 million L (100 million gal) per year plants are developed based on the ratio of the plant sizes (380/190 = 2). The cost estimating factor for the 380 million L plant is $(2)^{0.7}$ or 1.6245. Thus, the cost for 380 million L plant is estimated to be 1.6245 times the cost for a 190 million L plant. This technique of adjusting costs for scale is commonly used in many chemical and industrial processes. Based on responses from design/builders of ethanol plants, efforts to optimize and de-bottleneck plants can raise capacity 6% in the case of coal or biomass plants and 20% or more in the case of conventional plants (Nicola, 2005). Nameplate installed costs with necessary operating capital are summarized for the nine fuel/technology combinations in table 3.

Estimating Operating Costs and Other Baseline Assumptions

Table 4 contains the key baseline assumptions that affect profitability of the dry-grind ethanol plants being evaluated. It includes assumptions about the levels of debt and equity in the plant as well as the overall interest rate charged on the debt. A hurdle rate of return on equity was established, and the number of years assumed for depreciation was defined.

Baseline ethanol price was established at $0.42/L ($1.60/gal) received at the ethanol plant. Corn price was assumed to be $138/tonne ($3.50/bushel). Natural gas was established at $7 per decatherm (1.06 million kJ or 1 million BTUs). Electricity was assumed to be priced at 6¢/kWh under baseline conditions, whether the plant was buying or selling.

DDGS were established at the price of $110/tonne ($100/ton). In the scenarios when the syrup is combusted, the resulting co-product is DDG, which we assumed has a market value 110% of conventional DDGS. We base this on the 12-13% higher nitrogen/protein content (Rauch and Belyea, 2006; Morey et al., 2009), presumed attributes of greater consistency, and the higher inclusion rates that DDG should offer to dairy producers as a result of lower fat content. Corn stover was assumed to be priced at $88/tonne ($80/ton) when it was delivered in a dry, densified form at the plant gate (Sokhansanj and Turhollow, 2004; Petrolia, 2006). The value of ash was assumed to be $220/tonne ($200/ton) based on reported values for the ash collected at Corn Plus Ethanol in Winnebago, Minnesota. The ash is marketed as a nutrient source and liming agent with a reported nitrogen, phosphorus, and potash analysis of 0-18-28.

The low-carbon premium was established at 5.3¢/L (20¢/gal) for each unit of ethanol produced using biomass, based upon the savings in transportation costs that accrue when California ethanol buyers are able to purchase ethanol having a carbon imprint 1/3 that of ethanol produced at conventional dry-grind plants using natural gas and purchased electricity. In biomass cases that produce only process heat, it was assumed that 90% of the maximum credit is captured when biomass substitutes for process heat. The

Table 2. Total project costs for 190 million L (50 million gal) per year plants for nine biomass fuel/technology combinations.

		Process Heat Only			Combined Heat and Power (CHP)			CHP plus Electricity to the Grid		
Corn Stover Combustion		FOB Equip. Cost	(% new)	Total Project Cost	FOB Equip. Cost	(% new)	Total Project Cost	FOB Equip. Cost	(% new)	Total Project Cost
Biomass fuel handling	New	$1,275,000	6		$1,400,000	5		$1,750,000	5	
Fluidized bed boiler & steam system	New	$10,394,000	50		$13,203,000	49		$15,314,000	47	
Ash handling	New	$650,000	3		$650,000	2		$650,000	2	
Emissions control	New	$2,520,000	12		$2,575,000	10		$2,950,000	9	
Steam turbine gen. & acc	New	$0	0		$2,900,000	11		$5,566,000	17	
Steam tube dryer	New	$6,129,000	29		$6,312,000	23		$6,312,000	19	
Total cost: new items		$20,968,000	100	$69,749,000	$27,040,000	100	$89,697,000	$32,542,000	100	$107,773,000
Natural gas dryer & thermal oxidizer	Avoided	($9,000,000)	-43	($30,430,000)	($9,000,000)	-33	($30,430,000)	($9,000,000)	-28	($30,430,000)
Total additional cost: net (new-avoided)		$11,968,000	57	$39,319,000	$18,040,000	67	$59,267,000	$23,542,000	72	$77,343,000
Typical conventional ethanol plant cost	Baseline			$112,500,000			$112,500,000			$112,500,000
Biomass powered ethanol plant grand total:				$151,819,000			$171,767,000			$189,843,000
Syrup and Corn Stover Combustion										
Biomass fuel handling	New	$1,275,000	7		$1,400,000	6		$1,750,000	6	
Fluidized bed boiler & steam system	New	$9,264,000	53		$11,731,000	52		$13,867,000	49	
Ash handling	New	$650,000	4		$650,000	3		$650,000	2	
Emissions control	New	$2,481,000	14		$2,517,000	11		$2,565,000	9	
Steam turbine gen. & acc	New	$0	0		$2,600,000	11		$5,497,000	20	
Steam tube dryer	New	$3,700,000	21		$3,810,000	17		$3,810,000	14	
Total cost: new items		$17,370,000	100	$57,928,000	$22,708,000	100	$75,465,000	$28,139,000	100	$93,308,000
Natural gas dryer & thermal oxidizer	Avoided	($9,000,000)	-52	($30,430,000)	($9,000,000)	-40	($30,430,000)	($9,000,000)	-32	($30,430,000)
Total additional cost: net (new-avoided)		$8,370,000	48	$27,498,000	$13,708,000	60	$45,035,000	$19,139,000	68	$62,878,000
Typical conventional ethanol plant cost	Baseline			$112,500,000			$112,500,000			$112,500,000
Biomass powered ethanol plant grand total:				$139,998,000			$157,535,000			$175,378,000
DDGS Gasification										
Biomass fuel handling	New	$790,000	4		$890,000	4		$990,000	4	
Fluidized bed gasifier & steam system	New	$9,054,000	49		$10,586,000	45		$12,216,000	43	
Ash handling	New	$350,000	2		$350,000	1		$350,000	1	
Emissions control	New	$2,300,000	12		$2,414,000	11		$2,673,000	10	
Steam turbine gen. & acc	New	$0	0		$2,870,000	12		$5,556,000	20	
Steam tube dryer	New	$6,129,000	33		$6,312,000	27		$6,312,000	22	
Total cost: new items		$18,623,000	100	$62,045,000	$23,422,000	100	$77,811,000	$28,097,000	100	$93,170,000
Natural gas dryer & thermal oxidizer	Avoided	($9,000,000)	-48	($30,430,000)	($9,000,000)	-38	($30,430,000)	($9,000,000)	-32	($30,430,000)
Total additional cost: net (new-avoided)		$9,623,000	52	$31,615,000	$14,422,000	62	$47,381,000	$19,097,000	68	$62,740,000
Typical conventional ethanol plant cost	Baseline			$112,500,000			$112,500,000			$112,500,000
Biomass powered ethanol plant grand total:				$144,115,000			$159,881,000			$175,240,000

Table 3. Nameplate installed costs for conventional and biomass-fueled dry-grind ethanol plants.

	190 million L (50 million gal) Plants		380 million L (100 million gal) Plants	
Type	Capital Cost	Name Plate Cost $/L ($/gal)	Capital Cost	Name Plate Cost $/L ($/gal)
Conventional	$112,500,000	$0.59 ($2.25)	$182,757,000	$0.48 ($1.83)
Corn stover				
Process heat	$151,819,000	$0.80 ($3.04)	$246,631,000	$0.65 ($2.47)
CHP[a]	$171,767,000	$0.90 ($3.44)	$279,036,000	$0.73 ($2.79)
CHP + grid	$189,843,000	$1.00 ($3.80)	$308,401,000	$0.81 ($3.08)
Corn stover + syrup				
Process heat	$139,998,000	$0.74 ($2.80)	$227,427,000	$0.60 ($2.27)
CHP	$157,535,000	$0.83 ($3.15)	$255,916,000	$0.67 ($2.56)
CHP + grid	$175,378,000	$0.92 ($3.51)	$284,902,000	$0.75 ($2.85)
DDGS				
Process heat	$144,115,000	$0.76 ($2.88)	$234,116,000	$0.62 ($2.34)
CHP	$159,881,000	$0.84 ($3.20)	$259,727,000	$0.68 ($2.60)
CHP + grid	$175,240,000	$0.92 ($3.50)	$284,678,000	$0.75 ($2.85)

[a] CHP - Combined Heat and Power.

Table 4. Common assumptions for all systems.

Category	Baseline Values
Debt-equity assumptions	
Factor of equity	40%
Factor of debt	60%
Interest rate charged on debt	8%
Depreciation period	15 years
Output market prices	
Ethanol price	$0.42/L ($1.60/gal)
DDGS price	$110/tonne ($100/ton)
Electricity (excess) sale price	6¢/kWh
Sale price of ash	$220/tonne ($200/ton)
CO_2 price per liquid unit	$8.80/tonne ($8/ton)
Low-carbon premium	5.3¢/L (20¢/gal)
Government subsidies	
Federal small producer credit	2.6¢/L (10¢/gal)
RFS ethanol tradable credit	1.8¢/L (7¢/gal)
Federal renewable electricity credit	2¢/kWh
Feedstock delivered prices paid by processor	
Corn price	$138/tonne ($3.50/bushel)
Energy prices	
Natural gas	$7/decatherm
Stover delivered to plant	$88/tonne ($80/ton)
Electricity price	6¢/kWh
Propane price	$0.29/L ($1.10/gal)
Operating costs-input prices	
Denaturant price per gal	$0.32/L ($1.20/gal)
Denaturant rate (volume units per 100 of anhydrous)	2
Ethanol yield (anhydrous)	0.41 L/kg (2.75 gal/bushel)

Federal Renewable Energy Electricity Credit of 2¢/kWh was assumed to be received by ethanol plants producing electricity (even though it may be necessary for a private or corporate entity with sufficient passive income and tax liability to own the electrical generation equipment). There were additional minor assumptions including the Renewable Fuel Standard tradable credit of 1.8¢/L (7¢/gal) based on recent sales of Renewable Identification Number (RIN) certificates.

Certain expense items were considered scale-neutral and were applied equally in 190 million and 380 million L (50 million and 100 million gal) per year plants. These included per L (gal) expenses for enzymes, yeasts, process chemicals and antibiotics, boiler and cooling tower chemicals, water and denaturants. We assumed 1.1¢/L (4¢/gal) of enzyme expense, 0.11¢/L (0.4¢/gal) of yeast expense, and processing chemicals and antibiotics of 0.53¢/L (2¢/gal) (Shapouri and Gallagher, 2005). We also assumed boiler and cooling tower chemical costs of 0.13¢/L (0.5¢/gal) and water costs of 0.08¢/L (0.3¢/gal) of denatured ethanol produced. We assumed $120,000 of real estate taxes, $840,000 of licenses, fees and insurance, as well as $240,000 in miscellaneous expenses per year in the 190 million L (50 million gal) per year plants, whether powered by natural gas or biomass, with these figures doubled in the case of 380 million L (100 million gal) per year plants. We applied the conclusion that management and quality control costs represent one-third of labor costs for large and small plants (Nicola, 2005).

Maintenance expenses of biomass plants were established by starting with the costs per L (gal) of ethanol produced in a natural gas-fired plant (Shapouri and Gallagher, 2005) and then determining maintenance costs of the biomass technology cases in proportion to the capital costs of each biomass bundle. To establish maintenance costs for the 380 million L (100 million gal) per year biomass plants, we applied the same scale-up factor as used for capital costs [$(2)^{0.7}$ or 1.6245] to the maintenance costs of the 190 million L (50 million gal) per year plant.

Labor expenses of biomass plants were established by starting with the costs per gallon of ethanol produced in a natural gas-fired plant (Shapouri and Gallagher, 2005) and then adding the estimates of additional labor needed in the biomass technology cases. A 190 million L (50 million gal) per year biomass-powered plant producing process heat can be expected to have $184,000 more in labor expense than its natural gas-fired counterpart (Nicola, 2005). We assumed an additional $184,000 increase in labor expense for the 190 million L (50 million gal) per year biomass cases that generate electricity. For labor costs of 380 million L (100 million gal) per year plants, we applied the conclusion that the larger plants spend 75% as much per L (gal) produced as the smaller plants (Kotrba, 2006). Thus, a 380 million L (100 million gal) per year natural gas-fired plant can be expected to spend $4.5 million per year in labor versus $3 million in a 190 million L (50 million gal) per year plant. A 380 million L (100 million gal) per year biomass plant producing process heat is expected to have $368,000 greater labor expense than its natural gas-fired counterpart (Nicola, 2005). We assumed an additional $368,000 in labor costs for the larger plants that generate electricity.

Economic Model

Biomass fuel/technology combinations along with a conventional natural gas plant were compared in a workbook, with each assigned a specific worksheet. Pro forma budgets were constructed for each combination and a common menu page was established to orchestrate various economic conditions to determine the economic viability of various options. The format of the pro forma budgets used to analyze ethanol plant economic sensitivity was originally developed at the University of Minnesota (Tiffany and Eidman, 2003).

The nine biomass fuel technology combinations and the conventional plant are compared on the basis of rates of return on investment (ROR) using the base line assumptions for 190 million and 380 million L (50 million and 100 million gal) per year capacities. Sensitivities of rates of return to changes in some of the key variables are then evaluated.

Results

Baseline Cases

Rates of return on investment (ROR) for all biomass cases are higher than the ROR for the natural gas-fired plant at 190 million L (50 million gal) per year capacities (fig. 4).

Rates of return are higher for 380 million L (100 million gal) per year plants than for the smaller capacity plants, but the biomass RORs again are higher than the ROR for the natural gas-fired plant (fig. 5).

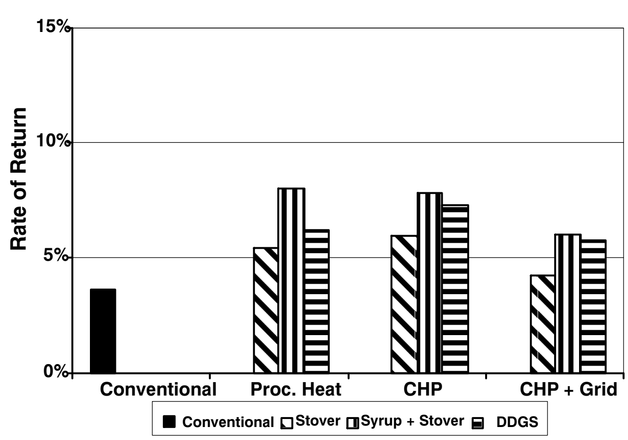

Figure 4. Baseline rates of return for 190 million L (50 million gal) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

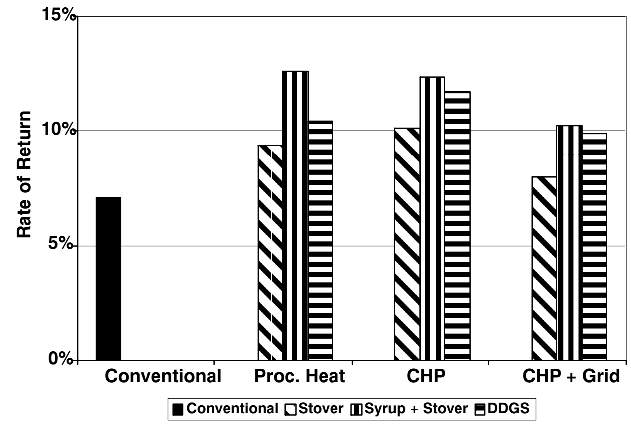

Figure 5. Baseline rates of return for 380 million L (100 million gal) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

Sensitivity to Changes in Key Variables

Sensitivities of rates of return to changes in key variables are compared in tables 5 and 6 for 190 million and 380 million L (50 million and 100 million gal) per year plants, respectively. Shaded values indicate higher rates of return on investment (RORs) for biomass alternatives than for the corresponding conventional plant. In general, RORs are higher for the larger plants; however, cases which favor biomass alternatives over conventional plants are usually the same for both plant sizes, with a few exceptions.

An exogenous rise in natural gas prices from $7 to $10 per decatherm would decrease the rate of return for a conventional ethanol plant with no effects shown on the biomass plants when all plants are at baseline conditions. A decrease in natural gas price from $7 to $4 per decathterm obviously favors the conventional plant. Ethanol plants are very sensitive to natural gas prices, and despite the higher capital costs to implement the biomass options, higher rates of return will be captured by plants utilizing biomass under conditions of high natural gas prices.

Increases in DDGS prices from $110 to $132 per tonne ($100 to $120 per ton) result in higher RORs for the conventional plants as well as most biomass plants. Over one-half of the biomass alternatives have RORs that exceed the conventional plants including those using stover or stover and syrup for process heat, and all cases involving combined heat and power (CHP). Declines in DDGS prices from $110 to $88 per tonne ($100 to $80 per ton) result in lower RORs for conventional plants using natural gas. Plants using stover as fuel have substantial declines in RORs as well, for they are producing as much DDGS as the conventional plant. The plants using syrup and stover are less affected and have less DDGS to sell in all cases because the syrup represents 40% of the dry matter in DDGS. The plants combusting DDGS are impacted least with the drop in DDGS price; and in the case of CHP plus sales of electricity to the grid, no effect is noted because all of the DDGS are combusted.

Higher ethanol prices would remove much of the economic attraction for designing and building ethanol plants capable of using biomass. Higher ethanol prices experienced when moving from the price of $0.42/L ($1.60/gal) at baseline to $0.50/L ($1.90/gal) result in a favorable rate of return on investment (ROR) in the case of

Table 5. Sensitivity of rates of return on investment in percent to changes in key economic parameters for 190 million L (50 million gal) per year plants.[a]

Economic Parameters	Convent. Plant Nat. Gas Electric.	Biomass Process Heat Corn Stover	Biomass Process Heat Stover & Syrup	Biomass Process Heat DDGS	Biomass CHP[b] Corn Stover	Biomass CHP[b] Stover & Syrup	Biomass CHP[b] DDGS	Biomass CHP + Grid Corn Stover	Biomass CHP + Grid Stover & Syrup	Biomass CHP + Grid DDGS
Baseline case	3.7	5.4	8.0	6.3	6.0	7.8	7.3	4.2	6.0	5.8
Natural gas: $7 to $10/decatherm	-1.7	5.4	8.0	6.3	6.0	7.8	7.3	4.2	6.0	5.8
Natural gas: $7 to $4/decatherm	9.0	5.4	8.0	6.3	6.0	7.8	7.3	4.2	6.0	5.8
DDGS: $100 to $120/ton	7.1	7.7	9.6	7.0	8.0	9.2	7.6	6.0	7.3	5.8
DDGS: $100 to $80/ton	0.2	3.1	6.5	5.5	4.0	6.4	6.9	2.4	4.8	5.8
Ethanol: $1.60 to $1.90/gal	19.7	15.9	19.4	17.3	15.2	17.9	17.2	12.6	15.1	14.9
Ethanol: $1.60 to $1.30/gal	-12.3	-5.1	-3.3	-4.8	-3.3	-2.3	-2.7	-4.2	-3.0	-3.3
Low carbon premium: 20¢ to 27¢/gal	3.7	7.6	10.4	8.5	8.1	10.1	9.6	6.1	8.1	7.9
Low carbon premium: 20¢ to 13¢/gal	3.7	3.2	5.7	4.0	3.9	5.5	5.0	2.3	4.0	3.7
Electricity sale price: 6¢ to 10¢/kWh	3.7	5.4	8.0	6.3	6.9	8.4	8.4	6.1	7.8	7.6
Corn price: $3.50 to $4.00/bu	-5.8	-0.8	1.3	-0.3	0.5	1.8	1.4	-0.8	0.7	0.4
Corn price: $3.50 to $3.00/bu	13.2	11.6	14.8	12.8	11.5	13.8	13.2	9.2	11.4	11.2
Corn stover price: $80 to $100/ton	3.7	3.6	7.3	6.3	4.0	6.8	7.3	1.9	4.5	5.8
Corn stover price: $80 to $60/ton	3.7	7.2	8.8	6.3	7.9	8.8	7.3	6.6	7.6	5.8
Natural gas: $7 to $10/decatherm and DDGS: $100 to $80/ton	-5.1	3.1	6.5	5.5	4.0	6.4	6.9	2.4	4.8	5.8
Natural gas: $7 to $10/decatherm and corn stover price: $80 to $120/ton	-1.7	1.8	6.5	6.3	2.1	5.8	7.3	-0.5	2.9	5.8
Sell-all, buy-all electricity: Sell at 6¢/kWh; buy at 6¢/kWh	3.7	5.4	8.0	6.3	6.5	8.7	7.8	4.8	6.6	6.3
Sell-all, buy-all electricity: Sell at 10¢/kWh; buy at 6¢/kWh	3.7	5.4	8.0	6.3	8.6	10.5	10.1	7.8	9.6	9.2

[a] Shaded values indicate higher rates of return for biomass alternative than for corresponding conventional plant.
[b] CHP - Combined Heat and Power.

the conventional plant. This effect occurs because of the lower capital costs associated with a plant built to run on natural gas and purchased electricity. The shift to lower ethanol prices is similar to conditions experienced by plants in the summer and early fall of 2007, with ethanol prices dropping from the baseline level of $0.42 to $0.34/L ($1.60 to $1.30/gal). With this exogenous shift, we observe that the biomass-powered plants have their rates of return trimmed much less than the conventional plants, although they are all still negative. This aspect may be somewhat comforting to boards of directors and possibly their bankers when considering the capital costs to implement a biomass option.

Changes in the premium price for ethanol produced with a low carbon footprint can have substantial impact on the rates of return of the biomass-powered plants. If the price premium increases from 5.3 to 7.1¢/L (20 to 27¢/gal), the biomass-powered plants at all fuel/technology combinations are favored over conventional ethanol plants. If the price premium is 3.4¢/L (13¢/gal) instead of the 5.3¢/L (20¢/gal) assumed in the baseline, the RORs of the biomass-powered plants are reduced; however, biomass RORs are superior to the conventional plants in 7 of 9 cases for both sizes of plants.

In instances where excess electricity can be sold at a favorable price of 10¢/kWh versus 6¢/kWh, the CHP and CHP plus grid cases experience higher rates of return. This would reflect a situation of a utility making a strong response to a state mandate for renewable energy. Such a shift with other levels at baseline results in increased rates of return for all biomass options involving electricity generation.

A rise in corn price from the $138/tonne ($3.50/bushel) baseline to $157/tonne ($4.00/bushel) reduces the rates of return for all the plants. However, it is interesting to note that the biomass-powered plants possess a degree of economic resiliency due to their control of the second highest operating cost, natural gas, faced by the conventional plant in this shift from baseline levels. This effect of greater economic resiliency for the biomass plants should offer some comfort for boards of directors of plants and bankers financing the plants. Despite higher capital costs than the conventional plants, biomass plants offer greater stability in their RORs and may be more successful in the face of corn prices substantially above the baseline of $138/tonne ($3.50 per bushel). A decrease in corn price from $138/tonne ($3.50/bushel) to $118/tonne ($3.00/bushel) with all other levels at baseline favors the conventional plants because they have lower capital costs.

A shift to higher stover prices from $88 to $110/tonne ($80 to $100/ton) results in reduced RORs for the options that use stover and no effect on the plants that use DDGS as a fuel. Corn stover plus syrup options for process heat and CHP applications maintain higher rates of return than conventional natural gas systems for both sizes of plants. Stover in the CHP applications has a slightly higher rate of return than natural gas for both plant sizes. These results offer some assurance that the additional expenses that may be required to densify and process corn stover can be economically justified by plants using corn stover. However, if corn stover were available as low as $66/tonne ($60/ton),

Table 6. Sensitivity of rates of return on investment in percent to changes in key economic parameters for 380 million L (100 million gal) per year plants.[a]

Economic Parameters	Convent. Plant Nat. Gas Electric.	Biomass Process Heat			Biomass CHP[b]			Biomass CHP + Grid		
		Corn Stover	Stover & Syrup	DDGS	Corn Stover	Stover & Syrup	DDGS	Corn Stover	Stover & Syrup	DDGS
Baseline case	7.1	9.4	12.6	10.4	10.1	12.4	11.7	8.0	10.2	9.9
Natural gas: $7 to $10/decatherm	0.5	9.4	12.6	10.4	10.1	12.4	11.7	8.0	10.2	9.9
Natural gas: $7 to $4/decatherm	13.7	9.4	12.6	10.4	10.1	12.4	11.7	8.0	10.2	9.9
DDGS: $100 to $120/ton	11.4	12.2	14.6	11.3	12.6	14.1	12.1	10.2	11.8	9.9
DDGS: $100 to $80/ton	2.9	6.6	10.6	9.5	7.7	10.6	11.3	5.8	8.7	9.9
Ethanol: $1.60 to $1.90/gal	26.8	22.3	26.6	24.0	21.5	24.8	24.0	18.3	21.4	21.1
Ethanol: $1.60 to $1.30/gal	-12.6	-3.5	-1.4	-3.2	-1.3	-0.1	-0.5	-2.3	-0.9	-1.3
Low carbon premium: 20¢ to 27¢/gal	7.1	12.0	15.5	13.2	12.7	15.2	14.5	10.4	12.8	12.5
Low carbon premium: 20¢ to 13¢/gal	7.1	6.7	9.7	7.6	7.5	9.5	8.9	5.6	7.7	7.4
Electricity sale price: 6¢ to 10¢/kWh	7.1	9.4	12.6	10.4	11.2	13.1	13.0	10.6	12.5	12.1
Corn price: $3.50 to $4.00/bu	-4.6	1.7	4.3	2.3	3.4	5.0	4.4	1.9	3.6	3.3
Corn price: $3.50 to $3.00/bu	18.8	17.1	20.9	18.5	16.9	19.7	19.0	14.1	16.9	16.6
Corn stover price: $80 to $100/ton	7.1	7.2	11.7	10.4	7.8	11.2	11.7	5.1	8.3	9.9
Corn stover price: $80 to $60/ton	7.1	11.6	13.5	10.4	12.5	13.6	11.7	10.9	12.2	9.9
Natural gas: $7 to $10/decatherm and DDGS: $100 to $80/ton	-3.7	6.6	10.6	9.5	7.7	10.6	11.3	5.8	8.7	9.9
Natural gas: $7 to $10/decatherm and corn stover price: $80 to $120/ton	0.5	5.0	10.7	10.4	5.4	9.9	11.7	2.3	6.3	9.9
Sell-all, buy-all electricity: Sell at 6¢/kWh; buy at 6¢/kWh	7.1	9.4	12.6	10.4	10.8	13.4	12.4	8.7	10.9	10.6
Sell-all, buy-all electricity: Sell at 10¢/kWh; buy at 6¢/kWh	7.1	9.4	12.6	10.4	13.4	15.7	15.2	12.4	14.6	14.1

[a] Shaded values indicate higher rates of return for biomass alternative than for corresponding conventional plant.
[b] CHP - Combined Heat and Power.

then RORs of all biomass plants are projected to exceed those of natural gas-fired plants.

The fourth to last case in tables 5 and 6 shows the effects of two exogenous factors on RORs of the competing technology bundles. If the price of DDGS were to drop from baseline at $110 to $88/tonne ($100 to $80/ton) and natural gas were to rise from baseline at $7 to $10 per decatherm, the ROR of a conventional plant would be reduced to -5.1% for the 190 million L (50 million gal) per year case, while all plants using biomass would be producing favorable rates of return of 2.4% or better. Although, all rates of return are higher for the larger plant, biomass alternatives produce much higher RORs than the conventional plant under these assumptions.

In the third to last case in tables 5 and 6, the price of natural gas rises from $7 to $10 per decatherm at the same time that the price of corn stover rises from $88 to $132/tonne ($80 to $120/ton). These two changes from baseline result in higher rates of return for all biomass scenarios compared to the conventional natural gas-fired case for both plant sizes. The rate of return for the 190 million L (50 million gal) conventional plant is -1.7%, while RORs for all biomass cases for this plant size are positive except CHP plus electricity to the grid with corn stover as fuel where the ROR is -0.5%. These results illustrate that as natural gas prices climb, biomass fueled systems can yield higher rates of return than conventional plants even at fairly high corn stover prices.

The last two cases in tables 5 and 6 show the effect of an ethanol plant selling all the electricity it produces from biomass and buying back the necessary power for its operations from the grid, sometimes referred to as “sell-all, buy-all.” This situation arises when power utilities are motivated to increase the amounts of renewable electricity in their portfolios according to state renewable energy objectives. An advantage of power produced by ethanol plants is that it would generally be constant, thus fulfilling the criterion of dependable, base load (high capacity factor) power, and therefore it could be the recipient of favorable rates due to capacity payments from the utilities. In the next to last case in both tables all electricity produced is sold at 6¢/kWh and the required electricity is purchased at 6¢/kWh. Comparing this result to the base case, the electricity producing options for “sell-all, buy-all” have higher rates of return than the base case because all electricity produced receives the 2¢/kWh Federal Renewable Electricity Credit, not just the net amount produced for sale. The last case in both tables illustrates a “sell-all, buy-all” scenario where electricity is sold at 10¢/kWh and purchased at 6¢/kWh. When compared to the case where only excess power is sold at 10¢/kWh, significantly higher rates of return are achieved because all electricity produced receives the higher sale rate as well as the 2¢/kWh Federal Renewable Electricity Credit.

Conclusions

We modeled various technology bundles of equipment, fuels and operating activities that are capable of supplying energy and satisfying emissions requirements for dry-grind ethanol plants of 190 million and 380 million L (50 and 100 million gal) per year capacity using corn stover, distillers dried grains and solubles (DDGS), or a mixture of corn stover and ”syrup” (the solubles portion of DDGS).

We estimated capital and operating costs for plants using biomass fuels. Although plants using biomass have higher capital costs, they may offer increased economic resiliency to changes in some of the key operating variables. Results showed favorable rates of return on investment for biomass alternatives compared to conventional plants using natural gas and purchased electricity over a range of conditions. The mixture of corn stover and syrup provided the highest rates of return in general. Factors favoring biomass included a higher premium for low carbon footprint ethanol, higher natural gas prices, lower DDGS prices, lower ethanol prices, and higher corn prices.

Acknowledgements

This work was supported by a grant from the Xcel Energy Renewable Development Fund as well as funds from the Minnesota Agricultural Experiment Station. Colleagues at RMT, Inc., Madison, Wisconsin, and AMEC E&C Services, Inc., Minneapolis, Minnesota made important contributions to the article. In particular, Frank Kalany of AMEC E&C Services, Inc. provided many valuable inputs on system configurations and equipment costs.

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