UNIVERSITY OF MINNESOTA

Twin Cities Campus

Department of Bioproducts and Biosystems Engineering

College of Food, Agricultural and Natural Resource Sciences
Institute of Technology

Biosystems and Agricultural Engineering Building
1390 Eckles Avenue
St. Paul, MN 55108-6005

612-625-7733
Fax: 612-624-3005
E-mail: bbe@ umn.edu
Web: www.bbe.umn.edu

Project Title: Biomass Electricity Generation at Ethanol Plants - Achieving Maximum Impact

Contract Number: RD3-23 Milestone Number: 4 Report Date: January 8, 2010

Reporting Period: September 1, 2009 to December 1, 2009

Milestone Description: Fourth three-month reporting period

Principal Investigator: R. Vance Morey
612-625-8775
rvmorey@umn.edu

Contract Contact: Bridget Foss
612-624-5571
foss0134@umn.edu

Congressional District: Minnesota fifth (UofM Sponsored Projects Administration)
Minnesota fourth (UofM Bioproducts and Biosystems Engineering)

Executive Summary

- Updated project web site www.biomassCHPethanol.umn.edu to make recent results more readily available to the public.
- Continued to refine the model of biomass integrated gasification combined cycle (BIGCC) power production at corn ethanol plants. Integrated superheated steam drying into four configurations. Results showed that although more total electricity was generated, increased demand for electric power for superheated steam drying and parasitic loads resulted in about the same amount of electricity delivered to the grid as with the systems using steam tube drying.
- Showed that the superheated steam drying process allowed for condensation, recovery, and reuse of water removed from the distillers wet grains, which could reduce the total water requirement for producing ethanol by approximately 1.3 gal/gal of ethanol produced.
- Continued to identify opportunities through financial markets, government policies, and incentives that will make it more attractive for potential investors to consider projects to generate renewable electricity at ethanol plants. Reviewed recently proposed electric generation projects, both new and upgraded power plants, to determine realistic values that utilities might be able to pay for renewable, base-load replacing biomass generated electricity. Investors need financial and policy information, as well as technical/economic analysis, when considering these large, long-term investments.
- Estimated life-cycle greenhouse gas emissions for corn ethanol produced with biomass fuel compared to conventional natural gas systems. Ethanol produced with biomass CHP or BIGCC resulted in much greater reductions in life-cycle greenhouse gas emissions compared to gasoline than ethanol produced with natural gas. Ethanol produced in BIGCC systems resulted in over 100% reduction in life-cycle greenhouse gases compared to gasoline. The ethanol produced in this way is a carbon negative biofuel.

Production of substantial amounts of renewable electricity from biomass and the replacement of base-load, coal generated electricity was responsible for these significant reductions. Sequestering the ethanol fermentation CO_2 caused the ethanol for all biomass powered systems (CHP as well as BIGCC) to be carbon negative. Documenting life-cycle greenhouse gas emission reductions for producing ethanol and generating renewable electricity will be an important consideration in policy and economic decisions related to investments in alternative energy. This information will be critical to investors and their bankers when firms consider adopting these new renewable technologies.

- Developed a more extensive model for gas cleanup by including a tar cracking reactor in the synthesis gas stream. This is an important step in creating a gas that is clean enough for combustion in a gas turbine.
- Communicated about project activities; carried out project management, accounting, and reporting functions.

Project funding provided by customers of Xcel Energy through a grant from the Renewable Development Fund.

Technical Progress

Prepared by
R. Vance Morey, Professor, Bioproducts and Biosystems Engineering Department
Douglas G. Tiffany, Extension Educator, Applied Economics Department
University of Minnesota

Summary of Tasks Listed under Milestone 4

1A. Integrated gasification combined cycle analysis

- Complete evaluation of combined cycle alternatives
- Continue specification of equipment and determination of capital and operating costs
- Begin rate of return study
- Begin evaluation of carbon footprint and green house gas reductions

We have continued to model BIGCC systems in Aspen Plus for a range of fuels, energy input rates, and compression levels for the gas turbine. All systems are designed to meet the process energy and electricity needs of a 50 million gallon per year ethanol plant, plus send as much electricity to the grid as possible. We modeled superheated steam drying and evaluated the impact on system performance. A schematic illustrating the integration of superheated steam drying in the ethanol process is shown in Figure 1. A schematic illustrating integration of steam tube drying in the ethanol process is shown in Figure 2 for comparison.

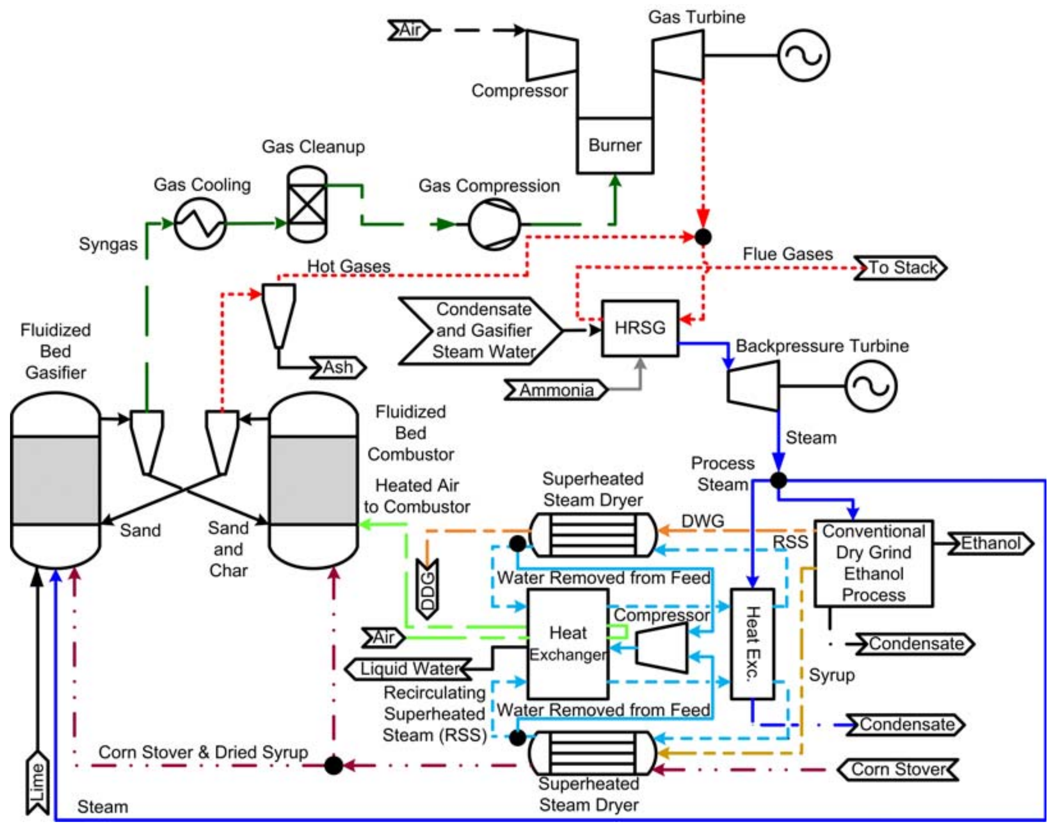

Figure 1. Schematic of BIGCC system using superheated steam dryers for syrup & corn stover fuel.

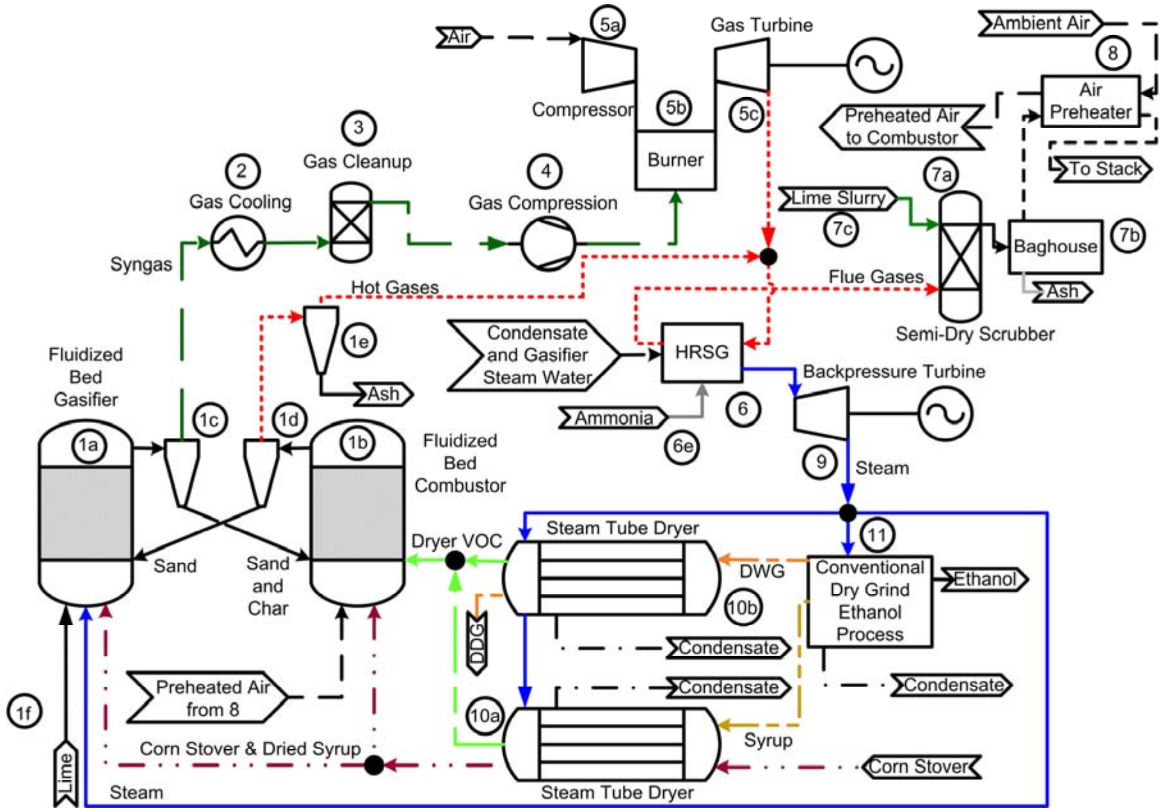

Figure 2. Schematic of BIGCC system with steam tube dryers for syrup & corn stover fuel.

System performance using superheated steam drying and conventional steam tube drying are compared in Tables 1 and 2 for syrup and corn stover and corn stover fuels, respectively. Fuel inputs rates are 110 MW_{th} with two levels of synthesis gas compression for the gas turbine – 10 atm which requires two compressors and is referred to as 10 atm (2 stage), and 20 atm which requires three compressors and is referred to as 20 atm (3 stage).

The superheated steam drying process requires much less process heat than the steam tube dryer, but some additional electric power to compress the superheated vapor so that it can be condensed at higher temperatures. The results in Tables 1 and 2 show that integrating superheated steam drying in the system rather than steam tube drying leads to higher electric generation efficiency, lower thermal efficiency, and more total power generated with a greater amount in the gas turbine and a lesser amount in the steam turbine. This leads to a greater portion of the fuel going to the gasifier and less to the combustor.

Although more total power is generated when the superheated steam dryer is used in the system, additional power required for the superheated steam dryer and greater parasitic BIGCC power requirements result in approximately the same amount of electricity available to send to the grid as with the steam tube dryer. System performance is approximately the same for both syrup and corn stover (Table 1) and corn stover (Table 2). The syrup and corn stover fuel shows a slight advantage in power sent to the grid for the superheated steam drying compared to steam tube drying, while the corn stover fuel alone does not.

Thus, it appears that the primary advantage of super heated steam drying in the ethanol production process utilizing BIGCC is the ability to recover and reuse water rather than to increase electricity sent to the grid. The water recovery is discussed in more detail under task 3.

Table 1. System performance comparing superheated steam drying versus steam tube drying for a 50 million gallon per year ethanol plant with syrup and corn stover fuel at 110 MW_{th} input rate.

	Superheated Steam Dryer		**Steam Tube Dryer**	
	2 stage	**3 stage**	**2 stage**	**3 stage**
Generation Efficiency	32.3%	35.0%	27.2%	28.6%
Thermal Efficiency	58.2%	59.8%	70.0%	70.7%
Power Generation, MW				
Gas turbine	28.1	31.0	18.6	20.1
Steam turbine	7.5	7.5	11.3	11.3
Total	35.6	38.5	29.9	31.4
Power Use, MW				
Ethanol process	4.7	4.7	4.7	4.7
Dryers	4.2	4.2	0	0
Parasitic BIGCC	4.5	5.7	4.0	4.8
To Grid	22.1	23.9	21.2	21.9
Total	35.6	38.5	29.9	31.4
Process Heat, MW_{th}				
Ethanol process	27.9	27.9	27.9	27.9
Dryers	5.1	5.1	23.2	23.2
Total	34.0	34.0	51.1	51.1
Fuel Split				
Gasifier	87%	87%	65%	63%
Combustor	13%	13%	35%	37%

Table 2. System performance comparing superheated steam drying versus steam tube drying for a 50 million gallon per year ethanol plant with corn stover fuel at 110 MW_{th} input rate.

	Superheated Steam Dryer		**Steam Tube Dryer**	
	2 stage	**3 stage**	**2 stage**	**3 stage**
Generation Efficiency	30.9%	33.1%	27.0%	28.8%
Thermal Efficiency	55.8%	54.8%	69.2%	70.2%
Power Generation, MW				
Gas turbine	26.6	29.5	18.6	20.4
Steam turbine	7.4	7.4	11.2	11.2
Total	34.0	36.9	29.7	31.6
Power Use, MW				
Ethanol process	4.7	4.7	4.7	4.7
Dryer	4.1	4.1	0	0
Parasitic BIGCC	4.7	5.9	4.0	4.8
To Grid	20.4	22.1	20.9	22.0
Total	34.0	36.9	29.7	31.6
Process Heat, MW_{th}				
Ethanol process	27.9	27.9	27.9	27.9
Dryer	4.2	4.2	22.6	22.6
Total	32.1	32.1	50.5	50.5
Fuel Split				
Gasifier	92%	92%	64%	63%
Combustor	8%	8%	36%	37%

Life-cycle GHG reductions

We have started to develop comparisons of various systems based on life-cycle greenhouse gas (GHG) reduction for ethanol production using biomass to provide heat and power. Life-cycle GHG estimates for ethanol production at a conventional plant which uses natural gas and fossil fuel generated electricity developed by Liska et al. (2009), Liska and Cassman (2009) and Plevin (2009) are used as a base line. The biomass fueled systems include life-cycle GHG estimates for corn stover nutrient replacement, collection, processing, and transport that were presented in the Milestone 3 report. Life-cycle GHG combustion emissions estimates (methane and nitrous oxides) for corn stover and syrup are also included in the calculation (GREET, 2009). These comparisons exclude the so called "indirect land use effect".

Percent reductions in GHG emissions compared to gasoline are shown for our biomass fueled systems and conventional systems in Figure 3. Conventional natural gas plants reduce life-cycle GHG emissions compared to gasoline by almost 44%. Combined heat and power (CHP) systems reduce the life-cycle GHG emissions by 72% for syrup and stover and 83% for corn stover. The lower GHG reduction value for syrup and stover is due to the fact that less distillers grains are produced, which reduces the coproduct credit. The BIGCC systems have life-cycle GHG reductions greater than 100% (113% for syrup and stover and 121% for corn stove alone). The larger reductions are due to increased electricity production, which allow more to be sent to the grid to replace coal generated power. A life-cycle GHG reduction of more than 100% compared to gasoline makes the ethanol produced a carbon negative biofuel. This is only possible if significant amounts of biomass generated electricity are sent to the grid to replace coal generated power.

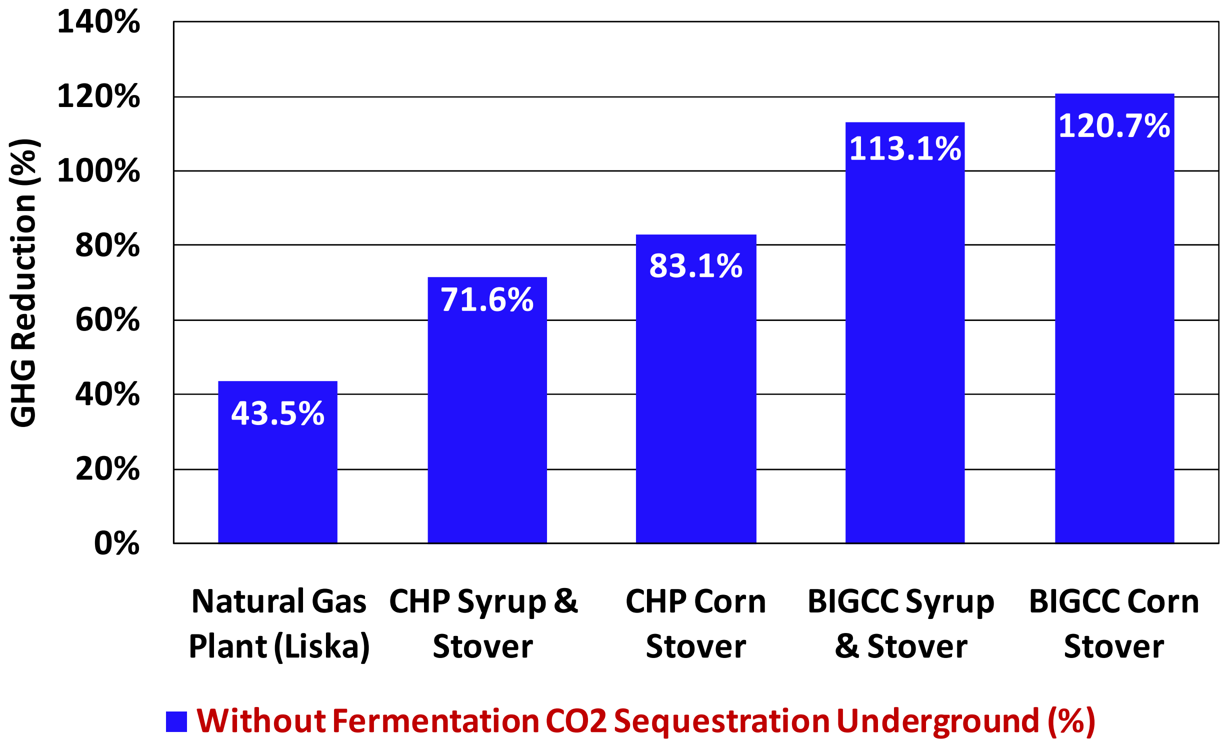

Figure 3. Life cycle greenhouse gas reduction without fermentation CO_2 sequestration compared to gasoline for several corn ethanol systems (excludes indirect land use change effects).

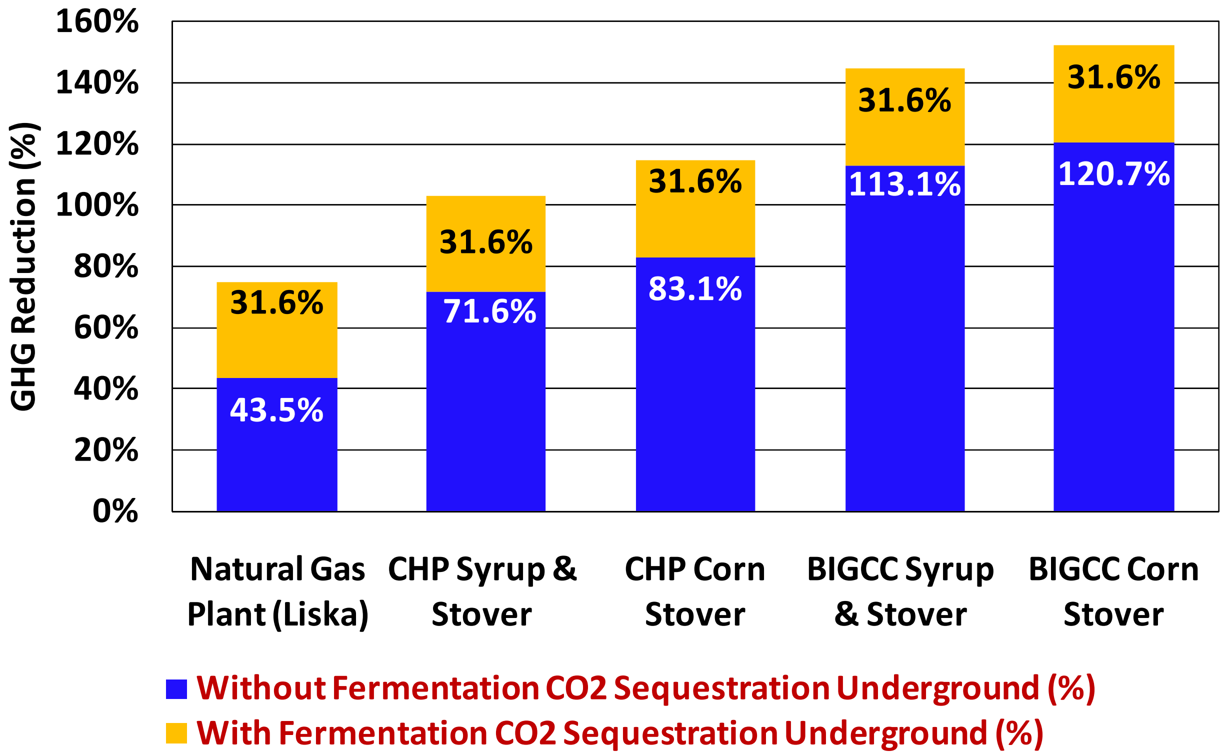

Figure 4. Life cycle greenhouse gas reduction with fermentation CO_2 sequestration compared to gasoline for several corn ethanol systems (excludes indirect land use change effects).

Approximately one-third of the corn entering the plant is converted to ethanol, one-third to distillers grains, and one-third to carbon dioxide (CO_2). The CO_2 captured in the top of the fermenter is almost pure CO_2. In some cases this CO_2 is sold for food processing or other uses, but in many cases it is vented to the atmosphere. Thus, it may be possible to sequester excess CO_2. We modeled that process and show the impact on the various systems in Figure 4. Combining CO_2 sequestration with biomass heat and power results in over 100% life-cycle GHG reduction for the ethanol produced. The BIGCC systems have life-cycle GHG reductions of 145 to 150% compared to gasoline. Again all of these comparisons exclude the indirect land use effect.

References

GREET. 2009. The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Ver. GREET 1.8c.0. Argonne, IL: Center for Transportation Research, Energy Systems Division, Argonne National Laboratory. Available at: http://www.transportation.anl.gov/modeling_simulation/GREET/index.html. Accessed 7 July 2009.

Liska, A.J., and K.G. Cassman. 2009. Response to Plevin: implications for life cycle emissions regulations. *Journal of Industrial Ecology* 13(4): 508-513.

Liska, A.J., H.S. Yang, V.R. Bremer, T.J. Klopfenstein, D.T. Walters, G.E. Erickson, and K.G. Cassman. 2009. Improvements in life cycle energy efficiency and greenhouse gas emissions of corn-ethanol. *Journal of Industrial Ecology* 13(1): 58-74.

Plevin, R.J. 2009. Modeling corn ethanol and climate: a critical comparison of the BESS and GREET models. *Journal of Industrial Ecology* 13(4): 495-507.

1B. Gasification – gas cleanup modeling and technology evaluation

- Complete determination of requirements for gas clean up
- Continue specifying gas cleanup technologies
- Continue determination of capital and operating costs

Synthesis gas clean up is an import requirement prior to combustion in the gas turbine. The first step in the process is tar cracking. A diagram of a portion of the Aspen Plus model for tar cracking is shown in Figure 5. Tar is modeled as C_6H_6O, C_7H_8, and $C_{10}H_8$. A tar cracking vessel is placed downstream from the cyclone at the exit of the gasifier to model a fixed bed catalyst reformer. Reforming reactions ($C_nH_m + {}_nH_2O \leftrightarrow (n+m/2)H_2 + nCO$) and water-gas shift reactions ($CO+H_2O \leftrightarrow CO_2+H_2$) are the main reactions in the tar reformer. At the same time, ammonia is also eliminated ($2NH_3 \leftrightarrow N_2+3H_2$). All the reactions are endothermic, so additional heat from the hot gas leaving the combustor is provided to the tar cracker by having the hot gas pass through a heat exchanger in the tar cracker. Synthesis gas enters the tar cracker at 870 ^oC, 1 atm, and leaves at 780 ^oC, 1 atm.

Following the tar cracker, the synthesis gas is further cooled, scrubbed, and cleaned as shown schematically in Figure 6. It involves cooling of the gas in a heat exchanger with the heat captured to partially reheat the condensed process steam. Gas is further cooled in a wet scrubber where water is sprayed to cool the gas by evaporation. Once the mixture is saturated with water vapor, additional water scrubs particles from the synthesis gas. The synthesis gas then passes through an acid gas clean up system to remove harmful components such as H_2S, HCl, and NH_3.

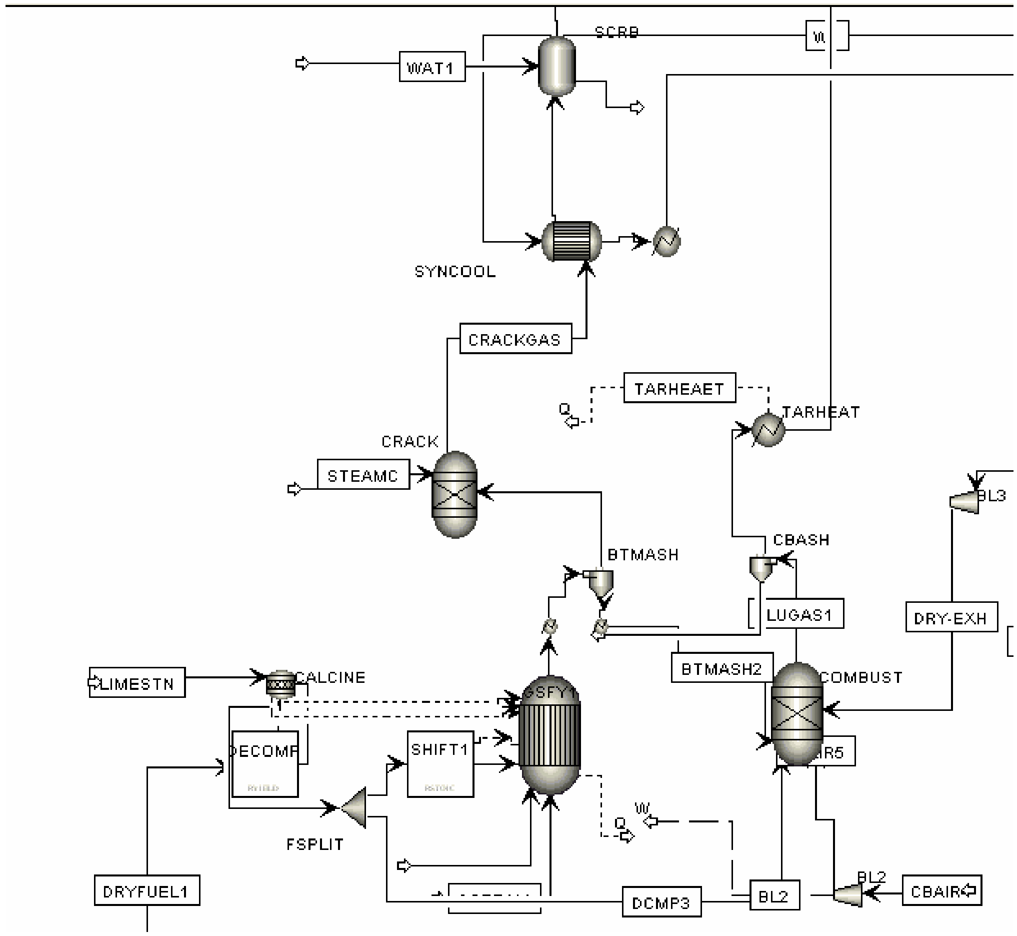

Figure 5. Tar cracking as the first step in gas cleanup.

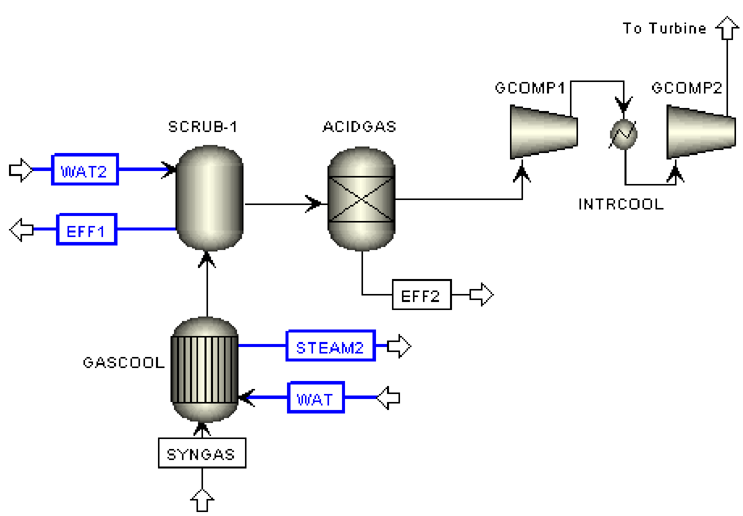

Figure 6. Synthesis gas cooling, scrubbing and cleanup followed by compression.

1C. Integration of superheated steam dryer technology

- Complete determination of process energy reduction
- Complete determination of process water reduction
- Complete determination of impact on electricity generation
- Continue study of changes in capital and operating costs
- Begin evaluation of rate of return

We showed a schematic of a BIGCC system with superheated steam dryers in Figure 1. If the fuel is a mixture of syrup and corn stover there will be two dryers (Figure 1), one which dries the distillers wet grains (wet cake) to produce distillers dried grains (DDG) and another which dries a mixture of syrup and corn stover to produce dry fuel for gasification and combustion. If the fuel is corn stover there will be one dryer, which dries a mixture of distillers wet grains (wet cake) and syrup to produce distillers dried grains with solubles (DDGS). The Aspen Plus model of the superheated steam dryer is the same for each configuration. Input streams will vary based on flow amount and moisture content. A schematic of the superheated steam drying process is shown in Figure 7.

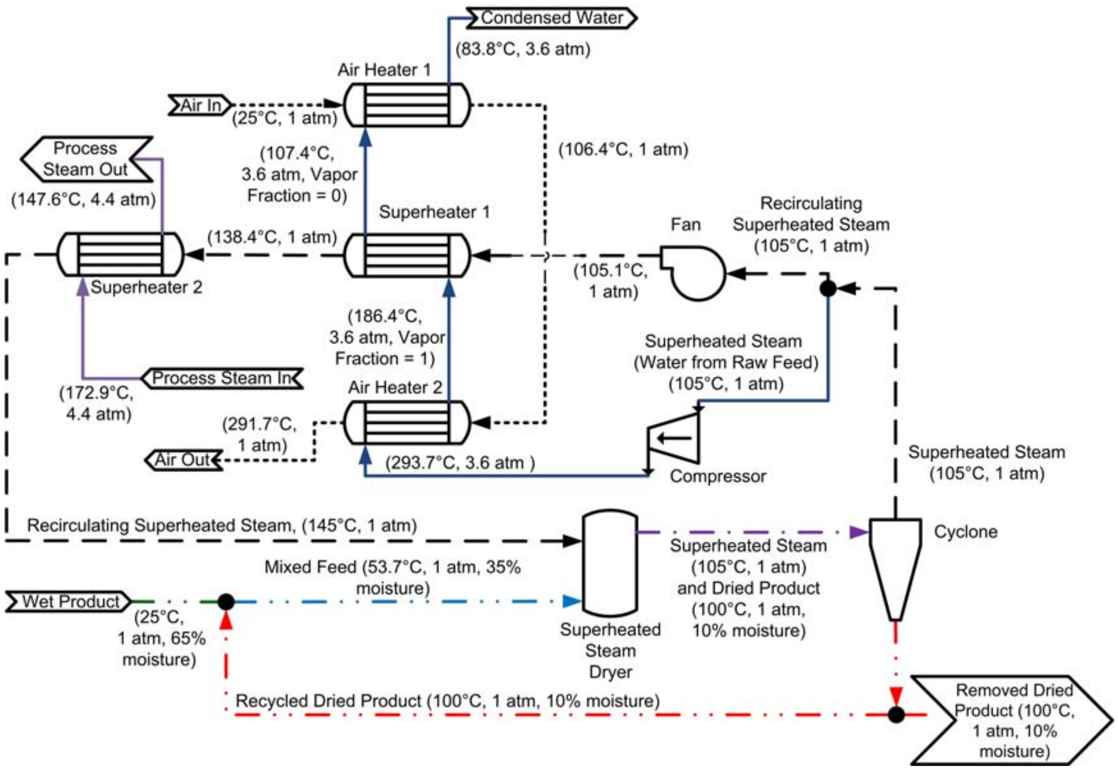

Figure 7. Schematic of superheated steam dryer to produce DDGS with 10% moisture.

Water vapor is removed from the distillers wet grains (DWG) and mixes with the superheated steam in the dryer. The mixture of superheated steam and dried product is separated in the cyclone. Some of the dried product (DDG) is removed and some recycled to reduce the moisture content of the product entering the dryer.

After the superheated steam leaves the cyclone, an amount of vapor equal to the water removed from the product in the dryer is separated for compression and condensing. The remainder is recirculated for drying. The recirculated superheated steam is partially reheated in a heat exchanger using energy from the condensing portion of the water removed. The recirculated superheated steam is brought to its final temperature with process steam. The water vapor removed is compressed to increase its condensing temperature and then run through a series of heat exchangers to preheat the combustion air (air heaters 1 and 2) and to preheat the recirculated super heated steam.

Detailed comparisons of the results for superheated steam drying and steam tube drying for the systems modeled under task one are presented in Table 3. Our modeling shows that we can condense all of the water and use it to preheat combustion air and the recirculated superheated steam. The net energy (process steam plus compressor and fan energy) required to remove water in the superheated steam dryer is about 1000 kJ/kg (430 Btu/lb) compared to about 2670 kJ/kg (1150 Btu/lb) in the steam tube dryer.

In addition, because the water is condensed and can be reused in the ethanol process when a superheated steam drying process is employed, the water requirement for producing ethanol is reduced by about 1.3 gallons of water/gallon of ethanol. This is not possible with the steam tube dryer because the water leaves as vapor in the drying air and is not easily recaptured. Current dry-grind ethanol production technology requires on the order of 2.7 to 3.7 gallons of water/gallon of ethanol at the plant. Thus, implementing a superheated steam dryer could reduce the requirement to the range of 1.4 to 2.4 gallons of water/gallon of ethanol.

The condensed mixture will be separated with a membrane process (not shown in Figure 6) into a relatively clean stream of water that flows back into the process and a dirtier stream which will contain volatile organic compounds (VOCs) and other materials released in the drying process. This portion will be a feed stream to the combustor where the VOCs and other materials will be destroyed in the high temperature process. There will no longer be an exhaust air stream from the dryer which will flow into the combustor.

Table 3. Comparison of performance of superheated steam and steam tube drying systems for a 50 million gallon per year ethanol plant.

	Syrup and Corn Stover		**Corn Stover**	
	Superheated St.	**Steam Tube**	**Superheated St.**	**Steam Tube**
Co-product dryer, MW				
Heat	2.5	12.8	4.2	22.6
Power	2.3	0	3.8	0
Fuel dryer, MW				
Heat	2.6	10.5	-	-
Power	1.9	-	-	-
Total, MW	9.3	23.3	8.0	22.6
Water removed, kg/hr	31,204	31,204	30,630	30,630
Energy, kJ/kg water	1070	2678	946	2659
Energy ratio relative to steam tube dryer	0.40	1.0	0.36	1.0
Water recovered, L/L ethanol	1.34	0	1.32	0

2. Develop and test business model

- Complete specification of key elements
- Continue grid evaluation and feasibility study
- Continue evaluation of technical issues and develop standard systems of implementation
- Continue development of plans for expedited permitting and regulatory approval
- Continue modeling procurement system

The following analysis was prepared by Larry L. Schedin, LLS Resources, LLC.

Key elements in developing and testing of the business model are the value of electric power generation produced that: A) replaces electricity otherwise purchased for on-site processing or B) is sold as a resource to wholesale electric market participants (or some combination thereof).

A. Replacing Utility-Supplied Electricity for On-Site Processing

1. Displaced Utility Cost Analysis

Presently, almost all ethanol plants purchase electricity for on-site processing use from the utility providing local retail service. The ethanol plants are captive customers of the local utility because of state service territory laws giving the local utility the exclusive right to provide retail service within their state-defined service territories. The local utility provides service under an industrial or large commercial tariff which to some extent includes economies of scale and other favorable usage characteristics of large industrial customers. In addition to a fixed monthly service charge, the industrial tariff includes three separate components to recover the utility's cost of generation, transmission and distribution. Under regulatory principles, the basic costs in each tariff element recover no more than the utility's embedded costs related to fuel and O&M, fixed capital, and administration assigned to each tariff category. Therefore, the benefit of a current industrial rate is that it recovers embedded costs, which are derived from the weighted average of investments of various vintages, which total far less than current incremental costs for new generation, transmission and distribution. The principal elements of a typical monthly bill for a 10,000 KW ethanol facility in Xcel Energy's service territory operating 8000 hrs per year and served at primary voltage would be calculated under Xcel's General Service Tariff as follows:

XCEL Energy Bill Item	Summer Month (June-Sept)	All Other Months (W)
Demand Charge: @ $9.25 (S) & $5.91(W) per KW-mo	$92,500	$59,100
Fuel +Purched Energy, Est: @ $0.035 (S) & $.028 (W) Per KWH	$233,334	$186,667
Other Energy Charge:		
@ $0.0280 per KWH Peak	$74,667	$74,667
@ $0.0165 per KWH Off-Peak	$66,000	$66,000
Other Riders (Renewable Energy, Envir. & Other): $0.0057 per KWH	$38,000	$38,000
Total $ (W/O taxes)	$504,501	$424,434
Total ($ per KWH)	$0.0757	$.0637
Total ($ per KWH weighted)	$.0677	

2. Standby Costs

Unfortunately, the foregoing seasonal amount monthly totals cannot be entirely saved by designating on-site site generation output to displace utility supplied power. This is because the utility will claim that it must continue to incur certain costs, recovered as standby charges, even with the facility load self generated. These continuing utility costs include standby generation costs, transmission costs, and distribution costs which are necessary to support facility operation when the on-site generation is out of service for planned and unplanned outages. Standby charges, applicable even when the on-site generation is fully operational, are typically in the range of $3.00 to $5.00 per KW month depending on unit performance. Additionally, a further demand charge penalty along with a fuel and purchased energy charge applied to replacement energy are assessed when the on-site unit is out of service. These standby cost factors can easily reduce the foregoing potential gross savings by 10%-15% or more and must be considered when calculating the total benefits of displacing utility supply for on-site uses.

3. Utility Cost Escalation

Utility costs will continue to escalate as utilities recover mercury removal and carbon trading costs via special riders and as they recover increases in renewable energy costs via existing riders, especially as Xcel and other utilities add renewable facilities to meet their state mandates (30% renewable energy by 2020 for Xcel and 25% renewable energy by 2025 for all other MN utilities). Furthermore, future utility base-load power plant additions are now limited primarily to re-powering of existing coal and nuclear plants along with a very limited number of biomass plants requiring large amounts of biomass fuels. The use of natural gas fueled combined cycle units as base-load surrogates will certainly place further upward pressure on utility rates.

B. Value of Electricity Sold to Wholesale Market Participants

1. Midwest Energy Markets

Although the Midwest Independent System Operator (MISO), located in Carmel, Indiana, operates an energy-only, hourly spot market for electricity, there is no comparable short-term or longer-term market for capacity in the MISO footprint. This is in contrast to the PJM (Pennsylvania, New Jersey, Maryland) Independent System Operator (to the east of MISO) which operates both a longer-term capacity market as well as an energy only spot market. Therefore, capacity purchased and sold by Midwest utilities is secured by bilateral contracts including capacity payments and energy payments (depending on the type of capacity being purchased or sold). Base-load generating units are generally those with relatively low operating costs and high capital costs such as large coal, hydro and nuclear plants, typically designed to operate on a round-the-clock (24x7) basis. Because most low-cost, base-load generation is presently fully utilized either by the owning utilities or by contract sales at market prices prevailing when the contracts prices were negotiated, present base-load capacity prices would presumably be set at the cost of new base-load capacity. Today we have a scarcity of cost data for new electricity generation assets because of the uncertainty about implementation of policies related to carbon emissions and safety. These factors plus the reduced demand for power have kept more conventional base-load units from being constructed. The only exceptions are re-powering of existing plants, a limited amount of biomass potential from other sources, and a limited amount of hydro power from Manitoba Hydro which is generally being sold on a 5x16 (peak hour) basis. In any event, it is helpful to examine costs of recently cancelled coal-fired units and current re-powering upgrades.

2. Economics of Recently Proposed New Coal Plants and Re-Powering Upgrades

Table 4 shows the results (6 examples) from our investigation to date regarding the cost of base-load energy. Three of the examples are coal-fired plants which have recently been cancelled. The other three are uprates of existing plants. Results show that the uprates (especially those at nuclear plants tied to operating permit extensions) certainly make economic sense compared to new coal-fired plants which are not feasible in any event. It is also important to note that since uprates are available from only a fixed set of existing plants (those with environmental improvement and constraint elimination potential) additional capacity from uprates will be quite limited.

Converting capital investment to $ per KW-yr from $ per KW was accomplished by applying a levelized annual revenue requirement annuity of 18% (typical for a long-term, comparative capital investment analysis for an investor-owned utility). The resulting conversion of $ per KW-yr to $ per KWH was based on the assumption of 8000 hrs of full-load annual use. Fuel and O&M costs for upgrades were determined on a marginal basis, while fuel and O&M costs for new units were estimated on a total cost basis. Data were taken from regulatory commission dockets, Federal Energy Regulatory Commission Reports (FERC Form No.1), and news releases.

Table 4. Calculation of base load generation value from six selected projects – recently proposed base-load steam plants and coal and nuclear plant upgrades.

Plant Surveyed	Fuel Type	Uprate or New Unit, MW	Capital Investment $/KW-yr	Capital Investment $/MWH	Fuel + O&M $/MWH	Total $/ MWH
Nelson Dewey*	Coal/Biomass	(N), 300 MW	$756	$94.50	$30.00	$124.50
Southerland*	Coal/Biomass	(N), 630 MW	$507	$63.40	$30.00	$93.40
Sherco 1&2*	Coal	(U), 70 MW	$550	$68.80	$18.90**	$87.70
Big Stone 2*	Coal	(N), 580 MW	$438	$54.70	$24.00	$78.70
Prairie Is. 1&2	Nuclear	(U), 164 MW	$362	$45.20	$6.40**	$51.60
Monticello	Nuclear	(U), 71 MW	$337	$42.10	$6.40**	$48.50

*Indicates project cancelled or on hold
** Indicates Fuel and O&M cost estimates are marginal

The foregoing estimates for new units are conservative because transmission costs for generator outlets are excluded while the uprates will require little or no transmission additions.

3. Wholesale Market Value of BIGCC On-Site Generating Units at Ethanol Plants

Although the BIGCC generating units under current study are not as large as utility-owned, conventional base load units, the BIGCC units have the same operating and capital cost characteristics as the larger units (low fuel costs protected from unreasonable escalation, high investment costs and continuous operation). BIGCC units can therefore be classified as base load generation and should be eligible for wholesale capacity sales at prices exceeding the value of on-site use provided that owners and developers are willing to enter into long-term contracts with wholesale buyers. Besides collectively filling a base-load power supply gap, BIGCC units also have other important attributes for added value:

a. Renewable Energy Credit (REC) value

b. Low carbon footprint (carbon credit) value

c. Reasonable transmission outlet cost value (as per DRG Study Phase II Report)

d. On-site fuel availability. It is important to note that the Laurentian Energy Authority operating biomass plants in Hibbing and Virginia was recently granted a further subsidy by Xcel Energy to cover unanticipated fuel shipment costs.

SELECTED PROJECT DETAILS

1. Proposed WPL (Alliant Energy) Nelson Dewey steam plant addition, Cassville, WI
a. Plant size: 300 MW
b. Plant fuel: Coal/biomass
c. Plant investment: $1.26 billion ($4,200 per KW = $756 per KW-yr)
d. Plant capital cost expressed as $ per KWH @8000 hrs use: $0.0945 per KWH
e. Total cost assuming fuel plus O&M @ 3.0 cents per KWH: $0.1245 per KWH
f. Status: Certification denied by WPUC December, 2008

2. Proposed Interstate Power Company (Also Alliant Energy) Sutherland Unit, Marshalltown, IA
a. Plant size: 630 MW
b. Plant fuel: Coal/biomass
c. Plant investment: $1.774 billion ($2,816 per KW = $507 per KW-yr)
d. Plant capital cost expressed as $ per KWH @8000 hrs use: $0.0634 per KWH
e. Total cost assuming fuel plus O&M @ 3.0 cents per KWH: $0.0934 per KWH
f. Status: Certification request withdrawn by Alliant Energy, 2009

3. Proposed Uprating of Xcel Energy Sherco Units 1&2
a. Planned Uprate: 70 MW
b. Plant fuel: Coal
c. Plant investment: Unit No.1: $146.4 million. Unit No.2: $67.6 million. $214 million total ($3,057 per KW = $550 per KW-yr)
d. Plant capital cost expressed as $ per KWH @8000 hrs use: $0.0688 per KWH
e. Total cost assuming fuel without added O&M @ 1.89 cents per KWH: $0.0877 per KWH
f. Status: Request temporarily withdrawn by Xcel Energy, 2008, MPUC Docket No. E002/CN-07-02

4. Proposed Big Stone Unit No. 2: By OTP, MDU and others
a. Planned Unit Size: Either 500 MW or 580 MW
b. Plant fuel: Coal
c. Plant investment: 500 MW: $1.272 billion. 580 MW: $1.411 billion (Range of $2,432 per KW to $2,544 per KW or $438 to $458 per KW-yr)
d. Plant capital cost expressed as $ per KWH @ 8000 hrs use: $0.0547 to $0.0542 per KWH
e. Total cost assuming fuel plus O&M @ 2.40 cents per KWH: $0.0782 to $0.0787 per KWH
f. Status: Remaining partners withdrew after OTP withdrew October, 2009

Note: Larger unit size used in final comparisons

5. Proposed Prairie Island Nuclear Plant Uprate, Units 1&2
a. Proposed uprate: 164 MW
b. Plant Fuel: Nuclear

c. Uprate Investment: $329.8 million ($2,011 per KW = $362 per KW-yr)
d. Plant marginal capital cost expressed as $ per KWH @ 8000 hrs use: $.0452 per KWH
e. Total cost assuming fuel <u>without</u> added O&M @$0.0064 per KWH: $0.0516 per KWH.
f. Status: Hearings under way, MPUC Dockets No. E002/CN-08-509 &510

6. Monticello Nuclear Plant Uprate

a. Proposed uprate: 71 MW
b. Plant Fuel: Nuclear
c. Uprate Investment: Ranges from $104.0 million to $133.0 million (from $1,465 per KW = $264 per KW-yr to $1,873 per KW = $337 per KW-yr (Used upper estimate for summary)
d. Plant marginal capital cost expressed as $ per KWH @ 8000 hrs use: $0.033 per KWH to $0.0421 per KWH
e. Total cost assuming fuel plus only variable O&M @$0.0064 per KWH: $0.0394per KWH to $0.0485 per KWH
f. Status: Uprate approved MPUC Docket No. E002/CN-08-185

3. Analysis of a biomass procurement system

- Complete study of biomass availability
- Complete study of biomass collection, local storage, and transport to processing facility
- Complete study of biomass processing facility
- Begin storage and transportation evaluation
- Begin specification of equipment and determination of capital and operating costs

We have continued to focus on the following components of the proposed system.

- Logistics associated with collection including shredding, raking, baling (1250 lb round bales), and bale moving of corn stover to a local storage within 1 to 2 miles of the field a few days after corn grain harvest in the fall. This process occurs in a 4 to 6 week period from October to mid-November. We considered nutrient replacement for the material removed.

- Bale to bulk processing at the local storage including tub grinding, roll compaction to 240 kg/m^3 (15 lb/ft^3), and loading trucks (25 tons each). Processing will occur throughout the year with mobile units moving from site to site. Processing will occur at the rate of 25 tons/hour (one truck load) with at least 200 tons per day. Thus, each local storage should contain at least 200 tons (320 bales at 1250 lbs each).

- Truck transport in 25 ton loads of bulk corn stover to end users.

Recent results summarizing the cost, fossil energy consumption, and life-cycle greenhouse gas emissions for the corn stover logistics system are shown in Figures 8 to 10.

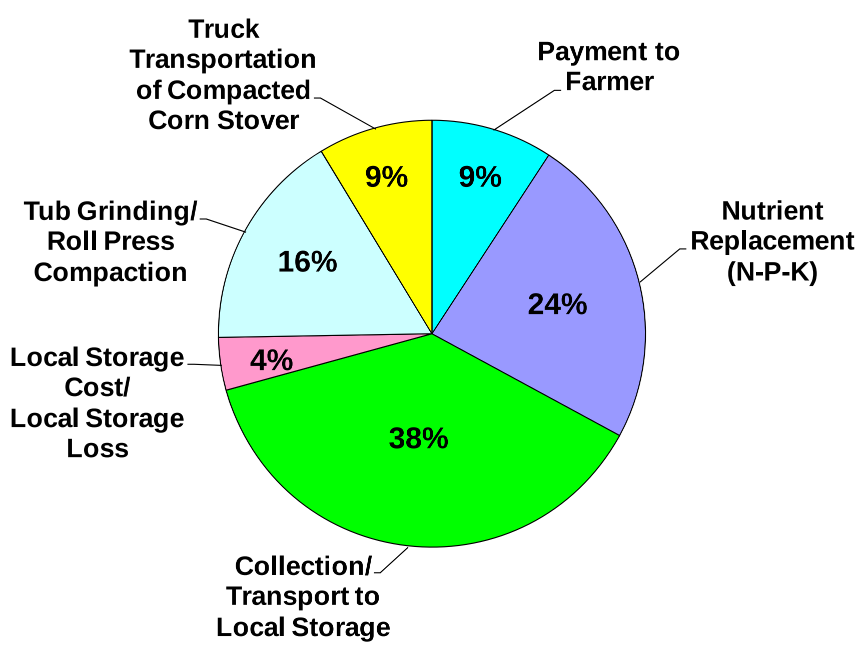

Figure 8. Distribution of total cost ($74/ton at 15% moisture) for corn stover delivered to the user.

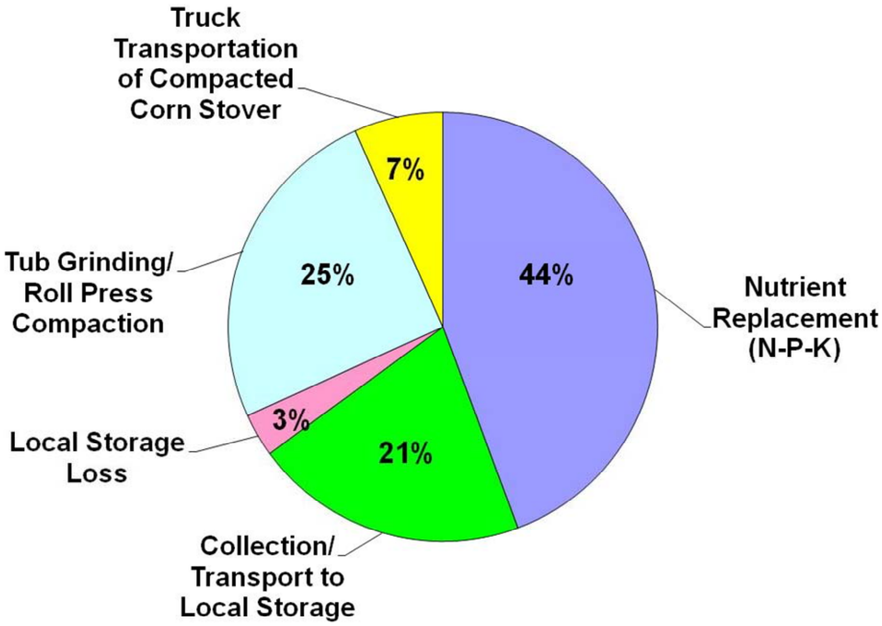

Figure 9. Distribution of fossil energy input (1100 MJ/dry tonne – 7% of dry biomass energy) for corn stover delivered to the user.

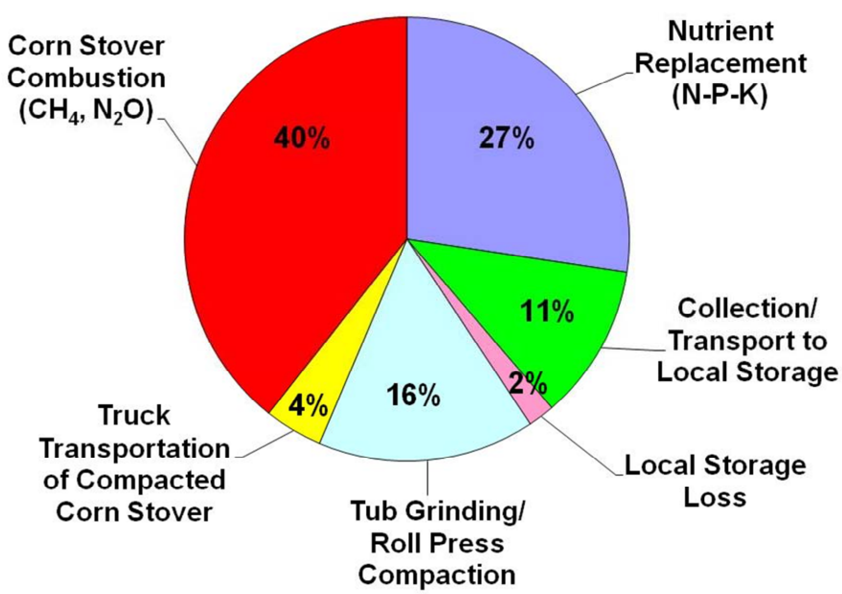

Figure 10. Distribution of life-cycle GHG emission (134 gCO_2e/dry tonne) for corn stover delivered to the user.

4. Outreach and education for investors, policy makers, utilities and the public

- Update web site
- Continue development of models, spreadsheets and other decision aids
- Continue workshops or presentations at conferences
- Continue presentation of papers
- Identify and document policy issues

We continue to update the web site to reflect the most recent project results. We are continuing to improve new sections on biomass logistics and biomass densification.

Presentation by Vance Morey related to BIGCC technologies

10/7/09 "Generating Electricity from Biomass – Making Ethanol from Corn More Renewable," Lecture to Elder Scholars, University of Minnesota, St. Paul, MN

Seminars and Conference Presentations by Doug Tiffany at which he discussed BIGCC technology

10/28/09 "Advanced Technologies and Biofuels Production," Lecture to Elder Scholars, University of Minnesota, St. Paul, MN

10/14/09 "Production Costs, Prices, and Profitability of Biofuels," Lecture to Elder Scholars, University of Minnesota, St. Paul, MN

9/30/09 "Economic Viability of Biofuels: the Interplay of Policies and Advancing Technologies," Keynote Address at International Congress of Biocombustibles, Guayquil, Ecuador.

9/23/09 "Biomass for Combined Heat and Power at Ethanol Plants," Lecture at Malavecchia Experiment Station, Venato, Italy

9/22/09 "Financial Performance of Current and Future Ethanol Production Technologies," Lecture to Graduate Students at Universita Degli Studi Di Padova, Padova, Italy

Project Status

Overall we continue to make good progress. We completed initial modeling on superheated steam drying and incorporated that model in the overall system model to determine the impact on electricity production and water recovery.

We updated results on biomass logistics and revised a paper that had been submitted for publication based on the reviewers' comments. We continue to participate in extension and outreach activities related to the project, primarily through the work of Doug Tiffany.

We had several meetings with our subcontractor, Larry Schedin, LLS Resources, to discuss various incentive programs and business models. He arranged several meetings with perspective investors so that they could learn about our work and we could gain a better understanding of their interests. We are working on scheduling meetings between ethanol plant managers and potential investors who are interested in using biomass to generate electricity at ethanol plants. This will help us further refine potential business models for generating electricity at ethanol plants.

We have also been meeting with our subcontractor, AMEC E&C Services to discuss practical equipment configurations to include in our modeling efforts. We continue to work with them to develop equipment configurations and cost estimates for several of the systems that we have modeled.