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: 5 Report Date: May 27, 2010

Reporting Period: December 1, 2009 to May 1, 2010

Milestone Description: Fifth 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. We revised our model of the gasification/combustion system to send all of the fuel to the gasifier with synthesis gas being sent to the combustor to provide the required additional energy. This should provide greater flexibility in gas cleanup.
- Adjusted the modeling of systems for steam tube drying by using the exhaust of the dryers as part of the input air for the gas turbine rather than sending it to the fluidized bed combustor for destruction of volatile organic compounds. This change provided increases of 17 to 23% in power sent to the grid compared to previous configurations for the same amount of biomass fuel.
- 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 recent developments in combined cycle power generation using natural gas fuel as a basis for determining the value of BIGCC generated power at ethanol plants. Investors need financial and policy information, as well as technical/economic analysis, when considering these large, long-term investments.
- Updated 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.

- Initiated modeling on a system to deal with alkali metals (potassium and sodium), prevalent in herbaceous biomass such as corn stover, which are notorious for causing boiler fouling in combustion configurations.
- 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 5

1A. Integrated gasification combined cycle analysis

- Continue specification of equipment and determination of capital and operating costs
- Continue rate of return study
- Continue 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.

Based on suggestions from industrial cooperators, we adjusted our modeling of the fluidized bed gasification and fluidized bed combustion configuration so that all of the biomass fuel is sent to the gasifier to produce synthesis gas, rather than sending some biomass to the gasifier and some to the combustor. Some of the resulting synthesis gas is then sent to the combustor along with char to meet its total heat load. The overall system thermal performance is about the same with this configuration as the previous configuration, but it provides greater flexibility for cleanup of gas that will be combusted to meet the total process heat needs. We believe this configuration provides better opportunity to deal with alkali metals (potassium and sodium), prevalent in herbaceous biomass such as corn stover, which are notorious for causing boiler fouling in combustion configurations.

We also changed the modeling of systems for steam tube drying by using the exhaust of the dryers as part of the input air for the gas turbine rather than sending it to the fluidized bed combustor for destruction of volatile organic compounds. Since the dryer exhaust air needs to be heated for destruction of volatile organic compounds, using it as a portion of the combustion air for the gas turbine allows more fuel to be sent to the gas turbine, which leads to greater power production for the same fuel input. Schematic diagrams illustrating the revised gasification/combustion configuration and the use of steam tube drying exhaust as part of the input air for the gas turbine are shown for superheated steam and steam tube drying systems in Figures 1 and 2, respectively.

System performances for the revised gasification/combustion configurations for both superheated steam drying and steam tube drying as well as the change to send dryer exhaust to the gas turbine 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).

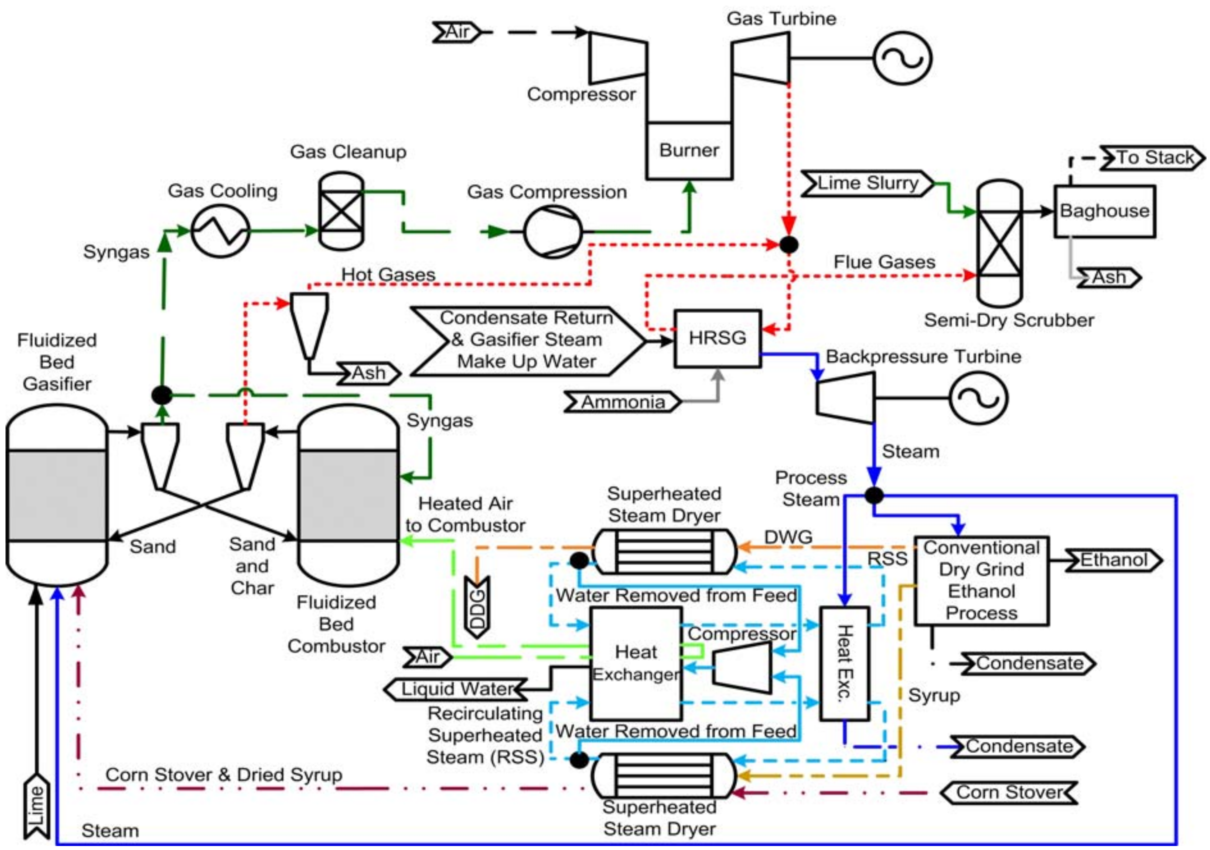

Figure 1. Schematic of BIGCC system using superheated steam dryers for syrup & corn stover fuel.

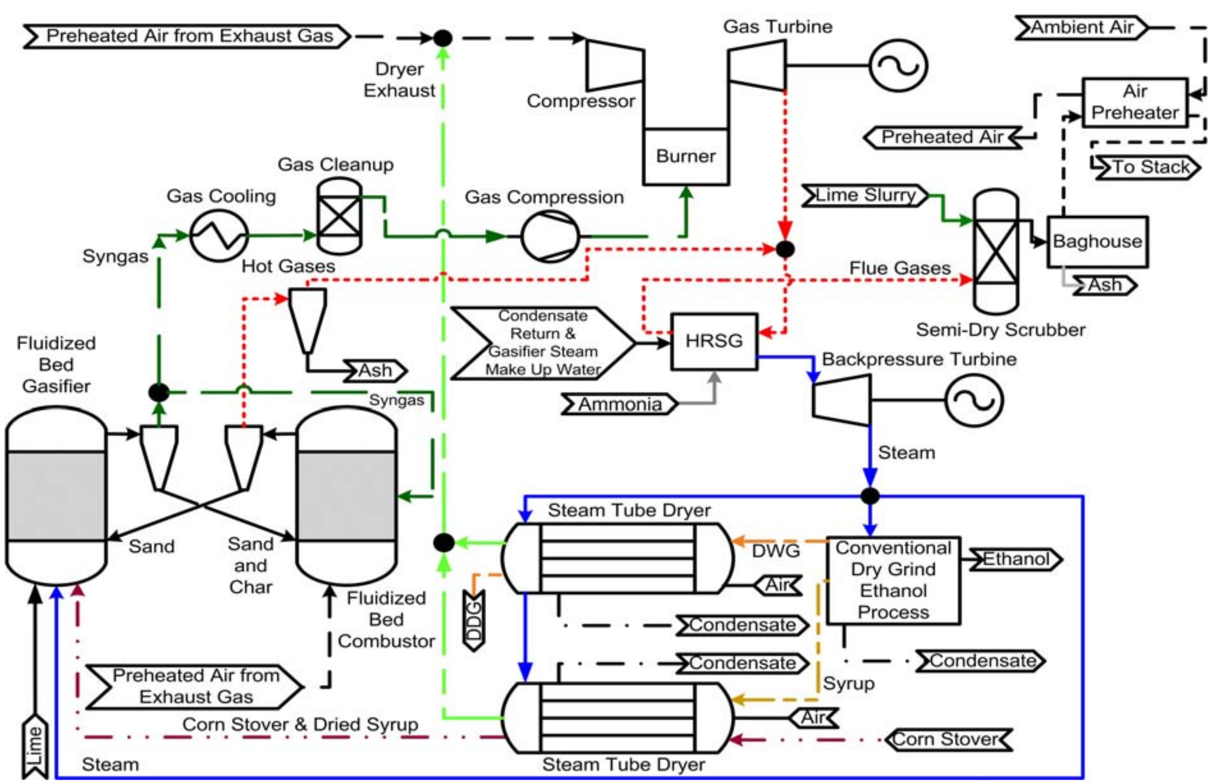

Figure 2. Schematic of BIGCC system with steam tube dryers for syrup & corn stover fuel.

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 revised gasification/combustion configurations provide about the same results for overall system performance as the previous configurations for all systems, but offer additional flexibility for gas clean up.

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 (all fuel to gasifier, steam tube dryer exhaust to gas turbine).

	Superheated Steam Dryer		**Steam Tube Dryer**	
	2 stage	**3 stage**	**2 stage**	**3 stage**
Generation Efficiency	31.4%	34.1%	30.7%	29.4%
Thermal Efficiency	56.6%	58.2%	73.4%	71.7%
Power Generation, MW				
Gas turbine	27.1	30.1	22.2	20.8
Steam turbine	7.4	7.4	11.6	11.6
Total	34.5	37.5	33.8	32.4
Power Use, MW				
Ethanol process	4.7	4.7	4.7	4.7
Dryers	4.2	4.2	0	0
Parasitic BIGCC	4.6	5.9	4.2	4.7
To Grid	21.0	22.7	24.9	23.0
Total	34.5	37.5	33.8	32.4
Process Heat, MW_{th}				
Ethanol process	27.9	27.9	27.9	27.9
Dryers	4.4	4.4	23.3	23.3
Total	32.3	32.3	51.2	51.2
Synthesis Gas Split, MW_{th}				
Combustor	4.7	4.7	6.9	6.9
Turbine	88.2	88.2	77.4	67.3
After turbine	--	--	8.6	18.7
Total*	92.9	92.9	92.9	92.9
Combustor Input, MW_{th}				
Char*	17.1	17.1	17.1	17.1
Gas	4.7	4.7	7.1	6.9
Total	21.8	21.8	24.2	24.0
Combustor Output, MW_{th}				
Gasifier heat duty	15.8	15.8	16.0	16.0
Combustion exhaust	6.0	6.0	8.2	8.0
Total	21.8	21.8	24.2	24.0

*Total synthesis gas plus char equals 110 MW_{th}

However, the change to send steam tube dryer exhaust air to the gas turbine rather than to the fluidized bed combustor leads to significant improvements in performance for the steam tube dryer systems. The improvements are greater for the 10 atm (2 stage) than the 20 atm (3 stage) steam tube dryer systems with significant improvements in electric generation and system thermal efficiencies as well as increases in the power sent to the grid of 17 to 23% compared to the old configuration. The steam tube dryer configurations provide more electricity to the grid than the superheated steam dryer configurations (Tables 1 and 2). The 10 atm (2 stage) steam tube drying configuration has both the greatest system thermal efficiency and the largest amount of power sent to the grid for the two fuel combinations shown in Tables 1 and 2. This configuration provides the best match for meeting power generation and process heat. In this case, a lower level of gas compression, 10 atm versus 20 atm, provides a better overall level of performance. The 20 atm (3 stage) compression for the gas turbine results in a greater temperature decrease in the turbine. This means that there is not enough energy to meet the process needs after the steam turbine. To compensate more synthesis gas needs to be supplied after the gas turbine, which decreases total power production from the gas turbine resulting in lower efficiency and less power to the grid than for the 10 atm (2 stage) configuration.

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 (all fuel to gasifier, steam tube dryer exhaust to gas turbine).

	Superheated Steam Dryer		**Steam Tube Dryer**	
	2 stage	**3 stage**	**2 stage**	**3 stage**
Generation Efficiency	30.9%	33.5%	31.5%	29.9%
Thermal Efficiency	55.8%	57.3%	73.4%	71.4%
Power Generation, MW				
Gas turbine	26.6	29.5	23.3	21.5
Steam turbine	7.4	7.4	11.4	11.4
Total	34.0	36.8	34.7	32.9
Power Use, MW				
Ethanol process	4.7	4.7	4.7	4.7
Dryer	4.1	4.1	0	0
Parasitic BIGCC	4.8	6.0	4.5	4.9
To Grid	20.4	22.1	25.5	23.3
Total	34.0	36.9	34.7	32.9
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
Synthesis Gas Split, MW_{th}				
Combustor	7.9	7.9	9.0	8.8
Turbine	84.1	84.1	78.9	67.1
After turbine	--	--	4.1	16.1
Total*	92.0	92.0	92.0	92.0
Combustor Input, MW_{th}				
Char*	18.0	18.0	18.0	18.0
Gas	7.9	7.9	9.0	8.8
Total	25.9	25.9	27.0	26.8
Combustor Output, MW_{th}				
Gasifier heat duty	18.0	18.0	18.0	18.0
Combustion exhaust	7.9	7.9	9.0	8.8
Total	25.9	25.9	27.0	26.8

*Total synthesis gas plus char equals 110 MW_{th}

It appears that the 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 distribution of synthesis gas to various demands in the system also is shown in Tables 1 and 2. Synthesis gas required for the fluidized bed combustor is somewhat less for the syrup and stover fueled systems (Table 1) than for the stover fueled systems (Table 2). This is because the syrup and stover is dried to 10% moisture while the stover is assumed to be received at 13% moisture and not dried. The lower moisture content lowers the heat duty for the gasifier and increases the energy content of the gas, which in turn reduces the amount of energy required for the combustor. The energy for the fluidized bed combustor is supplied by the char produced in the gasifier and some synthesis gas to meet the combustor output demand. For each fuel, somewhat less fuel energy is required for the fluidized bed combustor in the superheated steam drying systems than the steam tube drying systems because the superheated steam drying configuration provides a higher preheat temperature for the combustion air than the steam tube configuration.

Equipment Required for BIGCC Systems

Compressors, fans and pumps for the steam tube drying systems described in Tables 1 and 2 are listed in Tables 3 and 4. This will form the basis for equipment selection and capital cost analysis for each system.

Boilers and heat exchangers required for the 110 MW, 10 atm (2-stage) steam tube drying configuration for syrup and corn stove and corn stover alone are listed in Tables 5 and 6. We are focusing on this configuration because the analysis shows that it provides the best overall performance and it is simpler, which should mean that it has lower cost.

Some potential gas turbine/generators are listed in Table 7. These turbines operate with a pressure ratio of around 10 (10 atm) which is the range that we identified as providing the best performance in conjunction with a steam tube drying system.

Table 3. Characteristics of compressors, fans, and pumps involved in steam tube drying for syrup & stover as fuel.

	2 Stage				3 Stage			
	Flow rate, m^3/h	Pressure ratio	Temp., °C	Power, MW	Flow rate, m^3/h	Pressure ratio	Temp., °C	Power, MW
Compressors								
Syngas 1	31097	3.162	84	1.510	27182	2.714	84	1.122
Syngas 2	11800	3.162	157	1.803	11877	2.714	157	1.326
Syngas 3	na *	na	na	na	4350	2.714	157	1.316
Fans **								
Gasifier cyclone	115845	---	870	---	115845	---	870	---
Combustor cyclone 1	115177	---	990	---	115087	---	990	---
Combustor cyclone 2	115177	---	990	---	115087	---	990	---
Combust. air-preheat	35482	1.186	144	0.259	35632	1.186	146	0.260
Stack gas	377263	---	126	0.346	402361	---	127	0.368
Pumps								
Boiler feed water-recirculate	92.9	16.8	146	0.243	92.9	16.8	146	0.243
Boiler feed water-makeup	4.5	74	25	0.012	4.5	74	25	0.012

* na = not applicable.
** The flow rate of cyclones includes solids.

Table 4. Characteristics of compressors, fans, and pumps involved in steam tube drying for stover as fuel.

	2 Stage				3 Stage			
	Flow rate, m^3/h	Pressure ratio	Temp., °C	Power, MW	Flow rate, m^3/h	Pressure ratio	Temp., °C	Power, MW
Compressors								
Syngas 1	33498	3.162	87	1.625	29113	2.714	97	1.201
Syngas 2	12636	3.162	157	1.929	12456	2.714	157	1.39
Syngas 3	na *	na	na	na	4560	2.714	157	1.378
Fans **								
Gasifier cyclone	120284	---	870	---	120284	---	870	---
Combustor cyclone 1	131024	---	990	---	129821	---	990	---
Combustor cyclone 2	131024	---	990	---	129821	---	990	---
Combust. air-preheat	38758	1.186	134	0.283	39771	1.186	147	0.29
Stack gas	407252	---	115	0.363	414324	---	129	0.377
Pumps								
Boiler feed water-recirculate	91.7	16.8	146	0.24	91.7	16.8	146	0.24
Boiler feed water-makeup	4.7	74	25	0.013	4.7	74	25	0.013

* na = not applicable.
** The flow rate of cyclones includes solids.

Table 5. Boilers and heat exchangers for syrup & stover as fuel with 2-stage compression and steam tube dryer.

	Energy (MW_{th})	Fluid	Direction * L	Direction * R	Flow rate kg/h	Flow rate L, m^3/h	Flow rate R, m^3/h	Pressure (kPa)	L Temp. (°C)	R Temp. (°C)
Boilers										
Main boiler										
Economizer	0.06	water	→		75680	82.8	82.8	7500	157	158
		hot gas	←		302690	408534	409094	100	163	164
Boiler	42.9	steam	→		73409	80.4	2010	7500	158	286
		hot gas	←		302690	409094	792369	100	164	573
Super-heater	14.7	SH steam	→		87609	2398	4577	7000	286	482
		hot gas	←		302687	792576	915114	100	573	704
Syngas cooler										
Boiler	8.31	steam	→		14200	15.5	389	7500	142	286
		syngas	←		20868	36443	96536	100	150	870
Heat exchangers										
Syngas compressor 1	0.72	water	→		4490	4.5	5.4	7500	157	286
		syngas	←		21325	11800	13734	316	159	870
Air preheating										
Fluidized bed combustor	0.99	air	→		29348	25365	35482	100	25.0	144
		stack gas	←		304691	388185	397590	100	138	148
Gas turbine	1.15	air	→		172182	148812	160582	100	25.0	49.0
		stack gas	←		304691	377263	388185	100	126	138

* L = left, and R = right.

Table 6. Boilers and heat exchangers for stover as fuel with 2-stage compression and steam tube dryer.

	Energy (MW_{th})	Fluid	Direction * L	Direction * R	Flow rate kg/h	Flow rate L, m^3/h	Flow rate R, m^3/h	Pressure (kPa)	L Temp. (°C)	R Temp. (°C)
Boilers										
Main boiler										
Economizer	0.87	water	→		73818	80.1	80.9	7500	149	159
		hot gas	←		319278	418322	426532	100	153	161
Boiler	41.7	steam	→		71603	78.5	1960	7500	159	286
		hot gas	←		319278	426532	802000	100	161	543
Super-heater	14.5	SH steam	→		86713	2374	4530	7000	286	482
		hot gas	←		319276	802211	924750	100	543	668
Syngas cooler										
Boiler	9.0	steam	→		15110	16.4	414	7500	149	286
		syngas	←		22787	38252	103046	100	152	870
Heat exchangers										
Syngas compressor 1	0.80	water	→		4638	4.6	5.2	7500	25.8	173
		syngas	←		23375	12636	14763	316	157	228
Air preheating										
Fluidized bed combustor	1.02	air	→		32851	28393	38758	100	25.0	134
		stack gas	←		321278	397582	407252	100	128	138
Gas turbine	1.40	air	→		184792	159711	174038	100	25.0	51.7
		stack gas	←		321278	385186	397582	100	115	128

* L = left, and R = right.

Table 7. Selected commercial gas turbine models and their performance characteristics.

Manufacturer & Model	Shafts	RPM	PR *	TIT, °C (°F) *	TET, °C (°F) *	ΔT, °C (°F) *	Airflow (kpph)	Power, kW_e	LHV HR, BTU/kWh	LHV Eff., %	Price	
											MM$	$/kW_e$
GE5371PA	1	5100	10	963 (1765)	485 (905)	478 (860)	979	26555	11800	28.9	$12.5	$471
Kwasaki GPB60 (M7A-01)	1	1400	12.7	1104 (2020)	545 (1013)	559 (1007)	172	5533	11530	29.6	$2.8	$506
MAN TURBO THM 1304-10	2	7556	10	982 (1800)	495 (923)	487 (877)	351	9310	12190	28.0	$5.4	$580
MAN TURBO THM 1304-11	2	8600	11	996 (1825)	487 (909)	509 (916)	380	10760	11460	29.8	$6.3	$585
MAN TURBO THM 1304-12	2	8600	11	1010 (1850)	494 (921)	516 (929)	383	11520	11165	30.6	$6.6	$573
Rolls-Royce Avon-2648	2	5500	90	893 (1640)	438 (821)	455 (819)	608	14610	11885	28.7	$7.8	$534
Siemens SGT-200-1S (Rston, EGT Tornado)	1	11053	11.9	1024 (1875)	466 (871)	558 (1004)	229	6745	10910	31.3	$3.8	$563
Siemens SGT-500 (ABB, ALSTOM GT 35)	3	3600	12.1	863 (1585)	374 (705)	489 (880)	733	17015	10740	31.8	$8.9	$523
Solar Centaur 50	1	14950	10.7	1054 (1930)	517 (963)	537 (967)	151	4600	11630	29.3	$2.7	$586
Solar Mercury 50	1	14180	9.9	1093 (2000)	374 (705)	719 (1295)	140	4600	8863	38.5	$3.4	$760
Solar Mercury 50 (landfill gas)	1	14180	10	1093 (2000)	387 (729)	706 (1271)	144	4883	8850	38.6	$3.5	$717
Solar Taurus 60-T7800	1	14950	12.3	1093 (2000)	508 (946)	586 (1054)	166	5500	10860	31.4	$2.8	$509
Solar Taurus 60-T7900	1	14950	12.3	1093 (2000)	511 (952)	582 (1048)	170	5670	10835	31.5	$3.3	$582

* PR = pressure ratio, TIT = turbine inlet temperature, TET = turbine exit temperature, and ΔT = TIT – TET.

Life-cycle GHG reductions

We have continued to develop comparisons of various systems based on life-cycle greenhouse gas (GHG) reduction for ethanol production using biomass to provide heat and power as described in the Milestone 4 report. 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".

Input, output, and net life-cycle GHG emissions for conventional corn ethanol production compared to gasoline is shown in Figure 3. Conventional natural gas fired ethanol plants reduce life-cycle GHG emissions compared to gasoline by almost 44%. Using corn stover as fuel, combined heat and power (CHP) systems reduce net life-cycle GHG emissions by about 83% and BIGCC systems reduce them by about 121% compared to gasoline (Figure 4). The decrease in life-cycle GHG emissions is due both to reduction fossil fuel inputs and the biomass produced electricity which is 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.

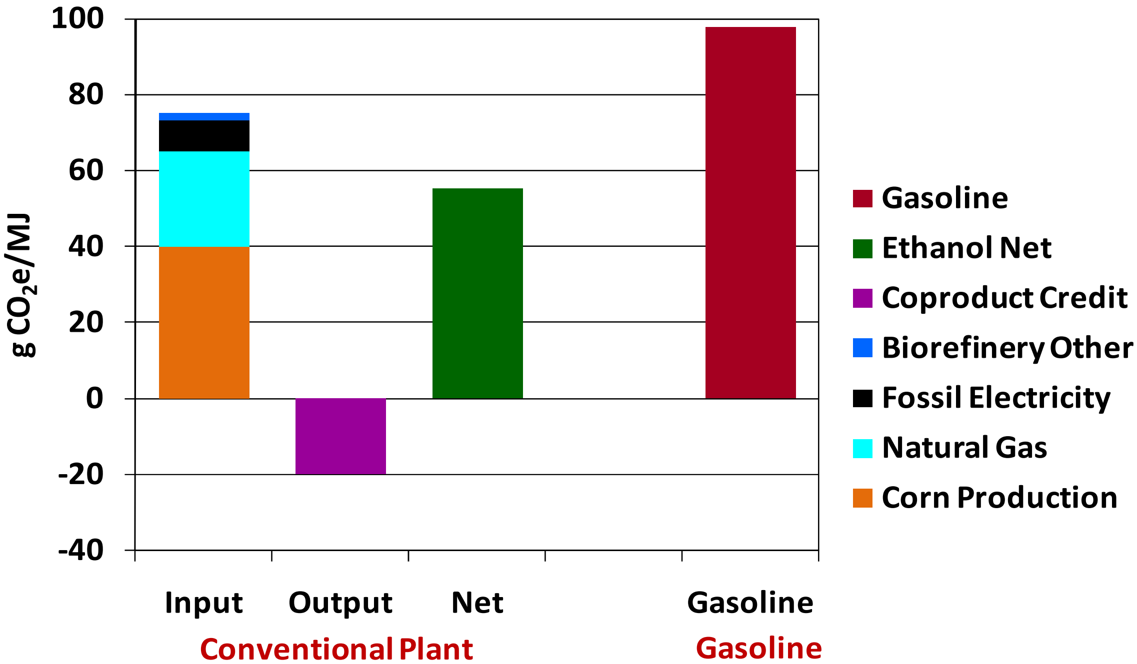

Figure 3. Life cycle greenhouse gas emissions (input, output, net) for conventional corn ethanol production compared to gasoline (excludes indirect land use change effects).

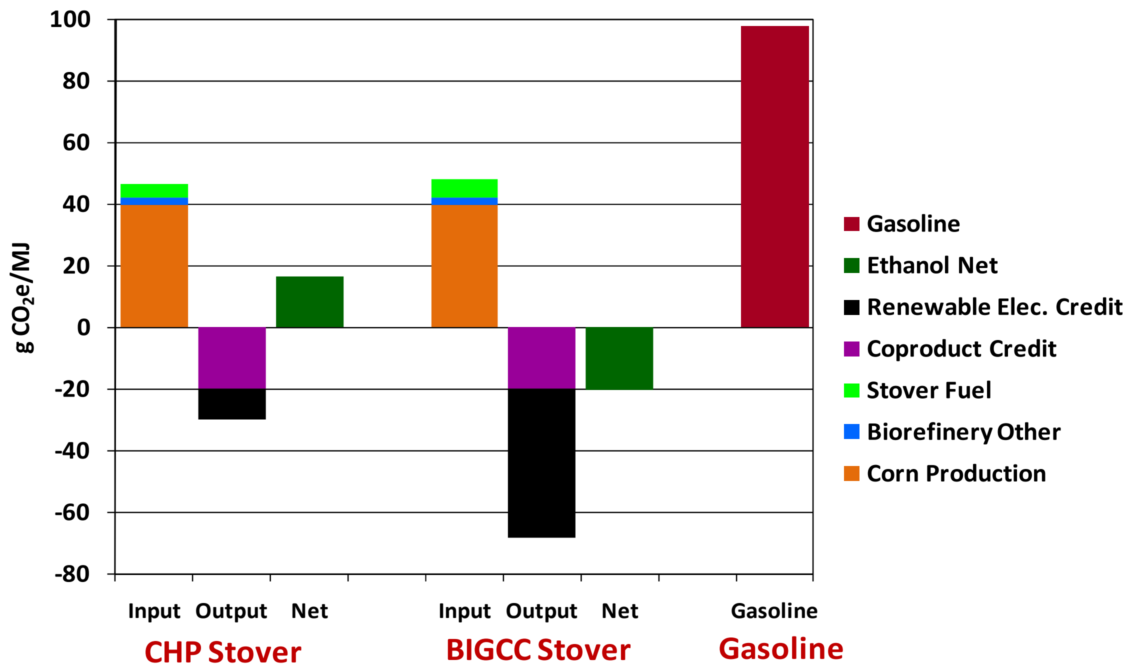

Figure 4. Life cycle greenhouse gas emissions (input, output, net) for combined heat and power (CHP) and BIGCC corn stover fueled ethanol production compared to gasoline (excludes indirect land use change effects).

Using syrup and corn stover as fuel, combined heat and power (CHP) systems reduce net life-cycle GHG emissions by about 72% and BIGCC systems reduce them by about 113% compared to gasoline (Figure 5). 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.

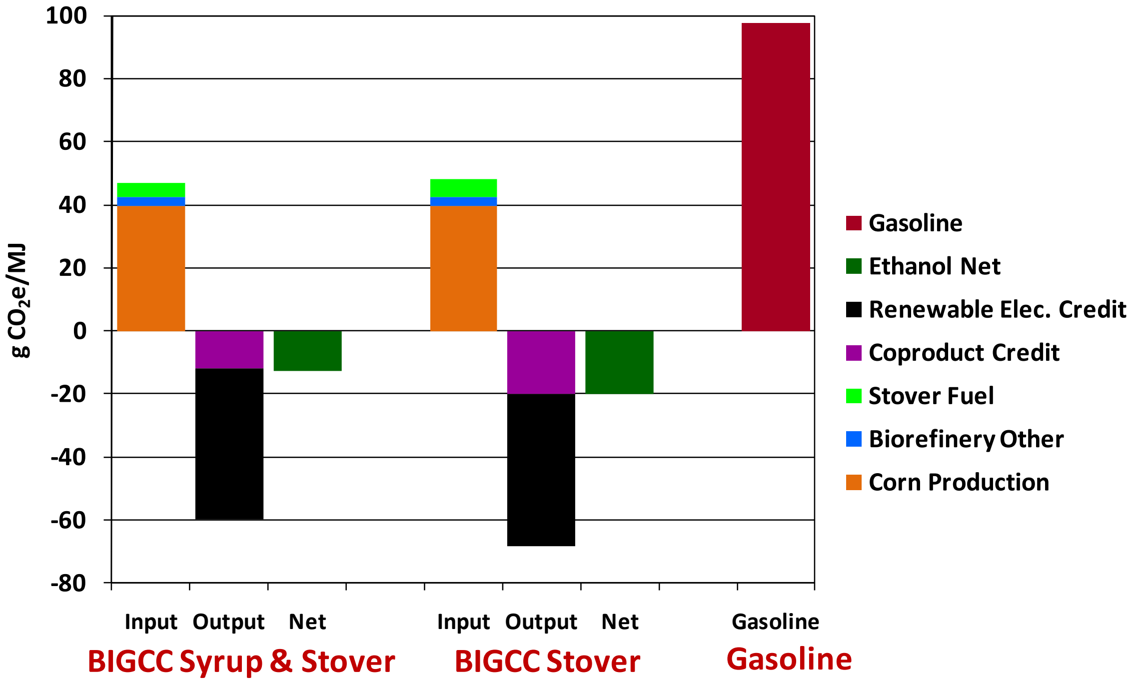

Figure 5. Life cycle greenhouse gas emissions (input, output, net) for BIGCC syrup & corn stover and BIGCC corn stover fueled ethanol production compared to gasoline (excludes indirect land use change effects).

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 specification of gas cleanup technologies
- Complete determination of capital and operating costs

Alkali metals (potassium and sodium), prevalent in herbaceous biomass such as corn stover, are notorious for causing boiler fouling in combustion configurations. Since some of the synthesis gas will be used in a combustion mode, it will first be cooled to the range of 370 to 540 ^{o}C (700 to 1000 ^{o}F) where we expect it will react with chlorine in the fuel to form NaCl, KCl, and $CaCl_2$. We expect that these alkali chlorides will condense and then be captured with a ceramic filter. We hope this process will remove some of the potassium and sodium as well as some of the chlorine. Detailed modeling of these systems is underway.

1C. Integration of superheated steam dryer technology

- Complete study of changes in capital and operating costs
- Continue evaluation of rate of return

We are continuing to evaluate integration of superheated drying in BIGCC systems at ethanol plants although we have put this technology at a lower priority for the time being because our most recent analysis indicates that it does not provide as favorable overall performance as steam tube drying. The primary attraction is the potential to reduce the water requirement for ethanol production by about 1.3 gallons of water/gallon of ethanol. This is not possible with steam tube drying 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 superheated steam dryer technology could reduce the requirement to the range of 1.4 to 2.4 gallons of water/gallon of ethanol.

2. **Develop and test business model**
   - 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
   - Begin development of standard contract clauses

The following analysis was prepared by Larry L. Schedin, LLS Resources, LLC. It summarizes recent developments in combined cycle power generation using natural gas fuel as a basis for determining the value of BIGCC generated power at ethanol plants.

I. Definition and Description

Combined cycle generation combines the rapid startup characteristics of a simple cycle combustion turbine (CT) with the efficiencies of a steam turbine (ST) resulting in a highly efficient rapid start combined generating unit. The basic configuration is a natural gas fired, simple cycle combustion turbine producing electricity while exhausting its discharge heat into a heat recovery steam generator (HRSG) which in turn produces steam driving a steam turbine. The steam turbine drives another electric generator, so that electricity is produced in two places. Alternative equipment configurations may have several CT's exhausting into one HRSG which in turn supplies one large ST.

Because of its inefficiencies, the exhaust gasses from a CT are typically rich in unburned oxygen (up to 15% by volume). Therefore, it is possible to place a supplemental natural gas burner (called a duct burner) in the CT exhaust stream to take advantage of the pre-heated combustion air. This makes for a very efficient way to add heat to the CT exhaust stream thereby increasing the HRSG steam capacity. This same effect can be attained by placing the supplemental burner internal to the boiler, called a register type burner, without increasing the inlet gas temperature to the HRSG. In any event, addition of a supplemental burner is referred to as a "fired unit" in contrast to an "unfired unit" without supplemental firing.

The term "heat rate", measured as Btu's per KWH is a typical measure of the efficiency of an electric power generator. The station net heat rate is the number of Btu's input to the prime mover in order to produce one KWH of output over and above station auxiliaries. A typical heat rate for a simple cycle CT is about 12,000 Btu's per KWH while a typical heat rate for a combined cycle unit is about 7,000 Btu's per KWH. However, to be precise, the heating value of the fuel (HHV vs LHV) must also be specified.

A simple cycle generating unit with a station net heat rate of 12,000 Btu's per KWH would have an overall efficiency of only 28% while a combined cycle generating unit with a station net heat rate of 7,000 Btu's per KWH would have an overall efficiency of 49% .

II. Utility Application of Combined Cycle Units

Since most combined cycle units are fueled with natural gas and since natural gas prices on an equivalent Btu basis are volatile and more expensive than coal, combined cycle units have been traditionally designated as intermediate duty units and are scheduled to run only after the coal-fired and nuclear units are scheduled. The capital cost per KWH generated is therefore calculated on a lower capacity factor basis (40% capacity factor for combined cycle vs 90% capacity factor for base load) which distorts any comparison of capital costs on a KWH basis. In spite of the higher efficiency of combined cycle units compared to base-load coal units, the more expensive natural gas fuel compared to coal more than offsets the efficiency advantage. The operating costs of combined cycle units are therefore also higher than coal-fired units. However, if combined cycle units are forced to higher operating hours to replace coal-fired units that cannot be built, then economic comparisons should be based on higher capacity factors than in the past.

III. PURPA Machines and Qualified Facilities (QF's)

The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted partly in response to the Arab Oil Embargo of 1973. The PURPA law gave special incentives to the output from generation utilizing renewable fuels thereby avoiding the use of coal and fuel oil. Key incentives for a qualifying facility (QF) required the local utility to purchase excess electricity at its avoided cost and to provide backup and standby capacity at a reasonable price. However, natural gas was included as an authorized fuel so long as it was used to supply a combined heat and power (CHP) facility with a PURPA efficiency of 42.5% or more. The PURPA efficiency for a natural gas fired unit was determined by dividing the electric output plus one-half the useful thermal output by the heat input. For example, a food product company in Buffalo, NY installed a natural gas fueled, Solar brand combustion turbine model "Centaur H" (about 3.5 MW) producing 22,500 lbs of steam per hr in an unfired mode from the connected HRSG. With a heat rate of about 12,500 Btu's per KWH, this results in a calculated PURPA efficiency of about 53% demonstrating that the facility was a QF. The local utility was then required to either purchase the entire facility electric output at its avoided cost or to provide backup and standby power for power utilized on site.

More in-depth QF definitions and applications can be found at the following web site.
http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp

IV. PURPA Reform

After the PURPA law was enacted, creative independent power producers demonstrated that a natural gas fueled combined cycle unit could be designed to be a QF thereby requiring the local utility to purchase the entire output. Because the local utility was a ready and nearby purchaser, this gave rise to a significant number of very large combined cycle units with outputs in the range of several hundred MW. For example, by 2005, the MISO pool of generating units included over 45 units with outputs of greater than 50 MW. The mandated purchase of the output from this growing fleet of combined cycle units drew strong objections from utility companies leading to PURPA reform legislation passed in 2005 which now limits the size of a QF to 20 MW or less, under a presumption which the local utility can challenge, i.e., a facility rated 20 MW or less is presumed to be a QF unless the local utility can show otherwise.

However, large combined cycle units are still being constructed in order to meet installed capability, and related reliability requirements of growing utilities, partly because base-load coal fired units are nearly impossible to get permitted. New combined cycle units are now often included in the integrated resource plans (IRP's) of investor-owned utilities who seek public utility commission approval prior to requesting a construction permit. In states such as Pennsylvania (part of the PJM ISO), combined cycle units can be approved via a PJM wide capacity market in which futures bidding is used to meet a projected PJM capacity deficiency. However, in MISO, there is only an energy spot market and no capacity market. Recently in Minnesota, the new High Bridge and Riverside combined cycle projects were approved by the MN PUC as part of the Metropolitan Emissions Reduction Project (MERP) to replace coal-fired units at these same locations. Xcel Energy is recovering the cost of these units under an automatic rate adjustment rider.

V. Cost of Combined Cycle Units as a Proxy for the Value of BIGCC Units

In previous analyses and a BIGCC Project report dated December 30, 2009, coal-fired, base-load generating units were evaluated as a proxy for the value of BIGCC generation. Development and testing of key elements of the business model included:

A) the value of electric power generation produced in replacing electricity otherwise purchased for on-site processing or

B) being sold as a resource to wholesale electric market participants (or some combination thereof) and

C) the value of by-product heat in reducing natural gas use.

As was stated in the earlier report, environmental concerns limit development of new coal facilities thereby leaving combined as the only near term alternative for utility needs for both intermediate and base-load needs.

This same procedure is used in this current report to examine the economics of six selected examples combined cycle (CC) power projects developed in the upper Midwest over the last 6 years. The typical CC project is made up one or more gas turbine generation sets along with a reheat steam turbine. A number of the plants are co-located with existing coal fired facilities adding CC to the generation mix at the power station. In most cases this results in savings by economizing on existing plant infrastructure. As was done in the previous report on coal plants 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 actual hrs of intermittent use on an annual basis. Fuel and O&M costs were determined on an actual reported total cost basis. Data was taken from regulatory commission dockets, Federal Energy Regulatory Commission Reports (FERC Form 1), and news releases.

Data for the most recently available FERC Form 1 were taken from reports for the 2008 reporting year. New FERC Form 1 reports for the 2009 reporting period are due to be filed on April 18, 2010. Additionally, some of the data supporting the report is still being gathered and updated.

Chart 1. Key financial aspects of the 6 facilities.

Plant Name	Nameplate Capacity (Megawatts)	Summer Cap of complex	Prime Mover	$/KW-yr	Cap Cost $/KW	Cap Cost /KWH	O&M/KWH	Fuel Cost/KWH	Total Cost/KWH	Initial Mo/Yr of Initial Operation
Emery Station	171	583	CT	$ 124	$ 690	$ 0.0780	$ 0.0057	$ 0.0596	$ 0.1434	5/06
Greater Des Moines	576	494	CA	$ 123	$ 684	$ 0.0583	$ 0.0076	$ 0.0658	$ 0.1317	12/04
West Campus Cogeneration Facility	54	130	CT	$ 150	$ 831	$ 0.1175	$ 0.0232	$ 0.1037	$ 0.2445	4/05
Port Washington Generating Station	269	545	CA	$ 110	$ 611	$ 0.0511	$ 0.0087	$ 0.0667	$ 0.1264	7/05
High Bridge	250	553	CC	$ 117	$ 650	$ 0.1110	$ 0.0135	$ 0.0875	$ 0.2120	5/08
Port Washington Generating Station	269	1,090	CA	$ 110	$ 614	$ 0.0205	$ 0.0191	$ 0.0208	$ 0.0604	5/08

Data in various Federal reports contain a number of discrepancies that make analysis accurate only at a high level. Because of ownership and financing alternatives, a total “apples to apples” review can be difficult. For example, the foregoing Port Washington facility which is leased is difficult to directly compare to a build, own and operate facility. Cost valuations were converted from actual costs to a long term lease payable from Wisconsin Electric to We Energies. In addition, the Port Washington facility was built in two different time periods with phase I completion July 2005 and phase II completion May 2008.

The Summer Capacity rating is often used as the key output variable available from the gas turbine generator sets. Output is limited (reduced) in the summer due to temperature/humidity conditions.

Operating and fuel costs are based on actual costs and hours the plants actually operated as reported on FERC Form 1 reports.

Capacity factors range from 12% to 61% and are reflective of the intermediate loading requirements of the economic dispatch system. Both Port Washington Generating Station and High Bridge plants reflect only part year operations in 2008 and as such probably overstate cost on a KWH basis. The 2009 reports will likely show a more accurate picture of costs.

Chart 2 is a list of additional CC plants under review. These will be added to chart 1 as information gathering is complete, especially after 2009 FERC Form 1’s are filed around April 18.

Chart 2. Additional combine cycle power plants under review

State	County	Company	Plant Name	Summer Cap of complex	$/KW-yr	Cap Cost $/KW	Cap Cost /KWH	Total Cost/KWH	Initial Mo/Yr of Initial Operation
WI	Rock	Rock River Energy LLC	Riverside Energy Center					-	6/04
WI	Rock	Rock River Energy LLC	Riverside Energy Center					-	6/04
WI	Rock	Rock River Energy LLC	Riverside Energy Center	598				-	6/04
MN	Rice	Minnesota Municipal Power Agny	Faribault Energy Park					-	5/05
WI	Outagamie	GE Energy Services	Fox Energy Center					-	6/05
WI	Outagamie	GE Energy Services	Fox Energy Center	425	$ 182	$ 1,012		-	6/05
MN	Blue Earth	Calpine Central LP	Mankato Energy Center					-	7/06
MN	Blue Earth	Calpine Central LP	Mankato Energy Center	300		$ -		-	7/06
WI	Outagamie	GE Energy Services	Fox Energy Center					-	6/06
MN	Rice	Minnesota Municipal Power Agny	Faribault Energy Park					-	8/07
MN	Hennepin	Northern States Power Co	Riverside					-	5/09
MN	Hennepin	Northern States Power Co	Riverside	275	$ 154	$ 856		-	5/09

3. Analysis of a biomass procurement system

- Complete storage and transportation evaluation
- Continue specification of equipment and determination of capital and operating costs
- Begin rate of return on investment study

We completed revisions on a paper on corn stover supply logistics which has been accepted for publication and will soon appear in print.

Morey, R. V., N. Kaliyan, D. G. Tiffany, and D. R. Schmidt. 2010. A corn stover supply logistics system. Applied Engineering in Agriculture 26(3): xxx-xxx.

One of the key elements of the corn stover supply logistics system is a process to coarsely grind the stover and then roll compact it to achieve a bulk density of at least 15 lbs/ft^3, which will allow trucks to load out at a 25 ton limit. We recently conducted pilot scale testing of a roll compaction system. The results were encouraging. Some of those results are summarized in Tables 8 and 9. We were able to achieve bulk densities of approximately 20 lbs/ft^3 with coarsely ground material. Intrinsic or unit densities of 30 to 45 lbs/ft^3 are possible which should improve performance of gasification and combustion systems.

Table 8. Properties of roll press compacted corn stover.

Roll force, ton	**Bulk density of compacted materials immediately after making, kg/m^3 (lb/ft^3) (n = 1 or 2) #**	**Measurements for cured compacted materials (after about one week of compaction) (n = 3)**			
		Durability, % *	**Moisture content, % w.b.**	**Angle of repose, deg ψ**	**Unit density of compacts based on water displacement method, kg/m^3 (lb/ft^3)**
Mighty Giant grinder screen size = 25.4 mm (1.0 in.); Particle size & = 5.10 ± 2.84 mm (0.20 ± 0.11 in.); Moisture content of particles = 17.9 ± 0.7% w.b.; Bulk density of particles with five taps = 91.8 ± 4.9 kg/m^3 (5.7 ± 0.3 lb/ft^3)					
24	262.7 ± 0.0 (16.4 ± 0.0)	81.7 ± 1.1	15.8 ± 0.4	26.3 ± 0.6	394.6 ± 31.8 (24.6 ± 2.0)
40	325.2 (20.3)	88.9 ± 3.3	14.9 ± 0.6	27.0 ± 2.6	508.4 ± 102.1 (31.7 ± 6.4)
60	330.0 ± 6.8 (20.6 ± 0.4)	91.9 ± 1.6	18.2 ± 0.5	25.7 ± 0.6	489.9 ± 28.7 (30.6 ± 1.8)
Mighty Giant grinder screen size = 76.2 mm (3.0 in.); Particle size & = 7.02 ± 3.01 mm (0.28 ± 0.12 in.); Moisture content of particles = 10.2 ± 0.2% w.b.; Bulk density of particles with five taps = 65.1 ± 1.8 kg/m^3 (4.1 ± 0.1 lb/ft^3)					
24	301.1 (18.8)	85.1 ± 3.0	10.3 ± 0.1	24.3 ± 0.6	420.9 ± 22.5 (26.3 ± 1.4)
40	338.0 (21.1)	87.4 ± 4.0	9.8 ± 0.1	21.0 ± 0.0	627.9 ± 72.4 (39.2 ± 4.5)
60	331.6 ± 18.1 (20.7 ± 1.1)	88.0 ± 2.4	9.7 ± 0.1	23.0 ± 1.0	724.4 ± 139.4 (45.2 ± 8.7)
Mighty Giant grinder screen size = 127.0 mm (5.0 in.); Particle size & = 5.62 ± 3.74 mm (0.22 ± 0.15 in.); Moisture content of particles = 14.6 ± 2.7% w.b.; Bulk density of particles with five taps = 75.8 ± 3.7 kg/m^3 (4.7 ± 0.2 lb/ft^3)					
24	275.5 ± 4.5 (17.2 ± 0.3)	82.8 ± 1.8	13.2 ± 0.1	21.7 ± 0.6	399.1 ± 17.8 (24.9 ± 1.1)
40	317.2 (19.8)	90.2 ± 3.3	13.3 ± 0.1	24.0 ± 0.0	488.1 ± 27.2 (30.5 ± 1.7)
60	320.4 (20.0)	91.5 ± 0.6	13.5 ± 0.2	25.0 ± 1.0	637.2 ± 105.8 (39.8 ± 6.6)

Bulk density of compacted materials was measured based on ASTM (2009). This procedure involved five taps of the 1 ft × 1 ft × 1 ft wooden cubic container with compacted materials.

* Durability (%) = [Mass of compacted materials retained on 19.1 mm (0.75 in.) screen after tumbling × 100 / Mass of compacted materials used for tumbling]. About 500 g of compacted materials was tumbled for 2.4 min at 50 rpm (i.e., 120 revolutions) in the ASABE tumbling can durability tester (ASABE Standards, 2009).
[ψ] Angle of repose of bulk sample of compacts (about 1000 g) on a galvanized steel surface was measured using a tilted-plane angle of repose apparatus (Mohsenin, 1986).
[&] Geometric mean particle length ± geometric standard deviation.

Table 9. Properties of roll press compacted native grasses.

Roll force, ton	**Bulk density of compacted materials immediately after making, kg/m^3 (lb/ft^3) (n = 2) [#]**	**Measurements for cured compacted materials (after about one week of compaction) (n = 3)**			
		Durability, % *	**Moisture content, % w.b.**	**Angle of repose, deg [ψ]**	**Unit density of compacts based on water displacement method, kg/m^3 (lb/ft^3)**
Mighty Giant grinder screen size = 25.4 mm (1.0 in.); Particle size [&] = 2.90 ± 2.68 mm (0.11 ± 0.11 in.); Moisture content of particles = 17.1 ± 0.7% w.b.; Bulk density of particles with five taps = 169.8 ± 11.6 kg/m^3 (10.6 ± 0.7 lb/ft^3)					
24	292.3 ± 3.4 (18.3 ± 0.2)	60.8 ± 4.3	14.8 ± 0.4	25.7 ± 0.6	374.9 ± 51.5 (23.4 ± 3.2)
40	341.2 ± 0.0 (21.3 ± 0.0)	79.0 ± 1.2	15.2 ± 0.3	23.0 ± 1.0	498.0 ± 12.4 (31.1 ± 0.8)
60	365.2 ± 4.5 (22.8 ± 0.3)	90.7 ± 4.4	13.9 ± 0.3	23.3 ± 2.1	510.2 ± 54.7 (31.9 ± 3.4)
Mighty Giant grinder screen size = 76.2 mm (3.0 in.); Particle size [&] = 3.66 ± 3.05 mm (0.14 ± 0.12 in.); Moisture content of particles = 17.4 ± 2.6% w.b.; Bulk density of particles with five taps = 116.4 ± 3.7 kg/m^3 (7.3 ± 0.2 lb/ft^3)					
24	290.7 ± 7.9 (18.2 ± 0.5)	65.0 ± 3.8	15.7 ± 0.1	23.7 ± 2.5	347.4 ± 23.6 (21.7 ± 1.5)
40	308.4 ± 14.7 (19.3 ± 0.9)	81.1 ± 0.8	15.4 ± 0.1	21.7 ± 0.6	456.5 ± 43.0 (28.5 ± 2.7)
60	355.6 ± 9.1 (22.2 ± 0.6)	88.0 ± 1.8	16.2 ± 0.1	23.7 ± 1.2	461.9 ±46.9 (28.8 ± 2.9)
Mighty Giant grinder screen size = 127.0 mm (5.0 in.); Particle size [&] = 3.71 ± 3.17 mm (0.15 ± 0.12 in.); Moisture content of particles = 16.5 ± 1.7% w.b.; Bulk density of particles with five taps = 96.1 ± 3.2 kg/m^3 (6.0 ± 0.2 lb/ft^3)					
24	273.1 ± 7.9 (17.1 ± 0.5)	66.3 ± 3.9	15.8 ± 0.2	24.3 ± 1.5	325.2 ± 55.2 (20.3 ± 3.4)
40	323.6 ± 2.3 (20.2 ± 0.1)	85.9 ± 1.2	12.0 ± 0.2	22.0 ± 1.0	488.9 ± 64.1 (30.5 ± 4.0)
60	359.6 ± 10.2 (22.5 ± 0.6)	86.3 ± 2.1	14.7 ± 0.6	24.3 ± 1.2	472.9 ± 68.3 (29.5 ± 4.3)

[#] Bulk density of compacted materials was measured based on ASTM (2009). This procedure involved five taps of the 1 ft × 1 ft × 1 ft wooden cubic container with compacted materials.
* Durability (%) = [Mass of compacted materials retained on 19.1 mm (0.75 in.) screen after tumbling × 100 / Mass of compacted materials used for tumbling]. About 500 g of compacted materials was tumbled for 2.4 min at 50 rpm (i.e., 120 revolutions) in the ASABE tumbling can durability tester (ASABE Standards, 2009).
[ψ] Angle of repose of bulk sample of compacts (about 1000 g) on a galvanized steel surface was measured using a tilted-plane angle of repose apparatus (Mohsenin, 1986).
[&] Geometric mean particle length ± geometric standard deviation.

References

ASABE Standards. 2009. S269.4: Cubes, pellets, and crumbles – Definitions and methods for determining density, durability, and moisture content. St. Joseph, Mich.: ASABE.

ASTM. 2009. E 873-82 (Reapproved 2006): Standard test method for bulk density of densified particulate biomass fuels. West Conshohocken, PA: ASTM International.

Mohsenin, N.N. 1986. Physical Properties of Plant and Animal Materials. New York, NY: Gordon and Breach Science Publishers.

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.

Presentations by Vance Morey related to BIGCC technologies, biomass logistics, and densification.

December 2, 2009
Presentation entitled "Biomass Densification" at Growing the Bioeconomy: Solutions for Sustainability, University of Minnesota, St. Paul, MN

February 2, 2010
Presentation entitled "Coproducts and other Biomass for CHP at Fuel Ethanol Plants" at the EUEC 2010 Energy and Environment Conference, Phoenix, AZ

March 11, 2010
Presentation entitled "Biomass Densification" at the Biomass Conversion to Heat and Electricity Workshop, Normal, Illinois

May 6, 2010
Presentation entitled "A Corn Stover Supply Logistics Systems" at the International Biomass Conference and Expo, Minneapolis, MN

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

March 1, 2010
Presentation given on densification, BIGCC, and torrefaction to Veridity, LLC and Redwood Area Development Commission at Redwood Falls, MN.

March 23, 2010
Presentation on densification, BIGCC, and torrefaction to Southwest Minnesota Energy Board Meeting consisting of area county commissioners and staff at Slayton, MN

March 23, 2010
Presentation and discussion with Mr. Brian Kletscher, General Manager of Highwater Ethanol, LLC regarding BIGCC, torrefaction, and densification, use of biomass at Lamberton, MN.

April 20, 2010
Meeting with Alex Marvin, research associate for Dr. Lanny Schmidt, regarding corn stover logistics, densification, and torrefaction at my office.

April 21, 2010
Conference call with Veridity Board and Jack Oswald of Syngest. (I discussed corn Stover logistics and costs of delivered corn stover.)

April 22, 2010
I delivered a class lecture for Dr. Roger Ruan's class on renewable energy at the University of Minnesota, discussing the use of biomass to reduce GHG emissions in the course of ethanol production, including the topics of corn stover logistics, BIGCC, and delivered corn stover costs.

Project Status

Overall we continue to make good progress. We revised our model of the gasification/combustion system to send all of the fuel to the gasifier with synthesis gas being sent to the combustor to provide required additional energy. This should provide greater flexibility in gas cleanup. We also changed the modeling of systems for steam tube drying by using the exhaust of the dryers as part of the input air for the gas turbine rather than sending it to the fluidized bed combustor for destruction of volatile organic compounds. This change in configuration provided significant improvement in electricity production including power sent to the grid.

We completed revisions on a paper on corn supply logistics which has been accepted for publication and will soon appear in print. We continue to participate in extension and outreach activities related to the project, primarily through the work of Doug Tiffany.

We have met with our subcontractor, Larry Schedin, LLS Resources, to discuss various incentive programs and business models. 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.