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: Generating Electricity with Biomass Fuels at Ethanol Plants

Contract Number: RD-56 **Milestone Number: 5** **Report Date: April 12, 2007**

Reporting Period: December 16, 2006 to March 15, 2007

Milestone Description: Fifth 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 with most recent results
- Completed evaluation of emissions relative to standards results
- Completed evaluation of emission control technologies results
- Completed ash characterization and evaluation results
- Completed electricity producing options results
- Updated capital and operating cost estimates
- Preliminary evaluation of compatibility with existing plant combustion systems
- Preliminary electricity production estimates and development of conceptual model results
- Preliminary incorporation of capital costs for technologies
- Communicated about project activities; conducted meetings of project participants in Minneapolis, MN in early February and early March; carried out project management, accounting, and reporting functions

This report was prepared as a result of work sponsored by NSP. It does not necessarily represent the views of NSP, its employees, or the Renewable Development Fund Board. NSP, its employees, contractors and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the use of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by NSP nor has NSP passed upon the accuracy or adequacy of the information in this report.

Technical Progress

Prepared by
R. Vance Morey, Professor, Bioproducts and Biosystems Engineering Department
Douglas G. Tiffany, Research Fellow, Applied Economics Department
University of Minnesota
and
Dennis L. Hatfield, Ethanol Team Leader, RMT Inc.

Summary of Tasks Listed under Milestone 5

- **Update website** – Three new draft chapters for the final report were added to the website for a total of five chapters.

- **Final evaluation of emissions relative to standards results** – The report for this task is included on the website in near final form. It is listed as Chapter/Task 7 and is found at the link below:

  www.biomasschpethanol.umn.edu/DraftChapters/index.html

- **Final evaluation of control technologies** – Alternatives for dealing with emissions of criteria pollutants such as particulate matter (PM), sulfur dioxide (SO_2), oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs), as well as hazardous air pollutants (HAPs) were summarized in Milestone 3 and 4 reports.

This task is completed except for summary of final technologies and costs, which are now being determined as part of the Capital and Operating Cost Estimates task. Data are in final stages of collection for various technology bundles for generating process heat and electricity. The focus is on technologies for controlling SO_2 and NO_x , which include addition of lime for SO_2 control and selective catalytic reduction (SCR) for control of NO_x.

- **Final ash characterization and evaluation results** – Characteristics of the ash, ash management equipment and possible beneficial uses were summarized in the Milestone 3 and 4 reports. Recent work on identifying specific opportunities for using ash as a soil amendment (fertilizer) is summarized below. A final version of the report on this task is nearly ready for posting on the web.

Ash Use As Fertilizer and Soil Amendment

Co-product ash may be suitable to improve soil chemical and physical properties. An evaluation of the soil is needed to determine crop requirements, and how the character of the ash may improve soil. The evaluation would include application rates to meet crop needs.

Studies have shown that combustion ash added to topsoil mixtures improves porosity, increasing seed germination rates, and improves plant yield for a variety of crops. Co-product ash can be used to treat soil pH and provide soil nutrients. The unreacted lime present in the ash will raise the pH of acidic soil, while the reacted lime (gypsum) is a source of calcium. Magnesium, phosphorus, potassium, and other minerals are also added to soil. The ash also improves physical properties, such as soil porosity, which improves aeration and water penetration for acidic soil, and increases moisture retention.

When used as agricultural liming materials, uncontaminated co-product limes can be distributed in accordance with Minnesota Statutes, sections 18C.531 to 18C.575, and Wisconsin Statutes, sections 94.65 to 94.66. Greenhouse studies demonstrated that ash-amended soil resulted in higher plant productivity than typical ag-lime–amended soil. These results possibly are due to pH and nutritional issues, but root penetration due to improved soil porosity was also probably a factor. Application rates for byproduct limes must be based on the lime recommendations of the University of Minnesota Extension Service and cannot cause the soil pH to exceed 7.1 after application. Site-specific application rates for byproduct lime must be determined by an individual who has a background and understanding of crop nutrient management such as a crop consultant. Recommended rates for lime can be obtained from the University of Minnesota Extension Service publication "Fertilizer Recommendations for Agronomic Crops in Minnesota" BU-06240-S, and the Minnesota Department of Agriculture publication "Ag-Lime Recommendations in Pounds ENP per acre" available on their Web site (www.mda.state.mn.us/lime). Similar recommendations for Wisconsin can be found at the University of Wisconsin-Extension Web site (learningstore.uwex.edu/Soil-Fertility).

Co-product ash is high in phosphorus, a nutrient commonly added to soil to increase crop yields. The addition of phosphorus to the soil depends on the total phosphorus already present and the amount of organic and inorganic acid extractables available in the ash. The rate of organic phosphorus is applied based on the soil nitrogen content. New regulations may limit the rate of ash co-product application based on the phosphorus soil test and runoff risk, the phosphorus content of co-product ash, and the phosphorus removal rate of the crop.

Co-product ash also contains significant amounts of potassium, calcium, magnesium, and sulfur. Most potassium in the ash is considered available, while the other mineral cations are available to varying degrees. High levels of sulfate may leach in the soil.

Trace metals such as boron, copper, zinc, iron, manganese, and molybdenum are present in the ash and serve as micronutrients, low amounts of which are required for plant growth.
Some sodium is present in the ash, which is detrimental to soil structure, as high levels of sodium are toxic to plants.

In the past (1940s through about 1980), agricultural research raised some concern about the proper soil calcium to magnesium ratio. The popular thinking was that high levels of magnesium cause soil to be "hard," with a drop in crop yields. More recent research, as highlighted on the Minnesota Extension Web site, has demonstrated that neither magnesium soil nor the calcium/magnesium ratio has any effect on crop growth and production. The calcium to magnesium ratio is an outdated concept and should be not used in making fertilizer recommendations.

A case-specific beneficial use determination (CSBUD) was made by the MPCA for the use of ash generated from the partner ethanol plant combusting syrup. The ash is land-applied as a fertilizer or an alternative liming agent. The ash is bundled, stored, tested, and reused according to the requirements of the CSBUD. Specific reporting and record keeping also apply. Soil testing is completed to verify the site suitability and application rates.

Little other information is available regarding the use of ash generated from combustion or gasification of ethanol co-products.

Studies on the ash from the gasification of alfalfa stems indicate the following (Mozaffar, M., C.J. Rosen, M.P. Russelle, and E.A. Nater. 2000. Chemical characterization of ash from gasification of alfalfa stems: Implications for ash management. Journal of Environmental Quality 29(3): 964-971; Mozaffar, M., C.J. Rosen, M.P. Russelle, and E.A. Nater. 2000. Corn and soil response to application of ash generated from gasified alfalfa stems. Soil Science 165(11): 896-906):

- Potassium concentrations increased and magnesium concentrations decreased significantly in corn.
- Little effect was noted for phosphorus or other trace elements.
- Ash application significantly increased salinity chlorine, extractable phosphorus, exchangeable potassium, calcium, magnesium, and sodium in soil.
- Although some PAH compounds were detected in ash, its application will not cause a major environmental concern when applied at reasonable agronomic rates.

It is not known if using ash from combustion rather than gasification of alfalfa stems would lead to similar results.

Ash Use in Construction

Ash is used as structural fill material in constructing highway embankments and road bases. Bottom ash can replace crushed stone sand, and gravel. Marketable uses for bottom ash consist of replacements for sand, gravel, and crushed stone; aggregate for concrete products; soil amendments; structural fills; base and sub-base pavements; anti-skid material for roads; roofing shingle granules; chip seal road topping; blasting grit; and material for snow and ice removal.

When ash is present with free lime, it reacts chemically to form cementitious materials, the type of which depends on the properties of the ash. Pulverized coal units, which are the most common type of coal combustion technology, produce both a bottom ash and a fly ash, which differ in chemical composition and physical properties. Fluidized bed combustion produces only a bottom ash, which is coarser than fly ash due to larger fuel particle size and increased combustion residence time. Fly ash has properties that are acceptable for use as a high-strength concrete (Portland cement), while bottom ash has use as an aggregate and direct use in manufactured products such as concrete bricks, blocks, and paving stone. The free lime, carbon content, and sulfate content of co-product ashes can limit their utilization to moderate-strength concrete block production, as free lime in ash will form water-soluble calcium hydroxide, resulting in some weakening of the block from contact with moisture. Such materials may not be preferred for heavy construction applications. When used as an aggregate, the bottom ash product has a lower unit weight than many naturally occurring aggregates, thus reducing the weight of the finished product.

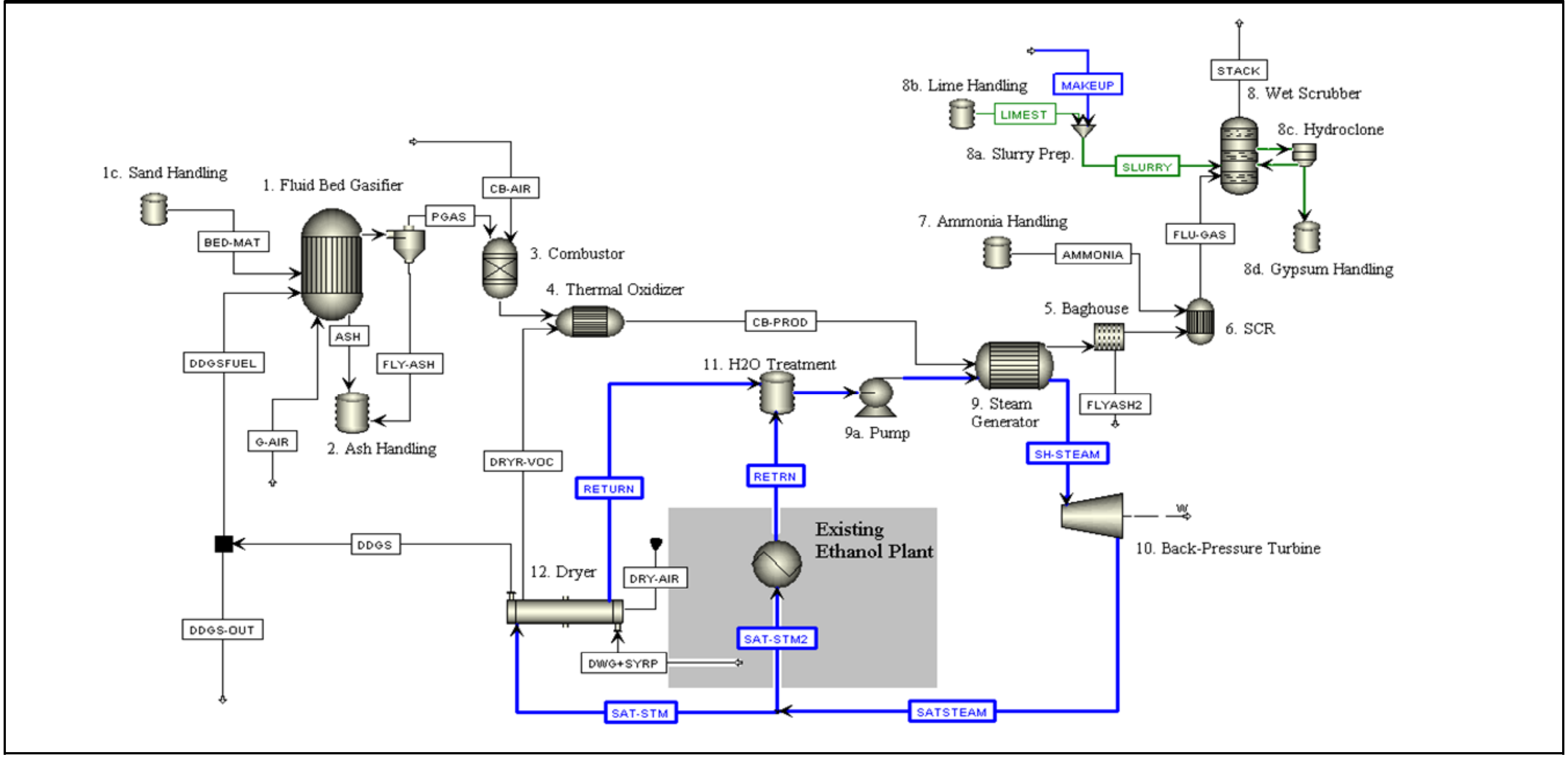
Ash can be used either mixed with or in the place of conventional backfill materials, such as soil, sand, or gravel, and to alleviate problems and restrictions generally associated with the placement of these materials. As the result is more cement-like, less compaction is required.

- **Final electricity producing options** –Detailed information about electricity producing options was included in the Milestone 3 and 4 reports. That information has been used in specifying technology bundles, which are now being evaluated to determine capital and operating costs. A final version of the report on this task is nearly ready for posting on the web.

- **Updated Capital and Operating Cost Estimates –** We have complete technology bundles related to combustion of corn stover and gasification of DDGS. Each set has three scenarios. The scenarios are being evaluated with by a local engineering firm to determine capital and operating costs. The process involves specifying equipment to components to satisfy the various functions including emission control. Cost estimates are solicited from potential equipment vendors to provide accurate estimates.

An example of the specifications for a technology bundle involving gasification of DDGS is shown on the next few pages.

FBG-ISD-2-DDGS (Process Heat & Electricity)



New Equipment

Description	Parameter	SI Units	*Parameter*	*Alt. Units*	Elec. Req. (kW)	Installed Cost	Operating Cost
1. Bubbling Fluidized Bed Gasifier						$ -	$ -
Operating Temperature	750	deg C	*1382*	*deg F*			
Fuel Feed Rate (WB)	15374	kg/h	*33894*	*lb/h*			
Fuel Feed Rate (DB)	13818	kg/h	*30464*	*lb/h*			
Fuel HHV (DB)	21.75	MJ/kg	*9349*	*Btu/lb*			

Fuel moisture content	10.12%	(WB)					
Footprint (approximate)	?	m^2					
1a. Cyclone(s)						$ -	
1b. Gasifier Air Fan					?	(Included)	
Air Flow Rate	21135	kg/h	*46593*	*lb/h*			
1c. Bed Material Handling (sand)					?	(Included)	
1. Subtotals					0	$ -	$ -
2. Ash Storage						$ -	$ -
Ash Storage Capacity	147816	kg	*5*	*Days*			
2a. Ash Cooling					?	$ -	$ -
Total Ash Flow Rate	1232	kg/h	*2716*	*lb/h*			
2. Subtotals					0	$ -	$ -
3. Combustion Tube (primary combustion)						$ -	$ -
Producer Gas inlet flow rate	35277	kg/h	*77771*	*lb/h*			
	113782	m^3/h	*66969*	*ACFM*			
Operating temperature	1114.81	deg C	*2039*	*deg F*			
3a. Combustion Air Fan					?	(Included)	(Included)
Combustion Air flow rate	21307	kg/h	*46974*	*lb/h*			
3. Subtotals					0	$ -	$ -
4. Thermal Oxidizer (secondary combustion)						$ -	$ -
Dryer Exhaust flow rate	74988	kg/h	*165319*	*lb/h*			
	96827	m^3/h	*56990*	*ACFM*			
Hot Products from Combustor flow	56584	kg/h	*124745*	*lb/h*			
	256841	m^3/h	*151171*	*ACFM*			
Operating Temperature	1296.48	deg C	*2366*	*deg F*			
4. Subtotals					0	$ -	$ -
5. Baghouse						$ -	$ -
HRSG Exhaust Gas Flow rate	131572	kg/h	*290064*	*lb/h*			
	245364	m^3/h	*144416*	*ACFM*			
HRSG Exhaust Gas Temperature	301.76	deg C	*575*	*deg F*			
5. Subtotals						$ -	$ -

6. Selective Catalytic Reduction (NOX scrubber)						$	-	$	-
Baghouse Exhaust flow rate	131572.13	kg/h	*290063.91*	*lb/h*					
	245363.65	m^3/h	*144415.60*	*ACFM*					
NO flow rate	324.58	kg/h	*715.56*	*lb/h*					
	510.27	m^3/h	*300.33*	*ACFM*					
NO2 flow rate	0.02	kg/h	*0.05*	*lb/h*					
	0.02	m^3/h	*0.01*	*ACFM*					
CO2 flow rate	22885.84	kg/h	*50454.13*	*lb/h*					
	24530.60	m^3/h	*14438.17*	*ACFM*					
N2 flow rate	66880.42	kg/h	*147444.56*	*lb/h*					
	112624.28	m^3/h	*66288.15*	*ACFM*					
O2 flow rate	427.38	kg/h	*942.21*	*lb/h*					
	630.05	m^3/h	*370.83*	*ACFM*					
SO2 flow rate	212.27	kg/h	*467.98*	*lb/h*					
	156.32	m^3/h	*92.00*	*ACFM*					
SO3 flow rate	0.42	kg/h	*0.92*	*lb/h*					
	0.24	m^3/h	*0.14*	*ACFM*					
HRSG Exhaust Gas Temperature	301.76	deg C	*575*	*deg F*					
6. Subtotals					0	$	-	$	-
7. Ammonia Handling/Storage					?	$	-	$	-
Storage Pressure				*psig*					
Ammonia Storage Capacity	91321	kg	*30*	*Days*					
Ammonia Flow Rate	126.83	kg/h	*280*	*lb/h*					
7. Subtotals					0	$	-	$	-
8. Wet Limestone Flue Gas Desulfurization Scubber						$	-	$	-
Flue Gas flow rate (from SCR)	131828.96	kg/h	*290630.13*	*lb/h*					
	252949.15	m^3/h	*148880.25*	*ACFM*					
NO flow rate	101.13	kg/h	*222.94*	*lb/h*					
	163.46	m^3/h	*96.21*	*ACFM*					
NO2 flow rate	0.01	kg/h	*0.02*	*lb/h*					
	0.01	m^3/h	*0.00*	*ACFM*					
CO2 flow rate	22885.84	kg/h	*50454.13*	*lb/h*					

	25221.98	m^3/h	*14845.10*	*ACFM*			
N2 flow rate	67188.76	kg/h	*148124.34*	*lb/h*			
	116332.40	m^3/h	*68470.67*	*ACFM*			
O2 flow rate	398.08	kg/h	*877.62*	*lb/h*			
	603.40	m^3/h	*355.15*	*ACFM*			
SO2 flow rate	212.27	kg/h	*467.98*	*lb/h*			
	160.72	m^3/h	*94.60*	*ACFM*			
SO3 flow rate	0.42	kg/h	*0.92*	*lb/h*			
	0.25	m^3/h	*0.15*	*ACFM*			
HCL flow rate	24.97	kg/h	*55.04*	*lb/h*			
	33.21	m^3/h	*19.55*	*ACFM*			
Flue Gas Temperature (from SCR)	317.96	deg C	*604.33*	*deg F*			
8a. Limestone Slurry Prep (Ball Mill)					?	(included)	(included)
Makeup water flow rate	?						
Lime flow rate	172.1	kg/h	*379.43*	*lb/h*			
8b. Lime Handling/Storage					?	(included)	(included)
Limestone Storage Capacity	41306	kg	*10*	*Days*			
8c. FGD byproduct Hydroclone(s)					?	(included)	(included)
FGD Solids (Gypsum) Outlet flow rate	?						
8d. Gypsum Handling/Storage					?	(included)	(included)
Gypsum Storage Capacity	?	kg		*Days*			
8. Subtotals					0	$ -	$ -
9. Steam Generator						$ -	$ -
Total Steam Generated	88755	kg/hr	*195669*	*lb/hr*			
Steam Pressure	5300.0	kPa	*769*	*psia*			
Steam Temperature	336.85	deg C	*638*	*deg F*			
Combustion Gas Inlet Temperature	1296.48	deg C	*2366*	*deg F*			
Combustion Gas Flow (from TO)	131572	kg/h	*290064*	*lb/h*			
	669899	m^3/h	*394288*	*ACFM*			
Flue Gas outlet Temperature	301.76	deg C	*575*	*deg F*			
Blowdown	2745	kg/hr	*6052*	*lb/hr*			
9a. Boiler Feedwater Pump					205.07	$ -	$ -
Efficiency	75%						
Feedwater Pressure into steam gen.	6500.0	kPa	*943*	*psia*			

Feedwater Temp into steam gen.	181.7	deg C	*359*	*deg F*			
9. Subtotals					205.07	$ -	$ -
10. Backpressure Steam Turbine						$ -	$ -
Generating Capacity	5.56	MW					
Isentropic Efficiency	72%						
Steam Inlet Pressure	5000.0	kPa	*725*	*psia*			
Steam Inlet Temperature	326.9	deg C	*620*	*deg F*			
Steam Outlet Pressure	1135.5	kPa	*165*	*psia*			
Steam Outlet Temperature	185.9	deg C	*367*	*deg F*			
10. Subtotals						$ -	$ -
11. Water Cleanup/ Deaeration					?	$ -	$ -
Makeup water	2745	kg/hr	*6052*	*lb/hr*			
Total Water flow rate	91500	kg/hr	*201721*	*lb/hr*			
11. Subtotals					0	$ -	$ -
12. Steam Tube (Indirect) Dryer						$ -	$ -
Flow rate of wet material in (WB)	50078	kg/hr	*110402*	*lb/hr*			
Moisture content of wet material	65.68%	WB					
Flow rate of dry material out (WB)	19122	kg/hr	*42156*	*lb/hr*			
Moisture content of dry material	10.12%	WB					
Water removed	30956	kg/hr	*68246*	*lb/hr*			
Heat Duty	22010	kW	*75,167,786*	*Btu/h*			
	2560	kJ/kg H2O	*1,783*	*Btu/lb H2O*			
Footprint (approximate)		m^2		ft^2			
12a. Dryer Fan					?	(included)	(included)
Dry Air Flowrate	44032	kg/hr	*97073*	*lb/hr*			
12b. Dryer Rotation Motor					?	(included)	(included)
12. Subtotals					0	$ -	$ -
New Equipment Totals					205.07	$ -	$ -

- **Preliminary evaluation of compatibility with existing plant combustion systems** –

Background of the Task
All fuel ethanol facilities have some type of on-site combustion system for steam generation. These combustion systems may be stand-alone steam generators, stand-alone emission control devices, or, in more modern units, may be dual-use, combining emission control and steam generation. A few facilities generate some electric power, which may be in conjunction with emission control and/or steam generation.

This project focuses on the applicability of generation of electricity using existing facility combustion systems, modified for biomass combustion. Using existing facility combustion systems would reduce capital costs and potential operational disruption as compared with installation of new systems. However, efficiency and operating cost should also be carefully evaluated, since specially designed systems are often more efficient and cost effective over the long run than retrofit systems.

A previous chapter, "Combustion Options" described the four combustion systems included in this project:

- Combustion in fluidized bed units
- Gasification in fluidized bed units
- Combustion of syrup using an injection nozzle in a standard boiler design
- Combustion of a combination of syrup and DWG, DDG, or DDGS using an injection nozzle in a standard boiler design

Since fluidized bed units are not typically at fuel ethanol facilities, only the liquid injection combustion option applies. As discussed in previous chapters, injection of both syrup or syrup and solids-containing portions (DWG, DDG, and DDGS) is feasible using essentially conventional technology. Based on the analyses performed as part of this project, and on the literature, the ethanol plant biomass solids are of a size necessary for injection into a combustion unit through a nozzle, and can be mixed with syrup or with other liquid or gaseous fuel for injection into an essentially conventional steam generator. However, the moisture content of the syrup and DWG, as received, are too high for stable, self-sustaining combustion. A substantial reduction of the moisture content, with associated costs and energy use, would be needed prior to combustion. A new potential technology to accomplish this moisture reduction for syrup is described further.

A new modular evaporation technology has recently been developed and is in operation to increase solids in syrup to over 50 percent. Combustion modeling in a previous chapter and the operating partner ethanol plant combusting syrup indicate that syrup with a reduced moisture content (near 50 percent moisture) may achieve self-sustaining combustion.

There are several disadvantages to using liquid injection via nozzles into a conventional combustion unit. As discussed above, the moisture content of the syrup would need to be substantially reduced to allow for stable, self-sustaining combustion. Feeding of syrup through pressure nozzles might lead to additional maintenance for the storage, feed system, and nozzles.

Syrup contains complex carbon compounds that would not be expected to burn as cleanly as natural gas. Particulates would be generated, some of which might cause fouling of the combustion or steam system. The relatively high levels of alkaline metals in the syrup may cause problems with slagging and ash fusion. A steam generator designed for natural gas may not be able to handle such particulates and ash. The sulfur content of the syrup might pose an emission problem, and, unlike a fluidized bed, adding chemicals to sequester the sulfur may be much more difficult, or may even be infeasible, for conventional systems. System modifications to allow for the combustion of syrup might not allow for the combustion of conventional solids, so that the potential for burning of other biomass, including DWG, DDG, or DDGS, might be compromised.

Overall, the best and most efficient use of existing combustion systems is to provide standby or supplemental steam to the fuel ethanol process.

- **Preliminary electricity production estimates and development of conceptual model results** –

Introduction

The generation, transmission, distribution, and sale of electricity are heavily regulated at both the federal and state levels, and may also be subject to requirements of the utility generating the electricity and to local and regional electricity transmission and distribution organizations. The generation of electricity by nonutility sources (such as ethanol plants), and the connection of these sources to the electricity grid for purposes of buying electricity from the grid and selling electricity to the grid, add another tier of regulatory complexity. Still more regulatory complexity is added if the fuel for the electricity generation is a renewable fuel, such as ethanol plant co-products. This regulatory complexity has significant potential impact on the economic, technical, and operational success of the ethanol plant. However, new regulations have also removed some of the barriers and improved price incentives.

In this section, these complex regulatory considerations will be examined, and their economic, technical, and operational impacts for ethanol plants will be discussed. Other sections of this report also bear on the impact on ethanol plants of the complex electricity regulatory framework.

Section 1. Regulatory Aspects of On-Site Electricity Generation

1.1 Federal and State Regulations

Both federal and state regulations and programs have been put in place to encourage the generation of electricity from biomass and other renewable energy sources. The mechanisms used to encourage this generation include the creation of renewable energy markets, favorable tax treatments, and favorable regulatory status. The major applicable regulations and programs are discussed below.

1.1.1 Public Utility Regulatory Policies Act (PURPA)

Under PURPA, facilities generating their own electricity and meeting certain fuel and efficiency standards (a “Qualified Facility” or QF) are accorded special regulatory qualifications. As initially approved, PURPA required that the local utility purchase all energy sold by the owner of a QF at its avoided cost and provide standby, backup, and maintenance power to the QF. However, EPACT ‘05 amended PURPA, such that where the Federal Energy Regulatory

Commission (FERC) determines that competitive conditions exist, such as areas that participate in regional transmission markets, a utility is no longer required to buy power from renewable energy and combined heat and power (CHP, or cogeneration) plants, even when such plants can generate power less expensively than the utility, and even when such plants would otherwise meet PURPA standards.

The revised PURPA standards do provide an exception for generating units rated 20 MW or less. Before being relieved of their purchase obligation from units rated 20 MW or less, the local utility must provide a showing that the units have access to competitive power markets. Smaller generating units, such as those at ethanol plant sites and generating only the plant load, are typically connected at distribution voltage and therefore do not have transmission access to the Regional Transmission Organization (RTO) markets, in this case the Midwest Independent System Operator's (MISO's) markets. To receive the full benefit of those parts of PURPA that still apply, a DG facility that cogenerates should be formally registered by the owner as a QF under the PURPA self-certification process. Despite any changes in federal regulations, the states of Minnesota and Wisconsin actively encourage the development of distributed generation, as discussed below

1.1.2 Renewable Energy Credits

Customers who generate their own electricity utilizing qualified renewable fuels, such as ethanol co-products, can sell Renewable Energy Credits (RECs) into national and state markets, where such markets exist, even when the electricity is all utilized on-site. However, once sold, the RECs remain with the property of the buyer, who can further trade the RECs. The current market for RECs are small and regional, though evolving, with transactions via over-the-counter trades or bilateral deals.

1.1.3 Production Tax Credits

Under the Energy Policy Act of 2005 (EPACT ’05), wholesale generators of electricity from biomass that is sold for use by others are eligible for a production tax credit (PTC), for the first 10 years of such electricity production. The PTC for 2006 for “open-loop” biomass is about one half of the $0.019/ kWh credit for other renewable energy technologies, with an annual adjustment for inflation. To be eligible for a PTC under the current law, the electricity-generating equipment must be on-line before January 1, 2008. Among other eligibility requirements for the PTCs, the regulations restrict the use of coal in the fuel-to-flame initialization and stabilization, and facilities that use the renewable energy to serve any on-site needs are ineligible. The energy associated with natural gas used in the production of electricity is not eligible for production tax credits, and any electricity produced by "co-mingling" natural gas and renewable fuels would need to be sorted by fuel type.

Similar to PTCs, renewable generation assets owned by tax exempt state and municipal utilities are eligible for renewable energy production incentive (REPI) payments from the federal government.

- **Preliminary incorporation of capital costs for technologies** – We have developed menu pages for the various technology bundles and are starting to enter capital costs as they become available. We have used the information in a preliminary format to prepare a paper entitled “Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants” for the proceedings of the Fifth International Starch Technology Conference to be held June 3-6 in Champaign-Urbana, IL.

- **Summary of project management activities, travel, etc. for period (RMT)** – Dan Haak of RMT met in Minneapolis on February 7 and March 8 with AMEC personnel, Larry Schedin and UofM personnel to discuss project tasks and progress.

Dan Haak visited the Corn Plus Ethanol plant in Winnebago, MN on March 7 along with Doug Tiffany, Matt DeKam and Vance Morey.

- **Summary of project management activities, travel, etc. for period (UofM) –** Doug Tiffany, Vance Morey, and Matt De Kam met with Dan Haak of RMT, AMEC personnel, and Larry Schedin on February 7 and March 8 to discuss project tasks and progress.

Doug Tiffany, Vance Morey, and Matt De Kam visited with Frontline Bioenergy in Ames, Iowa on February 9 to discuss their gasifier technology that is being developed for use at ethanol plants.

Doug Tiffany, Matt DeKam and Vance Morey visited the Corn Plus Ethanol plant in Winnebago, MN on March 7 along with Dan Haak of RMT.

Doug Tiffany, Matt DeKam and Vance Morey attended an AURI sponsored energy conference in Redwood Falls, MN on March 13, which was attended by representatives of ethanol plants. Doug Tiffany presented comparisons of corn versus cellulosic ethanol and Vance Morey presented results from the Xcel Energy RDF project on Generating Electricity with Biomass Fuels at Ethanol Plants.

Doug Tiffany, Vance Morey and Matt DeKam prepared a paper entitled “Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants” for the proceedings of the Fifth International Starch Technology Conference, which focuses on energy issues this year. The conference will be held June 3-6 in Champaign-Urbana, IL. The paper will be presented at the conference and includes results from the Xcel Energy RDF project on Generating Electricity with Biomass Fuels at Ethanol Plants.