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Project Title: Generating Electricity with Biomass Fuels at Ethanol Plants

Contract Number: RD-56 Milestone Number: 6 Report Date: August 10, 2007

Reporting Period: March 16, 2007 to July 15, 2007

Milestone Description: Fifth three-month reporting period

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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 capital and operating cost estimating procedures
- Completed evaluation of compatibility with existing plant combustion systems
- Completed electricity production estimates and development of conceptual model results
- Completed incorporation of capital costs for technologies
- Preliminary economic analysis results were obtained
- Presented one paper on project results at the International Starch Conference at the University of Illinois – Champaign-Urbana in early June
- Presented two papers on project results at the ASABE International Annual Meeting in mid-June
- Participated in the Fuel Ethanol Workshop meeting in St. Louis where we discussed project results with ethanol plant managers and equipment suppliers
- Communicated about project activities; carried out project management, accounting, and reporting functions

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 6

- **Update website** – Added several papers and presentations made during this reporting period.

- **Final Capital and Operating Cost Estimating Procedures –** We have completed technology configurations related to combustion of corn stover, combustion of a syrup-corn stover mixture, and gasification of DDGS. Each configuration has three cases or levels – process heat only, combined heat and power (CHP), and CHP plus electricity to the grid. Schematics of several of the configurations/levels are show below.

The primary components of the dry grind ethanol process such as fermentation, distillation, and evaporation were not changed. Only those components impacted by using biomass fuel were modified. They included steam generation (biomass combustion or gasification), thermal oxidation, and co-product drying.

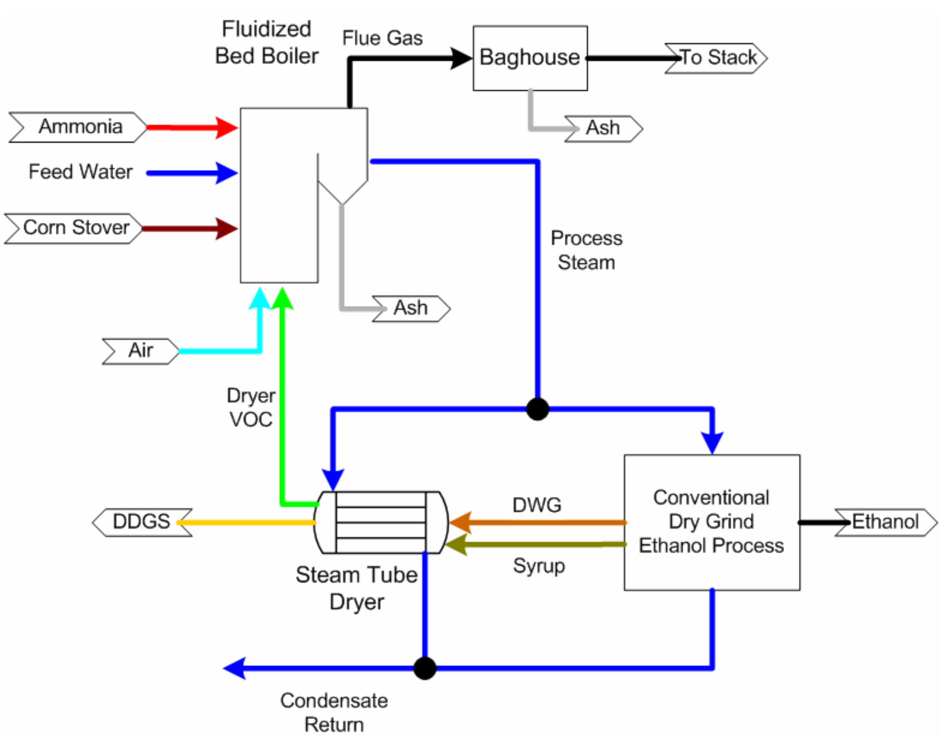


Figure 1. Corn stover combustion, level 1: process heat only.

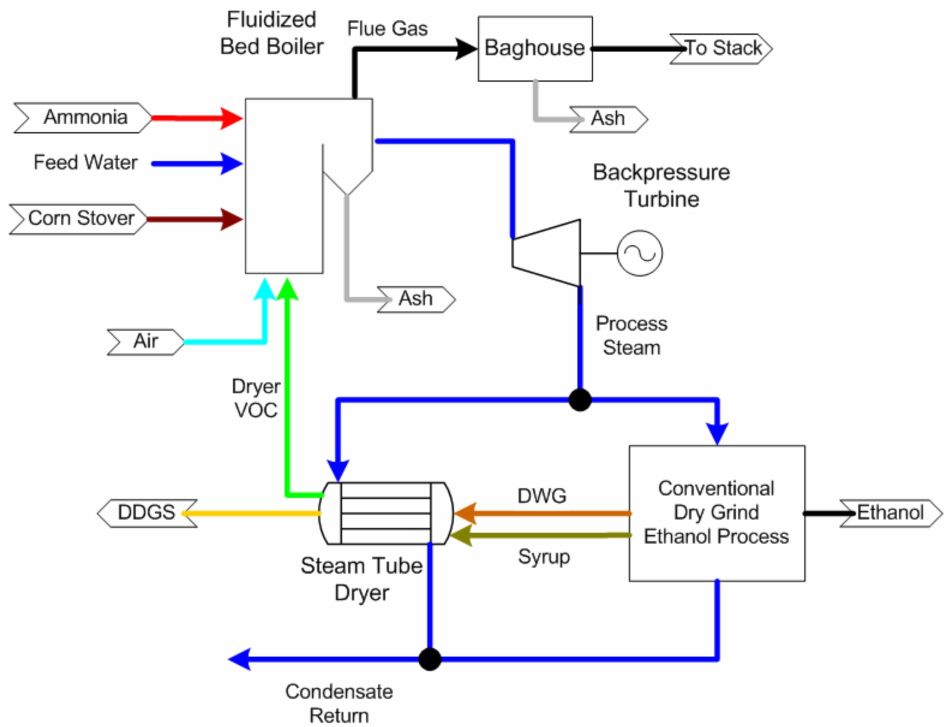


Figure 2. Corn stover combustion, level 2: CHP.

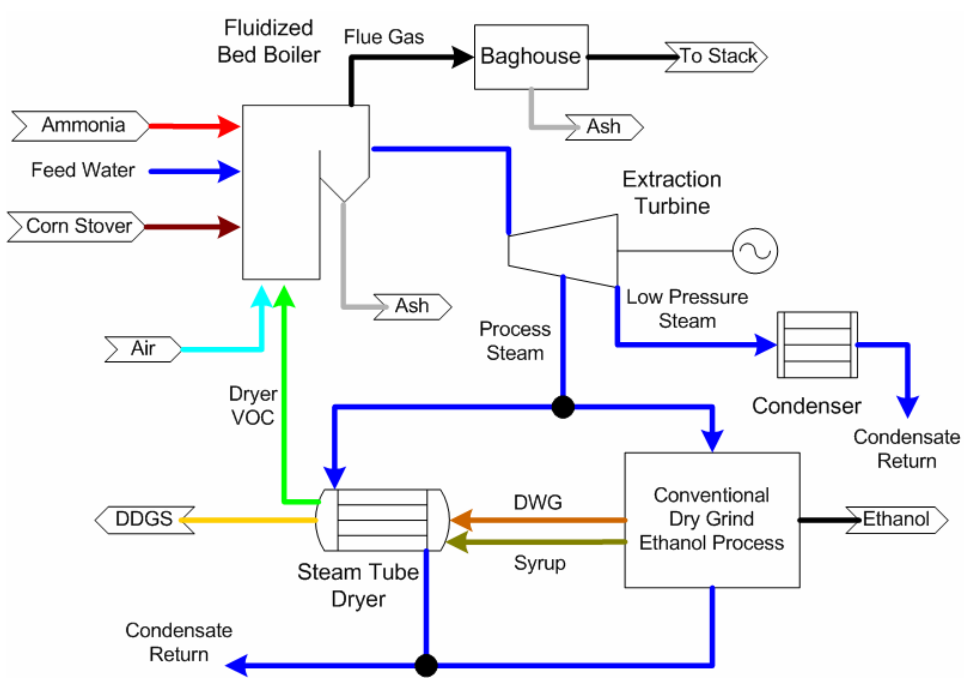


Figure 3. Corn stover combustion, level 3: CHP and electricity to the grid.

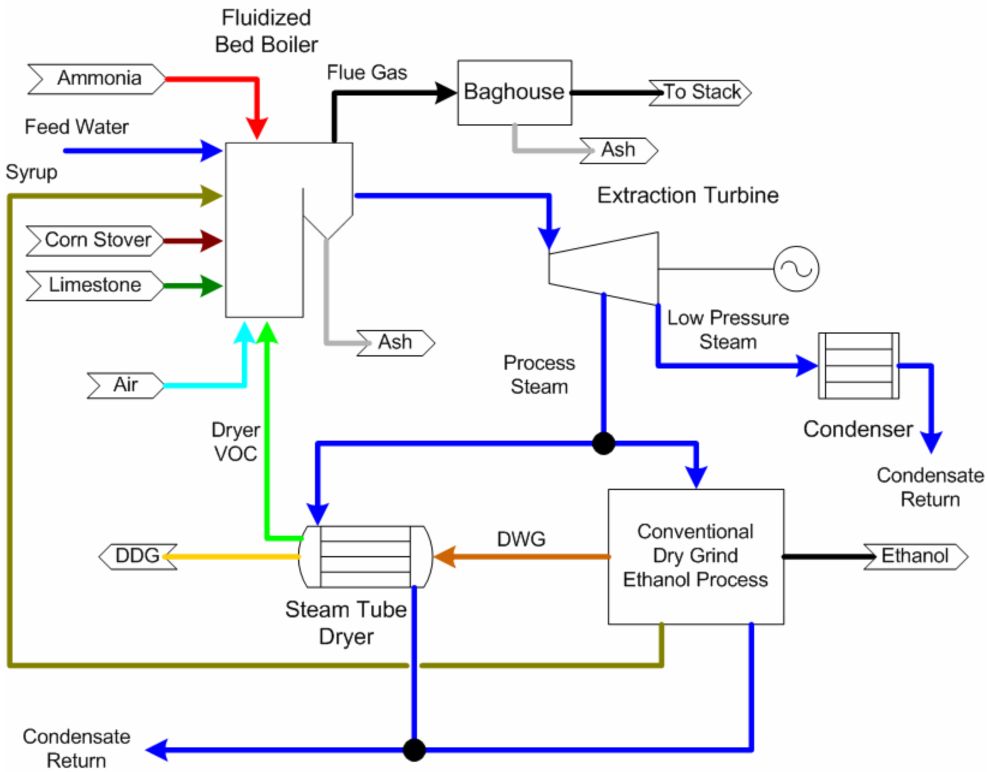


Figure 4. Syrup and corn stover combustion, level 3: CHP and electricity to the grid.

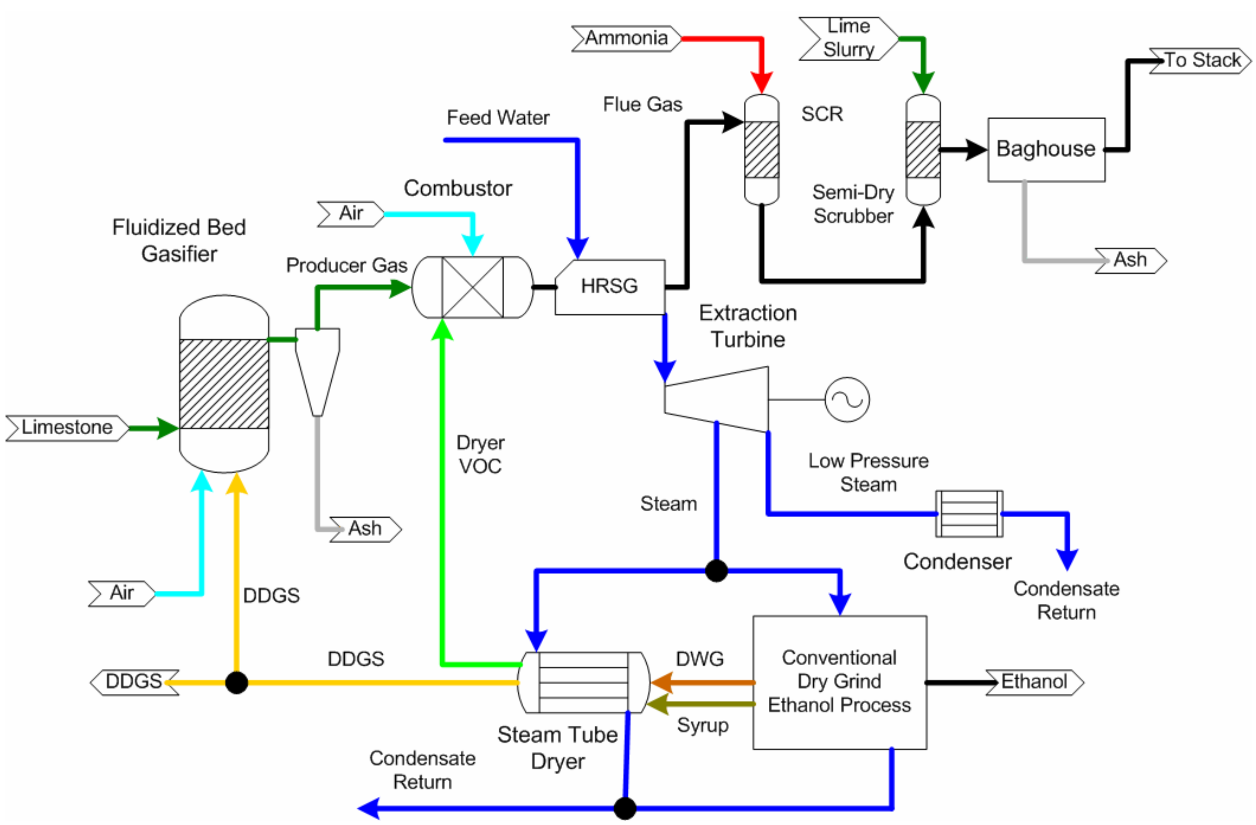


Figure 5. DDGS gasification, level three: CHP and electricity to the grid.

The scenarios are being evaluated by a local engineering firm (AMEC) to determine capital and operating costs. The process involves specifying equipment and components to satisfy the various functions including emission control. Cost estimates are solicited from potential equipment vendors to provide accurate estimates. Cost estimates are categorized according to new equipment and equipment that is replaced. We are focusing on the net change in equipment and, therefore, capital cost required to construct a dry grind ethanol plant to use biomass rather than natural gas as a fuel. Results for the three corn stover cases are summarized below. All estimates are for a 50 million gallon per year dry grind ethanol plant.

Table 1. Capital cost summary for corn stover system – process heat only.

Equipment Category		**Equip. Cost, $**	**Installed Cost, $**	**% of Net**	**% of New**
Biomass Fuel Handling	new	1,275,000	4,069,340	12.1	6.5
Fluidized Bed Boiler and Steam System	new	9,834,000	31,386,378	93.3	50.3
Ash handling	new	650,000	2,074,565	6.2	3.3
Emissions Control	new	1,650,000	5,266,204	15.7	8.5
Steam Turbine Generator and Acc.	new	0	0	0	0
Steam Tube Dryer	new	6,129,000	19,561,555	58.2	31.4
Natural Gas Dryer and Thermal Oxidizer	replaced	(9,000,000)	(28,724,751)	(85.4)	(46.1)
Total Cost – net (new – replaced)		**10,538,000**	**33,633,492**	**100.0**	**53.9**
Total Cost –new items		**19,538,000**	**62,358,243**		**100.0**

Table 2. Capital cost summary for corn stover system – CHP.

Equipment Category		**Equip. Cost, $**	**Installed Cost, $**	**% of Net**	**% of New**
Biomass Fuel Handling	new	1,400,000	4,434,229	9.1	5.8
Fluidized Bed Boiler and Steam System	new	12,386,600	39,238,490	80.7	50.9
Ash handling	new	650,000	2,058,749	4.2	2.7
Emissions Control	new	1,785,000	5,653642	11.6	7.3
Steam Turbine Generator and Acc.	new	2,000,000	6,334,612	13.0	8.2
Steam Tube Dryer	new	6,129,000	19,412,420	39.9	25.2
Natural Gas Dryer and Thermal Oxidizer	replaced	(9,000,000)	(28,505,756)	(58.6)	(37.0)
Total Cost – net (new – replaced)		**15,352,600**	**48,626,386**	**100.0**	**63.0**
Total Cost –new items		**24,352,600**	**77,132,142**		**100.0**

Table 3. Captial cost summary for corn stover system – CHP plus electricity to the grid.

Equipment Category		**Equip. Cost, $**	**Installed Cost, $**	**% of Net**	**% of New**
Biomass Fuel Handling	new	1,750,000	5,518,624	8.4	5.9
Fluidized Bed Boiler and Steam System	new	14,507,600	45,749,706	70.0	48.8
Ash handling	new	650,000	2,049,775	3.1	2.2
Emissions Control	new	1,709,000	5,387,330	8.3	5.8
Steam Turbine Generator and Acc.	new	4,980,000	15,704,426	24.0	16.8
Steam Tube Dryer	new	6,129,000	19,327,797	29.6	20.6
Natural Gas Dryer and Thermal Oxidizer	replaced	(9,000,000)	(28,381,493)	(43.4)	(30.3)
Total Cost – net (new – replaced)		**20,725,600**	**65,358,164**	**100.0**	**69.7**
Total Cost –new items		**29,725,600**	**93,739,652**		**100.0**

Equipment costs are first estimated and then other costs associated with the project are added. They include installation, building, electrical, contractor costs and fees, engineering, contingency, and escalation to arrive at the total project cost. Total project costs are divided by equipment costs to yield a factor to use for estimating the contribution of each category of equipment to the total cost. The factors worked out to be 3.19, 3.17, and 3.15 for cases shown above in Tables 1, 2, and 3, respectively.

We assumed that a package natural gas boiler would be included for backup and also perhaps to phase into biomass as a fuel source over time, so the cost of that equipment is not deducted.

The estimates in each table represent the net increase in capital costs required for a 50 million gallon per year dry grind ethanol plant. They are added to recent estimates for conventional (natural gas) dry grind plants to come up with capital costs for the biomass fueled plants. Similar estimates are made for the syrup-corn stover combination.

Nameplate installed costs are summarized for corn stover and syrup plus corn stover at three levels for each in Table 4. Cost estimates for the 100 million gallon per year plants are based on the ratio of the plant sizes (100 million/50 million = 2). The cost estimating factor for the 100 million plant is $(2)^{0.7}$ or 1.62. Thus, the cost for 100 million gallon plant is estimated to be 1.62 times the cost for a 50 million gallon plant for a similar fuel and level. This technique of adjusting costs for scale is commonly used in many chemical and industrial processes.

Table 4. Nameplate Installed Costs for Technology Bundles in Plants of 50 MM and 100 MM Gallons

	Conventional Plant	Stover #1	Stover #2	Stover #3	Syrup + Stover #1	Syrup + Stover #2	Syrup + Stover #3
50 MM Cost/Gal.	$2.25	$2.82	$3.13	$3.46	$2.71	$3.02	$3.35
50 MM Total Cost	$112.50	$141.00	$156.50	$173.00	$135.25	$150.75	$167.25
100 MM Cost/ Gal.	$1.83	$2.29	$2.54	$2.81	$2.20	$2.45	$2.72
100 MM Total Cost	$182.76	$229.06	$254.24	$281.04	$219.71	$244.89	$271.70
Capacity Factors Applied	1.20	1.06	1.06	1.06	1.06	1.06	1.06

We are in the process of finalizing cost estimates for the gasification of DDGS at all three levels and await cost estimates from one of our research partners.

Additional operating cost estimates for labor, lime for SO_x control, ammonia for NO_x control, and others are included in the spreadsheets representing various options of using biomass to produce process heat and electricity at ethanol plants.

● **Final evaluation of compatibility with existing plant combustion systems** – Potential opportunities to use existing plant combustion systems were summarized in the Milestone 5 report. The basic conclusion was that existing plant combustion systems would be limited to providing standby or supplemental steam to the fuel ethanol process.

As described in the previous section, we assumed in our cost analysis that a package natural gas boiler would be included for backup and also perhaps to phase into biomass as a fuel source over time. This appears to be the best potential opportunity to use existing types of plant combustion systems. A few dry-grind ethanol plants have chosen to use coal as fuel for their process heat. There may be easily exploited opportunities to use biomass with these systems, but we have not analyzed such systems up to this point.

● **Final electricity production estimates and development of conceptual model results** – Opportunities for sending electricity to the grid and associated regulatory issues were summarized in the Milestone 5 report. The remaining activities associated with this task involve incorporating feed streams, combustion options, and electricity production options in a conceptual plant. That has been incorporated in the task related to Capital and Operating Costs presented earlier and the sections on Incorporation of Capital Costs for Technologies and Economic Analysis that follow.

● **Final incorporation of capital costs for technologies** – We have developed a menu page that feeds assumptions to the various technology bundles, and we can enter capital costs as they become available for each new scenario that is evaluated. That information is included in the results of the next section entitled Preliminary Economic Analysis.

● **Preliminary Economic Analysis** – Some preliminary economic results are summarized below.

The assumptions of baseline conditions are shown in Figure 5 for plants with conventional energy sources (natural gas and purchased electricity) as well as stover and syrup + stover plants using biomass at the three levels of intensity conforming to 1) process heat, 2) process heat + own electricity (CHP), and 3) CHP plus sales of electricity to the grid. Figure 6 shows baseline conditions for the competing technology bundles in 50 Million gallon per year plants. Figure 7 shows baseline conditions for the same technology bundles in 100 Million gallon per year plants.

Figure 5. Baseline conditions for economic analysis and comparisons.

Assumptions Common Across All Processes		6/4/2007
INSTALLED COSTS	**Active Val.**	**Base Val.**
Debt-Equity Assumptions		
Factor of Equity	**40%**	40%
Factor of Debt	60%	60%
Interest Rate Charged on Debt	**8%**	8%
Investor Required Return on Equity	**12%**	12%
Depreciation based on asset life (years)	**15**	15
Output Market Prices		
Ethanol Price (denatured price) $/gal.	**$1.80**	$1.80
DDGS Price $/T	**$100.00**	$100.00
Electricity Price (Plant is Seller) ($ per kWh)	$0.06	$0.06
Value of Ash ($ per Ton)	**$200.00**	$200.00
CO2 Price ($ per Ton liq. CO2)	**$8.00**	$8.00
Max. Premium for Low-Carbon ($.00 per gallon)	**$0.20**	$0.20
Government Subsidies		
Federal Small Producer Credit ($/gal.)	**$0.10**	$0.10
RFS Ethanol Tradable Credit ($/gal.)	**$0.10**	$0.10
Feedstock Delivered Prices Paid by Processor		
Corn Price ($ per bu.)	**$3.50**	$3.50
Energy Prices		
Natural Gas Price ($ per 1,000,000 Btu)	**$8.00**	$8.00
Stover Purchased @ ($ per dry Ton)	**$80.00**	$80.00
Electricity Price (Plant is Buyer) ($ per kWh)	**$0.06**	$0.06
LP (Propane) Price ($ per gallon)	**$1.10**	$1.10
Operating Costs/Input Prices		
Denaturant Price / gal	**$1.80**	$1.80
Denat/100 gal Anhyd.	**5**	5
Feedstock-to-Ethanol Conversion Yields		
Ethanol Yield (anhydrous gal per bushel)	**2.75**	2.75

Figure 6. Baseline rates of return using installed capital costs for 50 million gallon plants.

Author: Douglas G. Tiffany, University of Minnesota

Conventional Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid		50MM Gal
11.86%	13.84%	13.04%	9.88%	Stover	
	17.05%	15.63%	11.95%	Syrup + Stover	

INSTALLED COSTS

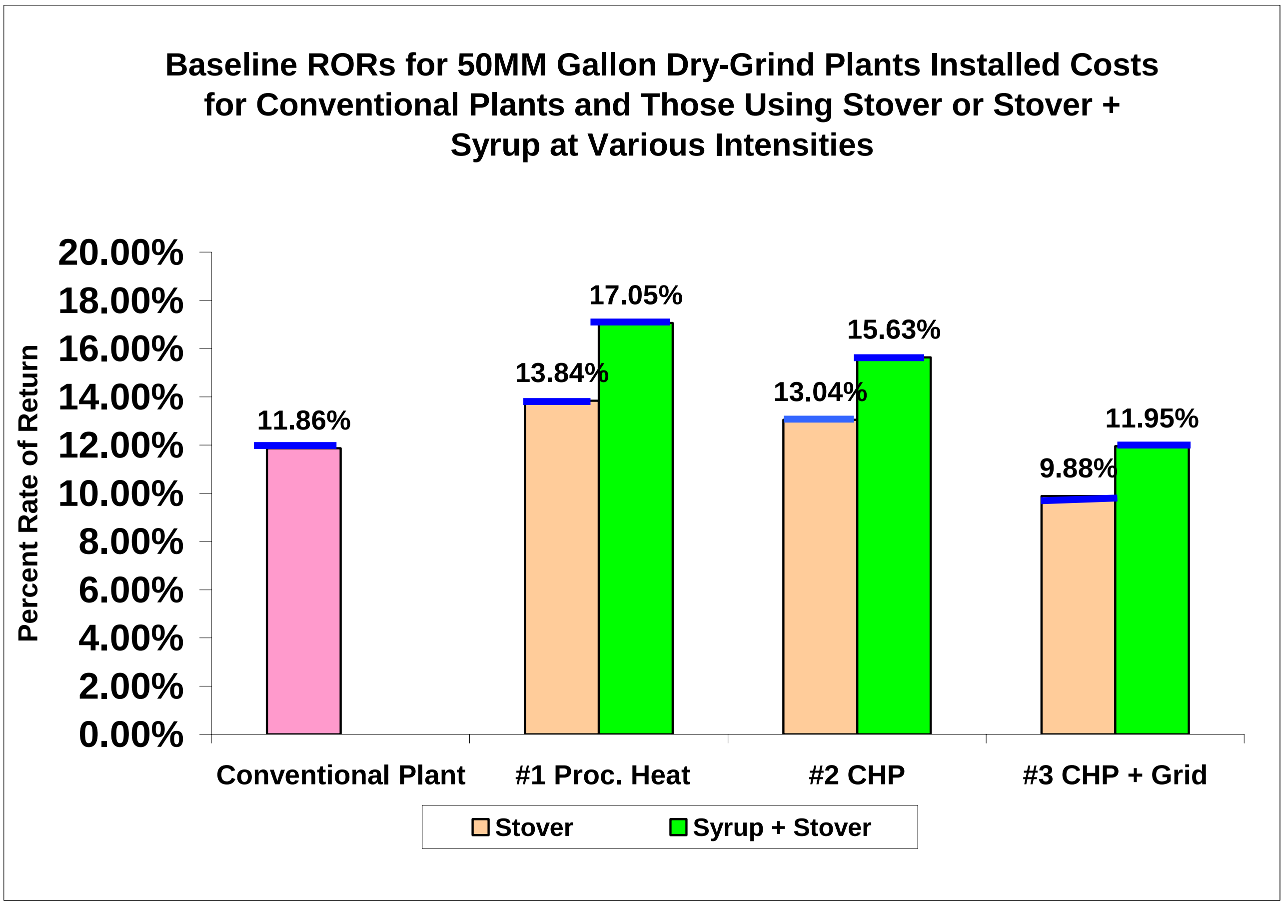
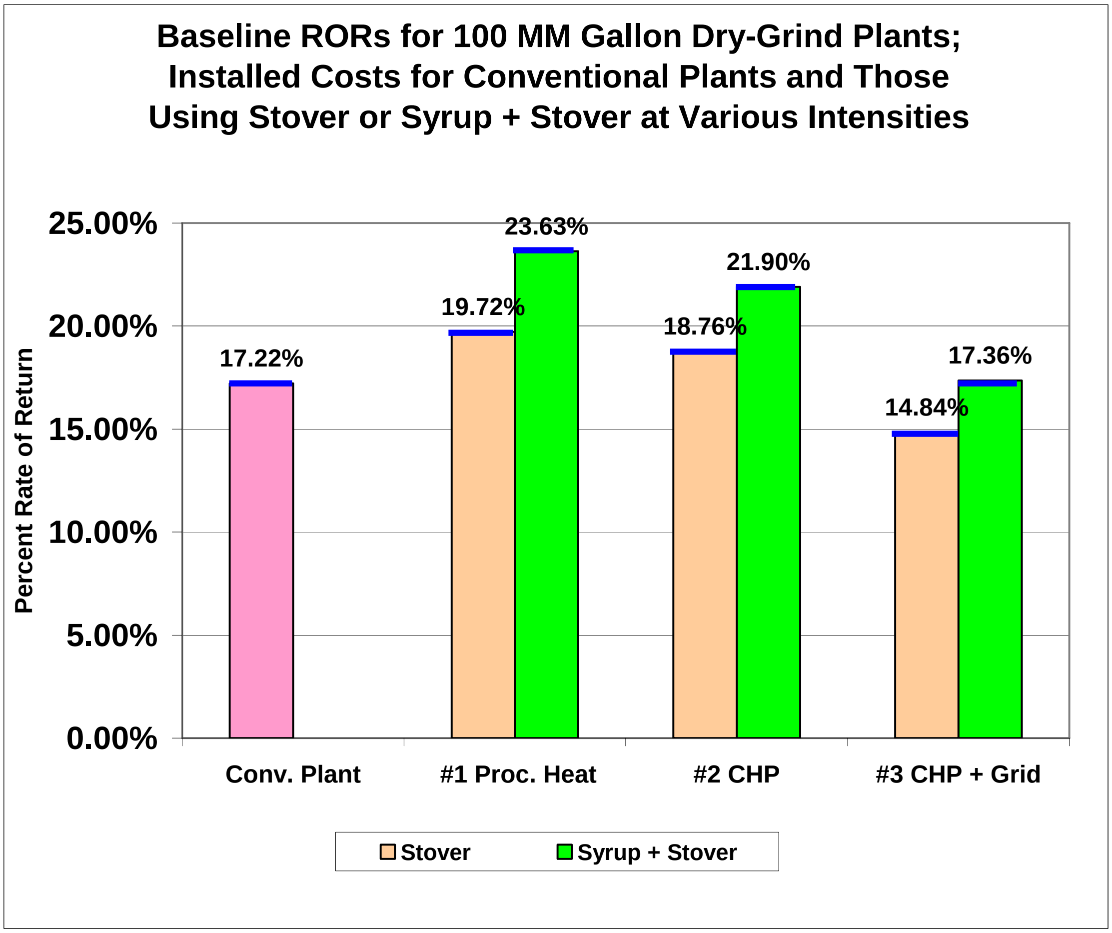


Figure 7. Baseline rates of return using installed capital costs for 100 million gallon plants.

Author: Douglas G. Tiffany, University of Minnesota

Conv. Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid		100 MM Gal.
17.22%	19.72%	18.76%	14.84%	Stover	
	23.63%	21.90%	17.36%	Syrup + Stover	

INSTALLED COSTS



Comparison of the graphs produced for the 50 Million gallon plants and the 100 Million gallon plants reveals that the larger plants experience significantly higher rates of return. This effect occurs for many variables, due to the lower capital costs per unit of production.

Figure 8 demonstrates the effect on rates of return for 50 million gallon plants when natural gas prices shift from $8.00 to $12.00 per dekatherm. These graphs show the favorable rates of return that would accrue to ethanol plants using biomass versus the conventional plants using natural gas for process heat. The blue line on the graph for the conventional plant shows the rate of return that previously existed at baseline conditions. Note the vulnerability of the conventional ethanol plant as natural gas prices rise.

Figure 8. The effect of natural gas prices on rates of return for 50 million gallon per year plants.

Author: Douglas G. Tiffany, University of Minnesota

Conventional Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid		50MM Gal
4.75%	13.84%	13.04%	9.88%	Stover	
	17.05%	15.63%	11.95%	Syrup + Stover	

INSTALLED COSTS

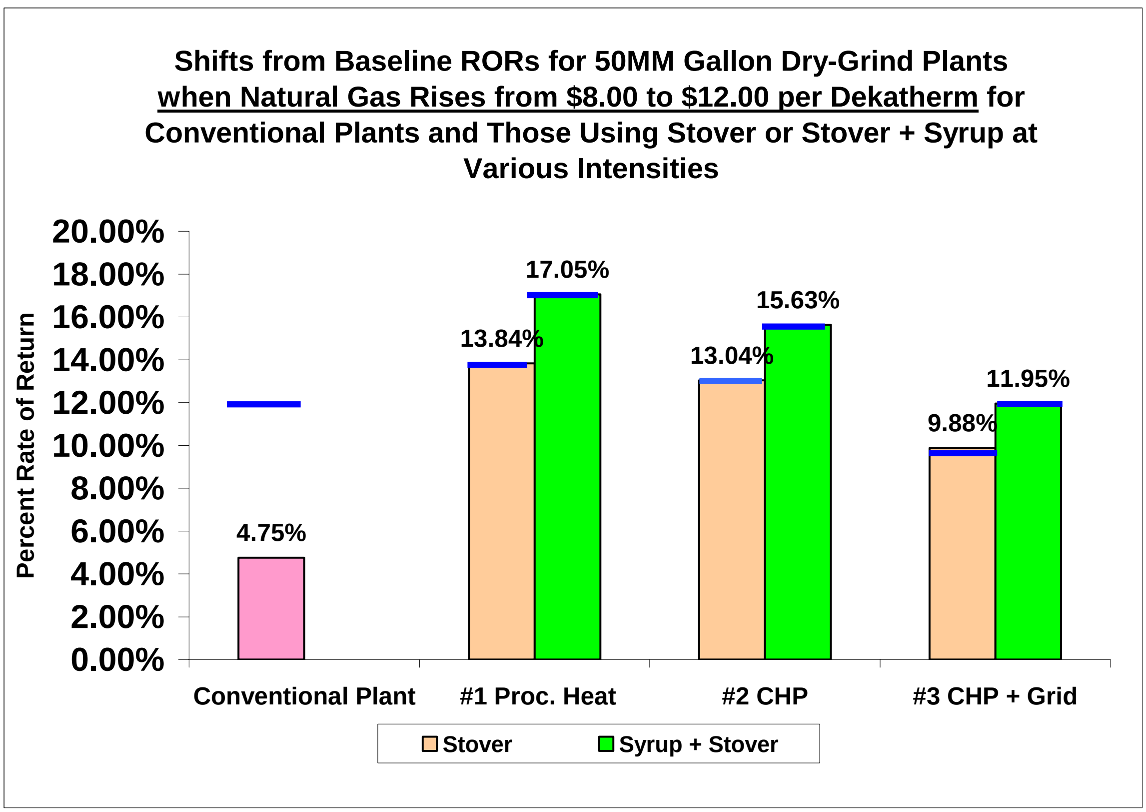


Figure 9 shows the effect of an adverse change in the price of the densified stover on the technology bundles with the price shifting from $80 to $100 per ton. Note how the conventional plant is unaffected and how the effect is proportionally less in the case of the plants that use syrup. The blue lines on the graph represent the baseline levels before this exogenous change in stover price. The figures on the graph refer to the active values conforming to these assumptions.

Figure 9. The effect of corn stover prices on rates of return for 50 million gallon per year plants.

Author: Douglas G. Tiffany, University of Minnesota

Conventional Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid		50MM Gal
11.86%	11.84%	10.98%	7.32%	Stover	
	16.32%	14.76%	10.29%	Syrup + Stover	

INSTALLED COSTS

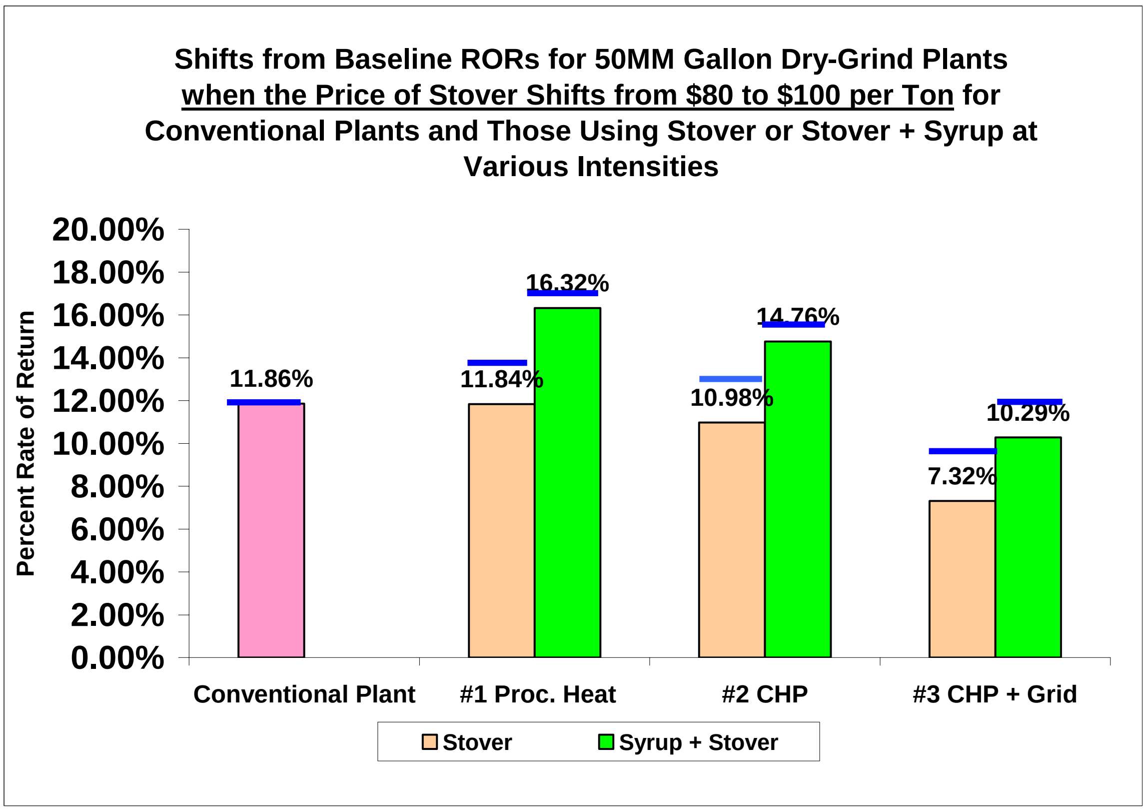


Figure 10 shows the effect on rates of return that particularly affects the third level of biomass intensity as the price paid for electricity sold to the grid rises from $.06 per kWh to $.10 per kWh. This case offers some insight into the sensitivity of the option to produce power for the grid with this stock of equipment and the baseline price of the biomass used. In this case, the rate of return for the option with sales of power to the grind becomes even more favorable in the case of syrup + stover, while the stover alone case improves, but not enough to surpass the rate of return in the conventional plant.

Figure 10. The effect of price paid for electricity on rates of return for 50 million gallon per year plants.

Author: Douglas G. Tiffany, University of Minnesota

	Conventional Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid		50MM Gal
	11.86%	13.84%	13.18%	11.16%	Stover	
		17.05%	15.63%	13.21%	Syrup + Stover	

INSTALLED COSTS

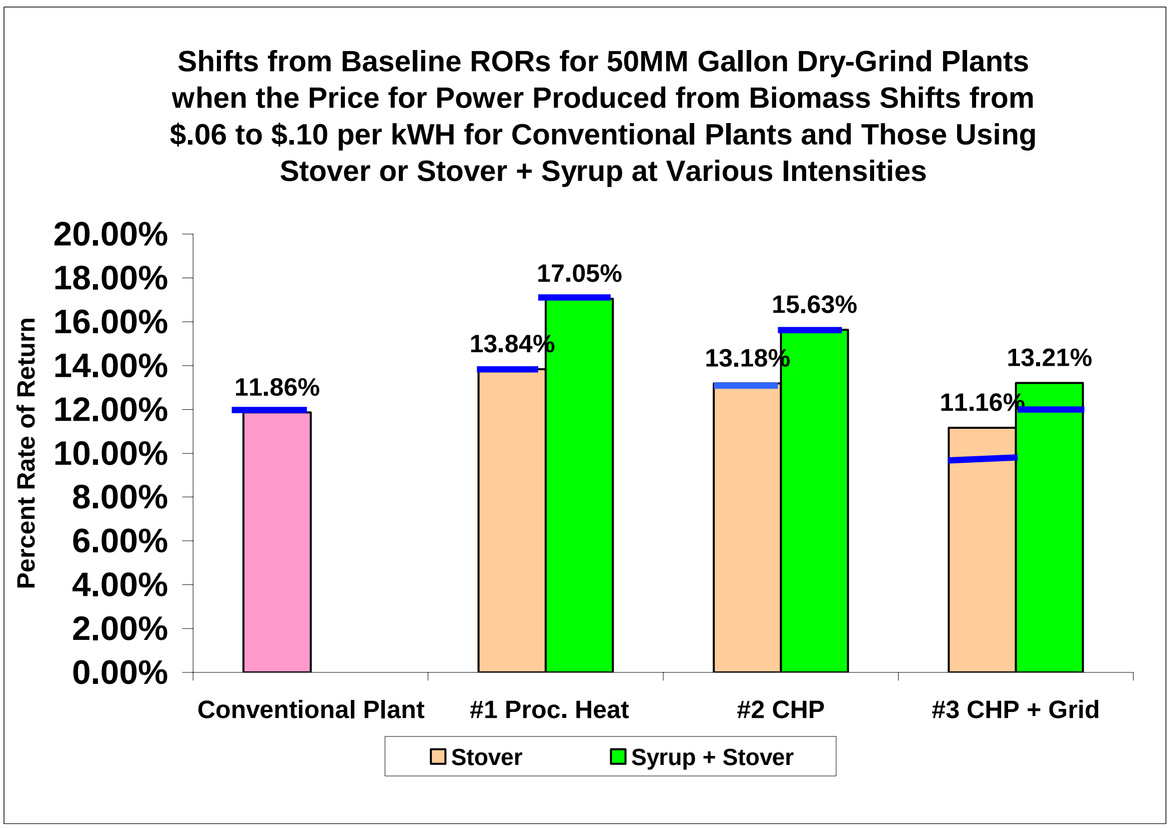
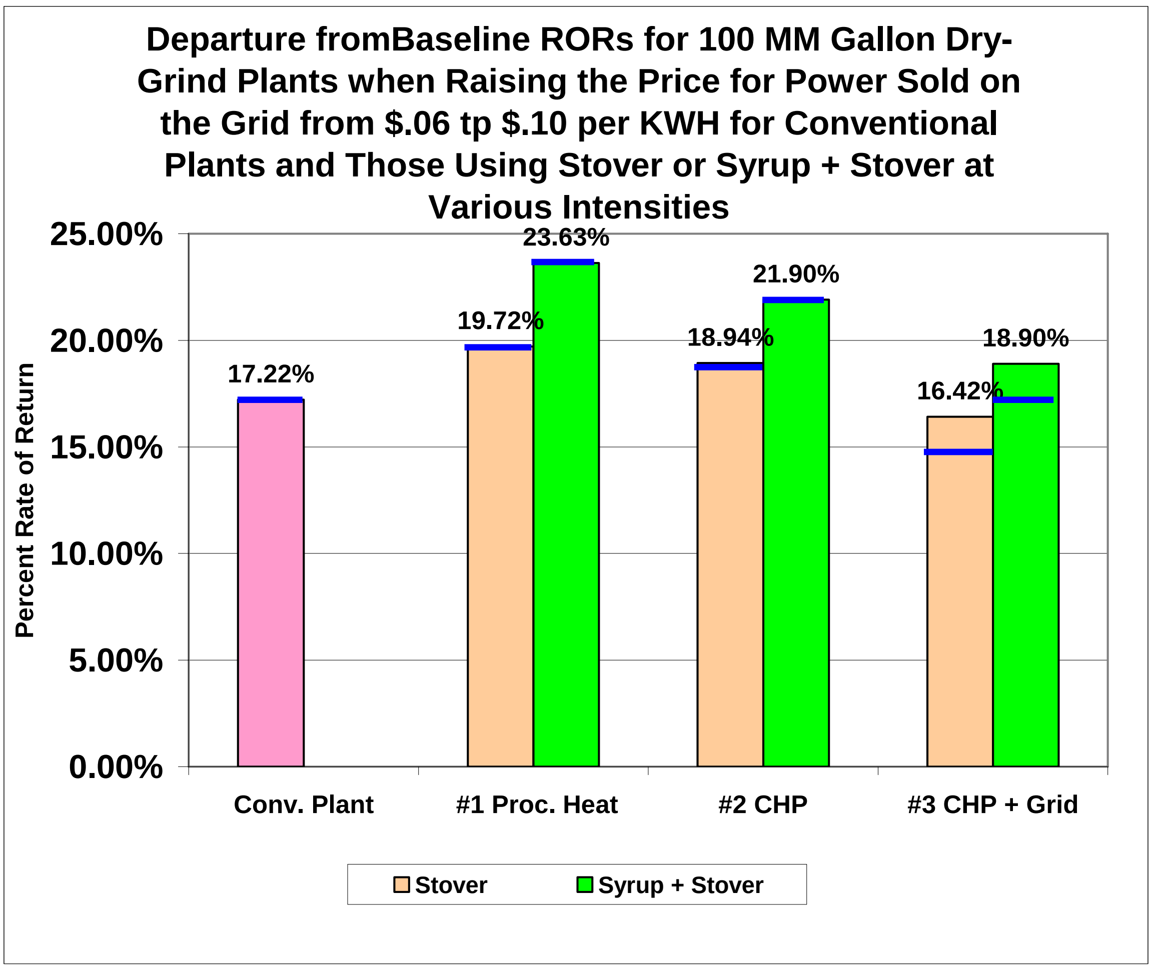


Figure 11 shows the same effect of an exogenous increase in the price paid for electricity sold to the grid for ethanol plants of the larger scale of 100 Million gallons per year capacity, with the lower capital costs per unit of capacity, overall. Here the pattern reflects the pattern of the smaller plants, the syrup + stover option that sells power to the grid does better than the conventional plant, while the stover-powered plant selling to the grid still has rates of return inferior to the baseline levels.

Figure 11. The effect of price paid for electricity on rates of return for 100 million gallon per year plants.

Conv. Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid		100 MM Gal.
17.22%	19.72%	18.94%	16.42%	Stover	
	23.63%	21.90%	18.90%	Syrup + Stover	

INSTALLED COSTS



● **Summary of project management activities, travel, etc. for period (RMT)** – Dennis Hatfield of RMT visited AMEC in Minneapolis on June 5 to discuss project activities.

Dennis Hatfield attended the Fuel Ethanol Workshop in St. Louis on June 26 to 28 to meet with ethanol plant and equipment supplier contacts and to visit with Doug Tiffany and Matt De Kam of the UofM about project activities.

● **Summary of project management activities, travel, etc. for period (UofM) –** Doug Tiffany and Vance Morey presented a paper entitled "Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants" at the Fifth International Starch Technology Conference held June 3-6 in Champaign-Urbana, IL. The conference focused on energy issues in starch related industries including ethanol plants.

Doug Tiffany, Matt De Kam, and Vance Morey attended ASABE International annual meeting held in Minneapolis on June 18 to 20, where they presented papers entitled "Integrating Biomass to Produce Heat and Power at Ethanol Plants" and "Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants".

Doug Tiffany and Matt De Kam attended the Fuel Ethanol Workshop in St. Louis on June 26 to 28 to meet with ethanol plant and equipment supplier contacts and to visit with Dennis Hatfield of RMT about project activities.