Driftless Area Initiative Biomass Energy Project
Final Scientific/Technical Report

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Project Executive Summary: The Driftless Area Initiative Biomass Energy Project evaluated the potential for biomass energy production and utilization throughout the Driftless Region of Illinois, Iowa, Minnesota and Wisconsin. The research and demonstration aspect of the project specifically focused on biomass energy feedstock availability and production potential in the region, as well as utilization potential of biomass feedstocks for heat, electrical energy production, or combined heat and power operations. The Driftless Region was evaluated because the topography of the area offers more acres of marginal soils on steep slopes, wooded areas, and riparian corridors than the surrounding “Corn Belt”. These regional land characteristics were identified as potentially providing opportunity for biomass feedstock production that could compete with traditional agriculture commodity crops economically.

The project researched establishment methods and costs for growing switchgrass on marginal agricultural lands to determine the economic and quantitative feasibility of switchgrass production for biomass energy purposes. The project was successful in identifying the best management and establishment practices for switchgrass in the Driftless Area, but also demonstrated that simple economic payback versus commodity crops could not be achieved at the time of the research. The project also analyzed the availability of woody biomass and production potential for growing woody biomass for large scale biomass energy production in the Driftless Area. Analysis determined that significant resources exist, but costs to harvest and deliver to the site were roughly 60% greater than that of natural gas at the time of the study.

The project contributed significantly to identifying both production potential of biomass energy crops and existing feedstock availability in the Driftless Area. The project also analyzed the economic feasibility of dedicated energy crops in the Driftless Area. High commodity crop prices and land values coupled with low fossil fuel prices, particularly natural gas, hampered the likelihood of widespread production and/or utilization of for large scale heating or electrical generation at the time of the study.

Summary of Project Goals/Accomplishments: The original goals of the scientific and technical portion of the project were to 1) pinpoint biomass development opportunities to meet energy needs and improve water quality, wildlife habitat and the economic viability of rural communities, and 2) develop a knowledge base for producer/utility infrastructure for biomass crop-renewable energy conversion.

The project was successful in evaluating the potential of biomass feedstock development opportunities in the Driftless Area to meet energy needs and ancillary benefits, but was not widely successful in resulting public implementation due to restrictive economic factors. The project also identified an existing producer/utility infrastructure set for potential conversion to biomass crops given positive economic feasibility.

The following reports detail the switchgrass establishment study, woody biomass feasibility study and boiler/infrastructure for biomass energy study.

Switchgrass Establishment and Harvesting Demonstrations in Southwest Wisconsin




Final Report

June 2012

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Switchgrass Establishment and Harvesting Demonstrations in Southwest Wisconsin

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INTRODUCTION

Switchgrass *(Panicum virgatum)* is a perennial warm season grass native to North America, where it occurs naturally from 55 N Latitude in Canada southwards into the United States and Mexico. Switchgrass is one of the dominant species of the central North American tallgrass prairie and can be found in remnant prairies, in native grass pastures, and naturalized along roadsides. It is used primarily for soil conservation, forage production, game cover, as an ornamental grass, and more recently as a biomass crop for ethanol, fiber, electricity, and heat production and for biosequestration of atmospheric carbon dioxide. Because switchgrass is native to North America it is already resistant to insect infestations and disease. Switchgrass has been planted by farmers through the United States Department of Agriculture (USDA) Conservation Reserve Program (CRP) since 1986.

In 2007 the Southwest Badger Resource Conservation and Development (RC&D) Council began a study to evaluate switchgrass quality and volume on existing CRP fields. Unfortunately, the establishment and maintenance techniques used on these early plantings were minimal and did not utilize varieties or management practices to maximize yield. The data available from existing CRP plantings, while providing valuable information, only informs us about a worst case scenario of little to no management. If switchgrass is to be seriously considered as a feedstock for energy or biofuel production, data on realistic yields and best management practices for establishment, fertilization, and management are necessary. When this study was started in 2008 there was little data available on the costs associated with planting, maintaining, and harvesting of switchgrass specific to southwest Wisconsin. The only available research on switchgrass yields in the Midwest under intensive management was conducted in Nebraska and the Dakota states, a climate vastly different than southwest Wisconsin.

In 2008 Southwest Badger RC&D established farm-scale demonstration plots of switchgrass at six farms in Grant County, Wisconsin. Data collected from the demonstrations provides valuable information on realistic yields that can be achieved in Southwest Wisconsin and takes some of the uncertainty out of switchgrass production. Quantification of yield potential is essential to developing a business plan for using swithgrass as an energy feedstock.

Southwest Badger worked with researchers at the University of Wisconsin-Madison Departments of Agronomy and Soil Science on this research. The UW research included additional objectives not included in the Southwest Badger project. For a full reporting of the UW results, see Appendix B, "Sustainability of Switchgrass for Biofuel in Southwest Wisconsin."

GOALS AND OBJECTIVES

The goals of the project were to establish field-scale swithgrass demonstrations on marginal cropland and determine best management practices to maximize yield in southwest Wisconsin. The USDA defines marginal cropland as "land that should not be subjected to intense cultivation due to steepness of slope and shallow, highly erodible soils." The entire Driftless Area which encompasses southwest Wisconsin has a high percentage of marginal cropland due to its steep slopes and fragile soils resulting from a lack of glacial activity. There is widespread agreement among conservationists that marginal soils should be planted to some type of perennial cover, thus switchgrass is an excellent crop to target. Switchgrass is well suited to marginal land as it can thrive in soils with low fertility and organic matter. Targeting marginal soils also makes sense economically as 2008 rental rates in Grant County averaged near $150 per acre for marginal land and up to $300 per acre for prime agricultural land. Most farmers would rather not plant corn and beans on marginal cropland; however, the current soil conserving crops such as hay and alfalfa are labor intensive, risky, and provide little profit. If established switchgrass markets become available to producers in Southwest Wisconsin, the impact to water quality and wildlife could be of landscape proportion.

All demonstrations were established on cropland that was planted to corn or soybeans the previous year. By utilizing existing cropland the project ensured that the demonstrations reflected actual on-farm conditions under current agronomic practices. This type of demonstration will build landowner knowledge and provide producers with data based on field scale research rather than traditional small scale experimental plots.

The objectives of the project included:

1. Determine maximum yields of switchgrass that can be produced in Southwest Wisconsin on Marginal Soils
2. Determine if weed management can improve establishment and productivity of switchgrass
3. Document the costs associated with establishment
4. Determine costs associated with production (management and harvest)
5. Utilize existing agricultural practices and equipment in implementing the project
6. Involve producers in all aspects of the demonstrations

METHODS

Study Sites

The demonstration project was located on six working farms in Grant County, Wisconsin. Grant County is in the unglaciated Driftless Area of southwestern Wisconsin, which is characterized by relatively steep and rugged topography. All demonstration plots were established on cropland with a history of glyphosate-resistant corn or soybeans grown with minimum to no tillage. As noted earlier, the project sought to locate all demonstrations on marginal land. However, in the end five of the six demonstration sites were classified as marginal lands. The sixth demonstration at the DS Farm was established on silt loam prairie soils which would be considered prime farmland for crop production.

Weed populations, while variable across sites, consisted of annual grasses (primarily foxtail, *Setaria* spp.) and annual and biennial broadleaf weeds, with few perennial weeds. Soils at these sites are moderately eroded, well-drained silt loams in the Dubuque, Fayette, and Hixton series (Grant County Soil Survey, 1961). Thirty year mean annual precipitation is 34.9 inches (88.7 cm) and mean growing-season temperature (Apr-Oct) is 60.98 °F (16.1 °C)(USDA).

Table 1: Soil Profile and Cropping History

Farm	**Slope (%)**	**Soils**	**Soil Characteristics**	**Crop/Tillage History**
CR	12-18	Dubuque Series: DsD2, DtF2, DtE2.	Moderately deep or deep, silty or loamy soils underlain by limestone or sandstone	2006-2007: Corn following corn in a fall chisel, spring soil finisher system
DS	2-6	Fayette Series: FaB2, FaB3	These are deep, silty soils formed on uplands and broad ridge tops near soils of the Dubuque Series	2006-2007: Corn following corn using a fall chisel spring soil finisher system. A rye cover crop was planted in the fall after corn residue was removed for sileage.
FR	4-7	Fayette and Dubuque Series: FaB2, FaC2, DtD2	The Fayette series is located near the ridge top and the Dubuque Series is located down slope from the Fayette Series.	2006: Soybeans following corn using a fall chisel spring soil finisher system. 2007: Corn following soybeans using a spring soil finisher system.
TS	8-12.	Dubuque Series: DvC3, DtC2, DsD2	These soils range from moderately to severely eroded and are underlain by limestone or sandstone.	2006: Corn following corn using a no till system. 2007: Soybeans following corn using a no till system.
SC	12-16	Dubuque and Hixton Loam Series: DuF2, HxD2	These soils are severely eroded and are underlain by limestone or sandstone.	2006: Corn following soybeans using a spring soil finisher system. 2007: Soybeans following corn using a fall chisel, spring soil finisher system.
WO	12-18	Dubuque Series: DsD2, DtE2	These soils are moderately deep, silty or loamy soils underlain by limestone or sandstone	2006-2007: Corn following corn planted no till

Establishment

To evaluate the effects of various weed suppression strategies on biomass crop production, five experimental treatments were implemented at each farm in May 2008. These treatments were selected because they targeted common weed species in the region, are common weed management strategies, and include low and high intensity management options. The treatments included three switchgrass monocultures, switchgrass planted with a companion crop of oats (Avena sativa), and a prairie mixture that included five native grasses and four native forbs (Appendix A). The Cave-in-Rock variety was used in all switchgrass treatments at a seeding rate of 8 pounds per acre. For the oats as a companion crop treatment, the seeding rate was 8 pounds per acre of switchgrass and one bushel per acre of oats. The prairie treatment included: switchgrass , side-oats grama, indian grass, big blue-stem, little blue-stem, Illinois bundle flower, partridge pea, Canada milk vetch, and yellow coneflower (see Appendix A for seeding rates). All rates are pure live seed (PLS). All demonstration plots were planted with either a Truax conventional drill or a Truax FLEXII no-till drill (Truax Company; New Hope, MN); row spacing was 7.5 inches (19 cm) with 0.2 to 0.5 inch (0.6 - 1.3 cm) seeding depth. However, on two farms (SC and CR) tillage occurred prior to planting. The SC Farm site was tilled with a soil finisher in spring and the CR Farm site was chisel plowed in fall and disked in the spring.

Iowa Chapter of Pheasants Forever Establishing Switchgrass plot with Truax Drill

Weed management treatments for the switchgrass included pre-emergent applications of glyphosate, pre-emergent applications of glyphosate + post-emergent applications of 2,4-D, pre-emergent applications of glyphosate and imazapic (Journey), and oats (*Avena sativa*) planted as a companion crop + pre-emergent applications of glyphosate (Table 2). The companion crop treatment was selected to reduce soil erosion during switchgrass establishment and to suppress weeds.

Pre-emergent herbicides (imazapic 70 g ae ha-1 + glyphosate 140 g ae ha-1) were used at all farms in 2008 to promote robust early establishment, rather than applying glyphosate post-emergence, which likely would have contributed to poor forb establishment. The herbicide mixture was selected for residual control of broadleaf weeds and control of annual grasses such as foxtails (*Setaria spp.*) which tend to be a common agricultural weed in first year prairie plantings.

The forbs in the prairie mix were selected for tolerance to the pre-emergent herbicide imazapic. Weed height exceeded the height of sown plants at the two farms (SC and CR) where tillage practices occurred prior to planting.

Table2: Treatments, Seeding Rates, and Weed Control Treatments

#	Crop	Seed rate	Pre	Post[2]
1	Switchgrass[1]	8 lbs/A	Glyphosate	-
2	Switchgrass[1]	8 lbs/A	Glyphosate	2,4-D
3	Switchgrass[1] + oats	8 lbs/A + 1 bu/A	Glyphosate	-
4	Switchgrass[1]	8 lbs/A	Journey	-
5	PRAIRIE	See Table 2	Journey	-

[1] Cave in the rock variety
[2] Treated 7/22/08

Fertility

The UW-Madison researchers conducted fertility trials on small scale plots at each site. However yield data from these plots is not included in the data presented in this report, nor are the results of the fertility trials. For additional information on the fertility trials see Appendix B. Not fertilizer was added to any of the large scale demonstrations included in this report.

Management

In May 2009, each experimental field was further divided into four plots to evaluate effects of second year weed management strategies. The second-year treatments included a low-intensity prescribed burn; application of the herbicide glyphosate (1.12 kg ae ha^{-1}); application of Journey, a mixture of imazapic +glyphosate (imazapic 70 g ae ha^{-1} + glyphosate 140 g ae ha^{-1}); and an untreated control.

Prescribed fire is a common tool for natural areas management; glyphosate is a standard herbicide treatment for establishing native perennial species, and Journey provides additional control for annual grasses 1-2 months after application at the rate applied.

Herbicide treatments were applied on May 12 – 15, 2009. Many introduced forbs and native grasses had emerged at this time; native grasses ranged from 0.5 – 2 inches in height with 1-2 fully exposed leaves. After herbicide application researchers could see damage to the switchgrass; however, all evidence of damage was gone by the time species composition surveys were conducted later in the summer.

Damage from Journey application.

Prescribed burn treatments were conducted on May 6 – 11, 2009. The fuel type at 5 of the 6 farms was 6 inch stubble that remained standing after plots were harvested in autumn 2008. One farm was not harvested in autumn 2008 because of steep slopes and the fuel type was 3-3.5 feet-tall dead grasses and forbs. The grasses and forbs were compressed and laying down over approximately 60% of the plot area. Ambient temperature ranged from 55°-63° F and wind speeds ranged from 0-10 mph (gusting to 15 mph at one of the mowed farms). Average relative humidity ranged from 58% to 79% . Cool temperatures and high relative humidity contributed to low-intensity fires (flame lengths ranging from 2.5 – 23 inches). Approximately 35% of the ground surface area burned across all farms (determined by tallying observations of charred vs. uncharred vegetation at 100 sample points along a transect placed across each burned plot).

Harvesting

It is recommended that Switchgrass not be harvested until at least twelve days after a killing frost to allow the plant to achieve full senescence. Senescence is the dying off process where mobile nutrients, such as K, P, and N are transferred from the leaves and stems to the root systems. This reduces the removal of valuable fertilizer through harvesting and dramatically reduces alkaloids such as phosphorus and potassium. Reducing the alkaloids in biomass makes it more acceptable for use in combustion systems where alkaloids cause boiler slagging and corrosion problems.

In 2008, plots were harvested using a small plot harvester and biomass from four 300 square foot areas (3 ft. by 10 ft. swaths) per treatment per site which were collected and weighed in the field; wet mass was recorded to 0.1 pound accuracy (0.05-kg accuracy) and grab samples were collected and returned to the laboratory. Moisture of grab samples was determined by recording wet mass for each sample, drying samples at 140 °F (60 °C) for 48 hours, and recording dry mass. Moisture values for these grab samples were used to

Small plot harvester

calculate dry mass yield from wet biomass weighed in the field for each plot. We note that in practice, these perennial bioenergy crops would not be harvested in the first year of establishment because of low yield; our 2008 harvests were conducted for the purposes of our study only.

In 2009 and 2010, the TS and DS demonstrations were harvested with a 14 foot self-propelled Hesston haybine with a mechanical crimper and baled with a New Holland round baler. The CR, FR and WO demonstrations were harvested with a New Idea 5209 diskbine and a John Deere round baler. There has been discussion amongst professionals in the field that a diskbine may be a required to effectively cut the course switchgrass stems, however, the haybine performed flawlessly. Bales were weighed individually on portable field scales.

New Holland baler used in harvest.

2009 harvest at TS farm.

RESULTS AND ACCOMPLISHMENTS

<u>Year 1- 2008</u>

Establishment Costs

Establishment costs varied between $148 to $205 per acre (Table 3). The prairie mix had the highest establishment cost due to higher seed costs. The Journey treatment had the lowest establishment cost. While the herbicide costs were higher for this treatment, no mowing was necessary thus reducing overall costs.

In early August, weed pressure was accessed. Plots where weed height exceeded plant height were mowed to a height of 6 inches (15 cm) to remove the weed canopy. Weed pressure was highly variable and mowing was only done where needed.

Table 3: Establishment Costs per Acre for each Treatment

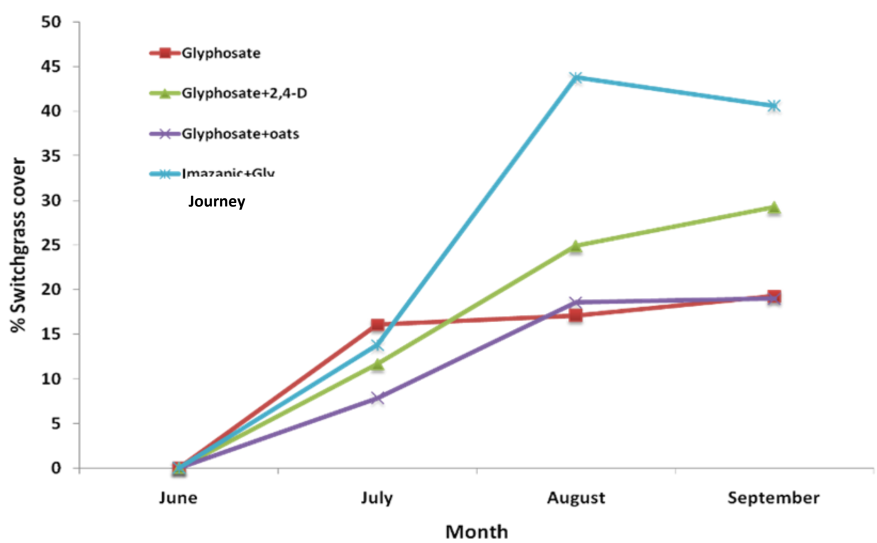
TRT	Planting (seed and planter)	Herbicide (includes spraying cost)	Mowing*	Total
Glyphosate	$101	$36	$18	$155
Glyphosate + 2,4-D	$101	$57	$18	$176
Glyphosate +oats	$106	$36	$18	$160
Journey	$101	$47	$0	$148
Prairie/ Journey	$158	$47	$0	$205

*Mowing was only done on fields that needed it and was highly variable across sites.

Weed Management/Establishment Success

As indicated in Figure 1, the Journey treatment produced by far the best switchgrass cover during the establishment year. In September average switchgrass cover in the Journey treatment was about 40%. The glyphosate and glyphosate + oats treatments produced the lowest percent cover, averaging only about 18% switchgrass cover.

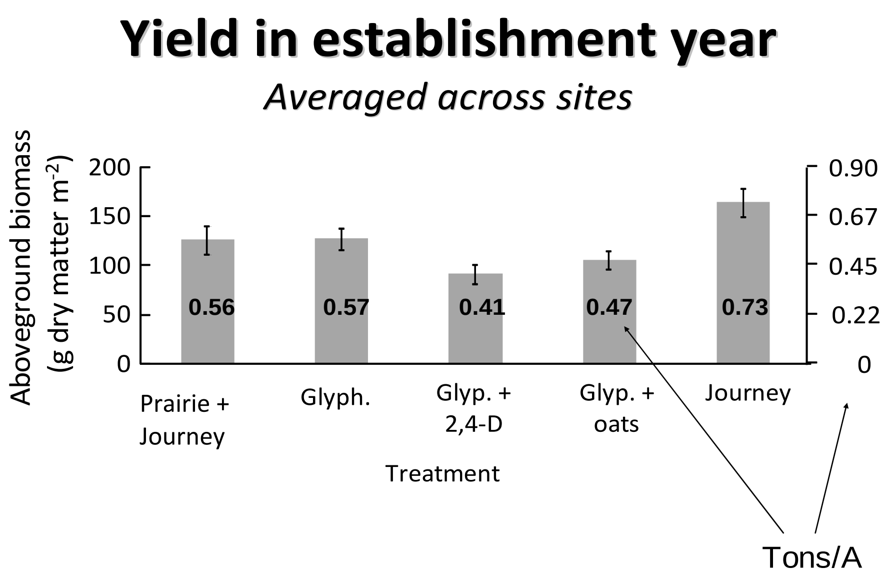
Figure 1: Switchgrass Cover in Establishment Year



Yields

Past research has shown very low establishment year yields as warm season grasses tend to put much of their first year growth into the development of root systems. Figure 2 shows the average harvest weight by treatment when combining the 2008 plot data from all six farms involved in the project.

Figure 2: Yields in Establishment Year



The Journey treatment produced by far the best yields on average across all farms with 1,460 lbs. of biomass per acre. The highest single plot yield with the Journey treatment was 1,955 lbs/ac and an individual sample from this field yielded 2,932 lbs/ac.

The yield results indicate that it does not appear to be economically feasible to harvest switchgrass for biomass in the establishment year. With these results we now have a baseline for Cave-in-Rock variety switchgrass grown in Southwest Wisconsin. Researchers are currently breeding varieties of switchgrass that they claim will produce substantially better yields than Cave-in-Rock switchgrass. The development of these new varieties may still lend hope that establishment year harvests can be economically feasible.

Year 2 - 2009

Management

The second year management research was carried out through the implementation of the following practices: 1) managed burning; 2) application of 22 ounces of glyphosate (Roundup) per acre; and 3) application of 11 ounces of Journey (glyphosate and imazipic) per acre. These second year management research trials were applied to all six switchgrass demonstration sites. Southwest Badger RC&D contracted with a Wisconsin certified burn boss to carry out the managed burns on the six farms. Controlled burning began on May 5 and was completed by May 12.


Prescribed burn at TS farm.

The spraying of the herbicides was conducted by Southwest Badger RC&D staff. Spraying began on May 13 and was completed by May 20, 2009.

In year 2 establishment success was accessed for each treatment. Results showed successful establishment in 100% of the Journey treatment plots, 50% of the glyphosate + 2,4-D plots, 40% of the glyphosate +oats treatment plots, and 17% of the plots receiving glyphosate alone. Successful establishment was defined as more than 30% switchgrass cover.

Figure 3: Percent of Total Cover Per Treatment that was Switchgrass Across all Farms in Year Two (2009).

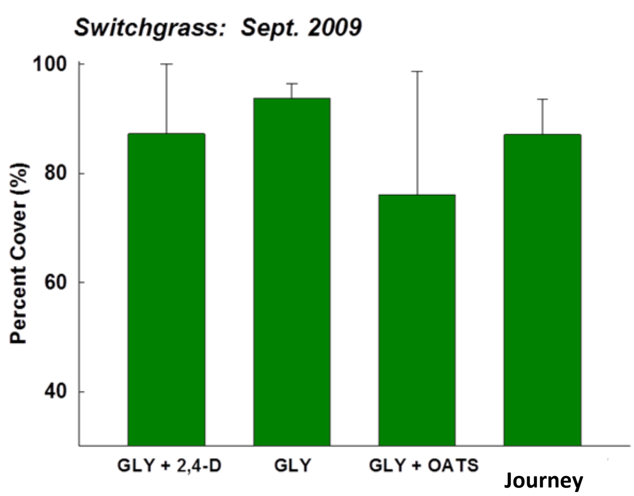
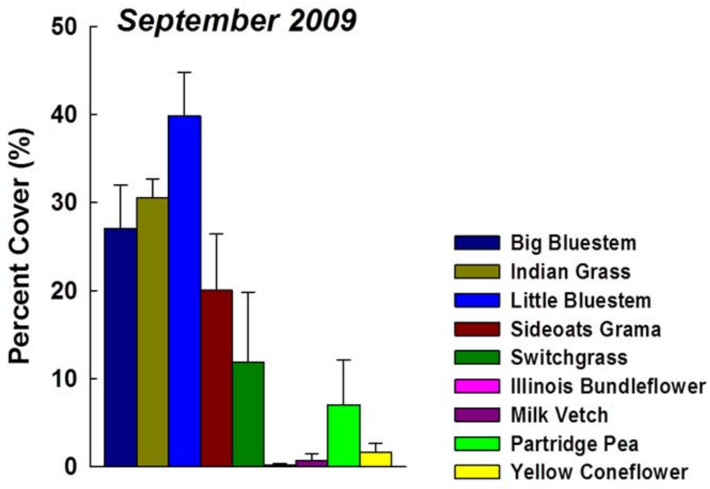


Table 4: Percent of Total Cover by Prairie Species for Prairie Treatment Across All Farms in Year 2

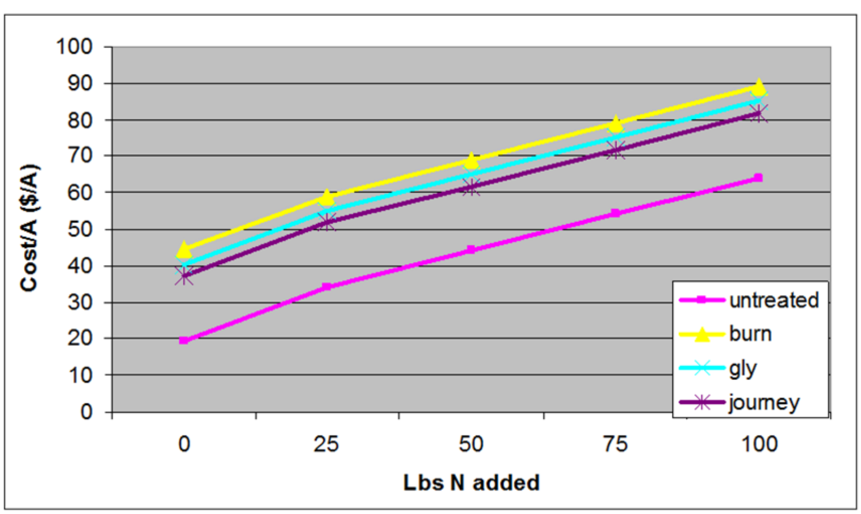


2nd Year Management costs

Management costs for second year management ranged from $19 to $42 per acre for the large scale demonstration sites in this project (Figure 5). All management treatments were comparable in cost with the Journey treatment averaging $38/acre, the glyphosate treatment averaging $40/acre, and the burn treatment averaging $42/acre.

While the fertility trials were not technically a part of this project, it is interesting to note that when fertility is included, second year management costs are driven by the amount of N applied and range from $19 to $100 per acre, see Appendix B for additional information on fertility treatments.

Figure 5: Second Year Management Costs



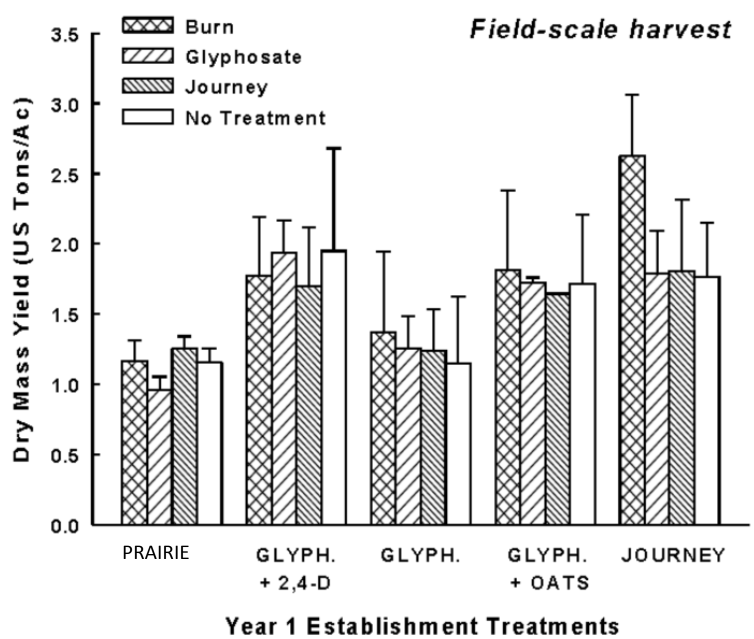
Yield

The harvesting window for the switchgrass demonstrations was very short in 2009 due to a late frost and early winter weather. The first killing frosts in the project area occurred in late October pushing harvest to mid November. Intense rains began on November 24th soon followed by snow thus ending the switchgrass harvest season for 2009. Although the harvest season was short, five of the six demonstration sites were harvested.

Harvesting of the Switchgrass Demonstrations began on November 9 with the mowing of the DS and TS sites. The mower utilized was a 14 foot self-propelled Hesston haybine with a mechanical crimper and the baler was a New Idea round baler. There has been discussion amongst professionals in the field that a diskbine may be needed to effectively cut the course switchgrass stems, however, the haybine performed flawlessly. Harvesting was completed at the DS farm on November 10 and the TS farm was completed on November 11. All of the bales from each research plot were weighed individually on portable field scales.

The WO Farm and CR Farm demonstrations were mowed and baled on November 16. A New Idea 5209 diskbine was used for the mowing and a John Deere round baler was used for the harvesting. Bales were again weighed individually on portable field scales. The FR demonstration plot was mowed and harvested on November 23 using the same equipment as the WO and CR Farms. Intense rains followed by snow on November 24 halted field work for 2009 and the bales from the FR farm were not weighed.

Figure 6: Year 2 Harvest Yields by Year 1 Establishment Treatment



Year two switchgrass yields ranged from 0.60 to 3.06 tons per acre with an average yield of 1.5 tons per acre (Figure 6). The prairie plots yielded on averaged about half what the monotypic switchgrass plots yielded with yields ranging from 0.83 to 1.39 tons per acre. The maximum yield on the prairie plots was 1.39 tons per acre. First year establishment success does appear to have an influence on second year yields. The first year management treatment resulting in the highest yields across all switchgrass plots was the Journey treatment with the Glyphosate + 2,4-D treatment a close second. Second year management had no statistically significant effect on yields.

Year 3-2010

Management

No management other than harvesting was performed in year 3.

Yield

Adequate killing frosts did not occur until mid-November and heavy snows on November 24 put an abrupt halt to switchgrass harvesting in 2010. Only three of the six demonstration plots were harvested (WO, DS, and TS). The plots harvested did include the two most productive plots.

Harvesting took place at the WO Farm on November 11. The plots were cut with a 14 foot John Deere diskbine and were baled with a New Holland small square baler. The diverse prairie plots and oat cover crop plots were not harvested due to the steepness of the plots which created a safety hazard for the contractor.

Harvesting took place at the DS and TS farms on November 22. The plots were mowed with a Hesston self-propelled diskbine. The DS farm was baled with a New Holland round baler and the TS farm was baled with a John Deere round baler. No problems were encountered with mowing or harvesting the switchgrass with conventional hay making equipment.

Year 3 results from the three demonstration plots harvested:

- Maximum yielding switchgrass plot in 2010 was 3.87 tons
- Maximum yielding prairie plot was 3.22 tons
- Second year management treatments showed little yield difference compared to the control; emphasizing that first year establishment and weed control dictate yield potential
- Journey as a first year treatment on the DS farm provided the maximum yield in year 3 however the same treatment on the TS farm led to the lowest yielding treatment which may prove our assumption that Journey's impact on eroded soils with low surface organic matter is very different than what is experienced on prairie silt loam soils
- The prairie mix yielded approximately 0.625 ton less per acre than switchgrass when comparing maximum yielding plots
- Looking at annual average yields over the three years switchgrass yields are increasing on average by one ton per year

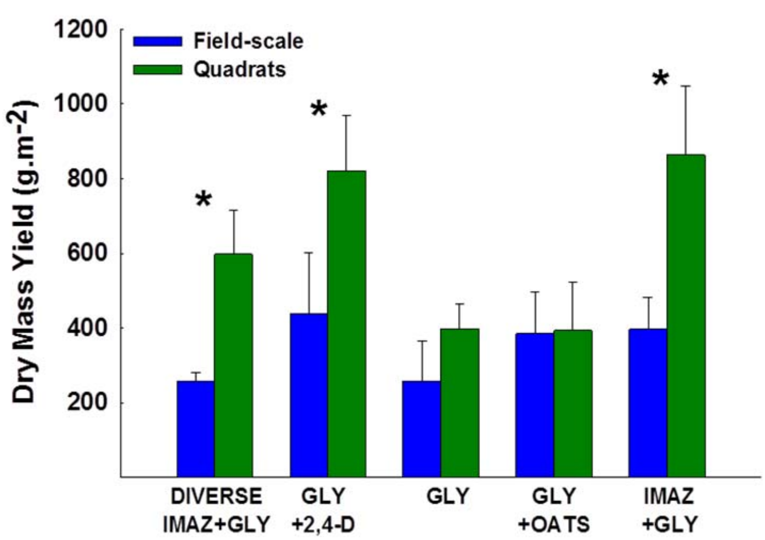
When this project began in 2008 we assumed an average yield of 5 tons per acre was achievable. Year 3 results indicate that real world yields are closer to 3 tons per acre. Two factors that may contribute to lower yields include the fact that we purposely targeted lower producing cropland and that no fertilizer was applied to the demonstration plots.

Differences in Yield Estimates Between Field Scale Harvest and Quadrant Samples

Southwest Badger focused on field scale harvesting as the goal was to replicate real world conditions to provide the best data possible for farmers. The UW study also collected small scale (1 m^2) quadrant samples. The quadrant samples were hand harvest in mid-October at randomly selected locations within each treatment plot. The field harvest was completed in mid-November

As Figure 7 illustrates, the small scale harvesting tends to overestimate yields when compared with field scale harvest results. The small scale harvest overestimated yield by almost two tons per acre in three of the five treatments. This did constitute a statistically significant difference for these three treatments. The differences between the yields for the glyphosate and glyphosate+oats treatments were not statistically significant.

Figure 7: Comparison of Field-Scale vs Small Scale Yields in Year 2



Impact of Soil Type on Yields

Field observations showed that soil types and depths had very little effect on biomass yields. We've included antidotal observations (Table 4) on each demonstration site for those interested.

Table 4: Antidotal Field Observations from each farm.

Farm	Field Observations
CR	The plots at this site were planted with a Truax conventional drill into fall chiseled corn stalks with a spring soil finish system. There was a weed problem in the plots at this site from the time it was planted in 2008 through 2010. The plot that was planted with an oats companion crop appeared to be a failure in 2008 as no switch grass plants were found. There was a definite correlation between good emergence after planting and better yields in later years. The plots at this site were extended to the 4th year in 2011. A noticeable increase in biomass was noted in all plots including the plot planted with the oats cover crop. We have no explanation for this. The plots at this site were on a west facing hillside.
DS	The plots at this site were no tilled with a Truax no till drill into rye cover crop stubble. The rye was planted into corn stalks in the fall of 2007 and harvested in the spring of 2008 as a forage crop. The stubble was sprayed with glyphosate to kill the rye. We did not see any appreciable biomass yield differences from these deep soils as compared to the Dubuque Series. We did however notice an increase in yield of the diverse plot. The plot on this soil was located on a broad ridge top that had very little slope. Also at this site biomass yield decreased as you moved down the slope. We have no explanation for this. Here again as at the other sites, biomass yields in the plot that was planted with an oats cover crop seeded with the switchgrass yielded less. This site was an east facing gently sloped broad ridge.
FR	The plots at this site were planted with a Truax no till drill planted into corn residue. Yields were spotty at the plots on this site with no appreciable differences as to soil types. The plot planted with an oats companion crop was nearly a failure in the first year. It wasn't until 2010 that a moderate stand of switch grass was achieved. This site was on an upland, southeast facing hilltop.
TS	The plots at this site were planted no till in soybean residue using a conventional Truax drill. Emergence was very uniform and stands were relatively weed free and produced our best biomass yields each of the three years. The plots on this site were continued into a fourth year and yields increased each year. This site had our poorest soils, yet produced the best yields at harvest time. The site was a northeast facing hillside.

SC	The plots at this site were planted into spring soil finished soybean residue with a conventional Truax drill. A fall application of fertilizer along with the spring tillage seemed to lead to weed problems. The switchgrass coverage on this site was less than 30% in year one and remained poor through year three, especially the plots facing the southeast. The switchgrass plot facing north, however had a moderate stand by the end of year three. The plot where the oats companion crop was planted with the switchgrass had a very poor stand, similar to the other sites. This site included two different fields, one field faced southeast and the other faced north.
WO	The plots at this site were planted with a Truax no till drill into chopped corn stalks. These fields had been in a continuous no till corn rotation for 7 years. During the planting of the plots there were a lot of problems with corn residue plugging the drill. It would have been better not to chop the corn stalks prior to planting the plots. Biomass yields were very good in the third year. The fields at this site were a west and northwest facing hillside.

SUMMARY AND CONCLUSIONS

The overall goal of this project was to establish field scale switchgrass demonstrations on marginal cropland and determine the best agronomic practices for maximizing yields in southwest Wisconsin. The main objectives of the project included determining a benchmark for switchgrass yields in the Driftless Area of Wisconsin, determining costs of establishment and production, and determining if weed management can improve productivity. While we could not analyze the profitability of growing switchgrass because important parameters, namely a demand for the product and a corresponding market price, are nonexistent; the data within the report provides a key basis for such calculations should a market develop.

This project sought to select farms with "marginal soils" since previous studies indicated that warm season grasses are able to thrive in soils considered marginal for cash grain production. Five of the six demonstration farms had marginal soils, while the DS Farm had silt loam prairie soils which would be considered prime farmland for crop production. The DS Farm was used as a demonstration site due to its availability. However it does allow for an interesting comparison and it is worth noting that this farm did not produce the highest yields. The relatively low nutrient demand of warm season grasses may explain why we did not see higher yields on the higher quality soils.

The technical staff involved in the layout of the study plots agreed that successful establishment of warm season grasses is more likely when the seed bed is as weed free as possible. To help ensure a minimum weed seed bed the project targeted fields that had been planted with Roundup Ready corn or soybeans for a minimum of two years. In addition, the project used no-till planting to minimize the incorporation of weed seeds.

However, two of the sites were tilled prior to being planted. As expected, the two demonstration sites where tillage occurred experienced heavy weed pressure for the entire three years of project. Statistically both tilled demonstrations were considered unsuccessful establishments in the first year (less than 30% of total biomass consisting of switchgrass) and heavy weed pressure persisted throughout year two. In year three both sites improved dramatically, showing an increase in switchgrass cover and a decrease in weed species; however, neither site achieved yields comparable to the untilled demonstrations. The untilled sites were planted into unharvested residue from previous crops of corn (1), soybeans (2), and winter wheat (1). There was no evidence over the three year study that the crop planted prior to establishing switchgrass affected weed pressure, stand establishment, or yield.

The research design for this project included mechanical harvesting of all six demonstration farms in the establishment year (2008) as well as the second and third growing seasons (2009-2010). Although successful establishment was achieved on four of the six demonstration sites in the establishment year, the amount of biomass produced in the establishment year did not justify mechanical harvesting. All demonstration sites experienced yields of less than 0.75 tons per acre in the establishment year.

In the second growing season (2009) five of the six demonstration plots were harvested with conventional hay making equipment. The highest yielding plot from all farms was 3.06 tons per acre. The highest yielding farm when averaging all plots (10 acres) had a yield of 2.0 tons. When averaged across all demonstration farms the average yield was 1.5 tons/acre.

In the third growing season (2010) an early winter cut the harvesting season short allowing us to only harvest three demonstration plots. The highest yielding plot from all farms was 3.87 tons per acre and the highest yielding farm when averaging all plots per farm (10 acres) had a yield of 3.17 tons. The next highest yielding farm when averaging all plots produced a yield of 2.73 tons per acre.

To determine whether yields would increase in the fourth growing season (2011), the demonstration farm (TS) with the highest average annual yield from 2010 was harvested in the fall as one unit (no plots). The average total yield was 3.0 tons per acre, slightly less than the 2010 yield on the farm. This appears to indicated that maximum yield of switchgrass can be achieved in the third growing season assuming successful establishment is achieved.

A previous study conducted by the Southwest Badger RC&D Council quantified yields of warm season grasses on more than forty Conservation Reserve Program (CRP) fields in three counties in southwestern Wisconsin. The study showed a correlation between the use of herbicides and higher yields. Drawing from these results a research design was created to test the impact of three herbicides on establishment success in both the establishment year and the second growing seasons (mid-management).

The highest percentage of switchgrass cover in the establishment year occurred in the Journey (imazipic and glyphosate) treatment. The Journey treatment plots also produced the highest yields in the second growing season when averaged across all demonstration sites. This study used an application rate of 10.7 ounces of Journey per acre. The plots treated with Journey experienced noticeable stunting of switchgrass in the first two months of growth. Given the sensitivity of switchgrass to the Journey at this application rate we believe a rate of 6 ounces per acre would provide adequate weed control while minimizing impacts.

Demonstration sites with higher occurrences of broadleaf plants benefited from an early July application of 2,4D. Yields from plots with this treatment were a close second to the Journey treatment yields in second year yield.

Controlled burning was also utilized as a second year mid-management treatment.

When averaging across fields, none of the mid-management treatments, herbicide or burning, were found to impact second year yields. Yields from control sites (no mid-management activities) actually seemed to indicate that second year herbicide applications may have reduced yields.

Based on our finding, we offer the following recommendations:

1. Planning – Scout fields for weed pressure
2. Seedbed – No-tilling into Round-up ready soybeans or corn with minimal weed pressure provided the best yields.
3. Planting rate – 8 lbs. pure live seed per acre.
4. Herbicide – For best establishment use Journey at 6-11 oz/acre or Glyphosate pre-planting followed by2,4-D in early July.
5. Mowing – If weed pressure is evident, mow to 6 inches in early to mid-July for cool season grass
6. Harvest – Do not harvest until a minimum of 10 days after the first killing frost if biomass is to be used as biomass fuel.

The growing of switchgrass in Wisconsin is still in a semi-experimental state. Stands of switchgrass have been successfully established but ways of growing switchgrass for maximum yield are still being worked out. This study provides some baseline information on best management practices and costs. Farmers considering growing switchgrass should also realize that markets for switchgrass biomass are – at the time of this writing (June 2012) – limited.

APPENDICES

Appendix A: Prairie Seed Mix Species and Seeding Rates

Common Name	Scientific Name	Rate	Photo
Switchgrass	*Panicum virgatum* L. Photo credit: Jeff McMillian @ USDA-NRCS PLANTS Database	1 lb a^{-1}	
Side-oats grams	*Bouteloua curtipendula* (Michx.) Torr. Photo credit: Robert Soreng @ USDA- NRCS PLANTS Database	1.5 lb a^{-1}	
Indian grass	*Sorghastrum nutans* (L.) Nash Photo credit: Jennifer Anderson @ USDA-NRCS PLANTS Database	2 lb a^{-1}	
Big blue-stem	*Andropogon gerardii* Vitman Photo credit: Jennifer Anderson @ USDA-NRCS PLANTS Database	2 lb a^{-1}	
Little blue-stem	*Schizachyrium scoparium* (Michx.) Nash Photo credit: L. Glasscock @ USDA-NRCS PLANTS Database / USDA SCS. 1991. *Southern wetland flora: Field office guide to plant species*. South National Technical Center, Fort Worth	2.5 lb a^{-1}	
Illinois bundle flower	*Desmanthus illinoensis* (Michx.) MacMill. ex B.L. Rob. & Fernald Photo credit: Thomas G. Barnes, University of Kentucky @ USDA-NRCS PLANTS Database	4 oz a^{-1}	

Common Name	Scientific Name	Rate	Photo
Partridge pea	*Chamaecrista fasciculata* (Michx.) Greene Photo credit: Clarence A. Rechenthin @ USDA-NRCS PLANTS Database	8 oz a^{-1}	
Canada milk vetch	*Astragalus canadensis* L. Photo credit: Joe F. Duft @ USDA-NRCS PLANTS Database / USDA NRCS. 1992. *Western wetland flora: Field office guide to plant species*. West Region, Sacramento.	8 oz a^{-1}	
Yellow coneflower	*Ratibida pinnata* (Vent.) Barnhart Photo credit: Larry Allain @ USDA-NRCS PLANTS Database	2 oz a^{-1}	

Appendix B: Sustainability of switchgrass for biofuel in southwestern Wisconsin

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Sustainability of switchgrass for biofuel in southwestern Wisconsin

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Project Period: 01 July 2008 – 30 September 2011

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Executive Summary

The production of energy from perennial biomass crops holds potential to supplement fossil fuel use and thereby reduce fossil fuel emissions. Perennial biomass crops also have the potential to decrease soil erosion, improve soil quality, increase carbon (C) sequestration, and also provide other benefits such as wildlife habitat. Switchgrass and mixtures of native prairie plants (warm season grasses and forbs) have been identified as potential herbaceous bioenergy crop candidates. We evaluated the sustainability of these energy crops when planted on marginal agricultural land in Wisconsin. Specifically we estimated productivity of select agronomic practices (weed management and fertility) and estimated how potential carbon sequestration, soil erosion, greenhouse gas fluxes, and global warming potential were affected by these practices. Below is a summary of the results from this project within each of these categories.

ESTABLISHMENT AND PRODUCTIVITY:

- A range of weed management methods were effective at establishing a productive switchgrass stand on marginal lands in Wisconsin.
- Additional management after the establishment year did not improve productivity of either switchgrass or diverse stands.
- While fields produced minimal amounts of biomass in the establishment year (< 1 ton/ac), treatments yielded between 2 and 4 tons/ac annually, two and three years after establishment.
- The diverse prairie treatment yielded between 2 and 3 tons/ac annually, two and three years after establishment. Yield was less than the most productive switchgrass treatment in 2009, but similar to all switchgrass treatments in 2010.
- Annually adding up to 100 lbs/ac of nitrogen fertilizer after the establishment year increased productivity of switchgrass stands by 0.5-1.5 tons/ac each year.
- Fuel quality was improved by delaying harvest until spring, but this delayed harvest decreased yield by between 1 and 2 tons/ac.

CARBON SEQUESTRATION:

- Belowground carbon sequestered in plant material and microbes respiring CO_2 were similar between switchgrass monocultures and diverse stands.
- Burning monocultures of switchgrass increased sequestered carbon in aboveground tissue compared to diverse stands, but unburned switchgrass monoculture had similar amounts of carbon sequestered.

GREENHOUSE GAS FLUXES:

- No differences in carbon dioxide (CO_2) or methane (CH_4) fluxes were found in 2009 or 2010 with respect to establishment treatments or fertilizer application.
- Nitrous oxide (N_2O) fluxes were increased with fertilizer applications in 2009 and 2010.

GLOBAL WARMING POTENTIAL:

- Burning switchgrass monocultures during establishment may support greater soil C accumulation, but simply planting and harvesting this perennial grass should achieve desired goals of minimizing global warming potential for a harvested perennial grass system.
- Even lower global warming potential would likely be realized from switchgrass stands that left more residual material present or were even left unharvested as grass cover would keep soils cool thereby reducing soil respiration.

SOIL EROSION:

- Estimated soil loss calculations did not differ between establishment practices in 2008 or 2009.
- Values of soil loss ranged between 11.0 and 18.6 t/ac in 2008 and 2.2 and 7.6 t/ac in 2009, and were closely related to slope of the field.
- A noticeable decline in soil loss occurred from 2008 to 2009, demonstrating the benefit of planting a perennial crop.
- Field or plot level measures of switchgrass planted as a primary crop are required to validate model outputs on soil erosion.

Results suggest that switchgrass and diverse prairies can be established on marginal soils in Wisconsin and become productive in the second or third production year. Fuel quality will increase as fields are harvested late in fall to early spring. While this increased quality will be desired by industry, producers will require increased premium prices for this product as delaying harvest can result in a substantial loss in productivity. Although differences among management and plant community treatments in carbon sequestration and greenhouse gas fluxes were measured, these differences were relatively small.

Object of Research:

The purpose of this project was to provide information that contributes to the development of economically and environmentally sound energy production in Wisconsin. We established switchgrass on marginal agricultural land to compare the effectiveness of various agronomic practices for achieving successful crop establishment and maximizing harvestable biomass for bioenergy use. Because the effects of bioenergy crops on the environment also influence their potential for long-term use, we evaluated the effects of establishment and management methods on key ecosystem services including carbon sequestration, soil stability, and nutrient availability. We compared the results obtained from switchgrass monocultures to those obtained from a mixture of native warm-season grasses planted in conjunction with native legume species. These demonstrations provide valuable information on environmental impact of native perennial grassland species used for bioenergy production in Wisconsin.

The specific project objectives were to:

1) Assess soil carbon sequestration and global warming potential of establishing switchgrass stands
2) Evaluate the potential for soil loss among various establishment methods
3) Measure optimum N fertilizer application rates for productivity and how they impact biomass quality and thermal energy.

Methods

Study site

This study was located on six working farms in Grant County, WI. Grant County is in the unglaciated Driftless Area of southwestern WI, which is characterized by relatively steep and rugged topography. Fields selected for inclusion in this study had a history of glyphosate-resistant annual crops grown with minimum to no tillage, and were selected for their lower productivity and/or greater potential for erosion relative to other fields within each farm. Weed populations, while variable across sites, consisted of annual grasses (primarily *Setaria* spp.) and annual and biennial broadleaf weeds, with few perennial weeds. Soils at these sites are moderately eroded, well-drained silt loams in the Dubuque, Fayette, and Hixton series (mixed, superactive, mesic Typic Hapludalfs) (SSS 2010). Thirty-year mean annual precipitation is 88.7 cm and mean growing-season temperature (Apr-Oct) is 16.1 °C (USDA 2010).

Field establishment

To evaluate the effects of various weed suppression strategies on biomass crop production and ecosystem services, we established five experimental treatments at each farm in May 2008 (Table 1). These treatments were selected because they targeted common weed species in the region, are common weed management strategies, and include low and high intensity management options. Treatments included 3 switchgrass monocultures, switchgrass planted with a companion crop of oats (*Avena sativa*), and a diverse mixture that included 5 native grasses and 4 native forbs (Table 1). Weed management treatments for switchgrass included pre-emergent applications of glyphosate (hereafter GLY), pre-emergent applications of glyphosate + post-emergent applications of 2,4-D (hereafter GLY+2,4-D), pre-emergent applications of glyphosate and imazapic (hereafter S-IMAZ+GLY), and oats (*Avena sativa*) planted as a companion crop + pre-emergent applications of glyphosate (hereafter GLY+OATS) (Table 1). The companion crop treatment was selected to reduce soil erosion during switchgrass establishment and to suppress weeds.

The Cave-in-Rock variety was used in all switchgrass treatments. Species planted in the diverse treatment (hereafter D-IMAZ+GLY) included: switchgrass (Forestburg variety; *Panicum virgatum* L.; 1.12

kgha-1), side-oats grama (*Bouteloua curtipendula* [Michx.] Torr.; 1.68 kg ha-1), indian grass (*Sorghastrum nutans* [L.] Nash; 2.24 kg ha^{-1}), big blue-stem (*Andropogon gerardii* Vitman; 2.24 kg ha^{-1}), little blue-stem (*Schizachyrium scoparium* [Michx.] Nash; 2.80 kg ha^{-1}), Illinois bundle flower (*Desmanthus illinoensis* [Michx.] MacMill ex. B.L. Rob & Fernald; 0.28 kg ha^{-1}), partridge pea (*Chamaecrista fasiculata* [Michx.] Greene; 0.56 kg ha^{-1}), Canada milk vetch (*Astragalus canadensis* L.; 0.56 kg ha^{-1}), and yellow coneflower (*Ratibida pinnata* [Vent.] Barnhart; 0.14 kg ha^{-1}). All rates are pure live seed (PLS). The prairie mixture was established with either a Truax conventional drill or a Truax FLEXII no-till drill (Truax Company; New Hope, MN); row spacing was 19 cm with 0.6 - 1.3 cm seeding depth. We utilized pre-emergent herbicides (imazapic 70 g ae ha^{-1} + glyphosate 140 g ae ha^{-1}) at all farms in 2008 to promote robust early establishment, rather than the alternative application of glyphosate post-emergence, which likely would have contributed to poor forb establishment. This herbicide mixture was selected for residual control of broadleaf weeds and control of annual grasses, as foxtails (*Setaria* spp.) are among the most common agricultural weeds in this region (Fickett et al. 2008). Forbs were selected for tolerance to the pre-emergent herbicide imazapic used in this study. Weed height exceeded the height of sown plants at two farms 3 months after planting, and these plots were mowed to 15 cm height in August 2008 to remove the weed canopy.

Table 1. Pre-establishment field crops and tillage for switchgrass and diverse species mixture bioenergy crops at each farm; Grant Co., WI.

Farm	Slope (%)	Previous Crop	Field Preparation	Field History (2006-2007)
CR	9-18%	Corn	Fall chisel, spring disked	Corn planted into corn residue using fall chisel/spring disk system[a,b]
DS	1-2%	Winter rye	No-till	Corn planted into corn residue using fall chisel/spring disk system[a,b]
FR	4-7%	Corn	No-till	Corn planted into soybean residue; spring disked[a]. Soybeans planted into corn residue using fall chisel/spring disk system[b]
TS	9-11%	Soybeans	No-till	Soybeans planted into corn residue using no-till system[a]. Corn planted into corn residue using no-till system[b]
SC	15-25%	Soybeans	Spring disked	Soybeans planted into corn residue using fall chisel/spring disk system[a] . Corn planted into soybean residue; spring disked[b].
WO	10-16%	Corn	No-till	Corn planted into corn residue using no-till system[a,b]

[a] Crop year 2007
[b] Crop year 2006

Second year management

In May 2009, each experimental field was further divided into four plots to evaluate effects of 2nd-year weed management strategies. These 2nd-year treatments included a low-intensity prescribed burn (hereafter Burn), herbicide management as glyphosate (1.12 kg ae ha^{-1}), a mixture of imazapic + glyphosate (imazapic 70 g ae ha^{-1} + glyphosate 140 g ae ha^{-1}), and an untreated control (hereafter Control). Prescribed fire is a common tool for natural areas management; glyphosate is a standard herbicide treatment for establishing native perennial species, and the mixture of imazapic and glyphosate provides additional control for annual grasses 1-2 months after application at the rate applied. Herbicide treatments were applied between 12 – 15 May 2009. Many introduced forbs and native grasses had emerged at this time; native grasses ranged from 1-5 cm in height with 1-2 fully exposed leaves. Visual herbicide injury was noticed on planted grasses after application, but was not evident by the time species composition surveys were conducted.

Prescribed burn treatments were conducted at 06 May 2009 at five farms and on 11 May 2009 at one farm. The fuel type at 5 of the 6 farms was 15 cm stubble that remained standing after plots were harvested in autumn 2008. One farm burned on 06 May was not harvested in Autumn 2008 because of steep slopes and the fuel type was 1 m-tall dead grasses and forbs; because the vegetation had remained standing over winter, the standing grasses and forbs were compressed and prostrate over approximately 60% of the plot area. Across both dates, ambient temperature ranged from 13-17° C and wind speeds ranged from 0-16 km h^{-1} (gusting to 24 km h^{-1} at one of the mowed farms). Average relative humidity was 79% on 06 May and 58% on 11 May. Cool temperatures and high relative humidity contributed to low-intensity fires (flame lengths ranging from 0.07 – 0.60 m; average rate of spread 6.1 cm s^{-1}). Average ground surface area burned (determined by tallying observations of charred vs. uncharred vegetation at 100 sample points along a transect placed across each burned plot) was 32 ± 14 % across all farms.

Fertility experiments:

The experimental design at each site was a randomized complete block, split-plot with four replications. The whole plot factor was N fertilization rate in the form of granular ammonium nitrate and was applied by hand on 18 June 2009 and 21 June in 2010. The whole plot N rates were 0, 56, 112, 168 and 224 kg $ha^{-1}$of N. Across sites, each treatment was replicated 16 times. The split-plot factor within the whole plot N rate treatments was harvest timing. The split-plot treatments were three harvest times: one in mid-fall, another in late-fall and the final harvest in early spring. Harvest times for the 2009 growing season were 19 October 2009 (mid-fall harvest), 11 November 2009 (late-fall harvest) and 9 May 2010 (spring harvest). For the 2010 growing season, harvest times were 25 October 2010 (mid-fall harvest), 23 November 2010 (late-fall harvest) and 31 March 2011 (spring harvest).

Each site measured 33.5 × 21.3 m (0.07 ha). Plot dimension for the N fertilizer treatments measured 3.0 x 9.1 m. To make the split-plots for harvest timing treatments, the whole plot N rate treatments were divided evenly into 3 × 3 m sub-plots and assigned a harvest timing. Placement of N rate and harvest timing treatments were randomized across blocks. Alleyways were mowed with a DR field and brush mower on 28 July 2009, 29 July 2010 and 18 August 2010 (DR Power Equipment, Vergennes, VT).

Measurements

<u>Biomass estimates (objective 1):</u> In 2008, plots were harvested to 15-cm stubble height using a small plot harvester and biomass from four 4.5-m^2 area quadrats was collected and weighed in the field; wet mass was recorded to 0.05-kg accuracy, and grab samples were collected and returned to the laboratory. Moisture of grab samples was determined by recording wet mass for each sample, drying samples at 60 °C for 48 hours, and recording dry mass. Moisture values for these grab samples were

used to calculate dry mass yield from wet biomass weighed in the field for each plot. We note that in practice, these perennial bioenergy crops would not be harvested in the first year of establishment because of low yield; our 2008 harvests were conducted for the purposes of our study only. In 2009 and 2010, we estimated yield by harvesting three 1.0-m^2 quadrats to 15-cm stubble height in each plot using hand-operated landscaping shears. Biomass was weighed in the field and grab samples were collected to determine moisture content for calculating dry biomass yield, as described above.

<u>Carbon sequestration in soil and biomass (objective 1):</u> We sampled soil at the end of the growing season in 2009 and 2010. In each experimental plot, we took 10 soil samples to 15 cm depth using a 2.5 cm diameter stainless steel soil probe, and composited these 10 samples into a single sample for analysis. Composited samples were sieved through a 2mm screen to remove stones and root fragments. A subsample was removed, dried for 48 hours at 60° C, and ground to a fine powder before analysis via dry oxidation/fluorescence on a Carlo-Erba CN analyzer.

We estimated C content in belowground biomass using ingrowth root cores. We installed four, 5 cm diameter x 15 cm height ingrowth root cores before the growing season in each experimental plot. Each core was filled with a standard mixture of 75% field soil and 25% sand. Ingrowth root cores were removed at the end of the growing season in each year, following a killing frost and the biomass harvest. Each core was returned to the lab and soil was washed from the roots using deionized water. Roots were placed in a drying oven for 48 hours at 60° C and weighed. Dried roots were ground to pass a 1 mm screen, and analyzed for percent C and N content as above. We calculated estimates of belowground C content from percent C content in roots and the total root biomass obtained from each ingrowth core.

We removed 3 subsamples of aboveground biomass from the end-of-season biomass harvested from each plot, ground each subsample to pass a 1mm screen, and analyzed percent C as above. We calculated aboveground C content from the mean percent C content in biomass subsamples and the total biomass yield from each plot.

<u>Greenhouse gas fluxes (objective 1)</u>*:* We sampled greenhouse gas (GHG) fluxes at 2-week intervals from each of the four focus treatments in the main project, and from each of the fertility treatments in 2009. In 2010, we sampled GHG fluxes from fertility treatments at approximately daily intervals for one week prior and one week post fertilizer application. We also sampled GHG fluxes for one date near the end of the growing season to evaluate persistent effects of fertilization on GHG fluxes. We used a closed static chamber and removed 30mL samples of chamber air at 0 and 30 minutes. Each sample was injected into a glass vacuum vial, returned to the lab, and analyzed for CO_2, CH_4, and N_2O concentrations. Flux rates were calculated from the difference in concentration between samples taken at 0 and 30 minutes.

<u>Soil erosion estimates (objective 2)</u>*:* The soil loss model RUSLE2 (version 1.26.6.4) was used to estimate soil loss for 2008 and 2009. Model input for each plot included soil type, slope percent and slop length, location (county), crop management factors (tillage, previous crop, when and how previous crop was harvested, current crop, seeding practice, etc.).

<u>Biomass estimates (objective 3)*:* </u>Harvests were conducted by randomly placing a 1 m^2 quadrate within each harvest timing plot. Switchgrass was cut 15 cm above the soil surface. Fresh weights were recorded on-site. Weeds and switchgrass were separated and subsamples were collected, weighed, and dried at 60°C to determine dry matter (DM) yield, moisture content and the concentration of weeds in the switchgrass.

Biomass quality analysis (objective 3): Tissue samples from the 0, 56 and 112 kg ha^{-1} N rate treatments in all three harvest treatments at sites 1 and 4 were analyzed for Cl^- concentration. The Cl^- can clog up boilers during burning and low mineral concentrations are preferred. Chloride was selected as an indicator of switchgrass quality. Sites 1 and 4 were chosen because they had minimal weed pressure and produced greater switchgrass yields than sites 3 and 4. Fertilizer treatments of 168 and 224 kg ha^{-1} N rate treatments were excluded from nutrient analysis because there was little evidence of a yield response above the 112 kg ha^{-1} N rate. The University of Wisconsin's Soil and Plant Analysis Lab (SPAL) carried out the Cl^- analysis of switchgrass. A digital chloridometer (LabConCo model # 442-5000, Labconco Corporation, Kansas City, MO) was used to determine chloride concentrations in the switchgrass samples (Chloride Determination, 1980).

Biomass btu analysis: The thermal energy content of switchgrass was determined on a bomb colorimeter (Parr 1266 Isoperibol Bomb Calorimeter, Parr Instrument Company, Moline, IL). The analysis followed the standard ISO 1928:2009 for thermal content of a material. Switchgrass samples from N rate treatments of 0 and 112 kg ha^{-1} of the fall and spring harvests of the 2009 and 2010 growing seasons were analyzed. Samples from the 2009 growing season were weighed on a scale that went to the 0.001^{th} g and the 0.0001^{th} was extrapolated. Samples from the 2010 growing season were weighed on a digital scale that went to the 0.0001^{th} g.

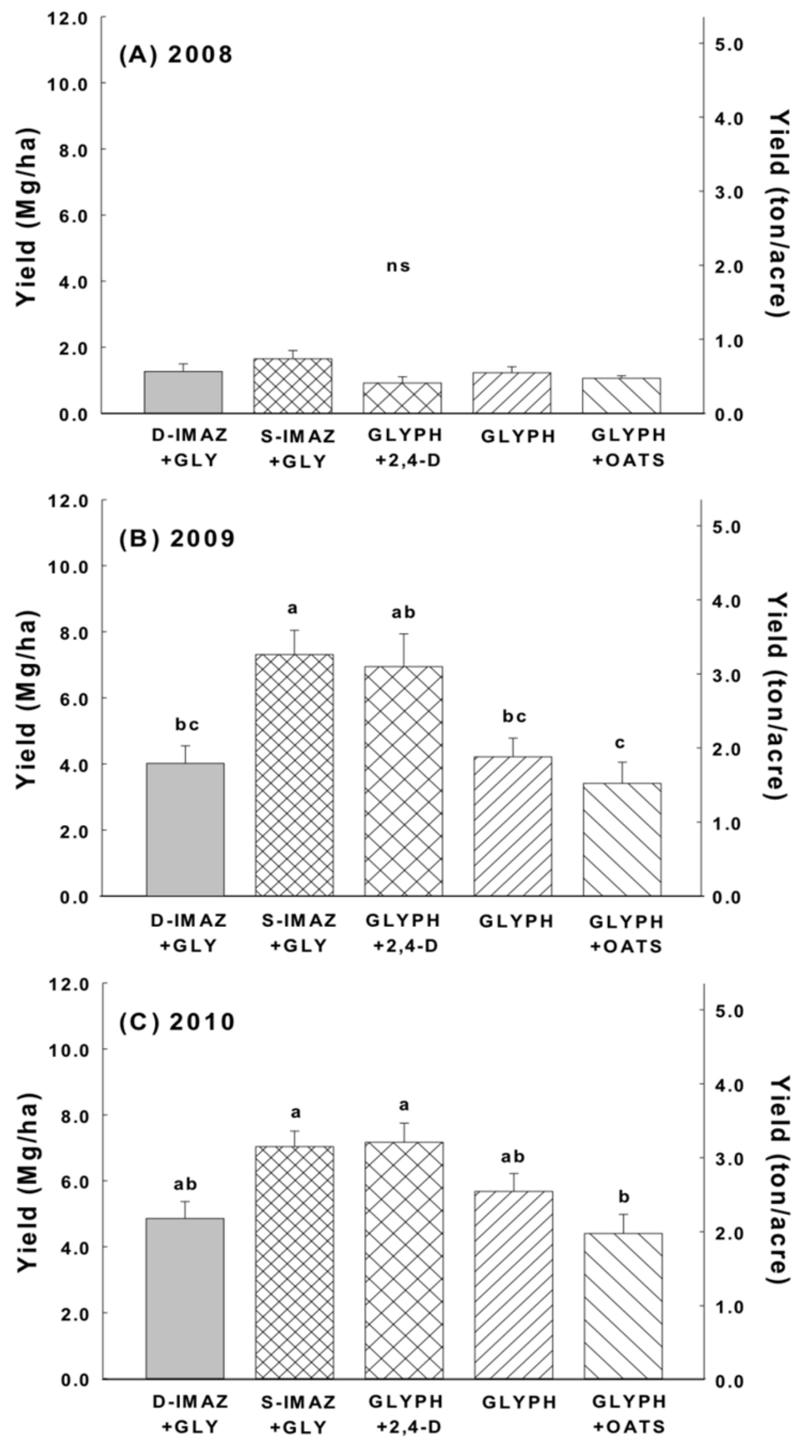
Summary of Results/Accomplishments:

Objective 1: Assess soil C sequestration and global warming potential of establishing switchgrass and prairie stands

A significant component of potential C sequestration is C fixed by plants via net primary production (npp). The other main part of the C sequestration equation is microbial respiration of CO_2 to the atmosphere. Hence, here we report on treatment effects on both npp and microbial respiration of CO_2.

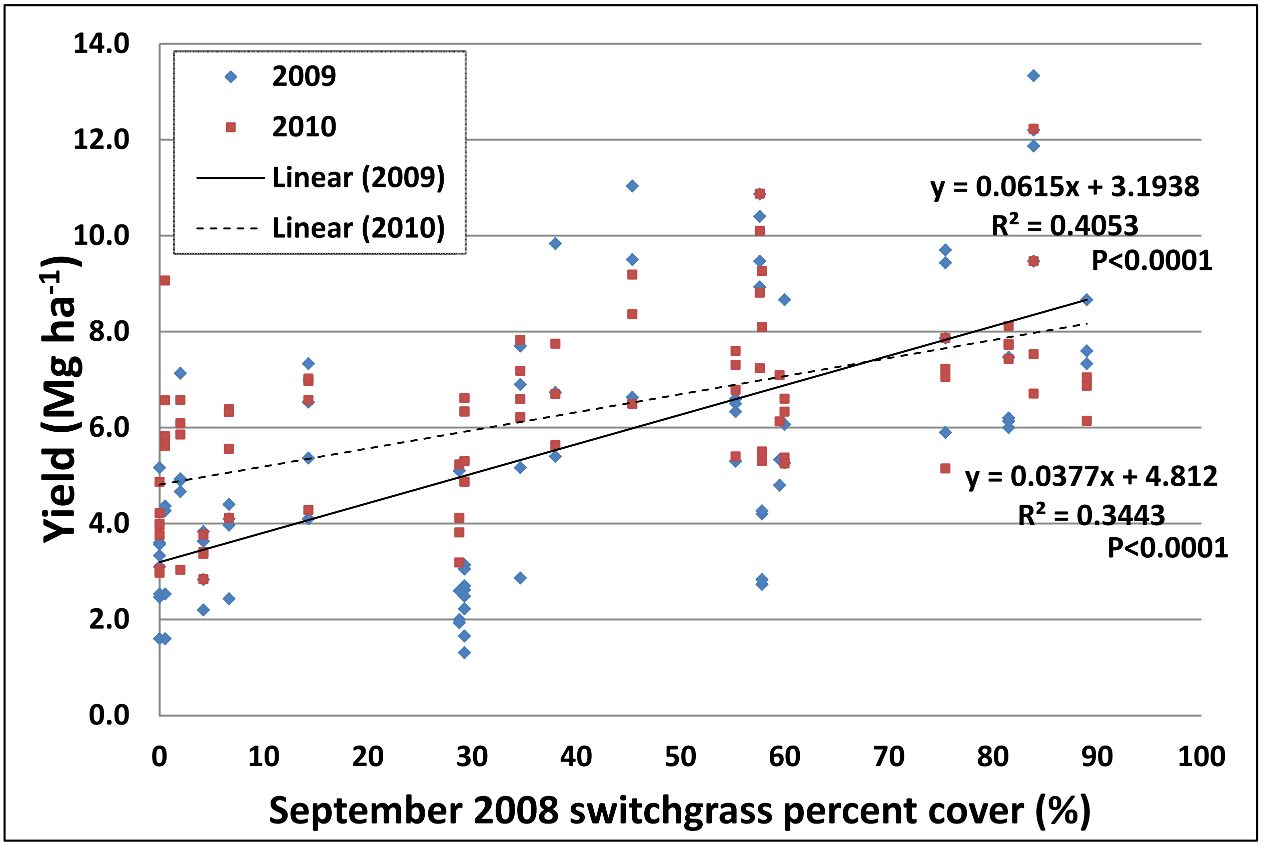
How does field establishment and management affect biomass yield?
There were no significant differences in biomass yield among treatments in the establishing year (2008) ($p=0.10$). In 2009, we observed the greatest yield in the switchgrass imazapic + glyphosate treatment and the lowest yield in the switchgrass glyphosate + oats treatment ($p=0.006$). In 2010, the switchgrass imazapic + glyphosate and glyphosate + 2,4-D treatments produced greater yield than the switchgrass glyphosate + oats treatment ($p=0.004$) (Fig. 1). The diverse prairie treatment yielded less than the most productive switchgrass treatment in 2009 (imazapic + glyphosate) ($p=0.006$), but did not differ from any switchgrass treatments in 2010.

Figure 1. Dry mass of biomass yield from each experimental treatment established in 2008, for 2008 (A), 2009 (B), and 2010 (C). Lowercase letters indicate statistically significant differences among means for each year. D-IMAZ+GLY = diverse imazapic + glyphosate; S-IMAZ+GLY = switchgrass imazapic + glyphosate; GLYPH+2,4-D = switchgrass glyphosate + 2,4-D, GLYPH = switchgrass + glyphosate; GLYPH+OATS = switchgrass glyphosate + oats.



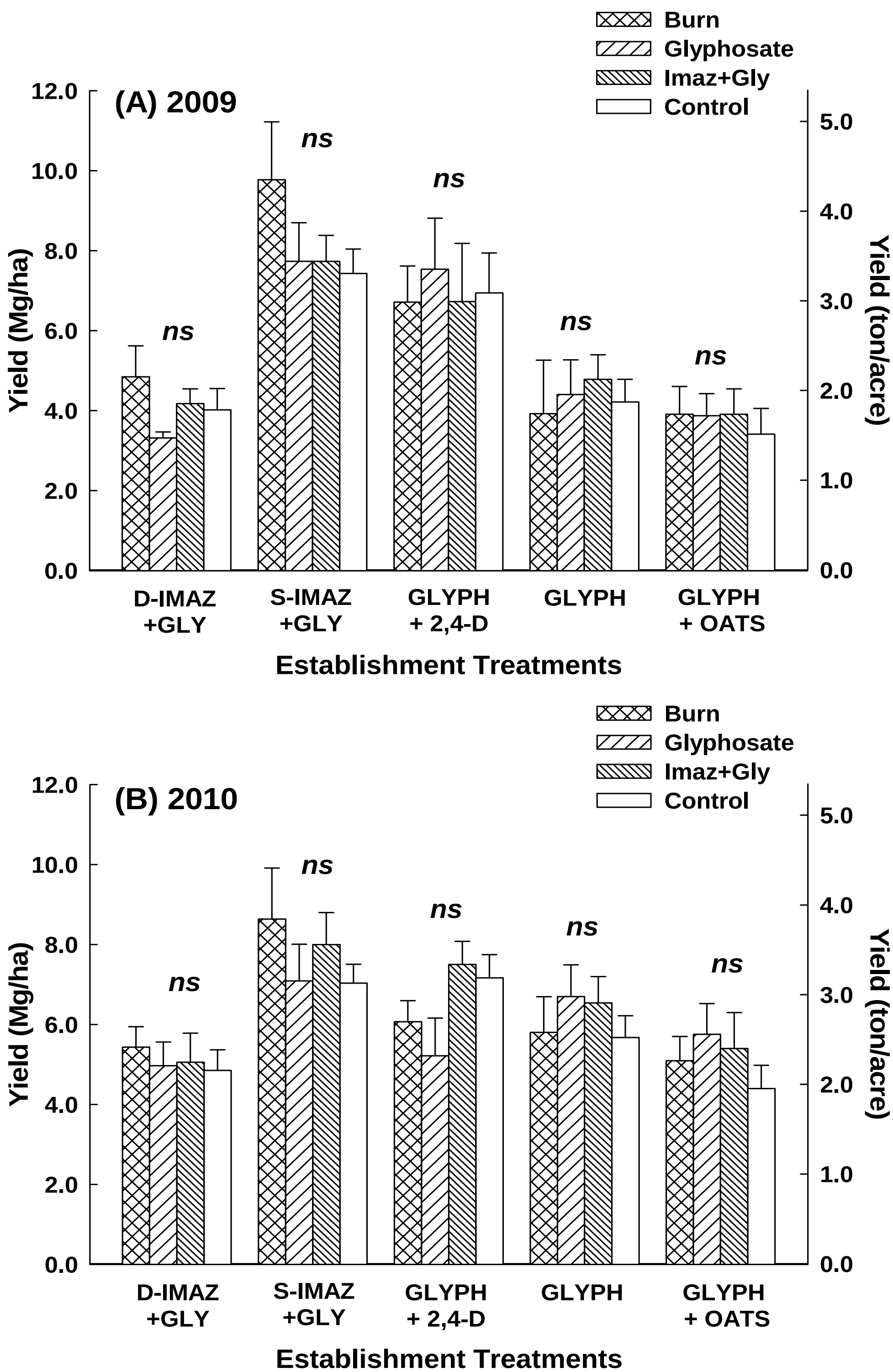
How does establishment success in the first year influence yields in later years?
We found that the percent cover by switchgrass in 2008 was positively correlated with yield in 2009 and 2010, indicating that more successfully established switchgrass stands would produce greater biomass in subsequent years, although the trend appears to be declining over time (Fig. 2).

Figure 2. Scatterplot of percent cover by switchgrass in 2008 by biomass yield obtained in 2009 (blue circles) and 2010 (red squares). Equations, R^2, and significance values are given for line of best fit for 2009 (upper) and 2010 (lower).



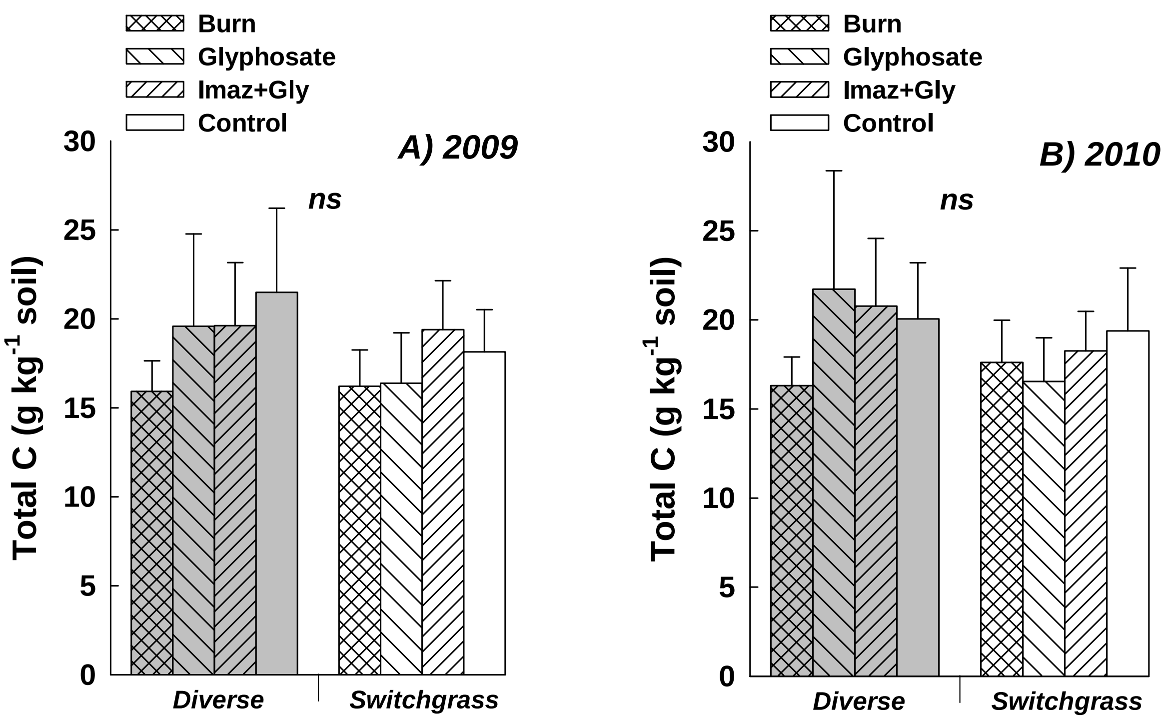
How does additional weed management treatments, applied in the year following stand establishment, influence yield in the 2nd and 3rd growing seasons post-establishment?
There were no statistically significant effects of post-establishment weed management treatments on yield in the 2nd or 3rd growing seasons, within any of the establishment treatments ($p>0.05$ for all)(Fig. 3). This suggests that management of weed species should be focused in the establishment year to ensure adequate establishment, and management after establishment does not influence productivity.

Figure 3. Yield from 2nd-year weed management treatments overlaid on each 2008 establishment treatment, measured in 2009 (A) and 2010 (B). Lowercase letters indicate statistically significant differences among means for each year. Treatment abbreviations follow figure 1.



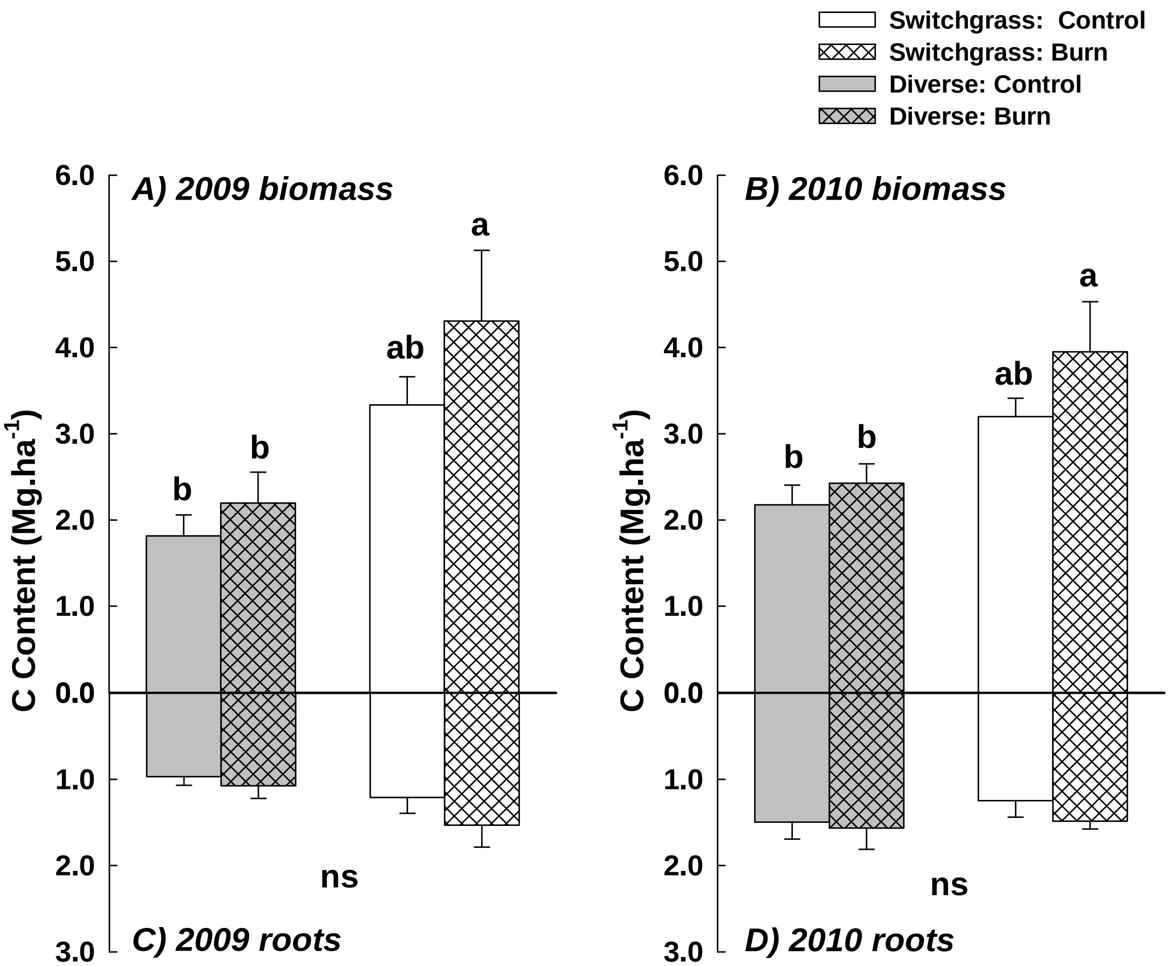
Was total soil C affected by management treatments?
No significant differences in total soil C were observed across treatments for either 2009 or 2010 (Fig. 4). Results suggest that soil C is similar between pure switchgrass stands and diverse prairie plantings. It also appears that weed management within these stands does not affect soil C.

Figure 4. Soil total carbon (C) concentration in 2009 (A) and 2010 (B) in diverse mixture (shaded bars) and switchgrass monoculture bioenergy crops in Grant County, WI. Bar pattern indicates 2nd-year weed management strategy applied to each crop.



How did treatments affect total C content of above- and below-ground biomass?
The switchgrass monoculture treated with prescribed fire supported a greater biomass C concentration than did the unburned and burned diverse mixture. There was no statistically significant difference in biomass C concentration between the unburned switchgrass monoculture and any other treatment. These patterns were identical between 2009 (aboveground $p=0.0001$; belowground $p= 0.189$) and 2010 (aboveground $p<0.0001$; belowground $p=0.295$) (Fig. 5).

Figure 5. Carbon (C) content sequestered in aboveground biomass (A, B) and roots (C, D) in 2009 and 2010 in Grant County, WI. Shaded bars indicate diverse mixture. Bar pattern indicates 2nd-year weed management strategy applied to each crop.



How did treatments affect emissions of greenhouse gases from soils to the atmosphere?

No significant effects of treatments were observed on microbial respiration (CO2 flux in Fig 6A), methane consumption from the atmosphere into soils (Fig. 6B), or nitrous oxide fluxes the year after establishment (2009) (Fig. 6C). There were also no differences in CO_2 and CH_4 flux rates among fertility treatments at any sampling date in 2009. In contrast there were differences in N_2O flux among fertility treatments only at the July 30 sampling date. At this date, N_2O flux was greater in the 150 lb/ac treatment than in the 50 lb/ac treatment, but neither of these treatments differed significantly from the 0, 100, and 200 lb/ac treatments (p=0.035)(Fig. 7). There were no differences in CO_2 and CH_4 flux rates among fertility treatments at any sampling date before or after the application of fertilizer in 2010 (Fig. 8), but we did observed statistically significant differences in N2O fluxes among fertility treatments at the 27 May (pre-treatment, p=0.024), 04 June (post treatment, p=0.020), and 07 June (post-treatment, p= 0.028) sampling dates (Table 2). Differences in N2O fluxes on these dates were observed with various rates of N applied when compared to the untreated control.

Figure 6. Greenhouse gas fluxes in burned and unburned switchgrass monoculture and diverse mixture treatments, monitored biweekly in 2009. Note differences in Y-axis scales among (A) CO_2 (carbon dioxide) flux, (B) CH_4 (methane) flux, and (C) N_2O (nitrous oxide) flux. Legend for (B) and (C) follows (A).

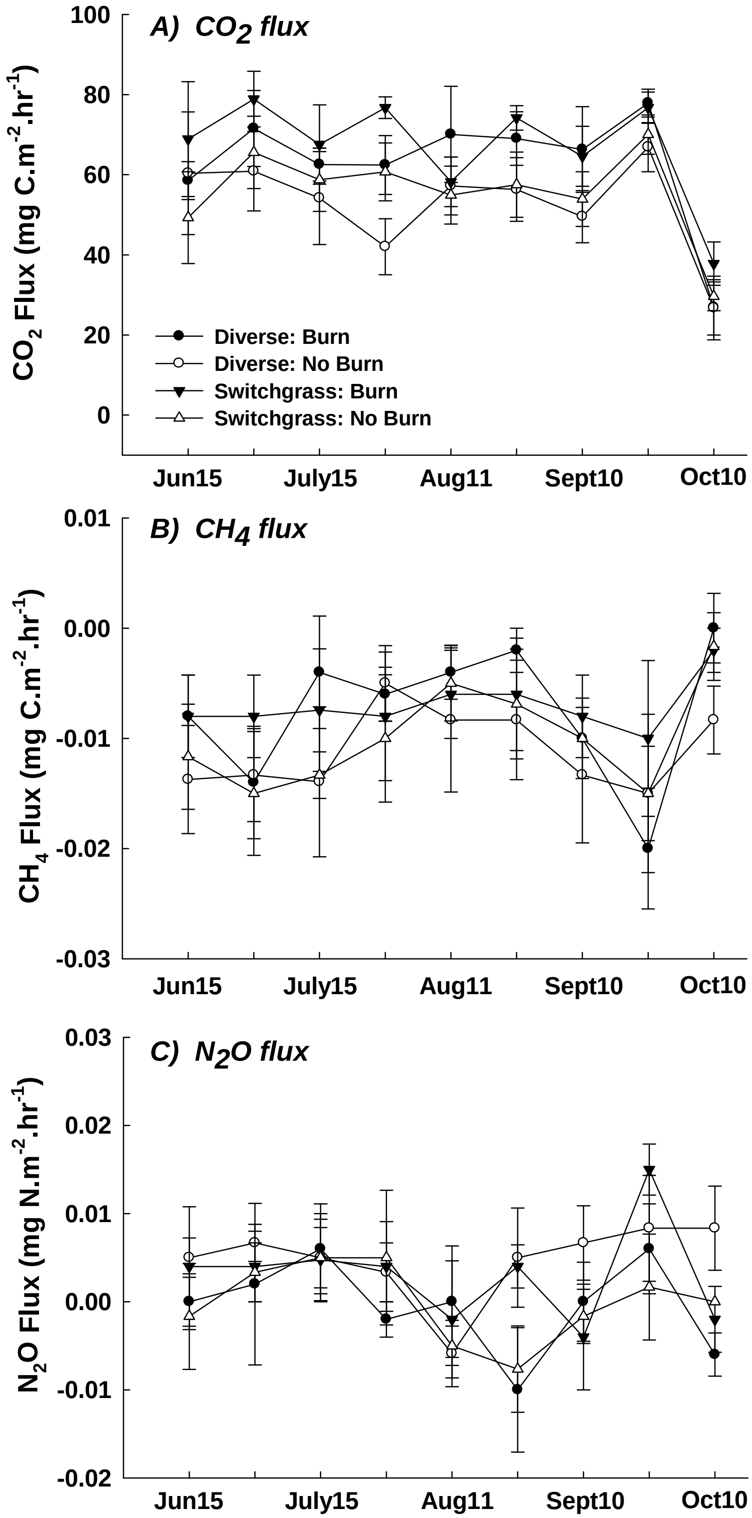


Figure 7. Greenhouse gas fluxes in fertilized switchgrass monoculture, monitored biweekly in 2009. Note differences in Y-axis scales among (A) CO_2 (carbon dioxide) flux, (B) CH_4 (methane) flux, and (C) N_2O (nitrous oxide) flux. Legend for (B) and (C) follows (A). Asterisks (*) indicate significant differences among treatments within a measurement period.

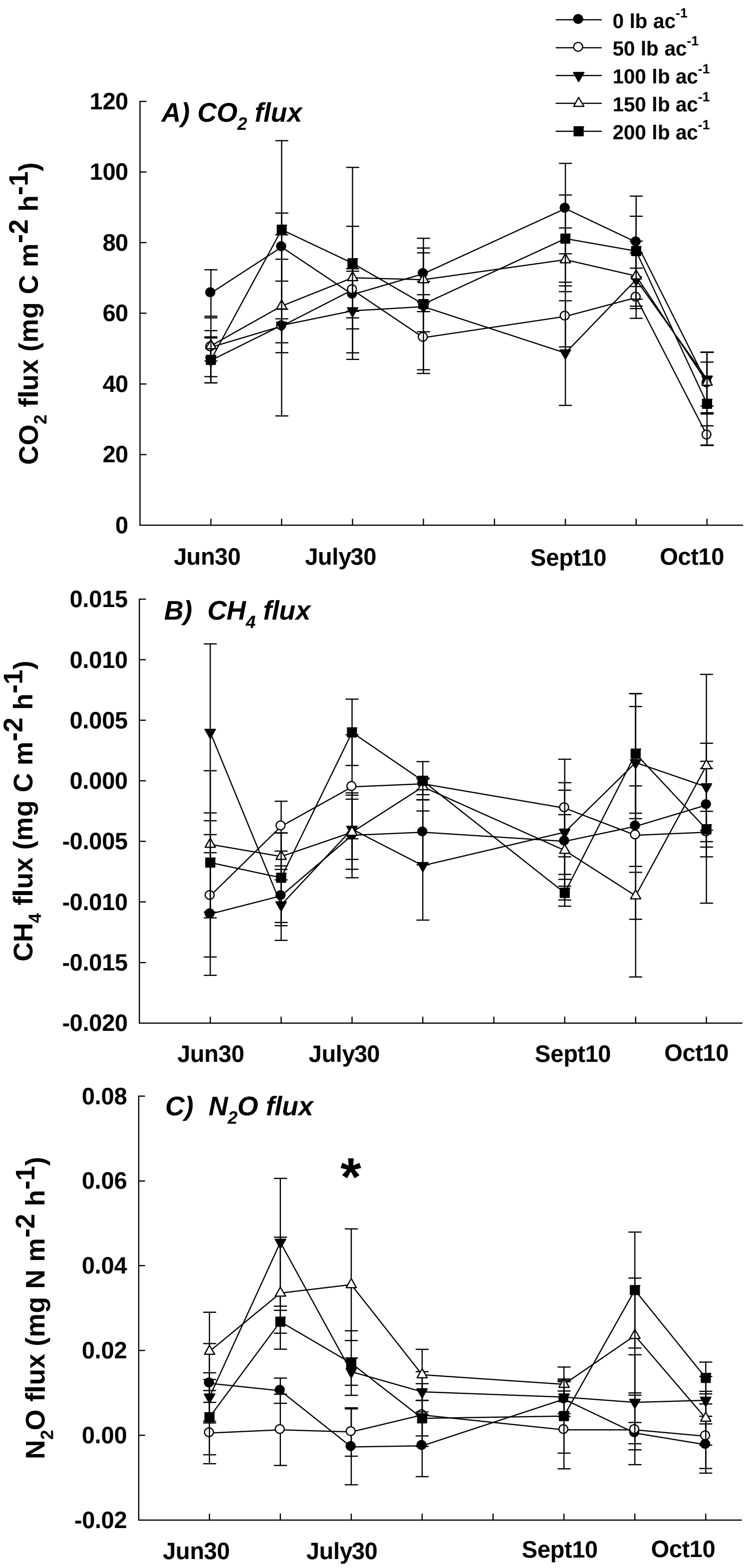


Figure 8. Greenhouse gas fluxes in fertilized switchgrass monoculture, measured before (*Pre*) and after (*Post* and *Delay*) fertilizer application in 2010. Note differences in Y-axis scales among (A) CO_2 (carbon dioxide) flux, (B) CH_4 (methane) flux, and (C) N_2O (nitrous oxide) flux. Legend for (B) and (C) follows (A). Asterisks (*) indicate significant differences among treatments within a measurement period.

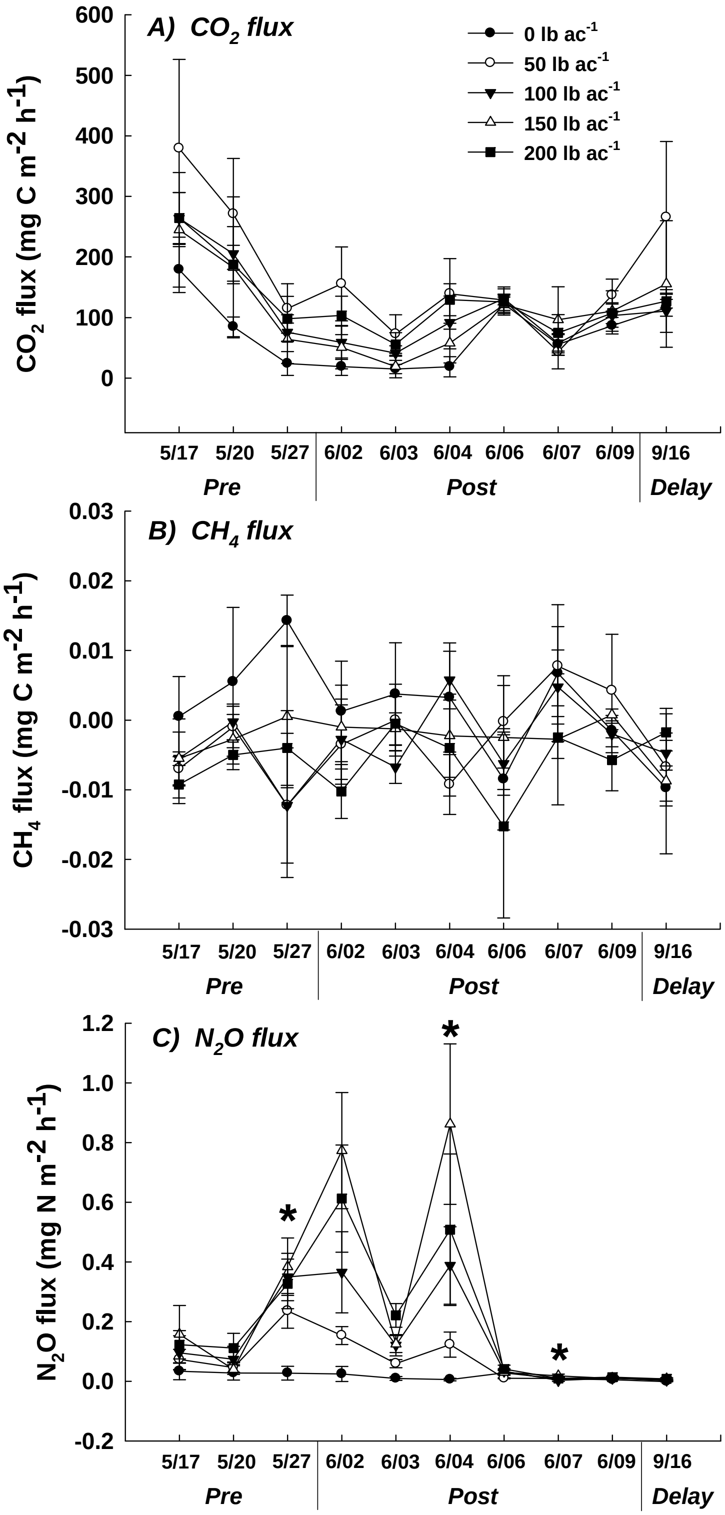


Table 2. Means separations for N2O fluxes for sampling dates at which significant differences among treatments existed. Letters indicate significant differences among treatment means, within sampling date.

Date	**Treatment (lb/ac)**				
	0	50	100	150	200
27 May	*b*	*ab*	*ab*	*a*	*ab*
04 June	*b*	*ab*	*a*	*ab*	*ab*
07 June	*b*	*b*	*ab*	*ab*	*a*

Summary of Objective 1 work: Effects of treatments on components of ecosystem C balance were only observed on aboveground plant production, where burned switchgrass monocultures were more productive than diverse treatments whether burned or not. The switchgrass monoculture was not significantly more productive than unburned switchgrass. Burning had no significant effects on C fluxes as CO2 or CH4 or N2O. Hence, spring burning switchgrass monocultures during establishment may support greater soil C accumulation, but simply planting and harvesting this perennial grass should achieve desired goals of minimizing global warming potential for a harvested perennial grass system. Even lower global warming potential would likely be realized from switchgrass stands that go unharvested because grass cover would keep soils cool thereby reducing soil respiration.

Objective 2: Evaluate the potential for soil loss among various establishment methods

Estimated soil loss ranged between 11.0 and 18.6 t/ac in 2008 and 2.2 and 7.6 t/az in 2009 (table 3). This estimate did not differ with respect to establishment treatments tested in 2008 (p=0.77) or 2009 (p=0.28) . A noticeable decline in soil loss occurred from 2008 to 2009. This can be attributed to greater plant growth and greater exposed, bare soil during the establishment year. Direct measures of soil loss from switchgrass plots or fields are noticeably absent from the scientific literature. Most studies have evaluated switchgrass as a grass used in buffer strips, and the result has generally been positive. Switchgrass, when planted at the field edge, can reduce edge-of-field losses of sediment up to 91% (Blanco-Canqui, 2010). **Field or plot level measures of switchgrass planted as a primary crop are required to validate our assumptions or model outputs.** Differences in estimated soil loss are likely a result of soil slope. The slope of the field is the main factor responsible for demarking fields as "marginal". In this study, field slopes ranged from less than 1 to 25% and greater slopes were associated with greater soil loss. Regression analysis between slope percentage and estimated soil loss resulted in an R2 value of 0.70 for 2008 and 0.64 in 2009 (data not shown).

RUSLE2 is typically used to evaluate soil loss over an entire rotation, so continued estimation or measurement of soil loss for the length of the switchgrass "rotation" is of interest. If soil loss continues to decline over the length of rotation, then the large soil loss in the first year has less impact. It should also be noted that RUSLE2 programmers are attempting to improve the prediction of soil loss for over-wintering crops (such as switchgrass and alfalfa). The new RUSLE2 (version 2) is not yet publically available but is using a new vegetation database. One major "fix" is the current RUSLE2 underestimates for residue cover for perennial vegetation, which can result in an overestimation of erosion from hay fields.

Table 3. RUSLE2 model estimates of soil loss for each 2008 establishment treatment, modeled for 2008 and 2009.

Establishment treatment	2008 Soil loss estimate (t/ac)	2009 Soil loss estimate (t/ac)
Diverse mixture		
Imazapic +Glyphosate	10.2 ± 2.0	6.3 ± 0.9
Switchgrass treatments		
Imazapic + Glyphosate	11.0 ± 2.9	2.2 ± 0.5
Glyphosate	11.5 ± 2.5	6.3 ± 1.2
Glyphosate + 2,4-D	18.6 ± 4.2	3.6 ± 0.4
Glyphosate + Oats	11.8 ± 1.9	7.6 ± 0.6

Objective 3: Measure optimum N fertilizer application rates for productivity and how they impact biomass quality and thermal energy.

How did N rates and harvest timing affect biomass production?

Dry matter (DM) yield of switchgrass ranged from 0.6 to 17.0 Mg DM ha^{-1} across treatments, sites and both growing seasons (table 4). There was one plot at spring harvest in the 2010 growing season where no switchgrass was collected because of a dominance of weeds. When averaged across sites and treatments by year, DM switchgrass yield improved from 5.5 Mg ha^{-1} in 2009 to 8.2 Mg ha^{-1} in 2010, an increase of 46%. The increase in switchgrass yield from the 2009 to 2010 growing season was expressed across all sites but was variable per site, with increases of DM Mg ha^{-} ranging between 8% and 96%.

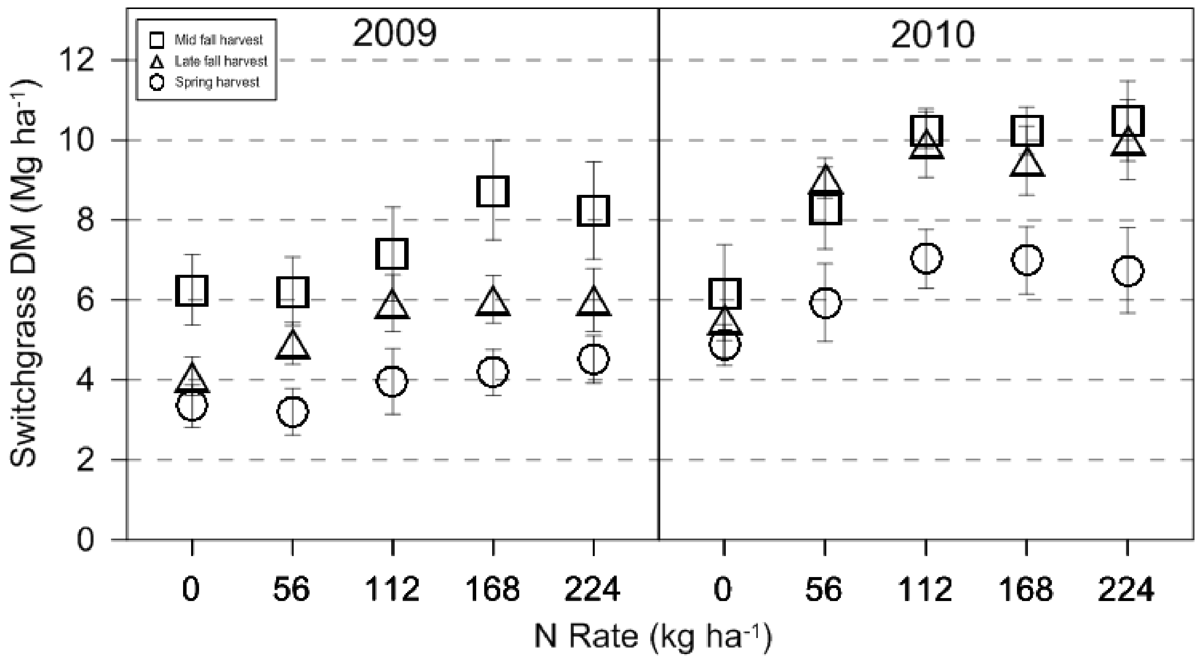
Nitrogen (N) fertilizer positively increased switchgrass yield up to a rate of 112 kg ha^{-1} of N in both the 2009 and 2010 growing seasons when analyzed over all sites and harvest timings (Fig. 9). Averaged across harvest timing treatments in the 2009 growing season, the 112 kg ha^{-1} of N treatment produced a greater switchgrass yield than the 0 kg ha^{-1} of N treatment. The 112 kg ha^{-1} of N treatment produced a similar yield to the 56 kg ha^{-1}, 168 kg ha^{-1} and 224 kg ha^{-1} of N treatments. However, the 56 kg ha^{-1} of N treatment yielded less than the 168 and 224 kg ha^{-1} of N treatments. During the 2010 growing season, the 56 kg ha^{-1} of N treatment produced more switchgrass than the N rate of 0 kg ha^{-1}. The 112 kg ha^{-1} of N treatment yielded significantly more switchgrass than both the 0 and 56 kg ha^{-1} of N treatments and was not statistically different than yield the 168 or 224 kg ha^{-1} of N treatments.

Averaged across N rates, switchgrass yields were highest at mid-fall harvests in both the 2009 and 2010 growing seasons at 7.3 and 9.1 Mg DM ha^{-1}, respectively (Table 4). In the 2009 growing season, yields significantly decreased with later harvest timings, relative to mid-fall harvest, to 5.4 Mg DM ha^{-1} at late-fall and 3.9 Mg DM ha^{-1} at spring harvest. Yield reductions across N rates were a reduction of 26% from mid-fall to late-fall harvest and a further reduction of 29% from late-fall to spring harvest (Table 4). During the 2010 growing season, switchgrass yield was not significantly different between the mid-fall and late-fall harvests. The switchgrass yield at spring harvest was 28% less than mid and late-fall harvest at 6.3 Mg DM ha^{-1}.

Table 4. Average switchgrass dry matter (DM) yield and ANOVA results for site and across sites as affected by nitrogen (N) rate and harvest timing (H)

	2009					2010				
Treatments	Site 1	Site 2	Site 3	Site 4	Ave.	Site 1	Site 2	Site 3	Site 4	Ave.
	---------- Mg ha^{-1} ----------									
N Rate (kg ha^{-1})										
0	6.2	2.7	3.4	6.0	4.6	6.4	4.1	5.3	6.3	5.5
56	7.6	3.4	2.7	5.5	4.8	8.6	7.8	5.7	8.9	7.8
112	8.7	4.5	3.3	6.2	5.7	9.7	8.2	7.8	10.1	9.1
168	9.2	5.1	4.0	7.0	6.3	9.4	8.9	7.3	10.0	8.9
224	8.7	5.0	3.8	7.6	6.3	9.3	9.2	7.6	10.2	9.1
Harvest timing										
Mid fall	10.2	5.8	5.2	8.2	7.3	9.9	8.7	8.4	9.5	9.1
Late fall	8.1	3.6	3.1	6.8	5.4	9.5	8.5	7.2	10.1	8.8
Spring	6.0	3.1	2.1	4.3	3.9	6.8	5.8	4.7	8.0	6.3
	---------- $p < F$ ----------									
Variation										
Block	0.139	0.128	0.402	0.515	-	0.002	0.240	0.149	0.915	-
N rate	<0.001	0.003	0.186	0.192	<0.001	<0.001	<0.001	0.012	<0.001	<0.001
H	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
N × H	0.541	0.896	0.302	0.560	0.697	0.017	0.690	0.462	0.517	0.065

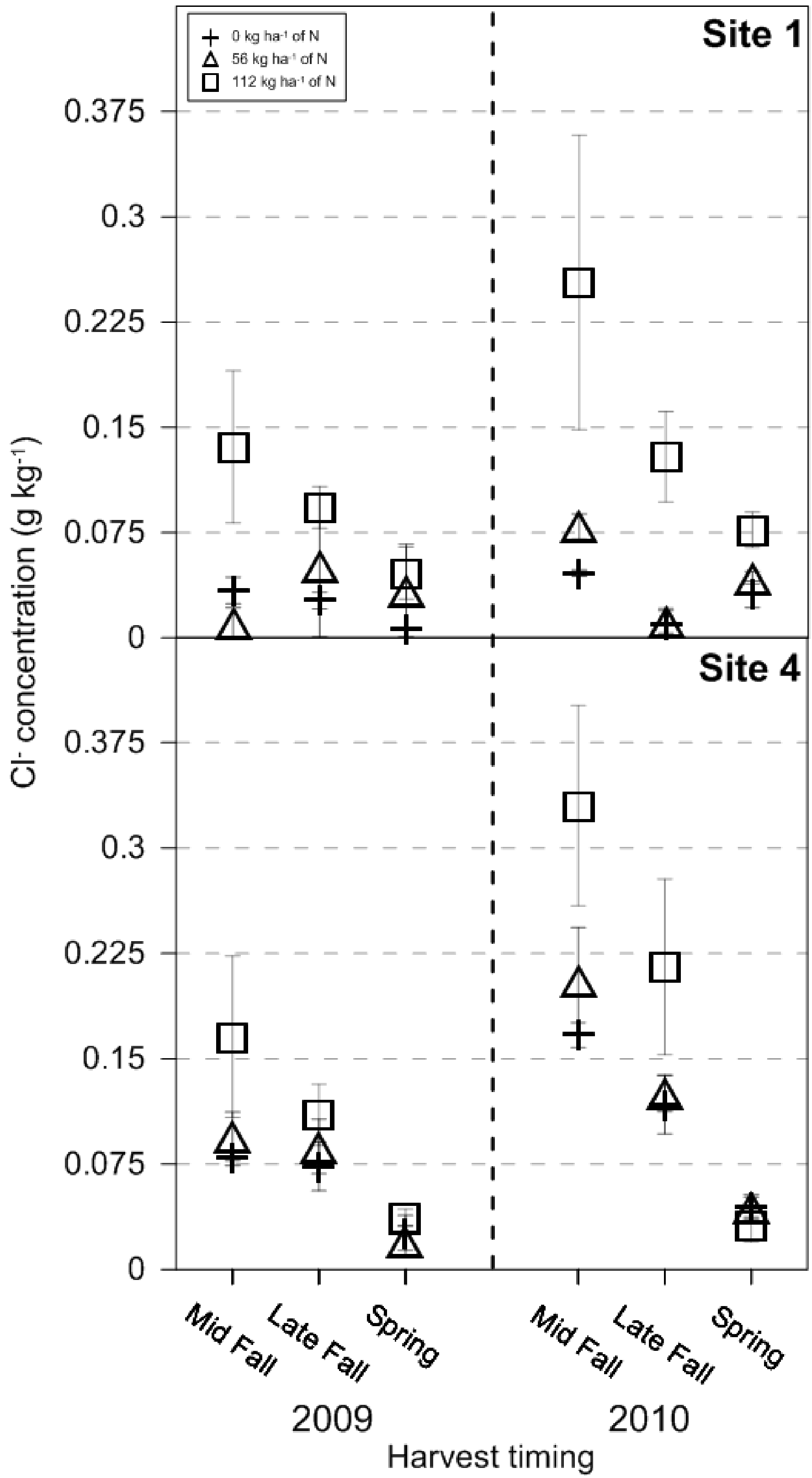
Figure 9. Switchgrass dry matter (DM) yield averaged across sites as affected by nitrogen (N) rate and harvest timing for the 2009 and 2010 growing seasons.



***How did N rates and harvest timing affect biomass* quality?**

Chloride (Cl-) was used as an indicator of switchgrass quality for burning. Averaged across harvest timings, concentrations of Cl^- in switchgrass were influenced by N rate treatments in both the 2009 and 2010 growing seasons (Fig. 10). Concentrations of N Cl^- in switchgrass increased with higher N rates. Harvest timing treatment, when averaged across N rate, influenced concentrations of Cl^- in switchgrass grown during both growing seasons. The concentrations of Cl^- had the greatest rate of decreased with each harvest in both the 2009 and 2010 growing seasons, falling by >70% from mid-fall to spring harvest.

Figure 10. Chloride (Cl^-) concentration in switchgrass as affected by site, nitrogen (N) rate and harvest timing for the 2009 and 2010 growing seasons.



***How did N rates affect thermal energy content and yield*?**

The thermal energy content of switchgrass on a weight basis had little variability across treatments and years (CV=3). The thermal energy content of switchgrass was not affected by N fertilizer rate or harvest timing with a mean thermal content of 18.3 Mj kg^{-1} (Figure 11). The thermal energy yield from a hectare of switchgrass ranged from 60.0 to 230.1 Gj ha^{-1} across growing season, sites and treatments. When energy yield is averaged across harvest timing treatments, the thermal energy yield per hectare increased by 41% in 2009 and 38% in 2010 with the application of 112 kg ha^{-1} of N. Averaged across N rate, a harvest timing in the spring decreased the thermal energy yield decreased by 35% and 27% in the 2009 and 2010 growing seasons, respectively [1] (Figure 12). There was an interaction between N rate and harvest timing in 2010. While the mid-fall harvest's 0 and 112 kg ha^{-1} of N treatments were significantly different, spring's 0 and 112 kg ha^{-1} of N treatments were not significantly different from one another.

Figure 11. Thermal energy content reported as higher heating value of switchgrass from 0 and 112 kg ha^{-1} nitrogen (N) rate and mid fall and spring harvest treatments.

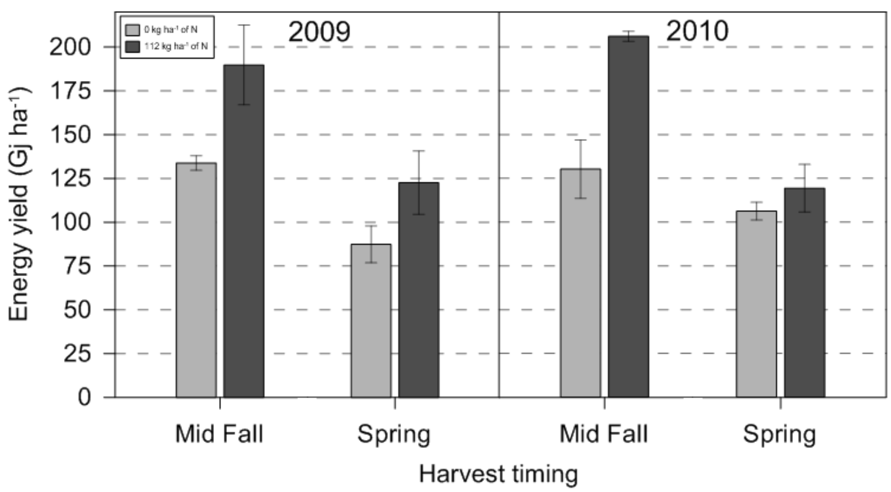
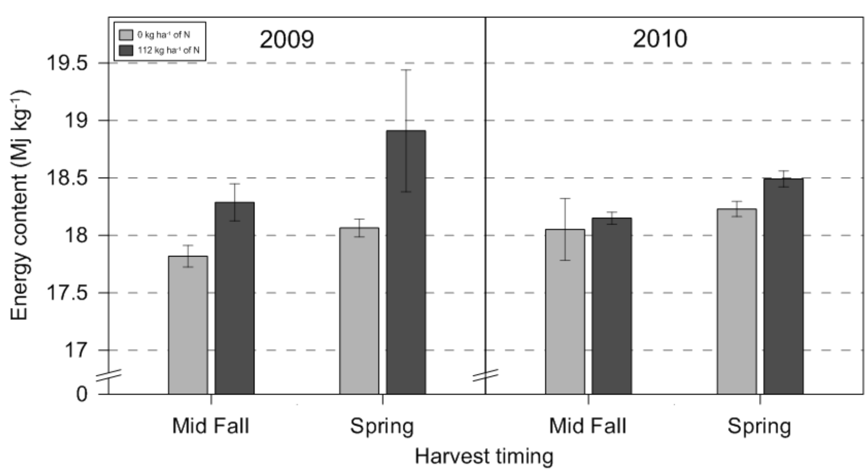


Figure. 12. Thermal energy yield reported as higher heating value of switchgrass from 0 and 112 kg ha^{-1} nitrogen (N) rate and mid fall and spring harvest treatments.



Summary of Objective 3 work: As a nascent industry, the bioenergy sector has a considerable opportunity for optimization of how it produces biogenic fuel sources and how they are utilized. By understanding how crop management strategies affect the quantity and quality of switchgrass grown as solid fuel for use in industrial boilers, growers and energy producers will be able to expect certain quantities of acceptable quality for energy production. Quantity on an area basis is improved by applying N fertilizer to switchgrass, and fuel quality is improved by delaying harvest. While N fertilizer does not strongly affect fuel quality, delaying harvest decreases yield and the potential of slagging, fouling and corrosion of boilers. On-farm management strategies for switchgrass to meet the goals of the grower and the energy producer will necessitate collaboration between the two parties. Growers will need to work with energy producers to balance the trade-offs between yield and improved fuel quality in establishing crop management strategies. Fuel quality parameters will be based on the type and tolerances of the energy conversion technology that the energy producer employs. Because yield is lost through fuel quality improvements with delayed harvests, premiums will need to be paid on higher quality fuel.

Future Directions/Activities:

Of the 6 farm fields utilized in this study, 2 have been enrolled in CRP and are no longer available for research that involves harvesting biomass. Two other farmers have expressed interest in continuing to make their fields available for research, which provides valuable opportunity to investigate longer-term trends in bioenergy crop establishment on erodible soils in southwestern Wisconsin.

The quantity and extent that switchgrass bioenergy cropping is able to perform ecosystem services for a region lacks understanding and academic research. Further research is not only needed in harvest equipment technology for bioenergy crops but also breeding programs to improve quantity and fuel quality. Small-plot research is less likely to encompass an understanding of the geo-spacial effects switchgrass cropping will have on a region's aquatic ecosystem. To perform this research, significantly larger areas will need to be put into switchgrass production.

Presentations of data from this study include:

Miesel, J.R., M.D. Raudenbush, M.J. Renz, and R.D. Jackson. 2011. Nitrogen dynamics, soil respiration, and microbial exoenzyme activity in contrasting perennial bioenergy systems in southwestern Wisconsin. Ecological Society of America 96th Annual Meeting, Austin, TX. 7-12 August 2011. *Poster.*

Miesel, J.R., J.E. Doll, M.J. Renz, S. Bertjens, and R.D. Jackson. 2010. Net ecosystem carbon budgets for contrasting perennial biomass crops in southwestern Wisconsin. Ecological Society of America 95th Annual Meeting, Pittsburgh, PA. 1-6 August 2010. *Poster.*

Miesel, J.R., M.J. Renz, M.D. Raudenbush, R.D. Jackson, J.E. Doll, and S. Bertjens. 2010. Using native species mixtures for energy crops: effects of management practices on crop yield and other ecosystem services. The Stewardship Network's Science, Practice, & Art of Restoring Ecosystems Conference, Lansing, MI. 22-23 January 2010. *Poster.*

Research papers generated through this project include:

Miesel, J.R., M.J. Renz, J.E. Doll, and R.D. Jackson. Effectiveness of weed management in establishment of switchgrass and a native species mixture for biofuels. Biomass and Bioenergy. *Accepted.*

Miesel, J.R., and M.J. Renz. Reconstructed prairie for bioenergy feedstocks and ecological restoration: effects of weed management on plant community characteristics. *In Preparation for Restoration Ecology.*

Miesel, J.R., M.J. Renz, and R.D. Jackson. Carbon stocks and fluxes in contrasting perennial biomass crops in southwestern Wisconsin. *In Preparation for Agriculture, Ecosystems & Environment.*

Miesel, J.R., M.J. Renz, and R.D. Jackson. Nitrogen dynamics and microbial activity in soils amended with biochar, sawdust and manure. *In Preparation for Biology & Fertility of Soils.*

Miesel, J.R., M.R. Raudenbush, and M.J. Renz. Species composition influences N availability and microbial activity in reconstructed grasslands. *In Preparation for Soil Biology & Biochemistry.*

Miesel, J.R., M.J. Renz, M.D. Ruark, and R.D. Jackson. Global warming potential of switchgrass monocultures under increasing fertilization rates. *In Preparation for Agriculture, Ecosystems & Environment.*

Assessment of Biomass Sources for Electricity Production in Northwest Illinois – Thomson, Illinois

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June 2012

Executive Summary

The purpose of this report is to evaluate the potential availability of wood supplies for energy for a proposed 25-MW wood-burning electrical generation facility to be located near Thomson, Illinois. The facility under consideration is expected to be located in northwestern Illinois and would be owned and operated by Jo Carroll Energy, a member-owned electric cooperative providing power and other services to the local area. The majority of biomass supplied to the proposed plant is expected to be wood derived from the lower-valued components of forest stands that are harvested for higher-valued uses such as sawtimber and veneer. This biomass would come from stands that have regenerated naturally as part of the matrix of agricultural and forested landscapes in the area. In addition to naturally-occurring stands, biomass derived from "purpose-grown" dedicated energy crops is considered to put the potential availability and cost of these crops into perspective. Costs and amounts of biomass to be delivered to the plant are estimated using a combination of forest resource data in a spatially-explicit context coupled with estimates of harvesting and trucking costs. Together, these costs comprise the total delivered cost to the generating facility and allow comparison of a biomass-fueled production system to other options such as natural gas.

The means to compare various fuels for purposes of this report is the "heat-rate" of the fuels. Based on conversations with staff from Jo Carroll Energy, comparisons of fuels used heat-rates of 15,825 and 7,245 for wood fuels and natural gas, respectively. A heat-rate of 15,825 equates to a conversion efficiency of 21.5% and the conversion efficiency of natural gas to electricity is 47%. Using this heat rate, approximately 1074 kilowatt-hours of electricity would be generated per dry ton. Based on these calculations, the cost-competitive value of wood relative to natural gas is $31.13 per dry ton. Using the heat-rate estimates provided by Jo Carroll staff and the assumed operational days per year, the estimated total biomass required to be delivered annually to the facility is roughly 200,000 dry tons per year.

The area of interest is a 125-mile radius around Thomson, Illinois. The study area encompasses a total of 31,415,927 acres of land with 4,297,137 acres being forested; roughly 13% of the total land area in forested cover. Obviously the dominant land use in the study area is agricultural production. In order to calculate trucking costs more accurately, we chose to divide the study area into five, 25-mile distance bands surrounding the Thomson location out to a total of 125 miles. Trucking costs are an important part of the overall cost of delivering bulk commodities such as wood for energy. Sectioning the study area into the distance-bands allows us to estimate the total delivered costs of wood in greater detail.

We used the USDA-Forest Service FIA Evalidator program to provide estimates of stand volumes by species, stand age class, ownership and stand volume separated into product classes (e.g. sawtimber, pulpwood, top-and-limbs). The dominant cover types of the Oak/Hickory, Elm/Ash/Cottonwood and Maple/Beech/Birch groups account for the majority of the acreage in the study area. In total, these groups account for 92.5% of the total forested acreage with 67, 17 and 8 percent of the acreage in the Oak/Hickory, Elm/Ash/Cottonwood and Maple/Beech/Birch groups, respectively. Overall, private ownership accounts for 87% of the total forestland. For this reason, we chose to focus analysis on the potential energy biomass supply from the largest covertypes.

Using the database of pulp and top-and-limb biomass with distance and availability-reduction factors to account for land ownership and willingness to sell, we determined the minimum travel distance required to procure the total of 200,000 dry tons annually or, in our analysis, 2,000,000 tons of biomass over three, ten year periods. Based on this analysis, the first ten-year period requires a transportation distance of slightly greater than fifty miles. The total cumulative biomass at the 50-mile mark for the first time period is 1,830,892 dry tons at fifty miles. Thus, to obtain the remaining 169,108 tons of biomass would require a small fraction; 8 %, of the additional incremental biomass found in the 51-to-75 mile distance band. In order to procure 8% additional resources, the maximum travel distance is 52 miles in Period 1 (first decade). In time period 2, the distance required to obtain the same harvested biomass increased to 57 miles and, in period 3, 59 miles. We use these estimated distances to construct a table of the total tonnages harvested by distance band for each time period with associated transportation costs.

Harvest was assumed to be limited to clearcuts of pulp and top-and-limb biomass associated with the final harvest of timber for sawlogs. A recent report entitled “True Costs of Harvesting Woody Biomass in the Driftless Area of the Upper Midwest Final Report” conducted by the Southwest Badger RC&D report is used as a basis for estimating harvesting costs. Using data from this report, the average harvest cost value for clearcut stands is $38.29. Based on a composite of harvesting cost data and an assumption that costs will likely be reduced with larger operations servicing a consistent large market such as an energy facility, we chose to use an average harvest cost for pulpwood of $32.00 per dry ton. The cost of collecting top-and-limb biomass is assumed to be zero to the landing as this material is assumed to be skidded to the landing in whole-tree form and the cost of harvesting the tree is assigned to the pulpwood harvest. An analysis of product type distribution in stands derived an average blended cost for all forms of energy biomass delivered to the landing of $22 per dry ton. Analyses of logistics and fixed and variable costs of chipping equipment were done to determine the additional cost of chipping tree biomass for delivery to the facility. Chipping cost is estimated to add $9.00 per dry ton to the total on-site processing cost. As a result, the total harvesting cost including felling, skidding and chipping is estimated to be $31.00 per dry ton.

Based on information developed through contacts with area loggers, we developed a simple non-linear distance-dependent cost function to estimate trucking costs. In order to adjust for the “tortuosity” of the transportation network, we used Google Earth and the imbedded road network to estimate the ratio of straight-line distance to actual road distance by selecting a set of randomly selected points surrounding the proposed site. This adjustment was used to estimate the transportation distance within each 25-mile distance band.

Once the various factors of forest location, land management policies, equipment costs and trucking costs are accounted for, estimates of total volume and price were made. We assumed a stumpage price of $10.00 per dry ton. Combining all of the components of stumpage, harvest, processing and trucking costs produces a total estimated delivered cost to the mill. Estimated delivered cost to the Thomson site is $49.93, $51.63 and $52.69 per dry ton for the three, ten-year time periods, respectively.

At the request of Jo Carroll and the Blackhawk RC&D staff, we included a brief discussion of energy crops. A potential supplementary source of biomass for energy is crops grown specifically for biomass often referred to as "dedicated energy crops". These crops are typically perennial crops that are planted once and support continual harvest for an extended period, often ten years, without replanting. Cash flow models for hybrid poplar and switchgrass were used to estimate the breakeven price of these crops using cost inputs for the production systems. The breakeven price of biomass produced from dedicated energy crops is estimated to be approximately $40.00 per dry ton FOB-farm. However, as these crops are assumed to be produced on agricultural land, the more important consideration is the revenue currently produced to the landowner from growing agricultural crops. Based on this analysis, additional research is recommended to determine those specific agricultural sites having lower productivity and, as such, might be potential sites for energy crop production. At this time, the lack of information on the relationship between land quality and energy crop yield precludes more detailed analysis of expected costs of biomass delivered to the proposed facility.

This analysis indicates that the total delivered cost of biomass to the Thomson site is estimated to be roughly $50.00 per dry ton. The bulk of these costs are comprised of harvesting and chipping which is commonly the case in many forestry operations. Also, it should be noted that there are additional costs associated with procuring wood and disposing of ash generated through the combustion of wood. While expected to be minimal, personnel costs and logistics of arranging for sites for harvest and ash disposal may add $5.00 to $10.00 per dry ton.

As mentioned, the natural gas-equivalent value of wood is $31.13 per dry ton using a heat-rate of 15,825. Based on this analysis, the delivered cost of wood is estimated to be roughly 60% higher than the equivalent cost of natural gas. While it may be possible to alter this heat-rate through air-drying of a portion of the stand that is roundwood (pulp component), this comes at a cost of inventory management and additional handling. At this time, in an environment of relatively inexpensive natural gas, it does not appear to be feasible to use biomass derived from area forests to produce electricity cost-competitively with natural gas.

Introduction and Background

The purpose of this report is to evaluate the potential availability of wood supplies for energy for a proposed 25-MW wood-burning electrical generation facility to be located near Thomson, Illinois. The facility under consideration is expected to be located in northwestern Illinois and would be owned and operated by Jo Carroll Energy, a member-owned electric cooperative providing power and other services to the local area. In light of the increased regulation aimed at reducing emissions of a variety of substances such as carbon dioxide, mercury and particulate matter, the potential exists to use renewable fuels such as wood from natural stands in the surrounding area as well as "purpose-grown" energy crops such as poplar or switchgrass. These sources are generally considered to be entirely renewable and low in net emissions of carbon dioxide and mercury and as such, a potentially attractive option to fossil fuels such as coal or natural gas. This report describes the existing wood resource surrounding the proposed Thomson site and attempts to estimate the cost and amounts that could be delivered to the plant site. Also, a discussion of the economics of production of biomass crop options such as switchgrass and poplar is briefly presented with particular reference to production on agricultural sites in the area.

The majority of biomass supplied to the proposed plant is expected to be wood derived from the lower-valued components of trees that are harvested for higher-valued uses such as sawtimber and veneer. This biomass would come from stands that have regenerated naturally as part of the matrix of agricultural and forested landscapes in the area. In addition to naturally-occurring stands, biomass derived from "purpose-grown" crops is considered in this report to put the potential availability and cost of these crops into perspective. Costs and amounts of biomass to be delivered to the plant are estimated using a combination of forest resource data in a spatially-explicit context coupled with estimates of harvesting and trucking costs. Together, these costs comprise the total delivered cost to the generating facility and allow comparison of a biomass-fueled production system to other options such as natural gas.

Fuel Characteristics and Options

In an analysis such as this, it is important to first consider the likely "next-best" fuel option for production of electricity. For purposes of this study, we assumed that the most attractive option for electrical generation for comparison would be generation capacity fueled by natural gas. Given the direction of regulations and standards on electrical facilities using coal, we are not considering coal as a viable next-best option in this report. The boom in production of natural gas has resulted in a relatively rapid decline in the price of natural gas (Figure 1). Most fuels are priced using a metric of energy content, typically the price in US dollars per million British Thermal Units (MMBTUs). Natural gas prices have fluctuated widely over the past decade with prices reaching over $10.00 per MMBTU in mid-2008. Prices have dropped dramatically since that time and are expected to remain relatively low throughout the next decade due to the increase in exploration and improvements in extraction technology. For purposes of this study, we are assuming that the reference for comparison of biomass fuels to natural gas is $4.50

per MMBTU for natural gas delivered to the Thomson, Illinois location. This value will be the ultimate benchmark of comparison for wood delivered to the proposed facility.

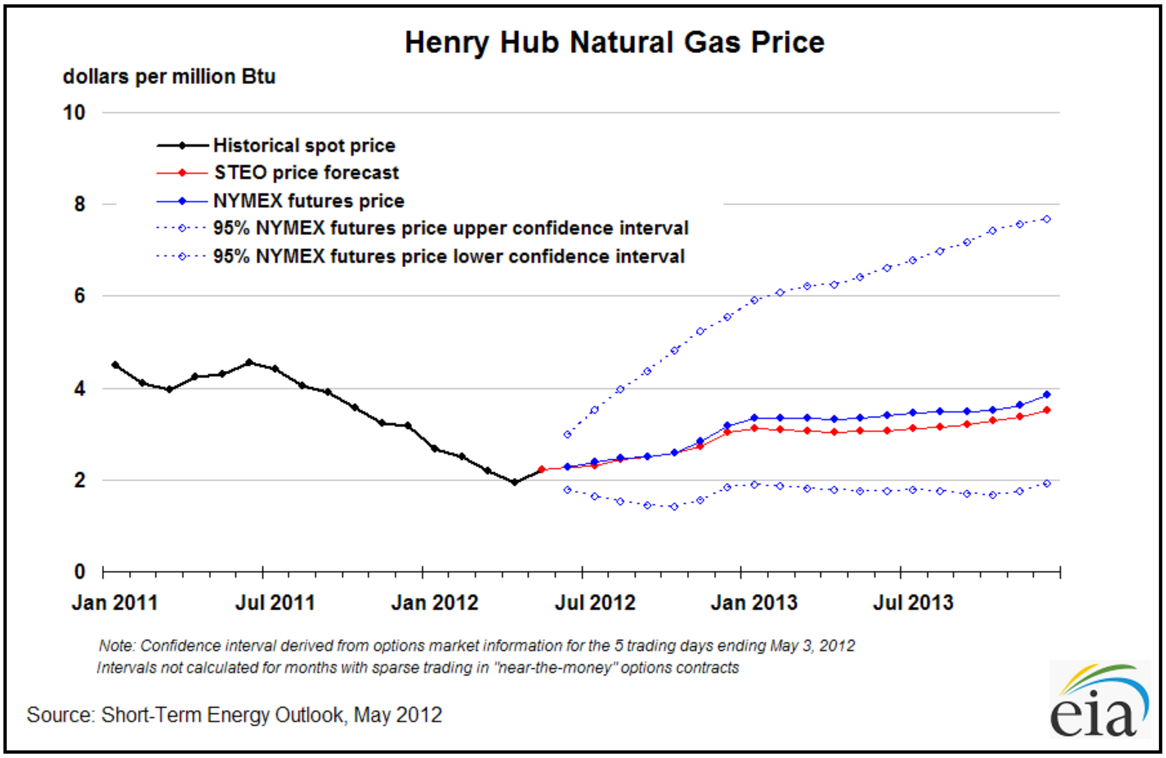

Figure 1. Current and estimated future price of natural gas at the Henry Hub, Louisiana (source: USDOE/EIA Short-Term Energy Outlook 2012)

Wood Energy Content

Wood can vary widely in specific gravity and, as a result, can have markedly different energy contents on a volume basis. However, most hardwood species have an energy content of 8,500 BTU per oven-dry pound or 17 MMBTU per oven-dry ton. For purposes of our analysis, all forest resource data are presented in terms of dry biomass (moisture-free basis) and therefore, no conversion of wood volume to energy content is needed. The value of 17 million BTU per dry ton is used with adjustments to this maximum potential value (higher heating value) to more accurately reflect the actual expected heat that can be extracted from wood in a state-of-the-art boiler system specifically designed to burn wood. As a point of clarification, care must be taken when discussing wood moisture content as there are two dominant methods of calculating wood moisture content; green-weight basis and dry-weight basis. For example, if half of the tree weight is water and the other half wood, the moisture content on a green-weight basis is 50% (weight of the water divided by the dry weight of the wood plus the original weight of the water). In contrast, many wood scientists and those involved in the dimension lumber industry use the dry-weight basis as the standard for expressing moisture content. Using the same values, wood moisture content would be 100% on a dry weight basis (weight of water divided by the weight of the dry wood). In most energy circles, the green weight basis of expressing moisture content is used and we have used the green weight basis of expressing moisture content in this report.

Many fuels such as natural gas are free of moisture and, as such, the efficiency of conversion to usable heat is relatively high. However, wood in an as-harvested condition is typically 50% moisture (½ water, ½ wood). Moisture content of wood in tree-form can be reduced through air-drying in a relatively short time period during the spring, summer and fall periods but wood harvested during the dormant period will be relatively high in moisture content. Also, the logistics of harvesting systems may not allow air drying of wood due to the fact that wood is likely to be chipped on-site with limited ability for further air-drying of chips in piles. Therefore, we have assumed that wood will be delivered to the generating facility with a moisture content ranging from 45 to 50% moisture content (expressed on a green weight basis).

Energy Prices and Wood Energy Value

In any consideration of the potential for a biomass-fueled system, an important consideration is the possible alternate, competing use of wood for other purposes. We have assumed in this report that no sawtimber, regardless of species, is economically available as a source of wood for energy. Table 1 below supports this assumption with prices ranging from $200 per thousand board feet for lower-demand species such as Sweet Gum to over $1,000 per thousand board feet for Walnut. Using a conversion of 500 board feet per dry ton, the estimated average equivalent value in terms of biomass ranges from $100 to over $500 per dry ton delivered to a sawmill. Also, as shown, pulpwood prices are extremely low due to low demand and the fact that the industry is dominated by sawmills processing high-valued hardwoods with very little demand for smaller-diameter portions of trees. Stumpage price for pulpwood on a green ton basis are reported to be $4 per green ton or roughly $8 per dry ton. Obviously, based on prevailing stumpage prices, the only realistic source of wood for energy is pulpwood.

Table 1. Stumpage and FOB prices through February 2011 for major species in Illinois (source: USDA-NASS and Illinois Dept. of Natural Resources, Division of Forestry, http://web.extension.illinois.edu/forestry/il_timber_prices/pdf/itp_feb2011.pdf)

	Nov 2009 - Feb 2010		**May 2010 - Aug 2010**		**Nov 2010 - Feb 2011**	
	Stumpage	**FOB Mill**	**Stumpage**	**FOB Mill**	**Stumpage**	**FOB Mill**
Ash	$140	$280	$140	$310	$130	$300
Basswood	$100	$240	$110	$220	$110	$260
Beech	$80	$220	$80	$200	$70	$210
Cottonwood	$70	$200	$70	$190	$70	$220
Sweet Gum	$90	$210	$90	$220	$80	$200
Elm & Hackberry	$80	$210	$80	$200	$80	$210
Hickory	$140	$270	$150	$300	$140	$310
Cherry	$260	$480	$260	$490	$270	$450
Soft Maple	$120	$250	$120	$230	$130	$250

	Nov 2009 - Feb 2010		May 2010 - Aug 2010		Nov 2010 - Feb 2011	
	Stumpage	**FOB Mill**	**Stumpage**	**FOB Mill**	**Stumpage**	**FOB Mill**
Sugar Maple	$190	$370	$210	$390	$200	$370
Black Oak	$180	$300	$180	$310	$160	$300
Pin Oak	$100	$240	$90	$210	$120	$230
Red Oak	$230	$400	$250	$480	$200	$380
White Oak	$290	$530	$310	$540	$360	$570
Yellow Poplar	$140	$260	$130	$260	$120	$270
Sycamore	$80	$210	$90	$220	$90	$230
Black Walnut	$650	$940	$700	$1,100	$840	$1,170
Woods Run Bottomland	$110	$220	$130	$240	$130	$210
Woods Run Upland	$220	$370	$230	$400	$230	$380
FACE VENEER - $ PER M BD. FT.						
Red Oak	$560	$950	$560	$950	$360	$650
White Oak	$1,130	$1,860	$1,150	$1,950	$1,240	$1,950
Walnut	$1,780	$3,000	$1,900	$3,100	$2,450	$3,180
Cherry	$540	$1,050	$600	$1,200	$580	$880
COOPERAGE - $ PER M BD. FT.						
White Oak	$300	$590	$310	$600	$320	$610
UNPEELED PULPWOOD - $ PER TON						
Ton	$4	$25	N/A	N/A	$3	$26

In addition to evaluating the current prices for the next-best energy alternative, it is important to put other potential wood uses into context. Potential uses can range from wood pellets for home and commercial heating to conversion of cellulosic materials to liquid fuels such as ethanol or other liquid fuels having a higher energy density such as butanol or diesel fuel. Wood pellets for home heating and commercial applications are particularly attractive in those areas where natural gas is not available and the only fuel available for home heating is higher-price propane or heating oil. Table 2 below shows a comparison of some common fuels and estimated prices for realized heat from the combustion of each fuel. After taking into account conversion efficiency, the cost per million British Thermal Units (mmBTUs) of wood-based energy is currently lower than heating oil and propane and similar to natural gas depending on wood form be it chips, roundwood or pellets. The price advantage of wood pellets over propane and heating oil, in particular, has been the impetus for the development of the pellet fuels industry over the past five years in the Lake States. The differential in price between heating oil or propane and wood is sufficient to encourage investment in pellet production infrastructure and commercial and residential combustion equipment to replace these higher-priced fuels. Thus, the use of wood to produce energy can be expected to increase and could become a significant part of the future energy picture particularly in rural areas where the infrastructure to transport less expensive fuels such as natural gas is too much of an economic burden to justify distribution to those areas having a low population density.

Table 2. Comparison of common residential fuels and net realized price per mmBTU as of May 2012.

Fuel Type	$/unit	Unit	$/mmBTU	Conversion Efficiency	Net Cost ($/mmbtu)
Natural Gas	**$5.60**	**Mmbtu**	**$5.60**	**0.9**	**$6.22**
Heating Oil	**$3.79**	**Gallon**	**$28.76**	**0.85**	**$33.84**
Propane	**$1.99**	**Gallon**	**$22.10**	**0.9**	**$24.56**
Wood Pellets	**$200**	**Ton**	**$11.76**	**0.8**	**$14.70**
Round Wood	**$75.00**	**Dry Ton**	**$3.83**	**0.6**	**$7.35**
Wood Chips	**$30.00**	**Gr. Ton**	**$3.52**	**0.6**	**$5.88**

In addition to heating applications, new developments in the field of conversion of cellulosic materials to liquid fuels such as ethanol are important to understand due to the potential of these technologies to impact supplies of wood as well as other cellulosic materials. It is no surprise that gasoline prices have risen to a point where potential alternate fuels may be considered. The U.S. produces only about one-third of its oil domestically and a steady petroleum supply is critical to the U.S. economy. New developments in technology to convert cellulose to ethanol have the potential to alter the demand for cellulosic sources such as wood. There are many technologies being considered and many of these technologies have advanced past the laboratory scale to the pilot plant stage of development with commercial systems being installed in Iowa by Poet and Dupont Danisco. A technology under development by ZeaChem is testing conversion of wood derived from hybrid poplar plantations in a pilot plant located near Boardman, Oregon. Based on their current estimates, the conversion efficiency could reach as high as 135 gallons of ethanol per dry ton. Using a RBOB price of $2.89 per gallon (price of gasoline without taxes and transport, Source: Bloomberg Commodities Market data - http://www.bloomberg.com/markets/commodities/futures), the estimated equivalent value of ethanol would be approximately $2.30 per gallon assuming a 20% deduction for reduced mileage using ethanol (note – this assumes adoption of new vehicles specifically designed to use ethanol fuels). Using a value of $2.30 and a conversion rate of 135 gallons per dry ton, the potential value-added using a gasoline-equivalent price is estimated to be $312 per dry ton. Put another way, if wood were delivered to a fuel conversion facility at $100 per dry ton, the wood feedstock would comprise $0.74 of the finished price of ethanol or 32% of the gasoline-equivalent fuel value. Based on a report done by the National Renewable Energy Laboratory (Aden etal, 2002), the estimated capital and operating cost minus the cost of the feedstock, was estimated to be $0.74 per gallon of ethanol for the "nth" plant (i.e. mature technology). While there are many unknowns with respect to these emerging technologies, the take-home message is that cellulosic conversion to ethanol is not without justification and may be competitive in today's world of relatively high priced liquid fuels.

On the other hand, there is no guarantee that the price of the next-best alternative, natural gas, will continue to remain low throughout the life of the project. In many cases, forms of energy are fungible and replacement of one fuel for another may take place over time. Although not widespread at the moment, natural gas may be used to replace gasoline in the future. Migration of gasoline-powered transportation to compressed natural gas (CNG) is currently technically and potentially economically feasible. However, the development of the infrastructure to make CNG widely available in the U.S. is required. Although highly localized, the current price of a gallon-gasoline-equivalent (GGE) of CNG in the U.S. varies from less than one dollar to $2.50. Thus, the fact that some forms of energy may readily substitute for another (such as wood pellets for propane or CNG for gasoline) should be appreciated because of the potential to alter the demand and price of a given fuel type over time and its associated effect on the local price of raw material as markets shift to the next least expensive energy option. Given the wide swings in energy prices over the past decade, investments in new biomass-based industry must be done with an appreciation of the impacts of the world energy markets and how quickly those effects are felt at a local level.

Fuel Value and Comparison

In order to estimate the value of wood as a fuel relative to natural gas for electrical generation, differences in actual heat usable to generate the final product must be considered. The conversion efficiency of the raw material to final product depends on factors such as inherent energy density, ash content and, most important in the case of wood fuels, moisture content. Water is associated with wood in two forms; free water, typically water present at moisture contents of 35% and above, and bound water, which is water that is a structural part of the wood fiber and held more tightly. While it is possible to air-dry wood down to a moisture content of 35% on a green-weight basis, it is difficult to achieve moisture contents below this level without the addition of supplemental heat. Due to logistical consideration associated with stockpiling and air-drying wood, we have assumed our base case to be wood delivered to a generation facility at 50% moisture, or field moisture content.

The means to compare various fuels for purposes of this report is the “heat-rate” of the fuels. Based on conversations with staff from Jo Carroll Energy, we are basing comparisons of fuels on heat-rates of 15,825 and 7,245 for wood fuels and natural gas, respectively. In the case of electricity, the unit of interest for our purposes is a kilowatt-hour. The energy content of a kilowatt-hour is 3,412 BTU. Expressed another way, a heat-rate of 15,825 equates to a conversion efficiency of 21.5% (3412/15,825) and the conversion efficiency of natural gas to electricity is 47%. These efficiencies are based on as-is heat content (lower heating value) and reflect real-world expectations in state-of-the-art combustion facilities.

As mentioned above, wood and bark of most common hardwood species contains 8,500 BTU per pound or 17 million BTU per dry ton. Using a heat rate of 15,825, approximately 1074 kilowatt-hours of electricity would be generated per dry ton. If we assume that wood is delivered to an energy facility for $70.00 per dry ton, the contribution of the fuel cost to the end product would be $0.065 per kilowatt-hour or $65.00 per megawatt-hour. Assuming a long-term contract price for natural gas of $4.00

per million BTU, the contribution of fuel to the final product is $0.029. Thus, wood could be over twice the cost per kilowatt-hour if the average wood price delivered to a facility were the equivalent of $70.00 per dry ton. Based on these calculations, the cost-competitive value of wood relative to natural gas is $31.13 per dry ton. This is an extremely low value and the following analysis will highlight estimated amounts and cost of wood fuels delivered to the Jo Carroll facility at Thomson, Illinois.

Study Area

The location of the proposed facility is Thomson, Illinois which is situated along the Mississippi River in northwestern Illinois (figure 2). The area of interest is a 125-mile radius around this location. The study area encompasses a total of 31,415,927 acres of land with 4,297,137 acres being forested; roughly 13% of the total land area in forested cover. Obviously the dominant land use in the study area is agricultural production. The far reaches of the study area include portions of the Chicago metro area while the majority of the study area falls in northwestern Illinois, eastern Iowa and southwestern Wisconsin. An insignificant portion of the study area is located in Minnesota with the farthest 125-mile band barely touching the extreme southeastern corner of Minnesota. As can be seen in Figure 2, most of the area is rural with a relatively small portion of land in urban land use. Also, it stands to reason that the bulk of forested acreage tends to be found in areas that are either too steep or too wet for agriculture. Some forested cover types follow major rivers which tend to both be steeply sloping or riparian areas subject to risk of frequent flooding. Land clearing was not done for agriculture on these sites and, as such, they have remained in forested cover.

In order to calculate trucking costs more accurately, we chose to divide the study area into five, 25-mile distance bands surrounding the Thomson location out to a total of 125 miles. Because forest resources vary significantly in each zone depending on the dominant land use, dividing the analysis into five zones provides a greater level of resolution to the study both in terms of describing the forest resource as well as estimating transportation cost. Trucking costs are an important part of the overall cost of delivering bulk commodities such as wood for energy. Sectioning the study area into the distance-bands allows us to estimate the total delivered costs of wood in greater detail.

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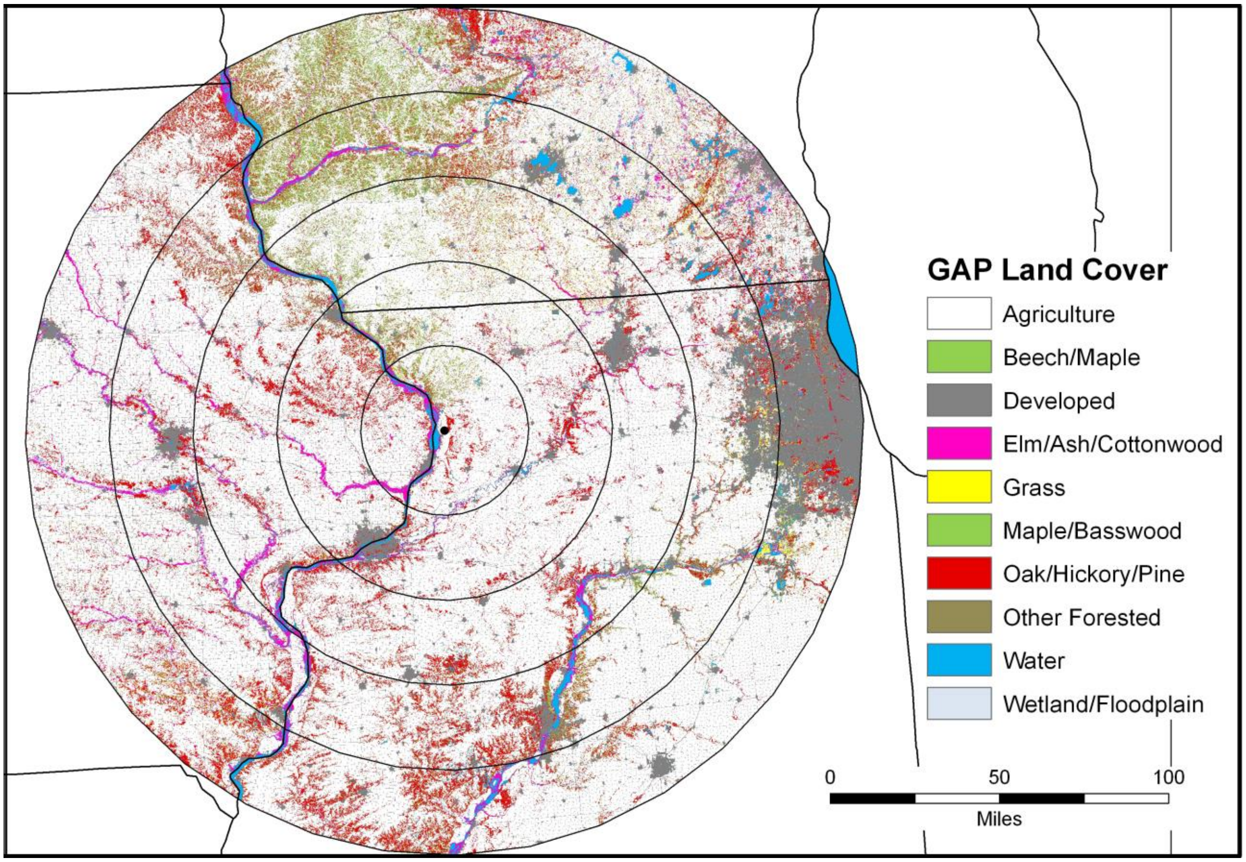

Figure 2. Forest resource analysis study area in 25-mile distance bands sorrounding Thomson, Illinois with dominant GAP land cover group.

FIA Inventory Program Description

The datasets used in this analysis are derived from the United States Department of Agriculture, Forest Service Forest Inventory and Analysis (FIA) program (Miles, 2012), a Congressionally-mandated program charged with monitoring the condition, growth and health of the nation's forestlands. The FIA program is the most extensive inventory of forest resources in the United States and methods of data collection are standardized across the entire country. The FIA program is a three-phase program which involves overlaying a grid of points across a state with aerial photography used to determine land cover, be it forest, agriculture, urban, water or other land uses. Once a point is determined to be forested, the second phase involves establishment of measurement plots on the ground where detailed data on stand attributes and individual trees are collected. This ground-plot information includes data on tree species, diameter, condition and volume as well as other characteristics important in the assessment of stand condition and health. The third step of the FIA program involves evaluation of forest health.

For this study, we have used the FIA Evalidator program to provide estimates of stand volumes by species, stand age class, ownership and stand volume separated into product classes (e.g. sawtimber, pulpwood, top-and-limbs). The FIA program data used to be collected periodically in concentrated years and no annual updates were provided until the next survey interval came about. However, this has changed to a system whereby a portion of plots in the dataset is collected annually with the target being a complete remeasurement every ten to fifteen years. The datasets used in this analysis include the following survey information:

Illinois: 2006; 2007; 2008; 2009; 2010
Iowa 2007; 2008; 2009; 2010; 2011
Wisconsin: 2007; 2008; 2009; 2010; 2011

We did not attempt to adjust age class information to 2012 and the data are centered around a starting point of 2008.

Markets and Product Class

As mentioned above, the economic value of an individual tree is directly related to species, diameter and tree condition (see table 1). Generally, markets can be described as sawtimber, pulp and biomass. In the FIA data, sawtimber is described as that portion of a tree that is greater than 11 inches in diameter for hardwoods (walnut, maple, oak, etc) and 9 inches for softwoods (pines). The value of these trees is markedly higher than other product classes due to their relative value in manufacturing of high-valued solid wood products and veneer for decorative purposes such as furniture and flooring. Pulpwood is commonly used for the production of paper, oriented-strandboard sheathing, medium density fiberboard and other products where the wood is typically reconstituted into a smaller form (e.g. fiber, flakes) before being used to produce the final product. While sawtimber is much more valuable than pulpwood, both product classes have a stipulation of minimum diameter for the material to facilitate removal of bark prior to manufacture of the final forest product. Finally, the least valuable product classification is that portion of the tree that is too small to be efficiently debarked and is usually restricted to small-diameter sections of the main tree bole (top biomass) and limbs. Due to the small size of this class of material, the use of this material is often restricted to animal bedding and production of energy. In this report, we refer to this material as top-and-limb biomass.

Markets in a given area have a direct effect on the management for production of high-valued hardwoods, the dominant economic driver of forest management in the region. As stated in the document "Illinois Statewide Forest Resource Assessments and Strategies" (Illinois Department of Forestry), the lack of markets for the lower-value, smaller-diameter components of the stands limits the production and regeneration of higher valued species and, with time, can greatly affect the composition of the forest. As cited in this document, one of the major concerns of the forest management community is the lack of regeneration of the oak stand type caused by selective harvesting of large-diameter trees with the remaining low-value, medium-diameter trees shading out any future regeneration of higher-valued species. If markets existed for the lower-valued products, this presents opportunities to remove the competing shade canopy and encourage regeneration of those high-valued species that require full sunlight in order to achieve adequate regeneration. Therefore, development of a market for small-diameter trees and less desirable species will have a positive effect on the management of forest for higher-valued uses. Development of a steady market for biomass for energy is generally viewed very positively by forest professionals in the region.

Information from the FIA databases were summarized based on acreage within each cover type classification, stand age and ownership within the five, 25-mile bands surrounding the study center. Also, stand biomass data by product type were summarized within these distance bands based on sawtimber, pulpwood and top- and limb-biomass. As is evident is Figure 3 below, the dominant cover types of the Oak/Hickory, Elm/Ash/Cottonwood and Maple/Beech/Birch groups account for the majority of the acreage in the study area. In total, these groups account for 92.5% of the total forested acreage with 67, 17 and 8 percent of the acreage in the Oak/Hickory, Elm/Ash/Cottonwood and Maple/Beech/Birch groups, respectively. Overall, private ownership accounts for 87% of the total forestland. All other species groups comprise the remaining 7.5% of the forested area. For this reason, we have chosen to focus most of the discussion of silviculture and implications on potential energy biomass supply on the largest covertypes.

Covertype or forest type group is critically important in this analysis as it indicates the dominant species and species types that are found in these stands, and as a result, the economic value of the stand. As shown in Table 1, the value of sawtimber is greatly influenced by species composition. In the most extreme case, Black Walnut sawtimber and veneer can command a price roughly three times greater than most of the other valuable hardwoods. In contrast, a relatively low valued species such as cottonwood may be one tenth the value of Black Walnut in sawlog form. As shown in Table 1, pulpwood values are extremely low with current pulpwood stumpage selling for roughly $5.00 per green ton or $10.00 per dry ton. These factors are important as the relative value of a stand has a direct effect on the decision of a landowner to sell timber from a particular stand and the level of effort that a landowner may exert in preparing the site to achieve proper regeneration. If partial harvests are done removing only the largest, most valuable trees, little sunlight is available to foster the growth of new seedlings. As a result, those trees that are of lower value continue to grow and eventually will comprise a greater proportion of the volume in the stand, thereby reducing the value of the stand through time. Factors affecting stand management will be discussed relative to the three major cover types in the following section.

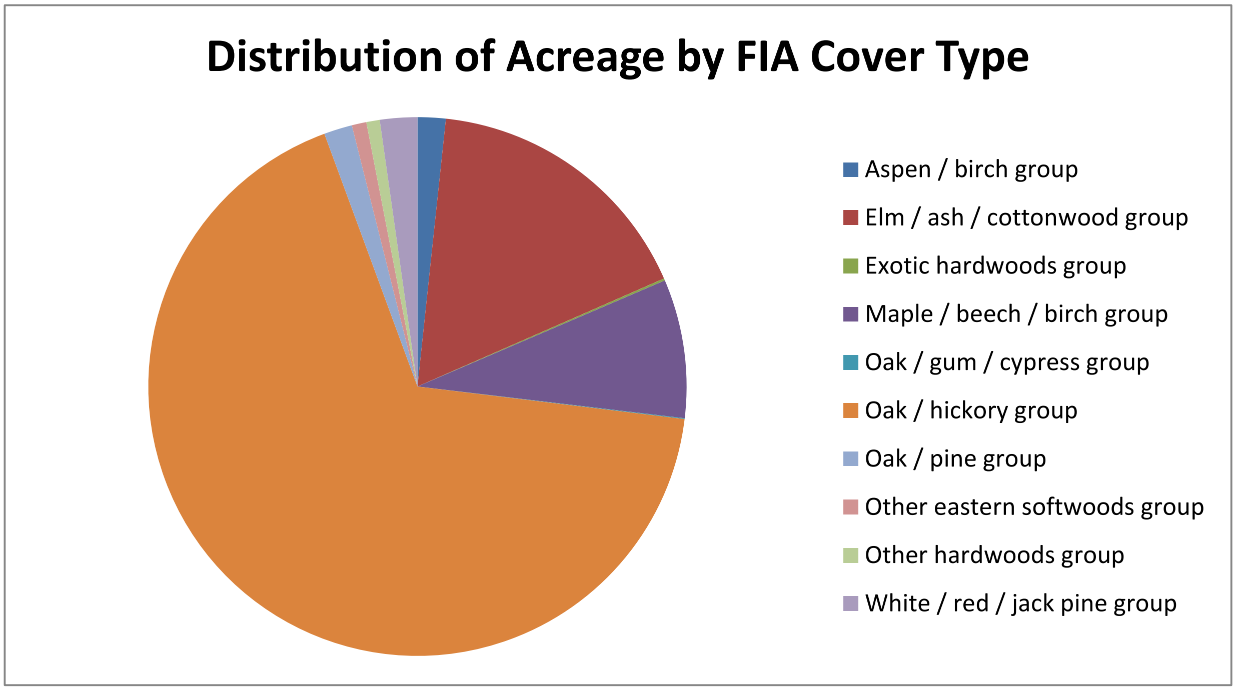

Figure 3. Forest Acreage by Major Cover Type with the Study Area

<u>Oak-Hickory Forests</u>

While the Oak-Hickory forest type is comprised of a significant portion of the major species, the variability and diversity of species in this forest type is immense. Figure 4 shows the species makeup of these forests showing the ten dominant species commonly found in these stands and all other species in the "other" category. As expected, oak and hickory species dominate within these stands. However, the "other" category accounts for approximately one quarter of the stand volume and is comprised of 53 species with a very small portion of the stand of any one species. This underscores the fact that a significant portion of these stands is comprised of species that are not in demand at the present time and could be considered for harvest in the event that an energy market were to develop for this lower-valued material.

Combining stand species composition with market data allows us to make an estimate of the current market value of these stands on a per-acre basis. Using current prices for sawtimber and pulpwood by species published by the Illinois Department of Forestry, Table 3 shows the current estimated value of stand components within the Oak-Hickory cover type. As shown, the total estimated stand value is $2,185 per acre including sawtimber of all species and pulp prices for small diameter and currently non-merchantable biomass. The relatively low value of small-diameter material from merchantable trees as well as whole trees of non-merchantable species accounts for only 13 percent of the total stand value.

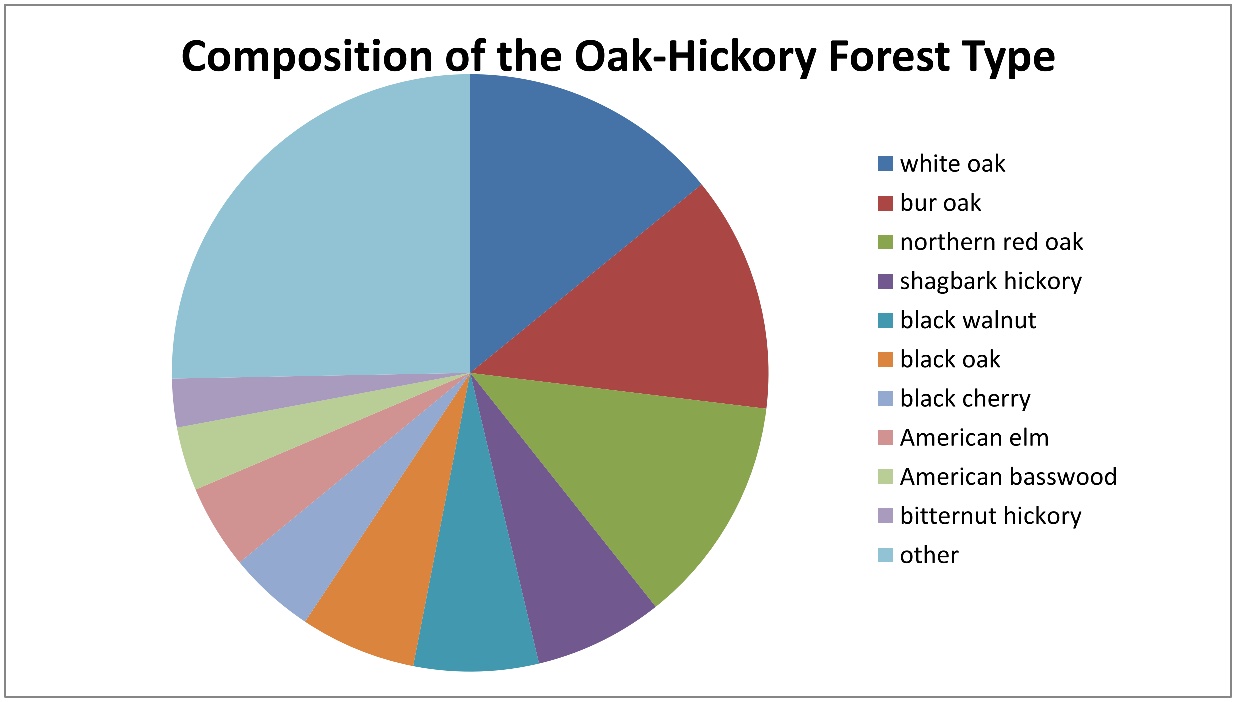

Figure 4. Species composition of the Oak-Hickory forest cover type within the study area based on volume.

Table 3. Value of components of a typical Oak-Hickory stand in the study area.

Species	*Sawtimber (bdft/acre)*	*Pulp (DryTons/ac)*	*Tops/Limb (DryTons/ac)*	*Value $/1000bdft*	*SawTimber Value/ac*	*Pulp/Tops/Limb Value/ac*
white oak	1395	2.3	1.1	$320.00	$446.29	$34.03
bur oak	1133	2.6	1.0	$80.00	$90.65	$35.81
northern red oak	1428	1.5	1.0	$227.00	$324.11	$24.57
shagbark hickory	504	1.3	0.6	$143.00	$72.05	$19.33
black walnut	710	1.2	0.6	$730.00	$518.41	$17.91
black oak	624	1.0	0.5	$173.00	$108.01	$15.48
black cherry	386	1.0	0.5	$263.00	$101.65	$14.88
American elm	216	1.2	0.5	$80.00	$17.30	$17.04
American basswood	560	0.6	0.3	$107.00	$59.93	$9.18
bitternut hickory	151	0.6	0.3	$143.00	$21.55	$8.55
Other	1853	5.5	2.4	$80.00	$148.25	$79.61
Total	8961	19	9		$1,908	$276

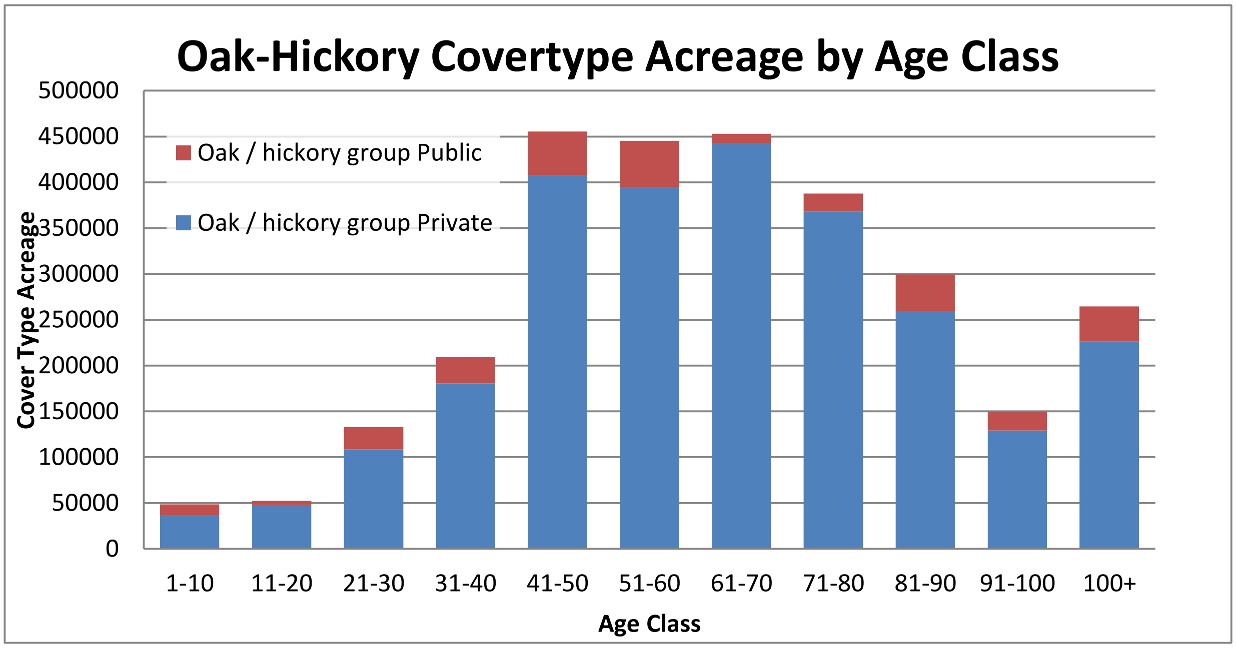

Figure 5. Age class distribution of the Oak-Hickory forest type.

Figure 5 shows the distribution of the Oak-Hickory type by age class. As can be seen, there is relatively little acreage regenerating into the younger age-classes. Young stands are usually only found in those areas that have been clearcut to allow regeneration. Most stands have scattered residual oak and hickory with timber conversion to walnut, elm, cherry, ash and other species being the goal of forest management following harvest. At the current time, most oak hickory stands are uneven aged with a rotation age ranging from 60 to 80 years. This is due to a history of selecting only the high-valued portion of the stand and lack of clearcutting to "reset the biological clock". For this reason, most stands are not growing up to their potential both in terms of total stand volume and quality.

Few if any of these stands are commercially thinned before the final harvest due to lack of markets and the potential to harm valuable "crop" trees due to bark scrapes and breaking of branches. If any timber stand improvement work is done, it is usually a non-commercial crop tree release with the undesirable trees girdled and left standing to eventually die. Due to the high value of these stands for sawtimber production, we did not assume that any mid-rotation thinning would be done to remove wood for energy. The risk of damaging the higher-valued component of these stands as well as the difficulty of removing material on sloping sites, a common condition in the area, caused us to preclude removal of biomass for energy in these stands until the final felling of the stand. In this way, the high-quality, high-value component of the stand can be removed prior to felling of the remaining low-valued tree species. Also, the cost of removing trees through thinning of high-quality hardwood stands is deemed to be too high to be financially feasible for delivery to an energy market.

Management Opportunities

At this time, harvests remove 2,000-4,000 bdft per acre with a selective sale in unevenaged stands and 9,000-12,000 bdft per acre in those cases when the stands are clear cut. There is great opportunity to increase stand quality and production through more widespread implementation of sound forest practices on these sites. According to forestry consultants familiar with these stands, active management with the aid of forestry professionals has the potential to reduce the rotation age to final harvest to 50 years on good sites. The following management protocol could be considered if stands were clearcut to allow regeneration of young trees of more desireable species.

Age 1: Planting of Black Walnut to increase species mix to high-valued species
Age 15 First Thinning remove 150-300 trees per acre 4-8 inches (girdled)
Age 25 Second Thinning remove 150 trees per acre 8-12 inches (girdled)
Age 35 First Commercial Thinning 100 tree per acres 12-16 inch (actual harvest)
Age 50 Final Harvest 60-80 trees per acre (harvest)

Using the above management protocol, the estimated costs and revenue associated with management through time are as follows:

Table 4. Management costs and potential revenues associated with actively-manageed productive Oak-Hickory stands in the study area (based on cost input from Kevin Oetkin, consultant).

	Year 1	Year 2	Year 15 non commercial	Year 30	Year 50
Site Prep Weed/Coppice	-200				
Savings from Pulpwood sale	100				
Tree Planting		-500			
girdling			-120		
1st Commercial harvest				200	
Final - Walnut Sawtimber					24000
Final – Sawtimber all other species					2000
Final Cut - pulp/fuelwood					160
Net/Acre	-100	-500	-120	200	26000

With active management by a forestry professional, the volume of walnut sawtimber is expected to be 12,000 board feet per acre at harvest on productive sites. Using an average value of $2.00 per board foot for veneer and sawtimber, the total revenue realized at harvest is $24,000 per acre for walnut alone. Using the above values in a cash-flow analysis and assuming a three percent discount rate (value of future costs and revenues discounted to year one at 3%), the net present value (NPV) per acre of these stands is estimated to be $5,583, considerably higher than the typical current stand having low value and a relatively small percentage of walnut. If one assumes that 8,000 board feet of walnut will be produced on moderately-productive sites, the NPV is reduced to

$3,704 per acre. While there is no guarantee that wood markets will be the same fifty years from now, forest management decisions are made based on the best estimate of future value as well as a view toward the future as an investment in the land for future generations. From, a strictly economic viewpoint, it appears to make sense to actively manage these stands with total removal of competing overstory playing an important role in management. Based on cash flow analysis, the integration of biomass harvest for energy into current management not only addresses concerns cited above about losing the acreage of this type but also appears to be a prudent, albeit, long-term economic decision.

<u>Elm, Cottonwood, Silver Maple</u>

The Elm-Ash-Cottonwood forest type occupies a total of 719,580 acres in the 125-mile radius study area or 16% of the forested area. This timber type is most commonly located in river bottoms and flood plains due to the ability of these species to tolerate periodic flooding. These sites contain excellent soils and have the potential to grow very large volumes of timber. Most of the cottonwood and maple are harvested for lumber and some of the younger maple is harvested for firewood. Few markets for chip or pulp exist at this time. Most of these stands are even-aged with a 50 year rotation age. With proper management, the rotation age could be reduced to 40 years on well managed stands. A selective harvest may generate 4,000-8,000 bdft per acre and a clear cut will typically generate 14,000-20,000 bdft per acre. Due to the amount of volume on these sites, a considerable amount of biomass for energy could be generated in tops, and non-commercial trees.

If managed for optimal wood production these stands could be managed as follows:

10-15 years	First Thinning remove 150-300 trees per acre
25	Second thinning remove 150-300 tree per acre
40	Final Harvest 80-120 trees per acre

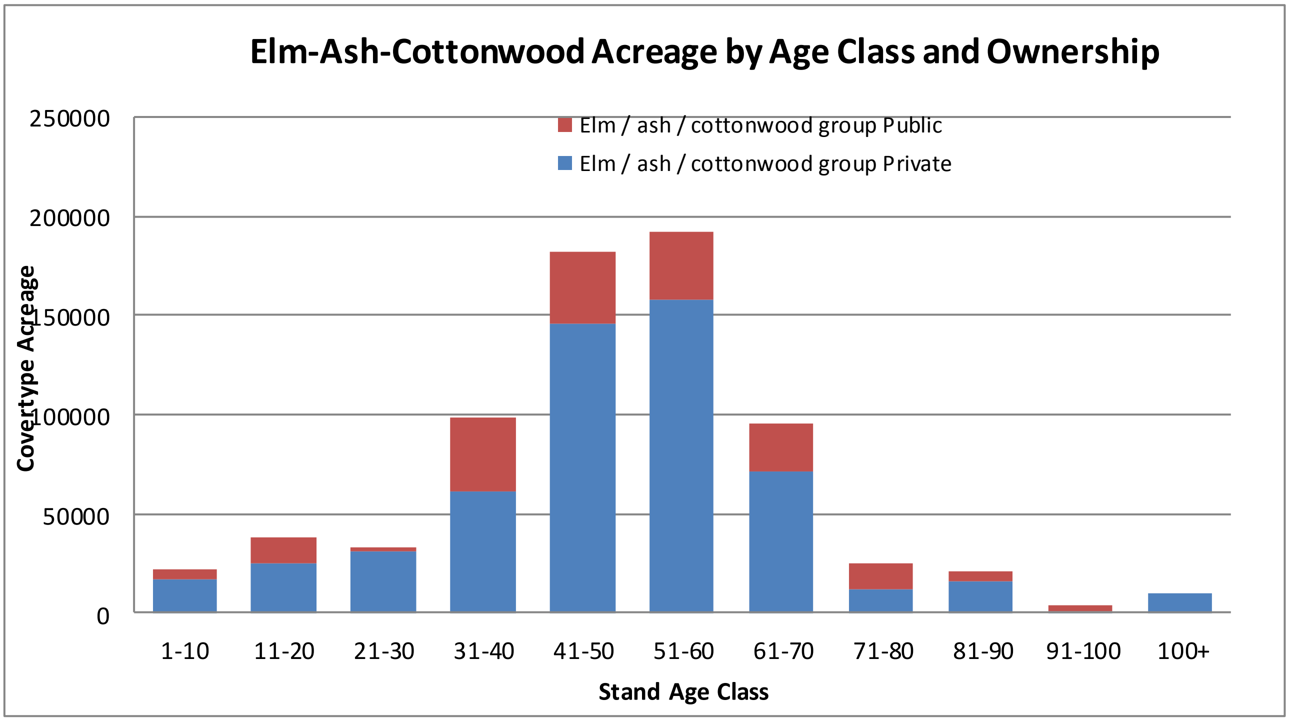

Figure 6. Age distribution of Elm-Ash-Cottonwood forest type within 125 miles of Thomson, Illinois (FIA, 2012).

Additional Biomass Sources

In addition to the major forest types described above, we included a small amount of biomass from the pine and aspen types. We assumed a forty year rotation on the aspen forest type and a clearcut harvesting system. A sixty year rotation final rotation was assumed in Red Pine stands with periodic thinning done at ten-year intervals with one-third of the stand removed in each thinning. Where markets allow, this thinning regimen is a standard practice and is done to increase the average diameter, and hence, the value of the stand over time. The total amount of biomass ultimately derived from these cover types for energy biomass is negligible but it was included in our estimates of the total potentially available resource.

<u>Analysis of Energy Biomass by Distance Band</u>

The facility under consideration is assumed to be 25 megawatt generation facility. We used the following assumptions to estimate tonnages to supply the needed biomass for this facility:

350 operational days per year
24 hours/day, 7 day/week during operational time
15, 825 btu/kwh heat rate (btu of raw fuel to produce one kwh)
17 MM BTU per dry ton of wood

Using the heat-rate estimates provided by Jo Carroll staff and the assumed operational days per year, the estimated total biomass required to be delivered annually to the facility is 195,485 dry tons per year. The analysis that follows is based on procurement of this amount of biomass within the five, 25-mile distance bands discussed previously. For sake of simplicity, we rounded this value upward to 200,000 dry tons per year.

Figure 6 below shows the acreage of the three dominant forest types with distance away from Thomson, Illinois. As can be seen in the figure below, the shape of the curves with distance from the proposed site becomes significantly steeper at the 75-mile distance band and, as noted previously, the oak-hickory forest type is by far the dominant forest cover type.

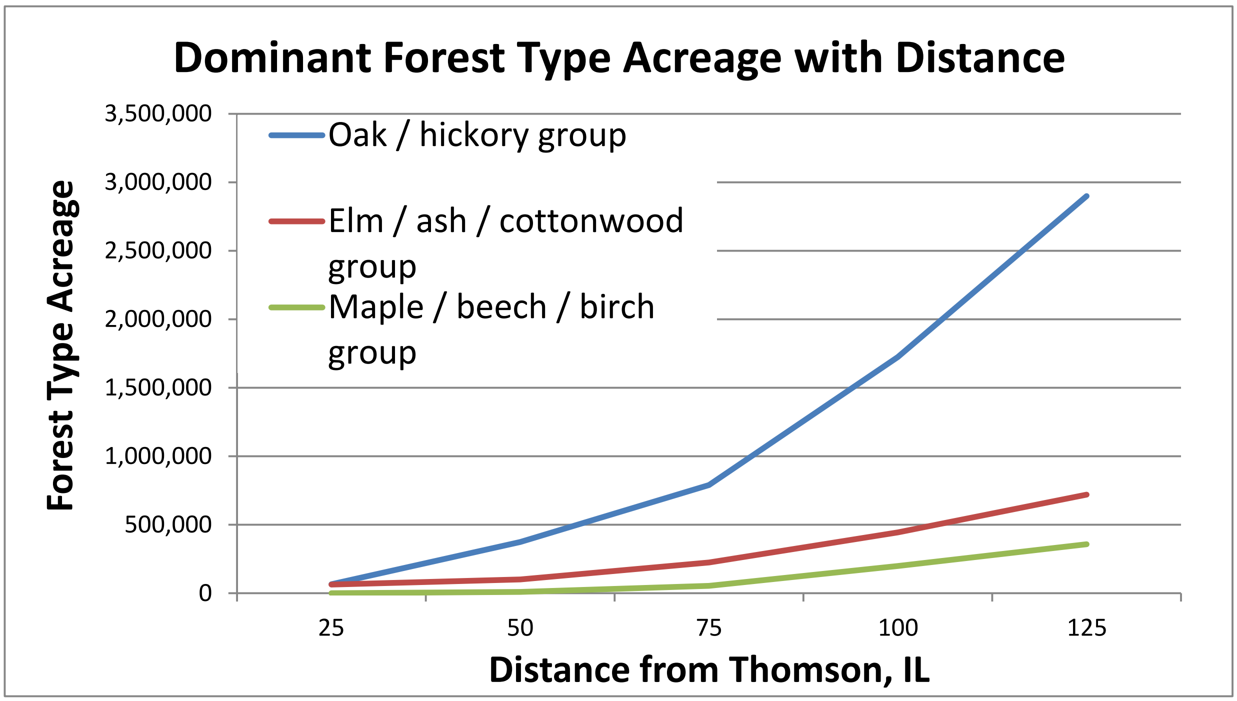

Figure 7. Acreage of the major forest types with distance from the potential facility site.

We derived datasets from the FIA inventory system by product classification to separate sawtimber, pulpwood and top-and-limb biomass. We also assumed that all sawtimber biomass was not eligible to be used as energy feedstock due to the high price commanded for sawtimber of most of the species in the area. We prepared summaries of the biomass data for each of the three major forest types by product class (pulpwood and top-and-limb biomass) and distance band to allow a greater degree of resolution in estimating transportation distance and harvest costs. Although much less in terms of total biomass, we also included the aspen-birch and pine forest types in the analysis. Appendix A shows the complete dataset used in this analysis.

Methods to produce transportation and harvest cost estimates are described in the following sections. Also, because we did not assume that any intermediate thinning was done in these stands, the stands that are considered eligible for harvest are limited to a minimum age of 60 years in the larger forest cover types. This screen on the data ensures that stands have reached maturity for the production of sawlog volume. We summarized data for a thirty year period using three separate decades. Thus, the first decade analysis includes all stands exceeding sixty years of age, the second decade adds in those stands that were in the 51 to 60 years of age in the next time period plus the remaining unused stand volumes from the previous period (rollover). Similarly, the third period included all wood currently 41 years of age adding twenty years plus the amount left unused in each distance band.

Before conducting the final analysis of wood availability, we wanted to evaluate the data that came from the FIA inventory to ensure that the values conform to experience with these forest types. The average total biomass per acre for all products, including sawtimber, is relatively similar with 55.5, 57.3 and 53.3 dry tons per acre for the oak-hickory, elm-cottonwood and maple-beech-basswood forest types respectively. These values are expected, particularly in light of the relatively high wood density of many of the species contained in these stand types. For example, the specific gravity of oak and hickory ranges from 0.65 to 0.77 which translates to a density of 40.5 and 48 dry pounds per cubic foot. Assuming a modest stand density of 100 square feet of basal area and an average height of 70 feet produces an estimated total cubic foot volume of 2,859 cubic feet per acre or roughly 60 total tons in the main bole only. Accounting for top-and-limb biomass would add a minimum of 20% additional biomass bringing the estimated total biomass on the site to 72 dry tons per acre. Based on this simple example, it isn't difficult to envision that a stand comprised of denser hardwoods would have an average biomass equal to and greater than 50 dry tons per acre. Even in the case of a low-density species such as cottonwood (specific gravity = 0.35), the estimated total tonnage for a stand of similar volume is estimated to be 55 tons. Therefore, although these stands appear to be relatively high in average biomass, the fact that stands are relatively long-lived and our dataset was limited to a minimum stand age of sixty years of age contributes to stands having relatively high total biomass on an area basis. Of this total amount, the average percentage of sawtimber in these stands is 50, 43 and 47 for the oak-hickory, elm-cottonwood and maple-beech-basswood forest types, respectively. The average biomass of low-valued components (pulp and top-and-limb) is 27, 32 and 28 dry tons per acre for the oak-hickory, elm-cottonwood and maple-beech-basswood forest types, respectively.

In an attempt to bring some level of realism to the analysis, we inserted factors to limit the availability of timber on private lands in each time period. Based on discussions with forest consultants and land managers familiar with the area, we limited availability to 25% on private land with 100% of the acreage available if managed by a public agency, typically a state forestry agency. While the specific percentage reduction assumed on private land is somewhat subjective, we didn't feel it is realistic to assume that all stands were available simply because there is a new market for the lower valued portions of stands. This analysis could be done using any factor to reflect the landowner's willingness to sell but a factor of 25% was considered to be realistic in light of the fact that the additional value provided to the landowner for the energy biomass is relatively low compared to the total potential value of the stand. Using the sawtimber and energy biomass discussed above and an average value of $10.00 per dry ton for energy biomass stumpage, we estimate that the additional return to the landowner will be approximately $276 per acre versus $1908 for sawtimber. Thus, the market for energy will likely not drive to decision to harvest a stand and consideration must be made to account for a landowner's willingness to sell timber at any given time period.

In order to test our assumption of reduced availability in a more rigorous way, we used the timber removals dataset available in the FIA system to construct a database of timber removals with distance. These modified data are shown below in Figure 7. Harvests intensity was expressed as tonnage per unit land area in each distance band to account for increasing area contained in each distance-band. After reviewing these data, we noted an unusually high harvest level in the 25-mile distance band, roughly fifteen times the average harvest intensity in the other four distance bands. The majority of this harvest occurred in the elm-cottonwood type which we assume is related to disease infestations in elm and is likely not a long-term harvest level. In order to compensate for this, we "normalized" the harvest level in the 25-mile band to conform to the average harvest intensity calculated from data in the other distance bands. In this way, we have an estimate of expected harvest intensity with distance. As can be seen, in order to achieve the harvest level of 200,000 dry tons per year, the distance traveled is estimated to be 62 miles. For sake of clarity, the two lines in the following graph show both the incremental biomass added with each distance band as well as the total cumulative biomass available to the facility with increasing distance.

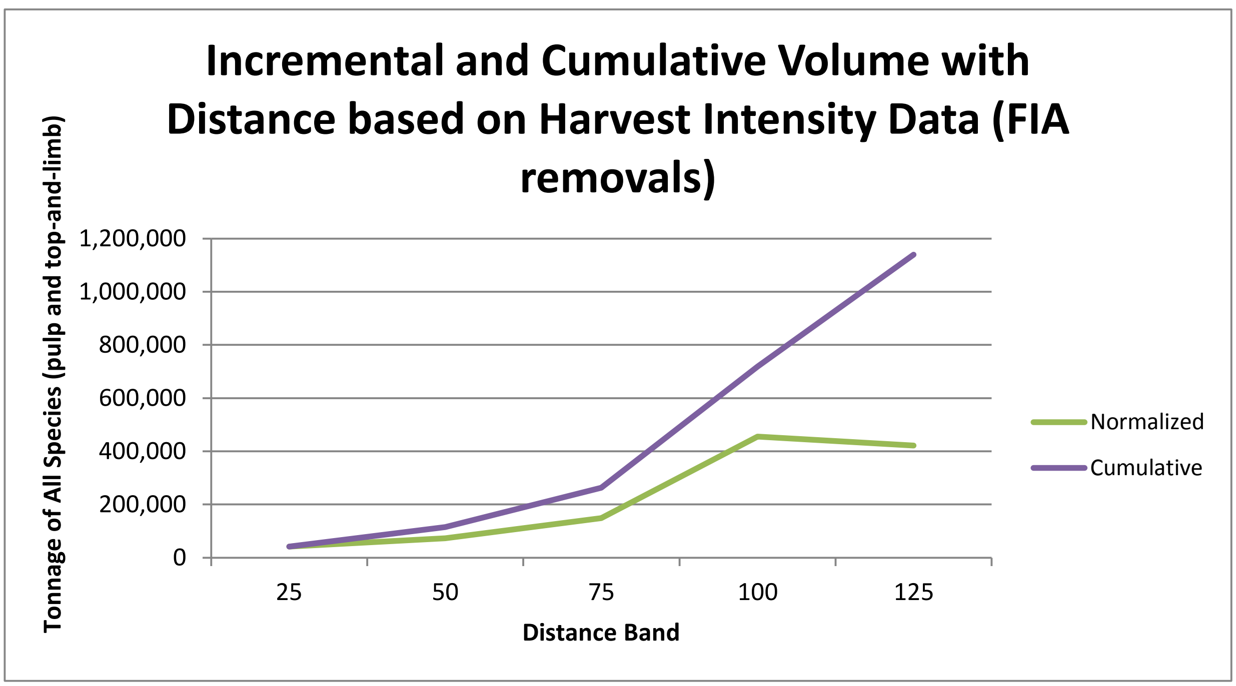

Figure 8. Pulp and top-and-limb biomass harvested using normalized estimate for 25-mile distance band expressed as incremental and cumulative biomass.

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Using the database of pulp and top-and-limb biomass with distance and the availability-reduction factors discussed above, we determined the minimum travel distance required to procure the total of 200,000 dry tons annually or, in our analysis, 2,000,000 tons of biomass over a ten year period. As can be seen in Table 5, the first ten-year period requires a transportation distance of slightly greater than fifty miles. The total cumulative biomass at the 50-mile mark for the first time period is 1,830,892 dry tons at fifty miles. Thus, to obtain the remaining 169,108 tons of biomass would require a small fraction; 8 %, of the additional incremental biomass found in the 51-to-75 mile distance band. In order to procure 8% additional resources, the maximum travel distance is 52 miles in Period 1 (first decade). In time period 2, the distance required to obtain the same harvested biomass increased to 57 miles and, in period 3, 59 miles. We use these estimated distances to construct a table of the total tonnages harvested by distance band for each time period with associated transportation costs. Transportation costs as well as all cost components are summarized further in this report.

It is worthwhile to note that our assumption of a 25% availability factor conforms very closely to the values shown above in the analysis of harvest intensity. Based on our modified harvest removals data, we estimated that the travel distance would be approximately 65 miles which conforms closely to our analysis using the assumption of a 25% reduction in availability on private lands. Therefore, we have a higher degree of confidence that using the reduction factors on private land is appropriate and our estimated procurement distances are supported by historical harvest data in the area.

Table 5. Pulp and top-and-limb biomass with distance assuming a 25% availability factor for private land and 100% for public forestlands.

		Time period 1			Time period 2				Time period 3			
Distance	Acres	Biomass (dry tons/acre)			Acres	Biomass (dry tons/acre)			Acres	Biomass (dry tons/acre)		
		Pulp	Tops/Limbs	Cumulative		Pulp	Tops/Limbs	Cumulative		Pulp	Tops/Limbs	Total
25	28,180	355,346	205,098	560,443	17,905	365,349	180,459	545,807	14,483	281,293	139,534	420,827
50	44,525	855,035	415,414	1,830,892	20,789	393,862	195,799	1,135,468	16,176	311,389	154,410	886,626
75	75,322	1,393,245	692,893	3,917,030	31,191	599,091	294,500	2,029,059	30,147	577,510	287,423	1,751,559
100	217,709	4,801,544	2,061,928	10,780,502	80,679	1,607,263	781,874	4,418,196	86,532	1,675,874	833,073	4,260,506
125	271,795	4,823,999	2,662,468	18,266,968	96,034	1,941,753	953,774	7,313,723	86,624	1,717,279	849,317	6,827,102
Total	637,530	12,229,168	6,037,800	18,266,968	246,597	4,907,317	2,406,406	7,313,723	233,961	4,563,345	2,263,757	6,827,102

Harvesting Costs

Harvest costs are obviously a significant component of the final product price. As mentioned above, we chose to limit harvests only to clearcuts of pulp and top-and-limb biomass associated with the final harvest of timber for sawlogs. A recent report entitled "True Costs of Harvesting Woody Biomass in the Driftless Area of the Upper Midwest Final Report" conducted by the Southwest Badger RC&D report is used as a basis for estimating harvesting costs. This project developed harvest cost data for various stand types and silivicultural treatments using actual cost data conducted on stands in the area.

Table 6 below shows a summary of these costs and stand parameters on which harvest costs are based. Using data from this report, the average harvest cost value for clearcut stands is $38.29. Based on our conversations with loggers in Minnesota on large stands, harvest costs of wood delivered to a landing range from $25.00 to $30.00 per dry ton. Undoubtedly, the relatively small acreage of stands in the area contributes to higher harvest costs. Based on a composite of harvesting cost data and an assumption that costs will likely be reduced with larger operations servicing a consistent large market such as an energy facility, we chose to use an average harvest cost for pulpwood of $32.00 per dry ton.

The cost of collecting top-and-limb biomass is assumed to be zero to the landing as this material is assumed to be skidded to the landing in whole-tree form and the cost of harvesting the tree is assigned to the pulpwood harvest. Based on our analysis of product type distribution in stands in the area, the ratio of pulpwood to top-and-limb biomass is estimated to be 66% pulpwood versus 34% top-and-limb by weight (18.3 and 9.3 dry tons per acre for pulp and top-and-limbs, respectively). Using this ratio, we estimate that the average blended cost for all forms of energy biomass delivered to the landing is $22. However, we further assume that all material must be chipped for transport to the energy facility. Therefore, chipping costs must be added to the harvest cost to estimate the total harvesting costs.

Table 6. Harvest cost data from the "True Costs" report (Southwest Badger RC&D, 2010)

						Harvest Cost		
	Harvest Type	Acres	Total Cords	Cords/Acre	Harvested Tons	$/cord	$/green ton	$/dry ton
1	Bottomland Clearcut	10	94	9.4	215	$35.40	$15.48	$30.96
2	Black Locust Clearcut	17	274.2	16.1	727	$27.98	$10.55	$21.10
3	Black Locust Clearcut	8	135	16.9	358	$43.18	$16.28	$32.56
4	Shelterwood	19.2	190	9.9	410	$34.50	$15.98	$31.96
5	Hardwood Thinning	22	214	9.7	535	$58.74	$23.50	$47.00
6	Aspen/Hdwd Clearcut	8.2	109.8	13.4	285	$35.05	$13.50	$27.00
7	Hardwood Clearcut	30	430	14.3	1075	$62.56	$25.02	$50.04
8	Hardwood Thinning	19.6	267	13.6	688	$60.71	$24.27	$48.54
9	Oak Clearcut	24	602	25.1	1489	$40.67	$16.44	$32.88
10	Birch/Aspen Clearcut	23	190	8.3	440	$84.74	$36.59	$73.18
11	Oak Clearcut	27	696	25.8	1740	$48.21	$19.29	$38.58
12	Pine Thinning	13	367	28.2	801	$18.39	$8.42	$16.84
13	Pine Thinning	17	220	12.9	479	$25.89	$11.89	$23.78
14	Pine Thinning	20.4	171.3	8.4	385	$20.87	$9.27	$18.54
15	Pine Thinning	18	244.6	13.6	532	$33.25	$15.29	$30.58
16	Bottomland Thinning	20	154.6	7.7	386	$71.18	$28.50	$57.00
	Average – All Stands	18.5	272.5	14.6	659.1	$49.04	$20.05	$40.09
	Average - Clearcut	18.4	316.4	16.2	791.1	$47.22	$19.14	$38.29

Chipping Cost Estimation

We contacted manufacturers of large forestry chipping equipment in order to assess the costs of purchase, ownership and operation of chippers capable of handling the larger-diameter trees that are expected to be encountered in stands in the area. We separated variable costs (cost incurred in active chipping operation) from fixed costs to allow a more accurate estimation of chipping costs. Fixed costs are those associated with financing and ownership and are independent from the amount of material processed. Generally, the hourly capacity of chippers is much greater than the capacity of the overall harvesting operation to deliver material to the landing. As a result, chippers typically sit idle in this type of application waiting for material to amass for chipping. We assumed that a chipper would be integrated into a harvesting operation (feller/buncher, skidders) in a "hot" handling system whereby chips are produced immediately or shortly after material is brought to the landing. We did not consider the possibility of a separate chipping contractor chipping energy biomass after the sawlog harvesting operation has left the site. Due to the fact that stands are clearcut, stockpiling of material for a separate operator was deemed to be infeasible due to constraints on acreage and landing size in these operations. Most of these stands are assumed to be located near active agricultural acreage and stockpiling of energy biomass is not possible on a year-around basis.

Based on this information, a table of all assumptions (Appendix D) was constructed to estimate both fixed and variable costs associated with in-woods chipping. As shown in this table, we estimated the capacity of the harvesting system and the annual number of stands that could be harvested annually. Because the assumed average stand size is seven acres, the harvesting system must be moved weekly. The number of stands that could be harvested annually is estimated to be 65 stands which is the basis for the calculation of total tonnage of energy biomass that can be produced and calculation of variable costs. The ratio of fixed to variable cost is roughly 1.4 indicating a relatively high cost of ownership relative to operation. Forestry-grade chippers and most heavy equipment are designed for an average life of a minimum of 10,000 hours. As can be seen in Appendix D, the estimated annual hours of active chipping is only 417, a fraction of the potential of the machine. Therefore, it could be argued that the fixed costs could be spread over a longer time horizon as the life of the machine will be much longer when used in this specific situation. Therefore, we estimated the effect of a 50% reduction in fixed costs on a per-ton basis. Assuming a 50% reduction in fixed costs results in a reduction in chipping cost from $10.25 per dry ton to $7.22 per dry ton; a slight reduction. Based on this analysis, we used an estimated chipping cost of $9.00 per dry ton.

Combining the harvesting cost of $22.00 per dry ton cited above and the chipping cost of 9.00 per dry ton results in an estimated cost of $31.00 per dry ton. This is used as the basis for the estimates of the total delivered cost.

Trucking Cost

In addition to stumpage, harvesting and processing costs, trucking cost is a significant component of the delivered price of biomass. Trucking cost is obviously dependent on distance from the logging site to the mill. The most common form of delivery for harvest residues is in 25 ton-capacity chip vans. Based on information developed through contacts with area loggers, we developed a simple non-linear distance-dependent cost function to estimate trucking costs. Trucking cost can then be applied to the total tonnage of harvest residues available at any particular distance to calculate a delivered cost for biomass to a mill location. As shown in Figure 10, the trucking cost is not linear with distance with higher prices per one-way mile assumed closer to the mill. This was done to capture the fact that short hauls involve a greater proportion of time in unloading and delivery than longer hauls in which the truck is travelling at highway speed for a greater proportion of the trip. Based on conversations with logging contractors, the additional time needed for loading and unloading on short hauls requires that fixed costs such as driver salaries and capital expenses be distributed over fewer miles resulting in higher per-mile charges for short hauls.

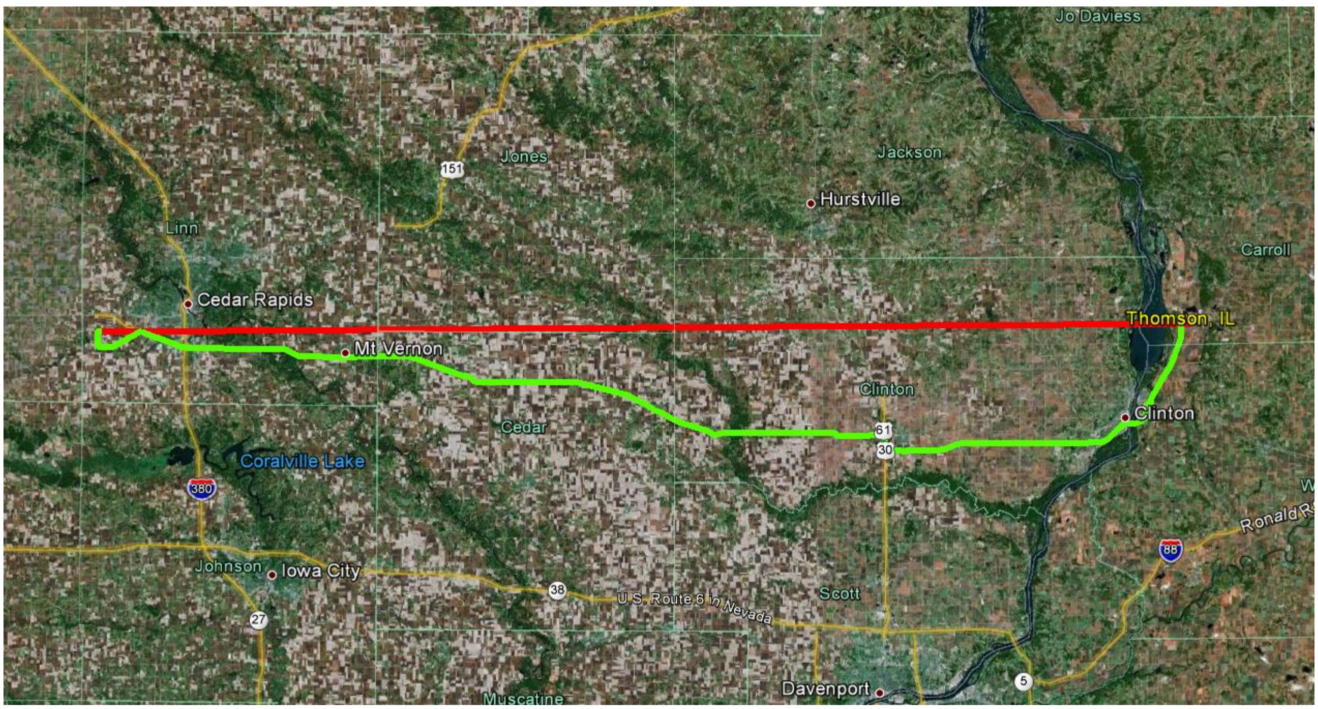

Figure 9. Example of straight-line distance to actual road network used to develop adjustment factors for transportation.

Trucking costs cannot be calculated on a straight-line distance due to the fact that there is additional distance involved in moving freight on the actual road system. This “tortuosity” effect will vary by direction and distance. Longer hauls will tend to have less of an effect of adjustment for the road system due to the fact that a greater proportion of the trip will likely be on major highways. In contrast, shorter hauls as calculated by straight-line distance may vary in the actual miles travelled depending on the specific location of the sale. We used Google Earth and the imbedded road network to estimate the ratio of a set of randomly selected points surrounding the proposed site in 16 sections (22.5 degrees) at the five distance-bands to estimate the adjustment factors to more accurately estimate transportation distance. An example of this analysis is shown in Figure 9 below. The results for each distance band are shown in Table 7.

Table 7. Adjustment factors to straight-line distance by distance band to account for tortuosity of the road network.

Mileage Band	*Direct Miles*	*Road Miles*	*% difference*
25	17.7	24.2	137%
50	35.4	50.1	142%
75	53.0	72.0	136%
100	70.7	92.8	131%
125	88.4	120.4	136%

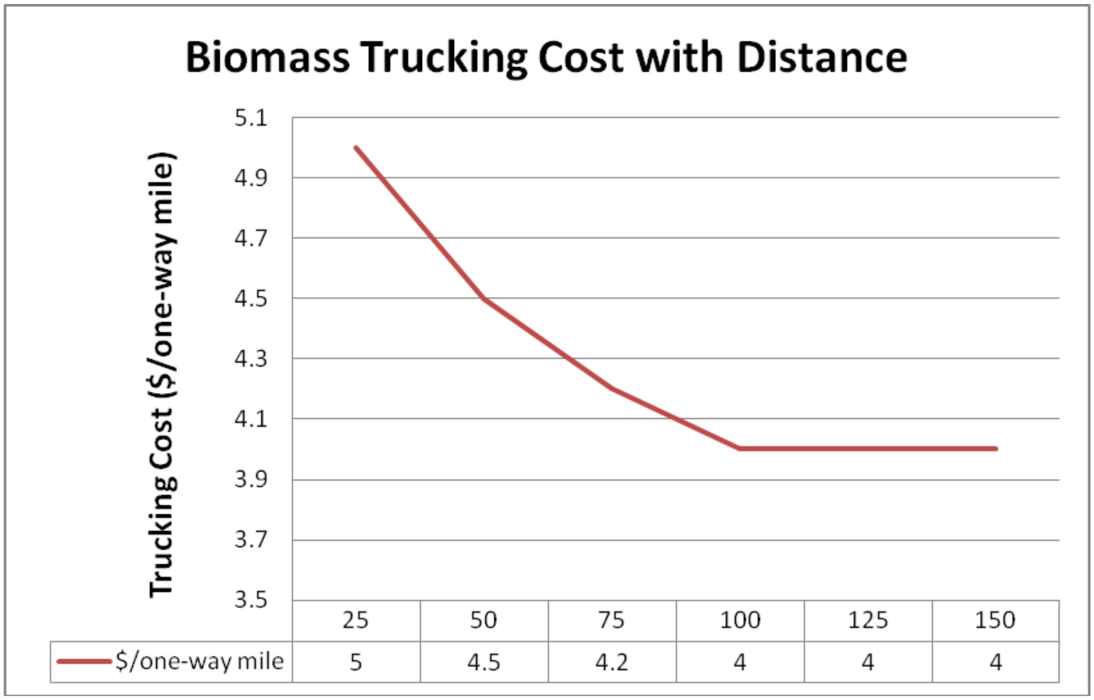

Figure 10. Trucking cost function used in estimation of trucking costs.

<u>Estimation of Delivered Costs</u>

Once the various factors of forest location, land management policies, equipment costs and trucking costs are accounted for, estimates of total volume and price can be made. Based on information cited above, the stumpage price for energy biomass is assumed to be $5.00 per green ton or $10.00 per dry ton. Combining all of the components of stumpage, harvest, processing and trucking costs produces a total estimated delivered cost to the mill. Table 8 below shows the combined costs for each component and the resulting total annual cost for the purchase of biomass to the energy facility and the estimated cost of delivered biomass expressed on a per-ton basis. Transportation costs were derived by using the assumptions of constraints on land availability (land availability reduced depending on ownership) and the trucking adjustment factors for straight-line distance described above.

Table 8. Combined costs of stumpage, transportation, harvest and chipping including total annual cost for biomass purchase and per-ton delivered price.

		Per-Ton Haul Costs			Total Haul Costs		
Mileage Band	Road Adjustment Factor	Period 1	Period 2	Period 3	Period 1	Period 2	Period 3
25	137%	$4.84	$4.84	$4.84	$271,461	$264,372	$203,835
50	142%	$10.04	$10.04	$10.04	$1,275,647	$592,073	$467,705
75	136%	$14.14	$14.69	$14.96	$239,186	$1,269,825	$1,665,607
Total Cost					$1,786,294	$2,126,270	$2,337,147
Stumpage ($10/dry ton)					$2,000,000	$2,000,000	$2,000,000
Harvest ($22 /dry ton)					$4,400,000	$4,400,000	$4,400,000
Chipping ($9 /dry ton)					$1,800,000	$1,800,000	$1,800,000
Total Costs					**$9,986,294**	**$10,326,270**	**$10,537,147**
Average Cost ($/per dry ton delivered) - 200,000 dry tons/yr					**$49.93**	**$51.63**	**$52.69**

Conclusions – Forest Resource Availability and Cost

This analysis indicates that the total delivered cost of biomass to the Thomson site is estimated to be roughly $50.00 per dry ton. The bulk of these costs are comprised of harvesting and chipping which is commonly the case in many forestry operations. Also, it should be noted that there are additional costs associated with procuring wood and disposing of ash generated through the combustion of wood. While expected to be minimal, personnel costs and logistics of arranging for sites for harvest and ash disposal may add $5.00 to $10.00 per dry ton. A full-time procurement manager would likely be necessary to deal with these issues. At a total cost of $100,000 per year (salary, fringe benefit, other charges), an additional cost of $5.00 to $10.00 per ton for these operations appears to be reasonable.

As mentioned in the section discussing energy value and comparisons to natural gas, the natural gas-equivalent value of wood is $31.13 per dry ton using a heat-rate of 15,825. Based on this analysis, the delivered cost of wood is estimated to be roughly 60% higher than the equivalent cost of natural gas. While it may be possible to alter this heat-rate through air-drying of a portion of the stand that is roundwood (pulp component), this comes at a cost of inventory management and additional handling. At this time, in an environment of relatively inexpensive natural gas, it does not appear to be feasible to use biomass derived from area forests to produce electricity cost-competitively with natural gas.

Energy Crops

At the request of Jo Carroll and the Blackhawk RC&D staff, we have included a brief discussion of energy crops. A potential supplementary source of biomass for energy is crops grown specifically for biomass often referred to as "dedicated energy crops". These crops are typically perennial crops that are planted once and support continual harvest for an extended period, often ten years, without replanting. Energy crops under study by the Department of Energy include a wide variety of species including woody and herbaceous species. These include woody crops such as poplars and willows and herbaceous crops such as switchgrass, Miscanthus, energy cane and sweet sorghum. Analyses of national biomass resources such as the "Billion Ton Study" (Perlack, et.al. 2005) and the Billion Ton Update study (USDOE, 2011) indicate that agricultural residues (e.g. corn stover, wheat straw, other plant parts), forest harvest residues and thinnings, and energy crops are expected to be the dominant sources of available cellulosic feedstock. Of the total 1.4 billion tons identified in the original 2005 Billion Ton Study, approximately one fourth (377 million dry tons) was estimated to be produced annually through planting of energy crops on agricultural lands. However, the updated Billion Ton Report puts even greater reliance on dedicated energy crops.

Due to the more northerly location of the project, we have included a description of two potential energy crops, poplar and switchgrass. The following section briefly describes the characteristics of these crops with a focus on the economics of growing these crops for biomass.

Hybrid Poplar

The University of Minnesota, NRRI has been conducting research on tree crops since the early 1980s and manages one of the largest poplar breeding and field-testing programs in the United States. Also, work is underway by a number of groups to evaluate yield and management inputs of grass crops and mixed prairie species (Casler and Boe, 2003). Based on work done by the University of Minnesota, Duluth-NRRI, Iowa State University (Dr. Rick Hall) and the US Forest Service, yields of poplar plantations on sites in the region are expected to range from 4.0 to 5.0 ovendry tons per acre annually. While the potential exists, development of this resource will require a significant investment. Work is needed to identify optimum sites and genetics as well as inputs needed and yields on a range of site throughout the region.

Based on our research and commercial experience to date, the average yield that can be expected in new plantations on land of average agricultural productivity in the region ranges from 4.0 tons acre^{-1} year^{-1} to 5.0 tons acre^{-1} year^{-1}. The yield value of 4.0 dry tons acre^{-1} year^{-1} is used as the starting point for economic analysis in the following section.

Poplar Production Economics and Agricultural Crop Profit

While yield is a critical part of biomass production, it is helpful to combine yield and production costs to provide a more complete picture of the economic feasibility of producing biomass energy through dedicated energy crops such as poplar. Through the cooperation of Verso Paper staff managing a large-scale industrial program in Minnesota, we have developed a cash-flow model that contains management inputs necessary to achieve optimal production on agricultural soils typical of those in Minnesota. Input on the management practice, frequency of application and other information such as herbicide rate applied were verified through discussion with Verso Paper staff. In order to provide some degree of "arms-length" disclosure of industrial cost of production, we used a combination of published custom rate sheets for agricultural operations (Edwards, Iowa State 2010, https://www.extension.iastate.edu/store/ItemDetail.aspx?ProductID=1792) and contacts with agricultural contractors to fill in the cost data for each practice. Appendix E shows the cash flow model, practice and cost on a per-acre basis throughout the life of the plantation. We have assumed a single-harvest, twelve year rotation with one year added for site preparation and an average annual yield of four dry tons acre^{-1} year^{-1}. We then vary the stumpage price (direct revenue to the landowner) to estimate a breakeven production price using a real discount rate of three percent annually. As shown in Appendix E, the total discounted production cost is $450.00 per acre with the total yield held at 48 dry tons per acre at harvest. The breakeven price per dry ton at a 3% discount rate is estimated to be $15.63 per dry ton. In addition to this value, the cost of harvesting trees using a dedicated harvesting system designed for these stands is estimated to be $25.00 per dry ton (Dr. Bob Rummer, USFS Auburn, AL, personal communication). Therefore, the total price of poplar biomass delivered to the roadside is approximately $40.00 per dry ton FOB-farm.

Switchgrass Production Opportunities

Switchgrass is a warm season perennial grass which is considered as a potential energy crop for a large portion of the Midwest. The reader is referred to the document entitled "Management Guide for the Production of Switchgrass for Biomass Fuel in Southern Iowa" authored by Teel, et.al. for further information on the agronomic practices required to grow this crop.

In a manner similar to that described for poplar energy crops, we constructed a cash-flow model for switchgrass using the framework described in Duffy and Nanhou (2002) with costs updated through the cooperation of commercial growers of switchgrass for seed production (Kaste Seed – Paul and Garth Kaste, Fertile, MN). The resulting spreadsheet of costs and breakeven price estimate is shown in Appendix F. Based on this analysis, the breakeven price of biomass produced in a dedicated biomass production system using switchgrass is $36.77 per dry ton. In both cases, transportation costs would have to be added to the breakeven values to estimate the final delivered price. Using the analysis of trucking costs described above, delivered prices would likely required adding a minimum of $10.00 per dry ton to this FOB-farm price.

While breakeven prices for a specific production system provides some level of insight, a potentially more relevant question concerns alternate uses for the land and revenue to the landowner assuming competing crops. Thus, the appropriate question is; what does the stumpage value for biomass have to be to provide the same profit as other crop options? To address this question, we used published production cost data from the FINBIN website, maintained by the University of Minnesota (http://www.finbin.umn.edu/). Using this information, the total direct (site prep, seed, planting, cultivation, herbicide, fertilizer, etc.) and indirect costs (buildings, machinery, interest, etc.) costs for selected crops was calculated. The total cost of corn production on owned land is reported to be $555 per acre including direct and indirect costs of $400 and $155, respectively. Assuming an average yield of 180 bushels per acre and a current market price of $5.55 per bushel, gross revenue minus expenses is $444.00 per acre. Based on a four to five dry ton annual yield for energy crops, the "opportunity cost" would add approximately $80 to $100 per dry ton to this cost. Conducting a similar analysis for wheat in Minnesota, the estimated stumpage price would have to be $50.00 per dry ton to produce the same revenue growing wheat. The delivered price for wheat-competitive biomass is estimated to be $90.00 per dry ton.

While we do not advocate growing biomass in direct competition with major commodities, it is nevertheless instructive to understand the range of production cost for biomass assuming that energy crops are grown on some portion of the cropland base. Based on this analysis, it is obvious that work must be done to quantify the relationship between energy crop yield and soil quality particularly on the lower end of the range of agricultural production. Assuming that energy crops were located on the less productive agricultural soils, it is likely that the range of delivered cost to a conversion facility would range from $70.00 to $100.00 per dry ton.

Conclusion – Energy Crops

The foregoing analyses show clearly that biomass produced from dedicated energy crops is the most expensive option for biomass procurement. Although there is great potential of energy crops to produce significant quantities of biomass, it is obvious that production costs are higher than biomass derived from natural forest in the area. This is due mainly to the fact that high prices of agricultural commodities limit the land on which these crops could be grown profitably. Research is needed to determine the relationship between land quality and crop yield. Also, testing of new hybrid poplar plant material will be required to develop a genetically-diverse set of hybrids for the region. While the potential of energy crops is significant, the long lead-time and expense of this option is not considered as a part of the strategy for supplying biomass feedstock to the Jo Carroll facility.

Appendix A. Biomass amounts with distance by forest group and product type for each ten-year time period (note – data are incremental not cumulative for each distance band).

		Time Period 1			Time period 2			Time period 3		
Forest Type	Distance	Acres	Biomass		Acres	Biomass		Acres	Biomass	
			Pulp	Tops/Limb		Pulp	Tops/Limb		Pulp	Tops/Limb
			(dry tons)	(dry tons)		(dry tons)	(dry tons)		(dry tons)	(dry tons)
Elm/ash/cottonwood	125	19,819	456,741	248,759	29,318	553,159	274,871	23,889	450,723	223,969
Elm/ash/cottonwood	100	32,861	779,690	299,950	12,992	245,118	121,802	25,930	489,227	243,102
Elm/ash/cottonwood	75	6,579	54,557	51,559	12,029	226,949	112,773	10,008	188,831	93,833
Elm/ash/cottonwood	50	5,951	250,729	73,394	3,998	75,428	37,481	1,533	28,929	14,375
Elm/ash/cottonwood	25	6,990	80,920	32,655	15,764	297,419	147,791	11,142	210,227	104,464
Maple/beech/birch	125	27,268	473,184	235,245	8,556	161,431	80,217	6,391	120,583	59,919
Maple/beech/birch	100	27,344	537,675	247,705	4,566	86,154	42,811	4,367	82,385	40,938
Maple/beech/birch	75	7,331	158,636	93,042	4,656	87,843	43,650	472	8,905	4,425
Maple/beech/birch	50	1,522	27,542	14,908	0	0	0	305	5,745	2,855
Maple/beech/birch	25	0	0	0	0	0	0	0	0	0
Oak/hickory	125	215,781	3,601,369	2,053,640	56,560	1,067,145	530,277	55,609	1,049,207	521,363
Oak/hickory	100	152,341	3,327,279	1,449,355	60,004	1,132,125	562,566	56,236	1,061,032	527,239
Oak/hickory	75	59,351	1,135,726	530,968	13,790	260,184	129,288	19,667	371,069	184,388
Oak/hickory	50	36,708	567,179	322,854	16,791	316,810	157,427	14,339	270,533	134,431
Oak/hickory	25	21,190	266,180	168,485	2,141	40,400	20,075	3,340	63,022	31,317
Aspen/birch	125	8,926	114,552	33,554	1,600	34,403	8,956	735	11,686	4,113
Aspen/birch	100	5,164	107,869	43,395	3,117	67,021	17,447	0	0	0
Aspen/birch	75	2,063	31,784	11,735	717	15,411	4,012	0	0	0
Aspen/birch	50	344	8,152	3,648	0	0	0	0	0	0
Aspen/birch	25	0	0	0	0	0	0	0	0	0
White/red/jack pine	125		178,151	91,270		125,615	59,453		85,081	39,953
White/red/jack pine	100		49,031	21,524		76,845	37,248		43,231	21,793
White/red/jack pine	75		12,543	5,589		8,705	4,776		8,705	4,776
White/red/jack pine	50		1,434	611		1,624	891		6,182	2,749
White/red/jack pine	25		8,246	3,958		27,530	12,593		8,043	3,753

Appendix B. Terms used in this report from FIA Glossary (USDA, USFS FIA Program)

Forest type group: A combination of forest types that share closely associated species or site requirements.

White-red-jack pine: Forests in which eastern white pine, red pine, or jack pine, singly or in combination, comprise a plurality of the stocking. Common associates include hemlock, aspen, birch, and maple.

Oak-hickory: Forests in which upland oaks or hickory, singly or in combination, comprise a plurality of the stocking except where pines comprise 25-50 percent, in which case the stand is classified as oak-pine. Common associates include yellow-poplar, elm, maple, and black walnut.

Elm-ash-cottonwood: Forests in which elm, ash, or cottonwood, singly or in combination, comprise a plurality of the stocking. Common associates include willow, sycamore, beech, and maple.

Maple-beech-birch: Forests in which maple, beech, or yellow birch, singly or in combination, comprise a plurality of the stocking. Common associates include hemlock, elm, basswood, and white pine.

Aspen-birch: Forests in which aspen, balsam poplar, paper birch, or gray birch, singly or in combination, comprise a plurality of the stocking. Common associates include maple and balsam fir.

Net volume in cubic feet: The gross volume in cubic feet less deductions for rot, roughness, and poor form. Volume is computed for the central stem from a 1-foot stump to a minimum 4.0-inch top diameter outside bark, or to the point where the central stem breaks into limbs.

Saw log: A log meeting minimum standards of diameter, length, and defect, including logs at least 8 feet long, sound and straight, and with a minimum diameter inside bark of 6 inches for softwoods and 8 inches for hardwoods, or meeting other combinations of size and defect specified by regional standards.

Sawtimber tree: A live tree of commercial species containing at least a 12-foot sawlog or two noncontiguous saw logs 8 feet or longer, and meeting regional specifications for freedom from defect. Softwoods must be at least 9.0 inches d.b.h. Hardwoods must be at least 11.0 inches diameter outside bark (d.o.b.).

Sawtimber volume: Net volume of the saw-log portion of live sawtimber in board feet, International 1/4-inch rule (unless specified otherwise), from stump to a minimum 7.0 inches top d.o.b. for softwoods and a minimum 9.0 inches top d.o.b. for hardwoods.

Timberland: Forest land that is producing or is capable of producing crops of industrial wood and not withdrawn from timber utilization by statute or administrative regulation. (Note: Areas qualifying as timberland are capable of producing in excess of 20 cubic feet per acre per year of industrial wood in natural stands. Currently inaccessible and inoperable areas are included.)

Appendix C. Specific query information used in USFS Evaluator to create biomass datasets

Sawtimber and pulpwood biomass components of stands:

bolewood biomass total biomass – tops and limbs biomass
sawtimber biomass bolewood biomass x (sawtimber cuft volume / total bole cuft volume)
pulpwood biomass bolewood biomass – sawtimber biomass

Timberlands Cuft volume of all live trees by ownership and age

Estimate type Volume of all live on timberland (cuft)
Page variable=Ownership group - Major
Row variable=Forest type group
Column variable=Stand age 5 yr classes

Net volume in cubic feet: The gross volume in cubic feet less deductions for rot, roughness, and poor form. Volume is computed for the central stem from a 1-foot stump to a minimum 4.0-inch top diameter outside bark, or to the point where the central stem breaks into limbs.

Timberlands Cuft volume of sawtimber by ownership and age

Estimate type Volume of sawlog portion on timberland (cuft)
Page variable=Ownership group - Major
Row variable=Forest type group abbr
Column variable=Stand age 5 yr classes

Sawtimber volume: Net volume of the saw-log portion of live sawtimber in board feet, International 1/4-inch rule (unless specified otherwise), from stump to a minimum 7.0 inches top d.o.b. for softwoods and a minimum 9.0 inches top d.o.b. for hardwoods.

Timberlands total biomass by ownership and age

Estimate type All live tree and sapling aboveground biomass on timberland (oven-dry short tons)
Page variable=Ownership group - Major
Row variable=Forest type group
Column variable=Stand age 5 yr classes

Timberlands biomass volume for tops and limbs

Estimate type All live top and limb biomass on timberland (oven-dry short tons)
Page variable=Ownership group - Major
Row variable=Forest type group
Column variable=Stand age 5 yr classes

Harvest removals of all live trees on timberlands

Estimate type Harvest removals (utilized trees and trees killed as a result of harvest operations but not utilized) of all live on timberland (cuft per year)
Page variable=Ownership group - Major
Row variable=Forest type group
Column variable=Stand age 5 yr classes

Timberland acres by ownership and forest type

Estimate type Area of timberland (acres)
Page variable=Ownership group – Major
Row variable=Forest type group
Column variable=Stand age 5 yr classes

Appendix D. Assumptions used to estimate chipping cost based on medium-sized chipper.

Purchase Price	$360,000
Residual Value Ratio	0.2
Fixed Costs (annual basis)	
Depreciation (5 year - residual value)	$57,600
Interest (5% for 60 months)	$9,524
Insurance	$8,640
Variable Costs/Hour	
maintenance (knives, engine)	$34.00
fuel (18 gals/hr @ 4.00)	$72.00
Operator	$20.00
Total Variable/hour	$126.00
Harvest Operation Assumptions	
operating hours/day	8
operating days/yr	250
operating hours/yr	2000
Average Stand Size (acres)	7
Average Stand Volume (dry tons/acre)	55.5
Dry tons/cord (85 cubic ft/cord wood+bark)	1.7
Total Stand Volume (cord-equivalents)	229
Harvest System Production Rate (cords/day)	80
Days Harvesting Per Stand	2.9
Loading/Moving/Setup/Maintenance (days/stand)	1
Total Days/Stand	3.9
Stands Harvested Annually	65
Energy Wood Volume (dry tons/acre)	27.6
Energy Wood Volume per Stand (dry tons)	193.2
Energy Wood Harvested Annually (dry tons)	12,524
Green Tons Harvested Annually	25,048
Chipping Rate (green tons/hour)	60
Annual Chipper Operating Hours	417
Total Fixed Costs/yr	$75,764
Total Variable Costs/yr	$52,600
Total Annual Costs	$128,364
Estimated Chipping Cost ($/dry ton)	**$10.25**
If Fixed Costs Cut by 50% (longer payoff)	**$7.22**

Appendix E. Cash flow model for a single harvest, 12-year rotation poplar biomass production system.

		Year of Operation												
Practice	Info Source	0	1	2	3	4	5	6	7	8	9	10	11	12
Burn-down Herbicide1	personal comm - Central Ag Services	13.5												
Primary Tillage2	Custom Rate – IA St – Edwards	14.1												
Secondary Tillage3	Custom Rate – IA St – Edwards	11.4												
Secondary Tillage3	Custom Rate – IA St. – Edwards		11.4											
Secondary Tillage3	Custom Rate – IA St. – Edwards		11.4											
Marking	AURI/UM - hybridpoplar.org		15											
Planting														
cuttings (450/acre @ $0.10)	personal comm - Jake Eaton - GWR, Mike Young, Verso		45											
planting (450/acre @ $0.05)	personal comm - Jake Eaton - GWR, Mike Young, Verso		22.5											
Pre-mergent Herbicide4	personal comm - Central Ag Services		43	43										
Cultivation	Custom Rate – IA St. – Edwards		9.3											
Cultivation	Custom Rate – IA St. – Edwards		9.3	9.3										
Cultivation	Custom Rate – IA St. – Edwards		9.3	9.3										
Cultivation	Custom Rate – IA St. – Edwards													
Post-Emerge Herbicide5	personal comm - Central Ag Services		43	43	43									
Fertilizer Application	personal comm - Central Ag Services							38.2		38.2		38.2		
Annual Sum of Costs		39	219.2	104.6	43	0	0	38.2	0	38.2	0	38.2	0	0
Revenue														750
Cash Flow		-39	-219.2	-104.6	-43	0	0	-38.2	0	-38.2	0	-38.2	0	750

Appendix F. Cash flow model for a switchgrass biomass production system.

				Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Establishment	Unit	Price/Unit											
Operation Costs													
Disking	acre			$16.00									
Harrowing	acre			$9.00									
Seeding	acre			$18.00									
Spray - imazethapyr/2,4 D	acre			$12.00									
Material Costs													
Seed	lbs of PLS	10	$8.00	$80.00									
Fertilizer				$0.00									
Lime				$0.00									
Herbicide													
atrazine	quart	9.52	$1.50	$14.28									
2,4 D	quart	5.25	$1.50	$7.88									
Land Rent				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Reseeding (25% probability)					$30.09								
Production Years ($/acre)													
Operations													
Nitrogen Application					$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Application of P+K					$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Spraying chemicals					$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00
Material Costs													
Nitrogen Fertilizer (elemental)	lb	0.6	$80.00		$48.00	$0.00	$48.00	$0.00	$48.00	$0.00	$48.00	$0.00	$48.00
P- Fertilizer (elemental)	lb	0.27	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
K - Fertilizer (elemental)	lb	0.5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Herbicide - atrazine	qt	3.75	$1.50		$5.63	$5.63	$5.63	$5.63	$5.63	$5.63	$5.63	$5.63	$5.63
Herbicide - 2,4 D	qt	5.25	$1.50		$7.88	$7.88	$7.88	$7.88	$7.88	$7.88	$7.88	$7.88	$7.88
Harvesting and Storage													
Mowing/conditioning	per acre		$11.00		$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00
Raking	per acre		$6.20		$6.20	$6.20	$6.20	$6.20	$6.20	$6.20	$6.20	$6.20	$6.20
Baling (large square bales)	per ton		$11.00		$38.50	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
Staging and loading	per ton		$5.14		$25.71	$25.71	$25.71	$25.71	$25.71	$25.71	$25.71	$25.71	$25.71
Annual Costs				$157.16	$190.00	$128.41	$176.41	$128.41	$176.41	$128.41	$176.41	$128.41	$176.41
Revenue					$128.70	$183.85	$183.85	$183.85	$183.85	$183.85	$183.85	$183.85	$183.85
Cashflow				-$157.16	-$61.31	$55.44	$7.44	$55.44	$7.44	$55.44	$7.44	$55.44	$7.44

Input Section	
Land Rent	0
Yield	4
Price/dry ton (harvested)	$36.77
NPV	-$0.02
Discount Rate	0.03

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Southwest Wisconsin Boiler Study

Sponsored by: Southwest Badger RC&D

Authored by William A. Johnson, Biomass Consulting Services, Pardeeville, WI

1/18/2012

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Figures

Attachments:

Boiler Assessment Program, Bob Govert, (Excel)

Objectives and Methodology

Southwest Badger RC&D Boiler Survey

Objective: To determine the potential for utilization of biomass as an energy source for businesses in the Southwest Badger RC&D service territory. This report also reviews renewable energy fuels and boiler technology options for businesses interested in using alternative biomass fuels and types of technical and financial assistance available.

In addition to questions about the use of biomass fuels we included questions about their interest in using other sources of renewable energy such as geo-thermal, solar thermal, bio-gas, photo-voltaic, wind and other sources of renewable energy.

Study Methodologies: Using databases provided by the Wisconsin Department of Administration (DOA) we decided to target boilers annually inspected by the DOA and boilers inspected every three years. Surveys were only mailed to customers operating boilers fueled by electricity, oil or liquid propane (LP). Where we had e-mail contact information the surveys were sent to businesses via e-mail. Survey participants were given the opportunity to return the survey by mail or use an internet Zoomerang account to reply to the survey questions.

For the 1 yr. boiler inspection list we e-mailed 17 and mailed 38 surveys, for the 3 yr. boiler inspection list we mailed 78, none were e-mailed.

Survey Outcomes: We initially sent 55 surveys to the 1 year inspection; and sent a follow-up post card reminding them to go to the Zoomerang website to complete the survey, we only had one reply. Based on the low client response we revised the survey to make it more user friendly and resent it to seventy-eight (78) businesses in the 3-year boiler inspection group that met our boiler fuel criteria. Again we had very poor response to this survey, no one replied. We waited 2 weeks after the survey was mailed and began to call the businesses to interview them to complete the survey.

It took many calls and much time to locate a spokesperson that could answer the survey. Once the appropriate person was contacted on the phone, participants were very cooperative and provided good information.

Benefits of Biomass For Our Economy, Environment, and National Security

Encouraging the use of biomass for heating and cooling would help fill in some of the missing pieces of our nation's energy policy. Biomass thermal energy fulfills the same public policy objectives that are the basis and justification for renewable energy tax incentives or subsidies. These include:

- Reducing consumption of foreign fossil fuels, and thereby increasing energy security;

- Lowering emissions of greenhouse gases;
- Strengthening local economic development and job creation through the domestic production of fuels, system installation and service, and fuel distribution.

The following discussion on biomass fuels and biomass combustion technologies provides an overview of the most common fuels, how they can be processed and utilized, and information on emerging technologies. While this study is primarily limited to the use of biomass for combustion, for heat and power, we cannot overlook other high value potential uses of biomass such as biopharmaceuticals, biochemicals and transportation fuels.

There is redundancy in this document as it is difficult to discuss the form of a fuel without providing a description of conversion technologies and vice versa. This document is not comprehensive. It is intended to provide an accurate description of common and emerging uses of biomass and serve as a useful reference and guide when considering biomass and its potential to create economic value for Southwest Wisconsin.

Southwest Badger RC&D Boiler Study Area

Existing Utility Scale Biomass Demand

Currently two utility-grade power plants operate within the Southwest Badger RC&D region. Each facility utilizes biomass and is heavily dependent on the use of railroad ties as fuel. Future competition for rail road ties, and the expectation of impending regulatory changes affecting the use of such fuels, compels users to consider the use of more native sources of biomass.

Xcel Energy's French Island-LaCrosse, Wisconsin facility (XFI) burns approximately 30,000 tons of 20% moisture (6,700 Btu/lb.) railroad ties annually in their two, 14 MW circulating fluidized bed boilers. Much of XFI's remaining fuel is Municipal Solid Waste (MSW) originating from the LaCrosse County Landfill. This fuel type is also commonly referred to as Refuse Derived Fuel (RDF). Detroit Edison's (DTE) Cassville, Wisconsin facility, located approximately 100 miles south of XFI, recently began full operation of their approximately 50 MW facility. DTE's facility primarily burns construction/demolition wood and railroad ties. These facilities' combined demand for rail road ties, and the expectation of impending regulatory changes affecting the use of such fuels, implies that both DTE and XFI anticipate the need to use more native sources of biomass.

<u>Region Served by Southwest Badger</u>

The Southwest Badger RC&D area includes Crawford, Grant, Green, Iowa, LaFayette, La Crosse, Richland, Sauk, and Vernon counties in southwest Wisconsin. The area encompasses a region of southwestern Wisconsin known as the Driftless Area. This region is characterized by heavily wooded hillsides intertwined with cropland in the valleys and ridge tops.

Figure 1, Forested Land by County

County	Crawford	Grant	Green	Iowa	LaCrosse	Lafayette	Richland	Sauk	Vernon
Acres	171,292	204,309	41,247	170,673	126,042	53,004	172,881	189,914	167,404
Total Acres									**1,296,769**

Source: US Forest Service Forest Inventory Analysis (FIA) data. FIA updates 20 percent of acreage each year. Data shown represents data analyzed on December 17, 2011.

Project Area Forest Conditions

This area contains 4,102,656 acres of land (Source: Wisconsin Counties Association), with about 31.6 percent of that acreage, or 1,296,769 acres, classified by the United States Forest Service as "accessible forest" (Source: U.S. F.S., FIA data base). The forests are approximately 95 percent hardwoods with over 90 percent of the forest land privately owned. The area's topography is commonly steep wooded hillsides. The lack of a pulp market has resulted in a lack of removal of small diameter low quality trees. The abundance of thick canopy, low quality trees and lack of significant Timber Stand Improvement (TSI) woodlot harvesting has resulted in little forest soil vegetative cover. This lack of cover leaves the land vulnerable to soil erosion and subsequently threatens water quality and the important trout fishery. Timber stand improvement through the use of proper harvesting methods outlined in landowner conservation and woodlot management plans enhances wildlife habitat. This practice will provide for greater wildlife diversity and improved quality of outdoor recreational opportunities, including wildlife observation and hunting.

Historically, the Project Area has supported a healthy hardwood saw log and veneer market, while lacking a robust pulp market. Without consistent demand for pulp, loggers typically leave low quality trees standing, resulting in an increasing population of non-merchantable timber.

Silvaculture best management practices recommend removal of low grade trees to improve both the economic value of higher value tree species and the habitat for many species of wildlife. A characteristic of low grade trees, such as Iron Wood and Blue Beech, is a thick canopy. This canopy limits sunlight from filtering on to the forest floor, restricting the re-establishment of high value species, such as oaks. Removal of these types of trees will also enhance forest vegetative diversity, reduce soil run-off, and enrich wildlife habitat.

Project Area Agricultural Conditions

Agricultural land cultivated for production of corn, corn silage, soybeans, oats and alfalfa utilizes 41.9 percent of the land base or 1,722,800 acres (Source, 2008 Wisconsin Agricultural Statistics, Wisconsin Department of Agriculture and Consumer Protection).

Dairy farming has historically been the dominant agriculture practice within the area. There has been a decline in the number of dairies (a greater than 10% reduction from 2007 to 2010) with a shift to more crop production (see Figure 2). From existing corn acreage there is the potential to harvest an additional 1,215,600 tons of corn stover (at 2 tons / acre) for biofuel use.

Figure 2, 2008 Agriculture Crop Production in Project Area (Acres)

County	Forage	Soybean	Corn Silage	Corn Grain	Oats	Totals
Sauk	36,500	30,500	19,900	82,000	30,500	198,400
Crawford	36,000	16,100	7,300	33,000	5,300	97,700
Grant	93,000	53,400	28,000	161,000	19,000	353,400
LaCrosse	25,800	13,000	4,900	34,500	2,600	80,800
Green	42,100	46,700	15,000	101,000	47,800	252,600
Richland	48,700	11,000	10,200	40,000	4,700	114,600
LaFayette	37,700	49,800	15,000	128,000	49,900	280,400
Vernon	70,200	25,400	11,900	64,000	9,700	181,200
Iowa	39,000	30,800	17,200	70,000	6,700	163,700
Totals	483,500	222,600	120,100	607,800	68,500	1,722,800

Source: Wisconsin, USDA Agricultural Statistics Service, 2008

A macro trend, within the project area, has been the acquisition of lands purchased for recreational purposes (consumptive and non-consumptive). Consumptive activities, such as trout fishing and waterfowl, turkey and deer hunting are popular pursuits by resident and non-resident landowners. The abundance of deer in southwest Wisconsin has caused a significant challenge in the evolution of successional forests, as deer browse heavily on seedlings and small trees. Opening the forest floor through tree removal will help mitigate deer browse damage through increasing the abundance of young trees and the number of high value trees available for timber harvest.

Water Resources

The Project Area is composed of a mix of slight grade agricultural fields and timber lands with significant slopes. The most predominant land feature exhibits slopes between 0% and 45% with concentrated flow areas draining to natural drainages. Perennial streams within these drainages feed to larger rivers which eventually flow into the Mississippi River.

The major threat to these surface waters are peak flow events that cause stream bank erosion and downstream sedimentation, impairing aquatic habitat and water quality. Storm water and spring run-off from agricultural fields are significant problems. The region's conservation community has worked hard to reduce water flow within the coulee regions to reduce peak water flows. The primary tool for reducing peak flows is to increase water retention zones in upland areas, thereby reducing the impact of the spring melt and heavy rains. Woody perennials provide some shade in the spring and delay the snowmelt. The primary agricultural land water conservation techniques have been to maintain concentrated flow areas in perennial vegetation buffer strips, plowing contours, terraces and by restoring vegetation to riparian and stream bank buffers. Programs such as the Conservation Reserve Enhancement Program (CREP) have been utilized by landowners for assistance in this effort.

Survey Results

Due to proprietary and privacy concerns, individual business responses are not provided.

Question 1: What are your current energy sources for heat?

Heat Fuel Source	Number of Facilities Reported	Frequency
Electric	3	11.1%
Natural Gas	10	37%
Oil	5	18.5%
Propane	4	14.8%
Coal	3	11.1%
Other	2	7.4%
Total	**27**	

Interpretation: Over one third of the respondents utilized natural gas for their heating fuel. Natural gas is one of the lowest cost fuels; however, it is not available in all locations surveyed. No one using natural gas as their heating fuel was interested in switching to an alternative fuel. Biomass can be cost competitive to electric (11.1%), propane (14.8%) and oil (18.5%), but under current price and regulatory conditions is not competitive to coal (11.1%) or natural gas (37%). Respondents classified as "other" (7.4%) used wood or biogas some. Therefore, 51.9% or a total of 14 businesses were considered viable candidates for switching heating fuel.

2. How do you use your boilers?

Use	Number of Boiler Uses Reported	Frequency
Space Heating	15	36.6%
Water Heating	14	34.1%
Processing	7	17.1%
Electric Power	0	0%
Refrigeration	1	2.4%
Other	4	9.7%
Total	**41**	

Interpretation: It is important to identify how boilers are used to determine if there is year around or seasonal demand for heating fuel. Note that the number of boilers exceeds the number of businesses as some businesses operate multiple boilers. None of the respondents used their boilers to generate power, 36.6% (15) boilers were used for space heating, leaving 63.4% of the boilers required for year around operation. The "other" use of boilers was for the operation of small steam engines at an amusement park and a steam show location.

Further analysis shows that 9 of the boilers NOT using natural gas and used for year around heating are aged, and based on the assessment of the person interviewed, due for replacement, representing 2,235 horsepower of potential boiler replacement in the near future. Each of these respondents stated that they would consider use of biomass as their alternative fuel.

3. How many boilers do you have?

Number of Boilers	Number of Facilities Reported	Frequency
1	8	38.1%
2	9	42.9%
3	2	9.5%
9	1	4.8%
75	1	4.8%
Total	**21**	

Interpretation: This table indicates the largest frequency (81.0%) of boiler numbers per business is 1 to 2 boilers, where demand for fuel and necessary storage capacity requirements would be modest. The largest demand was at one facility with two 900 h.p. boilers. The largest number of boilers owned by any respondent was 75, reported by Land's End, unfortunately, they did not complete an inventory of boiler fuels and capacities for this survey.

4. **What are the boiler nameplate capacities of your five most used boilers?**

Boiler Capacity (Horse Power)	Number of Boilers Reported	Frequency
10 - 35	7	21.2%
80 - 150	11	33.3%
200 - 350	12	36.4%
600 >	3	9.1%
Total	**33**	

Interpretation: This data was difficult to obtain as several respondents were unable to identify boiler capacity, others reported capacities in Therms, Btu's or Horsepower. For ease of interpretation all values are converted to horsepower. The largest boilers were reported by the University of Wisconsin-LaCrosse; they can operate their boilers on natural gas, propane or coal and have no interest in switching to biomass fuels.

5. **When were your boilers installed and how many of the boilers may be due for replacement or upgrade?**

Number to be Replaced at any one Location	Number of Locations Reporting	Total Boilers Due for Replacement
0	6	0
1	3	3
2	8	16
3	1	3
Total	**18**	**22**

Interpretation: Only 5 of those surveyed knew when the boilers were installed: 1962, 1966, 1987 (2), 1995 (2), and 2008 (2). Therefore this information is very incomplete. Age of the boiler had a strong influence on whether the respondent determined the boiler had served its useful life and was due for replacement. The other influencers were boiler performance and cost of fuel.

*The average number of boilers to be replaced was **1.2** boilers per customer location, if we apply the same replacement rate/frequency to the 133 businesses identified in the study there would be **160** boilers due for replacement in the study area. The 39 boilers we have capacity information for average **251 h.p**., if we assume an average boiler size of 251 h.p. for 160 boilers that would be an equivalent of **40,060 h.p.** due for replacement or approximately **30 mW** of power generating capacity. Using 87% capacity factor, 9,600 Btu boiler heat rate (Btu's / kWh) and an average 6,000 Btu/ lb. fuel (~20% moisture), 160 boilers would require over **183,000 tons** of biomass annually.*

6. What are your current annual energy costs for electricity?

Only two respondents were able to state how much their annual electrical costs were, they were $26,500 and $66,000. Had the respondents had access to their companies operating expense financial spreadsheet, that information may have been more available. In most cases the person interviewed had boiler operation responsibilities and were aware of electrical costs but not responsible for recording costs. No boilers covered in the survey were used to meet electrical power requirements.

7. What are your current annual energy costs for heat?

Five respondents knew boiler fuel costs; they ranged from $54,000 – $318,000 per year with an average of $139,101. Had we been able to interview the financial officer of the businesses, we may have learned what impact heating fuel costs have on business profitability and better judge urgency of improving boiler heating performance.

8. Have you considered alternative fuels for your source of heat?

Of the 20 respondents answering this question, they were evenly divided on whether they had considered alternative renewable fuels or not.

9. If YES to question 8, what sources have you considered?

Heat Source	Number of Facilities Reported	%
Wood Chips	4	22.2
Biomass Pellets	2	11.1
Geothermal	2	11.1
Biogas	5	27.8
Solar Thermal	5	27.8
Other	0	0
Total	**18**	

Interpretation: Eight respondents answered this question; some had considered several fuels for their heat source. While we can't apply tests of significance to this small number of surveys, it is clear there is awareness of renewable energy sources, with biomass (wood chips, biomass pellets, and biogas) representing 61.7% of their fuel considerations. Based on the interviews it appears much awareness comes from publicity over use of wood chips at Meister Cheese in Muscoda and biogas at Montchevre in Belmont. A dairy in Lancaster, Wis. expressed interest in pretreating liquid waste discharge with an anaerobic digester. While we did not interview farms for this project, manure from another large dairy located in Lancaster, Wis. offers good synergy for such an energy project.

10. Have you considered alternative energy sources for your electrical needs?

Only three (16%) interviewed businesses considered alternative energy sources for power generation.

Interpretation: When interviewed respondents showed contentment over their current electrical energy costs, they spoke of on-peak and off-peak rates, industrial electrical rates and advancements in energy efficiency technologies assisting them with managing electrical energy costs. Sixteen (16) respondents had not considered alternative electrical energy sources, while three (3) had considered alternatives to their current source of electrical energy.

11. If YES to question 10, what sources have you considered?

Interpretation: From the three respondents considering alternative sources of electrical energy; one considered wind generation systems, but found they did not have an adequate footprint at their location to site a tower. Another said they explored photovoltaic, but determined they would have to purchase such a large array that it would be too expensive and they had inadequate roof space or surrounding land to mount enough of the desired number of units. Two considered fueling a steam boiler with biomass and elected against it because of the start-up cost and long payback time. One discussed an engine or microturbine operating on biogas as a reasonable alternative and would continue to consider the option.

12. How would you describe the wastes from your facility?

Waste Stream	Number of Facilities Reported	%
Solid Waste Office Paper	2	18.2
Cardboard	1	9.1
Garbage	2	18.2
Plastics	2	18.2
Wood	1	9.1
High Strength Process Water	1	9.1
Low Strength Process Water	2	18.2
Total	**11**	

Interpretation: This question was asked to determine if there were self-generated waste streams sufficient to supplement or support any one of a variety of renewable energy technologies. Seven respondents provided answers. It was determined that there were insufficient waste to solely fuel an energy system except for high volumes of process water that could support an anaerobic digester system. We cannot estimate the size of a potential anaerobic digester without measuring the biological strength of the waste stream.

13. Would you like to speak to someone about using renewables to provide heat and/or power for your facility?

Interpretation: Seventeen (17) respondents answered this question, nine (53%) would like assistance in determining whether a renewable energy system for heat and/or power is appropriate for their business. It is likely that with the number of businesses in the region there are many more businesses interested in an analysis of their energy systems and whether renewable energy systems are an appropriate business investment.

Forms of Biomass Fuels

While all fossil fuels are of biomass origin, for purposes of this report a review of biomass fuels conventionally thought of as renewable: such as wood, grass, crop residues, and biogas are reviewed.

Fuel influences the combustion process through its physical and chemical characteristics, mainly with respect to fuel composition, volatile/char content, thermal behavior, density, porosity, size, and surface area. Fuel composition is important in respect to caloric value, emissions, ash, and how its chemistry impacts the boiler both physically and chemically. The impact of fuel moisture content on its heating value is illustrated in Figure 3 (Frontline, T.J. Pasch).

Biomass generally contains high volatile content and low char content compared to coal, which makes biomass a highly reactive fuel. However, the volatile content varies for different biomass fuels and influences the thermal behavior of the fuel. Thermal behavior is also influenced by the different chemical structures present in the different biomass fuels (Loo & Koppejahn).

Figure 3, Effect of Fuel Moisture on Heating Value

Moisture Content (as-received)	Heating Value (as-received)	Moisture-corrected Heating Value (as-received)	Moisture-corrected Heating Value (dry-basis)	Moisture-corrected Feedstock Value (dry basis)	Moisture-corrected True Cost (dry-basis)
wt%	Btu/lb wet	Btu/lb wet	Btu/lb dry	$/ton	$/MMBtu
0%	8500	8500	8500	$50.00	$2.94
10%	7650	7550	8389	$49.35	$2.98
20%	6800	6600	8250	$48.53	$3.03
30%	5950	5650	8071	$47.48	$3.10
40%	5100	4700	7833	$46.08	$3.19
50%	4250	3750	7500	$44.12	$3.33
60%	3400	2800	7000	$41.18	$3.57
70%	2550	1850	6167	$36.28	$4.05
80%	1700	900	4500	$26.47	$5.56

** Feedstock at $50/ton (dry basis), with a dry-basis heating value of 8500 Btu/lb*

$$Moisture\ corrected\ heating\ value\ \left(\frac{Btu}{lb}\right) = dry\ heating\ value \times \left(1 - \frac{Moisture\ Content\ (\%)}{100}\right) - 1000 \times \left(\frac{Moisture\ Content\,(\%)}{100}\right)$$

Cord Wood

Cord wood is what most of us associate with residential wood burning systems and many hours in the woods cutting, splitting, hauling, and stacking fire wood. By definition cord wood is sold as a "cord" (128 cu. ft., 4 ft. x 4 ft. x 8 ft. dimension). However, when sold as firewood, cord wood is usually split and stacked and sized appropriately for use in a wood burner. Cord wood is used in very few industrial systems in the United States. The author witnessed many industrial combined heat and power systems utilizing cord wood in grate fed boilers in Brazil. Cord wood from Eucalyptus trees grown in closed loop industrial plantation forests is a significant energy industry in Brazil, where they grow over 8.5 million acres of this fast growing hardwood. Eucalyptus can grow to 6 feet in diameter and 75 feet in height in 8 years, it grows straight and is cut when the tree diameter is 6 inches or greater. The tree lends itself well for use as cord wood or chipping. Native trees, commonly found in southwest Wisconsin (except Aspen) do not adapt well to this type of system. Research is ongoing in Wisconsin to identify tree species and management systems capable of providing plantation style tree biomass production systems. Cord wood does not require the extra cost of handling and processing found with producing chips or pellets, nor does cordwood utilize small limbs and branches that are commonly used in chipping and ground wood system. Cord wood is more expensive than wood chips because harvesting wood for chips is faster and more highly automated. There is also a greater quantity of wood used for chipping as all parts of a tree can be chipped, whereas cord wood systems require labor intensive removal of limbs and branches.

Cord wood is easily stored as it is normally stacked; stacks can be aligned to take greatest advantage of drying from the sun and prevailing winds. Material handling systems at most existing solid fuel boilers are not equipped to handle cord wood due to its dimensions.

Chipped Wood

Woodchips are a medium-sized solid material made by cutting, using sharp knives. Controlling the “feed rate” and knife setting determines chip dimensions. Woodchips may be used as a biomass solid fuel or debarked and chipped for paper and chip board making. Wood chips may also be used as organic mulch in gardening, landscaping, and restoration ecology. According to the different chemical and mechanical properties of the wood, wood logs are mostly peeled for the paper and chip board industries but generally chipped whole for combustion. Bark chips are higher in ash and lower in cost than peeled wood.

Sources of wood and wood residuals are from construction, demolition, agriculture, and landscaping. Sawmills and logging residuals are common sources of virgin wood for combustion.

Conveyance of biomass can be challenging (compared to the conveyance of coal), as pneumatic, conveyer belt, and batch systems are challenged due to the fibrous nature and durability of wood chips. It is difficult to utilize chips in many existing large solid fuel boilers (pulverized coal and cyclone) as the fuel is run through a “crusher” to produce fuel material compatibly sized for combustion. Some existing (grate and fluidized bed) boilers are well adaptable to handling wood chips. In addition, unlike the smooth, uniform shape of manufactured wood pellets, woodchip size and moisture vary and are often mixed with twigs and sawdust. This mixture increases the probability of jamming feed mechanisms used in wood pellet boiler systems. Sooner or later, jams will occur in conventional fossil fuel conveyance systems reducing their reliability, as well as increasing maintenance costs. Researchers experienced with woodchips, say no woodchips, no matter their size, are compatible with the 2 inch (5 cm) auger used in pellet stoves.

Wood chips compared to other fuels

Newer wood fuel systems for commercial/industrial heating systems use either woodchips or wood pellets. The advantage of woodchips is their lower cost; the advantage of wood pellets is consistency of the fuel value as pellets are uniform density and moisture and thus greater heating value compared to wood chips.

Woodchips are less expensive than wood pellets and are theoretically more energy efficient than pellets, because less energy is required for manufacturing, processing, and transportation; assuming they're used in an appropriately designed burner. Unless force dried, wood chips are higher in moisture than pellets; their energy per pound can be as low as 50 percent the value of pellets. Chips are mostly available for large systems designed for commercial/industrial use. In contrast to the lack of many residential systems, commercial heating installations have been very successful in terms of performance, cost, reliability, and efficiency.

As mentioned earlier woodchips are less expensive than cordwood, because harvesting is faster and more highly automated. There is a greater supply, partly because all parts of a tree can be chipped, whereas small limbs and branches can require too much labor to be worth converting to cord wood. Woodchips are more amenable to automation than cord wood or ground wood, particularly for smaller systems. Cordwood generally needs to be "seasoned" or "dry" before it can be burned cleanly and efficiently. On the other hand, woodchip systems are typically designed to cleanly and efficiently burn "green chips" with very high moisture content of 43 to 47 percent (wet basis).

Wood chip quality is determined by ASTM (American Standard for Testing & Materials) standards for size, moisture, and specific gravity. Wood chipped or pelleted with its bark on has greater ash content than debarked wood, thus lowering the heating value per pound.

Ground Wood

Ground wood is produced from feeding wood acquired from the same sources as wood chips into a hammer mill using screens that determine the size of the end product being produced. Tub grinders and horizontal grinders are the most common type of processing equipment. The ground wood product is a long, fibrous, torn woody material.

Ground wood differs from chipped wood in that the physical form of wood is diminished by hammers rather than sharp rotating blades, producing greater variability of wood particle size.

Grinding is more easily accomplished on large materials (whole trees) than chipping. Ground wood has less predictable dimensions and because of its long fibrous physical form (even though screens are used during the grinding process to ”size” the wood) compared to wood chips or pellets, ground wood has increased friction and does not flow or store as easily and creates more dust issues when handled than chips or pellets.

Storage and handling of ground wood has challenges that differ from wood chips or pellets as ground wood doesn’t flow easily and can form a mat of intertwined/entangled material. Because of its increased surface area ground wood is hydrophilic and when stored in a pile ground wood has the potential to heat more easily than wood chips or pellets.

Management of stored wood is very important whether it is chipped, ground or pelleted, as wood heats when stored (especially green wood) which can result in rapid decomposition and spontaneous combustion. It is extremely important to manage wood piles by using first wood in as the first wood out, and mechanically mixing the wood pile and storing wood at the lowest practical water content.

Construction and Demolition Wood (C&D) and Municipal Solid Wastes (MSW)

Construction and demolition wood (C&D) and municipal solid wastes (MSW) are not considered renewable fuels by many definitions; however, near urban locations they can be readily available. The current economy has resulted in a shrinking supply of C&D materials, causing end users to turn to other biomass fuels. Some risks in using C&D wood as fuel is the presence of undesirable chemicals used to preserve and protect wood such as penta, creosote, and lead based paints. Additionally wood needs to be separated from vinyl, asbestos, insulation, tar paper, shingles, metals, and other materials before being burned. Ground C&D wood is commonly used as a fuel where a secondary separation process is used to reduce the chance of undesirable materials.

MSW also has risks as there is large variability in what is collected by municipal waste curbside garbage collection. Xcel Energy is LaCrosse utilizes MSW and has invested heavily in air emission reduction technology to protect the region from pollutants found in MSW. It is also important to have an effective recycling program to reduce glass, metals, and toxic chemical contamination of the fuel supply. Fueling with MSW has an added benefit of reducing the cost of operating landfills.

Solid Densified Biomass

With the rapid annual growth of wood pellet and briquetting manufacturing capacity in the United States in recent years, much research has occurred to make this fuel more cost competitive. Pellets have achieved commodity status with pellet production standards and grading. The pellet market has standard contracts, transparent pricing, spot trading, derivatives and the potential to take a place on the commodity trading floor. Eighty percent of U.S. produced pellets are exported.

The following explanation of the process of forming a pellet (similar process for briquettes) is offered to assist the reader in understanding why pellets are more expensive to produce than chips or ground wood. The attached descriptions were made available through direct communication with the Pellet Fuels Institute and work with several pelleting companies.

Before physical compression in the pellet mill can take place the wood, straw, grass or any other form of biomass must be reduced in size through grinding to a small particle size. Only raw material of consistent quality can produce consistent quality pellets. Part of this consistency is the size of raw material particles used in the pellet mill. Particles, too small or too large, can severally affect pellet quality and increase energy consumption. The “right” size particle depends on the raw material being ground. Plant materials differ in their pelleting characteristics, corn stover, miscanthus, and reed canary grass often pellet easily, while switchgrass and rice straw are more challenging to consistently make into good pellets.

Raw Material Moisture Content, Pellet Quality, and Production Rates

One of the reasons pellet fuel is popular is pellets have moisture content below 10 percent. This enables the pellets to burn efficiently, and produce little smoke during combustion.

Raw Material Composition and The Inclusion of Binders and Lubricants

In pellet production every raw material behaves differently, and some materials produce quality pellets more easily than others. It has been the author’s experience that materials high in lignin such as wood and alfalfa form the best pellets; whereas, warm season grasses such as switchgrass are more challenging. Depending on equipment used, the composition of raw material may need to be changed to produce quality pellets. Conditioning is the pre-treatment of the raw material before it reaches the pellet mill. Conditioning can include specific mixing techniques and the introduction of additional water or steam. Steam can be used to pre-anneal the raw material and start the lignin melting process. Though conditioning can have several benefits, in some cases the benefits are negligible and in other cases it is simply not practical to use conditioning. However, generally for production of wood pellets, steam is used.

Changing the composition can include adjusting particle size or moisture content. However, it may also include the blending of materials (binders) such as sawdust, corn stover, paper fiber, or polyethylene. Wood Residuals in Montello, Wis. produces three-quarter inch pellets using low density polyethylene (LDP, used silo bags) in the production. The result is a high energy value, durable, hydrophobic pellet and a reduction in problematic used silage storage bags.

Raw Material Pellet Mill Feed Rate

Another adjustment known to impact pellet production is the feed rate into the pellet mill. Adjustments on feed rate and maintaining a consistent feed rate can be a key difference to pellet density and durability and how well the pellet mill operates, even if the raw material is perfectly prepared.

Pellet Mill Operating Temperatures

Temperature is a key requirement in pellet production. Unless a certain temperature is reached in the pellet mill, natural lignin will not melt. It is not possible to produce biomass pellets without sufficient heat. However, if the temperature is too high it can damage the pellets and the pellet mill.

Pellet Mill Roller and Die Clearance

Another adjustment that can impact how successfully the pellet mill operates is the distance between the roller and die template. The roller and die are wearing, consumable parts, due to the abrasive nature and pressure of compression. The distance set between the roller and die can impact how much energy the pellet mill uses, the quality of the pellet, pellet mill productivity, and the amount of fines produced. Correctly setting up the die on a pellet mill will also increase the life of the roller and die, and reduce the cost of changing these consumable parts.

Changes in Pellet Mill Die Template Rotation Speed

The speeds at which the roller and die turn affect the complex relationships during pellet compression. Some materials require a greater time under compression, and therefore require a slower rotation speed. Also, the speed and torque requirements of the pellet mill change.

Pellets as a Fuel.

As stated, pellets are of generally consistent quality which makes them a desirable fuel as there is little variability in heating value. Pellets must be durable to withstand the rigors of handling and transportation. Boiler combustion systems that reduce the size of fuel through crushing or grinding find pellets simple to fracture to the desirable fuel size. Because of their low moisture content pellets pose little risk of heating during storage, but they require storage protection from the elements as pellets are normally hydrophilic and turn into mush if they absorb much water. Well manufactured pellets have very good flow and durability characteristics and can be transported, stored, and handled in conventional agriculture grain bins and silos. Pellets can be handled by material handling system used for coal or grain. Industrial wood pellets are commonly made with tree wood and bark, whereas residential heating pellets are made from debarked trees and can have a heating values (7,88-8,500 Btu/ lb.) close to that of sub-bituminous coal (~9,000 Btu's lb.). Bark content decreases pellet Btu value and increases the pellet's ash content.

It is obvious why biomass pellets are viewed as an excellent fuel substitution for other solid fuels. Their biggest drawback is cost, with pellets currently ranging from $130 -$220 per ton.

Briquettes

Briquettes are also referred to as bats, hockey pucks, or bricks. They come in assorted shapes and dimensions and are formed using a variety of densification technologies. One form of briquette is sold in packages and marketed as a fireplace log, usually made of sawdust, but can be formed from a variety of types of biomass. Log shaped briquettes are formed using a hydraulic ram forcing biomass through a die. The die can be externally heated or becomes heated from the friction of biomass passing through extrusion dies that come in various diameters. Round briquettes are found in several diameters up to 4 inches. While working with briquette technology companies, we found that ground wood (6 mm screens) formed briquettes with densities up to 39 percent greater than similarly ground herbaceous material through the same dies. Heat causes lignin (found in greater quantities in wood than in grasses) to liquefy, requiring temperatures around 572°F (200°C) to make a good briquette and when cooled it forms a hard dense mass giving the briquette durability. Many presses in operation today do not have a way to cool the die without stopping the operation to allow cooling; otherwise the die will overheat and char the biomass. Briquettes formed through an extrusion die can be cut to a variety of lengths, thus they are often referred to as pucks or bats. While some consider briquetting with hydraulic pressure an easier way to form a durable and consistent product it is a slower process than conventional pellet making, a typical hydraulic ram produces 2 tons of briquettes per hour or less. Because of their large size round briquettes are more challenging to store and handle than small pellets; however, it is my experience that they process successfully through coal crushers, but not as easily as ¼ inch pellets. It has also been my experience that biomass products that are difficult to pellet are easier to briquette. Because of a briquette's size compared to pellets they create more unique challenges when storing and handling with equipment designed for grain handling.

In contrast, another method of briquetting avoids many material handling steps. A mechanized in-field cubing machine forms a square briquette/cube as herbaceous biomass is harvested from a windrow. This type of briquette is formed into a 2 inch cube by being forced through a ring press similar to ones used in pelleting and conveyed to a wagon towed by the cubing machine. Once a popular machine manufactured by John–Deere in the 1970's to form alfalfa cubes, the machine is no longer manufactured. Successful in-field operation requires consistent quality biomass feedstock which is difficult to regulate during in-field conditions, raw product moisture and stem length is important in making a consistent "cube briquette." Much research has been done in recent years to resurrect the in-field cubing machine. Professor Kevin Shinners of the University of Wisconsin-Madison has overseen research in this area and determined that successful in-field briquetting was largely confined to crops the machine was originally intended to process, namely alfalfa. Crops such as switchgrass and grain stovers are very difficult to process into a consistent quality product. Research into adding a binder such as Low-Density Polyethylene (LDP) has been promising with bench top research, but less successful for in-field application. If in-field densification became a successful reality, it has the potential to reduce costs associated with handling and processing at a stationary facility and has the potential to make solid densified biomass more cost competitive.

Torrefied Fuels

Torrefaction is a thermal treatment of biomass at 200° C to 316° C (392° F - 600° F) that occurs in an inert atmosphere (without oxygen). A technology developer and manufacturer operated by New Hampshire-based investment firm Cate Street Capital Inc., is bringing a microwave-based woody biomass torrefaction technology to Maine. The technology, created by U.K. firm Rotowave Ltd., uses a series of simultaneous electromagnetic frequencies in combination with a ceramic drum to maximize heat transfer throughout every biomass particle in the unit, making the process of pyrolysis used to turn woody biomass into a biocoal product more efficient.

The thermal and microwave processes remove moisture and low weight organic volatile components and depolymerizes the long polysaccharide chains (lignin, hemicellulose and cellulose). During the torrefaction process biomass typically loses 20 percent of its mass (dry bone basis), while only losing 10 percent of its energy content, producing a solid hydrophobic product that can be added to outdoor coal piles without the weather compromising fuel quality, while having increased energy density (on a mass basis) and greatly increased grindability. The resulting product is referred to as torrefied biomass or "bio-coal" that improves the thermal value of wood to about 9,400 Btu per pound. As a result, lower energy is required to process torrefied fuel and it doesn't require separate handling facilities when co-fired with coal in existing power stations. It has been demonstrated that torrefied fuel which looks much like charcoal can be compacted into high grade pellets with substantially superior properties when compared with standard wood pellets. Currently there are no commercial scale torrefaction facilities in the United States.

Torrefied biomass may be a fuel of the future that plays an important role with coal fired combustion facilities in the reduction of their air emission profile while not requiring large capital investments in modification of existing facilities, storage, material handling, and boiler systems. River Basin Energy of Laramie, Wyoming recently announced it was breaking ground on a 100,000 ton per year biocoal facility, one of the first of its kind in the United States.

Pyrolysis Fuels

Pyrolysis is a thermochemical conversion technology used to produce higher density energy from any biomass product. Pyrolysis involves the heating of organic materials in the absence of oxygen, to achieve decomposition. When pyrolysis takes place in the presence of water, it is called hydrous pyrolysis. When biomass is heated to about 550° C (1055° F), in the absence of oxygen many of its volatile organic compounds turn to vapor and when condensed become a liquid that retains heating value greater than the solid biomass of its origin. For best results biomass being converted through pyrolysis should be as low in moisture content as practically possible. Even when using dry biomass at 6 percent moisture pyrolysis oil will be about 22 percent moisture from biomass moisture content and reforming of hydrogen and oxygen coming from the biomass itself. Liquid fuels can be easily processed, stored, and handled using conventional liquid handling systems modified to accommodate characteristics of pyrolysis, such as pH and short shelf life.

Slow pyrolysis takes several hours to complete, products of pyrolysis include intermediate products such as syngas, whereas the primary final products are bio-oil and bio-char. Pyrolysis is capable of processing a wide variety of feedstocks including gases, bio-oil, bio-chemicals, and charcoal. Pyrolysis is a promising approach in the production of bio-oil that can be used to power industrial facilities. Charcoal is being studied as a possible soil amendment, incorporated into the soil to promote fertility, carbon sequestration, and organic matter through synergistic processes between the soil, soil organisms, and plant roots. The growing concerns about climate change have brought biochar into the limelight. Combustion and the normal decomposition of woody biomass and agricultural residues results in the emission of carbon dioxide. Biochar stores carbon, and if applied to the soil it can reduce nitrous oxide and methane emissions and lead to a reduction in greenhouse gas emissions (GHG's) while enhancing soil fertility through improvement of tilth and organic matter. Biochar can also be returned to the boiler and reburned as a fuel.

The portability and storage of pyrolysis oil fits well with conventional transportation and storage systems, and the oil can also be processed into higher value co-products though refining methods used by the petroleum industry. Bio-oil from pyrolysis has historically been very acidic and has short shelf life stability. Recent technical breakthroughs offer promise in addressing both of these characteristics.

However, pyrolysis is a largely unproven commercial technology for large scale production of liquid fuels. Wisconsin has one of the few commercial pyrolysis facilities in the United States, Ensys located in northern Wisconsin produces bio-oil marketed as “Liquid-Smoke,” another facility was proposed in Cashton, Wis., but has not been built. A facility under construction by Avello in Des Moines, Iowa plans to produce bio-asphalt through pyrolysis of biomass.

Gasified Fuels

Gasification was an important and common technology widely used to generate “town gas” from coke, mainly for lighting purposes during the 19th and early 20th century. Hydrogen, methane and carbon monoxide gases were generated and combined for use as residential and commercial heating and lighting (Wikipedia).

During the late 19th century internal combustion engines were sometimes fueled by town gas and during the early 20th century many stationary engines switched to using gas created from coke which was substantially cheaper than gas produced through distillation (pyrolysis) of coal.

Gasification has a number of advantages over use of fossil fuels: the gases can be used to run internal-combustion engines (or gas turbines, for maximal efficiency) while using biomass. They are cleaner burning than gasoline-powered engines (without emissions controls), and produce little if any soot. When used in a stationary design, they reach their true potential, as they are feasible for use in small combined heat and power scenarios; for example, to heat water for hydronic heating.

The author has experience with gasification at Chippewa Valley Ethanol in Benson, Minn., where a boiler using wood was installed to off-set the high cost of natural gas of 5-6 years ago. Gasification can be an excellent technology when using biomass (ex. corn stover and whole grains) that has corrosive properties or causes slagging on boiler steam tubes. A gasifier using a gas clean up system to remove alkalis, chlorides, and tars can be used as a mitigation tool before injecting cleaned producer gas into a steam boiler, thereby protecting steam tubes from corrosion and slagging.

The disadvantages of wood gas generators are their large size and relatively slow start and stopping speeds compared to natural gas fired systems.

Anaerobically Derived Biogas

Biogas originates from biogenic material and is a type of biofuel. Biogas is produced by the anaerobic (absence of oxygen) digestion or fermentation of biodegradable materials such as manure, sewage, municipal waste, green waste, plant material, and crops. Biogas comprises primarily methane and carbon dioxide and may have small amounts of hydrogen sulphide (H2S), moisture, and a unique gas from landfills called siloxanes (silica gas, largely from paints and cosmetics). It is especially important to remove siloxanes which are most prevalent in landfill gas before using in internal combustion engines, as silica is highly abrasive and can quickly destroy an internal combustion engine. Prior to use as a fuel in an engine biogas high in hydrogen sulfide should have H2S removed through cooling and removal of the condensate that has a high sulphuric acid content. If H2S isn't removed from the gas prior to injection into an engine, the gas would have a corrosive impact on the engine.

The primary gases of anaerobic processes, methane, hydrogen, and carbon monoxide, can be combusted or oxidized with oxygen. This allows biogas to be used as a fuel. When produced in an anaerobic digester biogas is typically used in a gas engine or turbine to convert the energy to power and heat. In some cases biogas is cleaned of nitrogen compounds, sulfurs, and moisture and compressed for use in internal combustion engines for powering motor vehicles or injected into a natural gas pipeline.

A biogas plant is the name often given to an anaerobic digester that treats farm wastes or energy crops, however, municipal and industrial waste water can be similarly treated. Montcherve Cheese factory in Belmont, Wis. treats their waste water with an anaerobic digester for heating water and generation of power (sold to Alliant Energy).

Biogas can be produced utilizing anaerobic digesters. These plants can be fed with energy crops such as corn silage or other biodegradable materials such as food waste. In recent years Germany has taken great strides to encourage the development of anaerobic digesters with a total of over 5,500 digesters in operation today (compared to less than 150 in the United States). Many German on-farm digesters use crop biomass as their principal substrate. During the digestion process, an air-tight container with methanogen bacteria transforms biomass waste into methane gas.

Landfill gas is produced by the decomposition of organic waste under anaerobic conditions in a landfill. The waste is covered and mechanically compressed by the weight of the material that is deposited from above, this material prevents oxygen exposure thus allowing anaerobic microbes to thrive. Heat produced from bacterial metabolism maintains landfill heat fostering methanogenic bacteria. This gas builds up and is slowly released into the atmosphere if the landfill site has not been engineered to capture the gas.

The composition of biogas varies depending upon the origin of the anaerobic digestion process. Landfill gas typically has methane concentrations around 50 percent. Advanced waste treatment technologies can produce biogas with 55 to 75 percent methane.

Figure 4, Typical Composition of Biogas

Compound	Chem	%
Methane	**CH_4**	50–75
Carbon dioxide	**CO_2**	25–50
Nitrogen	**N_2**	0–10
Hydrogen	**H_2**	0–1
Hydrogen sulfide	**H_2S**	0–3
Oxygen	**O_2**	0–0

Crop Residues

Crop residues and grasses can be used as a source of biomass for the fuels described above. However, there are important agronomic considerations when using agricultural crop residues such as; what impact does residue removal have on soil fertility, soil susceptibility to wind and water erosion, soil organic matter, and soil microbiological populations. Fast growing plants store greater quantities of soil nutrients than slow growing plants such as trees. An important consideration is the impact of elemental nutrients (ex. potassium, phosphorous, and chlorides) found in plant material and their effects on boiler metallurgy and boiler performance. Before biomass is used as a fuel each source must be analyzed for their elemental content and managed by the end user accordingly.

Industrial Co-products

Co-products and by-products of industrial feed and food processing such as grain fiber, distillers grains, hulls, damaged grains, and gluten meal are frequently available and can be used as a source of biofuel. Some industrial processes concentrate elements making them more of a threat to mechanical systems and boilers due to their corrosive or abrasive properties. In some cases the ash content of materials are so high they are not economical. Rice hulls and rice straw are examples of materials high in silica, making it very abrasive and high in ash content. In the case of glycerol a by-product of bio-diesel production, its pH is often too low and corrosive to run through existing liquid fuel systems. Whatever product becomes available for combustion must have at least a Proximate Analysis done in order to access its compatibility with the boiler technology.

Closed Loop Biomass

Much research has gone into "purpose grown" or "closed loop" herbaceous and woody biomass crops. Examples are switchgrass, miscanthus, King Grass, sorghum, hybrid poplar, willow, and larch. Each crop has traits that lend it advantages depending on the region's climate, topography, cost of land, and the end use of the crop. For example, some annual crops such as high yield hybrid sorghums have been bred for high sugar content and lend themselves well to sugar or ethanol fractionation. To optimize yields, high sugar sorghums require long growing seasons, so they are more suited for southern climes. Depending on variety and geographical location the perennial crop Miscanthus has high yield potential. However, it is costly to establish and requires at least 1-2 years before the crop can be harvested. Long crop rotation cycles are characteristic of woody crops such as Hybrid Poplar which may require a 10-15 year rotation. Like any crop, closed loop biomass crops must meet a market demand before the land owner determines what crop to grow and where and how to grow it.

In general, faster growing crops have a greater potential for concentrations of less desirable chemical elements such as chlorine. Nutrients concentrate more in the above ground portions and more closely reflect soil fertility in fast growing plants than in slow growing plants. While it is important to know the plant chemistry, some of the concerns can be mitigated if the problematic fuel is mixed with fuels of lower elemental chemistry.

The Process of Combustion

In order to understand combustion technologies and their fuels, a primer on the basics of biomass combustion is useful in understanding descriptions of how forms of biomass can be used as fuel.

Biomass can be converted into useful energy (heat or electricity/power) or energy carriers (charcoal, oil or gas) by thermochemical and biochemical conversion technologies. Biochemical conversion technologies include fermentation for alcohol production and anaerobic digestion for production of methane-enriched gas. Four thermochemical biomass conversion technologies for energy production exist: pyrolysis, gasification, combustion, and liquefaction. The primary products from these conversion technologies may be in the form of energy carriers such as charcoal, oil, gas, or heat. Secondary products can be derived through additional processing. In principle, most petroleum-derived chemicals can be produced from biomass, but require differing routes for synthesis.

The process of biomass thermochemical combustion involves a complexity of physical and chemical processes. The nature of combustion depends on the fuel's properties and the combustion technology used. Biomass solid fuel combustion can be divided into several processes*:* drying, pyrolysis, flame combustion or gasification, and char combustion.

Techniques used in delivery of biomass for the process of combustion in a boiler can be divided into continuous or batch combustion processes, these techniques have an effect on the behavior of the thermo-chemical process. Batch combustion is most applied to small scale combustion boilers such as traditional residential wood stoves. Continuous combustion applications are typical of medium to large scale combustion units.

Thermochemical Combustion Processes (references: Van Loo & Koppenjan, Brown)

Drying and pyrolysis/gasification are always the first steps in solid fuel combustion. The importance of each of these steps will vary depending on the combustion technology deployed, fuel properties, and combustion conditions (ex. in the presence of oxygen).

Drying is the process of removing moisture. Moisture will evaporate at low temperatures (less than 100°C/212°F). Vaporization of water uses energy released during combustion and lowers the temperature in the combustion chamber slowing down the combustion process. Heating and drying of the particle is normally not accompanied by chemical reactions. Water is driven from the fuel particle as the thermal front advances into the interior of the fuel particle. If wood moisture exceeds 60 percent, the wood requires so much energy to evaporate water that combustion chamber temperatures are reduced below the minimum temperature to sustain combustion. Therefore, moisture content of fuel is an important variable. As long as water remains, the temperature of the particle cannot raise high enough to initiate pyrolysis, the second phase of combustion.

Pyrolysis is a series of thermally driven chemical reactions that decompose (devolatilzation) organic compounds in the fuel in the absence of supplied oxygen. Pyrolysis proceeds at relatively low temperatures depending on the type of plant material. Hemicellulose begins to pyrolyze at temperatures between 225° and 325° C (437° to 612° F) while lignin pyrolysis is initiated between 250° and 500° C (482° to 932° F). Pyrolysis products are primarily tar and carbonaceous charcoal and carbon dioxide, carbon monoxide, and methane gases and high molecular weight compounds that condense to a tarry liquid if cooled before they are burned. Fine droplets of these condensable compounds are the smoke associated with smoldering fires. Pyrolysis follows the thermal front through the biomass particle, releasing volatile compounds and leaving behind pores in the solid fuel that penetrate to the surface of the particle. Pyrolysis is very rapid compared to the overall burning process; it may be as short as a second for small particles of fuel or minutes for wood logs. Although the net of combustion is oxidation of fuel molecules and the release of heat, neither of these occurs to a significant extent during pyrolysis. For pyrolysis to proceed, heat must be added to the fuel. Oxygen is excluded from pyrolysis by the large outflow of gasses from the fuel particles surface. Only after the pyrolysis gases escape the particle and diffuse into the air are they able to burn. Upon completion of pyrolysis, a porous carbonaceous residue known as char remains. Pyrolysis products (char and gas) can be used in a variety of ways, including the condensation of the gas to form pyrolysis oil or bio-oil which can be upgraded for use as a crude oil substitute. Char can be used as a soil amendment to improve soil tilth and a storage form of carbon, it can also be upgraded for industrial uses or re-burned in the boiler.

Gasification or flame combustion can be defined as thermal degradation (devolitization) in the presence of supplied oxygen. While pyrolysis is optimal for maximum char production, gasification is optimal for maximum gas production. The gas (sometimes called “producer gas” or “syngas”) can be utilized for direct combustion in a boiler or in a gas turbine or if cleaned of gas contaminants used in an internal combustion engine or injected into a natural gas pipeline. In essence, a limited amount of oxygen or air is introduced into the reactor to allow some organic material to be "burned" to produce carbon monoxide and energy, which drives a second reaction that converts further organic material to hydrogen and carbon dioxide. Further reactions occur when the formed carbon monoxide and residual from the organic material react to form methane and excess carbon dioxide. This third reaction occurs more abundantly in reactors that increase the residence time of reactive gases and organic materials, as well as heat and pressure. Catalysts are used in more sophisticated reactors to improve reaction rates.

Char Combustion or Combustion

Combustion can be ideally defined as complete oxidation of fuel. Hot gases from combustion may be used for direct heating (wood burner), heating water in boilers, or the production of steam for electricity generation and other processes.

Liquefaction

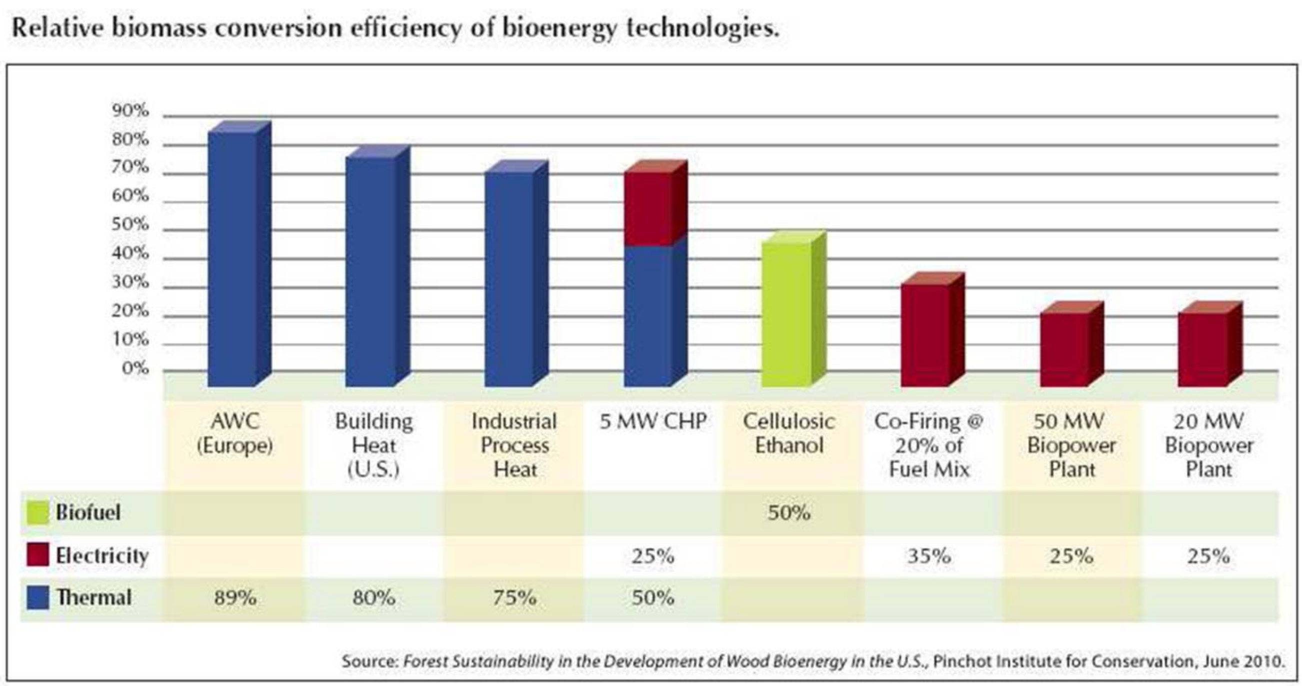
Liquefaction is defined as thermochemical conversion in the liquid phase at low temperatures and high pressures. Catalysts are commonly used to improve the selectivity of what the end product will be. Compared to pyrolysis, liquefaction has a higher yield of liquid and is more akin to processes used in the petroleum industry in making a variety of chemicals and fuels.

Common Technologies for Heat and Power

Heat Applications

Among those surveyed, power production was the exclusive application of utilities. The remainder of those surveyed used boilers for heating water for low pressure hot water or for high pressure steam production for space heating or process heat. Examples of process heat uses include, cheese production, operating room instrument sterilization, and vegetable food processing. Following is a review of current large scale uses of biomass for heat and power production. Two large users of biomass in the region are power producers Xcel Energy, in LaCrosse, Wis. and DTE, in Cassville, Wis. Depending on the combustion technology used and quality of the electrical transmission and distribution systems, efficiency of power production averages between 30 and 35 percent. Greater energy efficiency (80% – 90%) is achievable by having an energy system that combines the use and advantage of producing both heat and power (CHP). CHP biomass technologies generate more usable energy per unit of fuel than power systems alone (Figure 5). If CHP systems exist in the study area, they were not identified during the survey, the author knows of only one new CHP system contemplated for the region.

Figure 5, Relative Conversion Efficiency of Bioenergy Technologies



Rankine Cycle

The Rankine cycle converts heat into work. Heat is supplied externally to a closed loop, which usually uses water. This cycle generates about 80 percent of all electric power used throughout the world, including virtually all solar thermal, biomass, coal, and nuclear power plants.. The Rankine cycle is the fundamental thermodynamic underpinning of the steam engine and describes the most commonly found technology in power plants. Common heat sources for power plants using Rankine cycle are the combustion of coal, natural gas, oil, and nuclear fission.

The efficiency of a Rankine cycle is usually limited by the working fluid. Without pressure reaching super critical levels for the working fluid, the temperature range the cycle can operate over is quite small. Turbine entry temperatures of the working fluid are typically 565° C (1049° F) and condenser temperatures are around 30° C (86° F). The working fluid in a Rankine cycle follows a closed loop and is reused constantly. Water vapor with entrained droplets often seen billowing from power stations is generated by the water cooling systems and represents wasted heat energy (pumping and vaporization) that could not be converted to useful work in the turbine. While many substances could be used in the Rankine cycle, water is usually the fluid of choice as it is nontoxic, chemically unreactive, abundant, and low cost. Companies such as Energy Unlimited in Dodgeville, Wis. manufacture a power system that uses refrigerant gas as a medium rather than water. When the gas expands through heating, the expanded gas is used to drive a cylinder connected to a drive shaft which turns a generator producing power.

Figure 6, Rankine Cycle Boiler Operating Design

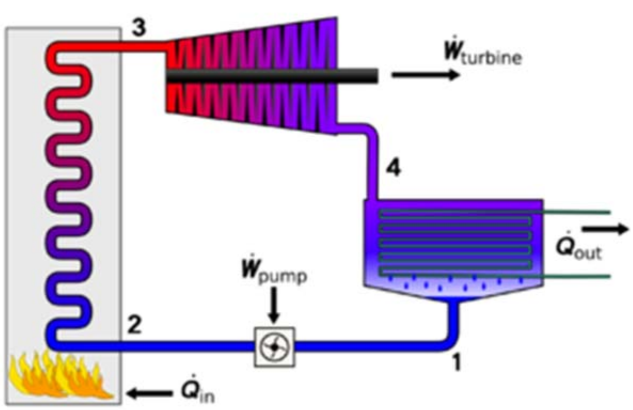


Diagram of a typical Rankine cycle as described in (*Wikipedia*)

There are four processes in the Rankine cycle. These states are identified by numbers in the diagram above.

- **Process 1-2**: The working fluid is pumped from low to high pressure, as the fluid is a liquid at this stage the pump requires little input energy.
- **Process 2-3**: The high pressure liquid enters a boiler where it is heated at constant pressure by an external heat source to become a dry saturated vapor. The input energy required can be easily calculated using published steam tables.
- **Process 3-4**: The dry saturated vapor expands through a turbine, generating power. This decreases the temperature and pressure of the vapor, and some condensation may occur. The output in this process can be easily calculated using published steam tables.
- **Process 4-1**: The wet vapor then enters a condenser where it is condensed at a constant temperature to become a saturated liquid.

There are several derivations of the above Rankine design including Reverse and Organic Rankine technologies that we will not discuss here. Needless to say, the principals of Rankine design are important in converting fuels to heat and power. Rankine boilers are useful over a wide range of heat and power requirements. Most existing boilers covered by this survey utilize Rankine principles. Several of the energy technologies described in this document utilizes Rankine designs or principles.

Residential/Small Commercial Wood Burning Appliances

Domestic batch fed wood burning appliances include “high efficiency” fireplaces, fireplace inserts, wood stoves, central heating furnaces, and boilers. We will not consider fireplaces as a heating device because of their low thermal efficiency. Because of the high amount of combustion air they use, most fireplaces consume more energy than they produce if the outdoor temperature is below O° C (32° F).

Wood stoves are free-standing appliances for heating the space where they are located. Stoves release heat energy into their surroundings by radiation and convection. Fireboxes are typically lined with fire-resistant materials, usually fire-brick. The burn rate is regulated by controlling the rate of secondary combustion air.

Normally smoke will ignite and burn only at high temperatures, it is difficult to obtain the required temperature outside the primary combustion zone in a wood burner, however a wood burner with a catalytic combustor can reduce smoke ignition temperature to around 260° C (500° F), a temperature more easily obtained. In addition to increasing heating efficiency a catalytic combustor reduces emissions resulting from incomplete combustion.

Fireplace Inserts are basically a wood stove installed in an existing fireplace. Fireplace inserts function in a manner similar to a stove, but require a more elaborate heat transfer system to avoid excessive heat loss. In fireplace inserts heat is transferred to some extent by radiation from the front door, however the most important heat transfer mechanism is natural or forced convection.

Heat Storing Stoves are constructed of pre-fabricated heavy stone plates, ceramics, or purely of stone. During combustion, wood is burned at a high burn rate, and high temperatures forcing the burning flue gases into the upper portion of the combustion chamber (through a contraflow energy design), hot gases are guided down and into side channels, where the heat is transferred to the exterior stone, after the fire is extinguished, a stone stove will continue to release the stored heat to the room space fort 1-2 days.

Wood Log Boilers are designed as over-fire or under-fire boilers and often used as the heat source for hydronic (described below) heating systems. *Over fire* are the simplest and cheapest boilers for burning wood logs. As in wood stoves, combustion takes place in a batch more or less at the same time. The boiler is normally equipped with a primary air inlet under the grate and a secondary air inlet over the fuel, into the combustion zone. Wood is fed through an upper door and ashes removed from the lower door. Emissions of unburned hydrocarbons may be high if operated at low burn rates. In u*nder-fired boilers* gasification and partial combustion take place in a small amount of the fuel in the bottom of the fuel storage. Final combustion takes place in a separate combustion chamber, while ashes fall through a gate to the ash box. Most wood fuels can be used in an under-fired boiler, however, wood pellets are not suitable because of their small particle size and high density.

Down draft boilers are a relatively recent innovation in wood log combustion. The basic principle is flue gases are forced to flow down through a hole in a ceramic grate the burning wood is stacked on. Strict air emission limits have made it necessary to introduce down draft boilers.

Wood pellet appliances have become common heating appliances as free standing or connected to central heating systems. Wood pellet fuels are of special interest because of their low moisture content, low emissions, and relatively low ash content (when made without wood bark). Pellets made from herbaceous material should be studied before use, as some materials are high in silica and other constituents that may make them undesirable for use in a residential system. Pellet stoves have a fuel storage hopper used to feed the combustion chamber through a feed auger that prevents burn backing into the storage hopper. A draw back to pellet fueled appliances is they require electricity to run the feed auger.

Wood chip appliances are also used for domestic heating. An advantage of using wood chips instead of firewood or logs are their automatic operation (similar to wood pellet stoves) and lower emissions because of the use of the fuel's feed rate rather than air supply to control heat release rates. A drawback to using woodchips is the making and of storing chips and the possible investment in artificial drying.

Hydronics is the use of water as the heat-transfer medium in heating and cooling systems. Some of the oldest and most common examples are hot-water radiators. They are also becoming increasingly popular in outdoor wood burner home heating systems. While using Rankine Cycle principles, hydronics are worthy of separate discussion as they utilize hot water rather than steam and have been used historically, in large-scale commercial buildings such as high-rise and campus facilities. A hydronic system may include both a chilled and a heated water loop, to provide for both heating and air conditioning. Chillers and cooling towers are used separately or together as a means to provide water cooling, while boilers heat water. Recent innovations in chiller boiler systems, provide an efficient form of Heating Ventilation and Air Conditioning (HVAC) for homes and smaller commercial spaces. Hydronic systems are increasingly popular used with outdoor wood burner systems.

Many larger cities have a district heating system that provides, through underground piping, publicly available steam and chilled water. A building in the service district may be connected to these on payment of a service fee. Residential heating districts are very common in Europe.

Many of us can recall radiators in our homes using steam or hot water as the heat sources. In the oldest hydronic heating systems, a single-pipe system delivers steam to the radiators where the steam gives up heat and is condensed back to water. Common heating technologies used increasingly today are in floor hydronic heating loops heated by a wood fired boiler or traditionally fueled boilers. Single-pipe systems are limited in both their ability to deliver high volumes of steam (that is, heat) and the ability to control the flow of steam to individual radiators (because closing off the steam supply traps condensate in radiators). Because of these limitations, single-pipe systems are no longer installed, double loop systems are preferred.

Modern systems almost always use heated water rather than steam. This opens the system to the possibility of also using chilled water to provide air conditioning.

In most water systems, the water is circulated by means of one or more circulating pumps. This is in marked contrast to steam systems where the inherent pressure of the steam is sufficient to distribute the steam to remote points in the system. A system may be broken up into individual heating *zones* using either multiple circulator pumps or a single pump and electrically operated zone valves.

Water expands as it heats and contracts as it cools. A water-loop hydronic system must have one or more expansion tanks in the system to accommodate this varying volume of working fluid. These tanks often use a rubber diaphragm pressurized with compressed air.

Industrial Grate/Stoker Fired Boilers (EPA Combined Heat and Power Partnership, Biomass CHP Catalog)

Stoker boilers employ direct fire combustion of solid fuels with air, producing hot flue gases, which then produce steam in the heat exchange section of the boiler. The steam is used directly for heating purposes or passed through a steam turbine generator to produce electric power. Mechanical stokers are the traditional technology that has been used to automatically supply solid fuels to a boiler. All stokers are designed to feed fuel onto a grate where it burns with air passing up through it. The stoker is located within the furnace section of the boiler and is designed to remove the ash residue after combustion. Stoker units use mechanical means to shift and add fuel to the fire that burns on and above the grate located near the base of the boiler. Heat is transferred from the fire and combustion gases to water tubes on the walls of the boiler.

Modern mechanical stokers consist of four elements: 1) fuel admission system, 2) stationary or moving grate assembly that supports the burning fuel and provides a pathway for the primary combustion air, 3) overfire air system supplying additional air to complete combustion and minimize atmospheric emissions, and 4) an ash discharge system.

Stoker boilers are typically described by their method of adding and distributing fuel. There are two general types of systems—***underfeed*** and ***overfeed***. Underfeed stokers supply both the fuel and air from under the grate, while overfeed stokers supply fuel from above the grate and air from below.

Combustion air is introduced from below the grate and moves up through the burning bed of fuel.

Underfeed stokers supply both fuel and primary combustion air from beneath the grate so that the top of the fuel pile is not cooled by cold and moist fuel or cold air. The fuel is moved into a hopper and onto the grate by either a screw- or ram-driven mechanism. Underfeed stokers push the fuel into the bottom of the bed of fuel while heat causes volatilization and complete combustion of the fuel by the time it rises to the top of the bed as ash and is discharged. As the fuel moves out over the grate where it is exposed to air and radiant heat, it begins to burn and transfer heat to the water tubes.

As with any combustion process, ash accumulates as the fuel, is burned. The two basic types of underfeed stokers are: 1) the horizontal-feed, side-ash discharge type and 2) the gravity-feed, rear-ash discharge type. The demand for underfeed stokers has diminished due to cost and environmental considerations. Underfeed stokers are best suited for relatively dry fuel (under 40 to 45 percent moisture.)

Overfeed stokers are generally classified by the way the fuel is distributed and burned within the boiler. The primary designations are mass-feed or spreader stokers. Mass-feed stokers introduce fuel continuously at one end of a grate. As the fuel moves into the boiler, it falls onto the grate by gravity. To control the amount of fuel that enters the boiler, a gate can be moved up or down, or the speed at which the fuel moves beneath the gate can be adjusted. Inside the boiler, the fuel burns as it travels along the grate. Primary combustion air flows upward from beneath the bed of fuel, allowing for complete combustion. Any ash that remains on the grate is then discharged at the opposite end of the system. The two primary mass-feed stokers are: 1) water-cooled vibrating grate and 2) moving (chain and traveling) grate stokers.

Spreader stokers are the most commonly used stokers because of their versatility. They are capable of distributing fuel evenly and to a uniform depth over the entire grate surface by using a device that propels the individual fuel particles into the air above the grate. Methods used to propel the fuel particles include air injection and underthrow and overthrow rotors. As the fuel is thrown into the boiler, fine particles ignite and burn while suspended in the combustion air. The coarser particles that fall onto the grate end up burning in a thin bed of fuel on the grate. Primary combustion air is supplied from beneath the grate. Because the fuel is evenly distributed across the active grate area, the combustion air is uniformly distributed under and through the grate.

Chain grate, traveling grate, and water-cooled vibrating grate stokers are other less common configurations that use various means to maintain an even, thin bed of burning fuel on the grate. Other specialized stoker boilers include balanced draft, cyclone-fired, fixed bed, shaker hearth, tangential-fired, and wall-fired.

Industrial Pulverized Fuel Boilers

Pulverized fuel systems are very common in large modern coal fired power plants, where coal is crushed as fine as talcum powder and injected into the vertically oriented boiler. The Chariton Valley Switchgrass project in Ottumwa, Iowa studied co-firing of ground switchgrass with Powder River Basin sub-bituminous coal in the Alliant Energy Ottumwa Generation Station’s pulverized coal boiler. Due to the short residence time (1 – 1.5 seconds) of fuel being in the boiler, the material is ground very small (10-20 mm maximum) and must have a moisture content of 20 percent or less for complete fuel combustion to occur. Fuel is transported into the boiler via pneumatic material handling systems and injected from various ports along the wall of the boiler; transportation air serves as the primary combustion air. Due to the explosion-like gasification of fine fuel particles, the fuel feed and secondary air must be carefully controlled. Because of the small particle size, fuel gasification and charcoal combustion take place at the same time, therefore fast changes in fueling rates and efficient load control can take place. Due to small fuel particle size, biomass fuels such as sawdust and fine wood shaving serve as good biomass fuels in contrast to chipped or ground wood which cannot be successfully burned. Pulverized boiler systems are designed to crush coal before it enters the boiler. The crushing systems effectively crush wood pellets (pre-ground to be made into a pellet) but are unable to decrease the particle size of whole fibrous herbaceous or woody material.

Industrial Cyclone Boilers operate similarly to pulverized coal systems except they handle larger sized fuels (1/4 inch maximum) that are combusted by the fuel passing over hot slag on the combustion chamber's wall. Slag is fluidized mineral deposited by burning fuel. The vertically oriented boiler has air fans that inject primary and secondary combustion air resulting in a vortex of fuel and air, touching the boiler wall. When fuel is completely burned its ash is recovered from the bottom of the boiler or in the form of fly ash captured from the exiting air stream. Examples of cyclone boilers are found at Alliant Energy's Nelson-Dewey 1 and 2 in Cassville, Wis.

Liquid or gas fueled systems

All of the above described industrial scale boilers are or can be designed to burn fossil or biomass derived liquid and gaseous fuels. Most of the described systems start combustion by using fuel oil, natural gas, or propane. When combustion becomes self-sustaining the gaseous or liquid fuels are shut off. I did not review biomass derived liquid or gaseous fuel systems in the above discussion as most industrial systems have the capability or can be designed to co- or primary fire these fuels.

Overview of advantages and disadvantages of industrial biomass combustion technologies.

The following table (Figure 7) is not offered as a comprehensive list; however, it serves as a summary of items discussed and provides additional information not found in the above discussion.

Gasification

Gasifiers take the thermo-chemical combustion process to the gasification stage of combustion and treat volatile gasses in a variety of ways. Several types of gasifiers are currently available for commercial use: counter-current fixed bed, co-current fixed bed, entrained flow, and plasma gasifiers.

Counter-Current Fixed Bed ("up draft") Gasifier

A fixed bed of carbonaceous fuel (ex. coal or biomass) through which the "gasification agent" (steam, oxygen and/or air) flows in a counter-current configuration. The nature of the gasifier

Figure 7, Advantages and Disadvantages of Various Industrial Boiler Systems

Advantages	Disadvantages
Grate/Stoker Furnaces • Low investment costs for plants <200 MW • Low operating costs • Low dust load in flue gas • Less sensitive to slagging than fluidized bed furnaces	• Mixing of co-firing fuels not possible, unless specially constructed • NOx reduction requires special technology • High oxygen (5-8% by volume) decreases efficiency • Combustion conditions not as homogenous as fluidized bed
Fluidized Bed • No moving parts in the combustion chamber • NOx, reduction by staging air works well • High flexibility concerning kind of biomass and moisture content • Low excess oxygen (3-4% by volume) raises efficiency and < flue gases	• High investment cost, most effective 20 MW> • High operating costs • Cannot utilize high alkali fuels, due to possible bed agglomeration • High dust load in flue gas • Can lose bed material with ash removal
Pulverized Coal • Low excess oxygen (4-6% by volume) increases efficiency • Good load control and fast alteration of load is possible	• Limited particle size (<10-20 mm) • Extra start-up burner is required • Difficult to feed wood chips and coal through shared fuel feed system (wood does not crush) • Greater wear on boiler brickwork from abrasive fuels
Cyclone • Greater fuel size flexibility than pulverized coal • High NOx reduction, if vortex burner are used • Higher alkali fuels can enhance boiler performance over pulverized coal	• Start-up burner required • Difficult to feed wood chips and coal through shared fuel feed system (wood does not crush)

means that the fuel must have high mechanical strength and ideally be non-caking so that it will form a permeable bed, although recent developments have reduced these restrictions to some extent. The throughput for this type of gasifier is relatively low. Thermal efficiency is high as gas exit temperatures are relatively low. However, this means that tar and methane production is significant at typical operation temperatures, so the gas must be extensively cleaned before use. The tar can be recycled and burned in the reactor.

In the gasification of fine, undensified biomass such as oat hulls it becomes necessary to force air into the reactor (combustion boiler) by means of a fan. This creates very high gasification temperatures, at times as high as 1000° C (1,832° F). Above the gasification zone, a bed of fine, hot char is formed, and as the gas is forced through this bed, most complex hydrocarbons are broken down into simple components of hydrogen and carbon monoxide.

Co-current Fixed Bed ("down draft") Gasifier

Similar to the counter-current type, but the gasification agent gas flows in co-current configuration with the fuel (downwards, hence the name "down draft gasifier"). Heat needs to be added to the upper part of the bed, either by combusting small amounts of the fuel or from external heat sources. The produced gas leaves the gasifier at a high temperature, and most of the heat is transferred to the gasification agent in the top of the bed, resulting in energy efficiency on par with the counter-current type. Since all tars must pass through a hot bed of char in this configuration, tar levels are much lower than the counter-current type of gasifier.

Fluidized Bed Reactor

Readers may recall this technology was proposed for use in the power plant planned for construction by Alliant Energy, in Cassville, Wis. (Nelson-Dewey 3). The fuel is mixed with oxygen, steam, air or other media such as calcium carbonate (lime) or sand. Temperatures are relatively low in dry ash gasifiers, so the fuels must be highly reactive; low-grade coals and biomass are particularly suitable. Conversion efficiency can be rather low due to the process of separating lighter particles from heavier ones using a vertically-directed stream of gas of carbonaceous material. Fluidized bed systems work well for the combustion of variable sized and moisture content fuels. Fluidized bed gasifiers are also useful for fuels that form highly corrosive ash that would damage the walls of slagging gasifiers. Some biomass fuels containing high levels of corrosive ash can be reasonably managed in this type of system.

Entrained Flow Gasifier

Entrained flow gasifiers produce a dry pulverized solid, an atomized liquid-like slurry of fuel gasified with oxygen. The gasification reactions take place in a dense cloud of very fine fuel particles. Most coals are suitable for this type of gasifier because of their high combustion temperatures and because the coal particles are well separated from one another.

High temperatures and pressures also mean that higher throughput of fuel can be achieved; however thermal efficiency is somewhat lower as the gas must be cooled before it can be cleaned using existing technologies. High temperatures also mean that tar and methane are not present in the producer gas. All entrained flow gasifiers remove the major part of the ash as slag as the gasifiers operating temperature is well above the ash fusion temperature.

Some fuels, in particular certain types of biomass (i.e., corn stover) can form slag that is corrosive to the inner walls that serve to protect the gasifier outer wall. However some entrained bed types of gasifiers have a water or steam cooled wall covered with partially solidified slag. These types of gasifiers do not suffer from corrosive slags.

Some fuels have ash with very high ash fusion temperatures; however, it can vary widely between the same fuel depending on the biomass plant's growth rate and the soil fertility where it is grown. In these cases limestone can be mixed with the fuel prior to gasification. Addition of a little limestone can lower ash fusion temperatures. Fuel particles in this type of gasifier must be smaller than for other types of gasifiers. This means the fuel must be pulverized, which requires more energy than for the other types of gasifiers. However, the most energy consumption related to entrained bed gasification is not the milling of the fuel but the production of oxygen used for gasification.

Plasma Gasifier

In a plasma gasifier a high-voltage current is fed to serve as a torch, creating a high-temperature arc. Inorganic residue is retrieved as a glass-like substance. Plasma gasifiers are high cost to operate and are well suited for incineration of hazardous biological materials. The process uses plasma gas to super heat waste materials. The extreme heat ranges between 10,000 to 15,000° F. The high heat rearranges the molecular structure of the waste and transforms organic materials to syngas for conversion to electricity or liquid fuels such as ethanol or diesel fuels. In the next stage of combustion the inorganic wastes are recycled into other products. Waste Management Company recently announced a joint venture with InEnTec to construct a commercial scale plant in the state of Oregon for the destruction of certain waste streams.

Boiler Retrofit or Replacement Applications of Gasification Technology

Whatever gasification technology is used the volatile gas (syngas) produced is used to maintain flame combustion or can be processed as gas for use in internal combustion engines and turbines or cleaned and injected in a gas pipeline and transported to a gas end user. A common issue with syngas is its content of tar and corrosive alkalis that are damaging to metal surfaces. Proprietary gas clean-up systems exist that are capable of cleaning the gas as it exits the gasifier before its end use. Such a system is used as a natural gas replacement at Chippewa Valley Ethanol outside of Benson, Minn.

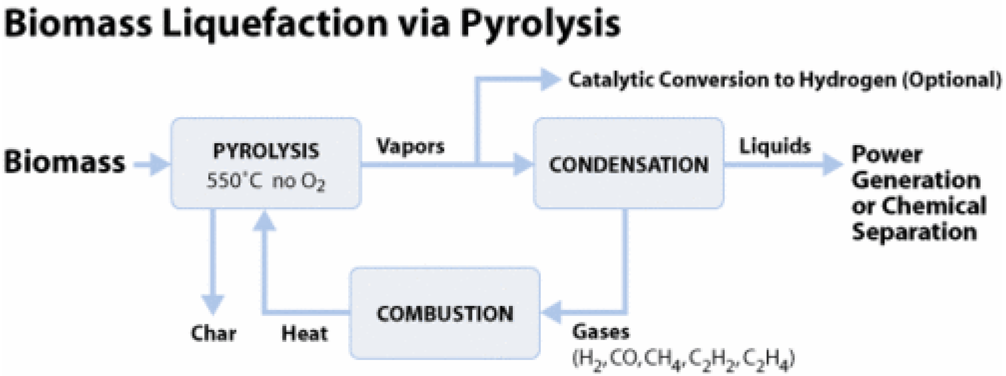
Installation of a gasifier may have practical application for the introduction of syngas as a fossil fuel replacement in existing coal, propane, or natural gas combustion systems. Due to the capital, operating, and maintenance costs of such systems, gasification systems have greater practical application for industrial and utility scale operations. When fuels containing high alkali content (ex. corn stover) predominate, a gasifier with a gas clean–up system may be considered for co-firing or as a stand-alone replacement fuel. Such a system would reduce coal consumption while utilizing an existing power or CHP boiler and reduce air emissions while co-firing with coal. See Figure 8 for a comparison of boiler technologies, their capacities, and biomass fuel limitations.

Figure 8, Boiler Comparisons

Biomass Conversion Technology	Common Fuel Types	Feed Size	Moisture Content	Capacity Range
Stoker grate, underfire stoker boilers	Sawdust, bark, chips, shavings, end cuts, sander dust	0.25–2 in.	10–50%	4 to 300 MW (many in the 20 to 50 MW range)
Fluidized bed boiler	Wood residue, peat, wide variety of fuels	< 2 in.	< 60%	Up to 300 MW (many in the 20 to 25 MW range)
Cofiring—pulverized coal boilers	Sawdust, bark, shavings, sander dust	< 0.25 in.	< 25%	Up to 1000 MW
Cofiring—stoker, fluidized bed boilers	Sawdust, bark, shavings, wood chips	< 2 in.	10–50%	Up to 300 MW
Fixed bed gasifier	Chipped wood, rice hulls, shells, sewage sludge	0.25–4 in.	< 20%	Up to 50 MW
Fluidized bed gasifier	Most wood and agriculture residues	0.25–2 in.	15–30%	Up to 25 MW

Pyrolysis is a conversion technology used to produce higher density energy from any biomass product. Pyrolysis involves the heating of organic materials in the absence of reagents, especially oxygen, to achieve decomposition. When pyrolysis takes place in the presence of water, it is called hydrous pyrolysis. The flow chart below illustrates that when biomass is heated to about 550 degrees Celsius (1022° F), in the absence of oxygen many of its volatile organic compounds turn to vapor and when condensed become a liquid that retains heating value greater than the solid biomass of its origin. For best results biomass being converted through pyrolysis should be as low in moisture content as practically possible. Even when using dry biomass at 6 percent moisture, pyrolysis oil will be about 22 percent moisture from biomass moisture content and reforming of hydrogen and oxygen coming from the biomass itself. Liquid fuels can be easily processed, stored, and handled using conventional liquid handling systems modified to accommodate characteristics of pyrolysis, such as pH and shelf life. Pyrolysis technology is illustrated in Figure 9.

Figure 9, Biomass Liquefaction via Pyrolysis



(Wikipedia)

Types of Pyrolysis Technologies

There are two types of Pyrolysis technologies, Fast and Slow Pyrolysis.

Fast Pyrolysis

Fast pyrolysis is currently the most widely used pyrolysis system. Fast pyrolysis (flash pyrolysis) takes place with any biomass material in less than two seconds with temperatures between 300 and 550 °C (572- 1022 °F). Char accumulates quickly in fast pyrolysis and must be removed frequently. Fast pyrolysis is known for its high yields, up to 70 percent by weight conversion of dry biomass to liquid fuel. The conversion process takes about 2 seconds after heating biomass at 520 to 550° C (968-1022° F) for 6 percent moisture fuels less than one-quarter inch thick. Oil yields are impacted by biomass ash content, with hardwood at approximately 1 percent, softwoods at approximately 2 percent and grasses at greater than 5 percent ash content. Fast pyrolysis yields 60 percent bio-oil and takes seconds to complete; in addition, it gives 20 percent biochar and 20 percent syngas.

Bio-oil is a dark brown liquid and has a similar composition to its biomass of origin. It has a much higher energy density than woody materials which reduces storage and transport costs. Bio-oil is not suitable for direct use in standard internal combustion engines. However, the oil can be upgraded to either a special engine fuel or through gasification processes to a syngas and then bio-diesel. Bio-oil is particularly attractive for co-firing because it can be more readily handled and burned than solid fuel and is cheaper to transport and store.

Fast Pyrolysis can be further categorized into the following:

Ablative Fast Pyrolysis - pressure is applied to biomass to increase speed of decomposition through use of centrifugal or mechanical force. Larger particles of biomass can be used in this process.

Cyclonic Fast Pyrolysis - also called vortex fast pyrolysis, separates the solids from the non-condensable gases and returns the solids to the vortex mixer.

Rotating Cone Fast Pyrolysis - uses a compact high intensity reactor in which biomass of ambient temperature is mixed with hot sand. Upon mixing with the hot sand, the biomass decomposes into 70 percent condensable gases with 15 percent non-condensable gases and 15 percent char.

Slow Pyrolysis (also called vacuum pyrolysis)

Feedstocks for Slow Pyrolysis include any biomass material that is sorted to an acceptable particle size of less than 6 mm (1 to 2 mm, preferred) and less than 10 percent moisture content to assure high heat transfer rate.

Products

Slow pyrolysis takes several hours to complete and results in biochar as the main product. Other products of slow pyrolysis include intermediate products such as syngas and charcoal, whereas the primary final products are bio-oil and charcoal.

Utilization of the technology

Pyrolysis is a largely unproven commercial technology for large scale production of liquid fuels. Wisconsin has one of the few commercial pyrolysis facilities in the United States, Ensys produces bio-oil marketed as "Liquid-Smoke" in northern Wisconsin, another facility was proposed in Cashton, Wisconsin, but has not been built. A facility under construction by Avello in Des Moines, Iowa plans to produce bio-asphalt through pyrolysis of biomass. Pyrolysis oil as a combustion fuel is challenged by its history of low pH and short self-life, these issues are being researched and likely not to be issues in the near future.

Biogas Production

Biogas plant is the name often given to an anaerobic digester that treats farm solid wastes and energy crops, however, municipal and industrial waste water can be similarly treated. Montchevre' cheese factory in Belmont, Wis. is an example where waste water is treated in an anaerobic digester for production of heated process water and power generation (sold to Alliant Energy).

Biogas contains a high percentage of methane and can be produced in air tight vessels fed with energy crops such as corn silage or with materials that include sewage sludge, manure, and food waste. During the digestion process, anaerobic methanogenic bacteria transform biomass into biogas that contains many gases including methane that can be used to produce renewable energy used for heating, electricity, and other operations such as fueling internal combustion engines or micro-turbines. There are three different temperature dependent anaerobic digestion processes: mesophilic, thermophilic, and psychrophilic digestion. Mesophilic digestion occurs at 100° to 105° F (38° - 41° C). This is the common temperature range used with manure digesters. There is a wide range of mesophilic methanogen (methane producing) temperature bacteria, and mesophiles are more tolerant of substrate and temperature variation than thermophilic bacteria. Thermophilic digestion occurs at approximately 135° F (57° C). Thermophilic systems produce the greatest methane yield of the three temperature range methanogens. However, they have a higher energy requirement due to the need to maintain higher temperatures for thermophilic methanogens. Psychrophilic bacteria operate at ambient temperatures of 14° to 59° F (-10° to 15° C) requiring no external heat input. They produce the lowest methane yield. Manure lagoons operate at this temperature range.

Landfill gas (LFG) is produced by wet organic waste decomposing under psychrophilic anaerobic conditions found in the landfill. Landfill waste is covered and mechanically compressed by the weight of the material deposited above; this material prevents oxygen exposure, allowing anaerobic microbes to thrive. Heat produced from bacterial metabolism maintains landfill heat which can foster development of methanogenic bacteria. The gas produced builds up and is slowly released into the atmosphere if the landfill site has not been engineered to capture the gas. Landfill gas is hazardous. It becomes explosive when it escapes from the landfill and mixes with oxygen. The lower explosive limit is 5 percent methane and the upper explosive limit is 15 percent methane. Additionally, methane contained within biogas is 21 times more potent as a greenhouse gas than carbon dioxide; therefore, uncontained landfill gas escaping into the atmosphere may contribute to the effects of greenhouse gases (GHG) and potentially to global climate change. Figure 4 (page 23) lists the typical chemical composition of biogas.

The composition of biogas varies depending upon the origin of the process and the biological material used. Biogas typically has methane concentrations around 50 percent. Advanced waste treatment technologies can produce biogas with 55 to 75 percent methane, which can be increased to 80 to 90 percent methane using gas purification techniques. As-produced, biogas also contains water vapor. In some energy applications a condenser is used to remove water vapor. Hydrogen sulfide also found in biogas in the presence of water vapor will form corrosive sulfuric acid, necessitating removal before introduction into a combustion system. In some cases landfill derived biogas contains siloxanes. Siloxanes are formed from the anaerobic decomposition of materials commonly found in soaps and detergents. During combustion of biogas containing siloxanes, silicones are released and combine with free oxygen or various other elements in the combustion gas. Deposits are formed containing mostly silica (SiO_2) or siloxanes (Si_xO_y), but can also contain, sulfur, zinc, and phosphorus. Biogas containing these elements is analogous to adding sand to your engine's fuel, such a combination results in abrasion and short engine or micro turbine life. Such deposits can also accumulate on surfaces and form thicknesses of several millimeters, necessitating removal by chemical or mechanical means. Practical and cost-effective technologies to remove siloxanes and other biogas contaminants are available.

The author has experience with siloxanes and strongly advises their removal from biogas to avoid costly repairs to power and thermal systems.

Biogas Benefits

In North America, utilization of biogas from livestock operations has the potential to generate enough electricity to meet up to three percent of the continent's electricity expenditure. In addition, biogas could potentially help reduce greenhouse gasses (GHGs). Normally, manure left to decompose releases three gases contributing to greenhouse gases: carbon dioxide, nitrous dioxide, and methane. Nitrous dioxide warms the atmosphere 310 times more than carbon dioxide and methane 21 times more than carbon dioxide. By converting cow manure into methane biogas via anaerobic digestion, it has been estimated that the millions of cows in the United States would be able to produce one hundred billion kilowatt hours of electricity annually, enough to power millions of homes across the United States. Furthermore, by converting cow manure into methane biogas instead of letting it decompose, we would be able to reduce United States sources of GHGs. The United States has approximately 125 on-farm anaerobic digester systems, in comparison Germany has over 5,500 anaerobic digesters; the potential for anaerobic digester systems in North America is largely untouched. Increasingly, on-farm anaerobic digesters are accepting bio-degradable organic wastes from ethanol plants, food processors, and field crops to increase biogas production. In European countries with very favorable electrical buy-back rates some farms grow crops exclusively for use in their digesters.

Common Anaerobic Digester Designs

Nearly all mesophilic or thermophilic systems derive their heat for maintaining substrate temperature from the heat produced from biogas fueled internal combustion engines, turbine exhaust, radiator/engine jacket cooling systems, or from biomethane fueled boiler systems.

Plug Flow

Plug flow systems are commonly used on livestock farms for their ease of operation and low cost design. A common design is a U-shaped underground storage tank, substrate is frequently added to one end of the container, after an appropriate “residence time” effluent empties from the other end of the U-shaped container. Substrate empties the system as a first in first out design. To optimize gas production in a mesophilic temperature system, substrate should remain in the digester for 18 to 21 days.

Complete Mix

Complete mix systems are designed as single or multiple (usually above ground) tanks where substrate is frequently and mechanically mixed with substrate already contained within the digester. To increase “residence time” and optimize gas production substrate is commonly pumped into an addition tank. Substrate empties the system as first in, mixed, or random material out design.

Partial Mix

This system can be similar to a plug-flow design where a portion of the effluent is mixed with incoming substrate in an attempt to “inoculate” new substrate with methanogens from the effluent. This type of system is designed to reduce time necessary for new substrate to foster development of methanogens sufficient to produce biogas early in the substrate’s residence time. Substrate empties as a first in first out design.

On farm digesters using the above stated designs have been successfully deployed with reasonable pay-back periods in herds of 300 head or greater. Smaller herds may be able to incorporate digester technologies into their manure management system; however, the return on investment may be long to non-existent.

Biogas Membrane Technologies

Mobilized Film

Mobilized film technology is especially useful for waste water systems with low percent solids content in the waste stream, such as milk or other beverage processing systems. These processing systems are characterized by large volumes of low biological solids content liquid substrate. Anaerobic digester systems described earlier would necessitate very large containment vessels. To reduce residence time and investment in large storage vessels, methanogen bacteria are attached to high density particles (such as sand), substrate is pumped through the sand (usually from the bottom of the vessel) to mix and expose organic material in the substrate to methanogens. This type of system reduces residence time from days to hours. Mobilized film does not work well where a high percentage of solids exists as the solids will carry away the mobilized particles. Substrate is usually monitored for its biological oxygen demand (BOD) and discharged when BOD is low enough to meet allowable discharge limits.

Fixed Film

Fixed film anaerobic digestion systems work on many of the same principals as mobilized film, however, methanogen bacteria are fixed to an immobile delivery system such as a mesh. Fixed film digesters can sustain themselves in greater viscosity substrates (but are generally not well suited to manure) than the mobilized film technology and not be carried away.

Applications

Biogas can be utilized for heat or electricity production in a boiler, internal combustion engine, or micro turbine. Waste heat from the engine is conveniently used for heating the digester, cooking, space heating, and process heating. If compressed, it can replace fossil fuels for use in vehicles, where it can fuel an internal combustion engine. Compressed biogas is widely used in Sweden, Switzerland, and Germany. This application is used at the Rodefeld Landfill in Dane County, Wis. In cooperation with Cornerstone Environmental Company, Dane County Government is fueling some of their pick-up trucks with biomethane.

Methane within biogas can be concentrated via a biogas cleaning system to the same standards as fossil derived natural gas (which itself has had to go through a cleaning process), and become biomethane. If the local natural gas provider network allows, the producer of the biogas may sell the cleaned gas into the local gas distribution networks. Gas must be very clean to reach pipeline quality, and must be of the correct composition for the local distribution network to accept. Such a system is in use at a dairy farm in southern Michigan. Carbon dioxide, water, hydrogen sulfide, and particulates must be removed in order to become pipeline quality.

Retrofit or replacement boiler applications.

Anywhere suitable biodegradable materials are available for anaerobic digestion; clean biogas can be utilized as a replacement for natural gas. Existing propane systems require modification to utilize biogas as the Btu value of biogas is akin to natural gas and not suitable for unmodified propane systems. Some solid fuel systems can be modified to accommodate co-firing or exclusive firing with biomethane. As discussed earlier these systems are being used successfully both regionally and locally. Gunderson Lutheran Health System in LaCrosse, Wis. heats one of its clinics using biogas from a waste water treatment plant operated by City Brewery.

Stirling Engine: A Power Generation Technology

The **Stirling engine** is operated by compression and expansion of a fixed working gas trapped in the engine cylinder. Unlike a steam engine (or more generally a Rankine cycle engine) which uses a working fluid in both its liquid and gaseous phases, the Stirling engine cylinder encloses a fixed quantity of permanently installed gasses such as air or hydrogen. Typical of heat requiring engines, the operating cycle consists of compressing cool gas, heating the gas, expanding the hot gas, and finally cooling the gas before repeating the cycle. The efficiency of the process is narrowly restricted by the temperature difference between the hot and cold reservoirs. The Stirling engine is traditionally classified as an external combustion engine, as all heat transfers to and from the working gas take place through the engine wall. This contrasts with an internal combustion engine where heat input is by combustion of a fuel within the body of the engine cylinder.

The heat source of a Stirling Engine can come from the combustion of almost any fuel since combustion products do not mix with the working fluid (that is, external combustion) or come into contact with the internal moving parts of the engine. A Stirling engine can run on fuels that would damage other (that is, internal combustion) engine's internal parts, such as landfill gas containing siloxanes.

The practical use of Stirling engines has largely been confined to low-power domestic applications. Stirling technology is common on boats and yachts as the engine can provide hot water and power within a small space. Stirling engines have a reputation of being high maintenance as the working gas frequently chosen is hydrogen, and hydrogen often leaks from the engine (due to its small molecular size) requiring a hydrogen supply or operation of a hydrogen generator.

Boiler Technology Costs

Any discussion of technology cost must be preceded with "it all depends." It depends on whether the technology will be used as a retrofit, co—fire, or new installation. It depends on the fuel, fuel availability, and storage and material handling system requirements. It depends on the footprint required to install the technology. It depends on local and regional permits and emission standards. It depends on how the heat and/or power will be used. It depends on the size of the combustion unit. Therefore cost is relative to what, why, where, and how the unit will be used.

In general terms, depending on the technology, economies of scale most often apply to heat and power systems. While there are many "off the shelf" technologies, their installation and application, especially in commercial and industrial uses are customized to their application. Figure 10 (EIA, Annual Energy Outlook 2010, December 2009, DOE/EIA-0383(2009) provides a graphic illustration of relative costs of a variety of renewable energy options including capital and operating and maintenance costs. Figure 11 (EIA, Annual Energy Outlook 2010, December 2009, DOE/EIA-0383(2009) compares the cost of installation and operation of a few biopower combustion technologies.

Figure 10, Relative Costs of Renewable Options

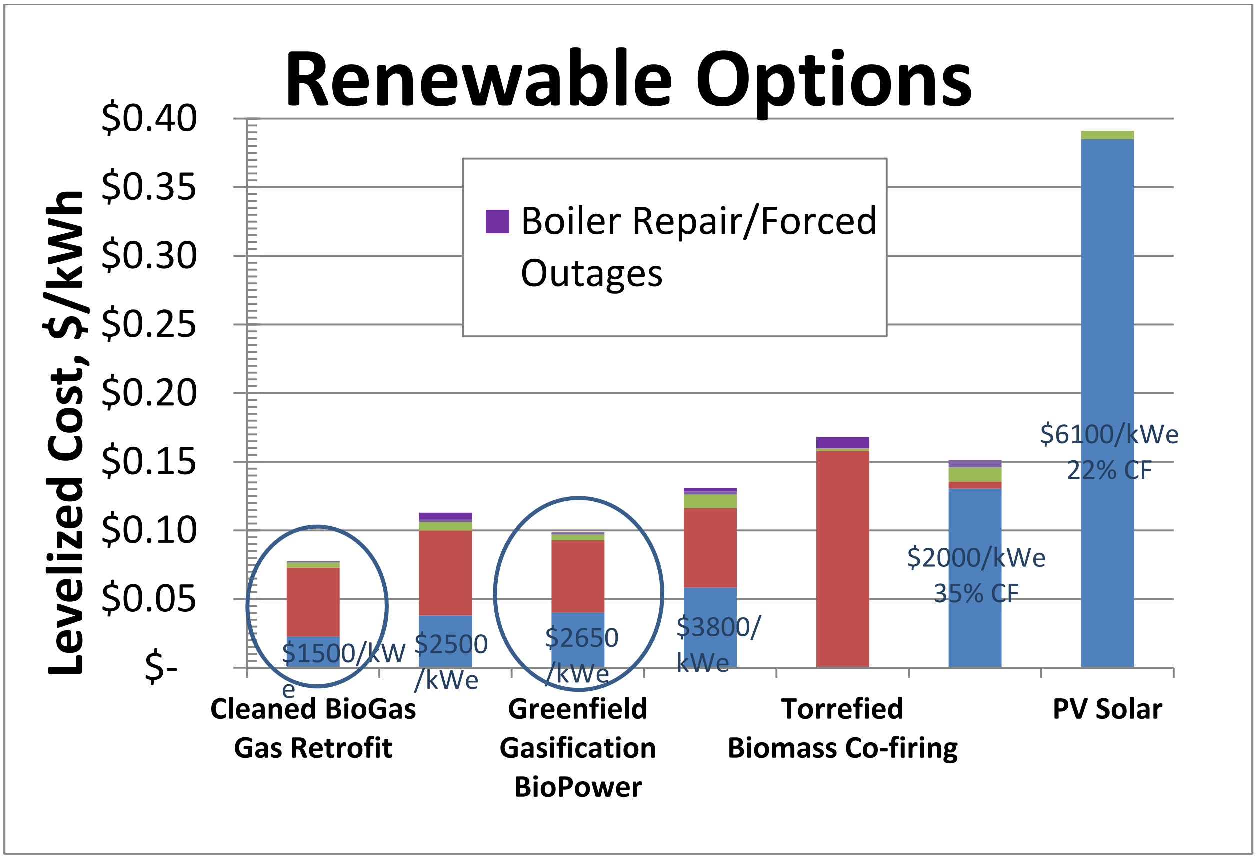
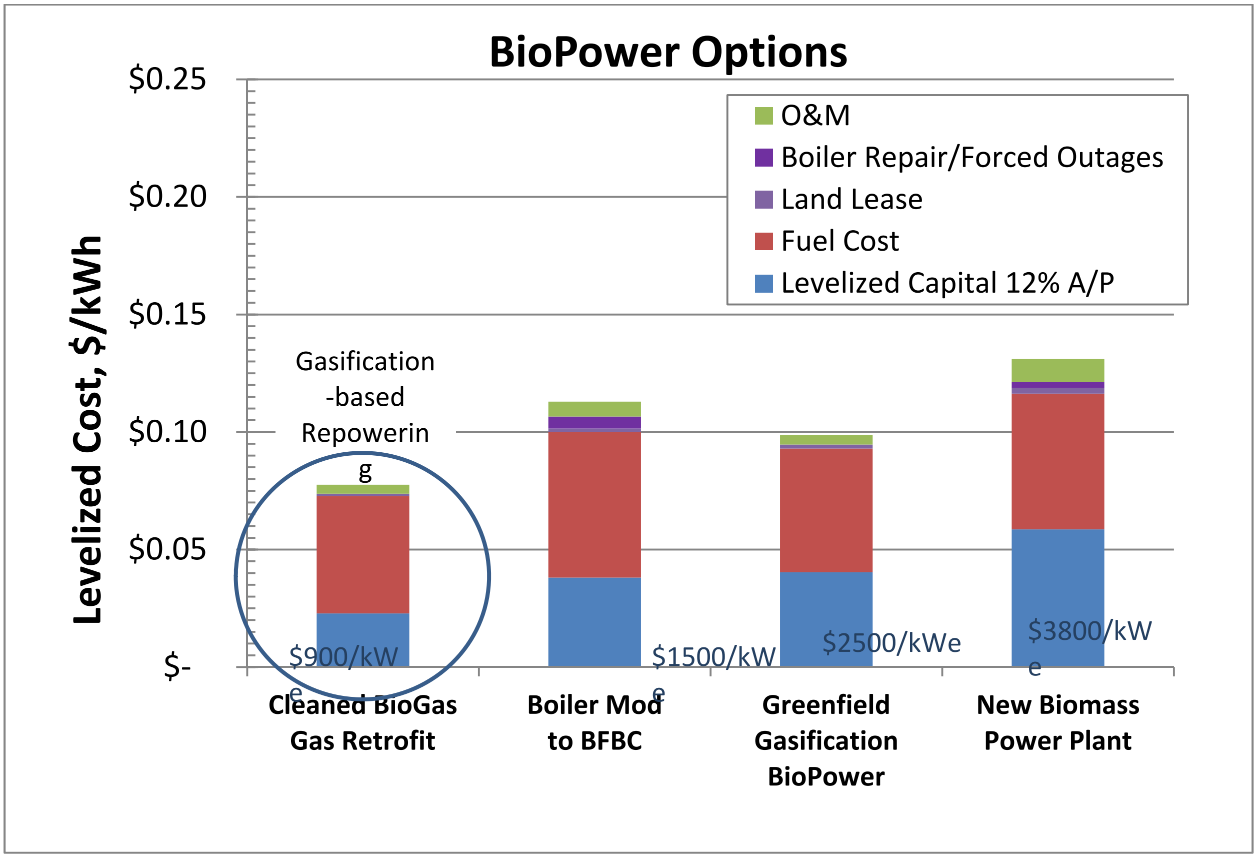


Figure 11, Relative Costs of Biopower Options



Biomass Financial Assessment

An Xcel spreadsheet, designed by Bob Govert of the University of Wisconsin-Stevens Point, with the financial assistance of Lumberjack RC&D Council, Wisconsin Department of Natural Resources and the U.S. Forest Service, is available through Southwest Badger RC&D to provide an initial overview of the financial feasibility of utilizing wood chips or wood bark as a boiler fuel. The tool provides users with a simple “payback” analysis through comparison of wood fuels with other common boiler fuels. Directions for using the biomass calculator are included on the spreadsheet. Free tutorial assistance is available by contacting Bob Govert at (715) 316-4212, rgovert@uwsp.edu. While working with some survey participants I used the spreadsheet and provided them with information useful in evaluation of boiler fuels.

While seeking an assessment tool and contemplating collaborative development of one with someone more skilled with spreadsheets than me, I reviewed simple and complex spreadsheets. I found the Govert spreadsheet friendly to use with little experience necessary to feel confident in the results. Recently, while teaching in Norway the author witnessed the use of a more complex and comprehensive spreadsheet useful in determining the impact of transportation costs by fuel type and physical form and the expression costs of fuel cost in terms of energy output, weight, and volume. The author is seeking permission to use and distribute the spreadsheet.

Other decision making considerations

Many questions need to be asked when considering whether to switch from fossil fuels to renewable fuels. This decision depends on many macro factors. It depends on whether the technology will be used as a retrofit, co-fire, or new installation. It depends on the fuel, fuel availability, and storage and material handling system requirements. It depends on the footprint required to install the technology. It depends on local and regional permits and emission standards. It depends on how the heat and/or power will be used. It depends on the size of the combustion unit. There are many details to consider when designing a system depending on whether it will be designed in concert with or around an existing system or if it is an entirely new system.

The list of considerations is exhaustive and best left to an experienced design engineering company. While some technologies are available off-the-shelf, all systems require customization to their locale.

Biomass Incentives and Assistance

There are a variety of incentives to develop renewable energy projects with various sources for their funding.

Renewable Portfolio Standards (RPS)

Twenty-nine states, Washington, DC and Puerto Rico have RPS polices requiring power generation companies to produce power from renewable sources. Wisconsin has a goal of achieving 10 percent renewables by 2015. This is a modest goal which can be largely achieved with wind powered projects. Individual Wisconsin utilities have varying renewable energy targets based on targets negotiated with the Wisconsin Public Service Commission. Utilities respond independently based on their generation portfolio requirements, status of their generation fleet, and access to renewable resources.

Some Wisconsin utilities can achieve their renewable targets through their own investments. Most have developed incentives for sources of small scale distributive power generation through "buy-back" Power Purchase Agreements (PPA) or Net-Metering rates above their "avoided cost" that encourages renewable energy project development. Avoided cost is the utility's cost of power production, which is the minimum they are required to pay for new power generation. Incentive rates must be approved by the Wisconsin Public Service Commission (WPSC) and are usually for a fixed period of time (years) and for a maximum limit of kilowatt hours the utility annually purchases at that rate. The utility is allowed to recover costs from rate payers through rate setting fuel adjustment cost provisions. Utilities' incentives often target technologies or fuel sources (ex., on-farm anaerobic digestion) to encourage their development. Each utility has unique incentives, rates, and programs supporting their appetite for sources of renewable energy.

Wisconsin Renewable Energy Incentives

Wisconsin RPS (The following WPSC descriptions were provided to the author by the Wisconsin Public Service Commission)

Note: In 2010 S.B. 273 amended Wisconsin's RPS to allow certain technologies which displace electricity use (i.e., rather than generate renewable electricity) to qualify for the standard. The rulemaking associated with this change has not yet been completed. While the list of eligible technologies includes several examples of such electricity displacement resources (e.g., solar water heating), it remains to be seen whether any or all of these technologies will ultimately be deemed eligible for the standard.

In 1998 Wisconsin enacted Act 204, requiring regulated utilities in eastern Wisconsin to install an aggregate total of 50 MW of new renewable-based electric capacity by December 31, 2000. In

October 1999 Wisconsin enacted Act 9, becoming the first state to enact a renewable portfolio standard (RPS) without having restructured its electric-utility industry. Wisconsin's RPS originally required investor-owned utilities and electric cooperatives to obtain at least 2.2 percent of the electricity sold to customers from renewable-energy resources by 2012. Legislation (S.B. 459) enacted in March 2006 increased renewable-energy requirements and established an overall statewide renewable-energy goal of 10 percent by December 31, 2015. The requirements are as follows:

- For the years 2006 through 2009, each utility -- including municipal utilities -- may not decrease its renewable-energy percentage below the utility's average renewable-energy percentage for 2001 through 2003.
- For the year 2010, each utility had to increase its renewable-energy percentage by at least two percentage points above the utility's average renewable-energy percentage for 2001, 2002 and 2003.
- For the years 2011 through 2014, each utility cannot decrease its renewable-energy percentage below the utility's renewable-energy percentage for 2010.
- For the year 2015, each utility must increase its renewable-energy percentage by at least six points above the utility's average renewable-energy percentage for 2001 through 2003.
- For each year after 2015, each utility may not decrease its renewable-energy percentage below the utility's renewable-energy percentage for 2015.

Electric providers, wholesale suppliers and customers of electric providers may petition the PSC for a one-year extension of a compliance deadline. By June 1, 2016, the Wisconsin Public Service Commission (PSC) must determine if the state has met a renewable-energy goal of 10 percent by December 31, 2015. If the goal has not been achieved, the PSC must indicate why the goal was not achieved and must determine how it may be achieved.

Qualifying electricity generating resources include tidal and wave action, fuel cells using renewable fuels, solar thermal electric and photovoltaics (PV), wind power, geothermal, hydropower, and biomass (including landfill gas). In May 2010, the RPS was amended by S.B. 273 to allow solar, geothermal, biomass, and biogas resources that produce a measurable and verifiable displacement of conventional electricity resources to also qualify as eligible resources (i.e., non-electric resources which displace electricity). Furthermore, the new law permits electricity generated (or electricity displacement) by certain waste resource technologies to qualify for the standard. The PSC is developing rules in Docket 1-AC-234 to establish standards for measuring and verifying non-electric technologies. Renewable energy generated outside of Wisconsin is eligible, but the electricity must be used to meet a provider's retail load obligation in Wisconsin (i.e., it must be delivered to Wisconsin customers).

Electricity generated by hydropower receives special treatment. For small hydropower (less than 60 MW), utilities receive credit for the sum of (1) all hydropower purchased in a reporting year,

(2) the average of the amounts of hydropower generated by facilities owned or operated by the utility for 2001, 2002 and 2003, adjusted to reflect the permanent removal from service of any of those facilities and adjusted to reflect any capacity increases from improvements made after January 1, 2004; and (3) the amount of hydropower generated in the reporting year by facilities owned or operated by the electric provider that are initially placed in service on or after January 1, 2004. As a result of S.B. 81 enacted in July 2011, beginning December 31, 2015 (the effective date of S.B. 81), electricity from large hydropower facilities (60 MW or more) can be counted toward the RPS requirement if the facility was placed in service on or after December 31, 2010. Facilities in Manitoba, Canada are eligible if certain requirements are met.

A Renewable Resource Credit Program has been established, enabling utilities to buy and sell "renewable resource credits" (RRCs)* from one another for any electricity generated in excess of the percentage specified for a given year. Credits also may be used in subsequent years. Existing installations that qualify as renewable energy resources are eligible to be counted towards a utility's compliance, however, only generation capacity (including incremental additions at existing installations) added after January 1, 2004 is eligible to generate tradable RRCs. An RRC created before January 1, 2004 may be used for compliance until December 31, 2011, after which it will expire. An RRC generated after January 1, 2004 may be used for compliance up to 4 years after the year in which it was created.

The Wisconsin PSC was one of principal developers of the Midwest Renewable Energy Tracking System (M-RETS) to be used for this purpose. Public reports detailing utility progress under the RRC program are available on the M-RETs website.

** These credits are known as "renewable energy credits" (RECs) in most other states.*

Wisconsin Interconnection Standards

In an attempt to reduce confusion between technology vendors and electrical contractors about the installation of distributive generation power systems the Wisconsin Public Service Commission adopted interconnection standards for distributed generation (DG) systems up to 15 megawatts (MW) in capacity in February 2004. All investor-owned utilities (IOUs) and municipal utilities are required to abide by the standard provisions. (Electric cooperatives are encouraged -- but not required -- to adopt the state standards.) The rules categorize DG systems by capacity and provide for several levels of interconnection review, as follows:

- Category 1: 20 kilowatts (kW) or less
- Category 2: larger than 20 kW, but no larger than 200 kW
- Category 3: larger than 200 kW, but no larger than 1 MW
- Category 4: larger than 1 MW, but no larger than 15 MW

The PSC has published two sets of standard forms for interconnection, available on the program web site. One set pertains to systems smaller than 20 kW while the second set applies to larger systems up the maximum size of 15 MW. The PSC also maintains a list of utility interconnection contacts on their Distributed Generation web site. The Wisconsin Distributed Resources Collaborative (WIDRC) has published a set of interconnection guidelines that offer some additional details on the interconnection process.

Generally speaking, Wisconsin's interconnection requirements become more stringent as the system size increases. The rules apply to all public utilities. The 20-kW dividing line between Category 1 and Category 2 installations corresponds to the maximum individual system capacity allowed under the state's net-metering rules. Systems that qualify for net metering are not considered commercial ventures that require commercial liability insurance.

Minimum liability insurance of at least $300,000 per occurrence is required for systems 20 kW and smaller (Category 1) with higher amounts for larger systems based on the category of review under which they fall. However, the law also permits applicants to prove financial responsibility using a negotiated agreement with the utility in lieu of the insurance requirements. Additionally, Category 2-4 facilities must name the utility as an additional insured party in the insurance policy.

Application and study fees vary by category, but systems 20 kW and smaller are not required to pay fees for application reviews, engineering reviews, or distribution system studies. Facility owners are permitted to file an appeal with the PSC if they believe they are being held to unreasonable requirements, but the rules do not provide any guidance on how such appeals will be addressed.

Wisconsin - Net Metering

The Public Service Commission of Wisconsin (PSC) issued an order on January 26, 1982, requiring all regulated utilities to file tariffs allowing net metering (customer is paid their retail energy rate) to customers that generate electricity with systems up to 20 kilowatts (kW) in capacity. The order applies to investor-owned utilities and municipal utilities, but not to electric cooperatives. All distributed-generation (DG) systems, including renewables and combined heat and power (CHP), are eligible. There is no limit on total enrollment. For systems exceeding 20 kW utilities must allow eligible system electrical interconnection, but are only required to pay the “avoided cost” (cost of utility generation) for electricity.

The PSC has not adopted administrative rules for net metering.* Utilities' net-metering tariffs contain some variations. Customer net excess generation (NEG) is generally credited at the utility's retail rate for renewables, and at the utility's avoided-cost rate for non-renewables. NEG credit is carried over to the customer's next bill. If NEG credit exceeds $25, then the utility must issue a check for the amount, payable to the customer.

** Subsequent PSC decisions issued June 21, 1983, in docket numbers 05-ER-11, 05-ER-12 and 05-ER-13, further implemented Sections 201 and 210 of the federal Public Utility Regulatory Policy Act of 1978 (PURPA). These decisions were confirmed by an order issued September 18, 1992, in docket number 05-EP-6. This last order addresses net metering as it applies to Wisconsin's investor-owned utilities.*

Woody Biomass Harvesting and Processing Tax Credit (Corporate and Personal)

In May 2010 Wisconsin enacted legislation allowing taxpayers to claim a tax credit from income or franchise taxes of 10 percent of the cost of equipment primarily used to harvest or process woody biomass for use as a fuel or as a component of fuel. The adopted law creates identical tax credits in the portions of the Wisconsin tax code relating to income taxes on individuals (§71.07), income and franchise taxes on corporations (§71.28), and income and franchise taxes on insurance companies (§71.47). Woody biomass is defined as "...trees and woody plants, including limbs, tops, needles, leaves, and other woody parts, grown in a forest or woodland or on agricultural land." For equipment to be considered "primarily" for an eligible purpose, other uses of the equipment are limited to no more than 25% of total use. The credit may not be claimed for any business or trade expenses deducted by the taxpayer under 26 USC §162.

The credit will be available for 5 years, from January 1, 2010 to December 31, 2015. Allowable credits in excess of a claimant's tax liability for a given year will be refunded. Credits are limited to $100,000 per claimant in aggregate, and $900,000 in total each fiscal year. In addition the Department of Commerce is required to allocate $450,000 in tax credits each fiscal year to businesses that individually have no more than $5 million in gross receipts in Wisconsin for the taxable year in which the credit is claimed. Taxpayers will need to be certified by the Wisconsin Department of Commerce (DOC) in order to claim the tax credit. The DOC, in cooperation with the Department of Revenue, is required to develop regulations to implement the law.

Renewable Energy Sales Tax Exemptions

Wisconsin has two sales tax exemptions that apply to renewable energy. Legislation enacted in 1979 exempts wood sold as a fuel for residential use from the state sales and use tax (Wis. Stat. § 77.54(30)). Residential use means use in a structure or portion of a structure which is the person's permanent residence. A clause was added in 2007 expanding the exemption to include sales of all biomass -- as defined in Wis. Stat. § 196.378 (1) (ar) -- used as fuel for residential use. This definition includes wood, energy crops, biological wastes, biomass residues, and landfill gas.

The original Wis. Stat. § 77.54(30) was also amended in 1987 to exempt from the state sales and use tax gross receipts from the sale of qualifying biomass residues used as fuel for business activity. Qualifying residues are defined as arising from the "harvesting of timber or the production of wood products, including slash, sawdust, shavings, edgings, slabs, leaves, wood chips, bark and wood pellets manufactured primarily from wood or primarily from wood residue."

Separately, legislation was enacted in 2007 (Wis. Stat. § 77.54(56)) to exempt products whose power source is wind, solar radiation, or gas produced from the digestion of animal manure and other agricultural wastes from the sales and use tax, effective July 2009. However, in 2009 this section of code was amended (2009 Act 28) to delay the effective date of the exemption until July 1, 2011. In order to be considered an eligible product, devices must be capable of producing at least 200 watts of alternating current or 600 British thermal units per day. The exemption under *does not apply* to un-interruptible power sources that are designed primarily for computers. The law also exempts "receipts from the sale of and the storage, use, or other consumption of electricity or energy" produced by a qualifying system.

The Department of Revenue adopted an Emergency Rule in June 2011 to clarify the definition of "product." The rule reiterates that for the purposes of the exemption, "product" means "tangible personal property that converts wind energy, direct radiant energy received from the sun, or gas generated from the aerobic digestion of animal manure and other agricultural waste into alternating current electricity or heat." This does not include items that store the energy or consume electricity or heat, a foundation built for the system, items used to "convey, alter or transfer" the generated electricity or heat, or items used to transfer or store liquids or gases used in energy generation. Certain exceptions apply; consult the rule for further details, or contact the Department of Revenue.

Generally, purchasers must complete Form S-211, Sales and Use Tax Exemption Certificate and provide the completed form to the seller in order to claim the sales tax exemption. Questions should be directed to the Wisconsin Department of Revenue.

Wisconsin Based Technical Assistance

There are many qualified consultants, firms, and organizations that provide excellent technical advice and engineering throughout the state of Wisconsin. I've listed some non-profits that have a long standing history of providing a variety of excellent technical resources. I've offered an extensive review of Wisconsin's Focus on Energy program as it was legislatively mandated receiving its funding through fees charged utility customers.

Midwest Renewable Energy Association

MREA, 7558 Deer Rd., Custer, WI 54423, (715) 592-6695

The MREC is a non-profit organization dedicated to education on renewable energy technologies and their applications. The MREC sponsors the Midwest Renewable Energy Fair in Custer, Wis. held the second week of June each year where renewable energy technologies are displayed and seminars presented. The MREC staff is very knowledgeable on a variety of technologies and is available to assist with technology selection and application.

Wisconsin Energy Conservation Corporation (WECC)

431 Charmeny Drive, Madison, WI, 53719 (608) 249-9322, weccinfo@weccusa.org

WECC specializes in programs that address: residential, business and renewable energy. They also offer financing programs that support efficiency and renewable energy projects, BPI accredited trainings, support for certifying LEED Homes and guidance for Habitat for Humanity projects built in cold climates. In addition to program implementation, WECC offers a variety of consulting and support services that help utilities and state governments identify and address their energy needs.

Energy Center of Wisconsin (ECW)

455 Science Dr. # 200, Madison, WI, (608) 238-4601

The Energy Center develops solutions to energy challenges that promote economic and environmental sustainability through innovative research and education. The Energy Center is an independent nonprofit company that does energy research, training, education and outreach. In the bioenergy area, they do resource and technology assessments, case studies, market studies, and life-cycle analyses.

Wisconsin Focus on Energy

History of Focus on Energy (information provided through an energy industry internet site describing the Wisconsin FOE program)

The original legislation required utilities to fund energy efficiency programs and renewable-energy programs through (1) a public benefits fee that utilities collect directly from customers and (2) mandatory utility "contributions," which utilities recover from customers in rates. The amount of the charge was based on levels of utility expenditures for energy programs prior to the enactment of Act 9. The fee generated approximately $16 million annually, and the charge generated approximately $46 million annually. In fiscal year 2005, these two sources of revenue generated a combined total of $62.9 million for renewables and efficiency. In addition, the state's five major investor-owned utilities administered and funded several related programs required by the PSC. In 2004, the five utilities spent a combined total of approximately $38.8 million on these programs, which included energy-efficiency projects, renewable-energy projects, load management, and related measures.

**The definition of "renewable resource" under Wis. Stat. § 196.374 includes solar, wind, water power (i.e., hydroelectric), biomass, geothermal, tidal or wave, and fuel cells that use renewable fuels. However, at present Focus on Energy does not offer incentives for all of these technologies.*

In June 2011, Focus On Energy announced that the Renewable Energy Incentives will be temporarily suspended for non-residential projects beginning July 1, 2011. Applications for non-residential programs will no longer be accepted at this time. The residential program will remain open. At this time, only incentives for small systems are available.

Focus On Energy offered Renewable Incentives for installing or expanding renewable-energy systems in residential and non-residential buildings. Eligible projects include wind, photovoltaics (PV), solar hot water, and non-residential biomass. Solar pool heating systems installed at multi-family buildings or public pools are eligible for incentives, but standard residential solar pool heating systems are not. All projects must displace natural gas or electricity from a participating utility. Single-family homes are only eligible for the small solar electric, small solar hot water, and small solar wind incentives. The current application is valid through December 31, 2011, although the program itself has no specified expiration date for residential applications.

Focus On Energy incentives are generally calculated on the basis of the system's expected performance in Therms or in kilowatt-hours (kWh), with smaller systems eligible for larger per energy unit incentives. Participation in various energy efficiency programs, referred to collectively as Efficiency First, also entitles customers to 200% of the incentives. Below are some eligibility and incentive details for each type of eligible technology.

FOE Wind-energy systems (20 kW or less)

- Incentive is determined by the system manufacturer and size.
- Site assessment is required.
- System must have at least a 2-year installation warranty and the turbine must have at least a 5-year warranty.

FOE Solar hot water systems (8 panels or less)

- Incentive is determined by number of panels, compass direction, and shading.
- System must have at least a 5-year installation warranty.

FOE Photovoltaic systems (0.5 kW - 20 kW)

- System must have at least a 5-year installation warranty.
- Incentives are based on rated capacity of the system, compass direction, tilt, and shading.

FOE Biomass energy (5,000 Therms/yr. or less)

- The maximum incentive for a biomass energy system is $10,000 or 30%.
- Systems must have automated feed system and a combustion fan, or it must be listed by the EPA White Tag (Phase II) program.
- Systems must have at least a two-year installation warranty, and all major system components must have at least a one year warranty.

Customers must be located in the service territory of a participating electric provider or natural gas provider. It should be noted that individual utilities may have programs targeting specific renewable energy technologies providing technical and financial assistance. Renewable-energy systems must be installed on the property of an eligible customer and, for electricity-producing projects, must be sized to meet no more than 100% of the on-site load. Focus On Energy also routinely offers a Renewable Energy Grant program for eligible properties to propose funding for systems that exceed the size limitations described above.

Focus On Energy works with eligible Wisconsin residents and businesses to install cost effective energy efficiency and renewable energy projects. Focus information, resources and financial incentives help to implement projects that otherwise would not be completed, or to complete projects sooner than scheduled. Its efforts have historically helped Wisconsin residents and businesses manage rising energy costs, promote in-state economic development, protect our environment, and control the state's growing demand for electricity and natural gas.

Wisconsin Focus On Energy supports statewide programs that promote energy efficiency and renewable energy. The program was initially created by Act 9 of 1999 as a public benefit fund (PBF), which also provided energy assistance programs for low-income residents (the Home Energy Plus Program). Focus on Energy was restructured in March 2006 by S.B. 459 (2005 Act 141). This law, most of which took effect July 1, 2007, replaced existing renewable energy and energy efficiency PBF programs with programs that utilities create and fund through contracts with private program administrators, with oversight and approval by the Public Service Commission of Wisconsin (PSC). Because Act 141 requires utilities to pay directly for programs, the state will not be able to transfer or otherwise use these funds for general obligations. (From 2002 to 2006, the governor and legislature transferred or reallocated more than $108 million from the PBF to the state's general fund or for other uses.) Thus Focus On Energy is no longer precisely a state public benefits program, although it remains a statewide program that serves many of the same purposes that PBFs serve in other states. The 2011 total Focus on Energy budget is approximately $100 million.

Wisconsin utilities contract with Shaw Environmental & Infrastructure, Inc. to administer the mass markets, targeted markets, and research portfolios. Collectively, the energy efficiency, renewable energy, and research components comprise the Focus on Energy initiative. Focus on Energy provides information, financial assistance, technical assistance and other services to residents, businesses, schools, institutions and local governments. Financial assistance takes the form of rebates, grants, and loans.

Under Act 141, each electric and natural gas investor owned utility is required to spend 1.2% of the latest 3-year average of its gross operating revenue on energy-efficiency programs and renewable-resource programs. With PSC approval, a utility may retain a certain portion of the revenue it is required to spend on statewide programs to administer or fund a new energy-efficiency program for the utility's large commercial, industrial, institutional or agricultural customers. Act 141 originally authorized the PSC to specify a higher funding level which would be recovered by utilities through rate increases, but this measure was removed by the 2011 budget act.

"Large energy customers" may implement and fund an energy efficiency project with PSC approval, and may deduct the cost from the amount the customer is required to pay its utility for cost recovery. The utility, in turn, deducts that amount from the amount that it is required to spend on statewide or utility-administered programs. A "large energy customer" is defined as a customer that has a monthly energy demand of at least 1,000 kilowatts or 10,000 Therms of natural gas and, in any month, has been billed at least $60,000 for electricity or natural gas -- or both -- for all its facilities within a utility's service territory.

The state's municipal utilities and electric cooperatives have the option of participating in the state program or operating their own "commitment-to-community" programs, which are similar to Focus on Energy. There is a cap on fees for this programs of the lesser of $375 per month or 1.5% of the total other monthly charges. The PSC does not oversee "commitment-to-community" programs, but Act 141 does require cooperatives and municipal utilities to submit annual program audit reports to the PSC. These programs remain otherwise unaffected by the Act 141 amendments.

Federal Incentives

There are no National Renewable or Carbon Emission Standards encouraging development of renewable energy sources. However existing and impending EPA emission standards are creating conditions that will cause large emission sources to review opportunities to reduce site specific or fleet emissions through switching fuels, installing sophisticated air emission control technologies, or developing new power sources. Until the EPA completes its investigation and rule-making on how to determine carbon emissions of biogenic and anthropogenic carbon sources as part of their Tailoring Rule there will be a delay in committing to firing boilers with biogenic fuel sources. The arena of EPA regulation is changing quickly and may soon make this discussion out of date.

The Federal government has created a number of financial incentives for renewable energy investment:

Production Tax Credit equal to $0.021/ kWh indexed for inflation for closed loop biomass fuels power generation projects for a period of 10 years. Open loop biomass fueled projects receive 50 percent of the incentive provided for closed loop systems.

Investment Tax Credits (ITC’s) are available for 30 percent of eligible project costs.

In Lieu of ITC’s the investor my opt for a 1603 Grant and accelerated depreciation, however, in order to be eligible for this provision the project must commence construction before December 31, 2011 and must be operational by December 31, 2013, as this provision will soon retire I will not offer more detail on this program.

Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation (2008-2012), (federal incentives are as described to me by information provided by Baker-Tilly-Madison)

Note: definitions of eligible technologies included in this review are simplified versions of those contained in tax code, which often contain additional caveats, restrictions, and modifications.

Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. A number of renewable energy technologies are classified as five-year property (26 USC § 168(e)(3)(B)(vi)) under the MACRS, which refers to 26 USC § 48(a)(3)(A), often known as the energy investment tax credit or ITC to define eligible property. Such property currently includes:

- a variety of solar-electric and solar-thermal technologies
- fuel cells and microturbines
- geothermal electric
- direct-use geothermal and geothermal heat pumps
- small wind (100 kW or less)
- combined heat and power (CHP).
- The provision which defines ITC technologies as eligible also adds the general term "wind" as an eligible technology, extending the five-year schedule to large wind facilities as well.

In addition, for certain other biomass property, the MACRS property class life is seven years. Eligible biomass property generally includes assets used in the conversion of biomass to heat or to a solid, liquid or gaseous fuel, and to equipment and structures used to receive, handle, collect, and process biomass in a combustion system or refuse-derived fuel system to create hot water, gas, steam, and electricity.

The five year schedule for most types of solar, geothermal, and wind property has been in place since 1986. The federal *Energy Policy Act of 2005* (EPAct 2005) classified fuel cells, microturbines, and solar hybrid lighting technologies as five-year property as well by adding them to § 48(a)(3)(A). This section was further expanded in October 2008 by the addition of geothermal heat pumps, combined heat and power, and small wind under *The Energy Improvement and Extension Act of 2008.*

The federal *Economic Stimulus Act of 2008,* enacted in February 2008, included a 50% first-year bonus depreciation (26 USC § 168(k)) provision for eligible renewable-energy systems acquired and placed in service in 2008. This provision was extended (retroactively for the entire 2009 tax year) under the same terms by *The American Recovery and Reinvestment Act of 2009,* enacted in February 2009. Bonus depreciation was renewed again in September 2010 (retroactively for the entire 2010 tax year) by the *Small Business Jobs Act of 2010 (H.R. 5297).*

In December 2010 the provision for bonus depreciation was amended and extended yet again by The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (H.R. 4853). Under these amendments, eligible property placed in service after September 8, 2010 and before January 1, 2012 qualifies for 100% first-year bonus depreciation. For 2012, bonus depreciation is still available, but the allowable deduction reverts from 100% to 50% of the eligible basis.

To qualify for bonus depreciation, a project must satisfy these criteria:

- the property must have a recovery period of 20 years or less under normal federal tax depreciation rules;
- the original use of the property must commence with the taxpayer claiming the deduction;
- the property generally must have been acquired during the period from 2008 - 2012; and
- the property must have been placed in service during the period from 2008 - 2012.

If the property meets these requirements, the owner is entitled to deduct a significant portion of the adjusted basis of the property during the tax year the property is first placed in service. As noted above, for property acquired and placed in service after September 8, 2010 and before January 1, 2012, the allowable first year deduction is 100% of the adjusted basis (i.e., the property is fully depreciated and additional deductions under MACRS cannot be claimed). For property placed in service from 2008 - 2012, for which the placed in service date does not fall within this window, the allowable first-year deduction is 50% of the adjusted basis. In the case of a 50% first year deduction, the remaining 50% of the adjusted basis of the property is depreciated over the ordinary MACRS depreciation schedule. The bonus depreciation rules do not override the depreciation limit applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies.

For more information on the federal MACRS, I refer you to *IRS Publication 946, IRS Form 4562: Depreciation and Amortization*, and *Instructions for Form 4562*. The IRS web site also provides a search mechanism for forms and publications.

REAP

Note: The U.S. Department of Agriculture's Rural Development issues periodic Notices of Solicitation of Applications for the Rural Energy for America Program (REAP). The deadline to apply for grants and loan guarantees under the most recent solicitation was June 15, 2011. Grants and loan guarantees were awarded for investments in renewable energy systems, energy efficiency improvements and renewable energy feasibility studies. Another round of applications should be available in 2012.

The Food, Conservation, and Energy Act of 2008 (H.R. 2419), enacted by Congress in May 2008, converted the federal Renewable Energy Systems and Energy Efficiency Improvements Program,* into the Rural Energy for America Program (REAP). Similar to its predecessor, the REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. Congress allocated funding for the new program in the following amounts: $55 million for FY 2009, $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012. REAP is administered by the U.S. Department of Agriculture (USDA). In addition to these mandatory funding levels, there may also be discretionary funding issued each year.

Of the total REAP funding available, approximately 88% is dedicated to competitive grants and loan guarantees for energy efficiency improvements and renewable energy systems. These incentives are available to agricultural producers and rural small businesses to purchase renewable energy systems (including systems that may be used to produce and sell electricity) and to make energy efficiency improvements. Approximately 2% funding is also available to conduct relevant feasibility studies of total funding being available for feasibility studies. Eligible renewable energy projects include wind, solar, biomass, and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. These grants are limited to 25% of a proposed project's cost, and a loan guarantee may not exceed $25 million. The combined amount of a grant and loan guarantee may not exceed 75% of the project's cost. In general, a minimum of 20% of the funds available for these incentives will be dedicated to grants of $20,000 or less. The USDA likely will announce the availability of funding for this component of REAP through a Notice of Funds Availability (NOFA).

The USDA also makes competitive grants to eligible entities to provide assistance to agricultural producers and rural small businesses "to become more energy efficient" and "to use renewable energy technologies and resources." These grants are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities**, rural electric cooperatives and public power entities, and other entities, as determined by the USDA. These grants may be used for conducting and promoting energy audits; and for providing recommendations and information related to energy efficiency and renewable energy. Of the total REAP funding available; approximately 9% is dedicated to competitive grants for energy technical assistance.

** The Renewable Energy Systems and Energy Efficiency Improvements Program were created by the USDA pursuant to Section 9006 of the 2002 federal Farm Security and Rural Investment Act of 2002. Funding in the amount of $23 million per year was appropriated for each fiscal year from FY 2003-2007. In March 2008, the USDA announced that it would accept $220.9 million in applications for grants, loan guarantees, and loan/grant combination packages under the Renewable Energy Systems and Energy Efficiency Improvements Program. The application deadline was June 16, 2008.*

***Land grant colleges and universities are referred to above as "schools" and "institutions". It is important to note that K-12 schools are not eligible for this grant.*

Recent Renewable Energy Budget Cuts

The Senate Appropriations Committee slashed funding for the Rural Energy for America Program (REAP) in the Agriculture Appropriations Bill for FY2012. The Committee reduced overall funding from $75 million in FY2011 to $38.5 million in FY2012.

Most Farm Bill programs were reduced by 5%. In contrast, The Rural Energy for America Program (REAP) was reduced by nearly 50% and the Bioenergy Program for Advanced Biofuels to $75 million, a cut of nearly 30%.

REAP is a popular and oversubscribed program that has funded over 7,600 farm energy projects since 2003, directly benefitting farmers in all agricultural sectors and every state and by making renewable energy and energy efficiency projects more affordable.

Clean Renewable Energy Bonds (CREB's)

CREB History

The federal *Energy Policy Act of 2005* (EPAct 2005) established Clean Energy Renewable Bonds (CREBs) as a financing mechanism for public sector renewable energy projects. This legislation originally allocated $800 million of tax credit bonds to be issued between January 1, 2006, and December 31, 2007. Following the enactment of the federal *Tax Relief and Health Care Act of 2006,* the IRS made an additional $400 million in CREBs financing available for 2008 through Notice 2007-26.

In November 2006, the IRS announced that the original $800 million allocation had been reserved for a total of 610 projects. The additional $400 million (plus surrendered volume from the previous allocation) was allocated to 312 projects in February 2008. Of the $1.2 billion total of tax-credit bond volume cap allocated to fund renewable-energy projects, state and local government borrowers were limited to $750 million of the volume cap, with the rest reserved for qualified municipal or cooperative electric companies.

Note: The IRS is not currently accepting applications for New CREB bond volume. The deadline for New CREB applications from electric cooperatives under IRS Announcement 2010-54 expired November 1, 2010. Bond volume for other eligible sectors (government entities and public power providers) was fully allocated in October 2009.

The terms "New" and "Old" CREB's are used in the following summary to distinguish between prior CREB allocations and the New CREB authorizations made by the U.S. Congress in 2008 and 2009. The use of the term "New CREB's" has legal significance in that New CREB's authorized under 26 USC § 54A and 54C have different rules than prior CREB allocations authorized under 26 USC § 54.

Clean renewable energy bonds (CREBs) may be used by certain entities -- primarily in the public sector -- to finance renewable energy projects. The list of qualifying technologies is generally the same as that used for the federal renewable energy production tax credit (PTC). CREBs may be issued by electric cooperatives, government entities (states, cities, counties, territories, Indian tribal governments or any political subdivision thereof), and by certain lenders. CREBs are issued -- theoretically -- with a 0% interest rate.* The borrower pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest.**

The Energy Improvement and Extension Act of 2008 (Div. A, Sec. 107) allocated $800 million for new Clean Renewable Energy Bonds (CREBs). In February 2009, the American Recovery and Reinvestment Act of 2009 (Div. B, Sec. 1111) allocated an additional $1.6 billion for New CREBs, for a total New CREB allocation of $2.4 billion. The Energy Improvement and Extension Act of 2008 also extended the deadline for previously reserved allocations ("Old CREBs") until December 31, 2009, and addressed several provisions in the existing law that previously limited the usefulness of the program for some projects. A separate section of the law extended CREBs eligibility to marine energy and hydrokinetic power projects.

Participation in the program is limited by the volume of bonds allocated by Congress for the program. Participants must first apply to the Internal Revenue Service (IRS) for a CREBs allocation, and then issue the bonds within a specified time period. The New CREBs allocation totaling $2.4 billion does not have a defined expiration date under the law; however, the recent IRS solicitations for new applications require the bonds to be issued within 3 years after the applicant receives notification of an approved allocation (see History section below for information on previous allocations). Public power providers, governmental bodies, and electric cooperatives are each reserved an equal share (33.3%) of the New CREB's allocation. The tax credit rate is set daily by the U.S. Treasury Department. Under past allocations, the credit could be taken quarterly on a dollar-for-dollar basis to offset the tax liability of the bondholder. However, under the new CREBs allocation, the credit has been reduced to 70% of what it would have been otherwise. Other important changes are described in IRS Notice 2009-33.

CREB's differ from traditional tax-exempt bonds in that the tax credits issued through CREBs are treated as taxable income for the bondholder. The tax credit may be taken each year the bondholder has a tax liability as long as the credit amount does not exceed the limits established by the federal *Energy Policy Act of 2005*.

A new solicitation (IRS Announcement 2010-54) was issued in September 2010 for roughly $191 million in unallocated New CREB bond volume available only to electric cooperatives. The award announcement for this allocation was made in March 2011. It remains to be seen if or when the IRS will issue new funding announcements for Old CREB allocations which are not issued by the December 31, 2009 deadline, or New CREB allocations which miss the three-year issuance period.

Biomass Crop Assistance Program for USDA-FSA

The Biomass Crop Assistance Program (BCAP) provides financial assistance to owners and operators of agricultural and non-industrial private forest land who wish to establish, produce, and deliver biomass feedstocks. BCAP provides two categories of assistance:

- Matching payments may be available for the delivery of eligible material to qualified biomass conversion facilities by eligible material owners. Qualified biomass conversion facilities produce heat, power, bio-based products, or advanced biofuels from biomass feedstocks.

- Establishment and annual payments may be available to certain producers who enter into contracts with the Commodity Credit Corporation (CCC) to produce eligible biomass crops on contract acres within BCAP project areas.

Congressional funding for BCAP in 2012 is currently in question, review of BCAP's recent contract awards illustrates that forest biomass is currently not a BCAP priority. National energy independence goals appear to the author to more closely align with reducing foreign dependence on transportation biofuels which favors cellulosic liquid fuel projects, not power or heat.

Listed are some companies experienced with the design and installation of bioenergy combustion systems. No endorsement is implied or intended through listing these companies. There are many other experienced companies not included on this list.

Residential/Commercial Biomass Energy System Manufacture and Engineering Companies

SunWoodSystems.com

Viessman.com, up to 13,000 kWh

Wellonsfei.ca

Blackcarbon.dk

Industrial:

Babcock & Wilcox

Black and Veatch

Energy Products of Idaho, epi2@energyproducts.com

Frontline Bioenergy, Frontline.com

Hurst Boiler, hurst.com

Nexterra, Nexterra.com

Pacific Pyrolysis, Pacificpyrolysis.com

Anaerobic Digesters

DVO, Inc.

Clear Horizons

Eisenmann Biogas GW

Ovivo

References:

Baker-Tilley, Madison, Wisconsin

Biomass Assessment Handbook, Rosillo-Calle, de Groot & Hemstock, Earthscan Publishing, Sterling. VA, 2008

Biorenewable Resources, Engineering New Products from Agriculture, Robert C. Brown, Blackwell Publishing, Ames, Iowa, 2003

EIA, Annual Energy Outlook 2010, December 2009, DOE/EIA-0383(2009)

EPA Combined Heat and Power Partnership, Biomass CHP Catalog

Govert, Bob, UW Stevens Point, rgovert@uwsp.edu

Handbook of Biomass Combustion and Co-Firing, Sjaak Van Loo & Jaap Koppejan, Earthscan Publishing, Washington, DC, 2010

Pasch, T.J., Frontline Bioenergy, Ames, Iowa

Pellet Fuels institute

Pinchot Institute for Conservation

United State Forest Service, Forest Inventory Analysis (FIA) Data Base

2008 Wisconsin Agricultural Statistics Service, Wisconsin Department of Agriculture

Wisconsin Counties Association

Wisconsin Public Service Commission

Wikipedia