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Techno-economic, location, and carbon emission analysis of thermochemical biomass to transportation fuels

by

Mark Mba Wright

A dissertation submitted to the graduate faculty

in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

Major: Mechanical Engineering

Program of Study Committee: Robert Brown, Co-major Professor William Morrow, Co-major Professor Song-Charng Kong Terry Meyer Brent Shanks Dermot Hayes

Iowa State University

Ames, Iowa

2010

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DEDICATION

Para Mamá Isabel Wright Bonoko 1951 - 2008

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CHAPTER 1. OVERVIEW

1.1 Introduction

There are significant technological and systemic challenges faced by today's advanced biofuel industry. These challenges stem from the current state-of-technology and from the system (consumer market, infrastructure, environment...) in which this emerging industry is being developed. The state-of-technology will improve with continued efforts in technology development, but novel approaches are required to investigate the systemic challenges that limit the adoption of advanced biofuels.

The motivation of this dissertation is to address the question of how to find cost-effective, sustainable, and environmentally responsible pathways for the production of biofuels. Economic competitiveness, long-term viability, and benign environmental impact are key for biofuels to be embraced by industry, government, and consumers. Techno-economic, location, and carbon emission analysis are research methodologies that help address each of these issues. The research approach presented in this dissertation is to combine these three methodologies into a holistic study of advanced biofuel technologies.

The value of techno-economic, location, and carbon emission analysis is limited when conducted in isolation because of current public perception towards energy technologies. Energy technologies are evaluated based on multiple criteria with a significant emphasis on the three areas investigated in this study. There are important aspects within each of these fields that could significantly limit the value of advances in other fields of study. Therefore, it is necessary that future research in advanced biofuels always consider the systemic challenges faced by novel developments.

The urgency to address these systemic challenges is underlined by aggressive biofuel pro-

duction targets. Governments around the world have shown support for the development of advanced biofuels. The Energy Independence and Security Act (EISA) of 2007 mandated a revised Renewable Fuel Standard (RFS2) that requires total renewable fuel production to increase from 9 billion gallons in 2008 to 36 billion gallons by 2022. Advanced biofuels from cellulosic materials are expected to contribute more than 16 billion gallons a year by 2022. A dramatic increase in cellulosic and advanced biofuel technologies would be required to meet this mandate. Cellulosic biofuels will require breakthrough technologies, new infrastructure, and consumer acceptance for widespread adoption. Conventional biofuel production has met its production targets, but cellulosic biofuel production has yet to meet the original goals set by the RFS2.

United States' grain ethanol 2009 production capacity exceeds 10.7 billion gallons per year, and corn ethanol projected production capacity for 2010 exceeds 14.5 billion gallons (12). The RFS2 mandate caps conventional ethanol production to 15 billion gallons by 2015. Advanced biofuels are expected to increase from less than one billion gallons in 2010 to 21 billion gallons in 2022 exceeding conventional ethanol production by 2021. Most cellulosic biorefineries are currently in development and construction phase with modest production capacities. Therefore, there is an urgency to invest in research efforts that would improve the commercial viability of cellulosic-based conversion technologies.

Biofuel technology development can lead to improvements in existing technologies or completely new approaches to energy production. These improvements are sometimes accompanied by cost reductions. Unfortunately, it is often difficult to forecast the market performance of novel technologies.

Biomass faces specific logistic challenges that distinguish it from other energy resources. Biomass material properties vary significantly within, and without, different species; biomass is commonly dispersed over wide areas; and biomass is typically bulky and difficult to transport. These are just a few of the reasons that will motivate the development of new infrastructure for the delivery of biomass to biorefineries.

Anthropogenic greenhouse gas (GHG) emissions are currently a cause of major concern in

the scientific community. There is little debate that human activity has impacted the climate, but there is much need for research on how to reduce our emissions. Of particular importance is the proper accounting of GHG emissions throughout the energy supply chain.

The three methodologies employed in this study address the motivation of this thesis. Techno-economic analysis is a commonly employed approach to evaluate improvements to current technologies and investigate the viability of novel concepts. Location analysis provides insight into the availability of feedstock to supply large-scale biorefineries and meet fuel demand at competitive prices. Carbon emission analysis is a key component in assessing the environmental impact of a given fuel technology.

This dissertation includes comparisons of various scenarios for the production of transportation fuels from biomass: a techno-economic model of corn stover fast pyrolysis and upgrading to biofuels; a techno-economic and location analysis of a mature Midwest corn stover to biofuel industry; and a techno-economic, location, and carbon emission comparison of distributed biomass processing.

1.2 Background

There are two major platforms for the conversion of biofuels to liquid fuels: the biochemical and thermochemical platforms. The biochemical platform employs enzymes and microorganisms to convert carbohydrates into fuels, most prominently ethanol and butanol, suitable for transportation applications. The thermochemical platform employs thermal and catalytic processes to generate a wide range of alcohol and hydrocarbon fuels. Figure 1.1 shows the main conversion pathways for cellulosic, sugars, oils, and wet (> 50% moisture) biomass to liquid fuels.

The conventional biochemical platform converts carbohydrates via fermentation to primarily ethanol (78) or butanol (102) depending on the micro-organism employed. Cellulosic ethanol production employs acid or enzymatic hydrolysis to convert carbohydrate polymers into simple sugars suitable (2) for fermentation. Conventional biodiesel production consists of extraction of lipids from oil seeds followed by esterification to biodiesel. Thermochemical pathways include



Figure 1.1 Biofuel Pathways to the Production of Liquid Fuels (Dashed Lines Indicate First Generation Biofuels, and Solid Lines Indicate Second Generation Fuels)(79)

gasification (122), pyrolysis (141), and hydro-thermal processing (55) for production a variety of liquid fuels including Fischer-Tropsch Liquids (FTL), dimethyl-ether (DME), methanol, mixed alcohols, and green diesel.

1.2.1 Biomass conversion pathways to power and liquid fuels and their costs

Researchers have explored various approaches to the conversion of biomass to power and transportation fuels. Biomass power generation is typically based on gasification or combustion to generate fuel gas or raise steam. Pyrolysis has also been considered in some studies for generation of electricity. Transportation fuels employ either biochemical or thermochemical pathways. Advanced technologies for both pathways are capable of converting either grain or cellulosic material to liquid fuels. The following section presents production cost estimates of these technologies as found in the literature.

Wright and Brown have compared the costs of various biomass to power and fuel pathways (138; 139). A summary of these costs is shown in Table 1. Biomass-based fuel production costs

have been estimated to range between \$1.05 and \$1.80 per gallon of gasoline equivalent (138). Capital cost estimates for advanced biorefinery concepts are typically higher than for similarly sized grain to ethanol plants.

| Technology | Capital | Operating | | Reference |
|--------------------------------------|-----------------|-----------------|-----------------------------|-----------|
| | \mathbf{Cost} | \mathbf{Cost} | | |
| | (millions) | (millions $)$ | | |
| Combustion to Power | \$600 (per | 0.075 (per | | (48) |
| | kW) | $\mathrm{kWh})$ | | |
| Gasification to Power | \$1600 (per | $0.05 \ (per$ | | (36) |
| | kW) | $\mathrm{kWh})$ | | |
| Pyrolysis to Power | \$2400 (per | $0.08 \ (per$ | | (33) |
| | kW) | $\mathrm{kWh})$ | | |
| | Capital | Operating | Fuel Cost | |
| | \mathbf{Cost} | \mathbf{Cost} | (\$/gal) | |
| | (millions $)$ | (millions) | | |
| Gasification to Hydrogen | \$282 | \$52.10 | \$0.29 | (64) |
| Gasification to Methanol | \$224 | \$60.60 | 0.70 | (64) |
| Gasification to Mixed Alcohols | \$137 | \$34.90 | \$1.01 | (101) |
| Gasification to Fischer-Tropsch Liq- | \$341 | \$50.80 | \$1.45 | (124) |
| uids | | | | |
| Gasification and Fermentation to | \$103 | \$18.20 | $2.80 \ (per$ | (37) |
| Hydrogen and PHA | | | $\mathrm{kg} \mathrm{PHA})$ | |
| Pyrolysis and Fermentation to | \$69 | \$39.20 | \$1.57 | (115) |
| $\operatorname{Ethanol}$ | | | | |
| Pyrolysis and Upgrading to Diesel | \$277 | \$107 | \$3.04 | (142) |
| and Gasoline | | | | |
| Pyrolysis and Gasification to Liquid | \$4,029 | \$852 | 1.55/gal | (140) |
| Fuels | | | | |

 Table 1.1
 Summary of Capital and Operating Costs for Biomass Conversion Technologies

A recent collaboration study between the National Renewable Energy Laboratory (NREL), Conoco-Phillips Company (COP), and Iowa State University (ISU) compared the cost of the biochemical, gasification, and pyrolysis platforms using common assumptions for key variables such as plant size (2000 metric tons per day), feedstock (corn stover), and investment analysis (20 year MACRS discounted cash flow) method (7). The biorefinery scenarios were selected as some of the best near-term prospects.



Figure 1.2 Schematic of the Biochemical-based Process for Production of Biofuels



Figure 1.3 Schematic of the Gasification-based Process for Production of Biofuels

Figure 1.2 is a flowchart for the biochemical design for corn stover to ethanol. The base case design employs dilute acid pretreatment and on-site enzyme production to produce 53.2 million gallons per year.

Figure 1.3 describes the unit operations for the corn stover to gasoline and diesel via gasification and Fischer-Tropsch synthesis scenario. Hydroprocessing consists of conventional hydrotreating and hydrocracking processes similar to those employed in petroleum refineries. The base case design consists of a high temperature gasifier producing 37.8 million gallons of gasoline and diesel per year.

Figure 1.4 shows process steps for corn stover pyrolysis to gasoline and diesel fuel. The base case design employs about 1/3 of pyrolysis condensable liquids (bio-oil) to generate requisite hydrogen for hydroprocessing. This design produces 35.4 million gallons of gasoline and diesel per year. If hydrogen is available from an external source, biofuel production increases to 54 million gallons per year. The corn stover pyrolysis to gasoline and diesel process is the topic of the first portion of this dissertation and discussed in detail in the ensuing sections.

Five plant scenarios were developed based on a down-selection process that sought to identify the most commercially ready technologies for each platform. Process designs focused on



Figure 1.4 Schematic of the Fast Pyrolysis-based Process for Production of Biofuels

technology that could be commercially available within a 5 to 7 year timeframe. Therefore, cost estimates from this study are typically higher than studies based on long-term designs. This study estimates the capital costs for 2000 metric tons per day nth plant design biorefineries to be \$380, \$610, and \$280 million for the biochemical, gasification, and pyrolysis pathways respectively. Fuel price estimates ranged between \$2.00 and \$6.00 per gallon of gasoline equivalent. Pioneer plant analysis based on methodology developed by RAND CorporationTM (87) was employed to estimate the costs of constructing a first-of-a-kind biorefinery based on these designs. Results show fuel prices increasing to between almost \$3.00 per gallon to more than \$12.00 per gallon for the most pessimistic scenarios. Figure 1.5 includes a comparison of fuel prices for the biochemical, gasification, and pyrolysis nth plant and pioneer plant (optimistic, most probable, and pessimistic) scenarios.

Laser et al. compared different kinds of biorefineries, assumed to be technically mature, for production of power and fuel from cellulosic biomass (80). Their study compared the process performance, environmental impact, and economics of biochemical and thermochemical processing to power and fuels. Investment costs were estimated to range between \$294 and \$675 million for 4535 metric tons per day biorefineries with operating costs between \$0.63 and \$1.92



Figure 1.5 Comparison of the Biochemical, Gasification, and Fast Pyrolysis nth and Pioneer Plant Fuel Cost Estimates for the Production of Biofuels

per liter of gasoline equivalent (\$2.38 and \$7.26 per gallon of gasoline equivalent). Table 1.2 includes a summary of the capital and operating costs for various mature biomass to power and liquid fuel biorefineries. All of these technologies were found to reduce CO₂ emissions by 70% or more compared to conventional gasoline emissions, which means that these concepts would meet the Environmental Protection Agency standard of 60% reduction for cellulosic biofuels (18).

Biorefinery techno-economic analyses presented in the literature typically assume a $\pm 30\%$ uncertainty in their estimates. Sensitivity and risk analysis are some of the most common methods employed to understand the impact and source of uncertainties. Pioneer and mature, or nth plant, designs are commonly employed designations to differentiate short-term and long-term technology forecasts. NREL has published various mature technology design reports for cellulosic ethanol (2; 101). The assumption of a mature technology process helps reduce the cost of biofuels due to dramatic improvements in process performance and lower implementation costs. Their 2007 design report on corn stover to mixed alcohols estimated a minimum ethanol-

| Table 1.2 | Capital and Operating Costs of Technically Mature Biochemical |
|-----------|---|
| | and Thermochemical Biorefineries (80) |
| | |

| Scenario | Total | Operating | | |
|---------------------------------------|---------|-------------|------------|-----------------|
| | | | | \mathbf{Cost} |
| | (MM $)$ | (\$/annual) | (\$/annual | (\$/L GEq) |
| | | GJ) | L GEq) | |
| E than ol + Rankine power | 359.1 | 21.45 | 0.69 | 0.73 |
| Ethanol + GTCC power | 532.6 | 28.7 | 0.92 | 0.69 |
| E thanol + F - T fuels + GTCC power | 569.8 | 29.38 | 0.94 | 0.66 |
| E than ol + F - T fuels (w/once- | 521.2 | 24.99 | 0.8 | 0.63 |
| ${ m through \ syngas}) + { m CH4}$ | | | | |
| E than ol + F-T fuels (w/recycle syn- | 477.9 | 22.03 | 0.71 | 0.65 |
| m gas)+CH4 | | | | |
| E than ol + H2 | 525.7 | 25.22 | 0.81 | 0.67 |
| E than ol + protein + Rankine power | 401.5 | 24.53 | 0.79 | 0.88 |
| E than ol + protein + GTCC power | 593.5 | 31.98 | 1.02 | 0.8 |
| E than ol + protein + F-T fuels | 674.9 | 34.7 | 1.11 | 0.77 |
| F-T fuels + GTCC power | 666.7 | 42.44 | 1.36 | 1.4 |
| Dimethyl ether + GTCC power | 617.6 | 41.64 | 1.33 | 1.92 |
| H2 + GTCC power | 488.3 | 28.03 | 0.9 | 0.75 |
| Rankine power | 294.2 | 32.96 | 1.06 | 1.23 |
| GTCC power | 527.5 | 38.83 | 1.24 | 0.91 |

selling price of \$1.01 per gallon by 2012.

1.2.2 Biomass resource availability

| Resource | Quantity [tons/year] |
|--------------------------|----------------------|
| Logging & other residue | 64 |
| Fuel treatments | 60 |
| Urban wood residues | 47 |
| Wood processing residues | 70 |
| Pulping liquor | 74 |
| Fuelwood | 52 |
| Perennial crops | 377 |
| Crop residues | 446 |
| Process residues | 87 |
| Grain-to-ethanol | 87 |

Table 1.3Biomass Resource Availability (98)

The USDA recently estimated that 1 billion tons of biomass could be available for conversion to biofuels (98). This estimate includes dedicated crops, forest and urban residues, and agricultural residues as shown in Table 1.3. Crop residues including corn stover, constitute the largest class of biomass resource available.

| | | | | | | |
|-----------------------|---------------|-------|-----------------|-------|-----------------|-------|
| Corn | USDA Baseline | | Technology | | Technology | |
| | (Year) | | Changes No | | Changes With | |
| | | | Perennial Crops | | Perennial Crops | |
| | 2001 | 2014 | Moderate | High | Moderate | High |
| Yield | 138.2 | 161.8 | 172.75 | 207.3 | 172.75 | 207.3 |
| $({ m bushels/acre})$ | | | | | | |
| Production | 9.51 | 12.4 | 13.2 | 15.9 | 13.2 | 15.9 |
| (billion | | | | | | |
| bushels) | | | | | | |

Table 1.4Billion Ton Study Corn Production Estimates with Change Scenarios (98)

Biomass resource availability is based on publicly available data collected by various governmental agencies. The USDA's billion ton study considered three different scenarios based on possible and sustainable levels of resource consumption, and improvements to agricultural practices resulting in increased biomass resources. For example, logging residue availability is based on a 65% recovery factor that takes into account collection losses from small and scattered piece-size material. Corn production was estimated to increase from 9.51 billion bushels (almost 238 million metric tons) in 2001 to 12.4 billion bushels by 2014. Technology changes could increase production to 13.2 or 15.9 billion bushels (see Table 1.4). Increased adoption of perennial crops is expected to increase the overall biomass availability without affecting corn production.

Sustainably recoverable quantities of corn stover vary depending on field conditions, agricultural practices, climate patterns and other management factors (61). Removal of corn stover exposes the soil surface and makes it susceptible to wind and water erosion (133). Erosion can reduce soil organic matter, which is an important factor related to the land productivity. Researchers from the USDA developed a linear relationship between corn yield and the quantity of corn stover that can be harvested without reducing the soil organic carbon under various agricultural practices (Figure 1.6). Reduced tillage leaves 15% to 30% of stover cover in the field to prevent erosion. Soybean leaves a smaller amount of residue available for cover than corn, which increases the necessary fraction of residue that should be left in the field to control erosion.

| Сгор | Dry weight residue/grain ratio | Residue harvest index | Factor used to convert bushel of grain to dry mass grain [kg/bushel] |
|--------------|-----------------------------------|--------------------------|---|
| Corn | 1:1 | 0.5 | 21.5 |
| Spring wheat | 1.3:1 | 0.57 | 23.6 |
| Soybean | 1.5:1 | 0.6 | 23.7 |
| Winter wheat | 1.7:1 | 0.63 | 23.6 |
| Barley | 1.5:1 | 0.6 | 18.6 |
| Oat | 2.0:1 | 0.67 | 12.5 |

Table 1.5 Residue to Grain Ratios, Harvest Index, and Factors used to Convert USDA Values of Grain Production from Bushels to Dry Mass (132)

In 2007, Graham et al. published a detail analysis of corn stover supply (61). This study



Figure 1.6 Corn Yield vs Harvestable Quantities of Corn Stover to Maintain Soil Organic Carbon (71)

estimates that about 30% of the 196 million metric tons of stover in current production could be collected at a cost of less than \$33 per metric ton. This estimate takes into account current rotation and tillage practices, erosion and soil moisture concerns, and nutrient replacement costs. Stover production rates were based on commonly employed residue to grain ratios such as those shown in Table 1.5.

There are three main constraints to the collection of corn stover: collection equipment, soil moisture, and water and wind erosion. Collection equipment leaves a fraction of the available biomass material in the field depending on the type of equipment. Collection rates ranging from 38% to 70% have been reported (89; 110). Montross et al. reported round bale collection efficiencies of 38%, 55%, and 64% using bale only, rake and bale, and mow, rake, and bale respectively. Schechinger and Hettenhaus reported 70% stover collection efficiency in large-scale operations in Nebraska and Wisconsin.

Regions with high local wind erosion climatic factors that practice rainfed agriculture would need to keep all the stover in the field to preserve moisture for the following season. Detailed regional data does not appear to be readily available and Graham et al. (61) employed personal communication and a 1983 map by Allmaras (4) for their study. Nelson et al.(94; 95) and Sheehan et al. (113) published methodologies to estimate the quantities of stover required to ensure that only a tolerable soil loss would occur due to erosion. Their approach takes into account cropping rotation, tillage, local climate conditions, and soil types found in a county. A single county-level rating can be specified by properly weighting the soil type values by their fraction of the county land area. Graham et al. (61) found that water erosion is the limiting constraint in states east of the Rocky Mountains, and wind is the main constraint in western states.

| ${f Region}^{ m a}$ | Switchgrass | | Hybrid poplar | | Willows | |
|---------------------|-------------------|-------------|-------------------|------------|------------|------------|
| | $({ m Mg/ha/yr})$ | | $({ m Mg/ha/yr})$ | | (Mg/ha/yr) | |
| | Average | Range | Average | Range | Average | Range |
| Lake States | 10.8 | 7.9 - 13.5 | 9.9 | 7.9-11.8 | 10.3 | 9.1-11.8 |
| Corn Belt | 13.4 | 11.1 - 15.1 | 10.4 | 8.4-11.7 | 10.6 | 10.1-11.4 |
| Southeast | 12.3 | 7.6 - 14.5 | 10.1 | 8.6-11.7 | - | - |
| Appalachia | 13.1 | 9.8 - 14.9 | 8 | 9.0 - 11.7 | 10.1 | 10.1-10.1 |
| North Plains | 7.8 | 4.5 - 12.3 | 8.6 | 7.3-9.7 | - | - |
| South Plains | 9.7 | 7.6 - 13.4 | 8.4 | 7.3 - 9.0 | - | - |
| Northeast | 10.9 | 7.9-12.4 | 9 | 7.7-10.0 | 11 | 7.1 - 13.0 |
| Pacific North- | - | - | 12.9 | 12.4-13.5 | - | - |
| west | | | | | | |

Table 1.6 Regional Crop Yields for Potential Bioenergy Crops (130)

^aLake States includes MI, MN, WI; Corn Belt includes IA, IL, IN, MO, OH; Southeast includes AL, AR, FL, GA, LA, MS, SC; Appalachia includes DE, KY, MD, NC, TN, VA, WV; North Plains includes MT, ND, SD, WY; South Plains includes CO, KS, NE, OK, TX; Northeast includes CT, NH, NJ, NY, MA, ME, PA, RI, VT; and Pacific Northwest includes OR, WA.

Bioenergy crops are a potential source of feedstock for cellulosic biofuels production. Walsh et al. (130) published an article on the potential quantities, land use changes, and economic impacts of bioenergy crop production. This POLYSYS-based study found that at farm-gate prices of \$2.44/GJ (about \$50 per metric ton) an estimated 17 million hectares would be devoted to energy crops. Approximately 171 million dry metric tons of biomass would be available annually. Assumed yields are based on high production practices primarily in conservation land (Table 1.6).

Walsh et al. modeled two bioenergy crop scenarios: production management practices to

| Scenario 1 (Wildlife Management Practices on CRP Hectares; Retain 75% of CRP Rental | | | | | | | |
|---|-------|------------------------|----------------|------|-------------------|--|--|
| Rate; Switchgrass Farm-gate Price of \$33/dry Mg) | | | | | | | |
| | Total | Current | \mathbf{CRP} | Idle | Pasture | | |
| | | crops | | | | | |
| Switchgrass | 12.32 | 10.44 | 1.1 | 0.23 | 0.55 | | |
| Poplar | 7.1 | 0 | 7.1 | 0 | 0 | | |
| Willow | 0 | 0 | 0 | 0 | 0 | | |
| Total bioenergy 19.42 10.44 8.2 0.23 0.55 | | | | | 0.55 | | |
| Scenario 2 (Production Management Practices on CRP Hectares; Retain 75% of CRP | | | | | | | |
| Rental Rate; Switchgrass Farm-gate Price of \$44/dry Mg) | | | | | | | |
| Total Current CRP Idle Pasture | | | | | | | |
| crops | | | | | | | |
| Switchgrass | 41.87 | 23.37 | 12.91 | 2.09 | 3.49 | | |
| Poplar | 0 | 0 | 0 | 0 | 0 | | |
| Willow | 0 | 0 | 0 | 0 | 0 | | |
| Total bioenergy | 41.87 | 23.37 | 12.91 | 2.09 | $3.\overline{49}$ | | |

Table 1.7Land Use Impacts of Increased Bioenergy Crop Production Based
on Cropland Type in Millions of Acres

maximize bioenergy crop yields, and wildlife management practices to improve biodiversity. The impact on land use is shown in Table 1.7. Wildlife management practices and \$33 per dry metric ton farm-gate prices would result in 19.4 million acres devoted to bioenergy production. Bioenergy crops would replace 10.4 million acres of current crop production land. Poplar is planted under the wildlife management scenario in CRP land only. Willow is economically less attractive than switchgrass and poplar and therefore not planted in any of the regions analyzed. Under the wildlife management scenario, total annualized bioenergy production would be 32.3 million dry metric tons. Production management practices would increase bioenergy output to 170.9 million dry metric tons.

These scenarios would result in increased prices for conventional crops ranging from 4 to 9 percent under wildlife management practices or 9 to 14 percent under production management. Price increases would result from reduced acreage devoted to conventional crops and market dynamics. These price changes are within the range of historical prices.

NREL publishes maps of biomass resource availability such as Table 1.7. NREL recently published an online tool to query resource availability and display a variety of renewable fuel



Figure 1.7 NREL United States Total Biomass (Crops and Residues) Resources (http://www.nrel.gov/gis/biomass.html)

information such as the location of biomass fuel and power plants and distribution of electricity cost in the continental United States.

Oak Ridge National Laboratory (ORNL) developed the Oak Ridge Energy Crop County Level Database (ORECCL) (59) based on agricultural data in 1996 to provide public agencies with easy access to energy crop information. The model has been renamed to BIOCOST, and has been employed in various studies (54; 126; 130) to analyze biomass resource availability, potential for energy crop production, and impact of energy and environmental policies. ORNL published in December of 2009 the second edition of their Biomass Energy Data Book (134). The Biomass Energy Data Book is a comprehensive report of the U.S. biomass availability and potential for power and fuel production. This report contains most of the data employed to develop the estimates found in the USDA's billion ton study.

1.2.3 Biomass collection and logistics analysis

Biomass availability, transportation costs, and environmental impacts are important considerations in the selection of a site for the construction of a biomass conversion plant. Various government agencies and researchers have explored these different issues.

| Field opera- | Completion | Total | \mathbf{Cost} | Energy | Carbon |
|------------------------|------------|--------------------|-----------------|-------------------|-----------|
| tions | day | $\mathbf{biomass}$ | (\$/Mg) | input | emission |
| | | (Mg) | | $({f MJ}/{f Mg})$ | (kg C/Mg) |
| Load | 124 | $450,\!900$ | 3.59 | 154.5 | 12.05 |
| Truck | 342 | $430,\!989$ | 13.76 | 640.6 | 49.87 |
| Unload | 342 | $430,\!989$ | 3.58 | 199.6 | 15.58 |
| Stack | 342 | $430,\!989$ | 0.44 | 7.5 | 0.585 |
| Grind | 343 | $430,\!989$ | 10.92 | 185.7 | 14.45 |
| Overall | | | 32.45 | 1087.5 | 93.1 |

Table 1.8Operation Requirements and Estimates for Transportation and
Pretreatment of Baled Corn Stover (116)

Biomass availability is limited by collection, cultivation, and sustainability practices. Up to 40% of available biomass can be lost during the collection of corn stover (118). The NRCS predicts that up to 30% of crop residues can be removed from some no-till systems without increased erosion or runoff (5). Biomass transportation and logistics have been explored in detail



Figure 1.8 Stover Collection Cost Curves Based on Collection Equipment and Quantity of Stover Collected

by ORNL (116). Their study found that delivery of 450,000 Mg of biomass from 500 storage sites to a biorefinery would have a transport cost of \$32.45 per Mg based on the estimates for logistic operations shown in Table 1.8. These estimates were developed using a dynamic model in $EXTEND^{TM}$ and take into account feedstock properties, farm management, and vehicle performance. Their assumptions are not applicable to every region in the U.S., but the method employed can be adjusted to study transportation costs at alternative locations. ORNL has made their integrated biomass supply analysis and logistics (IBSAL) model available online.

Graham et al. (61) employed the methodology developed by Perlack and Turhollow (97), Sokhansanj and Turhollow (117), and Sokhansanj et al.(118) to estimate the cost of collecting stover including nutrient replacement costs (\$7.17 per metric ton (53)). They estimated that up to 28% of current stover production could be collected at a baled farm gate cost of \$33.07 per metric ton. Cost curves based on the collection equipment and amount of stover collected are shown in Table 1.8.

An NREL life cycle assessment of corn stover to ethanol found this process to be renewable and sustainable (10). Nevertheless, the USDA Natural Resources Conservation Service (NRCS) cautions that sustainable quantities of crop residues will vary depending on management practice, crop yield, climate, topography, soil type and quality (5).



Figure 1.9 Iowa Corn Harvest Weekly Data and Regression for September 15, 2002 Harvest Season (116)

Corn harvest season in the American Midwest takes place during a small period of time in the fall. Moisture content is the key factor to determine when to start harvesting. Corn is harvested when its moisture content decreases to 40%, which occurs sometime between July and November depending on the location. Southern states harvest earlier than other regions in the US. Once harvest starts, farmers try to collect corn as fast as possible for a number of reasons that include market conditions, operating schedules, and weather forecast. The National Agricultural Statistics Service (NASS) tracks weekly statistics for corn harvest as shown in Figure 1.9.

In 2002, 60% of farms had harvested their corn crop within 45 days. This data applies to corn grain, but is very relevant to stover collection, which may be done simultaneously or soon after the corn grain has been collected. Biorefineries would have to provide ample storage to take into account that biomass delivered after harvest will likely exceed the daily plant conversion capacity. Morrow et al. developed in 2006 a detailed model of the production and distribution of switchgrass derived cellulosic ethanol in the United States (90). Morrow's model consists of a transportation optimization model for corn and switchgrass based ethanol production. Agricultural data for their analysis is based on the ORNL POLYSYS model. According to their analysis, about 48% of the total switchgrass produced would be available for biofuel production at a farmgate price of \$28 per metric ton. At \$55 per metric ton, about 85% of the total switchgrass produced becomes available to biorefineries. Biorefinery locations are based on 305 agricultural statistical districts (ASD) as defined in POLYSYS. Biorefineries draw the required amount of biomass from their respective ASD based on the biofuel demand and delivery cost. Transportation costs for biomass from the farmgate to the plant gate were estimated as \$5 per metric ton. Biofuel transportation employs truck and rail freight from biorefineries to Metropolitan Statistical Areas (MSAs). Total biofuel production was based on the quantity of ethanol required to meet a national E16 blend mandate. The average costs of delivered cellulosic E16 were estimated to be \$1.62 per gallon.

In 2009, Wakeley et al. investigated the economic and environmental transportation effects of large-scale ethanol production and distribution (129). Their study employed POLYSYS to estimate corn and switchgrass production in 305 regions within the continental United States. Their analysis employed a linear optimization model to allocate corn to ethanol facilities and switchgrass to cellulosic ethanol biorefineries. The objective of their optimization model was to minimize biomass and biofuel transportation costs. Results from this study indicate that corn E85 ethanol (85% ethanol to gasoline blend) could be delivered at an average cost of about \$2.42 per gallon of gasoline equivalent. Large-scale cellulosic ethanol delivered costs are estimated as \$2.91 per gallon of gasoline equivalent.

1.3 Contributions

This dissertation provides key significant contributions to how the future of energy, in particular biofuels, can be analyzed. The papers included in this thesis show how technoeconomic, location, and carbon emission analysis can be combined to better understand the economic and environmental implications of advanced energy technologies.

Techno-economic analysis combines process modeling with economic analysis. Process modeling investigates the technical requirements to implement a given process. Economic analysis addresses the cost implications of the technical requirements. Recent examples of technoeconomic analysis include reports by the National Renewable Energy Laboratory (NREL), Pacific Northwest National Laboratory (PNNL), and other researchers (105; 72; 65). The first paper in this dissertation is very similar to these techno-economic analyses in that it combines process modeling with economic assessment to determine the cost of producing biofuel, and is one of two papers on biomass fast pyrolysis for the production of transportation fuels. This approach is of particular interest to emergent biofuel technologies given the current urgency to develop practical and economical alternatives to fossil fuels.

Location analysis helps address the context in which energy technologies are developed. Location is an important factor in the siting of biorefineries. This is markedly true of biofuels because of the disperse nature of biomass resources. Feedstock availability and cost are functions of local agricultural productivity and distribution networks. Oak Ridge National Laboratory (ORNL) has conducted numerous studies on feedstock availability and transportation costs (116; 61; 98; 126). The second paper in this study expands on previous research by implementing a linear programming model to minimize costs in a mature Midwest corn stover to biofuel industry scenario.

Carbon emission analysis is a major aspect of understanding environmental impacts. This type of analysis is one of the first steps to understanding the life-cycle impacts of a given process. The literature includes several biofuel-related papers with carbon emission analysis as part of a larger environmental study (74; 56; 73), and as the main environmental impact measure (123; 39; 80). The third paper in this study focuses on biofuel carbon emissions within

the biomass production to vehicle consumption cycle.

The studies in this thesis focus on corn stover and drop-in transportation fuels. This combination of feedstock and fuel is of particular interest to the United States where goals have been set to meet quotas for renewable fuel production. These quotas are part of the Renewable Fuels Standard (RFS2) (18). Achieving the 16 billion gallons per year cellulosic fuel capacity of the RFS2 could be constrained by techno-economic, location, and environmental factors. Interactions between these three factors necessitate that analyses take all three into consideration. For example, the cost and environmental impact of growing feedstock is highly dependent on local conditions such as soil, weather, and agricultural practices. This methodology is applicable to other types of feedstock and biofuel production technologies. Similar studies could be explored for bagasse conversion in Brazil, jatropha in India, or wood in Europe using a variety of biochemical and thermochemical approaches to the production of biofuels.

The combination of techno-economic, location, and carbon emission analysis within a single project are not commonly found in the literature. Possible reasons for this include challenges in obtaining necessary data, the range of diverse fields involved, and relative inaccessibility to relevant software. This dissertation is an example of how to approach the assessment of energy technologies using a wide range of interdisciplinary tools leading to a comprehensive understanding of promising technologies.

1.4 Thesis Organization

This thesis proposal is organized in three main sections: Techno-economic analysis of biomass fast pyrolysis to transportation fuels; biorefinery location analysis for the conversion of corn stover to gasoline and diesel fuels; and location, economic, and environmental analysis of thermochemical distributed biomass processing to transportation fuels.

"Techno-economic analysis of biomass fast pyrolysis to transportation fuels" is a study of the process and economic performance of biomass fast pyrolysis for the production of naphtha and diesel range fuels. This analysis employs Aspen PlusTM modeling and economic analysis to estimate the minimum fuel selling price of gasoline and diesel fuel from corn stover. The primary researcher and author of this report is Mark M. Wright; the corresponding author is Robert C. Brown. Both authors are affiliated with the Iowa State University Department of Mechanical Engineering.

"Biorefinery location analysis for the conversion of corn stover to gasoline and diesel fuels" explores the impact of facility location on the cost of producing transportation fuels. This study employs a location-allocation model to determine the biorefinery locations and biomass allocation that minimizes biomass and biofuel transportation costs. This analysis employs county-level data for corn stover availability and metropolitan statistical area gasoline demand to allocate corn stover to naphtha and diesel biorefineries. The primary researcher is Mark M. Wright; contributing authors include William R. Morrow and Robert C. Brown, and the corresponding author is Robert C. Brown. All authors are affiliated with the Iowa State University Department of Mechanical Engineering.

"Location, economic, and environmental analysis of thermochemical distributed biomass processing to transportation fuels" compares distributed biomass processing pathways for the production of naphtha and diesel fuel. This study employs a location-allocation model to investigate the feedstock transportation costs and carbon emissions of distributed biomass processing scenarios. The primary researcher is Mark M. Wright; contributing authors include William R. Morrow and Robert C. Brown, and the corresponding author is Robert C. Brown. All authors are affiliated with the Iowa State University Department of Mechanical Engineering.
CHAPTER 2. Techno-economic analysis of biomass fast pyrolysis to transportation fuels

A paper published in the Fuel journal and accompanying report published by the National Renewable Energy Laboratory

Mark M. Wright, Daren E. Daugaard, Justinus A. Satrio, and Robert C. Brown

2.1 Abstract

The purpose of this project is to develop techno-economic models for the conversion of biomass to naphtha and diesel range products via fast pyrolysis and bio-oil upgrading. Two scenarios are explored in this project. The first scenario consists of a hydrogen production 2000 tpd corn stover fast pyrolysis plant with bio-oil upgrading. The second scenarios purchases hydrogen generated at a remote source. While the first scenario relies on bio-oil reforming to generate requisite hydrogen, the hydrogen purchase scenario employs merchant hydrogen to upgrade bio-oil into liquid transportation fuel. Major assumptions found in this analysis are common to comparison papers exploring biochemical and gasification scenarios.

Results indicate that naphtha and diesel range products production from corn stover is competitive at a product value (PV) of \$3.09 and \$2.11 per gallon (\$0.82 and \$0.56 per liter) for the hydrogen production and hydrogen purchase scenarios respectively. These values correspond to a \$0.83 per gallon (\$0.21 per liter) cost to produce bio-oil. Capital costs are estimated at \$287 and \$200 million for these scenarios with fuel yields 35 and 58 million gallons of naphtha and diesel range products (134 and 220 million liters) per year.

Sensitivity analysis identify fuel yield as a key variable for the hydrogen production scenario. A 5% decrease in the bio-oil to naphtha and diesel fuel yields increases fuel costs by \$0.80 and



Figure 2.1 Fast Pyrolysis Oil Costs from Previous(9; 41; 62; 63; 70; 92; 119) Biomass Fast Pyrolysis Studies Adapted for Inflation from Ringer et al. (105)

\$0.27 per gallon for the hydrogen production and purchase scenarios respectively. Biomass cost is important for both scenarios. Feedstock costs of \$50 to \$100 per short ton vary the price of fuel in the hydrogen production scenario between \$2.57 and \$3.62 per gallon. Fuel costs for a pioneer plant are estimated at \$6.55 per gallon for a hydrogen production plant and \$3.41 for a hydrogen purchasing plant. Although these results are competitive with other alternative fuels, there is high uncertainty in these estimates due to the low level of maturity of the bio-oil upgrading technology.

2.1.1 Background

There have been various publications dedicated to techno-economics of biomass fast pyrolysis to produce bio-oil, but very few explored upgrading of bio-oil to transportation fuel. Key assumptions found in the literature for biomass cost, plant capacity, reactor technology, and others variables vary widely between different studies. It is therefore difficult to compare costs from various studies without taking into account differences in process assumptions.

Figure 2.1 shows fuel costs for previous biomass fast pyrolysis techno-economic studies. Bio-

oil cost estimated in this study is also included (\$0.83 per gallon for 2000 metric ton per day capacity) in Figure 10. Capital cost estimates for these studies range from \$143 million (119) to \$37 million (9) for 1000 metric ton per day capacities. A recent study by the National Renewable Energy Laboratory for a 550 dry metric ton per day wood fast pyrolysis plant producing 28 million gallons (106 million liters) of bio-oil per year found the capital and operating cost to be \$48.2 and \$9.6 million (\$0.62/gal PV) respectively.

Few studies have explored the upgrading of bio-oil to naphtha and diesel range products. Although the technology for bio-oil hydroprocessing is based on commercially available equipment, actual implementations are in development. UOP is one of the main developers of this technology, and they have published various studies on bio-oil upgrading. A 2005 study found that gasoline from bio-oil is economically attractive if bio-oil is available at \$18/bbl (\$0.43/gal) and crude oil sells for \$50/bbl (85). A recent article estimates the cost of naphtha and diesel range fuel from corn stover to be \$1.80 per gallon (69).

2.1.2 Process description

Biomass fast pyrolysis is a thermochemical process that converts feedstock into gaseous, solid, and liquid products. The purpose of this computational model is to simulate this process in order to conduct a techno-economic study of transportation biofuels via fast pyrolysis and bio-oil upgrading. To accomplish this goal, AspenÂő software is employed to calculate mass and energy balances and economic costs related to the process. This model is based on the conversion of corn stover to naphtha and diesel range products. The biomass plant assumed here processes 2000 dry metric tons per day of corn stover using common equipment found in thermochemical conversion facilities. Modifications to existing equipment would be necessary to develop this process, and major changes are discussed in this report. The impact of process uncertainties are considered in the sensitivity and pioneer plant analysis. General processing steps include biomass pretreatment, fast pyrolysis, solids removal, bio-oil collection, char combustion, and bio-oil upgrading. An overall description of the biomass fast pyrolysis process to produce naphtha and diesel range products is shown in Figure 2.2. The hydrogen production



Figure 2.2 Combined Biomass Fast Pyrolysis and Hydrogen Production/Purchase Upgrading Process Diagram

scenario employs optional equipment to generate requisite hydrogen. Biomass with 25% moisture content is dried to 7 percent moisture and ground to 3 mm diameter size prior to feeding into a fluid bed pyrolyzer operating at 480° C and atmospheric pressure. Standard cyclones remove solids consisting mostly of char particles entrained in the vapors exiting the pyrolyzer. Vapors are condensed in indirect contact heat exchangers yielding liquid bio-oil that can be safely stored at ambient conditions prior to upgrading to transportation fuels. Non-condensable gases are recycled to the pyrolysis reactor after being combusted to provide process heat. This analysis assumes that pyrolysis solid products are sent to a combustor to provide heat for the drying and pyrolysis process. Excess solids consisting of char is sold as a low heating value coal substitute. Bio-oil upgrading, which is discussed in the hydroprocessing section, generates fuel compatible with existing infrastructure.

Biomass condition, as typically delivered, is an important factor not studied in detail in this analysis. Typical feedstock collection methods remove significant soil matter with the biomass from the ground. Soil matter reduces the thermal value of biomass and poses maintenance difficulties for combustion equipment. Ash content can cause fouling and plugging of high-temperature equipment. Minerals catalyze thermal decomposition reactions that are detrimental to the production of quality pyrolysis oil. Biomass washing using water or acid-removal techniques can reduce alkali content in biomass (45). Mineral effects were not considered in this study due to the limited knowledge of the mechanisms by which alkali affects pyrolysis yields.

The upgrading process considered in this study is bio-oil hydrotreating and hydrocracking. Hydrotreating and hydrocracking (hydroprocessing) are commonly employed in the petroleum industry to remove undesired compounds such as sulfur from crude oil and break large hydrocarbon molecules to produce clean naphtha and diesel range products. Bio-oil typically contains significant quantities of oxygenated compounds that are undesirable for combustion in vehicle engines. Hydrotreating can convert oxygen found in bio-oil to water and carbon dioxide molecules leaving hydrocarbons that are suitable for internal combustion engines. Complex hydrocarbon compounds are found in bio-oil and hydrocracking is a potential method to decompose these heavy compounds into naphtha and diesel range fuel.

Technical modeling is accomplished by employing Aspen PlusTM software to develop mass and energy calculations. Assumptions and operating conditions are taken from the literature and experimental data when available. Economic analysis is a combination of Aspen IcarusTM software equipment cost and sizing, and spreadsheet investment analysis calculations.

2.2 Design Basis

The purpose of this process is to convert biomass into liquid fuels suitable for transportation applications. This is achieved by converting biomass into bio-oil, which is subsequently upgraded to transportation fuels. The basis model employs nine distinct sections described in Table 2.1.

Biomass has been modeled on a proximate and ultimate analysis basis. There is scarce information found in the literature that is specific to corn stover pyrolysis. Nonetheless, this process feedstock is modeled using information from Table 2.2. Corn stover analysis is adapted from USDA experimental data (93). The ash content value is specified as 6% to meet the requirements of this project, and other values are adjusted accordingly. Char analysis is based

| Section Name | Section Description | Key Assumptions |
|------------------|---|------------------------------------|
| Chopping | Particle size reduction to 10 mm | Incoming biomass average size of |
| | | 10 to 25 mm |
| Drying | Biomass drying to 7% moisture | Steam drying at 200 C |
| Grinding | Particle size reduction to 3 mm | Incoming biomass maximum size |
| | | m of < 10 mm |
| Pyrolysis | Biomass conversion to pyrolysis | 480 Celsius and 1 atm; 2.75 kg of |
| | $\operatorname{products}$ | fluidizing gas per kg of biomass; |
| | | Heat provided by char |
| | | $\operatorname{combustion}$ |
| Solids Removal | Removal of entrained solid | 90% particle removal |
| | particles from vapor stream | |
| Bio-Oil recovery | Collection of condensing vapors | Rapid condensation to about 50 |
| | | m C;95% collection of aerosols |
| Storage | Storage of bio-oil and char | 4 weeks storage capacity |
| Combustion | Provides process heat and steam | 120% excess air combustion; 1100 |
| | generation | C gas temperature; 200 C steam |
| | | generation |
| Hydroprocessing | Upgrading of bio-oil to naphtha | Hydrogen production from oil |
| | and diesel range products | aqueous phase reforming; P>1000 |
| | fractions | psia and T $>300~{ m C}$ |

 Table 2.1
 Process Model Sections, Descriptions, and Key Assumptions

| Table 2.2 | Corn Stover | Ultimate | and Proximate | Analysis |
|-----------|-------------|----------|---------------|----------|
|-----------|-------------|----------|---------------|----------|

| Ultimate Analysis (dry basis) | | | |
|--------------------------------|--------------|--|--|
| Element | Value (wt %) | | |
| Ash | 6 | | |
| Carbon | 47.28 | | |
| Hydrogen | 5.06 | | |
| Nitrogen | 0.8 | | |
| Chlorine | 0 | | |
| Sulfur | 0.22 | | |
| Oxygen 40.63 | | | |
| Proximate Analysis (wet basis) | | | |
| Element | Value (wt %) | | |
| Moisture | 25.0 | | |
| Fixed Content | 17.7 | | |
| Volatile Matter | 52.8 | | |
| Ash | 4.5 | | |

| Ultimate Analysis (dry basis) | | | |
|------------------------------------|--------------|--|--|
| Element | Value (wt %) | | |
| Ash | 33.3 | | |
| Carbon | 51.2 | | |
| Hydrogen 2.12 | | | |
| Nitrogen | 0.45 | | |
| Chlorine | 0.471 | | |
| Sulfur | 0.935 | | |
| Oxygen | 11.5 | | |
| Proximate Analysis (dry, ash-free) | | | |
| Element | Value (wt %) | | |
| Moisture | 0 | | |
| Fixed Content | 51.21 | | |
| Volatile Matter | 49.79 | | |
| Ash | 0 | | |

 Table 2.3
 Char Ultimate and Proximate Analysis

on laboratory results shown in Table 2.3 (108), and these values are not modified in the model.

Biomass pyrolysis generates a large variety of organic and inorganic compounds that make modeling efforts difficult. Hundreds of compounds have been identified in bio-oil - the primary fast pyrolysis product (96). A common approach is to employ model compounds to represent chemical groups based on their significance and quantity. This model adapts pyrolysis oil and gas composition from research by the National Renewable Energy Laboratory as described in the pyrolysis section (105).

Table 2.4 Corn Stover (2000 tpd) Fast Pyrolysis Scenarios

| Scenario | Description |
|------------------------------|--|
| Hydrogen Production Fast | Large-scale pyrolysis with oil hydroprocessing employing |
| Pyrolysis with Bio-Oil Up- | hydrogen derived from bio-oil reforming. |
| grading | |
| Hydrogen Purchase Fast Py- | Large-scale pyrolysis with oil hydroprocessing employing |
| rolysis with Bio-Oil Upgrad- | off-site generation of hydrogen. |
| ing | |

Two models have been developed to study the performance of biomass pyrolysis for different scenarios: a hydrogen production scenario employs bio-oil reforming to generate requisite hydrogen for bio-oil upgrading, and a hydrogen purchase scenario using merchant hydrogen for bio-oil upgrading. Pyrolysis is a flexible process that can be designed with numerous configurations and scaled to various capacities. Small-scale pyrolysis is suitable for distributed processing scenarios that could lower costs associated with biomass transportation. Table 2.4 shows a description of the scenarios explored in this study.

These scenarios employ many of the same process sections described in Table 2.1 and share most of the general assumptions. Assumptions for biomass fast pyrolysis to generate bio-oil are identical for both processes, and the scenarios only differ by the bio-oil upgrading technology. hydrogen production fast pyrolysis and oil upgrading employs a fraction of bio-oil to generate the required hydrogen for oil hydroprocessing. Additional equipment including a reformer and gas compressor are required by the hydrogen production system. The second scenario forgoes the additional investment by purchasing hydrogen from a remote source. Scenarios are based on 2000 metric ton per day corn stover input.

2.2.1 Chopping/Grinding

Delivered feedstock typically requires processing prior to feeding into a pyrolysis reactor to avoid penalties that reduce yields and increase heat requirements. Mechanical particle size reduction and drying are commonly used in thermochemical processes.

Grinding costs can add up to \$11 per metric tonne of biomass (116). Specific energy requirements can vary based on equipment and feedstock conditions. Assuming 50 kWh/ton energy consumption is reasonable (Anon.), but this model employs research by Mani et. al. (83) that correlates the grinder screen size to the energy requirement for a hammer mill based on various types of biomass including corn stover. According to their model, the energy consumption for grinding biomass from a mean chop size of 7.15 mm to between 3.5 and 0.5 mm can be approximated by the following relation:

 $Energy[kWh * ton^{-1}] = 5.31 * size_2 - 30.86 * size + 55.45$

There are various advantages and disadvantages to using hammermills for biomass grinding. Hammermills can employ various screen sizes and work with friable material such as fiber; they incur low capital costs and require minimal maintenance. On the other hand, disadvantages of hammermills include that they are less efficient than roller mills, create noise and pollution, and produce a less uniform particle size output (77).

2.2.2 Drying

Feedstock drying is very important for thermochemical processes. Moisture embedded in the feed consumes process heat and contributes to lower process yields. For reasonable pyrolysis performance, moisture content of less than 7% is recommended (34). A good rule of thumb for determining the energy required is 5 MJ/kg (2000 BTU per lb) of water evaporated.

Dryers can be generally divided as direct or indirect dryers based on how heat is provided. Direct drying involves contact between the heating medium and feed. Direct dryers can further be divided as either air or superheated steam dryers. Most commercial dryers employ heated air or process gas to dry the feed. An example of an air dryer is the rotary dryer, which has the advantages of being less sensitive to particle size and can accept hot flue gases. An important disadvantage of air dryers is the potential fire hazard do to the nature of its operation. Steam dryers on the other hand pose less of a fire hazard and emit no air emissions. The disadvantages of steam dryers are higher capital costs and small particle size requirement (1). This project assumes that biomass is steam dried to 7% moisture.

Steam dryers can employ excess steam generated by a process plant. Thermochemical plants typically require steam as a mean to provide, or remove, heat from different equipment. Harmful volatile organic compounds (VOCs) can become entrained in the evaporating moisture. The implication is that dryer steam would require water treatment to reduce the accumulation of large quantities of unwanted chemicals and prevent the release of these compounds once the steam is discarded. Unfortunately, there is not enough information to properly model the release of VOCs from biomass drying.

| Material Yields (wt | $\mathbf{NREL}(3)$ | $\mathbf{NREL}(3)$ | $\mathrm{USDA(93)}^{*}$ |
|------------------------------|--------------------|--------------------|-------------------------|
| $\% \ { m dry \ basis})$ | | | |
| Non-condensable Gas | 14.3 | 11.7 | 21.9 |
| Oil | 57.6 | 55.0 | 61.6^{**} |
| Water | 4.9 | 7.9 | - |
| $\mathrm{Char}/\mathrm{Ash}$ | 19.4 | 19.5 | 17 |
| Total | 96.2 | 94.1 | 100 |

Table 2.5Corn Stover Fast Pyrolysis Yields

^{*}Current results adjusted from these yield values ^{**}Includes water content.

2.2.3 Pyrolysis

Fast pyrolysis of biomass is a thermal process that requires temperatures near 500 C, rapid heat transfer, and low residence times. Various reactor designs have been proposed for this process (32). Due to concerns over the scalability of existing reactor designs, this study assumes that multiple 500 metric ton per day reactors are employed in parallel. This size was selected based on assumptions from a report by the National Renewable Energy Laboratory (NREL). Commercial units as large as 200 metric ton per day are currently in operation. Pyrolysis product distribution is adapted from USDA data (93) using bio-oil and non-condensable gas (NCG) composition shown in 2.5. Bio-oil and NCG composition is a modification of NREL analysis (105). Bio-oil compounds were selected based on available Aspen Plus[®] software compounds and may not share the same properties as compounds selected by NREL. Table 2.6 shows various pyrolysis yields for corn stover. Table 2.5 includes the initial pyrolysis product yields employed in this study. The final yield is adjusted to ensure a mole and mass balance.

The USDA data provides yields for the major pyrolysis product groups as listed in Table 2.5. This project's model employs more detailed pyrolysis product composition as shown in Table 2.6. The final yield results combine the individual components and product group yields resulting in yields that vary from the initial sources. For example, the USDA oil yield is listed as 61.6 wt%, but calculations estimate oil yields of 63 wt% (dry basis). The USDA corn stover had a moisture content of 2.5% at the pyrolysis reactor and our analysis assumes 7% moisture content, which increases the combined water and oil yield to 72 wt% (about 4% of reaction water is generated during the pyrolysis process).

| Gas Compounds | Composition (kg/100 | | |
|-------------------|---------------------|--|--|
| | kg of dry biomass) | | |
| Carbon Dioxide | 5.42 | | |
| Carbon Monoxide | 6.56 | | |
| Methane | 0.035 | | |
| Ethane | 0.142 | | |
| Hydrogen | 0.588^{*} | | |
| Propene | 0.152 | | |
| Ammonia | 0.0121 | | |
| Bio-oil Compounds | | | |
| Acetic Acid | 5.93 | | |
| Propionic Acid | 7.31 | | |
| Methoxyphenol | 0.61 | | |
| Ethylphenol | 3.80 | | |
| Formic Acid | 3.41 | | |
| Propyl-Benzoate | 16.36 | | |
| Phenol | 0.46 | | |
| Toluene | 2.27 | | |
| Furfural | 18.98 | | |
| Benzene | 0.77 | | |
| Other Compounds | | | |
| Water | 10.80 | | |
| Char/Ash | 16.39 | | |

 Table 2.6
 Pyrolysis Product Composition

*Corrected to 0.02 kg/kg of biomass based on engineering judgment.

Yield adjustments from the original analysis are accomplished by using yield factors. Different factors are applied to the yield of individual compounds until a 100% mole balance within 1% is achieved. This effort has been done to maintain carbon, hydrogen, oxygen, and nitrogen mole balance, and ash mass balance throughout the model. Closer attention has been given to carbon, hydrogen, and oxygen since these are the most relevant elements in both the feedstock and final products.

2.2.4 Cleanup

Gases exiting from the pyrolysis reactor contain entrained particles of various sizes. Compared to particles generated from gasification, pyrolysis particles can be much smaller with sizes of less than 25 microns. The particle size is important because it affects the design and performance of cleaning equipment such as cyclones and filters. This model assumes that a set of parallel cyclones is employed to remove 90% of entrained char particles. Baghouse filters have been considered as a secondary collection unit, but conventional baghouse filters require modifications to be employed in pyrolysis applications, and even then, they may still cause yield reductions and require costly maintenance due to coking and vapor condensation on the filter surface.

Char collected from the cleanup section is sent to the combustion section where it is employed to provide process heat. A portion of the char is burned while the rest is collected and sold as a by-product.

2.2.5 Oil Collection

There are various possible approaches to the collection of pyrolysis oil. To collect high quality oil, and maintain high yields, vapors should be condensed within fractions of a second after exiting the pyrolysis reactor. Longer residence times allow secondary reactions to take place in the gas phase and reduce the quantity of oil collected.

To accomplish rapid condensation of pyrolysis vapors, this model employs an indirect heat exchanger to transfer heat from the vapors to a water stream. This design allows for the generation of excess steam. Although not considered in this report due to lack of reliable data, staged condensation of bio-oil allows for the collection of oil fractions with attractive properties. A simple example would be to condense a majority of water at a specific condenser and a higher concentration of oil in a different condenser. This takes advantage of the fact that different compounds will condense at different temperatures in similar fashion to the crude distillation process. After most of the oil has been condensed, an Electro-Static Precipitator (ESP) unit collects remaining droplets known as aerosols by using high voltage charges. The formation of aerosols is a complex process with scarce information on the mechanism involved. This model simply assumes that remaining char entrained in the vapors is collected in the ESP unit.

Non-condensable gases (NCGs) include significant amounts of methane and other combustible gases. NCGs are sent to the combustor to provide heat for biomass drying and the pyrolysis reaction. Combustion gases are then recycled to the reactor on a 1.6 kg of gas per kg of dry biomass ratio to provide process heat and aid in fluidizing the reactor.

2.2.6 Storage

Bio-oil and char are collected in the storage section, which can store up to 4 weeks of product. Bio-oil storage equipment requires stainless steel material to prevent corrosion from bio-oil acids. Char contains volatile material and when handled improperly can pose a fire hazard. Furthermore, the small size of char particles poses an inhalation hazard for people handling the material. Storage for the naphtha and diesel range products is similarly sized for 4 weeks of capacity.

2.2.7 Combustion

Process heat is required to operate the pyrolysis reactor. Heat can be provided to smallscale reactors by employing guard heaters with insulation to prevent heat loss. Large-scale reactors require a direct form of heating which could consist of using hot gases as the fluidizing agent. A possible scheme would be to combust pyrolysis gases in the combustion section prior to recycling back to the pyrolysis reactor. The current model assumes that recycled non-condensable gases and a fraction of pyrolysis char (27.5 MJ/kg (108)) is combusted to provide the necessary process heat for the pyrolysis process and steam generation. Combustion air, at 90% of the stoichiometric requirement, is sent to the combustion reactor. Combustion gases are cooled to provide additional heat to generate steam. Finally, cyclones collect ash from the combustion gases at a solids disposal cost of \$18 per short ton (24).

2.2.8 Hydroprocessing

Hydrotreating is an exothermic process commonly used in the oil industry to selectively remove impurities that could affect downstream equipment. Hydrotreating takes place in a hydrogen rich environment (about 95 mol % or 5% by weight). Typical process conditions for hydrotreating are 7 MPa to 10 MPa (1000 to 1500 psi) pressure and 300 to 400 degrees Celsius using a Cobalt-Molybdenum catalyst. Hydrocracking breaks down heavy molecules into shorter chains. For example, heavy hydrocarbons with 30 or more carbon atoms can be split into chains within the diesel (C12) or gasoline (C8) range. Process conditions are a bit more severe than hydrotreating with pressures of 10 MPa to 14 MPa (1500 to 2000 psi) and temperatures of 400 to 450 °C using a Nickel-Molybdenum catalyst.

| Feed | Wt% |
|-----------------------|-------|
| Pyrolytic lignin | 100 |
| Hydrogen | 4-5 |
| Product | |
| Light ends | 15 |
| Gasoline | 30 |
| Diesel | 8 |
| Water, carbon dioxide | 51-52 |

 Table 2.7
 Pyrolysis Lignin Hydrotreating/Hydrocracking Yield

Bio-oil contains a large variety of heavy and light compounds. Bio-oil includes a watersoluble aqueous phase that can be reformed to produce the required hydrogen and contains heavy molecules that can be hydrocracked to lighter molecules. Bio-oil may be suitable for both hydrotreating at an oil refinery where hydrogen can be provided separately and hydrogen



Figure 2.3 Upgrading of Pyrolysis Oil to Naphtha and Diesel Range Products

production processing that employs the oil aqueous phase to generate hydrogen. UOP published in 2005 (85) one of the few publically available reports on bio-oil hydrotreating. Their initial report employed bio-oil's aqueous phase to generate hydrogen to process the pyrolysis lignin (heavy) phase. Table 2.7 shows yields from UOP's 2005 report.

A schematic of the process proposed by UOP is shown in Figure 2.3. This process employs gravity separation to separate pyrolysis lignin from the water-soluble bio-oil compounds (aqueous phase oil). Aqueous phase oil is mixed with steam and sent to a high temperature pre-reformer and converted into syngas. This syngas is then fed into a reformer with methane to produce hydrogen. Various reactions including water-gas-shift take place in the reformer to produce hydrogen. Analysis from Marquevich et. al. (86) is employed in this analysis to model the reforming process. The general chemical formula for reactions taking place in the reformer is:

$$C_n H_m O_k + (2_n - k) * H_2 O \to n C O_2 + (2n + m/2 - k) * H_2$$
 (2.1)

This project modifies the original UOP analysis by assuming that a smaller fraction of oil is separated for reforming purposes. Bio-oil's aqueous phase can account for up to 70% of the bio-oil weight, which leaves only 30% left for upgrading. This project assumes that this process can be optimized to only separate as much bio-oil as required to produce the needed hydrogen. Estimates show that 38% of the bio-oil needs to be reformed into hydrogen to upgrade the remaining bio-oil.

| Feed | ${ m Wt}\%$ | | |
|------------------------|-------------|--|--|
| Pyrolysis oil | 100 | | |
| Hydrogen | 3-4.5 | | |
| Products | | | |
| Naphtha range | 21 | | |
| Diesel range | 21 | | |
| Water, carbon dioxide, | 60 | | |
| lights | | | |

Table 2.8 Pyrolysis Oil Hydrotreating/Hydrocracking Yields

UOP updated their bio-oil hydrotreating analysis in 2008 (69). Their most recent study explores converting all bio-oil components to transportation fuels therefore maximizing yields from pyrolysis oils. This approach requires a remote source of hydrogen such as an oil refinery. Yields for this scenario are shown in Table 2.8.

Hydrocracking typically processes hydrocarbons of long (+30) carbon chain lengths. The longest carbon chain for a compound used in this model has 10 carbon atoms, and therefore hydrocracking is not properly modeled. Nevertheless, a hydrocracking unit is included because this is an important component in the conversion of bio-oil to transportation fuels. This unit is sized and cost based on the mass and energy requirements calculated by Aspen PlusTM software. It is known that metals (P, K, Na, Ca and other) originating from corn stover will be contained in bio-oil. Traditionally, concentration of metals has to be lowered to 10 ppm or less by utilizing a guard bed with sacrificial catalyst in order to prevent significant poisoning of the hydrotreating catalyst. Typical levels of total metal content in bio-oil can be as high as 500 ppm. It is recognized that technology to remove metals specifically found in bio-oil is not well understood and is under current development. Therefore, in this model a placeholder component for the guard bed has been included. Capital costs for the guard bed were estimated as 15% of the hydroprocessing capital expenditure.

Bio-oil hydroprocessing generates significant amounts of fuel gas consisting mostly of methane and lesser amounts of carbon monoxide. A product value of \$5 per million BTU is employed in this study, which is comparable to the price of low cost industrial natural gas (17).

2.2.9 Economics

This project employs Aspen IcarusTM software to estimate equipment costs and Peters and Timmerhaus to calculate project investment expenditures (99). Estimates based on this methodology are typically accurate within 30%. The profitability of a given process can be determined from the operating costs and profitability analysis. NREL developed a discounted cash flow rate of return (DCFROR) analysis spreadsheet to calculate the product value (PV), and it is used in this study.

The plant is designed based on the current state of technology, and is assumed to be the nth plant of its kind. Economic analysis for a pioneer plant is developed using risk analysis formulas that take into account the maturity of the knowledge and accuracy of the simulation. The online time is 328 days per year (equivalent capacity factor of 90%). Construction time of less than 24 months is considered. The startup period is 25% of the construction time (6 months), and during this period, an average of 50% production is achieved with expenditures of about 75% of variable expenses and 100% of fixed expenses. Contingency is calculated as a 20% factor of total installed equipment cost and indirect costs. A pioneer contingency factor of 30% is employed. Equipment costing data, and installation factors, are collected from direct quotation, published data, and Aspen IcarusTM software evaluation with preference given in the order shown here.

Feedstock cost is assumed to be \$75 per dry short ton (\$83 per dry metric tonne) and includes delivery cost. Electricity cost is assumed to be \$0.054 per kWh. Catalyst replacement costs are estimated at \$1.77 million per year based on costs for crude oil processing (88). Working capital is assumed to be 15% of the total capital investment. It is assumed that the product, transportation fuel, will be made, shipped and payment received in 30 days. Annual maintenance materials are 2% of the total installed equipment cost.

General overhead is a factor of 60% applied to the total salaries and covers items such as safety, general engineering, general plant maintenance, payroll overhead (including benefits), plant security, janitorial and similar services, phone, light, heat, and plant communications The total plant investment cost is determined by applying overhead and contingency factors to installed equipment costs. Insurance and taxes are considered as 1.5% of the total installed equipment cost.

To determine the product value per gallon of naphtha and diesel range fuel, a discounted cash flow analysis is used (after knowing the major three costs areas: (i) total project investment, (ii) variable operating costs, and (iii) fixed operating cost). A 10% discounted cash flow rate of return is used over a 20 years plant life. The plant is considered 100% equity financed. The IRS Modified Accelerated Cost Recovery System (MACRS) is employed to calculate the federal tax return, with depreciation based on a Declining Balance (DB) method. This allows for the shortest recovery period and largest deductions. The general plant depreciation period is assumed to be 7 years. Property listed with a recovery period of less than 10 years uses a 200% DB depreciation method and a 20-year recovery period property uses 150% DB depreciation. State tax is not considered for these calculations because the location of the plant is not specified. Return on investment is calculated on a per gallon basis, and income tax is averaged over the plant life.

In the hydrogen purchase scenario explored for this project, bio-oil is upgraded employing hydrogen from an external source. The purchase price of hydrogen considered here is \$1.5 per gallon of gasoline equivalent (GGE) or nearly \$1.5 per kg.

2.2.10 Sensitivity Analysis

2.9 shows the sensitivity analysis parameters selected for this study. These parameters can have a strong impact on the performance and economics of the process. Capital cost is selected as a sensitivity variable due to the uncertainty associated with the estimate in this study. Upgrading of bio-oil to naphtha and diesel range products is a developing technology with little public information about the system performance. Upgrading yields can be strongly affected by bio-oil quality and catalyst performance, and requires further research.

| Sensitivity Analysis | Favorable | Base Case | Unfavorable | | |
|------------------------------|-----------|-----------|-------------|--|--|
| Hydrogen Production Scenario | | | | | |
| Biomass cost (\$/ton) | \$50 | \$75 | \$100 | | |
| Bio-oil yield $(wt/wt$ | 0.7 | 0.63 | 0.55 | | |
| feed) | | | | | |
| Fuel gas credit value | \$10 | \$5 | \$2.5 | | |
| (MMBTU) | | | | | |
| Char value $(\$/ton)$ | \$30 | \$20 | \$10 | | |
| Capital cost (millions \$) | \$173 | \$247 | \$321 | | |
| Catalyst cost (millions | \$0.88 | \$1.77 | \$3.53 | | |
| \$) | | | | | |
| Fuel yield (wt/wt feed) | 0.3 | 0.25 | 0.2 | | |
| Hydrogen Purchase Scenario | | | | | |
| Capital cost (millions \$) | \$120 | \$172 | \$223 | | |
| Fuel yield (wt/wt feed) | 0.47 | 0.42 | 0.37 | | |
| Hydrogen price | \$1 | \$1.5 | \$2 | | |
| (\$/GGE) | | | | | |

 Table 2.9
 Sensitivity Analysis Parameters for Fast Pyrolysis and Upgrading

 Table 2.10
 Description of Pioneer Plant Analysis Parameters

| Parameters | Range | Definition |
|--------------------|----------|---|
| NEWSTEPS | ≥ 0 | Number of new process areas |
| BALEQS | 0-100 | Percentage of M&E balance equations based on |
| | | commercial plant data |
| SOLIDS | 0 or 1 | A factor based on the presence of solids |
| WASTE | 0-5 | A factor of waste disposal |
| Plant Performance | 0-86 | |
| | | |
| PCTNEW | 0-100 | Percentage of equipment cost for new (under- |
| | | developed) equipment |
| IMPURITIES | 0-5 | A factor of impurities present in the process |
| COMPLEXITY | 0-5 | Number of consecutively linked plant areas |
| INCLUSIVENESS | 0-100 | Percentage of land purchase/lease, initial plant |
| | | inventory/parts/catalysts, and pre-operating per- |
| | | sonnel costs included in the analysis |
| PROJECT DEFINITION | 2-8 | A factor of level of detail in the analysis |
| Cost Growth | | |

2.2.11 Pioneer Plant Analysis

RAND Corporation[®] analysis is employed to estimate the costs associated with construction and operation of a pioneer plant (87). This appropriately takes into account the risk associated with building a first of a kind plant or processing unit. The methodology used here is based on statistical regressions for plant performance and cost growth. Plant performance is based on the assumption that a pioneer plant can require a few years to operate at peak capacity, and therefore a revenue penalty is assigned due to reduced output. Cost growth estimates the total project investment cost of a pioneer plant, which is typically higher than an equivalent nth plant. Plant performance and cost growth can be estimated using the equations shown in Eq. 2.2 and the parameters from Table 2.10.

$$PlantPerformance = 85.77 - 9.69 * NEWSTEPS + + 0.33 * BALEQS - 4.12 * WASTE - 17.91 * SOLIDS$$
$$CostGrowth = 1.1219 - 0.00297 * PCTNEW - 0.02125 * IMPURITIES - - 0.01137 * COMPLEXITY + 0.00111 * INCLUSIVENESS - - C1 * PROJECTDEFINITION$$
$$(2.2)$$

Once the risk analysis parameters are selected, and plant performance and cost growth calculated, the total project investment (TPI) and first year operating costs are calculated as indicated in Eq. 2.3:

$$TPI(PioneerPlant) = (TPI(n^{th}))/(CostGrowth)$$

$$OperatingCost(1^{st}year) = OperatingCost * PlantPerformance$$
(2.3)

The plant performance factor increases by 20% every year until it reaches 100% at which point the plant is operating at full capacity. It is important to note that if a plant fails to reach a 40% plant performance factor within the first year of operation, the plant is unlikely to achieve full nameplate capacity without significant capital investment. Subsequent plants

| Rand Analysis | Optimistic | Base Case | Pessimistic | Range |
|--------------------|------------|-----------|-------------|--------|
| NEWSTEPS | 2 | 3 | 4 | - |
| BALEQS | 0% | 0% | 0% | 0-100 |
| SOLIDS | 1 | 1 | 1 | 0,1 |
| WASTE | 3 | 4 | 5 | 0-5 |
| Plant Performance | 36.12 | 22.31 | 8.50 | 0-100 |
| | | | | |
| PCTNEW | 25.00 | 60.00 | 75.00 | 0-100% |
| IMPURITIES | 3 | 4 | 5 | 0-5 |
| COMPLEXITY | 4 | 5 | 6 | 2-7 |
| INCLUSIVENESS | 66% | 0% | 0% | 0-100% |
| PROJECT DEFINITION | 6 | 8 | 8 | 2-8 |
| Cost Growth | 0.56 | 0.29 | 0.22 | 0-1 |

 Table 2.11
 Selected Pioneer Plant Analysis Parameters for Biomass Fast

 Pyrolysis and Upgrading

would likely achieve improved performance. Table 2.11 shows the selected values for the pioneer plant analysis parameters.

2.2.12 Results

| | Hydrogen Production | Hydrogen Purchase |
|---|------------------------|----------------------|
| Capital Cost (millions \$) | \$287 | \$200 |
| Annual Operating Cost (millions \$) | \$109 | \$123 |
| Fuel Yield (million gallons/year) | 35.4 | 58.2 |
| PV (\$/gallon gasoline equivalent) | \$3.09 | \$2.11 |
| Pioneer Plant Capital Cost (million \$) | \$911 | \$585 |
| Pioneer PV ((GGE) | \$6.55 | \$3.41 |

Table 2.12 Summary of n^{th} Plant Cost Results

Table 2.12 includes a comparison of key results from this study. The hydrogen production scenario has higher capital costs due to additional equipment required for bio-oil upgrading compared to the hydrogen purchase scenario. Annual operating costs are higher for the hydrogen purchase scenario at a hydrogen price of \$1.50 per gallon of gasoline equivalent (nearly \$1.50 per kg). Higher fuel yields from upgrading all available bio-oil offset the increase in costs



Figure 2.4 Comparison of Process Energy Flows for 2000 tpd Biomass Fast Pyrolysis and Upgrading(15; 50)

resulting in a lower product value for the hydrogen purchase scenario. Detailed analyses of these results are provided in the following sections.

An interesting comparison for these scenarios involves detailing the primary energy flows, which are shown in Figure 2.4. Efforts have been taken to ensure that these scenarios avoid consumption of fossil fuel resources. Purchased electricity could come from nuclear, hydroelectric, or wind which are all prevalent in the corn belt. Most hydrogen available derives from fossil fuel processing although it is conceivable that hydrogen could be produced by hydrolysis of H2O with electricity from non-fossil sources. The hydrogen production scenario produces more fuel gas due to the bio-oil reforming process, which causes a decrease in liquid fuel yield.

2.2.12.1 Hydrogen Production Scenario

The product value for a 2000 metric ton per day corn stover hydrogen production fast pyrolysis and upgrading plant is \$3.09 per gallon (\$0.82 per liter) of fuel. This corresponds to a bio-oil production cost of \$0.83 per gallon of bio-oil (\$0.22 per liter). Capital expenditures for this plant are estimated at \$287 million. Bio-oil yield for 2000 tpd corn-stover pyrolysis is calculated as 104 million gallons (394 million liters) per year representing 72% yield by weight of the dry biomass input with a 15% water content. For the hydrogen production scenario, 38% of the bio-oil is reformed to produce 1500 kg per hour of hydrogen. Biomass to liquid fuel efficiency for the hydrogen production scenario is estimated at 36%. Fuel yield for the hydrogen production scenario is 35.4 million gallons (134 million liters) of fuel per year.

| Equipment Costs (millions \$) | | | |
|-------------------------------------|---------|--|--|
| Hydroprocessing | \$48.7 | | |
| Combustion | \$47.3 | | |
| Pyrolysis & Oil Recovery | \$28.0 | | |
| Pretreatment | \$20.2 | | |
| Utilities | \$9.1 | | |
| Storage | \$5.8 | | |
| Total Equipment Installed Cost | \$159.1 | | |
| | | | |
| Indirect Costs | \$46.9 | | |
| (% of TEIC + IC) | 20% | | |
| Project Contingency | \$41.2 | | |
| | | | |
| Total Project Investment (TPI) | \$287.4 | | |
| | | | |
| Installed Cost per Annual Gallon | \$4.50 | | |
| Total Project Investment per Annual | \$8.12 | | |
| Gallon | | | |
| Lang Factor | 5.46 | | |

Table 2.13Capital Costs for 2000 tpd Hydrogen Production Fast Pyrolysis
and Upgrading

Hydroprocessing incurs the largest expenditure shown in Table 2.13. Large-scale hydroprocessing is typically employed in industry to take advantage of economies of scale. At the plant capacity assumed in this study (2000 tpd), hydroprocessing costs are relatively expensive on a per gallon of output basis. Storage costs include 1 month of fuel storage. The project contingency for both scenarios is assumed as 20% of total direct and indirect costs.

Operating costs for the hydrogen production scenario are shown in Table 2.14. Feedstock costs contribute half the cost producing fuel from biomass in this scenario. Co-product credits,

Table 2.14Operating Costs for 2000 tpd Hydrogen Production Fast Pyrol-
ysis and Upgrading

| Operating Costs (cents/gal product) | | |
|---|---------|--|
| Feedstock | 153.8 | |
| Electricity | 16.4 | |
| Solids Disposal | 5.1 | |
| Catalyst | 5.1 | |
| Fixed Costs | 32.5 | |
| Co-product credits | -31.9 | |
| Capital Depreciation | 33.6 | |
| Average Income Tax | 26.4 | |
| Average Return on Investment $(10\%$ IRR) | 63.5 | |
| Total | 309.4 | |
| Operating Costs (millions \$/yr) | | |
| Feedstock | \$54.4 | |
| Electricity | \$5.8 | |
| Solids Disposal | \$1.8 | |
| Catalyst | \$1.8 | |
| Fixed Costs | \$11.5 | |
| Co-product credits | -\$11.3 | |
| Capital Depreciation | \$11.9 | |
| Average Income Tax | \$9.3 | |
| Average Return on Investment | \$22.5 | |
| Total | \$109.5 | |



Figure 2.5 Sensitivity Analysis for 2000 tpd Fast Pyrolysis and Upgrading with Hydrogen Production

primarily from the sale of fuel gas, generate significant income.

Electricity costs are estimated to contribute 16.4 cents per gallon to the cost of fuel. Investment in power generation could yield additional income from sale excess electricity, but this scenario is not explored in this project.

Sensitivity analysis results shown in Figure 2.5 indicate a strong impact from fuel yield. This implies that slight improvements in the bio-oil upgrading process could reduce the cost of fuel significantly whereas lower yields cause a rapid increase in fuel cost. Biomass cost sensitivity is also important not only because of its impact, but also because the cost to acquire feedstock can vary widely between locations and throughout the year. Overall, sensitivity results suggest a greater negative sensitivity.

Table 2.15 shows the risk analysis results for the hydrogen production scenario. These are the estimated costs for a pioneer plant based on the current process analysis. Absent of learning effects from available commercial implementations, building a first-of-a-kind biomass fast pyrolysis and upgrading plant is expected to cost about \$864 million. Fuel costs from this plant are \$6.55 per gallon.

| | n th Plant | Optimistic | Base Case | Pessimistic |
|---------------|-----------------------|------------|-----------|-------------|
| Capital Cost | \$287 | \$479.8 | \$911.6 | \$1,236.3 |
| (millions \$) | | | | |
| Product Value | \$3.09 | \$4.32 | \$6.55 | \$8.23 |
| (GGE) | | | | |

Table 2.15Pioneer Analysis for 2000 tpd Fast Pyrolysis and Upgrading
with Hydrogen Production

2.2.12.2 Hydrogen Purchase Scenario

The product value for a 2000 metric ton per day fast pyrolysis and upgrading plant with external hydrogen production is \$2.11 per gallon of fuel. Capital expenditures for this plant are estimated at \$200 million.

The hydrogen purchase scenario employs 2,040 kg per hour of hydrogen to upgrade 60,000 kg per hour of bio-oil. Feedstock to liquid fuel efficiency for the scenario purchase scenario is estimated at 50% and includes the hydrogen energy input (120 MJ/kg or 0.98 gallons of gasoline equivalent per kg of hydrogen). Fuel production for the hydrogen purchase scenario is 58.2 million gallons of fuel per year.

Table 2.16 includes capital costs for the hydrogen purchase scenario. Compared to the hydrogen production scenario, the hydroprocessing section has a much lower cost because it does not include equipment to reform and compress hydrogen.

Table 2.17 shows the operating costs for the hydrogen purchase scenario. Feedstock costs contribute almost half the cost of fuel. Although most operating expenditures are comparable to the hydrogen production scenario, the increase in fuel yield reduces the per gallon cost of fuel.

Sensitivity analysis results for the hydrogen purchase scenario are shown in Figure 2.6. Biomass cost has a significant impact on the cost of fuel, and at \$100 per ton the product value estimate is \$2.43 per gallon.

Risk analysis for this scenario shows a similar trend as the hydrogen production pioneer plant (see Table 2.18). Capital cost estimates for base case assumptions are \$585 million with pioneer plant fuel costs of \$3.41 per gallon. Table 2.16Capital Costs for 2000 tpd Fast Pyrolysis and Upgrading with
Hydrogen Purchase

| Equipment Costs (millions \$) | |
|--|---------|
| Combustion | \$45.9 |
| Pyrolysis & Oil Recovery | \$28.0 |
| Pretreatment | \$20.2 |
| Hydroprocessing | \$14.8 |
| Storage | \$1.7 |
| | |
| Total Equipment Installed Cost | \$110.6 |
| | |
| Indirect Costs | \$70.9 |
| $(\% 	ext{ of TEIC} + 	ext{IC})$ | 20% |
| Project Contingency | \$32.6 |
| | |
| Total Project Investment (TPI) | \$200 |
| | |
| Installed Equipment Cost per Annual Gallon | \$1.90 |
| Total Project Investment per Annual | \$3.43 |
| Gallon | |
| Lang Factor | 5.46 |



Figure 2.6 Sensitivity Analysis for 2000 tpd Fast Pyrolysis and Upgrading with Hydrogen Purchase

| Table 2.17 | Operating Costs for 2000 tpd Fast Pyrolysis and Upgrading with |
|------------|--|
| | Hydrogen Purchase |

| Operating Costs (cents/gal product) | | | |
|--|---------|--|--|
| Feedstock | 93.5 | | |
| Hydrogen | 40.7 | | |
| Electricity | 8.4 | | |
| Solids Disposal | 3.1 | | |
| Catalyst | 3.1 | | |
| Fixed Costs | 15.5 | | |
| Co-product credits | -10.1 | | |
| Capital Depreciation | 14.8 | | |
| Average Income Tax | 11.7 | | |
| Average Return on Investment (10% IRR) | 31.1 | | |
| Total | 211.4 | | |
| Operating Costs (millions \$/yr) | | | |
| Feedstock | \$54.4 | | |
| Hydrogen | \$23.7 | | |
| Electricity | \$4.9 | | |
| Solids Disposal | \$1.8 | | |
| Catalyst | \$1.8 | | |
| Fixed Costs | \$8.8 | | |
| Co-product credits | -\$5.9 | | |
| Capital Depreciation | \$8.6 | | |
| Average Income Tax | \$6.8 | | |
| Average Return on Investment | \$18.1 | | |
| Total | \$123.0 | | |

Table 2.18Pioneer Analysis for 2000 tpd Fast Pyrolysis and Upgrading
with Hydrogen Purchase

| | n th Plant | Optimistic | Base Case | Pessimistic |
|---------------|-----------------------|------------|-----------|-------------|
| Capital Cost | \$200 | \$307.9 | \$584.9 | \$793.2 |
| (millions \$) | | | | |
| Product Value | \$2.11 | \$2.54 | \$3.41 | \$4.07 |
| (\$/GGE) | | | | |

2.3 Conclusions

This techno-economic study explored the cost of converting corn stover into naphtha and diesel range stock fuel via fast pyrolysis and bio-oil upgrading. Based on the current analysis, naphtha and diesel range fuel can potentially be produced from biomass at a competitive product value (PV) of \$3.09 per gallon or \$2.11 per gallon when hydrogen is procured from a remote source. For a pioneer plant, fuel PV could increase to \$6.55 per gallon of fuel.

Two scenarios are modeled in this study. A hydrogen production scenario employing biooil reforming to generate requisite hydrogen, and a hydrogen purchase scenario that relies on merchant hydrogen. Both scenarios process 2000 metric tonnes per day of corn stover to generate 35 and 58 million gallons of naphtha and diesel range stock fuel respectively. The hydrogen production scenario sacrifices a portion of bio-oil to produce hydrogen, which results in lower yields compared to the purchase scenario. Capital costs were estimated at \$287 for the hydrogen production scenario and \$200 for the hydrogen purchase scenario. The difference is primarily due to the high cost of reforming equipment. Sensitivity analysis of key process variables find fuel conversion yields to have the most impact on the final cost of transportation fuel. Variations of 5% in the bio-oil upgrading yield result in product values of \$2.60 to \$3.89 per gallon for the hydrogen production scenario. Biomass cost and bio-oil yield are found to have significant impact on the cost of fuel for both scenarios. The capital cost sensitivity range is Â\$30% and has a relatively small impact with product values ranging between \$2.71 and \$3.48.

Pioneer plant analysis is employed in this study to estimate the capital and operating costs of a first-of-a-kind biomass fast pyrolysis and upgrading plant. Results indicate that a pioneer hydrogen production fast pyrolysis and upgrading plant could require an investment of \$912 million and have a product value of \$6.55. These high costs indicate that some aspects of this technology, notably the bio-oil upgrading process, require further research.

Biomass fast pyrolysis with bio-oil upgrading is in a very early stage of development. This technology platform is not as mature as the thermochemical and biochemical pathway to produce transportation fuels. This report provides a basis from which fast pyrolysis and upgrading can be compared to related studies employing gasification and fermentation technologies to produce liquid fuels.

2.4 Acknowledgments

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CHAPTER 3. Locating corn stover biorefineries to minimize feedstock transportation costs

3.1 Abstract

This paper describes a model to determine the locations of advanced biorefineries and allocations of corn stover within the Midwest to these refineries that minimizes delivered cost of biomass to refineries and biofuels to major metropolitan markets in the United States. The model determines the location of 70 technologically mature fast pyrolysis and hydroprocessing biorefineries in the six largest corn producing states — Illinois, Indiana, Iowa, Nebraska, Minnesota, and South Dakota — with transportation biofuels delivered to the 217 largest Metropolitan Statistical Areas. Optimally located advanced biorefineries produce biofuels at costs of \$2.00-\$2.50 per gallon, and reduce biomass transportation costs by \$1.15 billion per year, on average, over randomly located biorefineries. This comparison suggests that coordinating the location decisions of biorefinery investors and operators across the Midwest will significantly reduce the retail price of biofuels and the field-to-wheel greenhouse gas emissions of advanced biofuels.

3.2 Introduction

Transportation biofuels are anticipated to play a major role in the energy future of the United States (81). The federal government in the US has instituted a Renewable Fuel Standard (RFS2) to promote the use of renewable biofuels in US transportation. The RFS mandates the inclusion of 36 billion gallons of renewable biofuels per year by 2022 (18).

To date, the US RFS has been met primarily with first-generation biofuels like corn ethanol. Currently more than 10.7 billion gallons of ethanol per year is produced from corn grain (26), meeting 96% of the existing RFS mandate for the year 2009 (27). The RFS2 mandates that future biofuel production include increasing contributions from second-generation biofuels. The RFS2 mandate envisions production of up to 16 billion gallons of cellulosic biofuels as part of 21 billion gallons of advanced biofuels by 2022.

Next-generation biorefineries employ cellulosic biomass to generate fuel that is compatible with existing infrastructure and vehicle technology. Examples of cellulosic biomass include corn stover, switchgrass, wood chips (36). In particular, the US currently generates more than 323 million tons of corn stover every year (22). Unlike corn grain, corn stover is primarily a waste byproduct of corn production. Applying these large existing supplies of unused corn stover to produce transportation biofuels (47) would create a significant market for this byproduct, while potentially supplying a large volume of transportation fuels to meet the RFS.

While there is much research devoted to the technological challenges to the production of transportation biofuels from cellulosic biomass feedstocks like corn stover (7; 80; 52), the logistics associated with advanced biorefining remains a significant obstacle to widespread use of biofuels (54; 116; 89; 97). Biomass feedstocks like corn grain or stover must be harvested, separated, collected, and transported prior to conversion to transportation biofuels or other energy products at refinery sites. Several groups have applied linear programming models to determine the allocations of biomass feedstocks to existing biorefineries (129) and coal-fired electrical power plants (90; 91) that minimize total transportation and distribution costs. To the degree that transportation and distribution costs are driven by transportation distances, optimal allocations also play an important role in minimizing the greenhouse gas burden of this important renewable energy supply. For example, emissions from the electricity consumed or generated would vary depending on the grid power generation mixture for a given region (131).

This article describes a location-allocation model that simultaneously locates advanced biorefineries and determines optimal allocation of both biomass feedstocks and refined biofuels to minimize total collection and distribution costs. Previous studies dealing with the logistics of corn ethanol and coal-fired power plants constrained biorefinery locations to the 305 U.S. agricultural statistical districts (ASD) (90; 129). There is thus an opportunity to model more specific biorefinery locations by employing county-level data.

Analysis using a location-allocation model quantifies the benefits to be gained by coordinating the location of advanced biorefineries relative to the location of biomass feedstocks. For the case of Midwestern corn stover, optimally locating advanced biorefineries leads to a significant reduction in total annual collection and transportation-related costs, on average, relative to randomly-located biorefineries. This result suggests that regulatory coordination of biorefinery locations as they emerge could be an important component of national renewable fuels policy.

This report proceeds as follows: the biofuels production chapter presents various technologies proposed for the conversion of biomass, and corn stover in particular, into biofuels; the methodology section describes the model design, including parameters and data, for centralized and distributed pathways to the production of biofuels. The centralized model is applied to a Iowa-centric corn grain-to-ethanol model and a Midwest corn stover-to-gasoline and diesel model.

3.3 Background

3.3.1 Converting Biomass into Biofuels

There are two major platforms for the conversion of biomass to liquid fuels: the biochemical and thermochemical platforms (137). The biochemical platform employs micro-organisms to convert sugars into primarily alcohols (ethanol and butanol) suitable for transportation applications (7; 52). The thermochemical platform employs thermal and catalytic processes to generate a wide range of alcohol and hydrocarbon fuels (7; 52). 3.1 details the main conversion pathways for cellulosic, sugars, oils, and wet biomass (>50% moisture) to liquid fuels.

The conventional biochemical platform converts hydrocarbons via fermentation to fuels, most prominently ethanol (78) and butanol (102), depending on the micro-organism employed. Cellulosic ethanol production employs acid or enzymatic hydrolysis to expose hydrocarbons chains (2) to subsequent fermentation. Conventional biodiesel production consists of extraction of lipids from oil seeds and esterification to biodiesel. Thermochemical pathways consisting of gasification (122), pyrolysis (141), and hydro-thermal processing (55) generate a variety of



Figure 3.1 Biofuel Pathways to the Production of Liquid Fuels (Dashed Lines Indicate First Generation Biofuels, and Solid Lines Indicate Second Generation Biofuels)(79)

liquid fuels that include Fischer-Tropsch Liquids (FTL), dimethyl-ether (DME), methanol, mixed alcohols, and green diesel.

Second generation biorefineries will allow the renewable fuels industry to meet the RFS mandates for advanced biofuels. First generation biofuels have been dominated by the conversion of simple sugars to ethanol. The main feedstocks for ethanol production have been sugarcane in Brazil, and corn grain in the U.S. The commercial success of the corn grain to ethanol platform has allowed the industry to meet the renewable fuels mandate set by the RFS. To meet the mandates for advanced biofuels, producers will need to convert cellulosic feedstock to liquid fuels. Corn stover is a cellulosic agricultural residue derived from the production of corn grain that is commonly employed as a means to retain soil productivity, or to provide bedding and feed to livestock.

3.3.2 Converting Corn Stover into Biofuels

Table 3.1Corn Stover Biorefinery Technologies for the Production of
Transportation Fuels

| Technology | Fuel | Fuel | Feedstock | Fuel Cost |
|--|------------|---------------------|-----------------|-----------|
| | Output | \mathbf{Yield} | \mathbf{Cost} | (\$/gal) |
| | | $({f gal}/{f ton})$ | (\$/ton) | |
| Hydrolysis and $Fermentation(2)$ | Ethanol | 89.7 | \$30 | \$1.07 |
| Hydrolysis and $Fermentation(7)$ | Ethanol | 69.3 | \$75 | \$3.43 |
| Pyrolysis and Hydroprocessing(141) | Naphtha | 48.8 | \$75 | \$3.09 |
| | and Diesel | | | |
| Pyrolysis and Hydroprocessing(141) | Naphtha | 80.1 | \$75 | \$2.11 |
| | and Diesel | | | |
| Gasification and FTL Synthesis (122) | Naphtha | 61.0 | \$75 | \$4.27 |
| | and Diesel | | | |

Various techno-economic studies on the conversion of cellulosic biomass to transportation fuels employ corn stover as their feedstock. The National Renewable Energy Laboratory (NREL) has published various reports on the conversion of corn stover to ethanol (2). Iowa State University, in collaboration with ConocoPhillips Company and NREL, has compared the biochemical, gasification, and pyrolysis platforms for the production of transportation fuels from corn stover (7; 122; 141). A summary of the biorefinery technologies, fuel output and cost are shown in Table 3.1.

Corn stover is a bulky material that poses logistic challenges to large-scale advanced biorefining. Corn stover is dispersed throughout farms after corn grain has been harvested. To collect corn stover, farmers have to conduct a second harvesting step or upgrade their equipment to simultaneously collect grain and stover. Shinners et al. recently compared the performance of single-pass combines for the collection of corn grain and stover (Shinners et al.). Their study found that 64% of available stover was collected using a harvester with a stalk-gathering head, and 49% of available stover can be collected with a whole-plant head harvester. Once collected, stover can be loaded into trailers in the form of round or square bales and delivered to a biorefinery facility.

Oak Ridge National Laboratory has published various papers on the logistics of transporting biomass to large-scale biorefineries (61; 68; 116). A third or more of the delivered corn stover cost can be attributed to truck transportation costs (116). This results in diseconomies of scale that limit optimal biorefinery size, a challenge to large-scale second generation biorefining (136).

Several investigations consider how delivered feedstock costs can be reduced through locating biorefinieries. Sayler et al. (109) studied the feasibility of corn stover collection to a specific location in Nebraska counties. Graham et al. (60) developed a geographical information system-based model to evaluate marginal delivery costs of switchgrass. Their model has since been expanded to evaluate the delivered costs of corn stover (113), but there is limited information on the assumptions employed in the corn stover model.

Over the past half century the Operations Research (OR) field has developed methodologies to minimize transportation costs in supply chains (125). Several recent studies have employed OR methodologies to minimize biofuel delivery costs. Morrow et al. explored a transportation minimization function to distribute cellulosic ethanol from hypothetical biorefineries to the 271 largest metropolitan statistical areas in the United States (90). Wakeley et al. developed a study of the infrastructure requirements to deliver cellulosic ethanol and hydrogen within the
state of Iowa (128) and the contiguous United States (129). Their study sought to minimize the transportation costs of biomass to grain and cellulosic facilities for the production of ethanol as well as the delivery of ethanol to metropolitan statistical areas.

These studies (90; 129) employed the POLYSYS model to estimate switchgrass availability at specified biomass farm gate prices and the potential capacity of cellulosic ethanol plants at given locations. POLYSYS is a national simulation model of the U.S. agriculture sector which incorporates agricultural supply and demand to estimate crop production, prices, and environmental impact (46).

A common approach to minimizing transportation costs is to identify the marginal costs and locate facilities sequentially at the next lowest cost location. The approach employed in this study is to implement a location-allocation (LA) model to the delivery of corn stover from Midwest counties to nearby biorefineries. The benefit of this approach compared to a marginal delivery cost model is that the LA model can determine the optimum allocation of resources for competing biorefineries.

3.3.3 Corn Stover Fast Pyrolysis Biorefinery Capital and Operating Costs

The corn stover to biofuel model described in this report employs fast pyrolysis and hydroprocessing technology as a representative biorefinery for the conversion of cellulosic feedstock. Table 3.2 shows capital and operating costs for a 5500 Mg/day stand-alone fast pyrolysis biorefinery. This stand-alone facility tries to limit the use of fossil fuel sources during its operation. However, electricity purchased from the power grid could come from renewable or non-renewable sources. Feedstock costs contribute a significant portion of fuel production costs. Since delivered feedstock costs are likely to vary between different locations, they could have an important impact on the plant-gate cost of fuel.

The plant capacity is based on 7850 hours of operation per year (90% capacity factor). Capital charges assume a 13% annual interest rate over 20 years (10% annual cost). Electricity is based on 5.4 cents per kWh price. Solids disposal is assumed to be \$18 per ton (24). Fixed costs include the cost of labor and management. Co-products consist of fuel gas valued at

| Item | Value |
|--------------------------|---------------------|
| Plant Capacity (Mg/day) | 5500 |
| Total Project Investment | \$583,472,000 |
| | |
| Feedstock ($83/Mg$) | $$148,\!813,\!000$ |
| Capital Charges | \$58,347,000 |
| Electricity | $$15,\!950,\!000$ |
| Solids Disposal | $$4,\!950,\!000$ |
| Catalyst | \$4,950,000 |
| Fixed Costs | $$32,\!175,\!000$ |
| Co-product Credits | $-\$31,\!075,\!000$ |
| Total | $$234,\!110,\!000$ |
| Fuel Cost $(\$/gal)$ | \$2.67 |
| | |
| Fuel Yield (gal/ton) | 48.8 |
| Fuel Output (gal/year) | 87,840,000 |

Table 3.2Biorefinery Capital and Operating Costs for 5500 Mg/dayStand-Alone Fast Pyrolysis (adapted from (141))

\$5/MMBTU and char valued for \$20 per short ton as a low-cost coal substitute. The fuel output consists of naphtha and diesel range fuel-stock.

3.4 Methodology

Operations research studies have developed deterministic methods to solve linear and integer programming problems associated with inter-facility resource shipments and facility location decisions. Location-allocation models combine the evaluation of site location with resource allocation. The definition of a location-allocation problem was originally proposed by Cooper (40). Location-allocation models seek to minimize cost by evaluating the number, location, and capacity of facilities, and the amount of product allocated to customers. This project employs methodology described by Tsiakis and Papageorgiou (125) to evaluate optimal corn stover allocation and distribution of biorefinery network scenarios within the United States.

This model allocates available corn stover to biorefineries, and biofuel generated by these biorefineries is distributed to the 270 largest metropolitan statistical areas within the contiguous US. Biorefinery locations are determined by the optimization routine, which deterministically solves for biorefinery locations that result in the lowest system cost.

This study employs MatlabTM software to collect and process data and model results. The open-source GNU Linear Programming Kit (GLPK) is used to solve the linear equations developed for the model.

Table 3.3 Symbols used in location-allocation models

Feedstock Parameters

| N | Number of counties producing biomass feedstocks; | | |
|---------------------------|--|--|--|
| A_i | Available feedstock at county i ; | | |
| S_i | Sustainability factor for county i ; | | |
| $C^{S,C}$ | Variable feedstock collection cost; | | |
| $C^{S,L}$ | Variable feedstock loading cost; | | |
| | | | |
| Transportation Parameters | | | |

Transportation Parameters

| ℓ | Material loss factor; |
|-----------|---|
| $D_{i,j}$ | great circle distance from county i to county j ; |
| au | tortuosity factor; |
| $C^{S,T}$ | Variable feedstock transportation cost; |

Biorefinery Parameters

| V | Fixed biorefinery capacity for all locations; |
|-----------|--|
| Y | Biorefinery fuel process yield; |
| $C^{G,C}$ | Unit conversion cost per gallon of biofuel produced; |
| T | Number of biorefineries |

Metropolitan Statistical Areas (MSAs) and Gasoline Demand

| M Number of MSA | 's considered; |
|-----------------|----------------|
|-----------------|----------------|

 G_k Total gasoline demand for MSA k;

 $C^{G,T}$ Variable gasoline transportation cost;

Optimization Variables

| δ_j | Binary | variable t | hat de | etermines | if a | biorefi | nery | is | located | in | county | j |
|------------|--------|------------|--------|-----------|------|---------|------|----|---------|----|--------|---|
|------------|--------|------------|--------|-----------|------|---------|------|----|---------|----|--------|---|

 $f_{i,j}$ Flow of biomass feedstock from county *i* to county *j* (for refining);

 $q_{j,k}$ Finished gasoline flow from county j to MSA k;

In what follows, all lowercase roman letters denote model variables. All greek letters and upper-case roman letters denote problem parameters. Table 3.3 provides a complete list of symbols used in the LP and ILP formulations presented below.

3.4.1 A Pure Feedstock Allocation Model

Several existing studies use linear programming to compute allocations of biomass feedstocks. This section reviews the formulation of such models, with some minor generalizations from earlier work.

Suppose there are $N \in N$ counties that produce corn stover. Each county $i \in \{1, ..., N\}$ has $A_i \in R$ tons of total available corn stover and a "sustainability factor" $S_i \in \{0, 1\}$ providing the fraction of stover that must be left in the field to promote soil health. The total amount of stover available from county i for conversion to biofuels is thus $(1 - S_i)A_i$.

Some specified subset $R \subset \{1, ..., N\}$ of the counties also contain biorefining capacity. Country $j \in R$ has a refining capacity of $V_j \in Pos$ tons. This can be viewed either as a single biorefinery or as a county-level aggregation of biorefining capacity, and assumes that the specific location or locations of biorefineries within a particular county has a negligible impact on feedstock transportation costs and field-to-wheel GHG emissions of the resultant biofuels.

The flow of biomass feedstock from any county $i \in \{1, ..., N\}$ to any county $j \in R$ is denoted by $f_{i,j} \in Pos$. The total flow of feedstock into county j is $\sum_{i=1}^{N} f_{i,j}$. Let $\ell \in [0, 1)$ denote a "material loss factor" that describes the amount of material typically lost in loading, transportation, and unloading. $(1 - \ell) \sum_{i=1}^{N} f_{i,j}$ is then the amount of biomass feedstock at refinery county $j \in R$ that can be converted to biofuel. The inequality $(1 - \ell) \sum_{i=1}^{N} f_{i,j} = V_j$ requires the total flow of feedstock into county $j \in R$ for refining to be less than a given conversion capacity, $V_j > 0$. A total number of biorefineries T is specified that determines how many biorefineries are sited.

There are collection, loading/unloading, and transportation costs associated with the weight of feedstock collected and the distance it travels to a refinery. Collecting $f_{i,j}$ tons of feedstock from county *i* for transportation to refinery county *j* entails a cost of $C_i^{S,C} f_{i,j}$, where $C_i^{S,C}$ is a unit cost of collection (in \$/ton) for county *i*. Loading and unloading feedstock entails a cost of $C_i^{S,L} f_{i,j}$, where $C_i^{S,L}$ is a unit cost of loading and unloading operations (in \$/ton). Finally, actually transporting $f_{i,j}$ tons of feedstock from county *i* to county *j* entails a cost of $\tau D_{i,j}C^{S,T} f_{i,j}$, where $C^{S,T}$ is a unit cost of transport (in \$/ton-mile), $D_{i,j}$ is the great circle distance between counties i and j, and $\tau \in [1, \infty)$ is a "tortuosity" factor that accounts for the actual geography of the surface roads traveled by trucks. Wakeley et al.(129) refer to similar factors as rail and truck circuitry factors.

All biomass received at each refinery county $j \in R$ is converted to biofuels and shipped to any of $M \in N$ MSAs. The variable $q_{j,k} \in Pos$ denotes the amount of biofuel shipped from refinery county j to MSA k. The total amount of biofuel cannot exceed the total fuel demand in MSA k, denoted by $G_k \in Pos$, and thus $\sum_{j \in R} q_{j,k} \leq G_k$ for all k.

In any county j with refining capacity, biomass is converted at a yield of Y_j gal/ton. Accounting also for material losses, this conversion to and distribution of biofuel is characterized by the equality $(1-\ell) \sum_{i=1}^{N} f_{i,j}Y_j = \sum_{k=1}^{M} q_{j,k}$. At refinery $j \in R$, this conversion entails a cost of $\sum_{k=1}^{M} C^{G,C}q_{j,k}$ where $C^{G,C}$ is a unit conversion cost (in \$/gal). Distribution of the resultant fuel entails a cost of $\sum_{k=1}^{M} D_{j,k}C^{G,T}q_{j,k}$, where $D_{j,k}$ is the great circle distance between refinery county j and MSA k (in miles) and $C^{G,T}$ is a unit cost of transportation (in \$/gal-mile).

$$\begin{aligned} \text{minimize} \quad \sum_{i=1}^{N} \sum_{j \in R} (C_i^{S,C} + C_i^{L,C} + \tau D_{i,j}C^{S,T}) f_{i,j} + \sum_{j \in R} \sum_{k=1}^{M} (C^{G,C} + D_{j,k}C^{G,T}) q_{j,k} \\ \text{with respect to} \quad f_{i,j} \geq 0 \quad \text{for all } i \in \{1, \dots, N\}, \ j \in R \\ q_{j,k} \geq 0 \quad \text{for all } j \in R, \ k \in \{1, \dots, M\} \\ \text{subject to} \quad \sum_{j \in R} f_{i,j} \leq (1 - S_i)A_i \quad \text{for all } i \in \{1, \dots, N\} \quad (\text{feedstock availability}) \\ (1 - \ell) \sum_{i=1}^{N} f_{i,j} = V_j \quad \text{for all } j \in R \quad (\text{refinery feedstock demand}) \\ \sum_{j \in R} q_{j,k} \leq G_k \quad \text{for all } k \in \{1, \dots, M\} \quad (\text{MSA gasoline demand}) \\ (1 - \ell) \sum_{i=1}^{N} f_{i,j}Y_j = \sum_{k=1}^{M} q_{j,k} \quad \text{for all } j \in R \quad (\text{fuel output}) \\ \sum_{j \in R} f_{i,j} = T \quad \text{for all } j \in R \quad (\text{number of biorefineries}) \end{aligned}$$

T

Equation (3.1) provides a formulation of the allocation problem. The PA-LP is a linear program, and can be solved with widely-available software for linear programming. This study

employs $Gurobi^{TM1}$ optimization software to solve the PA-LP model.

3.4.2 A Location-Allocation Model

Conceptually, including location decisions into the pure allocation model described above is straightforward. Working from the PA-LP formulation above, let $J = \{1, ..., N\}$ and introduce a new set of binary variables $\delta_j \in \{0, 1\}$ for each $j \in \{1, ..., N\}$. δ_j takes the value 1 if county j contains biorefining capacity and 0 otherwise. The refinery feedstock demand constraint can be written as $(1 - \ell) \sum_{i=1}^{N} f_{i,j} = V \delta_j$. This requires the total flow of feedstock into county j(for refining) to be zero if county j has no refining capacity ($\delta_j = 0$), and less than $(1 - \ell) \in V$ if county j has refining capacity ($\delta_j = 1$) as in the pure allocation model.

Two simplifications to the biorefinery parameters are made to define a model that can be solved in a reasonable amount of time with the resources available. First, the refinery-specific capacities V_j are exchanged for a single capacity $V \in Pos$ valid for all facilities. Second, refinery yields Y_j are assumed to be uniform across refineries, and denoted by $Y \in Pos$.

¹Available online at http://gurobi.com

$$\begin{array}{ll} \text{minimize} & \sum_{i=1}^{N} \sum_{j=1}^{N} (C^{S,C} + C^{L,C} + \tau D_{i,j}C^{S,T}) f_{i,j} + \sum_{j=1}^{N} \sum_{k=1}^{M} (C^{G,C} + D_{j,k}C^{G,T}) q_{j,k} \\ \text{ith respect to} & f_{i,j} \geq 0 \quad \text{for all } i, j \in \{1, \dots, N\} \\ & q_{j,k} \geq 0 \quad \text{for all } j \in \{1, \dots, N\}, \ k \in \{1, \dots, M\} \\ & \delta_j \in \{0, 1\} \quad \text{for all } j \in \{1, \dots, N\} \\ \text{subject to} & \sum_{j=1}^{N} f_{i,j} \leq (1 - S_i) A_i \quad \text{for all } i \quad (\text{feedstock availability}) \\ & (1 - \ell) \sum_{i=1}^{N} f_{i,j} = V \delta_j \quad \text{for all } j \quad (\text{refinery feedstock demand}) \\ & \sum_{j=1}^{N} q_{j,k} \leq G_k \quad \text{for all } k \quad (\text{MSA gasoline demand}) \\ & (1 - \ell) \sum_{i=1}^{N} f_{i,j} Y = \sum_{k=1}^{M} q_{j,k} \quad \text{for all } j \quad (\text{fuel output}) \\ & \sum_{j \in R} f_{i,j} = T \quad \text{for all } j \in R \quad (\text{number of biorefineries}) \\ \end{array}$$

A formulation is given in Equation (3.2) Though this is a conceptually simple transformation of the formulation, it represents a nontrivial transformation of the problem. The LA-ILP is an integer linear program, a problem that can be considerably harder to solve. In fact, ILP problems are classified as NP-hard (non-deterministic polynomial-time hard) meaning that at worst they require evaluating every single possibility to ensure that a solution is optimal.

3.4.3 A Corn Grain to Ethanol Model

W

An interesting comparison can be made between the LA-ILP biorefinery model and existing corn grain ethanol plants. Parameter values for the formulation in Equation (3.2) can be chosen to model an optimal distribution of grain ethanol biorefineries. The number N of counties corresponds to the number of counties in the top 6 corn producing Midwestern states: Illinois, Iowa, Minnesota, South Dakota, Nebraska, and Indiana. Collection costs are based on data found in the Iowa farm custom rate survey (49) that show corn combining costs of

| Feedstock Pa | ameters | | |
|--|---|---|---------------------------------------|
| N | 539 | _ | |
| $C^{S,C}$ | 5.82 | f/t | (49) |
| $C^{S,L}$ | 4.39 | /t | (112 |
| Transportati | on Paramete | rs | |
| l | 0.05 | _ | |
| au | 1.27 | _ | (107) |
| $C^{S,T}$ | 0.19 | \$/t-mi | (112) |
| Biorefinery P | arameters | | |
| $\frac{\text{Biorefinery F}}{V}$ | $\frac{\text{Parameters}}{8 \times 10^5}$ | t/y gal/t | · |
| Biorefinery F V Y $C^{G,C}$ | $\frac{\text{Parameters}}{8 \times 10^5}$ 110 1.04 | t/y gal/t \$/gal (78): | |
| Biorefinery P V Y $C^{G,C}$ T | $\frac{\text{Parameters}}{8 \times 10^5}$ 110 1.04 42 | t/y gal/t gal(78); | |
| Biorefinery F V Y $C^{G,C}$ T MSAs and G | $\frac{2^{\text{arameters}}}{8 \times 10^5}$ 110 1.04 42 asoline Dem | t/ygal/t $f/gal (78);$ and | |
| Biorefinery P V Y $C^{G,C}$ T MSAs and G M | $\frac{2^{\text{arameters}}}{8 \times 10^5}$ 110 1.04 42 asoline Dem 270 | t/y gal/t \$/gal (78); and | · · · · · · · · · · · · · · · · · · · |
| Biorefinery F V Y $C^{G,C}$ T MSAs and G M $C^{G,T}$ (pipelin | $\frac{\text{Parameters}}{8 \times 10^5}$ 110 1.04 42 asoline Dem 270 ne) 0.027 | t/y gal/t \$/gal (78); and - \$/t-mi | (23) |

 Table 3.4
 Corn Grain Ethanol Location-allocation Model Parameters

\$26.60 per acre, and a corn yield assumption of 180 bu/acre. Losses during the collection and transportation of corn are assumed to be 5%. The tortuosity factor assumed here is 1.27. Variable transport costs are assumed as \$0.19 per tonne per mile, with fixed costs of \$4.39 per tonne. Biorefinery capacity is assumed to be 800,000 tonnes per year with an output of 110 gallons of ethanol per ton of corn grain. The capacity is an average based on 3.69 billion gallons per year of ethanol production in Iowa for 42 biorefineries. A summary of these parameters are shown in Table 3.4

3.4.4 A Corn Stover to Naphtha and Diesel Model



Figure 3.2 U.S. Annual (2007) County Corn Stover Production Yields (Mg/yr) (22)

Feedstock availability is based on county-level data collected by the National Agricultural Statistics Service (NASS) (22) for annual corn production measured in bushels per year (56 pounds per bushel). An equal weight of stover is available for every ton of corn grain produced (67). Figure 3.2 illustrates U.S. stover county yields in Mg per year.

The National Resource Conservation Service (NRCS) suggests that a minimum of 30% of



Figure 3.3 U.S. Fraction of Highly Erodible Land (HEL)

stover cover must remain in the field to prevent soil erosion. This implies a sustainability factor $S_i \ge 0.3$ to account for soil quality preservation. The sustainability factor is a function of the state-level fraction of highly erodible land (HEL) (20). The sustainability factor is calculated as 0.3 times the HEL factor with a range of [0,0.3). Figure 3.3 shows the U.S. state-level HEL distribution.

| Stover Collected ^a | Collection Cost ^b | Collection Method | |
|---|------------------------------|---------------------|--|
| (Mg/ha) | (\$/Mg) | (-) | |
| $A_i < 2.69$ | $51.72 \cdot A_i^{0.56}$ | Bale windrow | |
| $2.69 \le A_i \le 3.36$ | $48.01 \cdot A_i^{0.45}$ | Rake-windrow & bale | |
| $3.36 < A_i$ | $50.65 \cdot A_i^{0.41}$ | Shred-rake and bale | |
| ^a Includes nutrient replacement costs of \$7.17 per Mg (61); | | | |

Table 3.5 Stover Collection Costs as a Function of Stover Yield (Γ Mg/ha) and Collection Method (61)

^bStorage costs are assumed to be \$14.26 per Mg (100).

Stover collection costs are based on stover collected at a given county. Higher collection rates allow for lower cost methods and economies of scale. The yield ranges and corresponding cost functions are shown in Table 3.5.



Figure 3.4 U.S. Top 217 Metropolitan Statistical Areas by Gasoline Demand (13)

Gasoline demand is based on state-level gasoline transportation consumption data provided by the Energy Information Administration (EIA) (13), and MSA population data estimated for 2009. The gasoline demand for each MSA is calculated by determining the fraction of the MSA population to the state's population and allocating the same fraction of the state's gasoline demand. Figure 3.4 shows the location and relative magnitude of U.S. MSA gasoline demand.

Biorefineries are assumed to have a capacity of 1,800,000 Mg/yr (4,930 Mg/day). This capacity represents a large-scale biorefinery facility and assumes that there is a mature commercial biofuel industry. A recent study of mature biomass refining scenarios compared biorefineries with 4535 metric ton per day capacities (80). This study models 70 biorefineries, which represents a compromise between simulating a large number of facilities and developing a model that can be solved in a reasonable amount of time.

Distances between locations are based on the great circle distance between two points. This is the distance that a bird would have to travel when flying on a straight trajectory and takes into account the curvature of the planet. A tortuosity factor of 1.27 is included to account for travel distance along road networks. The tortuosity factor typically ranges between 1 for a straight path and 3 for a highly convoluted path. Biomass transport will typically take place in regions with varying degrees of tortuosity (107), but detailed transportation networks are not modeled in this study.

3.5 Results

This study presents biorefinery location-allocation models for Iowa corn grain to ethanol, U.S. Midwest corn stover to naphtha and diesel fuel, and U.S. Midwest distributed processing corn stover to naphtha and diesel. The following sections describe results from these models.

3.5.1 Corn Grain to Ethanol Model

This study compares the model results for the location of 42 Iowa corn grain biorefineries producing 3.7 billion gallons of ethanol per year to the locations of existing corn grain ethanol plants. Figure 3.5 shows the locations of current corn grain ethanol refineries in Iowa, and model results for the optimal location of corn grain biorefineries and the allocation of corn to these facilities. The model results assume a uniform, single biorefinery capacity of 88 million gallons of ethanol per year for a given county. Therefore, the possibility of multiple facilities within a county is not reflected in the model results. Biorefinery locations are constrained to the county seat, and differences in transport distances within the county are assumed to be negligible.

3.5.2 Corn Stover to Naphtha and Diesel Model

The U.S. produced 12.7 billion bushels of corn in 2007, which is equivalent to about 323 million tons of corn stover. In this study, 132 million tons of stover are transported to 70 biorefineries located throughout the Midwest as shown in Figure 3.6. Based on a 48.8 gallon of gasoline equivalent yield per ton of feedstock, 6.44 billion gallons of gasoline equivalent biofuels would be generated from corn stover grown in the Midwest.

Biomass allocation results are included in Table 3.6. Illinois and Iowa share 70% of the biorefineries located by the model. Iowa has the shortest average distance to a supply county,



Figure 3.5 Iowa Corn Grain Model Locations, Biomass Allocation, and Current Locations of Corn Ethanol Biorefineries



Figure 3.6 U.S. Biorefinery Locations, Biomass Allocation, and Distribution of Advanced Biofuels to Metropolitan Statistical Areas

| State | Biorefineries | Average | Average Biomass | Distance |
|--------------|---------------|---------------|-----------------|------------|
| | | Distance to | Weighted | Measure |
| | | Supply County | Distance to | Difference |
| | | (miles) | Supply County | |
| | | | (miles) | |
| Illinois | 20 | 28.20 | 19.70 | 30.17% |
| Indiana | 9 | 30.01 | 27.40 | 8.69% |
| Iowa | 20 | 26.78 | 22.19 | 17.14% |
| Minnesota | 10 | 28.40 | 23.37 | 17.70% |
| Nebraska | 9 | 29.95 | 24.86 | 17.00% |
| South Dakota | 2 | 29.48 | 28.41 | 3.65% |

 Table 3.6
 State-level Biomass Transportation to Biorefinery Results

which implies that biomass transportation would occur over shorter distances than in other states. Iowa also has the lowest average biomass weighted distance to supply counties suggesting that biorefineries collect most of their biomass from nearby farms. The difference between these two distance measures is an indication of the relative distribution of biomass within the state. A value of 0% represents an area where every county supplies the same amount of biomass to the biorefinery. If a biorefinery collects most of its biomass from a distant county, it is possible for the biomass-weighted distance to be higher than the average distance to supplier. Illinois' 32% difference suggests that its biorefineries are able to gather feedstock from the county in which their plants are located.

The maximum distance to a supply county has important implications for biorefinery negotiations with suppliers due to the hold-up problem. The hold-up problem occurs when a contractual partner refuses to offer a product at a given price because it would give the other partner a bargaining advantage even if that price would benefit both partners (103). This situation is common with farmers and biofuel producers: biorefineries pay a premium to farmers that have to transport feedstock from long distances; farmers that are located near the biorefinery will negotiate higher prices for their feedstock even though they do not have to transport their feedstock as far. The end result is that biorefineries pay every feedstock supplier almost the same price as to the supplier that is farthest away from the biorefinery.

The impact of biomass transportation costs can be appreciated by calculating the cost of

| State | Average of | Maximum | Average of | Maximum |
|-----------|----------------|----------------|-----------------|-----------------|
| | Delivered Cost | Delivered Cost | Collection Cost | Collection Cost |
| | (\$/Mg) | (\$/Mg) | | |
| Illinois | \$51.69 | \$62.55 | \$26.42 | \$32.85 |
| Indiana | \$53.02 | \$58.01 | \$27.67 | \$30.64 |
| Iowa | \$51.24 | \$56.97 | \$26.25 | \$30.80 |
| Minnesota | \$52.84 | \$57.78 | \$27.65 | \$30.75 |
| Nebraska | \$51.19 | \$56.36 | \$26.31 | \$30.10 |

Table 3.7State-level Average and Maximum Delivered and CollectionCosts for Corn Stover

fuel production at the various biorefinery locations. Table 3.7 shows how average and maximum delivered and collection costs vary by state. Average delivered cost is representative of what it would cost suppliers to deliver feedstock to a large facility. The maximum delivered cost is closer to the price that biorefineries would have to pay suppliers due to the hold-up problem. Collection costs are lower for states with higher production yields.

| State | Biofuels Supplied | Average Distance | Pipeline Delivery | Truck Delivery |
|-------|-------------------|------------------|-------------------|------------------|
| | (million gallons) | to Biorefinery | Cost (cents/gal) | Cost (cents/gal) |
| | | (miles) | | |
| CO | 26.22 | 331.47 | 2.40 | 7.21 |
| IA | 850.39 | 47.91 | 0.22 | 0.67 |
| IL | 1969.82 | 106.68 | 0.68 | 2.03 |
| IN | 1208.33 | 60.69 | 0.36 | 1.09 |
| KS | 381.40 | 258.44 | 1.84 | 5.53 |
| MI | 73.99 | 72.39 | 0.52 | 1.58 |
| MN | 1911.39 | 164.07 | 1.11 | 3.34 |
| MO | 2193.90 | 213.55 | 1.45 | 4.37 |
| ND | 107.10 | 193.04 | 1.33 | 4.01 |
| NE | 527.20 | 98.04 | 0.60 | 1.79 |
| OH | 143.90 | 48.26 | 0.35 | 1.05 |
| SD | 118.90 | 53.34 | 0.39 | 1.16 |
| WI | 560.77 | 204.89 | 1.46 | 4.38 |

 Table 3.8
 State-level Biofuel Allocation to Metropolitan Statistical Areas

Results for biofuel allocation are shown in Table 3.8. The cost to pump biofuel through existing gasoline pipelines is relatively small. For example, pumping gasoline 700 miles from an Iowa biorefineries to Colorado would cost 5 cents per gallon of fuel. Gasoline is typically distributed through pipelines to supply hubs in MSAs from which gasoline is trucked to fuel stations. Some biorefineries may not have a nearby gasoline pipeline and may have to rely on truck transport. Truck transport would costs 15 cents per gallon for a 700 mile delivery. The additional cost may justify investment in pipeline infrastructure to reduce the cost of delivering biofuels to coastal markets.



Figure 3.7 Distribution of Fuel Costs for 5500 Mg/day Stand-alone Fast Pyrolysis Midwest Biorefineries based on Maximum Delivered Feedstock Cost

Figure 3.7 shows the distribution of fuel costs for Midwestern 5500 Mg/day biorefineries. The average fuel production costs is \$2.22 per gallon with a median of \$2.23 per gallon. Biorefineries with high production costs could seek markets with higher fuel prices given that incremental transportation costs are small.

3.6 Discussion

3.6.1 The Importance of Coordinating Biorefinery Locations

Biorefinery facility locations are currently chosen by independent commercial entities in an uncoordinated fashion. It is likely that this process of locating biorefineries leads to sub-optimal biorefinery locations. Results from the corn grain PA-LP model showed that the current grain ethanol biorefinery locations are non-optimal. Based on model calculations, the difference in costs between the optimal and non-optimal distributions is \$110 million. This represents a \$0.03 per gallon cost inefficiency. This cost inefficiency is likely to increase as Iowa's corn ethanol production capacity increases.

Solving for optimal corn stover allocations for randomly chosen biorefinery locations quantifies the impact of coordinating biorefinery locations on advanced biofuels derived from corn stover. In 1,000 trials, a random set of 50 counties was chosen as the locations of stover biorefinery capacity. The optimal distribution of biomass to these refineries is then computed using the pure allocation framework. Figure 3.8 provides histograms of the increase in total transportation-related costs and the resulting costs of biofuel. Half of the randomly chosen biorefinery locations result in total transportation-related costs of \$5.77 billion or higher, an increase of \$1.15 billion above the optimal locations. This represents a \$0.16 increase in the per gallon cost of fuel. The average transportation-related costs for the 1,000 random trials was \$5.78 billion, which is similar to the median value of \$5.77 billion. These results demonstrate a significant advantage to regional coordination of biorefinery locations.

3.6.2 Scheduling Biomass Feedstock Deliveries

Delivering large quantities of corn stover to a location is likely to pose detailed scheduling challenges. Corn stover is harvested annually over a short period of about 80 days (25). On the other hand, biorefineries would prefer a steady delivery of feedstock throughout the year. Figure 3.9 shows the quantities of stover in various supply operations over the course of the year.

Corn stover harvested is based on a gamma distribution fit function of Iowa harvesting patterns with parameters calculated by Sokhansanj et al. (116). The number of harvesters is 900 with a collection productivity of 0.02 km^2 per hour (64% efficiency). Four hundred and fifty balers were assumed with 7.26 Mg per hour baling rate. Semi-trailers (330) have a cargo load of 18 Mg and load speed of 0.14 loads per hour (100). Operations take place over 14 hour



Figure 3.8 Biomass and Biofuel Transportation Cost Results for 1000 Simulations of Randomly Located - Optimally Allocated Biorefineries



Figure 3.9 Schedule of Corn Stover Supply Operations based on 5500 Mg/day, 328 days, 900 Harvesters, 450 Balers, 330 Semi-Trailers

work-days.

This scheduling exercise indicates that biomass storage could become an important aspect of biofuel logistics. Producers will have to determine and coordinate the locations at which biomass is stored to minimize material losses. This also opens the door to intermediate agencies that could specialize in the collection and delivery of biomass feedstock.

Results from this study clearly show that it is possible to lower the cost of biofuel production by coordinating plant locations and resource allocations. The methodology employed includes multiple parameters that can be adapted to various scenarios including alternative pathways to the production of transportation fuels. Future research will be necessary to determine which of these parameters and model assumptions can have the greatest impact on biofuel costs. Additional parameters can be included given more detailed information to further improve the model and provide additional insight into the challenges of selecting optimum biorefinery locations.

CHAPTER 4. Location, economic, and environmental analysis of thermochemical distributed biomass processing to transportation fuels

4.1 Abstract

Distributed biomass processing (DBP) addresses some of the major logistic challenges of developing a large-scale biomass to biofuel industry. This paper investigates economic and environmental costs of various DBP pathways for Midwestern corn stover to naphtha and diesel range stock fuel using a location-allocation analysis.

This study compares pelletization, torrefaction, and fast pyrolysis pretreatment; gasification and hydroprocessing upgrading technologies. Economic costs include biomass collection, pretreatment, transportation, upgrading, and capital costs. These process steps result in net carbon emission or displacement. Carbon credits are accounted for from sequestration of biochar and displacement of state grid power generation from fossil fuels. The location-allocation analysis determines the optimal location of the pretreatment and upgrading facilities that leads to minimum fuel costs.

Fuel production costs vary between \$2.00 and \$5.00 per gallon for the production of 500 million gallons of biofuel per year. Carbon emission reductions vary between 76 and 94% compared to fossil-based gasoline. These results highlight the economic and environmental differences between various DBP pathways and their opportunities to reduce biofuel costs.

4.2 Introduction

Commercial development of second generation biofuels has as of 2010 failed to meet expectations established by the Renewable Fuel Standard (RFS2). RFS2 targets for cellulosic biofuel production have been reduced to match current production levels (19). The United States Department of Agriculture (USDA) recently identified 4 challenges for next-generation biofuels: reducing high production and capital costs; securing financial support during precommercial development; establishing feedstock supply arrangements; and overcoming blend wall constraints (43). Addressing these challenges is key to reducing our dependence on fossil fuels, improving our environmental profile, and increasing our energy security.

There are promising and abundant sources of lignocellulosic feedstock available for conversion to energy (120). World biofuel production in 2008 was dominated by corn ethanol from the United States (9 billion gallons) and sugarcane ethanol from Brazil (6.5 billion gallons). Second generation biofuels are capable of converting a wider variety of feedstock allowing for greater flexibility to meet economic, infrastructure, and environmental constraints.

There are two major pathways under development for the conversion of cellulosic biomass into fuels: the biochemical and thermochemical platforms (137; 52). The biochemical platform improves on first generation biofuel technologies by developing enzymes and microorganims capable of converting cellulose and hemicellulose into liquid fuel (6). Biochemical conversion research efforts have focused on the production of ethanol (6; 78; 65). The thermochemical platform is an alternative approach that relies on thermal processes to breakdown biomass into molecules suitable for synthesis into transportation fuels. Research efforts on the thermochemical platform have presented approaches to the production of a variety of liquid fuels including: methanol, ethanol, hydrogen, Fischer-Tropsch liquids, gasoline, and diesel (65; 64; 124; 101; 135; 121).

Commercial development of second generation biofuels has lagged in great part by the challenges identified by the USDA. To meet these challenges, future biorefineries will have to consider various strategies. Reducing production and capital costs will require research breakthroughs and capturing economies of scale (136). Subsidies and industry investment are important sources of financial support. This study seeks to address the feedstock supply and blend-wall challenges.

Corn dominates the Midwest agricultural landscape with 52.85 million acres planted in 2010 (22). After harvest, most of this land is covered by corn stover, the non-edible portion

of this crop. Oak Ridge National Laboratory estimated that up to 75 million tons of corn stover per year could be employed in biofuel production (98). The challenge for biorefineries is in procuring stover in a way that is economically and environmentally sustainable. Various papers have explored the logistics and costs of collecting, transporting, and delivering crop residues such as stover to a large centralized facility (54; 116; 89; 97). Although much attention has been given to the production of cellulosic ethanol from corn stover, this study evaluates various thermochemical pathways to the production of gasoline-compatible fuels, which are not limited to the 10% blends with gasoline, as currently exists for ethanol.

The approach of this study is to estimate the costs of various corn stover distributed processing scenarios in optimal midwestern locations. Distributed processing is a two-step process that employs geographically dispersed small-scale pretreatment locations to store, process, and ship biomass material to a large-scale facility where the material is upgraded to the final product. This arrangement alleviates transport costs, and can reduce the overall cost of fuel at large capacities (140; 28).

Researchers have explored regional, and trans-continental arrangements for distributed biomass processing scenarios (140; 82; 127; 143). Wright et al. (140) compared the economies of scale of centralized and distributed processing scenarios for the production of FTL. Magalhães et al. (82) investigated pre-conversion processes for production of green diesel in the Netherlands. Uslu et al. (127)compared the cost and energy use of chains delivering pellets, torrefied pellets, bio-oil, FTL, and electricity from Latin America to West Europe. Zwart et al. (143) conducted an analysis of overseas biomass conversion to FTL. These studies found that FTL could be produced economically via distributed processing technologies, and that small-scale pretreatments reduced biofuel costs by lowering transportation costs.

The location of biorefineries, and allocation of feedstock to these refineries, can have significant impact on the cost of fuel (100; 90). Therefore, this study modifies a county-level location-allocation model to identify the optimal locations of the centralized and distributed biorefineries, and the distribution of biomass material to these locations.

This paper proceeds as follows: the biofuels production section describes various pretreat-

ment technologies and their upgrading pathways to the production of naphtha and diesel fuels; the methodology section summarizes the parameters employed in the calculation of production costs, environmental impacts, and location analysis; the results section presents findings from these calculations; the discussion investigates the implications of this analysis and some of the research limitations found in this study.

4.3 Background

4.3.1 Distributed processing of biomass to transportation biofuels

There are various thermochemical conversion technologies suitable for distributed processing of biomass feedstock. Pelletization, torrefaction, and pyrolysis have been proposed for smallscale processing (104; 127; 140). Pelletization is a mechanical process that converts biomass into high density solids called pellets (57). Torrefaction is a thermo-mechanical process that takes place in an oxygen-free environment, atmospheric pressure, and temperatures of 200 to 300°C. Pyrolysis occurs when feedstock is exposed to temperatures of about 500°C in an inert environment at atmospheric pressure (135). Commercial designs of these technologies have been developed for scales between 5 and 200 tons per day. These capacities would enable local co-ops and individual farmers to operate small biorefineries.

Small-scale biorefinery products can be employed for distributed heat and power generation or sent to a large-scale facility for upgrading to transportation fuels. Torrefied biomass, biomass pellets, and pyrolysis products can be converted to transportation fuels using thermochemical technologies such as gasification and hydroprocessing. Gasification is a thermal process that takes place at 750°C or higher with limited oxygen generating a combustible gas known as syngas. Syngas can be catalytically converted to various liquid fuels including ethanol, methanol, and Fischer-Tropsch Liquids (FTL). Hydroprocessing encompasses refining processes commonly employed by the oil industry to convert crude oil into products such as gasoline(88). Corn stover can be converted to gasoline and diesel using gasification (121), pyrolysis (135), and hydroprocessing. The pathways for converting corn stover to gasoline and diesel fuel considered in this study are shown in Figure 4.1.



Figure 4.1 Distributed processing pathways to the production of transportation fuels

4.3.2 Thermochemical biomass pretreatment technologies

Pelletizing is the mechanical process of compressing material into a small, cylindrically shaped, pellet. Biomass pelletization takes place in three major steps: drying to drive away excess moisture, grinding to reduce particle size, and pelletization. The pelletization steps employs a pellet mill to form shapes with sizes and properties tailored to desired specifications. The main benefit of pelletizing biomass is that it increases its density which makes it easier to store and transport than loose fibers.

The torrefaction process is similar to the pelletization process in the number and type of steps involved. Drying is more important for torrefaction because it helps drive moisture that can adversely impact the performance of the torrefaction reactor. An initial grinding step can be employed, although it is possible to feed long fibers into the torrefaction unit. Torrefaction employs low temperature heat to drive away moisture and roast biomass into dark, hydrophobic, friable fibers. Torrefaction yields 70% torrefied biomass and 30% torrefaction gases (30). The torrefied product contains about 90% of the biomass energy, and the torrefaction gases can supplement the energy required for drying. Torrefied biomass has attractive energy properties including higher mass (180-300 kg/m³ (66)) and energy (18-23 MJ/kg LHV (30)) densities. Transportation of torrefied biomass benefits from pelletization to further increase its density and reduce the amount of loose fibers that could be lost during shipping. Uslu et al. named the combined torrefaction and pelletization concept the TOP process (127).

Fast pyrolysis requires additional steps compared to torrefaction and pelletization. First, biomass is ground to particle sizes of 3 mm then dried to a moisture content of about 7%. The dried biomass feeds into the pyrolysis reactor where it is converted to three major products: bio-oil, biochar, and pyrolysis gas. The proportions of these products depends on the process heating rate and residence times. Heating rates of less than 100°C per second are typical of slow pyrolysis and yield 35% biochar, 30% bio-oil, and 35% pyrolysis gas (58). Fast pyrolysis requires heating rates of 1000°C per second or more and can increase bio-oil yields up to 70% of the biomass input with about 12% biochar and 17% pyrolysis gas (32). Pyrolysis products are collected in two subsequent steps. Biochar is removed from the gas flow using

conventional cyclones, and bio-oil is condensed using either a quench system or purposely designed condensers. An electro-static precipitator (ESP) can be included to collect aerosols entrained in the pyrolysis gas. The non-condensable gases (NCG) can be recycled to provide process heat or marketed as a low-energy natural gas substitute.

4.3.3 Thermochemical upgrading technologies to naphtha and diesel fuel

This paper considers two options for the production of biofuels at the centralized facility: gasification to convert solid fuels into FTL followed by hydroprocessing, and hydroprocessing of bio-oil. Hydroprocessing generates naphtha and diesel range stock fuel compatible with existing pipeline and vehicle infrastructure.

Biomass gasification employs 5 distinct processes: preprocessing including drying and grinding; gasification to generate syngas; syngas cleaning to remove solids and impurities; fuel synthesis of FTL, and hydroprocessing to naphtha and diesel range stock fuel. In addition to these common steps, a gasification biorefinery can include power generation and air separation to provide electricity and pure oxygen to the gasifier. Gasification can take place at low (850°C) or high (1300°C) temperature in the presence of air, oxygen, or steam with atmospheric or several bars of pressure. Gasification biorefineries can generate excess electricity. Figure 4.2 shows the block diagram of a biomass gasification to transportation fuel process with power export.



Figure 4.2 Biomass gasification to naphtha and diesel range stock fuel process block diagram

Hydroprocessing includes hydrotreating and hydrocracking. The purpose of hydrotreating is to remove impurities such as sulfur, nitrogen, and metals. Hydrotreating employs temperatures of 300 to 400°C and pressures of 7 to 10 MPa with 95 mol% hydrogen input. Hydrocracking breaks down long hydrocarbon chains of 30 or more carbon atoms to naphtha (C_8) and diesel (C_{12}) range stock fuel. Hydrocracking requires temperatures of 400 to 450°C and pressures of 10 to 14 MPa. Hydrotreating and hydrocracking employ cobalt-molybdenum and nickelmolybdenum catalysts, respectively. Figure 4.3 shows the process block diagram of bio-oil hydroprocessing to transportation fuel upgrading.



Figure 4.3 Bio-oil hydroprocessing to naphtha and diesel range stock fuel process block diagram

4.4 Methodology

4.4.1 A location-allocation model for distributed processing of corn stover to naphtha and diesel

This model allocates available corn stover to biorefineries, and biofuel generated by these biorefineries is distributed to the 270 most highly populated metropolitan statistical areas within the contiguous US. Biorefinery locations are determined by the optimization routine, which deterministically solves for biorefinery locations that result in the lowest system cost.

This study employs MatlabTM software to collect and process data and model results. GurobiTM software is used to solve the linear equations developed for the model.

In what follows, all lowercase roman letters denote model variables. All greek letters and upper-case roman letters denote problem parameters. Table 4.1 provides a complete list of symbols used in the LP and ILP formulations presented below.

The purpose of this section is to evaluate various distributed processing scenarios for the conversion of corn stover to gasoline and diesel fuel in the Midwest. These scenarios consist of

Table 4.1 Symbols used in location-allocation models

| Feedstock | Parameters |
|------------|------------|
| T COUDIOON | I aramouto |

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| N | Number of counties producing biomass feedstocks; |
|-------------|--|
| A_i | Available feedstock at county i ; |
| S_i | Sustainability factor for county i ; |
| $C^{S,C}$ | Variable feedstock collection cost; |
| $C^{S,L}$ | Variable feedstock loading cost; |
| $C^{P,L,C}$ | Fixed pretreated feedstock loading cost; |
| | |

Transportation Parameters

Biorefinery Parameters

| V | Fixed biorefinery capacity for all locations; |
|-----------|--|
| Y | Biorefinery fuel process yield; |
| $C^{G,C}$ | Unit conversion cost per gallon of biofuel produced; |
| T | Number of biorefineries |

Metropolitan Statistical Areas (MSAs) and Gasoline Demand

| M Number of MSA's considered | ed; |
|------------------------------|-----|
|------------------------------|-----|

- $\begin{array}{c} G_k \\ C^{G,T} \end{array}$ Total gasoline demand for MSA k;
- Variable gasoline transportation cost;

Optimization Variables

| δ_j | Binary variable that determines if a biorefinery is located in county j ; |
|------------|---|
| $f_{i,j}$ | Flow of biomass feedstock from county i to county j (for refining); |
| $q_{j,k}$ | Finished gasoline flow from county j to MSA k ; |

a pretreatment step followed by upgrading to the final product. Five pretreatment scenarios are included in this analysis: torrefaction, torrefaction and pelletization, pyrolysis with bio-oil upgrading, pyrolysis with bio-oil and bio-char upgrading, and pelletization. Upgrading steps consist of gasification and hydroprocessing, and hydroprocessing to produce gasoline and diesel fuel.

An optimization model is employed in this study to determine the location of the pretreatment and upgrading facilities that leads to the lowest cost of collecting, transporting, and converting corn stover to gasoline and diesel. The location-allocation biorefinery model was employed to compute allocations of supply between various agents in a distributed supply chain. This section describes the model formulation shown in Equation 4.1.

Given that there are $N \in N$ counties producing corn stover; each county $i \in \{1, ..., N\}$ generates and has available $A_i \in R$ tons per year of corn stover. A sustainable $S_i \in \{0, 1\}$ fraction of the corn stover must remain in the field to provide cover and prevent erosion. Therefore, each county can provide $(1 - S_i)A_i$ tons of corn stover per year.

A subset $R \subset \{1, \ldots, N\}$ of theses counties has a biorefining capacity that is equal to the amount of corn stover sustainably available at the county times. Therefore, county $i \in R$ has a pretreatment capacity of $(1 - S_i)A_i$ tons per year. County biorefineries convert corn stover into a pretreated product P with properties that are more suitable for storage and transportation prior to shipping to the upgrading facility $u \in R$. The quantity of pretreated product available at a biorefinery is $(1 - S_i)A_iP_iY_P$ where Y_P is the yield of converting a ton of corn stover into a specified pretreated material such as torrefied stover, bio-oil, or pellets. County municipality locations are employed as a point of reference for the county-level biorefinery. It is assumed that transport distances within the county have negligible impact on feedstock transportation costs.

The upgrading facility is located in a county $j \in R$ and has an upgrading capacity of $U_j \in Pos$. The flow of the pretreated feedstock from the county-level biorefinery $i \in R$ to the upgrading facility $j \in R$ is denoted by $f_{i,j} \in Pos$. The total quantity of pretreated feedstock leaving the county $i \in R$ must be less than the amount available at the biorefinery

 $fi, j \leq (1-S_i)A_iP_iY_{pr}$. The total flow of feedstock into the upgrading facility is $\sum_{i=1}^{N} f_{i,j}$. There is a material loss factor $\ell \in [0, 1)$ associated with different forms of pretreated feedstock. This material loss factor accounts for possible losses during loading, transportation, and unloading. The amount of feedstock that can be upgraded to transportation fuels at the upgrading facility $u \in R$ is $(1 - \ell) \sum_{i=1}^{N} f_{i,j}$. The equality $(1 - \ell) \sum_{i=1}^{N} f_{i,j} = U_j$ requires that the supply of biomass meets the specified upgrading capacity $U_j \geq 0$ in county $j \in R$.

There are various costs associated with the collection and transportation of feedstock from farms to the upgrading facility. Counties have collection costs of $C_i^{S,C} f_i$ for corn stover delivered at the county biorefinery where $C_i^{S,C}$ are given in f. Biorefineries have pretreated feedstock loading and unloading costs of $C_i^{P,L,C} f_{i,j}$ ($C_i^{P,L,C}$ is in f.) and transportation costs of $\tau C_i^{P,T,C} D_{i,j} f_{i,j}$ with $C_i^{P,T,C}$ provided in f. Ton-mile. $D_{i,j}$ is the great circle distance between counties i and j and $\tau \in [1, \infty)$ is a tortuosity factor that accounts for the actual distance that must be traveled due to the available geography and transport infrastructure.

$$\begin{array}{ll} \text{minimize} & \sum_{i=1}^{N} \sum_{j \in R} (C_{i}^{S,C} + C_{i}^{P,L,C} + \tau C_{i}^{P,T,C} D_{i,j}) f_{i,j} + \sum_{j \in R} \sum_{k=1}^{M} (C^{G,C} + D_{j,k} C^{G,T}) q_{j,k} \\ \text{with respect to} & f_{i,j} \geq 0 \quad \text{for all } i \in \{1, \dots, N\}, \ j \in R \\ & q_{j,k} \geq 0 \quad \text{for all } j \in R, \ k \in \{1, \dots, M\} \\ \text{subject to} & \sum_{j \in R} f_{i,j} \leq (1 - S_{i}) A_{i} P_{i} Y_{pr} \quad \text{for all } i \in \{1, \dots, N\} \quad (\text{feedstock availability}) \\ & (1 - \ell) \sum_{i=1}^{N} f_{i,j} = U_{j} \quad \text{for all } j \in R \quad (\text{refinery feedstock demand}) \\ & \sum_{j \in R} q_{j,k} \leq G_{k} \quad \text{for all } k \in \{1, \dots, M\} \quad (\text{MSA gasoline demand}) \\ & (1 - \ell) \sum_{i=1}^{N} f_{i,j} Y_{j} = \sum_{k=1}^{M} q_{j,k} \quad \text{for all } j \in R \quad (\text{fuel output}) \\ & \sum_{j \in R} f_{i,j} = T \quad \text{for all } j \in R \quad (\text{number of biorefineries}) \\ \end{array}$$

The upgrading facility converts pretreated feedstock P into naphtha and diesel range stock biofuel that is compatible with existing gasoline and diesel infrastructure. Biofuel is shipped to any $M \in N$ Metropolitan Statistical Areas (MSAs) to meet the demand at the MSA k. The amount of biofuel shipped from the upgrading facility j to the MSA k is denoted as $q_{j,k} \in Pos$. The total amount of biofuel supplied to a MSA must be less than the demand $G_k \in Pos$ at the given MSA ($\sum_{j \in R} q_{j,k} \leq G_k$ for all k). Biofuel is delivered via pipelines to the MSA at a cost $C^{G,C}$ given in \$/ton-mile. The total cost of biofuel distribution is thus $\sum_{k=1}^{M} D_{j,k}C^{G,T}q_{j,k}$. Equation 4.1 provides a formulation of the allocation problem.

Fuel demand at the MSA k is estimated as a percent of the state-level gasoline consumption as provided by the EIA (13); the percent is equal to the ratio of the population within the MSA and the state's total population based on Census data (16).

4.4.2 Economic costs of distributed biomass processing scenarios

Economic costs are estimated using Equation 4.2. P ("Project") costs for the pretreatment equipment assume that units are mass-produced resulting in linear economies of scale. A scale factor of 0.7 is applied to the upgrading capital cost. F feedstock costs consist of collection expenses at the pretreatment facilities, loading, and transportation costs to the upgrading facility. O operating costs include feedstock, pretreatment and upgrading operating costs, and a 10% annual capital charge (100% debt financing over 20 years with annual interest rate of 8%). The per gallon cost of fuel is based on the operating cost and fuel yield (ρ_{fuel} is 2.72 kg/gal).

$$P = P_{pretreatment} \frac{\sum_{i=1}^{N} f_{i,j}}{M_0} + P_{upgrading} \left((1-l)Y_{pr} \frac{\sum_{i=1}^{N} f_{i,j}}{M_0} \right)^{0.7}$$

$$F = \sum_{i=1}^{N} \left(C_i^{S,C} + C_i^{pr,L,C} + \tau C_i^{pr,T,C} D_{i,j} \right) f_{i,j}$$

$$O = F + O_{pretreatment} Y_{pr} \sum_{i=1}^{N} f_{i,j} + O_{upgrading} Y_f + 10\% \times P$$
Fuel Cost =
$$\frac{O}{\frac{Y_f \sum_{i=1}^{N} f_{i,j}}{\rho_{tuel}}}$$
(4.2)

The values required for the model parameters were collected from various sources with a focus on using the most recent publications. Table 4.2 includes the pretreatment, transporta-

| Scenario | Pretreatment | Transportation | Upgrading |
|---|--------------|----------------|-----------|
| Torrefaction(127) | 0.88 | 0.975 | 0.17 |
| Torrefaction + Pelletization(127) | 0.88 | 1 | 0.17 |
| $\begin{tabular}{lllllllllllllllllllllllllllllllllll$ | 0.80 | 1 | 0.17 |
| Pelletization(127) | 1 | 1 | 0.17 |
| Centralized Gasification (122) | 1 | 1 | 0.17 |
| Pyrolysis (Bio-oil)(141) | 0.63 | 1 | 0.25 |
| Centralized Pyrolysis (141) | 1 | 1 | 0.16 |

 Table 4.2
 Biomass processing material yield factors in kgs output per kg input

tion, and upgrading conversion factors for converting biomass to naphtha and diesel range fuels. Torrefied biomass transportation can incur significant losses similar to the transport of loose straw. Therefore we assume an additional 5% loss factor for the transport of torrefied biomass. Most of these scenarios assume that the pretreated material is upgraded via the gasification and FTL synthesis process followed by hydroprocessing to transportation fuels. The exception is bio-oil upgrading which is fed directly into a hydroprocessing process to produce naphtha and diesel fuel. It is very likely that upgrading performance would vary for the various types of pretreated materials, but there is insufficient commercial data available to justify major differences in the upgrading factors. For example, torrefaction has been reported to improve gasification H₂ and CO yields by by 7% and 20% respectively at temperatures of 1200°C (42).

Table 4.3 shows the densities, fixed, and variable transport costs associated with the pretreated materials considered in this study. The degree of densification increases proportionally with the severity of the process employed. Biomass densities of 145 kg/m^3 can be increased up to 1340 kg/m^3 in the case of a bio-oil and biochar mixture. Densification helps reduce fixed transport costs associated with loading and unloading. Liquified materials like bio-oil can be pumped resulting in negligible fixed costs, but in the United States, most truck transport is weight-limited meaning that densification does not reduce variable transportation costs significantly (28).

Capital and operating costs for the various transportation fuel scenarios are shown in Table 4.4. The distributed processing scenarios assume that the upgrading facilities are optimized to

| Scenario | Density | Fixed | Variable | |
|--|----------|----------------------------|----------------------------|--|
| | (kg/m3) | Transport | Transport | |
| | | $\operatorname{Cost}(112)$ | $\operatorname{Cost}(112)$ | |
| | | $(\$/tonne)^{\mathrm{a}}$ | (\$/tonne/mile) | |
| Torrefaction | 230 | 2.67 | 0.07 | |
| Torrefaction + Pelletization | 850 | 0.72 | 0.07 | |
| $\operatorname{Pyrolysis}$ (Bio-oil + Biochar) | 1340(31) | 0 | 0.05 | |
| Pelletization | 650 | 0.95 | 0.07 | |
| Centralized Gasification | 145 | 4.39 | 0.19 | |
| Pyrolysis (Bio-oil) | 1200 | 0 | 0.05 | |
| Centralized Pyrolysis | 145 | 4.39 | 0.19 | |

Table 4.3Pretreated product densities (28), fixed and variable transport
costs adapted from (112)

^aFixed transport consists of loading costs. Bio-oil and bio-oil + biochar mixture assume pump costs are negligible

Table 4.4Capital and operating costs for pretreatment and upgrading facilities

| | Capital costs | (MM (2007)) | Operating costs | | |
|--------------------------|---------------|-----------------------------|-----------------|-----------|--|
| Scenario | Pretreatment | Upgrading | Pretreatment | Upgrading | |
| | (200 | (2000 | (\$/ton) | (\$/gal) | |
| | Mg/day) | $\mathbf{Mg}/\mathbf{day})$ | | | |
| Torrefaction | \$10.1 | \$561 | \$90 | \$1.13 | |
| $(127; 122)^{\rm a}$ | | | | | |
| Torrefaction + Pelleti- | \$12.1 | \$561 | \$70 | \$1.13 | |
| zation $(127; 122)^{a}$ | | | | | |
| Pyrolysis (Bio-oil + | \$11.0 | \$561 | \$77 | \$1.13 | |
| Biochar) $(92; 122)$ | | | | | |
| Pelletization | \$9.61 | \$561 | \$64 | \$1.13 | |
| $(127; 122)^{\rm a}$ | | | | | |
| Centralized Gasifica- | - | \$606 | - | \$1.01 | |
| tion (122) | | | | | |
| Pyrolysis (Bio-oil) (92; | \$11.0 | \$104 | \$98 | \$0.67 | |
| 141; 88) | | | | | |
| Centralized Pyrolysis | - | \$287 | _ | \$0.60 | |
| (141) | | | | | |

^aEuro/\$ Conversion factor of 1.55

convert the pretreated material. Therefore, the upgrading cost estimates do not include costs for feedstock pretreatment (i.e. drying and grinding). Capital costs for the pretreatment facilities assume mass-scale production and linear scaling. A common pretreatment plant capacity of 200 Mg/day is assumed for all scenarios, and this capacity is within the range of those found in the references. The scale factor for the upgrading facility capital costs is 0.7. A currency conversion factor of 1.55 Euro to dollars is employed based on 2007 conversion rates. The cost basis year for all values shown here is 2007.



4.4.3 Carbon emissions of distributed biomass processing scenarios

Figure 4.4 Comparison of Biofuel Production Emissions via Centralized and Distributed Production Pathways

There are carbon emissions associated with biomass production, pretreatment, transportation/storage/distribution (TSD), upgrading, and vehicle operation. Figure 4.4 shows the various carbon sources and sinks considered in this study. Carbon emissions occur from the consumption of petroleum, heat (natural gas), electricity, and biofuels. Carbon sequestration/displacement is accomplished with biomass, biochar, and renewable electricity. Most of the biofuel emissions are balanced by biomass production resulting in near zero cycle emissions.

Carbon emission E calculations are described in Equation 4.3. E emissions are provided in units of g CO₂ per liter based on a fuel production rate R, and converted to g CO₂ per km using an average vehicle fleet mileage VE. Biomass carbon emissions include agricultural production emissions $e_{biomass}$ and non-recycled biomass carbon. A small fraction θ of carbon UT_c in the biomass is considered to be permanently emitted to the atmosphere. Pretreatment emissions $e_{pretreatment}$ and $e_{upgrading}$ assume a linear relationship between pretreatment plant output and carbon emissions, which corresponds with a linear increase in fuel and power use with capacity. The majority of TSD emissions derive from truck transport of pretreated biomass material and can be estimated based on the truck mileage TE, truck capacity v, and truck emissions. Here, TSD emissions $e_{emissions}$ are based on round trip transport of biomass from the pretreatment locations to the upgrading facility. Carbon sequestration and power grid fossil fuel based-power displacement is accounted for with a carbon credit e_{credit} .

$$E_{biomass} = \frac{e_{biomass}}{Y_{fuel}} + 3.67\theta \frac{LHV_{fuel}}{Y_{fuel}} UT_c \sum_{i=1}^{N} f_{i,j}$$

$$E_{pretreatment} = LHV_{fuel} \frac{e_{pretreatment}}{R}$$

$$E_{TSD} = LHV_{fuel} \frac{2e_{TSD} \sum_{i=1}^{N} d_{i,j} \frac{f_{i,j}}{TEv}}{R}$$

$$E_{upgrading} = LHV_{fuel} \frac{e_{pretreatment}}{R}$$

$$E_{credit} = LHV_{fuel} \frac{e_{credit}}{R}$$

$$E_{total} = E_{biomass} + E_{pretreatment} + E_{TSD} + E_{upgrading} - E_{credit}$$

$$E_{total,gCO_2km^{-1}} = \frac{E_{total}}{VE}$$

$$(4.3)$$

Carbon emission factors are employed in this study to compare the relative environmental impact of the scenarios considered. GHG calculations are similar to Laser et al.'s approach (80) for calculating carbon dioxide emissions. Well-to-wheel (WTW) carbon GHG emissions for biofuel production are primarily dependent on agricultural production practices, biomass transportation and delivery, biofuel production, and vehicle performance.

Corn production practices in the American Midwest employ significant quantities of fossil inputs in the form of inputs such as fertilizer and machinery fuel. Kim & Dale have authored various publications on the environmental impacts of corn production (75; 74; 73). They published a life cycle assessment of corn grain and corn stover production in the Midwest (76). Corn stover emissions based on a system expansion allocation method for Midwestern locations ranges between -40 and 90 g CO₂e per kg. The system expansion allocation method ensures that emissions associated with stover harvest and additional nutrient requirements are properly taken into account. The fast pyrolysis scenarios generate biochar, which contains 38% carbon (dry basis) (31). Roberts et al. estimate that 80% of biochar carbon remain permanently sequestered underground resulting in a carbon emission credit (106). A life cycle assessment of a biomass gasification combined-cycle power system conducted by the National Renewable Energy Laboratory (NREL) estimated that 5% of biomass carbon emissions permanently contribute to atmospheric carbon (84).

Biomass transportation and delivery emissions calculations are based on the distances between the pretreatment counties and upgrading location. Biomass and pretreated biomass are delivered by heavy-duty diesel trucks with average mileage of 2.81 km/L (6.6 miles per gallon) and a 18 tonne carrying capacity. Vehicle performance assumptions are based on GREET onroad gasoline internal combustion engine (ICE) vehicle mileage of 8.33 km/L (19.6 miles per gallon). Gasoline and diesel have an energy content of 32 and 36 MJ/L respectively; gasoline and low sulfur diesel emissions are 94.7 and 94.5 kg GHG/GJ (11). This study assumes that delivery trucks are fueled with fossil fuels. Consumer vehicles are fueled 100% with renewable fuel and have net zero emissions.

| State | Total | Coal (296 | Natural | Petroleum | Overall |
|--------------|-----------------|------------------------------|------------------------------|------------------------------|------------------------------|
| | Capacity | \mathbf{kg} | Gas~(155 | (252 m ~kg | Emission |
| | (\mathbf{MW}) | \mathbf{GHG}/\mathbf{GJ}) | \mathbf{kg} | \mathbf{GHG}/\mathbf{GJ}) | Factor (kg |
| | | | \mathbf{GHG}/\mathbf{GJ}) | | \mathbf{GHG}/\mathbf{GJ}) |
| Iowa | 14842 | 50% | 19% | 8% | 208 |
| Illinois | 48980 | 36% | 35% | 3% | 197 |
| Indiana | 30133 | 71% | 23% | 2% | 273 |
| Minnesota | 15678 | 36% | 33% | 6% | 199 |
| Nebraska | 7421 | 43% | 28% | 6% | 208 |
| South Dakota | 3374 | 14% | 24% | 9% | 116 |

Table 4.5Midwest state power capacity, fossil fuel contribution, and overall
emission factor

Second-generation biorefineries are capable of generating enough heat and power for their own operation and excess for export. In practice, biorefineries employ some form of nonrenewable energy because of economic and practical reasons (startup and shutdown for ex-
ample). This study assumes that fossil fuel use is negligible in the centralized gasification and pyrolysis upgrading facilities. The distributed units and stand-alone pyrolysis biorefinery purchase electricity from the grid. Although this is the most likely short-term scenario, it is possible that this electricity could be provided entirely from renewable sources resulting in even lower emissions. Grid emissions are based on the current power mixture generation in the state where the centralized biorefinery is located as provided by the Energy Information Administration (14). Table 4.5 shows the total state power capacity and contribution from fossil fuel sources with their respective emission factors (11).

| Scenario | WTW Fuel | Pretreatment | Upgrading | Carbon Se- |
|--------------------------|-----------------------|-------------------------|---------------------------------|---------------------------------|
| | \mathbf{Y} ield | Energy Use | Energy Use | questration |
| | $({f gal}/{f tonne})$ | $({ m kWh}/{ m tonne})$ | $(\mathbf{kWh}/\mathbf{tonne})$ | \mathbf{Credit} |
| | | | | (tonne |
| | | | | $\mathbf{CO}_2/\mathbf{tonne})$ |
| Torrefaction | 54 | 92 | -168 | 0 |
| Torrefaction + Pelleti- | 55 | 102 | -168 | 0 |
| zation | | | | |
| Pyrolysis (Bio-oil + | 50 | 115 | -168 | 0 |
| Bio-char) | | | | |
| Pelletization | 63 | 129 | -168 | 0 |
| Centralized Gasification | 63 | 0 | -168 | 0 |
| Pyrolysis (Bio-oil) | 58 | 115 | 31.4 | 0.21 |
| Centralized Pyrolysis | 59 | 0 | 162 | 0.21 |

Table 4.6 Fuel yield, energy, and biochar sequestration rates for GHG calculations (127; 122; 92; 141; 88)

The values of key scenario parameters employed in greenhouse gas emissions calculations are shown in Table 4.6. Well-to-wheel fuel yield accounts for pretreatment, transportation loss, and upgrading yields. Energy use consists of electricity consumption, and biomass is the main source of process heat. Scenarios that generate biochar receive a carbon credit of 0.21 tonnes of CO_2e per tonne of feedstock.

4.5 Results

4.5.1 Fuel costs of distributed biomass processing pathways

Distributed biomass processing envisions a large upgrading facility surrounded by smallscale pretreatment facilities. The PA-LP model determined an optimum location for the centralized and distributed facilities as shown in Figure 4.5. Given the current assumptions, the upgrading facility is located in Illinois and most of its biomass comes from within the state with small quantities from Iowa and Indiana. The upgrading facility generates 500 MM gallons per year of transportation fuels. This is equivalent to 59,000 barrels per day at a 90% capacity factor and roughly 4 times the volume of fuel generated in current ethanol biorefineries. The largest oil refinery in the U.S. processes 572,500 barrels of crude oil per day (21). The amount of biomass required varies between 8.0 and 10.0 MM tonnes per year for the various scenarios.



Figure 4.5 Plant Locations and Biomass Distribution for the Distributed Production of Biofuels

Figure 4.6 includes a comparison of the biofuel productions costs for various production pathways. Naphtha and diesel fuel costs for the various scenarios range between \$2.00 and \$5.00 per gallon. Pretreatment, upgrading, and capital contribute the majority of costs in the pretreatment scenarios. Pretreatment costs vary between \$1.60 and \$1.11 per gallon for the torrefaction and pelletization scenarios respectively. Bio-oil benefits from the lowest upgrading cost at \$0.50 per gallon compared to \$1.01 for the gasification-based distributed scenarios. Transportation costs for the centralized scenarios average \$0.54 per gallon compared to \$0.26 per gallon for the distributed pathways. The distributed pyrolysis scenario without bio-char upgrading has slightly lower costs than the centralized gasification facility although the difference is within the uncertainty of the analysis $\pm 30\%$.



Figure 4.6 Comparison of Biofuel Production Costs via Centralized and Distributed Production Pathways

4.5.2 Carbon emissions of distributed biomass processing pathways

Figure 4.7 shows the major sources and sinks of carbon emissions for the scenarios included in this study. The main sources of CO_2 emissions in these scenarios are agricultural production (average 83 g CO_2 per km) and biomass pretreatment (average 39 g CO_2 per km). Biochar sequestration can completely offset agricultural production emissions associated with corn stover (average -91 g CO₂ per km). This indicates that the amount of carbon sequestered in biochar is greater than the fossil-fuel emissions associated with stover production based on the system expansion allocation methodology. The gasification scenarios have upgrading emissions of -50.3 g CO₂ per km. This emissions credit derives from the displacement of coal, natural gas, and petroleum electric grid emissions.



Figure 4.7 Comparison of Biofuel Production Emissions via Centralized and Distributed Production Pathways

Figure 4.8 shows the percent reduction in carbon emissions for these biofuel supply chains compared to the gasoline baseline. All scenarios show better than 76% reduction in GHG emissions when compared to the fossil-fuel based gasoline baseline of 364 g CO_2 per km. Centralized gasification has the highest emission reduction with a 94% reduction from the baseline.



Figure 4.8 Comparison of Biofuel Production Emissions via Centralized and Distributed Production Pathways

4.6 Discussion

4.6.1 Challenges of developing a distributed processing infrastructure

Harvesting, storage, and transportation (HST) of biomass resources pose unique challenges for the energy industry. Some lessons from the agricultural industry serve the biofuel industry, but there are many new questions that will require innovative solutions. One of these solutions is distributed processing. Following is a discussion of current issues that researchers are investigating in HST.

Biomass species have unique characteristics that require minor, or even major modifications to harvesting equipment. The capabilities of harvesting equipment impacts the collection rate and the amount of recoverable biomass. Intrepid farmers may be willing to invest in new equipment, skills, and even novel crops given the proper return on investment, but it is more likely in the short-term that biomass will come from existing farms.

Farmers are very likely to embrace solutions that integrate seamlessly into their existing operations. Biorefineries may seek biomass HST standards that require new agricultural practices.

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This opens the door to third parties willing to intermediate between farmers and producers. These third party bioresource suppliers are the ones likely to adopt and develop distributed processing technology to improve their ability to store and commodifize their feedstock.

Bioresource suppliers will be concerned with their ability to store biomass for several weeks without major property changes, and their access to low-cost, long-distance transportation. Determining the full cost of biomass degradation may require a full WTW chain analysis that includes accounting for material loss, upgrading penalties, and potential impact on fuel quality. Long-distance transportation would broaden suppliers' access to markets. These two issues can benefit from a combined techno-economic and location analysis as shown in this report.

CHAPTER 5. Conclusions

The purpose of this study is to assess biomass to biofuel technologies. Techno-economic, location, and carbon emission analyses are employed to determine the economic and environmental costs of producing biofuels. The combination of these methodologies provides a comprehensive analysis of biofuel technologies. This dissertation includes three separate papers that combine these methodologies.

"Techno-economic analysis of biomass fast pyrolysis to transportation fuels" is a detailed study of the process performance and economic viability of biomass fast pyrolysis for the production of naphtha and diesel range fuels. It includes process modeling of two scenarios: hydrogen production, and hydrogen purchase. These two scenarios refer to the methods in which hydrogen is procured for the conversion of bio-oil into transportation fuels. Both scenarios process 2000 metric tons per day of corn stover into transportation fuels. Fuel yields are estimated as 35 and 58 million gallons per year with capital costs of \$287 and \$200 million. This study found that drop-in transportation fuels could be produced from corn stover at a competitive price of \$2.00 to \$3.00 per gallon.

"Biorefinery location analysis for the conversion of corn stover to gasoline and diesel fuels" explores the impact of facility location on the cost of producing transportation fuels. This study determined the optimum location of 5000 metric tons per day corn stover biorefineries in the U.S. Midwest. The optimum location is based on the lowest cost of producing biofuels based on feedstock availability, biorefinery feedstock demand, metropolitan gasoline demand, and biorefinery fuel output constraints. One thousand simulations of 70 randomly located biorefineries with optimum feedstock allocations found that optimum biorefinery locations could reduce biofuel costs by \$0.16 per gallon (\$1.15 billion per year).

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"Location, economic, and environmental analysis of thermochemical distributed biomass processing to transportation fuels" compares various distributed biomass processing pathways for the production of gasoline and diesel fuel. Pelletization, torrefaction, fast pyrolysis are the three distributed biomass processing technologies considered for small scale biomass conversion. These technologies all serve to densify biomass resulting in improve storage and transport properties. The densified products are upgrading using one of two pathways: solid products are gasified and converted to Fischer-Tropsch liquids before hydroprocessing, and liquid products are directly sent to hydroprocessing. Results found biofuel costs of \$2.00 to \$5.00 per gallon. Distributed biomass processing reduces transportation costs but results in pretreatment costs. Carbon emission analysis of these scenarios estimates reductions of 75% to 94% when compared to the gasoline baseline of 364 g of CO₂ per km.

These three papers provide a comprehensive analysis of biomass to biofuel production. The combination of techno-economic, location, and carbon emission analysis provides a better understanding of the challenges and opportunities available to these technologies.

CHAPTER 6. Recommendations for Future Work

The methodologies employed in this dissertation can be applied to a number of novel biofuel technologies and production scenarios. Following are a number of intriguing scenarios that could benefit from techno-economic, location, and environmental analysis.

Research in biomass thermochemical conversion technologies continues to present novel pathways for biofuel production(44). There are a number of interesting innovations in fast pyrolysis, hydro-thermal processing, and even gasification that range from novel reactor designs(35) to new catalyst implementations(38). Alternative reactors such as auger and entrained flow reactors present opportunities for reducing biofuel production costs at small-scale(140). Catalysts that allow for one-step conversion of biomass to liquid fuels are in development, and they could significantly improve the profitability of thermochemical systems. Techno-economic analysis of these new technologies would quantify their commercialization potential.

The importance of feedstock selection is encouraging research in the implications of largescale production of renewable biomass including algae(111; 29). Location analysis is a key aspect of assessing the suitability of given feedstock to a given biorefinery location. It is therefore important to understand how agricultural and environmental constraints impact the ability to produce, collect, and transport renewable feedstock(61). Assumptions for these key feedstock challenges have not commonly been included in biofuel techno-economic studies, but it is of growing importance if global targets for biofuel production are to be met.

Environmental analysis is a major aspect of life-cycle analysis where it has seen steady development(51). Techno-economic and environmental studies are typically done separately, and they have mostly focused on different sectors. Life cycle analysis has mostly focused on assessing the environmental impact of commercially developed technologies whereas technoeconomic studies tend to investigate experimental or lab-scale technologies. A better approach would be to combine these two types of analyses. There are a number of recent publications that combine environmental and techno-economic analysis to varying degrees(80; 75).

The most difficult challenge to expanding on this research is the accessibility to the required tools and data. There is commercial software suitable available for either techno-economic or environmental analysis, but very few packages are designed for both types of analyses. Cost is an important factor in gaining access to the necessary software. Data can be very limited for novel technologies. This is particularly true of very promising technologies, which could have limited publications due to patenting procedures or corporate protection of industrial secrets. Location analysis is enhanced by improved knowledge of local conditions that include environmental, economic, and social factors. The U.S. Department of Energy, Department of Agriculture, Natural Resources Conservation Service among other government organizations provide convenient access to a wealth of information. In particular, the U.S. D.O.E is aggregating this data into a centralized location that can be found at their website. These efforts will help the public, industrial, and research communities have access to relevant data.

These are a few of the opportunities available to further research in the areas of technoeconomic, location, and environmental analysis. Efforts in addressing these opportunities are likely to gather interest from the research community and public at large. There is also a potential for high impact from improving the state-of-knowledge in these fields because of the widespread interest in developing alternative fuels.

APPENDIX

.1 Aspen Plus®Software Mass Flow and Balance Results and Process Flow Diagrams

.2 Selection process of pyrolysis reactor technologies for further analysis under ISU, COP, and NREL collaborative project.

By: Mark M. Wright, Daren E. Daugaard, and Robert C. Brown

.3 Purpose

The purpose of this memo is to describe the selection process employed to down select pyrolysis technologies, and bio-oil upgrading to transportation fuels, for further research and development.

.4 Summary

Six different pyrolysis technologies were initially chosen to compare based on selected criteria. These technologies, based on the reactor design, were bubbling bed, circulating (transported) bed, auger, free fall (entrained flow), ablative, and catalytic pyrolysis (fluid bed.) Hydrothermal processing (HTP) was added during the down selection process based on its similar primary liquid product. Two bio-oil upgrading technologies were considered: hydrogenation (hydrocracking,) and gasification via the Fischer-Tropsch process.

Bubbling bed pyrolysis was chosen as the base case because of the availability of reliable and established data. Positive, and negative, ratings were given to other technologies based on

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| | In | Out | % Change | | In | Out | % Change |
|-----------|-------------|-------------|----------|--------------------------|-------------|-------------|----------|
| Plant | | | | Recovery | | | |
| Carbon | 0.91 | 0.91 | 100.03% | Carbon | 1.12 | 1.12 | 100.00% |
| hydrogen | 2.54 | 2.54 | 100.05% | hydrogen | 1.51 | 1.51 | 100.00% |
| Oxygen | 1.92 | 1.92 | 100.24% | Oxygen | 1.52 | 1.52 | 100.00% |
| Nitrogen | 2.44 | 2.44 | 99.92% | Nitrogen | 1.50 | 1.50 | 100.00% |
| Ash | 1.39 | 1.37 | 98.33% | Ash | 0.21 | 0.21 | 100.00% |
| Mass | $287,\!148$ | $287,\!252$ | 100.04% | Mass | $218,\!126$ | $218,\!126$ | 100.00% |
| | | | | | | | |
| Drying | | | | $\operatorname{Storage}$ | | | |
| Carbon | 0.91 | 0.91 | 100.00% | Carbon | 0.67 | 0.67 | 100.00% |
| hydrogen | 2.03 | 2.03 | 100.00% | hydrogen | 1.20 | 1.20 | 100.00% |
| Oxygen | 1.02 | 1.02 | 100.00% | Oxygen | 0.45 | 0.45 | 100.00% |
| Nitrogen | 0.01 | 0.01 | 100.00% | Nitrogen | 0.00 | 0.00 | 100.00% |
| Ash | 1.39 | 1.39 | 100.00% | Ash | 1.00 | 1.00 | 100.00% |
| Mass | $110,\!905$ | $110,\!905$ | 100.00% | Mass | $62,\!957$ | $62,\!957$ | 100.00% |
| | | | | | | | |
| Pyrolysis | | | | Combustion | | | |
| Carbon | 1.29 | 1.29 | 100.38% | Carbon | 0.73 | 0.73 | 100.00% |
| hydrogen | 1.61 | 1.61 | 100.05% | hydrogen | 0.47 | 0.47 | 100.00% |
| Oxygen | 1.53 | 1.53 | 100.07% | Oxygen | 1.30 | 1.30 | 100.00% |
| Nitrogen | 1.51 | 1.51 | 99.88% | Nitrogen | 2.26 | 2.26 | 100.00% |
| Ash | 1.42 | 1.39 | 98.36% | Ash | 1.19 | 1.19 | 100.00% |
| Mass | $230,\!902$ | $231,\!006$ | 100.04% | Mass | $226,\!395$ | $226,\!395$ | 100.00% |
| | | | | | | | |
| Cleanup | | | | Hydrotreating | | | |
| Carbon | 1.29 | 1.29 | 100.00% | Carbon | 0.56 | 0.56 | 99.18% |
| hydrogen | 1.61 | 1.61 | 100.00% | hydrogen | 1.65 | 1.65 | 100.03% |
| Oxygen | 1.53 | 1.53 | 100.00% | Oxygen | 1.14 | 1.14 | 100.30% |
| Nitrogen | 1.51 | 1.51 | 100.00% | Nitrogen | 1.67 | 1.67 | 100.00% |
| Ash | 1.39 | 1.39 | 100.00% | Ash | 0.20 | 0.20 | 100.00% |
| Mass | $231,\!005$ | $231,\!005$ | 100.00% | Mass | 180,854 | 180,854 | 100.00% |

 Table A.1
 Aspen Plus®Software Section Mass and Mole Balances



Figure A.1 Biomass Chopping Process Flow Diagram (PFD)



Figure A.2 Biomass Drying PFD



Figure A.3 Biomass Pyrolysis PFD

| | DR01 | DR03 | DR04 | DRST1 | DRST2 | DRST3 |
|-------------------|-------|-------|-------|--------|--------|--------|
| | | | | | | |
| Temperature C | 25 | 100 | 100 | 196.7 | 120 | 132.8 |
| Pressure bar | 1.013 | 1.013 | 1.013 | 14.479 | 1.983 | 2.181 |
| Mass Flow kg/hr | | | | | | |
| N2 | 0 | 0 | 0 | 0 | 0 | 0 |
| 02 | 0 | 0 | 0 | 0 | 0 | 0 |
| H2 | 0 | 0 | 0 | 0 | 0 | 0 |
| СО | 0 | 0 | 0 | 0 | 0 | 0 |
| CO2 | 0 | 0 | 0 | 0 | 0 | 0 |
| WATER | 27778 | 21633 | 6145 | 0 | 0 | 0 |
| NH3 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH4 | 0 | 0 | 0 | 0 | 0 | 0 |
| C2H4 | 0 | 0 | 0 | 0 | 0 | 0 |
| C3H6 | 0 | 0 | 0 | 0 | 0 | 0 |
| AR | 0 | 0 | 0 | 0 | 0 | 0 |
| C2H4O2 | 0 | 0 | 0 | 0 | 0 | 0 |
| C3H6O2 | 0 | 0 | 0 | 0 | 0 | 0 |
| C7H8O2 | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H10O | 0 | 0 | 0 | 0 | 0 | 0 |
| CH2O2 | 0 | 0 | 0 | 0 | 0 | 0 |
| C10H12O2 | 0 | 0 | 0 | 0 | 0 | 0 |
| C6H6O | 0 | 0 | 0 | 0 | 0 | 0 |
| C7H8 | 0 | 0 | 0 | 0 | 0 | 0 |
| C5H4O2 | 0 | 0 | 0 | 0 | 0 | 0 |
| C6H6 | 0 | 0 | 0 | 0 | 0 | 0 |
| NO | 0 | 0 | 0 | 0 | 0 | 0 |
| NO2 | 0 | 0 | 0 | 0 | 0 | 0 |
| SULF | 0 | 0 | 0 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 | 767236 | 767236 | 767236 |
| SO2 | 0 | 0 | 0 | 0 | 0 | 0 |
| CHAR | 0 | 0 | 0 | 0 | 0 | 0 |
| STOVER | 83334 | 0 | 83334 | 0 | 0 | 0 |
| ASH | 0 | 0 | 0 | 0 | 0 | 0 |

 Table A.2
 Aspen Drying Material Flows

| | PY01 | PY02 | PY03 | PY04 |
|-------------------|-------|-------|-------|-------|
| | | | | |
| Temperature C | 100 | 56.7 | 250 | 480 |
| Pressure bar | 1.013 | 1.098 | 1.013 | 1.013 |
| Mass Flow kg/hr | | | | |
| N2 | 0 | 75485 | 75485 | 75840 |
| 02 | 0 | 0 | 0 | 0 |
| H2 | 0 | 0 | 0 | 3 |
| СО | 0 | 328 | 328 | 4953 |
| CO2 | 0 | 57392 | 57392 | 67651 |
| WATER | 6145 | 7564 | 13709 | 16849 |
| NH3 | 0 | 0 | 0 | 0 |
| CH4 | 0 | 53 | 53 | 806 |
| C2H4 | 0 | 1 | 1 | 19 |
| C3H6 | 0 | 1 | 1 | 22 |
| AR | 0 | 0 | 0 | 0 |
| C2H4O2 | 0 | 46 | 46 | 2818 |
| C3H6O2 | 0 | 79 | 79 | 13723 |
| C7H8O2 | 0 | 0 | 0 | 433 |
| C8H10O | 0 | 1 | 1 | 2836 |
| CH2O2 | 0 | 362 | 362 | 12882 |
| C10H12O2 | 0 | 3 | 3 | 13698 |
| C6H6O | 0 | 0 | 0 | 36 |
| C7H8 | 0 | 22 | 22 | 363 |
| C5H4O2 | 0 | 41 | 41 | 3032 |
| C6H6 | 0 | 0 | 0 | 6 |
| NO | 0 | 0 | 0 | 0 |
| NO2 | 0 | 0 | 0 | 0 |
| SULF | 0 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 | 0 |
| CHAR | 0 | 288 | 288 | 15121 |
| STOVER | 83334 | 0 | 83334 | 0 |
| ASH | 0 | 0 | 0 | 55 |

 Table A.3
 Aspen Pyrolysis Material Flows



Figure A.4 Pyrolysis Gas Cleaning PFD



Figure A.5 Bio-oil Recovery PFD

| | CL01 | CL08 | CL10 |
|-------------------|-------|-------|-------|
| | | | |
| Temperature C | 480 | 480 | 480 |
| Pressure bar | 1.013 | 0.997 | 0.997 |
| Mass Flow kg/hr | | | |
| N2 | 75840 | 0 | 75840 |
| O2 | 0 | 0 | 0 |
| H2 | 3 | 0 | 3 |
| СО | 4953 | 0 | 4953 |
| CO2 | 67651 | 0 | 67651 |
| WATER | 16849 | 0 | 16849 |
| NH3 | 0 | 0 | 0 |
| CH4 | 806 | 0 | 806 |
| C2H4 | 19 | 0 | 19 |
| C3H6 | 22 | 0 | 22 |
| AR | 0 | 0 | 0 |
| C2H4O2 | 2818 | 0 | 2818 |
| C3H6O2 | 13723 | 0 | 13723 |
| C7H8O2 | 433 | 0 | 433 |
| C8H10O | 2836 | 0 | 2836 |
| CH2O2 | 12882 | 0 | 12882 |
| C10H12O2 | 13698 | 0 | 13698 |
| C6H6O | 36 | 0 | 36 |
| C7H8 | 363 | 0 | 363 |
| C5H4O2 | 3032 | 0 | 3032 |
| С6Н6 | 6 | 0 | 6 |
| NO | 0 | 0 | 0 |
| NO2 | 0 | 0 | 0 |
| SULF | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 |
| CHAR | 15121 | 12853 | 2268 |
| STOVER | 0 | 0 | 0 |
| ASH | 55 | 47 | 8 |

 Table A.4
 Aspen Gas Cleaning Material Flows

| | RE01 | RE02 | RE03 | RE04 | RE05 | RE06 | RE07 |
|-----------------|-------|-------|-------|-------|-------|-------|-------|
| | | | | | | | |
| Temperature C | 480 | 150 | 50 | 50 | 50 | 50 | 50 |
| Pressure bar | 0.997 | 0.997 | 1.014 | 1.014 | 1.013 | 1.013 | 1.013 |
| Mass Flow kg/hr | | | | | | | |
| N2 | 75840 | 75840 | 75840 | 0 | 0 | 0 | 75840 |
| O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| H2 | 3 | 3 | 3 | 0 | 0 | 0 | 3 |
| СО | 4953 | 4953 | 4953 | 0 | 0 | 0 | 4953 |
| CO2 | 67651 | 67651 | 67606 | 46 | 46 | 0 | 67606 |
| WATER | 16849 | 16849 | 6159 | 10690 | 10690 | 0 | 6159 |
| NH3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH4 | 806 | 806 | 806 | 0 | 0 | 0 | 806 |
| C2H4 | 19 | 19 | 19 | 0 | 0 | 0 | 19 |
| C3H6 | 22 | 22 | 21 | 0 | 0 | 0 | 21 |
| AR | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C2H4O2 | 2818 | 2818 | 689 | 2129 | 2129 | 0 | 689 |
| C3H6O2 | 13723 | 13723 | 1197 | 12526 | 12526 | 0 | 1197 |
| C7H8O2 | 433 | 433 | 0 | 432 | 432 | 0 | 0 |
| C8H10O | 2836 | 2836 | 8 | 2828 | 2828 | 0 | 8 |
| CH2O2 | 12882 | 12882 | 5472 | 7410 | 7410 | 0 | 5472 |
| C10H12O2 | 13698 | 13698 | 44 | 13653 | 13653 | 0 | 44 |
| C6H6O | 36 | 36 | 1 | 35 | 35 | 0 | 1 |
| C7H8 | 363 | 363 | 338 | 25 | 25 | 0 | 338 |
| C5H4O2 | 3032 | 3032 | 615 | 2417 | 2417 | 0 | 615 |
| С6Н6 | 6 | 6 | 6 | 0 | 0 | 0 | 6 |
| NO | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NO2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SULF | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CHAR | 2268 | 2268 | 454 | 1815 | 2210 | 396 | 58 |
| STOVER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ASH | 8 | 8 | 2 | 7 | 8 | 1 | 0 |

 Table A.5
 Aspen Bio-oil Recovery Material Flows

| | HY01 | HY02 | HY03 | HY05 | HY06 | HY07 | HY08 |
|-----------------|-------|-------|--------|--------|-------|-------|-------|
| | | | | | | | |
| Temperature C | 50 | 50 | 56.2 | 450 | 140.7 | 50 | 260 |
| Pressure bar | 1.014 | 1.014 | 68.948 | 68.948 | 1.014 | 1.014 | 13.79 |
| Mass Flow kg/hr | | | | | | | |
| N2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| H2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 |
| СО | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CO2 | 46 | 28 | 28 | 8500 | 0 | 18 | 18 |
| WATER | 10690 | 6576 | 6576 | 10501 | 0 | 4115 | 24204 |
| NH3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH4 | 0 | 0 | 0 | 1070 | 0 | 0 | 0 |
| C2H4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C3H6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AR | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C2H4O2 | 2129 | 1310 | 1310 | 0 | 0 | 820 | 820 |
| C3H6O2 | 12526 | 7705 | 7705 | 0 | 0 | 4821 | 4821 |
| C7H8O2 | 432 | 266 | 266 | 0 | 0 | 166 | 166 |
| C8H10O | 2828 | 1739 | 1739 | 0 | 0 | 1088 | 1088 |
| CH2O2 | 7410 | 4558 | 4558 | 0 | 0 | 2852 | 2852 |
| C10H12O2 | 13653 | 8398 | 8398 | 0 | 0 | 5255 | 5255 |
| C6H6O | 35 | 22 | 22 | 0 | 0 | 14 | 14 |
| C7H8 | 25 | 15 | 15 | 0 | 0 | 10 | 10 |
| C5H4O2 | 2417 | 1487 | 1487 | 0 | 0 | 930 | 930 |
| C6H6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 | 6691 | 6691 | 0 | 0 |
| C10H22 | 0 | 0 | 0 | 6691 | 6691 | 0 | 0 |
| CL2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CHAR | 2210 | 1360 | 1360 | 1360 | 0 | 851 | 851 |
| STOVER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ASH | 8 | 5 | 5 | 5 | 0 | 3 | 3 |

 Table A.6
 Aspen Bio-oil Reforming and Hydroprocessing Material Flows

| (continued) | HY09 | HY10 | HY11 | HY012 | HY12 | HY13 | HY14 |
|-----------------|-------|-------|-------|-------|-------|-------|-------|
| | | | | | | | |
| Temperature C | 400 | 696.1 | 700 | 50 | 410 | 40 | 38.8 |
| Pressure bar | 13.79 | 13.79 | 13.79 | 1.014 | 13.79 | 13.79 | 9.632 |
| Mass Flow kg/hr | | | | | | | |
| N2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 02 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| H2 | 0 | 0 | 1350 | 0 | 1350 | 1350 | 1350 |
| CO | 0 | 0 | 5029 | 0 | 5029 | 5029 | 0 |
| CO2 | 18 | 18 | 15763 | 46 | 15763 | 15763 | 0 |
| WATER | 24204 | 24204 | 14862 | 10690 | 14862 | 14862 | 0 |
| NH3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH4 | 0 | 0 | 3175 | 0 | 3175 | 3175 | 0 |
| C2H4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C3H6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AR | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C2H4O2 | 820 | 820 | 0 | 2129 | 0 | 0 | 0 |
| C3H6O2 | 4821 | 4821 | 0 | 12526 | 0 | 0 | 0 |
| C7H8O2 | 166 | 166 | 0 | 432 | 0 | 0 | 0 |
| C8H10O | 1088 | 1088 | 0 | 2828 | 0 | 0 | 0 |
| CH2O2 | 2852 | 2852 | 0 | 7410 | 0 | 0 | 0 |
| C10H12O2 | 5255 | 5255 | 0 | 13653 | 0 | 0 | 0 |
| C6H6O | 14 | 14 | 0 | 35 | 0 | 0 | 0 |
| C7H8 | 10 | 10 | 0 | 25 | 0 | 0 | 0 |
| C5H4O2 | 930 | 930 | 0 | 2417 | 0 | 0 | 0 |
| C6H6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CHAR | 0 | 0 | 0 | 2210 | 0 | 0 | 0 |
| STOVER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ASH | 0 | 0 | 0 | 8 | 0 | 0 | 0 |

Table A.7 Aspen Bio-oil Reforming and Hydroprocessing Material Flows

| (continued) | HY15 | HY16 | HY17 | HY21 | HY22 | HY24 | HY25 |
|-----------------|-------|-------|-------|-------|-------|-------|-------|
| | | | | | | | |
| Temperature C | 174.5 | 38.8 | 26.4 | 25 | 50.7 | 25 | 25.6 |
| Pressure bar | 25 | 9.632 | 1.013 | 1.014 | 1.014 | 1.014 | 13.79 |
| Mass Flow kg/hr | | | | | | | |
| N2 | 0 | 0 | 0 | 78064 | 78065 | 0 | 0 |
| O2 | 0 | 0 | 0 | 23703 | 3951 | 0 | 0 |
| H2 | 1350 | 0 | 1 | 0 | 0 | 1 | 0 |
| СО | 0 | 5029 | 5029 | 0 | 0 | 0 | 0 |
| CO2 | 0 | 15763 | 24244 | 0 | 43750 | 8500 | 0 |
| WATER | 0 | 14862 | 631 | 0 | 10137 | 10501 | 20089 |
| NH3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH4 | 0 | 3175 | 4230 | 0 | 0 | 1070 | 0 |
| C2H4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C3H6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AR | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C2H4O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C3H6O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C7H8O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H10O | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH2O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C10H12O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C6H6O | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C7H8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C5H4O2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C6H6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CHAR | 0 | 0 | 0 | 0 | 851 | 1360 | 0 |
| STOVER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ASH | 0 | 0 | 0 | 0 | 3 | 5 | 0 |

Table A.8 Aspen Bio-oil Reforming and Hydroprocessing Material Flows

| (continued) | HY26 | HY27 | HY28 | HY30 | HY31 | HY071 | HY152 |
|-----------------|-------|------|-------|-------|------|-------|-------|
| | | | | | | | |
| Temperature C | 371.1 | | 370 | 400 | | 51.3 | 382 |
| Pressure bar | 13.79 | | 13.79 | 13.79 | | 13.79 | 69 |
| Mass Flow kg/hr | | | | | | | |
| N2 | 0 | | 0 | 0 | | 0 | 0 |
| 02 | 0 | | 0 | 0 | | 0 | 0 |
| H2 | 0 | | 0 | 0 | | 0 | 1350 |
| CO | 0 | | 0 | 0 | | 0 | 0 |
| CO2 | 0 | | 0 | 0 | | 18 | 0 |
| WATER | 20089 | | 20089 | 0 | | 4115 | 0 |
| NH3 | 0 | | 0 | 0 | | 0 | 0 |
| CH4 | 0 | | 0 | 0 | | 0 | 0 |
| C2H4 | 0 | | 0 | 0 | | 0 | 0 |
| C3H6 | 0 | | 0 | 0 | | 0 | 0 |
| AR | 0 | | 0 | 0 | | 0 | 0 |
| C2H4O2 | 0 | | 0 | 0 | | 820 | 0 |
| C3H6O2 | 0 | | 0 | 0 | | 4821 | 0 |
| C7H8O2 | 0 | | 0 | 0 | | 166 | 0 |
| C8H10O | 0 | | 0 | 0 | | 1088 | 0 |
| CH2O2 | 0 | | 0 | 0 | | 2852 | 0 |
| C10H12O2 | 0 | | 0 | 0 | | 5255 | 0 |
| C6H6O | 0 | | 0 | 0 | | 14 | 0 |
| C7H8 | 0 | | 0 | 0 | | 10 | 0 |
| C5H4O2 | 0 | | 0 | 0 | | 930 | 0 |
| C6H6 | 0 | | 0 | 0 | | 0 | 0 |
| METHANOL | 0 | | 0 | 0 | | 0 | 0 |
| C8H18 | 0 | | 0 | 0 | | 0 | 0 |
| C10H22 | 0 | | 0 | 0 | | 0 | 0 |
| CL2 | 0 | | 0 | 0 | | 0 | 0 |
| STEAM | 0 | | 0 | 0 | | 0 | 0 |
| SO2 | 0 | | 0 | 0 | | 0 | 0 |
| CHAR | 0 | | 0 | 851 | | 851 | 0 |
| STOVER | 0 | | 0 | 0 | | 0 | 0 |
| ASH | 0 | | 0 | 3 | | 3 | 0 |

 Table A.9
 Aspen Bio-oil Reforming and Hydroprocessing Material Flows

| (continued) | HYEFFGAS | HYEFFLIQ | HYWATER |
|-----------------|----------|----------|---------|
| | | | |
| Temperature C | 62 | 26.4 | 25 |
| Pressure bar | 1.115 | 1.013 | 1.013 |
| Mass Flow kg/hr | | | |
| N2 | 78065 | 0 | 0 |
| 02 | 3951 | 0 | 0 |
| H2 | 0 | 0 | 0 |
| СО | 0 | 0 | 0 |
| CO2 | 43750 | 19 | 0 |
| WATER | 10137 | 24732 | 20089 |
| NH3 | 0 | 0 | 0 |
| CH4 | 0 | 15 | 0 |
| C2H4 | 0 | 0 | 0 |
| C3H6 | 0 | 0 | 0 |
| AR | 0 | 0 | 0 |
| C2H4O2 | 0 | 0 | 0 |
| C3H6O2 | 0 | 0 | 0 |
| C7H8O2 | 0 | 0 | 0 |
| C8H10O | 0 | 0 | 0 |
| CH2O2 | 0 | 0 | 0 |
| C10H12O2 | 0 | 0 | 0 |
| C6H6O | 0 | 0 | 0 |
| C7H8 | 0 | 0 | 0 |
| C5H4O2 | 0 | 0 | 0 |
| C6H6 | 0 | 0 | 0 |
| METHANOL | 0 | 0 | 0 |
| C8H18 | 0 | 0 | 0 |
| C10H22 | 0 | 0 | 0 |
| CL2 | 0 | 0 | 0 |
| STEAM | 0 | 0 | 0 |
| SO2 | 0 | 0 | 0 |
| CHAR | 851 | 1360 | 0 |
| STOVER | 0 | 0 | 0 |
| ASH | 3 | 5 | 0 |

 Table A.10
 Aspen Bio-oil Reforming and Hydroprocessing Material Flows



Figure A.6 Bio-oil Reforming and Hydroprocessing PFD

how they compare to the base case on various criteria. These ratings allowed for the selection of technologies for focus in the current project. Bubbling bed, auger, and free fall pyrolysis reactors were chosen for further research. Further inquiries into hydrothermal processing and hydrogenation will be done as well.

.5 Background

A process design matrix has been developed to aid in the collection of data for various technologies. These technologies are grouped into biochemical, gasification, pyrolysis, upgrading, and supporting technologies. The selected criteria includes capital expenditure, operating costs, plant efficiency, carbon efficiency, capacity factor, plant size (typical,) complexity of process, level of technology development, and energy content among others. Based on these criteria, circulating (transported) bed, auger, free fall (entrained flow,) ablative, and catalytic pyrolysis (fluid bed) were rated and compared to bubbling bed pyrolysis.

.6 Selection Process

Bubbling bed pyrolysis has been chosen as the base case pyrolysis technology because of reliable and established information. Following is a short description of how each of the considered alternative technologies compares in terms of the process design criteria to the base case.

.6.1 Circulating (Transported) Bed

This technology requires a higher capital cost due to the need for additional reactor vessels and related equipment. Operating costs are also expected to be higher because of increased fluidizing gas requirements and the recirculation of inert bed material. Based on available knowledge, circulating bed has a lower plant and carbon efficiency. The capacity factor rating, defined as the availability of the system, is lower than the base case due to additional maintenance requirements associated with the use of additional equipment. Circulating bed reactors, similar to bubbling bed, are better suited for larger sizes and are therefore not attractive economically for a distributed processing scenario. The complexity of this process is higher than the base case. In terms of level of technology development, this configuration had an identical rating to the bubbling bed technology.

.6.2 Auger

The auger reactor was given an identical capital expenditure rating to the base case based on the assumption that increases in capital requirements for the reactor could be offset by savings in auxiliary equipment. Augers are expected to reduce operating costs. Plant efficiency was given an identical rating, while the carbon efficiency is expected to suffer under this configuration due to lower yields. The use of mechanical moving parts reduced the capacity factor rating. An auger reactor's typical size is well suited for distributed processing scenario where smaller is better. Process steps might be eliminated, reducing the complexity of the process. The level of technology development is considered low for this technology.

.6.3 Free Fall (Entrained Flow)

A free fall reactor is the only option with a lower capital expense requirement. This reactor is also expected to have lower operating costs. Its plant efficiency is lower than the bubbling bed's efficiency, and the same applies to the carbon efficiency due to lower yields. This is the only option with a better capacity factor than the base case. The typical plant size is comparable to the bubbling bed. The complexity is expected to be lower, although the level of development is low.

.6.4 Ablative

Capital expenditure for ablative reactors is expected to be comparable to the bubbling bed technology. Operating costs are rated lower than the base case. Plant efficiency is similar to the bubbling bed. The carbon efficiency is lower for this technology, as is the capacity factor due to the mechanical requirements. Ablative reactors are better suited to small scale operations. The complexity and level of technology development both received a negative rating.

.6.5 Catalytic Pyrolysis

The catalytic pyrolysis analysis was based on the assumption that it employed a fluid bed reactor design. There has not been much research done in this area, but like catalytic gasification, catalytic pyrolysis suffers from sulfur and chlorine poisoning of the catalysts. This option received negative ratings for all criteria with the exception of plant size where it is expected to have the same typical size as the base case.

.6.6 Other Technologies

Hydrothermal processing is a different process than pyrolysis. This process involves pressurizing biomass in an aqueous solution using a batch process that requires heat and significant amounts of water. The hydrocarbon portion of the product contains less oxygen than typical bio-oil, and is closer in composition to fossil based oil. Since it is currently at a very early development stage, not enough techno-economic information is available although up to date commercialization efforts have not been promising. This process yields a superior product in terms of energy content than pyrolysis, and this is the main reason for its inclusion in this study. Hydrogenation/hydrocracking was selected for further study as well. This upgrading technology would be used at a large scale facility. The level of technology development for this process is considered to be low at this time.

.7 Action

The next step in this collaboration is to prepare Aspen®software models for the selected technologies: bubbling bed, auger, and free fall pyrolysis. hydrogenation/hydrocracking will also be evaluated. For this purpose, a work plan is being developed. In January of 2008 the plan will be presented regarding the Aspen®software models' level of detail and assumptions.

.8 Assumptions for Pyrolysis Technologies Techno-economic Studies

.8.1 Plant Size, Location and Construction

- Various plant sizes will be regarded as economically feasible plants size which would be plant capacities of 5, 50, and 550 tons per day (dry feedstock)
- Scenarios will aggregate plants to total capacity of 2000 tons per day.
- Biomass collection area for 2000 tons per day has 50 mile radius, and transportation costs are 23 percent of feedstock costs with linear scaling for smaller sized areas.
- The plant produces pyrolysis gas, bio-oil, and charcoal,
- The plant is considered to be located in the middle of corn farmland
 - -25% of the land will be tied up in infrastructure (roads and buildings), and
 - -75% of the farm land plants the corn
- The plant will be designed based on the State of the Technology, and would be the nth plant of its kind
- The online time would be 350 days per year (equivalent capacity factor of 96%)
- Construction time of less than 24 months is considered based on judgment

- Startup period would be 25% of the construction time (6 months)
- During this period, an average of 50% production will be achieved with expenditure of about 75% of variable expenses and 100% of fixed expenses.

.9 Feedstock

Corn stover (comprised of stalks, leaves, cobs and husks) is considered as feedstock

- The feedstock will be delivered to feed handling area of the plant
- Moisture content in the feed stock is 15% (wet basis)
- Variation of feed compositions will be incorporated in the model
- The feedstock transportation and management protocol are not considered
- Feed cost is assumed to be 50/dry MT with credit for reduced transportation cost

.10 Material and Energy Balance

.10.1 Material Balance

- Biomass will be modeled using ultimate and proximate analyses data, and Aspen®software coal model,
- Biomass handling will be specified to less than 5 mm grinding size, and 7% moisture content, also depending on specific process requirements,
- No biomass material is lost during washing
- Various bio-oil compositions will be considered; bio-oil components of interest are formic acid, hydroxyacetaldehyde, acetic acid, diacetyl, glyoxal, acetol, levoglucosan, cellobiosan, water, and pyrolytic lignin,
- Where necessary, Nitrogen will be employed as fluidizing agent, and pyrolysis gas recirculation will also be considered.

• Carbon efficiency can be calculated based on carbohydrate carbon content, as follows:

.10.2 Energy Balance

An Aspen®software Yield reactor model will be employed to calculate reaction energy balance, Combustor energy losses will be factored into the model,

The energy value of the products will be reported to measure an overall energy balance.

.11 Equipment Design, Material of Construction and Costing

.11.1 Equipment Design

The reactors will be modeled using experimentally determined conversions of specific reactions (kinetic expressions will be not used because of the level of their development)

If the size of any equipment is known to change linearly with the inlet flow, that information can be used for equipment scaling (a characteristic of the size might be the heat duty for a heat exchanger if the log-mean temperature difference is known not to change)

For some equipment, nothing can be easily related to the size, in that case the unit will be resized with each process change (for example heat exchangers with varying temperature profiles, in this case, the heat exchanger area will be calculated each time the model will be run and the cost will be scaled using the ratio of the new and original areas)

.11.2 Material of Construction

Most construction material will consist of Stainless Steel.

.11.3 Costing

• Equipment costing data, and installation factors, will be collected from direct quotation, published data, and Aspen Icarus®software evaluation with preference given in the order shown here.

- If process changes are made and the equipment size changes, the equipment will not be re-coasted following the exponential scaling expression: *or characteristic linearly related to the size
- The purchased equipment cost obtained in a particular year will be indexed to the year of interest (2012) using the Chemical Engineering Index o Existing value of the index will be regressed to extrapolate to the future year (2012)

.11.4 Chemical costing

Acids and other chemicals if considered will be obtained from quotation. The cost of the chemicals will also be indexed following Industrial Inorganic Chemical Index (from SRI) to estimate the cost of the chemicals in the future year of interest (2012).

.11.5 Operating cost

- Working capital is assumed to be 5% of the total capital investment
- It is assumed that the product will be made, shipped and payment received in 30 days
- Annual maintenance materials will be 2% of the total installed equipment cost
- Employee salaries will be indexed to future year of interest (2012) following the data of the Bureau of Labor Statistics
- Salaries of the yard employees will not include benefits and will cover in the general overhead category
- General overhead will be a factor of 60% applied to the total salaries and covers items such as safety, general engineering, general plant maintenance, payroll overhead (including benefits), plant security, janitorial and similar services, phone, light, heat, and plant communications

.12 Wastewater Treatment Plant

- The process will be designed for zero discharge to a municipal treatment plant in a steady state mode,
- Any process upset (sudden increase of solids in the wastewater) will not considered in the model
- Rain and snow run-off, equipment washing and other non process waters are assumed to flow to the municipal wastewater treatment system. Other intermittent loads (process spills) will not be considered in the design

.13 Greenhouse Emissions and Control

All of the sulfur into the combustor is converted to SO2

.14 Cost Analysis

- The total plant investment cost will be determined by applying overhead and contingency factors (NREL experience and literature) to installed equipment costs
- Insurance and taxes will be considered as 1.5% of the total installed equipment cost (Delta-T/NREL/published data) o The estimates are location sensitive
- To determine the product value per gallon of liquid fuel, a discounted cash flow analysis will be used (after knowing the major three costs areas: (i) total project investment, (ii) variable operating costs, and (iii) fixed operating cost) o A 10% discounted cash flow rate of return will be used over a 20 years plant life o The plant is considered 100% equity financed
- For federal tax return, depreciation will be determined as follows : o IRS Modified Accelerated Cost Recovery System (MARCS) which includes General Depreciation System (GDS) will be followed that allows both the 200 % and 150% Declining Balance (DB) methods of depreciation

- This allows shortest recovery period and the largest deductions o The other property not specifically described in the publication should be depreciated using a 7-year recovery period
- Property listed with a recovery period less than 10 years will use the 200% DB depreciation method and a 20-year recovery period property will use the 150% DB depreciation of State tax will not be considered for the calculation (because the location of the plant is not specified)
- Return on investment will be calculated on a per gallon basis, and income tax will be averaged over the plant life and that average will be calculated on a per gallon basis.

 Table A.11 Biomass Pyrolysis/Torrefaction Design Matrix

| low Rate of Return | |
|--------------------|-----------|
| Cash F | |
| Discounted | |
| Production | |
| Hydrogen | Worksheet |
| Table A.12 | |

| DCI BDR Work sheet | | | | | | | | - | | | | |
|--|--|----------------|-----------------|----------------|--|---|--|---|--|-------------------|--|--|
| tur | | 7 | • | • | - | ~ | - | • | | • | • | • |
| Fined Capital Investment | | 517,222,604 | 5105,463,605 | 190"191"191 | | | | | | | | |
| Lines Partners | | | | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Loan interest Payment | | 8 | 4 | 4 | | 2 | 3 | 8 | 3 | | 3 | 8 |
| Loss Principal | | 4 | 10 | 10 | 4 | 4 | 10 | 10 | 8 | 8 | 8 | 8 |
| Fuel Seles | | | | | 991,0995,189 | 4047920924 | 10100360904 | 1014036090 | \$154,126,919 | 9124126.9519 | 411001201414 | \$159012615 |
| By-Product Credit | | | | | 54,419,4512 | 15,019,500 | 15, 911, 940 | 43.019.940 | 15,409,309 | 45,404,509 | 95.409.50B | 955,909,309 |
| Plant Phylorematics | | | | | 1.00 | 140 | 140 | 1.40 | 100 | | | |
| TITLE Annual 1841 | | | | | 287,514,811 | 1110-049-408 | 1110045-408 | 1010040400 | 1110,040,478 | 1110,040,419 | 1110,046,479 | 31 10,046,479 |
| Annual Manufacturing Cont | | | | | 10100100 | 014 616 446 | OLA ADDRESS | OLA ADD. ADD. | 014 204 204 | Distant Ann | CLARK AND | CLUMPS OF ADDR |
| Circuit and a second se | | | | | ALC: NOT THE REAL PROPERTY. | A NOT A D A D A D A D A D A D A D A D A D A | ALC: NOT ALC | An and all a | And the state of the | An and a lot of a | An and a lot of the | ALC DESCRIPTION OF ALL DESCRIPTI |
| Cathoo C | | | | | ALL PART OF | AND | A NUMBER OF COMPANY | 10001000100 | 1000 100 100 | 1000100100 | CONTRACTOR OF | CONTRACTOR OF |
| indeman fixe | | | | | 604.204.000 | COLUMN TO A | COLUMN ON | COLARK COM | CLUMBE ADD | CO AMPLACE | CO AMPLANK ADV | CO AND CO |
| Solids Chaptered Court | | | | | 11.515.147 | 41,777,536 | 41.777.546 | 40. 277.400 | 40,277,410 | 41.777.500 | 41.777.510 | 41. PVP. 5100 |
| Fixed Descrines Cods. | | | | | 14, 161, 400 | 18, 841, 600 | 18, 581, 600 | 14.041.400 | 18.981.600 | 18,081,600 | 18,081,000 | 18.081.000 |
| Tend Product Cost | | | | | 564,722,543 | 995,542,417 | 595,542,417 | 595,542,437 | 595,542,457 | 595,542,487 | 595,542,417 | 595,542,412 |
| Annual Depreciation | | | | | | | | | | | | |
| Connect Plant | | | | | | | | | | | | |
| 609 | | | | | 854,200,774 | 516,471,462 | \$15,622,644 | 518,302,001 | 511,072,480 | 14/101/101 | 96,009,000 | |
| 3 | | | | | APA, PR, PR, PR, PR, PR, PR, PR, PR, PR, PR | 101/102/015 | 11/101/101 | \$16,014,17/B | 19971517515 | 110/15/1415 | 115,151,000 | |
| anges formerway | | | | | 100/10/201 | 100,073,054 | Dev./011/1100 | 6107187018 | \$12,682,799 | 111,1044,428 | 100'00'001 | |
| Actual | | | | | 814,200,074 | 516,471,462 | \$15,622,644 | 514,302,001 | 515/1S1/401 | \$15°'51'000 | \$15/JS1/001 | |
| Stream Plant | | | | | | | | | | | | |
| D08 | | | | | 8 | 8 | 8 | 8 | 8 | 2 | 8 | 2 |
| đ | | | | | 8 | 8 | 8 | 8 | 8 | 3 | 3 | 3 |
| termining value | | | | | 8 | 8 | 8 | 8 | 2 | 8 | 8 | 8 |
| Atta | | | | | 8 | 8 | 8 | 8 | 2 | 2 | 2 | 2 |
| Net Revenue | | | | | 010,404,510 | 0100/200700 | 18,881,147 | 090'00''915 | 895,522,848 | 895,525,663 | 895,525,546 | E14, 501, 991 |
| LONDER FORMERS | | | | | | 010, MM, 5101 | 00101/101/201 | 10-C1-Y649-Y6190 | 0518,4588,4158 | 8 | 8 | 8 |
| Taxable Income | | | | | 001/,M08,300 | 0000%//WID | HALF VARIATE | G11,690,409 | 15,158,879 | 847757945 | 111777111 | 194,501,991 |
| A DECEMBER OF A | | | | | | 200000000000000000000000000000000000000 | | | 10/10/001 | TO DO DO DO | ALC: NOT THE REAL OF | ALCONOM N |
| Menual Latin Income | | 101 | - | | C. NORONOWICK | THE REAL PROPERTY IN | THE PARTY OF THE P | A PARTICIPATION AND A | 0.000/01/21/2000/01/21/2 | CHUCKNESS OF | Contraction of the | CLANSING STREET |
| Assessed Processed Values | COLORIAN | | | | 011.647.480 | COLUCIAN | 01.401.100 | 121 Not 410 | E30.078.1 10 | 011.218.800 | C11.451.000 | 00.010.784 |
| Troal Capital Investment - Interest Net Present North | | 10,409,902,444 | 1114,000,988.56 | 582,611,178,67 | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | increme manahile incr | the other set of | | | | | | Ī |
| | | | | | nan interest subtract | and from taxable in- | the second | | | | | |
| | | | | | Dentit on compared | on loan added to m | Lowest Law | | | | | |
| MPV of Income Tax | DIRAMANN' | | | | 05 | 00 | 05 | 00 | H1/9H1/11 | 102,002,002 | 13,452,995 | 191727-981 |
| And the second s | Promotion and and and and and and and and and an | | | | Contraction of the local division of the loc | | APALATANA A | PROCESSION AND AND AND AND AND AND AND AND AND AN | THE PARTY OF THE P | A PROPERTY A | THE PARTY OF THE P | POPULATION OF |

Table A.13Hydrogen Production Discounted Cash Flow Rate of ReturnWorksheet (continued)

| 24 | (526,365,906 | 3 | 3 | ¥ | \$154,126,919 | \$5,919,509 | 1.00 | \$1 50,046,428 | \$54,426,688 | 54.501.654 | \$1.767,000 | \$23,685,976 | \$1,777,559 | 58,961,600 | 595,542,437 | | 2 | 2 | 3 | 3 | 524.502.001 | 01 | \$14,501,991 | \$13,456,557 | \$21,047,435 | 0.148643633 | 43.140.667 | (51,919,124.00 | | \$2,000,231 \$18,450,676 |
|----|--------------|----|----|----|---------------|-------------|------|----------------|--------------|-------------|-------------|--------------|-------------|-------------|--------------|---|------------|-----|----|----|---------------|----|--------------|--------------|--------------|-------------|---|----------------|--|-----------------------------|
| 19 | | 2 | 2 | 2 | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54,426,688 | 54.001.634 | \$1.767.000 | \$23,685,976 | \$1,777,539 | 58,981,600 | \$95,542,437 | 1 | <u>8</u> | \$0 | 05 | 05 | 534 502 001 | 20 | \$14.501.991 | \$13,456,557 | \$21,047,415 | 0.162507991 | A14 444 414 | | | \$2,200,255 |
| 16 | | 20 | 20 | 20 | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54,426,688 | 54.001.614 | 51.767.000 | \$23,685,976 | \$1,777,539 | 58,983,600 | \$95,542,437 | : | 20 | \$0 | 99 | 05 | £34 5A2 001 | 20 | \$14,501,991 | \$12,456,557 | \$21,047,415 | 0.17985870 | 41 144 444 | pacing the e | | \$2,420,280 |
| 17 | | 20 | 20 | 50 | \$124,126,919 | \$5,919,509 | 1:00 | \$130,046,428 | \$54,426,688 | 54.901.614 | \$1.767.000 | \$23,685,976 | \$1,777,539 | 58,981,600 | \$95,542,437 | : | 8 | 20 | 05 | 05 | 634,502,901 | 20 | \$14.501.901 | \$12,456,557 | \$21,047,415 | 0.107844660 | 64 1 C 4 1 C 4 1 C 4 2 | | | \$2,662,308 |
| 16 | | \$ | 20 | 20 | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | 554,426,688 | 14.501.634 | \$1.767,000 | \$23,685,976 | \$1,777,539 | 58,981,600 | \$95,542,437 | : | 2 | 2 | 2 | 3 | 524,502,601 | 2 | \$14.501.991 | \$13,456,557 | \$21,047,435 | 0.017620116 | 44 600 616 | restautur | | \$2,928,539 |
| 15 | | 2 | 2 | \$ | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54,426,688 | 54.001.634 | \$1.767,000 | \$23,685,976 | \$1,777,539 | 58,981,600 | \$95,542,437 | : | 0 5 | 20 | 05 | 95 | 534 503 001 | 20 | \$34,503,991 | \$13,456,557 | \$21,047,435 | 0.720202640 | 40 M20 C00 | assistante | | \$3,221,595 |
| 14 | | 20 | 05 | 20 | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54,426,688 | 54.001.614 | 51-767.000 | \$23,685,976 | \$1,777,539 | 58,983,600 | \$95,542,437 | : | 20 | \$0 | 95 | 05 | 534 5A2 961 | 20 | \$14,501,991 | \$12,456,557 | \$21.047,415 | 0.262221254 | 60 645 443 | 211-191-1910 B | | \$3,545,532 \$12,686,497 |
| 15 | | 20 | 20 | 20 | \$124,126,919 | \$5,919,509 | 1:00 | \$130,046,428 | 554,426,688 | 54.901.614 | 51.767.000 | \$23,685,976 | \$1,777,539 | 58,961,600 | \$95,542,417 | ; | 8 | 20 | 9 | 3 | C24, 502, 901 | 10 | 514.501.991 | \$13,456,557 | \$21,047,415 | 0.28066418 | 100 0000 000 | 100000000 | | \$3,897,885 |
| 12 | | 10 | 20 | 20 | \$154,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54,426,688 | \$4.901.634 | \$1.767,000 | \$23,685,976 | \$1,777,559 | \$5,981,600 | \$95,542,437 | : | 2 | 2 | 3 | 3 | 524,502,601 | 10 | \$14,501,991 | \$13,456,557 | \$21,047,435 | 0.218630818 | 10 100 101 | instanutas | | \$4,287,674 |
| - | | 2 | 2 | 2 | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54,426,688 | 54.001.634 | \$1.767,000 | \$23,685,976 | \$1,777,539 | 58,983,600 | \$95,542,437 | : | <u>8</u> | \$0 | 05 | 05 | 534,502,001 | 20 | \$34,503,991 | \$13,456,557 | \$21,047,415 | 0.250402809 | 1 | a character | | \$4,716,441 \$41,505,728 |
| 01 | | 20 | 20 | 20 | \$124,126,919 | \$5,919,509 | 1.00 | \$130,046,428 | \$54.426.688 | 54.001.614 | 51.767.000 | \$23,685,976 | \$1,777,539 | 58,983,600 | \$95,542,437 | : | 20 | \$0 | 20 | 05 | £34 5A2 001 | 20 | \$14,501,991 | \$13,456,557 | \$21,047,435 | 0.285542280 | 10 11 4 100 | 740° 11° 10 | | \$5,188,085 |
| 6 | | 50 | 20 | 20 | \$124,126,919 | \$5,919,509 | 07 | \$130,046,428 | \$54,426,688 | 54.901.614 | \$1.767.000 | \$23,685,976 | \$1,777,539 | \$3,961,600 | \$95,542,417 | | 8 | 20 | 05 | 3 | 524,502,901 | 10 | 514.501.991 | \$13,456,557 | \$21,047,415 | 0.424097618 | 10.000 | in the set of | | \$5,706,894 |
| | _ | | | _ | | | | | | | | | | | _ | | | | | | | | | | E | | | | | |
| (0.1000 Modelsheet | | | | | | | | | | | |
|--|--------------|------------------|----------------------------|--|--|-----------------|---|---|---------------|--|----------------|
| | 1 | 1 | • | ľ | ~ | | • | * | • | • | • |
| Prived Capital Investment Working Capital | 121,998,1218 | 1148,111,004 | 119,100,510 117,019,105 | | | | | | | | |
| Lines Represeit | | | | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 2 |
| Loan Interest Reymont | 9 | 2: | 2: | 2: | | | 81 | 2: | 2: | 81 | 2: |
| Liner Provinged | 3 | 2 | 2 | 2 | | | 100 | 00 | | | 100 |
| Total Same | | | | THAT AND ADDRESS OF AD | 100 100 100 | 100 100 100 | 1010 112 112 112 112 112 112 112 112 112 | 100/01/00/01 | ACCOUNT OF A | CONTRACTOR OF THE OWNER OWNER OF THE OWNER | COLUMN TO A |
| Plast Performance | | | | 100 | 100 | 100 | 1.00 | 1.00 | 1.00 | 140 | 1.00 |
| Total Annual Lates | | | | 100.021.024 | NUMBER OF STREET | TIMON NUMBER | TURANAMIN TO A TO | 100000000000000000000000000000000000000 | 10070670201 | 1100,042,0241 | 1000040001 |
| Annual Namdacuma Cost | | | | | | | | | | | |
| feethack | | | | 940,401,010 | \$54,404,648 | 154,404,648 | \$54,405,688 | 534,435,688 | \$34,424,688 | \$34,435,688 | \$34,424,688 |
| Gerschy | | | | 111/06/04 | 55,771,896 | 51.771.898 | 847/11/1458 | 497/1/168 | 48/1/1/188 | 15077-000 | 48/J/J/480 |
| Caralyse | | | | \$1.546.035 | \$1.062,800 | S1.747,000 | S1.747,000 | 11,242,000 | 000705076 | 000709/15 | 11,050,000 |
| Solute Disposal Cirer | | | | 151,016 | \$40.878 | 500.91% | \$400.81W | 940,978 | 944,978 | 944,978 | 944,978 |
| Fixed Operating Costs | | | | 10,000,010 | 11110011 | 111,489,017 | \$11,000,117 | 511,440,177 | 511,480,177 | 511,440,177 | 511,480,177 |
| Tage Product Cost | | | | 94X,174,440 | 171,509,740 | 171,509,740 | 1/1,509,140 | 511,000,140 | S11,508,740 | S 13, 50%, Peb | S 73, 50%, 740 |
| Ammund Chepresitation | | | | | | | | | | | |
| Central Plant | | | | | | | | | | | |
| 00 | | | | INVESTIGATION IN | 110,644,779 | 104/11/402 | 121,716,148 | 110,364,301 | BILLINUM | BALFACTOR . | |
| | | | | 61/TMT/015 | 129,407,240 | 121,221,140 | 0997007721 | 111,448,457 | \$21,448,457 | 11,448,457 | |
| Remaining Value | | | | 1174,041,045 | 124,114,415 | 100,001,010 | 104UH/170 | 6-0 ⁺ 096 ⁺ 046 | 002,858,512 | 101/101/101 | |
| Actual | | | | \$70421,408 | \$10, 644,779 | 104-111-400 | 121,714,148 | 521,448,457 | 121,448,457 | 11,448,457 | |
| Stean Flast | | | | | | | | | | | |
| 00 | | | | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 |
| 8 | | | | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 |
| Remaining Value | | | | 2 | 2 | 2 | 2 | 3 | 8 | 3 | \$ |
| Actual | | | | \$ | 2 | 2 | 2 | 8 | 8 | 3 | 3 |
| Not Revenue | | | | G45/404/245 | 00110100 | 111,279,664 | 121,514,940 | S25,804,634 | \$15,804,634 | S25,000,634 | 100/151/105 |
| LOBAR FORMAND | | | | | 044776007324D | (help/100/help) | COLUMPTING COLUMN | 0216,268,462.0 | 8 | 3 | 8 |
| Yawadhie Income | | | | 04/7100/1010 | (hele/100/tard) | disconceres of | Chief (Menterly) | 194,515,467 | \$15,804,634 | S25,404,604 | 547,1531,091 |
| increase face | | | | * | 4 | 2 | 2 | 11,11,005 | \$10,061,80.F | 510,000,000 | 518,414,115 |
| Annual Carb Incime | | | | THAM TO BE | 140'TUT'DH | 140711/204 | 141,211,040 | BRUNE BRUNE | 117,188,384 | 117,168,264 | DRUKOVURI |
| Oncident further | 121 | 2 | - | 0.909090908 | 0.82644628.0 | 0.711114601 | 0.6633013401 | 0.429421121 | 0.06447390 | 4.11111111 | 0.466/30738 |
| Annual Prevent Value 1301, MIV,008 | | | | 01/10/1/0710 | 110/10/01 | 101,001,040 | 014/302/111 | 130,000,112 | 190'046'04'1 | 119,061,061 | \$11,446,799 |
| Total Capital Investment = Interest | 01982/01/201 | 1111111011011011 | 1011070/19113 | | | | | | | | |
| Net Present World | | | 2 | | | | | | | | |
| | | | | | | | | | | | |
| | | | | And the second second second | ALC: NO TO A DECISION OF A DECISIONO O | | | | | | |
| | | | | and interest landon and | and from the date of the | | | | | | |
| | | | | an payment tubute | the fram around the | A Income | | | | | |
| | | | | | | | | | | | |
| Why of income Tax | | | | 4 | 8 | | 2 | 52,309,184 | 15,000,757 | 15,164,124 | 121,040,82 |

Worksheet

Table A.15 Hydrogen Purchase Discounted Cash Flow Rate of Return Worksheet (continued)

| 20 | (537,078,376) 50 50 5109,451,853 511,310,978 5120,762,853 5120,762,853 | \$54,426,688 \$5,771,898 \$1,767,000 \$10,778 \$11,483,177 \$11,483,177 \$11,483,177 \$11,483,177 | 20 50 50 50 50 50 50,252,752 51,252,752,752 51,252,752,752 51,252,752,752,752,752,752,752,752,752,752 | \$2,759,310 \$16,769,321 |
|----|--|--|--|-----------------------------|
| 19 | 50 50 5109,451,853 511,11,853 5120,762,831 5120,762,831 | \$54,426,688 \$5,771,896 \$1,767,000 \$1,667,000 \$11,683,177 \$11,483,177 \$11,483,177 | 50 50 50 50 50 50 50 51,231,091 51,428,705 51,428,705 51,542,705 51,542,705 51,542,705 51,542,705 51,542,705 54,713,017 54,713,017 | \$3,013,241 \$17,896,251 |
| 18 | 50 5109,451,853 511,310,978 5120,762,831 5120,762,831 | \$54,426,688 \$5,771,898 \$1,707,000 \$10,778 \$10,978 \$10,978 \$11,508,740 \$71,508,740 | 50 50 50 50 50 50 512,253,091 518,428,795 518,428,795 53,184,319 53,184,319 | \$3,314,565 \$19,685,878 |
| 17 | 50 50 5109,451,453 511,310,978 511,310,978 5120,762,831 | \$54,426,688 \$5,771,398 \$1,767,000 \$60,978 \$11,4683,177 \$71,509,740 | 10 50 50 547,353,091 547,253,091 518,428,705 518,428,705 518,428,705 518,428,705 518,428,705 518,702,751 55,702,751 | \$3,646,021 \$21,654,466 |
| 16 | 50 50 5109,451,853 5120,451,813 1.00 5120,762,831 | \$54,426,688 \$5,771,898 \$1,767,000 \$10,667,800 \$11,463,177 \$50,978 \$11,463,177 \$50,740 | 20 50 50 50 50 50 51,4251,001 511,4251,001 511,4251,001 511,4251,001 511,4251,001 511,4251,005 511,4251,005 511,4251,005 51,273,006 | \$4,010,623 \$23,819,912 |
| 15 | 50 50 5109,451,853 511,310,978 5120,762,831 | \$54,426,688 \$5,771,898 \$1,767,000 \$11,667,000 \$11,663,177 \$50,978 \$11,509,740 | \$0 \$0 \$0 \$47,451,091 \$44,248,705 \$18,428,705 \$18,428,705 \$18,428,705 \$18,428,705 \$18,428,705 \$5,900,829 \$5,900,829 | \$4,411,686 \$26,201,903 |
| ž | 50 5109,451,853 511,310,978 5120,762,831 5120,762,831 | \$54,426,688 \$5,771,898 \$1,767,000 \$1,762,177 \$50,978 \$11,568,177 \$71,509,740 | 50 50 50 50 50 50 50 512,253,091 518,428,705 518,428,705 518,428,705 518,428,705 518,428,705 518,428,705 518,428,705 518,428,705 51,590,962 | \$4,852,854 \$28,822,094 |
| 13 | 50 50 5109,451,453 511,310,578 511,310,578 5120,762,831 | \$54,426,688 \$5,771,898 \$1,767,000 \$60,978 \$11,468,177 \$11,468,177 \$11,508,740 | 10 50 50 547,353,091 547,253,091 518,458,705 528,5474,85 53,349,396 | \$5,338,140 \$11,704,301 |
| 12 | 50 50 510,453 518,454 518,15,16 51,20,762,831 51,20,762,831 | 554,426,688 55,771,808 51,777,808 51,777,809 511,463,177 511,509,740 | 50 50 50 547,353,091 547,253,091 518,428,705 518,428,705 518,4358 59,184,358 | \$5,871,953 \$34,874,733 |
| 11 | \$0 \$0 \$109,451,853 \$109,458 \$109,458 \$100,051831 \$120,705,831 | \$54,426,688 \$5,771,898 \$1,777,898 \$1,777,000 \$60,978 \$11,509,347 \$71,509,340 | 50 50 50 50 50 50 51,428,705 518,428,705 518,428,705 518,428,705 518,428,705 518,428,705 518,428,495 516,102,771 | \$6,459,149 \$38,362,207 |
| 10 | 50 50 5109,451,853 511,310,978 5120,762,831 5120,762,831 | \$54,426,688 \$5,771,896 \$1,707,000 \$1,707,000 \$11,9683,177 \$71,509,740 | 50 50 50 50 50 50 512,253,091 514,213,091 514,213,091 514,213,091 514,113,048 | \$7,105,064 \$42,198,427 |
| 6 | 50 50 50 50 50 50 511,310,653 511,310,653 511,310,653 51120,765,831 | \$54,426,688 \$5,771,898 \$1,777,898 \$10,878 \$11,485,177 \$71,509,740 | 90 90 547,253,091 547,253,091 547,251,091 547,251,095 547,879,701 518,418,705 548,4185 0,548,4185 512,224,353 512,224,353 | \$7,815,570 \$46,418,270 |

132

| Variable | Operating Costs | | | | | | | | | | |
|----------------------------|----------------------------------|------------|---------------------------------------|---------------|---|---------------------------|-------------------------------|--------------------|--------|---------------|---------------------|
| Costing Code | Raw Material | Stream No. | kg/te (or kW) | Ib/hr (or HP) | Quoted Price (\$/ton, or cents/kWh) | Year of Price Quote | 2000 Cost (cents / ton) | 2000 Cost (5/R) | S/hour | MM5/yr (2007) | Cents/gal (2007) |
| | Freedorick | | 43, 333 | 181.749 | | 2007 | | | | 54.43 | 111.00 |
| | flactricity | | 13,530 | 29,834 | 0.014 | 1000 | | | | 5.72 | 16.12 |
| Mand | Later and | | 10,010 | a rijer - | | | | | | | 10.00 |
| with Oil | | | | | | | | | | | |
| Aquenus | | | | | | | | | | | |
| Phase | Process Water | | 11,790 | 26.004 | 0.029 | | | | | 0.06 | 0.17 |
| 15% of | | | | | | | | | | | |
| Operating | | | | | | | | | | | |
| Cost | Catalyst | | | | | | | | | 1,77 | 5.00 |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
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| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | Saltaneal | | | | | | | | | 62.00 | 1 25 10 |
| | Suproval | | | | | | | | | 62.03 | 173.43 |
| | Wante Streems | | | | | | | | | | |
| B-1 6 7 10 | wasse streams | | | | | | | | | | |
| NREL Thermoch emical | | | | | | | | | | | |
| ethanol | Solids Osposal Cost | | 11,340 | | 18 | | | | | 1,78 | 5.03 |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | Subtortal | | | | | | | | | 1.78 | 5.03 |
| | | | | | | | | | | | |
| | By-Product Credits | | | | | | | | | | |
| SS/MMET | | | | | | | | | | | |
| U I | Fuel Gas (MMETU) | | 1,940,929 | | 5 | | | | | 9.70 | 27,44 |
| | Char (5./ton) | | 9,223 | | 310 | | | | | 1.61 | 4.54 |
| | | | | | | · · · · · · | | | | | |
| | Subcotal | | | | | | | | | 11.01 | 31.98 |
| | No. of Concession, Name | | | | | | | | | | |
| | Total Variable | | | | | | | | | | |
| | Operating Costs | | | | | | | | | 52.49 | 146.40 |
| | | | | | | | | | | | |
| | Fixed Operating Costs | | | | | | | | | | |
| | Plant Manager | 80000 | 1 | 80,000 | | 18 | 1 | | | | |
| | Plant Engineer | 65000 | - C | 59,560 | | 11 | | | | | |
| | Maintenance Supr | 60000 | | 60,000 | | 29 | k | | | | |
| | Lab Manager | 50000 | - B | 50,000 | | 24 | | | | | |
| | Shift Supervisor | 37000 | 5 | 169,318 | | 18 | k | | | | |
| | Lab Technician | 23000 | 2 | 45,816 | | 13 | E | | | | |
| | Maintenance Tech | 28000 | 2 | 205,254 | | 11 | (| | | | |
| | Shift Operators | 23000 | 30 | 458,156 | | 12 | r i | | | | |
| | Yard Employees | 20000 | 11 | 586,440 | | 10 | (| | | | |
| | General Manager | 100000 | | 0 | | 48 | k | | | | |
| | Clerks & Secretaries | 20000 | · · · · · · · · · · · · · · · · · · · | 54,979 | | 10 | k. | | | | |
| | Total Salaries | | 24 | 1,789,722 | | | | | | 1.77 | 5.00 |
| | | | | | | | | | | | |
| | | | of Labor & | | | | PEP 2008 | | | | |
| | Overhead Maint | 604 | Supervision | 1,061,833 | | 18.40 | farsen 37.660 | | | 1.06 | 3.00 |
| | | | | | | | | | | | |
| | Maintenance | 28 | of TPI | 4,756,232 | | | avg salary | (w/ benefits) | | 4.76 | 11.45 |
| | | | | | | | | | | | |
| | Insurance & Taxes | 1.18 | of TPI | 3,567,176 | | | 18264.20 | | | 8.57 | 10.08 |
| | | | | | | | | | | | |
| | Costs | | | 11,154,961 | | | | | | 11.15 | 31.54 |
| | | | | | | | | | | | |
| | Total Cash Cost | | | | | | | | | 63.65 | 179.93 |
| | Annual Capital Charge | | | | | | | | | 41.85 | 118.32 |
| | Annual Operation Cost | | | | | | | | | 107.50 | 204.24 |
| | Contract of the store of the set | | | | | | | | | 10.10 | 1.10.10 |

Table A.16Hydrogen Production Scenario Detailed Operating Cost Analysis

| Table A.17 | Hydrogen | Purchase | Scenario | Detailed | Operating | Cost | Analysis |
|------------|----------|----------|----------|----------|-----------|-----------------------|----------|
|------------|----------|----------|----------|----------|-----------|-----------------------|----------|

| Variable | Operating Costs | | | | | | | | | | |
|-------------------------------|----------------------------------|------------|-------------------------|---------------|--|---------------------------|---------------------------------------|---------------------|---------|------------------|---------------------|
| Costing Code | Raw Material | Stream No. | kg/hr (or kN0 | B/hr (or 187) | Quoted Price (1/son, or cents/kWh) | Year of Price Quote | (cents / ton) | 2000 Cost (5/10) | \$/hour | MM5/yr (2007) | Cents/gal (2007) |
| | Freedottech | | | 141.140 | | 1007 | | | | 14.43 | |
| | Bactering | | 11,000 | 15 115 | 0.014 | 1000 | | | | 4.90 | |
| Mand | Decount | | 11,499 | 43,413 | 0.014 | | | | | 1.09 | 6.5 |
| with Oil Aqueous Phase | Fresh Water | | 0 | | 0.029 | | | | | 0.00 | |
| 15% of Operating | | | | | | | | | | | |
| Cont | Catalyst | | | | | | | | | 1,767 | |
| | Hudrogen | | 2,041 | | 1939 | | | | | 23.69 | 40.70 |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | Subtotal | | | | | | | | | 84.78 | 142.61 |
| | | | | | | | | | | | |
| | Waste Streams | | | | | | | | | | |
| Ref 67 in NREL Thermoch | | | | | | | | | | | |
| ethanol | Solids Disposal Cest | | 11,340 | | 18 | | | | | 1.28 | 3.49 |
| | | | | | | | | | | | |
| | Sabtotal | | | | | | | | | 1.78 | 3.01 |
| | | | | | | | | | | | |
| | By-Product Credits | | | | | | | | | | |
| \$5 MMET | | | | | | | | | | | |
| ų | Fuel Cas (MMETU) | | 862,615 | | 5 | | | | | 4.31 | 7,41 |
| | Char (S/104) | | 9,223 | | 20 | | | | | 1.61 | 2.14 |
| | | | | | | | | | | | |
| | Subtotal | | | | | | | | | 5.92 | 10.17 |
| | Total Variable | | | | | | | | | | |
| | Operating Costs | | | | | | | | | 80.64 | 115.51 |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | Fixed Operating Costs | | | | | | | | | | |
| | Plant Manager | 80000 | | 80,000 | | 14 | | | | | |
| | Plant Engineer | 43000 | | 18,560 | | 31 | | | | | |
| | Maintenance Supr | 60000 | | 60,000 | | 29 | · · · · · · · · · · · · · · · · · · · | | | | |
| | Lab Manager | 50000 | | 58,800 | | 24 | | | | | |
| | Shift Supervisor | 3.79040 | 5 | 108,518 | | 10 | (| | | | |
| | Lab Technician | 25000 | | 45,816 | | 12 | | | | | |
| | Maintenance Tech | 24000 | 6 | 205,254 | | 11 | | | | | |
| | Shirt Operators | 23000 | 20 | 438,136 | | 12 | | | | | |
| | Yard Employees | 20000 | 14 | 586,440 | | 10 | | | | | |
| | Ceneral Manager | 100000 | | 0 | | | | | | | |
| | Clerks & Secretaries | 20000 | 1 | 14,879 | | 10 | - | | | | |
| | Total Salaries | | 74 | 1,768,732 | | | | | | 1.77 | 1.04 |
| | | | of Labor # | | | | HER DOLL | | | | |
| | Overhead Marri | 408 | Contraction of | 1.041.011 | | 18.40 | PEP 2000 | | | 1.04 | 1.81 |
| | Contraction in the second | | - appendix and a second | 1,011,011 | | 10.00 | CALLER OF LEVEL | | | | 1.000 |
| | Maintenance | 25 | of 1P | 1,105,992 | | | avg salary | w/ benefits) | | 3.31 | 5.64 |
| | | | | | | | | | | | |
| | Insurance & Taxes | 1.5% | of 1Pl | 2,479,494 | | | 18264.26 | | | 2.48 | 4.10 |
| | Canto | | | 8.617.047 | | | | | | | 10.00 |
| | | | | 4,411,341 | | | | | | - 60 | |
| | Total Cash Cost | | | | | | | | | 89.26 | 110.12 |
| | Carl Carl Carl | | | | | | | | | | |
| | Annual Capital Charge | | | | | | | | | 29.09 | 49.98 |
| | Annual Operation Cost | | | | | | | | | 116.35 | 200.10 |
| | Concerning and the second second | | | | | | | | | | |

 Table A.18
 Hydrogen Production Detailed Capital Investment Analysis

| | Total Capita | l Inve | estment | | |
|---------------------------------------|---------------|--------|---------------------|---------------|-------------------|
| | 2007 Dollars | | Peters & Timmerhaus | s 5th Edition | This method of co |
| Total Purchased Equipment Cost (TPEC) | \$52,683,115 | 100% | | | |
| Purchased Equipment Installation | \$20,546,415 | 39% | Percent of TPEC | 13% | % of TIC |
| Instrumentation and Controls | \$13,697,610 | 26% | Percent of TPEC | 9% | % of TIC |
| Piping | \$16,331,766 | 31% | Percent of TPEC | 10% | % of TIC |
| Electrical Systems | \$5,268,311 | 10% | Percent of TPEC | 3% | % of TIC |
| Buildings (including services) | \$15,278,103 | 29% | Percent of TPEC | 10% | % of TIC |
| Yard Improvements | \$6,321,974 | 12% | Percent of TPEC | 4% | % of TIC |
| Service Facilities | \$28,975,713 | 55% | | 18% | |
| Total Installed Cost (TIC) | \$159,103,006 | 3.02 | | | |
| Indirect Costs | | | | | |
| Engineering | \$16,858,597 | 32% | Percent of TPEC | 11% | % of TIC |
| Construction | \$17,912,259 | 34% | Percent of TPEC | 11% | % of TIC |
| Legal and Contractors Fees | \$12,117,116 | 23% | Percent of TPEC | 8% | % of TIC |
| Total Indirect | \$46,887,972 | 4.69 | | | |
| Project Contingency | \$41,198,196 | 78.2% | Percent of TPEC | 20% | % of TIC + IC |
| (Working Capital shown in DCFROR) | \$37,078,376 | | | | |
| Total Fixed Capital Investment | \$247,189,174 | 4.69 | | | |
| Non-depreciated Direct Costs | | | | | |
| Land | \$3,160,987 | 6.00% | Percent of TPEC | | |
| Total Investment (with Land) | \$287,428,536 | | | | |
| Lang Factor | 5.46 | | | | |

| | Total Capita | al Inv | vestment | | |
|---------------------------------------|---------------|--------|-------------------|----------------|----------------|
| | 2007 Dollars | | Peters & Timmerha | us 5th Edition | This method of |
| Total Purchased Equipment Cost (TPEC) | \$36,619,315 | 100% | | | |
| Purchased Equipment Installation | \$14,281,533 | 39% | Percent of TPEC | 13% | % of TIC |
| Instrumentation and Controls | \$9,521,022 | 26% | Percent of TPEC | 9% | % of TIC |
| Piping | \$11,351,988 | 31% | Percent of TPEC | 10% | % of TIC |
| Electrical Systems | \$3,661,931 | 10% | Percent of TPEC | 3% | % of TIC |
| Buildings (including services) | \$10,619,601 | 29% | Percent of TPEC | 10% | % of TIC |
| Yard Improvements | \$4,394,318 | 12% | Percent of TPEC | 4% | % of TIC |
| Service Facilities | \$20,140,623 | 55% | | 18% | |
| Total Installed Cost (TIC) | \$110,590,330 | 3.02 | | | |
| Indirect Costs | | | | | |
| Engineering | \$11,718,181 | 32% | Percent of TPEC | 11% | % of TIC |
| Construction | \$12,450,567 | 34% | Percent of TPEC | 11% | % of TIC |
| Legal and Contractors Fees | \$8,422,442 | 23% | Percent of TPEC | 8% | % of TIC |
| Total Indirect | \$32,591,190 | 3.91 | | 0.2 | |
| Project Contingency | \$28,636,304 | 78% | Percent of TPEC | 20% | % of TIC + IC |
| (Working Capital shown in DCFROR) | \$25,772,674 | | | | |
| Total Fixed Capital Investment | \$171,817,824 | 4.69 | | | |
| Non-depreciated Direct Costs | | | | | |
| Land | \$2,197,159 | 6.00% | Percent of TPEC | | |
| Total Investment (with Land) | \$199,787,656 | | | | |
| Lang Factor | 5.46 | | | | |

Table A.19 Hydrogen Purchase Detailed Capital Investment Analysis

.15 Equipment Cost and Description

Table A.20Equipment Costs for Fast Pyrolysis and Bio-oil Upgrading with
Hydrogen Production

| Number Required | Number Spares | No. Req. Variable | Area | Equipment Name | Equipment Type | Equipment Cost | Total Equipment Cost (with spares) | Installed Cost |
|-----------------|---------------|-------------------|--------------|-----------------------------|----------------|-----------------------|------------------------------------|--------------------------|
| 1 | 0 | 1 | Upgrading | Liquid/Gas Fuel Separator | DVT CYLINDER | \$283,200 | \$283,200 | \$855,264 |
| | - - | | Upgrading | Bio-oil Separation Vessel | DVT CYLINDER | \$145,100 | \$145,100 | \$438,202 @007_704 |
| - | | 77 0 | Upgrading | Kerorning Bio-ou Pump | DOP CENTRIF | \$47,0UU | \$93,200 | \$251,5U4 |
| | | 77 0 | Upgrading | Hydroprocessing Pump | DUP CENTRIF | \$114,200 \$45 700 | \$226,400 | \$089,708 6964.146 |
| | - | 77 - | Upgrading | Ketorming Water Pump | DCP CENTRIF | \$48,700 | \$97,400 | \$294,148 |
| - | ∍ - | | Upgrading | Hydrotreater/hydrocracker | DAL REACIOR | 0.0797700 | \$329,700 | \$995,094 ©4.455.700 |
| | - - | 4 6 | Upgradung | Deferming Water Heater | DHE FLOAT HEAD | \$941.100 | 00540145140 | 04,400,100 ©1 456 944 |
| + | - | 4 0 | Upgradung | hidrogen Coder | DHE FLOAT HEAD | \$500.300 | ©±02,200 \$1 108 600 | \$2,610,779 |
| - | - | 1 6 | Upgrading | Reformer Recycle Heater | DHE FLOAT HEAD | \$739.500 | \$1.479,000 | \$4.466.580 |
| | | ı — | Uperading | Catalvst Guard Bed | | \$827.815 | \$827.815 | \$2,500,000 |
| 1 | 0 | 1 | Upgrading | Reforming Steam/Water Sep | DVT CYLINDER | \$180,700 | \$180.700 | \$545,714 |
| 1 | 0 | - | Upgrading | Flue Gas Water Condenser | DVT CYLINDER | \$137,700 | \$137,700 | \$415,854 |
| 1 | 0 | - | Upgrading | hydrogen Compressor | DGC CENTRIF | \$2,015,500 | \$2,015,500 | \$6,086,810 |
| 1 | 0 | 1 | Upgrading | hydrogen Compressor 2 | DGC CENTRIF | \$3,655,600 | \$3,655,600 | \$11,039,912 |
| 1 | 0 | 1 | Upgrading | Pressure Swing Adsorption | DVT CYLINDER | \$76,300 | \$76,300 | \$230,426 |
| - | 0 | 1 | Upgrading | Bio-oil Reformer | DVT JACKETED | \$184,800 | \$184,800 | \$558,096 |
| - | 0 | 1 | Upgrading | Bio-oil Prereformer | DVT JACKETED | \$209,300 | \$209,300 | \$632,086 |
| - | 0 | 1 | Upgrading | Flue Gas Blower | EFN CENTRIF | \$214,700 | \$214,700 | \$648,394 |
| 1 | 0 | 1 | Upgrading | Flue Gas Combustor | EFU VERTICAL | \$2,800,100 | \$2,800,100 | \$8,456,302 |
| | | | | | | | | |
| 4 | 0 | 4 | Pyrolysis | Screw Feeder | ECO SCREW | \$162,500 | \$650,000 | \$1,963,000 |
| 1 | | 2 | Pyrolysis | Condenser Water Pump | DCP CENTRIF | \$669,700 | \$1,339,400 | \$4,044,988 |
| 1 | 1 | 2 | Pyrolysis | Bio-oil Condenser | DHE FLOAT HEAD | \$998,700 | \$1,997,400 | \$6,032,148 |
| 4 | 0 | 4 | Pyrolysis | Biomass Feeding Bin | DVT CONE BTM | \$41,400 | \$165,600 | \$500,112 |
| 1 | 0 | 1 | Pyrolysis | Electro-Static Precipitator | EDC ELC L VOLT | \$292,400 | \$292,400 | \$883,048 |
| 1 | 0 | 1 | Pyrolysis | NCG/Oil Separation | DVT CYLINDER | \$215,400 | \$215,400 | \$650,508 |
| | 0 | | Pyrolysis | Pyrolysis Vapor Cyclones | EDC CYCLONE | \$1,262,000 | \$1,262,000 | \$3,811,240 |
| 4 | 0 | 4 | Pyrolysis | Pyrolysis Fluid Bed | DVT JACKETED | \$836,000 | \$3,344,000 | \$10,098,880 |
| | 1 | , | | | | | | |
| | 0 | | Combustion | Char/Ash Feeding Bin | DVT CONE BIM | \$165,700 | \$165,700 | \$500,414 |
| | - | | Combustion | Screw Feeder | ECO SCREW | \$379,600 | \$379,600 | \$1,146,392 |
| | - | | Combustion | Water Softener System | 0 | \$1,858,000 | \$1,858,000 | \$5,611,160 |
| | 0 | | Combustion | Deaerator | C | \$223,000 | \$223,000 | \$673,460 |
| | 0 | _ | Combustion | Solids Combustor | DVT JACKETED | \$244,300 | \$244,300 | \$(3/,/80 |
| | | 2 | Combustion | BFW Pump | DCP CENTRIF | \$129,700 | \$259,400 | \$783,388 |
| 1 | | 2 | Combustion | BFW Heater | DHE FLOAT HEAD | \$2,543,600 | \$5,087,200 | \$15,363,344 |
| 1 | - | 2 | Combustion | BFW Preheater | DHE FLOAT HEAD | \$3,141,200 | \$6,282,400 | \$18,972,848 |
| 1 | 0 | | Combustion | Combustor Cyclones | EDC CYCLONE | \$1,104,700 | \$1,104,700 | \$3,336,194 |
| 1 | 0 | 1 | Combustion | Combustion Gas Blower | EFN CENTRIF | \$62,200 | \$62,200 | \$187,844 |
| | d | d | - - - | E | τ | 000 000 | 000 000 10 | @0.010.000 |
| 7 | • | 77 | Fretreatment | bale transport Conveyor | 5 | \$355,000 | 97,U00,UUU | \$5,219,520 |
| 2 | - | 77 | Pretreatment | Bale Unwrapping Conveyor | 0 | \$200,000 | \$400,000 | \$1,208,000 |
| | 0 | | Pretreatment | Discharge Conveyor | 0 | 000'29S | \$67,000 a #7 200 | \$202,340 |
| 1 | | | Fretreatment | Truck Scales | 5 0 | 000,040 | 040,000 000 000 | @006.050 @006.050 |
| 4 | | 4 | Prefreatment | Bale Moving Forklift | | \$24,000 | \$06.000 | \$280,920 \$280,020 |
| | 0 | · | Pretreatment | Concrete Storage Slah | 00 | \$600.000 | \$600.000 | \$1.812.000 |
| | 0 | | Pretreatment | Belt Press | 0 | \$133.000 | \$133,000 | \$401.660 |
| | 0 | | Pretreatment | Magnetic Separator | 0 | \$19,000 | \$19,000 | \$57,380 |
| 1 | 0 | 1 | Pretreatment | Biomass Chopping Screen | EVS ONE DECK | \$22,500 | \$22,500 | \$67,950 |
| 4 | 0 | 4 | Pretreatment | Rotary Dryer | ERD DIRECT | \$681,400 | \$2,725,600 | \$8,231,312 |
| - | 0 | 1 | Pretreatment | Biomass Grinding Screen | EVS ONE DECK | \$23,000 | \$23,000 | \$69,460 |
| 1 | 0 | 1 | Pretreatment | Steam Blower | EFN CENTRIF | \$803,300 | \$803,300 | \$2,425,966 |
| 1 | 0 | | Pretreatment | Grinding Hammermill | ECR HAMMER MED | \$302,200 | \$302,200 | \$912,644 |
| 1 | 0 | - | Pretreatment | Chopper | ECR HAMMER MED | \$302,200 | \$302,200 en | \$912,644 |
| 4 | 0 | 4 | Storage | Fuel Storage | DVT STOBAGE | \$469.800 | 00 \$1.879.200 | 35.675.184 |
| 1 | | 2 | Storage | Liquid Fuel Pump | DCP CENTRIF | \$24,300 | \$48,600 | \$146,772 |
| | | | | | | | | |
| 1 | 0 | - | Utilities | Cooling Tower | ECTWCOOLING WP | \$3,005,100 | \$3,005,100 | \$9,075,402 |
| | | | | | Totals | \$35,197,515 | \$52,683,115 | \$159,103,006 |
| | | | | | | | | |

Table A.21Equipment Costs for Fast Pyrolysis and Bio-oil Upgrading with
Hydrogen Purchase

| Installed Cost econ 762 | \$005,604 | \$2 500 000 | \$831 708 | \$1 906 788 | 00/12000 00/120000 | \$8,450,302 | 01000000 | \$1,963,000 | \$4,044,988 | \$6,032,148 | \$500,112 | \$883,048 | \$650,508 | \$3,811,240 | \$10,098,880 | \$500,414 | \$1,146,392 | \$5,611,160 | \$673,460 | \$737,786 | \$783.388 | \$15,363,344 | \$18,972,848 | \$1,972,966 | \$187,844 | | \$3,219,320 | \$1,208,000 | \$202,340 | \$135,900 | \$289,920 | \$289,920 | \$1,812,000 | \$401,660 | \$57,380 | \$67,950 | \$8,231,312 | \$69,460 | \$2,425,966 | \$912,644 | \$912,644 | \$1,503,356 | \$146,772 | | S119,665,732 |
|------------------------------------|------------------------------|---|--------------------------|--------------------------|-------------------------|--------------------|-------------|--------------|----------------------|-------------------|---------------------|-----------------------------|--------------------|--------------------------|---------------------|----------------------|--------------|-----------------------|------------|------------------|-------------|----------------|----------------|--------------------|-----------------------|---|-------------------------|--------------------------|--------------------|--------------|--------------------------|----------------------|-----------------------|--------------|--------------------|-------------------------|--------------|-------------------------|--------------|---------------------|----------------|--------------|------------------|-------------|--------------|
| Total Equipment Cost (with spares) | 02201±00 \$330.700 | 8023,100 \$827 815 | \$275.400 | \$420.400 | 012231200 00 000 100 | \$2,800,100 | 0.000 0.000 | \$650,000 | \$1,339,400 | \$1,997,400 | \$165,600 | \$292,400 | \$215,400 | \$1,262,000 | \$3,344,000 | \$165,700 | \$379,600 | \$1,858,000 | \$223,000 | \$244,300 | \$259,400 | \$5,087,200 | \$6,282,400 | \$653.300 | \$62,200 | ~ | \$1,066,000 | \$400,000 | \$67,000 | \$45,000 | \$96,000 | \$96,000 | \$600,000 | \$133,000 | \$19,000 | \$22,500 | \$2,725,600 | \$23,000 | \$803,300 | \$302,200 | \$302,200 | \$497,800 | \$48,600 | | \$39,624,415 |
| Equipment Cost | \$250.700 | \$877 815 | \$137 700 | \$91.4.700 | @0.000.1.00 | \$2,800,100 | 01 00 400 | \$162,500 | \$669,700 | \$998,700 | \$41,400 | \$292,400 | \$215,400 | \$1,262,000 | \$836,000 | \$165,700 | \$379,600 | \$1,858,000 | \$223,000 | \$244,300 | \$129,700 | \$2,543,600 | \$3,141,200 | \$653.300 | \$62,200 | | \$533,000 | \$200,000 | \$67,000 | \$45,000 | \$24,000 | \$24,000 | \$600,000 | \$133,000 | \$19,000 | \$22,500 | \$681,400 | \$23,000 | \$\$03,300 | \$302,200 | \$302,200 | \$497,800 | \$24,300 | a 10000 ang | \$25,609,715 |
| Equipment Type P.CD CENTRIE | DAT DEACTOD | DAL REACTOR | DVT CYLINDER | EFN CENTRIF | DET VOLVER OVE | EFU VERITCAL | | ECO SCREW | DCP CENTRIF | DHE FLOAT HEAD | DVT CONE BTM | EDC ELC L VOLT | DVT CYLINDER | EDC CYCLONE | DVT JACKETED | DVT CONE BTM | ECO SCREW | D | D | DVT JACKETED | DCP CENTRIF | DHE FLOAT HEAD | DHE FLOAT HEAD | EDC CYCLONE | EFN CENTRIF | | C | C | D | D | D | D | D | C | C | EVS ONE DECK | ERD DIRECT | EVS ONE DECK | EFN CENTRIF | ECR HAMMER MED | ECR HAMMER MED | DVT STORAGE | DCP CENTRIF | Ē | Totals |
| Equipment Name | Hidrofree for /hidrocroclear | Trydrou cater/ Hydrou acker Catalvst Guard Bed | Flue Cas Water Condenser | Fine Cas Riser Contenner | | Flue Gas Combustor | 1 | Screw Feeder | Condenser Water Pump | Bio-oil Condenser | Biomass Feeding Bin | Electro-Static Precipitator | NCG/Oil Separation | Pyrolysis Vapor Cyclones | Pyrolysis Fluid Bed | Char/Ash Feeding Bin | Screw Feeder | Water Softener System | Deaerator | Solids Combustor | BFW Pump | BFW Heater | BFW Preheater | Combustor Cyclones | Combustion Gas Blower | | Bale Transport Conveyor | Bale Unwrapping Conveyor | Discharge Conveyor | Truck Scales | Truck Unloading Forklift | Bale Moving Forklift | Concrete Storage Slab | Belt Press | Magnetic Separator | Biomass Chopping Screen | Rotary Dryer | Biomass Grinding Screen | Steam Blower | Grinding Hammermill | Chopper | Fuel Storage | Liquid Fuel Pump | | |
| Area | Upgrading | Upgradung | Unoradino | Uperading | UP8routing | Upgrading | - | Pyrolysis | Pyrolysis | Pyrolysis | Pyrolysis | Pyrolysis | Pyrolysis | Pyrolysis | Pyrolysis | Combustion | Combustion | Combustion | Combustion | Combustion | Combustion | Combustion | Combustion | Combustion | Combustion | | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Pretreatment | Storage | Storage | | |
| No. Req. Variable | - v | | - 6 | 7 6 | 4 - | - | | 4 | 2 | 2 | 4 | 1 | 1 | 1 | 4 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | - | 1 | | 2 | 2 | 1 | 1 | 4 | 4 | -1 | 1 | 1 | -1 | 4 | 1 | 1 | 1 | 1 | -1 | 2 | | |
| Number Spares | | | - | | - 0 | 0 | c | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | | |
| Number Required | - | | | - | | | | 4 | 1 | 1 | 4 | 1 | 1 | 1 | 4 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | 2 | 2 | 1 | 1 | 4 | 4 | 1 | 1 | 1 | 1 | 4 | 1 | 1 | 1 | 1 | 1 | 1 | | _ |

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