University of Alberta

Selection of a Biomass Processing Technology ©

by

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Abstract

The drive to use an increasing fraction of non-fossil renewable energy is growing around the world, to reduce the growth of greenhouse gases (GHG) in the atmosphere. Since there are many primary sources of renewable energy, e.g. wind, biomass, solar, and multiple end uses of the energy, e.g. transportation fuel and electricity, selections of appropriate sources, processing routes and end products are required.

In this study we take a major renewable energy resource, straw and corn stover (agricultural residues), and explore four processing alternatives to make two end products. Direct combustion with a conventional steam cycle and biomass integrated gasification and combined cycle (BIGCC) each produce electricity. Enzymatic hydrolysis and fermentation produces ethanol which can substitute for gasoline, while oxygen gasification and Fischer Tropsch processing produces a synthetic diesel that can replace conventional diesel fuel.

Biomass processes have an optimum size that results from the tradeoff between transportation and processing cost. The yield, optimum size, and processing cost are analyzed for each processing alternative. Life cycle assessment (LCA) is used to estimate the reduction in GHG emissions from each of the four processing schemes as compared to a "business as usual" case using fossil fuel. Cost and LCA emission data are then combined to calculate the required carbon credit subsidy, measured in dollars per tonne of avoided carbon dioxide equivalent, to have the biomass process earn a 12%

return on total capital investment. The criterion for process selection is minimum carbon credit. The selection between alternate end forms of energy, in this study electricity and transportation fuel, depends on the prices of oil and electricity.

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List of Abbreviations

AFEX	Ammonia fiber explosion
ATR	Auto thermal reformer
BIGCC	Biomass integrated gasification combined cycle
BOD	Biochemical oxygen demand
BP	British Petroleum
CERA	Cambridge Energy Research Associates
CFB	Circulating fluidized bed
COD	Chemical oxygen demand
DC	Direct combustion
DFC	Distance fixed cost
DVC	Distance variable cost
E_w	The energy required for the evaporation of water
EPA	Environmental Protection Agency
FT	Fischer Tropsch
GHG	Greenhouse gas
GREET	The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, created by the Argonne National Laboratory
HHV	Higher heating value
HRSG	Heat recovery steam generation
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change

LCA	Life cycle analysis
LHV	Low heating value
LPG	Liquid petroleum gas
MC	Moisture content
NREL	National renewable Energy Laboratory
ORNL	Oak Ridge National Laboratory
USD	United States dollars
USDA	United States Department of Agriculture
US DOE	United States Department of Energy

1 Introduction

1.1 *Purpose of Research*

Across the world a social consensus is emerging that actions are appropriate and required to reduce the human impact on the level of greenhouse gases (GHG). At different paces, countries are moving to reduce the amount of GHG emissions, with a particular focus on the contribution from fossil fuels (see, for example, US DOE 2007 and Environment Canada 2007). This has led to proposals for a huge variety of alternative energy projects and research, using different energy sources (e.g. solar, wind, and biomass) to produce different forms of energy (e.g. transportation fuels, heat, and electricity). (Note that alternative energy, renewable energy, and green energy are used interchangeably to describe new energy sources that have a substantially lower impact on GHG emissions than fossil fuel projects.) With rare exception alternative energy projects produce energy at a higher cost than from conventional fossil fuel projects. The incremental cost is supported by either a subsidy (a social payment from taxation) or from higher costs to consumers, who are often forced to pay the cost through a mandated target, e.g. 5% of transportation fuel being required to originate from carbon neutral sources, such as biomass. Whether the incremental cost is born by society at large through taxation, or by consumers through higher price, it is clear that at a societal level the actions to reduce the accumulation of GHG will come at an incremental cost.

There is a disturbing lack of knowledge of the relative cost of alternative energy, and in particular the cost relative to the reduction in GHG emissions. Projects are proposed based on their technical, or sometimes political, merits, and project proponents turn to government to either require consumers to purchase the output (through a targeted requirement for consumption) or a direct cash subsidy. A systematic exploration of the relative cost of energy from alternative sources is rare, and even rarer is a systematic analysis of the cost benefit of the incremental cost, i.e. the cost per unit of reduction of GHGs. Countries have promoted various alternative energy projects without a clear definition of the ultimate social cost (i.e. the incremental cost over the conventional technology) incurred to achieve the goal of GHG reduction. Since today alternative energy is a negligible part of the energy mix in almost all countries, the failure to understand the relative economics of GHG mitigation is not significant. However, as the contribution from alternative energy grows to a substantial portion of the overall energy mix, making cost effective choices will have a significant impact on the cost of energy, which ultimately is reflected in the cost of almost all goods. There is a danger of losing sight of the primary intention of alternate energy technology, which is to maximize the reduction of GHGs in the atmosphere for the lowest cost.

To illustrate this issue, consider straw and corn stover (the cobs and stalks left over after harvesting corn grain, having similar properties to straw), which can be turned into electricity via direct combustion (DC), into electricity via air gasification (called biomass integrated gasification and combined cycle (BIGCC)), into ethanol via enzymatic hydrolysis and fermentation (lignocellulosic ethanol), and into diesel fuel via oxygen gasification followed by Fisher Tropsch (FT) reaction of the syngas. Each of these alternatives is being proposed to governments for implementation, with subsidies. The United States has focused a tremendous research effort on the production of ethanol from corn stover, motivated not by GHG reduction but rather by reduction of oil imports. However, no previous study exists of the relative cost of these four alternatives, and in particular the incremental cost of these relative to fossil fuel alternatives, expressed as an incremental cost per unit of reduction of GHGs. The result of this is that governmental policy makers often make policy in a cost/benefit vacuum, without an understanding of how to best spend social dollars or achieve the lowest increase in energy costs. This is illustrated by the myriad of different policies that have emerged, often motivated by political lobbying. For example, in Canada the Province of Alberta is effectively supporting transportation fuel projects (see, for example, Permolex International LP 2007), while British Columbia focuses on power generation projects (see, for example, Kumar *et al.* 2008).

The purpose of this research is to develop and demonstrate a methodology for selecting renewable energy technologies to achieve the objective of the lowest social investment (incremental cost relative to a fossil fuel alternative) per unit of reduced greenhouse gas emissions. The methodology provides a transparent selection approach, outlining the social costs and environmental benefit. We illustrate the application of this methodology by taking one abundant biomass energy source, straw in Alberta, and performing a rigorous analysis of the cost of mitigating GHGs via the four processing alternatives identified above. As will be demonstrated below, the results are also applicable in areas that produce large amounts of corn stover; currently 90% of corn stover is left on the field to rot (PRA 2003). In general, agricultural residues are a significant mass of material. Data from Alberta suggest that 44% of total mass produced in grain production is straw (Kumar et al. 2003), and a Swedish study estimated that 40% of the total mass of crop production is residue (Borjesson and Gustavsson 1996).

The results of this analysis are novel and will provide critical information to both project proponents and to governments to help guide both research and project funding. The approach taken in this research can be extended in concept to other sources of lignocellulose in other areas, e.g. forest harvest residues (limbs and tops of trees from conventional forestry operations for pulp and lumber), and possible future purpose grown crops such as switchgrass. This study can also be extended to other alternate energy sources, e.g. wind or solar vs. biomass, since almost always a social payment is being made to achieve a social goal, GHG reduction, and calculating the cost vs. the benefit will be of value in deciding how to achieve the goal.

Straw is a residue from an abundant annual grain crop. It is accessible through an existing road infrastructure and has good yield in areas of high grain cultivation, both which make it more economical than forest harvest residues. Grain farmers already make a fertilizer pass over the field, so nutrient loss from straw recovery can be compensated for by increased dosage with no additional cost of application (further merits of straw are discussed in a later section). Straw is an annual abundant feedstock for energy conversion. Therefore, the objective of this research is to see how different alternative energy technologies compare in CO_2 reduction costs (in incremental cost per tonne CO_2 or its equivalent in other GHGs), as this is the key measure of the cost of green energy to society. This research demonstrates the variability of this measure among the chosen technologies for a model feedstock, and the impact of plant size selection on cost. What is novel is the integration of technological, economic, and environmental emissions for alternative energy technologies to bring them to a consistent comparative calculation of cost per unit of benefit.

One might envision other factors that define some perceived social good, for example, land use restrictions or energy independence. However, this study is focused on demonstrating a methodology for determining the lowest investment required for GHG reduction.

1.2 *Approach*

1.2.1 Methodology

Many decisions regarding renewable energy are based on insufficient cost information, much of which is based on small, uneconomic plant sizes. The methodology demonstrated in this thesis provides a thorough and transparent mechanism for selecting a renewable energy technology by minimizing social cost and maximizing GHG reduction, reflected in a minimum carbon credit. The methodology may be applied to many feedstocks and various technologies producing different products.

The production cost of the renewable technologies are determined by collecting the best publicly available information, and bringing the information to a consistent basis (outlined in Section 1.2.2). Once the processing cost is determined, the relevant feedstock costs, including purchase and transportation, are added to form a total production cost; for biomass, feedstock acquisition and transportation costs will be specific to a source of biomass. Recognizing the desire to reduce investment risk by reducing the capital cost, the appropriate plant size is not that corresponding to minimum production cost, but one corresponding to a production cost slightly higher (see Searcy and Flynn in press). The difference between the total production cost at the appropriate plant size and the wholesale pre-tax price of the conventional alternative form the numerator for the carbon credit. (For example, for direct combustion the conventional alternative would be power purchased from the grid.)

The denominator of the carbon credit is the avoided GHG emissions resulting from the replacement of the conventional fossil alternative with renewable energy, determined using the best publicly available information. For example, for direct combustion the conventional alternative used herein was supercritical coal power.

The technologies that minimize the carbon credit for each output (such as transportation fuels or power), are compared using a plot wherein the x and y axes are the conventional sale price for each alternative, and showing a line where the carbon credits for each technology are equal. Market conditions under which one technology is favored over the other are determined, keeping in mind the relative certainty of the information.

This process facilitates the determination of the appropriate plant size for each technology, and considers that different products have a different market value. Certain assumptions are region specific (for example, what the conventional alternative is, grid emissions, regional power price, feedstock type and cost, and transport cost), such that the best social decision can be made for a given location.

1.2.2 Economic Analysis

When using biomass as an energy source, there are three factors that have a strong impact on the cost of utilization: the end product (in this study power, diesel or ethanol), the technology of conversion, and the scale (Cameron *et al.* 2007). This study will consider the conversion technology and scale.

Capital costing was done based on a 25 year project life with a 12% rate of return on total installed capital cost for all options (corresponding to an annual capital recovery factor of 0.1275 times total capital cost). Processing costs were defined as the combination of annual operating and maintenance costs plus the annual cost of capital recovery. The processing cost per unit output decreases with increasing scale: it costs less to produce a unit output from a larger plant due to economies of scale. Equipment and operations costs from biomass size reduction and pretreatment to the final salable product were included. All costs were in 2006 USD, with conversions made from the Bank of Canada currency converter (2006) and the Federal Reserve Bank of Minneapolis inflation calculator (2006). Plants were assumed to have an availability of 90% (Wright and Brown (2007) and Yamashita and Barreto (2004) made the same assumption for renewable technologies), and annual maintenance costs were considered to be a percentage of total capital investment. Maintenance costs varied between technologies but a consistent number was applied in analyzing the data from different studies of the same technology. Inflation was not included, so values in this study are in constant purchasing value dollars. This does not affect a relative comparison of processing technologies since each alternative would be similarly affected by inflation. As well, it should be noted that the capital, maintenance and other operating costs are based on available data, in some cases studies for processes that have not been applied at a demonstration scale on a biomass feed. There is a higher level of confidence in cost estimates for power production by direct combustion, for example, than for BIGCC. This study incorporated data from a number of previous studies and data is often inconsistent between these studies, especially for technologies not in application today. As well, the previous studies were completed before a period of rapid rise in the cost of capital equipment over approximately the last five years. The result is a bias in this study towards low values for processing cost, and therefore the value of the carbon credits would also be biased low. However, as discussed in Section 7.6 this does not significantly bias conclusions about the relative economic merit of different processing technologies. Note that once a technology is identified for implementation, additional cost estimates of increasing detail would be required.

Processing costs were plotted to show the relationship between cost and capacity. Cost estimating identified a scale factor, the exponent for adjusting the cost of a system from one capacity to another $(\text{cost}_1=\text{cost}_2 \text{ x } \text{capacity}_2/\text{capacity}_1)^{\text{scale factor}}$. The scale factor was calculated from a best fit of multiple data sources and compared to expected values from literature on cost estimating (Park 1984; Hamelinck *et al.* 2003, 2004; Tijmensen *et al.* 2002; Kaylen *et al.* 2000; Wooley *et al.* 1999; Craig and Mann 1996; Larson *et al.* 2005).

Scale factors for processing plants, such as refineries or power plants, are less than 1 until very large plant sizes are reached. The consequence of this, as noted above, is the capital efficiency, as measured by a decreasing capital recovery cost per unit of output, increases with plant size, as shown in Figure 1.1. This effect is mirrored in operating costs, since annual maintenance cost is directly proportional to initial capital cost and operating labor for large plants is often little or no more than that for small plants. These effects are key in driving fossil fuel energy plants to be large size. For example, the size of power generation plants in western Canada is 400 to 500 MW, a size limited by grid stability issues rather than power generation economics. Still larger power plants have been built in Japan (Electric Power Development Company Limited 2000). However, in biomass plants there is an offsetting factor, in that delivered fuel cost increases with increasing plant size, because biomass is being transported from a larger draw area and transportation, often by truck, is a significant component of total delivered fuel cost. The competition between these two cost factors is illustrated in Figure 1.1, which also illustrates that total production cost for biomass plants often shows a relatively flat optimum as a function of plant size, with sharply rising costs at small scale and slowly rising costs at scales higher than the optimum size. For further discussion on optimum plant size for biomass energy conversion, see Searcy and Flynn (2008), Ghafoori *et al.* (2005), Jenkins (1997), Kumar et al. (2003), Larson and Marrison (1997), Nguyen and Prince (1996), Overend (1982), and Rodrigues *et al.* (2003).

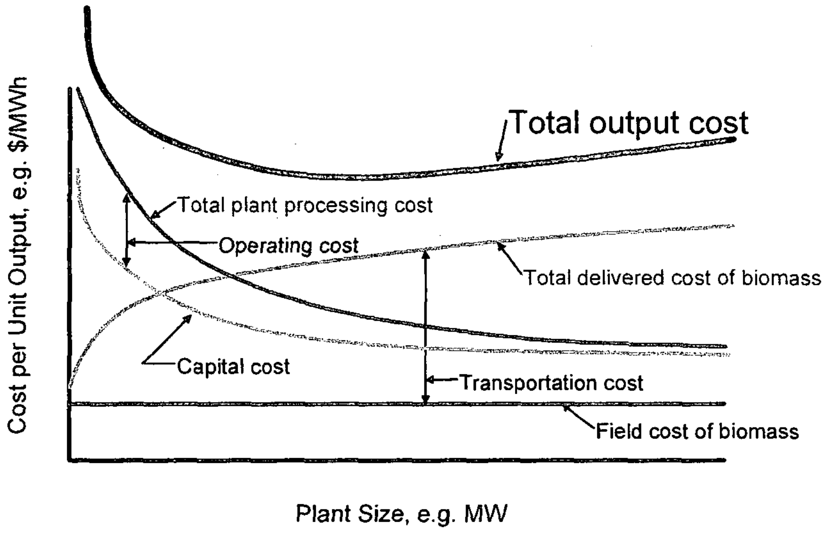


Figure 1.1. Relationship between cost per unit output and biomass-based energy plant size. Note that total output cost is a compilation of field cost of biomass (which may be negative if one is paid to remove the biomass, zero, or positive if one purchases the biomass from a farmer, for example), processing cost, and biomass delivery cost.

In Figure 1.1 the theoretical optimum size at which cost is minimized has a very flat profile. A detailed analysis of optimum size profiles showed that a 3% relaxation in the constraint of minimum cost, i.e. a total product cost of 1.03 times minimum, corresponded to a plant size of about 50% of the optimum size, but as plant size dropped below 50% product cost increased sharply (Searcy and Flynn in press). Note that the magnitude of the drop is specific to the biomass type and transportation cost. A higher transportation cost, lower biomass availability, and lower processing costs would be conducive to a sharper optimum, and therefore the 3% relaxation in minimum cost would correspond to a smaller drop in plant size (i.e. the plant size corresponding to 1.03 times the minimum production cost would be more that 50% the optimum size). In this study we evaluate processing technologies at the arbitrary target of 3% over theoretical minimum cost, and refer to this as "plant size", as compared to "optimum size". This reflects our belief that given the risk in developing a relatively new technology such as biomass processing, project developers would build a smaller plant with slightly less favorable economics rather than risk a larger amount of capital.

Note that most biomass plants to date have been built at small scale for three reasons: biomass supply may be limited, which is often the case with plants processing mill residues; secondly, many plants are for demonstration reflecting the uncertainty of the technology, and therefore economics are not the goal; and finally many projects are supported by public funds and the limitation on funding lowers the size selection (Cameron *et al.* 2007). Because the majority of historical plants are of smaller scale, most costs used in evaluating the economic potential of biomass energy are from estimates at larger scale rather than from existing plants.

In this study, transportation was assumed to be by truck reflecting the dispersed nature of biomass. The economics of transshipment are not compelling at the plant sizes in this study (Mahmudi and Flynn 2006, Kumar 2004). Truck transportation costs were made up of a distance fixed cost (i.e. the cost to load and unload the biomass, which are constant regardless of distance traveled) and the distance variable costs (the incremental cost per unit distance traveled). The formula for truck transport cost was drawn from Kumar *et al.* 2003 (and converted into 2006 USD):

$$\text{Transport Cost} = (\$0.140(\text{t km})^{-1} * (\text{distance traveled}) + \$5.13\ \text{t}^{-1})^{*}\ \text{dry t biomass}$$

where distance traveled was in km, and t biomass refers to the dry mass of biomass, as opposed to just the dry weight. The distance traveled was the collection radius for a given scenario, which depended on plant biomass requirements. For a more detailed discussion of transportation costs using various media, see Searcy *et al.* 2007.

Sale of electricity was considered as by-product revenue in the case of enzymatic hydrolysis, and the wholesale price of power was assumed to be \$60 MWh^{-1}. The cost of labor was assumed to be \$32.70 hr^{-1} (Kumar *et al.* 2003, adjusted to 2006 USD). Carbon capture and storage was not considered for any of the scenarios.

Historically biomass energy has had a higher cost than that from fossil fuels; however it brings the benefit of GHG reductions and using a feedstock that would potentially otherwise go to waste. An example of this would be the use of mill residues to generate power. The incremental cost was determined in this study by taking the total cost at a biomass energy plant size (which was a size where the production cost was 3% higher than that at optimum size), the delivered cost of feedstock, and the processing cost per unit output, and subtracting the cost of producing comparable output from fossil fuels. This incremental cost was divided by the social benefit, a reduction in GHG expressed as equivalent tonnes of CO_2, which gave the cost per unit benefit of the biomass technology. The carbon credit required to support a renewable energy process is calculated as a function of the cost of fossil derived energy, and two cases are tabulated in detail: a low case, with gasoline and diesel prices related to a \$65 bbl^{-1} oil price and a power price of \$60 MWh^{-1}, and a high case for a \$100 bbl^{-1} oil price and \$75 MWh^{-1}.

Cost estimates have an inherent uncertainty that is typically expressed as a percentage of the total estimated cost. This uncertainty is highest for new processes that have not been applied in multiple settings at large scale, such as Fisher Tropsch or BIGCC, somewhat lower for plants under construction at near commercial scale such as lignocellulosic fermentation, and still lower for technologies such as direct combustion that are in use processing biomass to generate electrical power. Previous studies have a range of estimated accuracy. Larson *et al.* (2006), Radian (1991), and Uddin and Barreto (2007) all report an accuracy of +/- 30% although Larson *et al.* and Radian have a far higher degree of definition of equipment. Hamelinck *et al.* (2003, 2004) had an even more highly detailed definition of equipment and also reported an accuracy of +/- 30%. Aden *et al.* (2002) developed a cost estimate based on a complete basic engineering package at a single plant size, and estimated the accuracy to be +/- 25%. Rollins *et al.* (2002) and Liscinsky *et al.* (2003) had less developed estimates but claimed an accuracy of +/- 20%. The Association for the Advancement of Cost Engineering (AACE), international recommended practice No. 18R-97 (1997), suggested an expected accuracy range for engineering estimates developed from equipment specification. Factors affecting the range included whether estimates are scaled from costs at a different size, and the degree of vendor input into the cost estimate. The lower end of the range of accuracy was given as - 20 to + 30%, and the upper end of the range was - 50 to + 100%. Given the very limited application of biomass energy in large scale projects, it is believed that the claims of estimated accuracy of 20 or 30% were optimistic, and that accuracies of 40 to 100% would be more reasonable, with the low end for direct combustion and the high end for FT. As noted above, recent increases in construction costs also impacted the accuracy of economic estimates (see Section 7.3 for further discussion). Note, however, that the objective of this research was to make comparisons between technologies. To the extent that cost elements are common between systems, for example feedstock receiving and handling, the inaccuracies between technologies would tend to cancel.

Several of the cost studies cited in this thesis used wood as a feedstock (for example, Hamelinck *et al.* 2003 and 2004, Yamashita and Barreto 2004, Wyman *et al.* 1999, and Wooley *et al.* 1999). Using straw as a feedstock would increase costs over using wood for various reasons, including increased handling costs and the presence of compounds that promote boiler and gasifier fouling. As this increase was not significant when considering the accuracy of the cost information used, there was no adjustment made to the costs.

1.2.3 LCA

GHG emissions from large scale biomass plants and "business as usual" fossil fuel plants were estimated incorporating data from a number of previous studies. In effect this is comparing existing processes to possible future technologies. Sheehan *et al.* (2004) studied the impact of uncertainty of future technology on LCA analysis and found that this only had a modest impact on the overall findings for projected CO_2 benefits.

It is not universally true that supercritical coal power generation is the likely future power production technology, although that is the case in Alberta (for example, a natural gas combined cycle plant may be more likely in an area rich in natural gas). If the business as usual technology were to have higher emissions than assumed in this study, the required carbon credit would decrease, and vice versa. As well, the use of straw as a feedstock may not be practical in some areas. Therefore when this methodology is applied to a different region, certain assumptions would be modified as appropriate. However, as is shown in Sections 3.8, 4.7, 5.7, and 6.6, large changes in the production emissions do not significantly change the value of the carbon credit. According to ISO 14040, there are 4 steps to a life cycle analysis: goal definition and scoping, inventory assessment, impact assessment, and interpretation (see, for example, Abbott *et al.* 2006).

1.2.3.1 *Goal Definition*

As was previously outlined, information from existing publically-available LCA literature was compiled for the determination of GHG emissions from the four predominant renewable energy technologies using biomass and their conventional counterparts. Steps included were the collection and production of the biomass/fossil fuel, its transport to the conversion facility, and its conversion to final product. Only carbon released from fossil fuels was considered to be released as CO_2 (discussed further below), and emissions common to all technologies were omitted. Emissions reductions from adopting the renewable alternatives versus the conventional technology that would otherwise be developed were used to calculate the GHG reduction. Therefore the decrease in GHG emissions of ethanol production were relative to an equivalent energy of gasoline production, FT syndiesel to petroleum diesel production, and both BIGCC and direct combustion to producing the same amount of power by supercritical coal combustion. The emissions from the production of conventional products (i.e. gasoline, diesel, and electrical power) were based on today's standards and production methods. As with cost estimates, the relative accuracy of emissions estimates varies based on the state of development of the technology, with values for FT processing being less certain, for example, than power production via direct combustion. Incremental cost and reduced emissions were combined to calculate the cost of carbon reduction, or the required cost to sustain a renewable technology expressed as a required carbon credit.

1.2.3.2 *Scoping*

LCAs require the use of a functional unit for comparison, e.g. a fixed energy amount of transportation fuel or a unit of electrical energy. The functional unit used for ethanol was one liter of fuel grade ethanol. Note that this approach was based on an assumption of an equivalent distance driven per unit of energy (LHV basis) in the fuel (Maclean *et al.* 2000), hence 0.66 L of gasoline has approximately the same energy content as one liter of ethanol. For diesel, the functional unit was one liter of syndiesel produced, since syndiesel has approximately the same energy content as diesel from petroleum (Laohalidanond *et al.* 2006; Abbott *et al.* 2006). For electrical power, one kWh was the functional unit for both direct combustion and BIGCC. Note that the operating life of all conversion facilities was considered to be 25 years.

Various types of emissions and environmental impacts can result from the life cycle of an energy processing facility. In this study, GHG emissions were the focus. Three major air emissions generally believed to make a long term contribution to global warming were included: CO_2, CH_4, and N_2O (Mann and Spath 1997, Furuholt 1995). Although water vapor is also a GHG and accounts for a substantial fraction of the GHG effect, it was not considered as it is believed to be short-lived in the atmosphere. There is some emerging research that suggests that water vapor concentration in the atmosphere is increasing due to human actions, however the studies are limited in number and breadth (for an example, see Santer *et al.* 2007). CO_2 emissions were described in terms of CO_2e, which is the weighted sum of CO_2, CH_4, and N_2O emissions considering their global warming potential. There is some scientific debate about precise equivalent values; the global warming potential numbers used in this study are shown in Table 1.1 and are consistent with IPCC Second Assessment Report (1996) and Alberta Environment (Spath *et al.* 1999, Alberta Environment 2007). $(S\&T)^2$ Consultants inc. *et al.* (2008) commented that for fuel combustion, CO_2 emissions generally far outweigh CH_4 and NO_x emissions, and therefore evolving minor changes in assumptions do not have significant impact on total CO_2e numbers.

Table 1.1. Characterization factors of several compounds.

Parameter	Characterization factor	Reference	$kg_{material}$ $kg_{reference}^{-1}$
CO_2	Global warming potential	CO_2	1
CH_4		CO_2	21
N_2O		CO_2	310

All LCAs for the conventional technologies included fuel extraction, and upgrading and refining in the case of diesel and gasoline, as well as any pipelining or truck transport involved. In the case of vehicle fuels, conversion of all carbon in the fuel to CO_2 was assumed (US EPA 2007). To calculate the CO_2 emissions from a liter or barrel of fuel, the carbon contained in the fuel was multiplied by the ratio of the molecular weight of CO_2 (44 g CO_2 mol^{-1}) to the molecular weight of carbon (12 g C mol^{-1}): 44/12. The study further assumed that differences in emissions of N_2O and CH_4 emissions from ethanol blend and gasoline engines were negligibly low (Beer *et al.* 2002, Sheehan *et al.* 1998, Furuholt 1995, IPCC 2006, $(S\&T)^2$ Consultants Inc. *et al.* 2008).

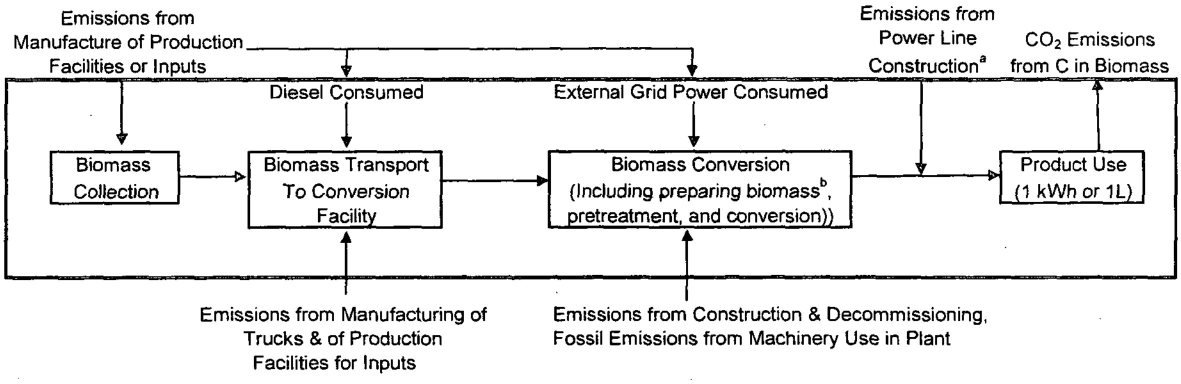
The biomass-based studies included feedstock processing, harvesting, and transport. Straw was considered to be carbon neutral when used as a feedstock for energy processing, as all carbon released from the straw during power production or fuel consumption was held in biomass. The biomass had absorbed the carbon from the atmosphere during its growth (see, for example, Lave *et al.* 2000). Therefore, only the CO_2 emissions resulting from fossil fuel consumption were considered.

The end point of the LCAs in this research was the product energy forms at the point of processing, i.e. the LCAs did not address product transport from the facility, and therefore transmission lines, pipelines, etc. leaving the plant were not included. Note that Tampier *et al.* (2004) found the effects of electricity distribution to be negligible.

The energy needed to manufacture and construct processing facilities as well as their decommissioning was not included, for two reasons. First, the energy used to produce the equipment for processing fossil fuels and for biomass can be assumed very similar. Second the energy throughput is two to three orders of magnitude larger than the energy contained in the facility, and was therefore negligible for the overall analysis (Tampier *et al.*2004, Mann and Spath 1997, Uddin and Barreto 2007). In the case of diesel and gasoline, exploration and drilling activities associated with fossil fuel discovery were not included; Tyson (1993) notes that the impact of these emissions was negligible.

Emissions from transport of biomass were specifically calculated, but are a small component of the overall LCA impact on emissions. Tampier *et al.* (2004) found the influence of biomass transportation distances to be small when looking at the entire life cycle of the plant. A threefold increase in distance traveled only raised the life-cycle energy consumption by 5 – 6% when producing ethanol from lignocellulosics (Tampier *et al.* 2004). Likewise, the impact on GHG was small; the largest impact being a 10% drop of the emission reduction benefits from switchgrass if the transport distance was tripled to 450 km. Schlamadinger (1997) summarized several studies and states that harvesting and transport of straw or logging residues usually makes up 4% of overall energy required for biomass energy systems. Increasing the distance from 50 km to 1000 km (mostly by ship or train) only raises this share to 7%. Similarly, Spatari *et al.* (2005) found transport emission for both corn stover (similar to straw) and switchgrass to be very low relative to total emissions.

Figures 1.2 through 1.4 show a summary of the general boundary diagrams for biomass energy conversion, crude oil conversion (i.e. gasoline and diesel production), and super critical coal power production, respectively. Note that only GHG emissions are shown, and system boundaries are indicated by the bolded line. System boundaries are drawn such to exclude items that would not have a significant impact on the outcome of the study, or they are approximately equal for all systems considered. By far the largest factor contributing to the difference in emissions between each renewable technology and its conventional alternative was the emissions from the consumption of the conventional alternative. Exclusions and uncertainty in factors within the boundary, such as emissions arising from processing, have a minor significance relative to substitution of a carbon neutral fuel for a fossil fuel. As a result, they do not significantly impact the relative results.



[a]Not applicable for FT syndiesel production
[b]*Includes drying, sizing, and cleaning where applicable*

Figure 1.2. Boundary diagram for biomass-based energy production

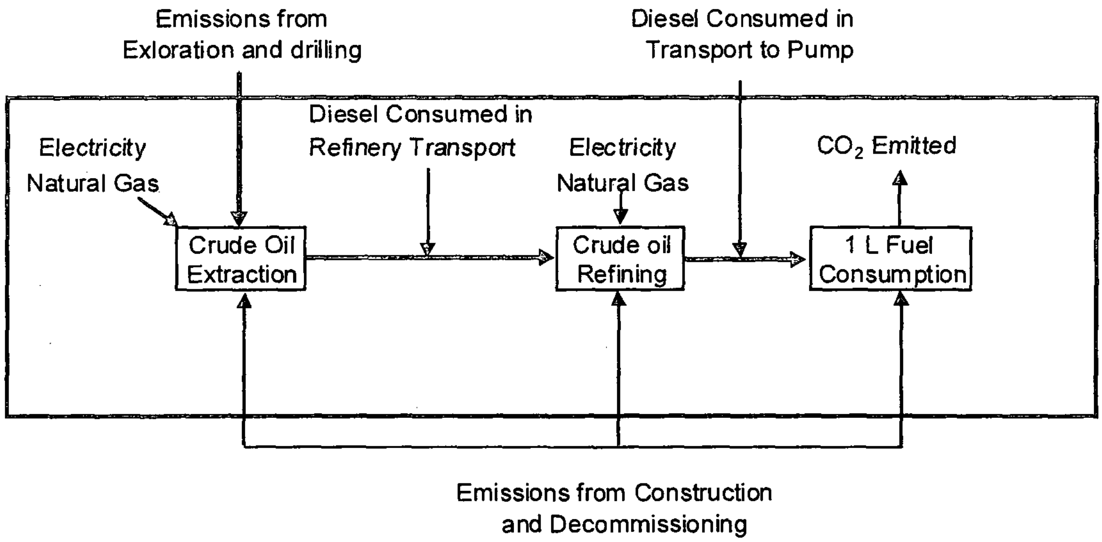


Figure 1.3. Boundary diagram for petroleum products (gasoline and diesel)

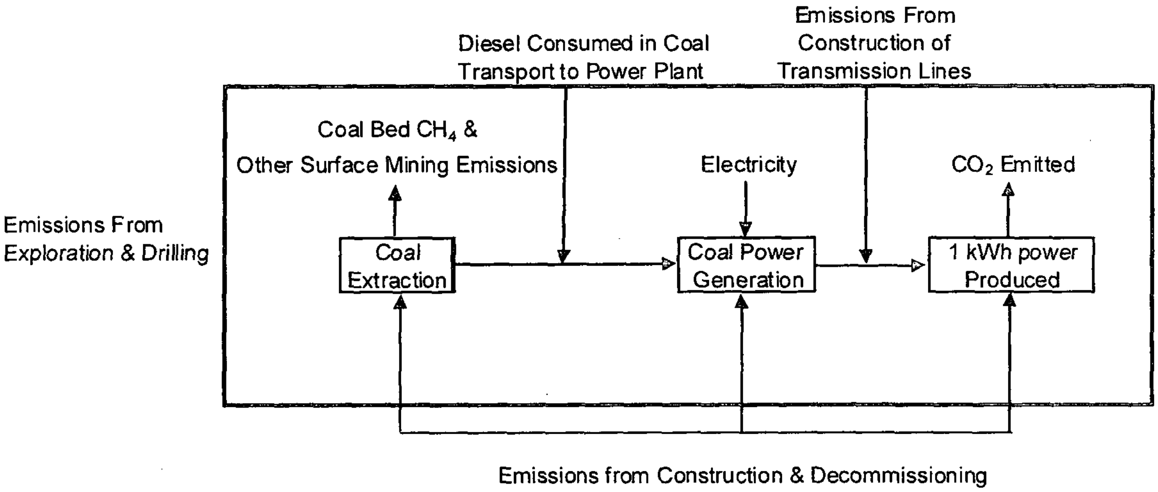


Figure 1.4. Boundary diagram for super critical coal power production

The impact of recovery of straw or corn stover on soil carbon levels was taken as zero in this study. Hartmann (1999) found no reduction in carbon level in black soils in western Canada after years of straw recovery. Other studies vary widely, from a loss of 4.5 to a gain of 40.3 Mg ha^{-1} for woodchips produced as an energy crop (Mann and Spath 1997), to no impact as reported by Henderson (2000) for agricultural residues. Studies that have shown that soil carbon can be increased through improved practices, including intensive cropping systems, reduced tillage, improved crop nutrition, and perennial vegetation have noted that the effect is variable and finite, i.e. soil carbon reaches a new level and stabilizes (Janzen *et al.* 2001, Grant *et al.* 2001, Izaurralde *et al.* 2001).

1.2.3.3 *Inventory Assessment (Sources of Data)*

As with cost data, emissions were drawn from a variety of publicly-available sources. In most cases where a level of certainty was given, the accuracy was cited as +/- 30%, reflecting the fact that most of the renewable processes have not been developed at a large commercial scale. According to the IPCC (2006), uncertainties for fossil combustion CO_2 emissions are relatively low; however there are intrinsic uncertainties in refinery and production emissions. The IPCC also comments that uncertainties are inherent in emission factors, and the degree of uncertainty is seldom known or accessible from empirical data. Details on the studies used in compiling emissions estimates are cited in Sections 3.3, 3.4, 4.3, 4.4, 5.3, 5.4, and 6.3. Where a process produces multiple products, e.g. oil refining, allocation of co-products by mass ratio is the most common method for assigning emissions, and was cited in a number of the prior studies.

1.2.3.4 *Interpretation*

In this study the assessment of impact of emissions was limited to the relative impact on climate change of the four alternative technologies, as measured by the magnitude of

CO_2e emissions as determined by the emissions of the three gases noted above. A higher level of GHG emissions implied a higher impact on climate change.

1.2.4 Organization of Thesis

This thesis was organized into 8 sections as follows:

- *Section 1: Introduction*
  This section outlines the need and motivation for the thesis, and describes details of the economic and LCA approaches. The methodology is presented as well.
- *Section 2: Straw as a Feedstock*
  This section provides the physical characteristics and energy content of the feedstock used in this thesis. The consequences of removing the straw from the field rather than letting it rot in place are addressed. As well, emissions relating to the use out straw as a feedstock are presented.
- *Section 3: Ethanol Production via Enzymatic Hydrolysis*
  A technical description is provided and the total production cost at an appropriate plant size is presented. Emissions from the conversion of biomass to ethanol are combined with production and transportation emissions from Section 2 to get total production emissions. The incremental cost of ethanol over gasoline at various wholesale pre-tax oil prices is combined with the avoided emissions from using ethanol instead of gasoline to get a range of carbon credits. The sensitivity of the carbon credit to changes in various parameters is examined at a wholesale pre-tax oil price of \$65 bbl^{-1}.
- *Section 4: Diesel Production via FT Synthesis*
  A technical description is provided and the total production cost at an appropriate plant size is presented. Emissions from the conversion of biomass to syndiesel are combined with production and transportation emissions from Section 2 to get total production emissions. The incremental cost of syndiesel over conventional low sulfur diesel at various wholesale pre-tax oil prices is combined with the avoided emissions from using syndiesel instead of conventional low sulfur diesel to get a range of carbon credits. The sensitivity of the carbon credit to changes in various parameters is examined at a wholesale pre-tax oil price of \$65 bbl^{-1}.
- *Section 5: Power Production via Direct Combustion*
  A technical description is provided and the total production cost at an appropriate plant size is presented. Emissions from the conversion of biomass to power via direct combustion are combined with production and transportation emissions from Section 2 to get total production emissions. The incremental cost of power via direct combustion over supercritical coal power at various wholesale power prices is combined with the avoided

emissions from using straw as a power source instead of coal to get a range of carbon credits. The sensitivity of the carbon credit to changes in various parameters is examined at wholesale power price of \$60 MWh^{-1}.

- *Section 6: Power Production via BIGCC*
  A technical description is provided and the total production cost at an appropriate plant size is presented. Emissions from the conversion of biomass to power via BIGCC are combined with production and transportation emissions from Section 2 to get total production emissions. The incremental cost of power via BIGCC over supercritical coal power at various wholesale power prices is combined with the avoided emissions from using straw as a power source instead of coal to get a range of carbon credits. The sensitivity of the carbon credit to changes in various parameters is examined at wholesale power price of \$60 MWh^{-1}.
- *Section 7: Choosing a Processing Technology*
  The cost, emissions, and carbon credit results are summarized. The value of the carbon credit is plotted against the price of the conventional alternative to determine the conventional price at which the more efficient yet more expensive alternative is favored. Recent increases in capital cost are discussed, as are other factors influencing technology selection including changing the field cost of biomass, reducing dependency on foreign oil, and the level of technological development.
- *Section 8: Conclusions and Future Research*
  Conclusions regarding costs, emissions, and carbon credit are summarized, and opportunities for future research are discussed.

2 Straw as a Feedstock

Corn stover, which has properties similar to wheat straw, is a major untapped source of biomass in the US, having an annual production of 68 M dry t in the US as compared to 10 M dry t yr^{-1} of wheat (Perlack *et al.* 2005). Only 1% is used for industrial processing and 5% is used for animal bedding. The rest (approximately 90%) is typically plowed into the soil to eliminate weed seeds, insects, and diseases in the crop and reduce the threat of toxins in the subsequent corn crop (PRA 2003). Other residues include manure, cotton, oil seeds, tobacco, sugar crops, potatoes, beans, miscellaneous root crops, and small grain residues (including sorghum, barley, oats, and rice).

Canada is also a large source of agricultural biomass (Table 2.1). Agricultural residues produced in Canada are estimated to be approximately 17.8 M dry t yr^{-1}, the largest fraction being 7.49 dry t from wheat (PRA 2003). The largest concentrated source of field-based agricultural residues in western Canada is straw from crops such as wheat and barley. The straw is a by-product that is typically left on the field during straw/seed separation and is mostly left to rot on the field or in the soil tillage (Kumar *et al.* 2003). When recovered it is left as a windrow, which is then baled and transported to a storage site for further use such as animal bedding. Based on published yield data (Carcajou 1998), the Province of Alberta alone could support 2000 MW of power generation from currently uncollected straw (Kumar *et al.* 2003). According to Tampier *et al.* (2004), Alberta had 6,218,000 t yr^{-1} of straw available in 2002, a comparable figure.

Table 2.1. Summary of agricultural production in Canada from 2001 - 2005 (Statistics Canada 2006).

	2001	2002	2003	2004	2005
	Seeded area (kha)				
Field crops					
Wheat	10,950	10,678	10,662	10,399	10,125
Canola (rapeseed)	3,826	3,891	4,735	5,319	5,491
Barley	4,700	5,147	5,046	4,677	4,440
Oats	1,907	2,398	2,272	1,994	1,853
Flaxseed	671	692	744	728	841
Rye	181	159	246	280	225
Soybeans	1,081	1,030	1,050	1,229	1,176
Grain corn	1,294	1,299	1,264	1,184	1,124
Tame hay	7,663	7,697	7,532	7,482	7,316
Specialty crops					
Canary seed	170	287	250	356	190
Lentils	708	600	553	778	883
Sunflower seed	72	99	118	87	93
Mustard seed	165	289	339	316	212
Peas	1,343	1,296	1,303	1,388	1,365

Annual crops are generally quite variable in yield due to varying availability of nutrients and water (Perlack *et al.* 2005, Freyman *et al.* 1982). Agricultural records for six years for three districts in central Alberta with black soil showed a range of grain production per gross hectare (which includes all area, including non-straw land such as towns, highway infrastructure, and land used for other crops) from 0.42 to 0.81 dry t (Carcajou 1998). Straw production for these areas ranged from 0.75 to 1.05 units of dry straw per unit of as-delivered grain (Hartman 1999, Kumar *et al.* 2003). In this study average annual straw gross yield (yield per total area in a region) in Alberta was set at 0.31 dry t ha^{-1}, equivalent to an assumed average availability of 75% straw or 37.5% corn stover. This number compares to a gross yield value used in this study for corn stover in the US Midwest (Aden *et al.* 2001). Gross availability is the amount of the total straw or stover crop that is available to a biomass processing plant, which is affected by alternate uses, the need for straw/stover in soil preservation or amendment, and the willingness of the farmer to collect and sell the agricultural residue.

2.1 *Physical Properties of Straw*

Straw is a lignocellulosic material, a physical mixture composed mainly of lignin, cellulose bundles, and hemicellulose. Lignin's chemical and fuel properties are close to that of low-rank coal. It has a high heating value and is usually regarded as a fuel resource, but it is not primarily carbohydrates and is not a source of sugars for ethanol conversion. Hemicellulose, to which the lignin attaches to strengthen the cell wall, and cellulose are long chain polymers of pentose (five-carbon) and hexose (six-carbon) sugars found in the cell wall (Figure 2.1).

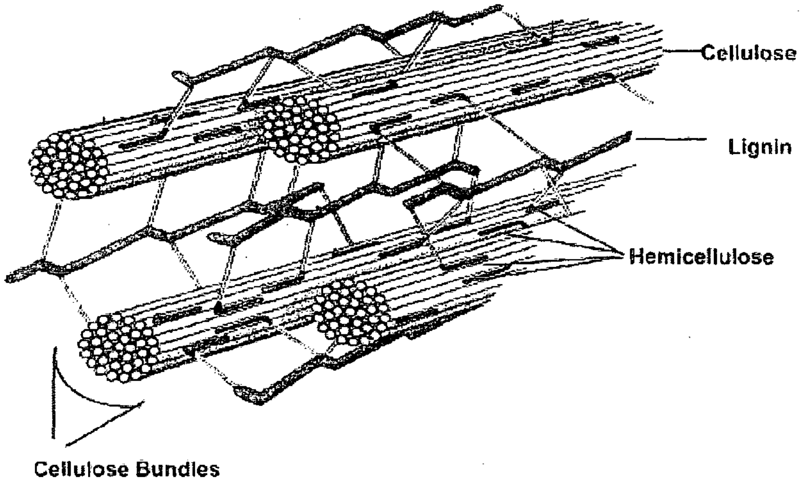


Figure 2.1: Typical cell wall arrangement (Murphy *et al.* 2005, reproduced with permission).

The bonds linking the sugar monomers together in the hemicellulose and cellulose polymers can be chemically broken by adding water to the bonds, a process called hydrolysis. Following hydrolysis, the sugars can be processed to produce ethanol or other products (Kaylen *et al.* 2000). Although there is some variation between varieties, wheat straw is made up of approximately 30 - 35% cellulose, 19 - 22% lignin, and 25 - 40% hemicellulose, with ash making up the remaining fraction (Demirbas and Demirbas 2003, Wright *et al.* 2005, Zanzi *et al.* 2002). Other lignocellulosic materials include switchgrass, native prairie grasses, and wood. Some properties of straw and other lignocellulosic materials are shown in Table 2.2.

Table 2.2. Biomass properties (Searcy *et al.* 2007).

	Straw	**Corn Stover**	**Woodchips from Forest Harvest Residues**
MC, %	15	15	45
Hydrogen content, wt %	5.46	5.46	6.08
Bulk density, dry kg m^{-3}	140	145	350
HHV, dry basis MJ kg^{-1}	18	18	20
LHV as is, MJ kg^{-1}	13.9	13.9	8.8
Gross yield, t yr^{-1}, gross ha^{-1a}	0.440	0.882	0.449
Gross yield, GJ ha^{-1}	6.12	12.25	3.95
Transport form	Bale	Bale	Chips

[a]Gross hectares refers to the total land area, including towns, roads, and other non-agriculturally productive area

2.2 *Energy Content*

The higher heating value (HHV) and lower heating value (LHV) of biomass tend to be significantly different because of the high moisture content of many sources of biomass. This often puts a large practical limit on the overall recovery efficiency, measured on an HHV basis, of all conversion technologies that produce water as a vapor since so much of the energy in the biomass is being used to evaporate water (Tampier *et al.* 2004). In this study we assume a 15% moisture content for straw/stover, with an HHV of 18.0 MJ kg^{-1} and an LHV of 13.9 MJ kg^{-1} at 15% moisture content (MC) (Table 2.2). The LHV and HHV are related according to the following equation:

$$LHV_{wb} = HHV_{wb} - E_w * (w_{wb}/100 + (h_{wb}/100 * m_{H2O}))$$

where $_{wb}$ is wet basis, E_w is the energy required for the evaporation of water (2.26 MJ kg^{-1} at 1.014 bar), w_{wb} (%) is the MC on a wet fuel basis, h_{wb} (%) is the hydrogen content on a wet fuel basis, and m_{H2O} is the weight of water created per weight unit of hydrogen. Energy values are in MJ and weights are in kg (van den Broek *et al.* 1995). At a MC above 87%, the LHV of straw becomes negative (Kumar 2004).

2.3 *Consequences of Removing Straw from the Field*

Factors relevant to the quantity of gross straw yield that is available for sale for utilization at a biomass processing plant are soil erosion, soil carbon levels, and soil nutrient levels.

2.3.1 Soil Erosion

It is commonly thought that erosion, whether from wind blowing dry soils or from water after heavy rain, is increased by the removal of agricultural residues. This can result in substantial and rapid loss of soil quality, with losses of subsequent production of as much as 25% or more if erosion is severe (Grant 2005). However, except in cases of highly sloped soils or unusually windy areas, straw cover on fields does not impact erosion control with proper stubble maintenance (for example, maintaining sufficient stubble height and using shelter belts such as trees, Saskatchewan 2001). An analysis of the effects of corn stover removal on soil erosion found that an average of two tonnes per acre of stover can be removed in Iowa without causing erosion rates to exceed the USDA's tolerable soil loss limits (Aden *et al.* 2002). Spatari *et al.* (2005) assumed that 62% of the aboveground corn stover was collected and 38% was left on the field to minimize soil erosion and therefore help in maintaining soil carbon. There is a high range of cited values for allowable availability rates of corn stover.

2.3.2 Soil Carbon Levels

Soil organic carbon is one indicator of soil health. As noted above, data on the impact of removing agricultural residue on soil carbon are variable and sometimes contradictory. Sheehan *et al.* (2004) found that it drops slightly in the early years of agricultural residue collection, but remains stable over the time frame of a 90-year study. The wheat roots in the soil add carbon, whereas the stubble removes carbon, although the removal is a small fraction of the total carbon in the soil. Kim and Dale (2005) found that corn stover removal could lower the accumulation rate of soil organic carbon but could also decrease N_2O emissions from the soil and reduce inorganic nitrogen losses due to leaching. However, a key study by Hartman (1999) demonstrated that repetitive straw recovery did not reduce soil carbon levels in black soils in western Canada. This may be because of the offset of carbon losses by contribution of residual stubble and roots to the soil. Therefore, soil carbon losses do not reduce the benefit caused by using the biomass for producing products or energy. Henderson (2000) had similar findings, and Mann and Spath (1997) found that in some circumstances soil carbon actually increases with straw or stover recovery, likely due to better diffusion of carbon into soil from the atmosphere. This study assumed the impact of changes in soil carbon to be negligible in the overall analysis, which is consistent with Spatari *et al.* (2005).

2.3.3 Nutrient Replacement

The decomposition of agricultural residues results in the return of some nutrients to the soil. Fertilizer containing similar nutrients is applied to grain crop fields. Removal of residues would increase the required rate of fertilizer application, but this can be accomplished by increasing the dosage rate, i.e. a second pass over the field is not required Hence the increased cost would only be the incremental cost of the extra fertilizer. Prairie soils are glacial till typically having an excess of calcium and trace minerals so nutrient replacement emissions are factored only for nitrogen, phosphorous, potassium, and sulfur (Kumar *et al.* 2003). It is not certain that all of the nitrogen and potassium in agricultural residues returns to the soil. Some of the nitrate in straw that sits on a field through the winter in western Canada is lost in the spring through microbial denitrification reactions (Hartmann 1999), and hence a payment to the farmer for all of the nitrate value in the straw more than compensates for the effective loss of nutrients from straw recovery. Estimation of the extent of nitrate loss through denitrification and quantification of the extent to which nitrogen is lost as N_2O rather than N_2 are areas of possible future research. In this study we assumed a total payment to the farmer of \$25 actual t^{-1} that covers the labor, equipment cost, fertilizer replacement cost and an additional payment of about \$5 dry t^{-1}, a value consistent with straw pricing in Alberta (Kumar *et al.* 2003). Table 2.3 summarizes the nutrient content in straw from various sources.

Table 2.3. Average nutrient content in straw, based on Alberta crops with 10% moisture (Hartmann 1999).

Crop	kg N t^{-1}	kg P_2O_5 t^{-1}	kg K_2O t^{-1}	kg S t^{-1}
Wheat	6	1.9	15	2.4
Barley	7.5	2	20	2.4
Oats	7	2	21	1.7
Peas	12	2.3	15	2.5

2.4 Emissions from Straw Production, Removal, and Transport to a Conversion Facility

Emissions from the production and harvesting of straw, and transport of straw per 100 km of driving distance to the conversion facility were considered identical for the alternative energy options. Therefore, production and harvesting emissions are presented per kg of dry biomass input and transportation emissions per kg 100 km.

2.4.1 Emissions from Straw Production and Removal

Mann and Spath (1997) calculated production and harvesting emissions for woodchips from energy crops; Tyson (1993) presents values for lignocellulosic material (trees, grass, and organic waste). Spatari *et al.* (2005) calculate these for corn stover in eastern Canada. The values from Spatari *et al.* (2005) are shown in Table 2.4; these values were used in this study based on the assumption that values for straw were comparable within the accuracy of this study on a per unit mass basis to corn stover. These numbers were essentially for residue collection, and account for emissions and energy use for residue collection and nutrient replacement resulting from residue removal. This assumption is not critical: as discussed below, both emissions from the production and harvesting of straw and from transporting straw have a minor impact in the overall comparison of emissions from fossil fuel vs. straw (European Council for Automotive R&D 2006, Spatari *et al.* 2005, Mann and Spath 1997, Tampier *et al.* 2004, Schlamadinger 1997, among others).

Table 2.4. Summary of air emissions from the production of 1 kg of corn stover, from Spatari *et al.* (2005).

Stressor	**Air Emissions (g kg biomass^{-1})**	**Equivalent Emissions (g kg biomass^{-1})**
CO_2	44.7	44.7
CH_4	0.14	2.95
N_2O	0.116	36.1
Total CO_2e (g kg^{-1} dry biomass)		*83.8*

The emission numbers presented in Table 2.4 include the production of process materials such as fertilizers, seeds, herbicides, fuel for operating agricultural machinery, and for machinery operation.

2.4.2 Emissions from Transport of Biomass to Conversion Facility

Emissions resulting from the transportation of biomass from the field to the processing facility are presented in Table 2.5 on a per km basis. All feedstock transportation was assumed to be by diesel truck.

Table 2.5. Summary of air emissions from the transportation of 1 kg of dry biomass to the conversion facility over 100 km (derived from Spatari *et al.* 2005).

Stressor	**Air Emissions (g kg biomass^{-1})**	**Equivalent Emissions (g kg biomass^{-1} 100km^{-1})**
CO_2	3.94	3.94
CH_4	0.0156	0.329
N_2O	0.00371	1.15
Total CO_2e (g kg^{-1} dry biomass 100 km^{-1})		*5.42*

The CO_2 emissions were nearly identical to that found by Tyson (1993), who calculated transport emissions for Portland, Oregon.

3 Ethanol Production via Enzymatic Hydrolysis

Presently, over 95% of ethanol produced in the US is from corn. The starch component of corn is relatively easily hydrolyzed to form sugars, which are converted to ethanol by bacterial fermentation. The two predominant conventional conversion methods (converting corn to ethanol) are wet milling and dry milling, the latter of which is the dominant method in North America (Shapouri and Gallagher 2005). Byproducts from corn fermentation are used as animal feed, and the overall economics of ethanol from corn depend on subsidies to grow corn and for the product ethanol, the value of whole corn as a human and animal feed, and the value of fermentation byproducts as animal feed. Some studies suggest that if corn ethanol production continues to grow the amount of byproducts will saturate the market and the economics of corn ethanol will become less economic than cellulosic ethanol (Maclean *et al.* 2004, McAloon *et al.* 2000). The cellulose in straw is far more difficult to convert to sugars compared to starch; typical processes will combine physical and enzymatic steps to hydrolyze cellulose (Solomon *et al.* 2007).

3.1 Technical Summary: Ethanol from Lignocellulosic Biomass

The basic process for converting lignocellulosic biomass to ethanol converts hemicellulose and cellulose to sugars by hydrolysis: water de-polymerizes the polysaccharides. The sugars are then converted to ethanol by bacteria. Lignin is not degraded, and it and unconverted solids can be recovered and used as a combustion fuel.

While the overall process concepts are simple, there are many technical challenges, and many alternatives for processing biomass to achieve a high yield at a low cost. This area is one of intense research and development. In North America and Europe many teams have worked on different processes, and more recently six projects at a commercial scale have been announced by the US Department of Energy, supported by substantial grants (US DOE 2007). In this section the process issues and some of the process alternatives will be identified.

All ethanol fermentation processes, and indeed almost all processes that use straw or corn stover for any purpose, begin with size reduction (see, for example, Aden *et al.* 2002, Hamelinck *et al.* 2003 & 2004, Wyman 1999, Yamashita and Barreto 2004, Larson *et al.* 2005). The one exception to this is in "cigar burning" boilers, in which whole straw bales are slowly pushed into a combustion zone (Bech 1995, Hulgaard 1990). Size reduction is usually achieved by chopping.

In straw cellulose fibers are sheathed in lignin, which creates a barrier to hydrolysis. Hemicellulose reacts more easily with water. To achieve a high conversion efficiency, a pretreatment step is included, to soften lignin and rupture cell walls, making the cellulose fibers more accessible for subsequent hydrolysis. Many pretreatment steps have been proposed, including AFEX (ammonia fiber explosion), mechanical grinding in water, treatment in water, treatment in dilute acid, alkaline hydrolysis, and treatment in strong acid (Sun and Cheng 2002). Some of these pretreatment steps initiate hydrolysis, e.g. the acid treatment steps, but conversion efficiency is sufficiently low that commercial processes normally include a subsequent saccharification step (Aden *et al.* 2002, Sun and Cheng 2002, Hamelinck *et al.* 2003).

The most common saccharification step uses enzymes to catalyze the de-polymerization of cellulose. Enzymes are a significant cost component of the overall process, and much research has been focused on reducing the cost of producing enzymes and reducing their deactivation in the process (Tampier *et al.* 2004, Pan *et al.* 2005, Gregg and Saddler 1996, Berlin *et al.* 2006). In addition to being high cost, enzymatic hydrolysis is also slow; there is a tradeoff between reaction time, which is longer, and efficiency of conversion, which is higher (Kaylen *et al.* 2000). For example, cellulose can be saccharified in strong acids at a faster rate, but the process must deal with corrosion and waste disposal problems, and the yield of ethanol per unit of biomass input is lower. On the other hand, the longer residence time for enzymatic hydrolysis increases the chance for contaminating organisms to grow during the saccharification step (McAloon *et al.* 2000).

The sugar solutions from the pretreatment step, primarily from hemicellulose, and the saccharification step, primarily from cellulose, are converted to ethanol through fermentation (note that not all of the sugars are converted). Nutrients and selected microorganisms are added to convert both C_5 and C_6 sugars to ethanol. Some processes take a side stream of sugars to both grow fermentation microorganisms and also produce the enzymes from other microorganisms, while others simply purchase these from suppliers (Levelton 2000). One area of active research focuses on achieving saccharification and fermentation in the same vessel (Aden *et al.* 2002, Wyman 1999, Hamelinck *et al.* 2003); all studies herein assume this technology is used.

The product of the fermentation step is referred to as "beer", and contains up to 15% ethanol (Aden *et al.* 2002). After fermentation, the ethanol is distilled from the beer. Ethanol forms an azeotropic mixture with water at about 96% concentration of ethanol. 4% residual water is too high for ethanol to be used as a vehicle fuel, so additional water is removed by molecular sieve to "break" the azeotrope, after which further distillation produces fuel grade ethanol at a purity of more than 99% (for example, Aden *et al.* 2002, Wooley *et al.* 1999, McAloon *et al.* 2000, PRA 2003). Distillation is energy intensive, and heat is required in the straw pretreatment step. Ethanol plants are highly heat integrated. The distillation bottom liquid (which contains all the unconverted insoluble and dissolved solids) can be dehydrated to form syrup, which is sent to the boiler.

System wastewater (such as evaporator condensate, boiler and cooling tower blow down, and cleaning water) can be treated by aerobic digestion in conventional waste water treatment, and by anaerobic digestion with methane/biogas from the later being sent to the combustor. Treated wastewater may be recycled to the process and therefore reduces the plant makeup water requirement (Aden *et al.* 2002, Shapouri and Gallagher 2005).

Non-fermentable solids, mainly lignin and other solids from distillation (residual cellulose compounds), which make up 30 - 38% of feedstock, and concentrated syrup from the evaporator and gypsum) can be filtered out, dried, and sent to the boiler where they can be combusted to produce steam and electricity for the plant. The boiler (which is more expensive than a conventional boiler) allows the plant to be self-sufficient in energy, reduces solid waste disposal costs, and plants of sufficient size can generate additional revenue through sales of excess electricity (Aden *et al.* 2002).

This study was based on the configuration shown in Figure 3.1.

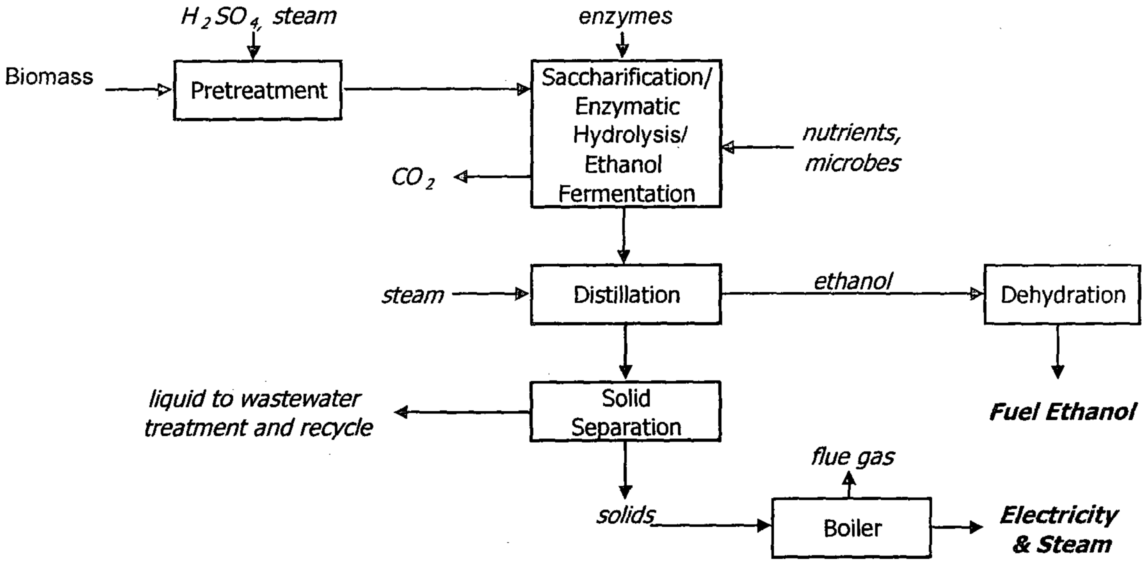


Figure 3.1. Schematic of enzymatic hydrolysis using simultaneous saccharification and cofermentation. Wastewater shown goes to wastewater treatment, and solids are filter pressed for dehydration prior to going into the boiler.

3.2 *Economics*

There have been several studies to determine the cost of producing ethanol from a variety of lignocellulosic feedstocks, including newspaper, trees, municipal solid waste, and agricultural residues (see, for example, PRA 2003, Energy Notes 2006, MacLean *et al.* 2004).

Six studies, discussed in detail below, examine the economics of ethanol production via enzymatic hydrolysis in plants that generate electricity from the combustion of residual solids, including the lignin fraction. The studies used different feedstocks, woody biomass and corn stover, although yields per dry tonne of biomass were comparable. The studies evaluated a common process, dilute acid pretreatment followed by enzymatic hydrolysis, and a common product, fuel grade ethanol, and all included utilization of byproduct lignin and residual other solids as a fuel. The sizes of the plants range from 952 to 4408 dry t d^{-1} of feedstock input, resulting in ethanol production ranging from 95 to 470 ML yr^{-1}, and all assume saccharification and fermentation occur simultaneously in one vessel.

The earliest of the six studies was that of Wooley *et al.* (1999) of the United States National Renewable Energy Laboratory (NREL), based on hardwood chips as a feedstock. Wooley *et al.* included design and cost details for each system component as well as futuristic scenarios that considered enzyme cost reductions and increased yields among other improvements and some opportunities for future developments. The ethanol yield is 20% on a dry mass basis with a feedstock input of 2190 dry t d^{-1} and an annual ethanol production of 198 ML. There have been advancements resulting in increased enzyme yield since the Wooley study was completed, and therefore this study was not used in subsequent analysis of the implied scale factor for ethanol production. The study by Aden *et al.* (2002), discussed below, reflects these advancements.

Wyman (1999) of Dartmouth College also based a study on wood chips, and reviewed the motivation for fuel ethanol, the history of ethanol production, and opportunities for improvements. The study scale was 1740 dry t d^{-1} of wood and yielded 220 ML yr^{-1} of ethanol. The yield is 27% on a dry mass basis. Wyman estimated the costing accuracy at +/- 25%.

As part of a US Department of Energy and US Department of Agriculture evaluation of corn and lignocellulosic ethanol, McAloon *et al.* (2000) compared the cost of ethanol from a corn dry milling plant and a corn stover plant, adjusting cost estimates for the corn stover plant to assume it was a mature technology. Both processing and capital costs were determined, and future markets for co-products for both ethanol processing routes were outlined. The processing cost was found to be about 60% higher for the enzymatic hydrolysis. The processing cost per liter of ethanol produced ($0.37) was found to be significantly higher than the other studies examined. The authors gave system costs for one size, 952 dry t d^{-1}, considerably smaller than the other lignocellulosic plant sizes studied, resulting in a larger capital cost per unit input/output. This size of plant yields an annual ethanol production of 94.6 ML based on a yield of 24% ethanol on a dry mass basis.

Aden *et al.* (2002) of NREL performed a detailed technical summary and cost analysis on one corn stover plant size of 2000 dry t d^{-1} producing 262 ML yr^{-1}. The study looked extensively at all aspects of producing the ethanol, assuming a 25% by mass yield of ethanol on a dry basis. The study includes feedstock production and collection with such details as the effect of plant size on collection distance and the cost of ethanol as a function of plant size. Plant size was not based on optimum size (lowest cost), but rather on an arbitrary limit on transportation distance of 50 miles/80 km. The study built an overall cost estimate from equipment component details, for which individual scale factors were given, and installation factors (the relationship of total installed cost to equipment cost). For the scale used in the study, the overall average installation factor is 1.61. The study also includes information on utilities; water, energy, and carbon balances; a sensitivity analysis; and opportunities for improvement. Costing accuracy was considered by Aden *et al.* to be +25 / -10%.

A study by Hamelinck *et al.* (2003) of The Netherlands' Universiteit Utrecht Copernicus Institute provided cost data for equipment for several alternative ethanol processes, including AFEX, alkaline hydrolysis, liquid hot water hydrolysis, dilute acid hydrolysis without the addition of enzymes, dilute acid pretreatment and enzymatic hydrolysis, and strong acid hydrolysis. The model was unique in that one could readily use the data to select a size, and then use tables provided to determine the system cost. A base investment cost was provided for a base scale of a component (which varied between components), and a scale factor such that one could size the equipment as desired. The scaled component cost was then multiplied by an installation factor to account for installation costs, and finally a maximum size was provided. Beyond the maximum size, the author considered that the scale factor no longer applied because a second unit would be installed. The study also presented three timeframes for the technologies, including short term (5 years), mid term (10 years, and the scenario used herein), and long term (20 years), each with varying yields and plant sizes. The model that was created for this paper requires the calculation of the energy fed into the system through the biomass, in effect based on the premise that any kind of lignocellulosic biomass can be processed with equal yield. Two scenarios, 2000 and 4408 dry t d^{-1}, were selected for presentation of results and the associated capital costs were calculated. The associated ethanol production was 213 and 470 ML yr^{-1}, respectively. The study includes a methodology for calculating ethanol yield as a function of the components of the biomass input; for straw or corn stover in an enzymatic hydrolsis process, the calculated yield on a mass basis is 25%; virtually identical values were calculated for a woody biomass feedstock. Costing accuracy was considered by Hamelinck *et al.* to be +/- 30%.

One group's work, that of Saddler, Mabee and co-workers of the University of British Columbia on the Organosolv process, was not considered in this study, because the work is in support of a proprietary process and cost data and process conditions are not in the public domain (Mabee *et al.* 2006, Gregg *et al.* 1998, Pan *et al.* 2006). Also, the process is designed specifically for softwood, which has different treatment requirements than hardwood.

A key step in this study was to manipulate the data from five studies to bring the data to a common and consistent basis, in order to allow a comparison of the studies and an analysis of the scale factor implicit from the various studies. All currencies were converted to a common basis: 2006 USD. The delivered cost of feedstock, which varies by region, was removed from all of the studies, to allow for comparison of processing cost. For studies that calculated US tax based on depreciation formulae, depreciation and tax were added back to calculate annual pre-tax operating cost. A common method of incorporating cost of capital was employed: 12% pre tax return on investment. A common operating factor was applied to all cases: a plant availability of 90%. A maintenance expense of 2.1% was applied consistently across all enzymatic hydrolysis studies, and was the average of all of the maintenance costs presented in the reports. Comparative analysis of the capital cost of sub-sections of the ethanol plant was not successful because different studies lump specific pieces of equipment into different groupings. One study, Hamelinck *et al.* (2003), provided highly detailed cost data for all major equipment; this was the only study that provided sufficient detail to allow cost estimates from a single study at multiple plant sizes.

Table 3.1 summarizes the results from this analysis of five studies.

Table 3.1. Summary of enzymatic hydrolysis economics.

	McAloon et al.	**Wyman et al.**	**Aden et al.**	**Hamelinck et al.**	**Hamelinck et al.**	**Wooley et al.**
Feedstock	corn stover	wood	corn stover	wood	wood	wood
Plant Feedrate (dry t d-1)	952	1741	2000	2000	4408	2191
Ethanol Production (ML yr^{-1})	94.6	219.5	262.3	212.7	468.7	197.6
Total Capital Investment (M)	$ 166,042	$ 218,875	$ 233,800	$ 218,017	$ 465,651	$ 294,588
Capital Recovery (M)	$ 21,170	$ 27,907	$ 29,809	$ 27,797	$ 59,371	$ 37,560
O&M + Cap Recovery (M)	$ 3,532	$ 51,506	$ 57,641	$ 50,427	$ 108,863	$ 63,418
(O&M + Cap Recovery)L^{-1} yr^{-1}	$0.37	$0.23	$0.22	$0.24	$0.23	$0.32
Excess Electricity Generated (kWh L^{-1})	0.73	N/A	0.6	0.73	0.73	0.47

Capital costs in Table 3.1 range from $166 to $466 million USD, and processing costs range from $0.22 to $0.37 L^{-1}. As would be expected, the largest processing cost was associated with the smallest plant size (McAloon *et al.* 2000). The remaining four studies included in this work, i.e. excluding Wooley *et al.*, all have a comparable processing cost, despite the Hamelinck *et al.* plant size being twice that of the other three. Most of the capital cost data presented in Table 3.1 is consistent with the estimates presented by Wright and Brown (2007), a range of $0.9 to $1.17 capital cost L^{-1} capacity with the exception of Wooley *et al.* (which was excluded from the study) and McAloon.

One critical element of any study of optimum size for biomass plants, where lower processing costs per unit of throughput compete with increasing feedstock costs as plant size increases, is an estimation of the impact of scale on capital and operating cost. The key component is the scale factor for the processing plant. Values from the studies vary. For the cost of capital only (i.e. equipment costs, not including installation), NREL reports a scale factor of 0.6 (Aden *et al.* 2002), with an earlier study reporting 0.7 (Wooley *et al.* 1999) for their enzymatic hydrolysis plant estimate. A Natural Resources Canada report ((S&T)^2 Consultants Inc. *et al.* 2004) suggested that scale factors may not apply to very large plant sizes. (S&T)^2 Consultants Inc. *et al.* did a curve fit for 19 dry mill corn ethanol plants built in the US between 1996 and 2004, ranging in production size from 44 to 190 ML yr^{-1}, and found a scale factor of 0.77 with a regression factor (an R^2) value of 0.96. Gallagher *et al.* (2005) similarly did an estimate of the scale factor for 20 US dry mill corn ethanol plants and found the scale factor to be 0.836. They commented that the scale factor in the chemical processing industry can range from 0.4 - 0.9. Kaylen *et al.* (2000) commented that the scale factor for ethanol from lignocelluslosic plants using dilute acid hydrolysis varies from 0.50 to 0.69, although they used 0.67 in their study. Nguyen and Prince (1995) found the scale factor to be 0.7 for Australian ethanol plants, and Wright and Brown (2007) presented a scale factor of 0.63 for cellulosic ethanol production.

Fitting the data from five studies (excluding Wooley *et al.* as noted above), as shown in Figure 3.2, gives an implied scale factor for this study of 0.62. This value is consistent with the range of scale factors typical of chemical processing plants, and with values estimated by individual studies. However, as might be expected from fitting data from different studies for non-commercial processes, the correlation coefficient is only 0.84.

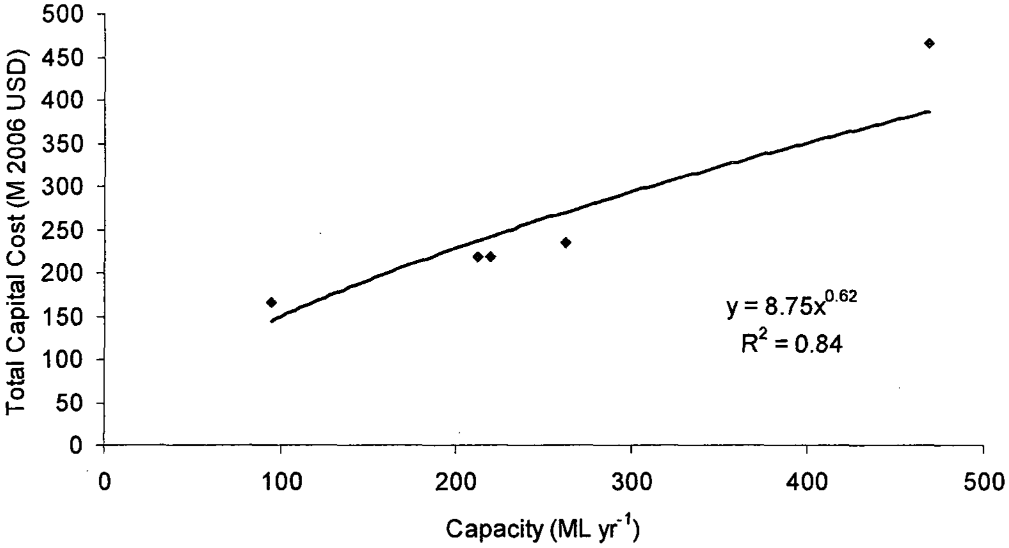


Figure 3.2. Relationship between total capital investment and annual ethanol production for enzymatic hydrolysis facilities.

The four studies, with two sizes calculated from the data of Hamelinck, were used to calculate a total processing cost, including capital recovery, maintenance, and operating costs. Operating costs were drawn from the specific studies. Annual maintenance costs were taken to be 2.1% of the total capital investment. The overall processing costs are shown in Figure 3.3 as a function of plant size; note that Figure 3.3 does not include feedstock cost. The best fit of the data in Figure 3.3 gives an overall scale factor for total processing cost of 1 - 0.31 = 0.69, which was rounded to 0.7. The correlation coefficient is not high, but again this reflects the diversity of data sources and assumptions between the studies. Overall, the best fit line from Figure 3.3 reasonably captures the cost results from the various studies, and this formula is used for subsequent comparison of ethanol production from straw compared to other processing alternatives.

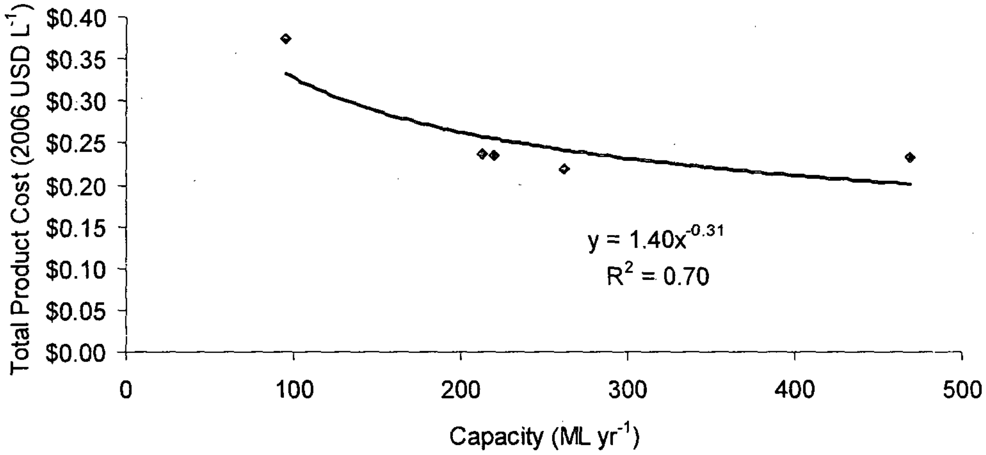


Figure 3.3. Relationship between unit processing cost and annual ethanol production from enzymatic hydrolysis.

3.2.1 Optimum Size of Plant

As noted above, any biomass based processing plant will have an optimum size that is specific to both the delivered cost of the feedstock and the cost of processing, including capital recovery. Biomass gross yield (in this case, 0.31 dry t $ha^{-1} yr^{-1}$) is a key factor affecting the delivered cost of biomass, because it determines the transportation distance for a given scale of plant. Kaylen *et al.* (2000) evaluated the optimum plant size for a lignocellulosic ethanol plant in Missouri using straw and woody biomass and producing large amounts of furfural as a second product. They found an optimum at 1.3 Mt yr^{-1} of biomass, producing 180 ML yr^{-1} of ethanol. The determination of the optimum plant size for the enzymatic hydrolysis scenario herein is shown in Figure 3.4.

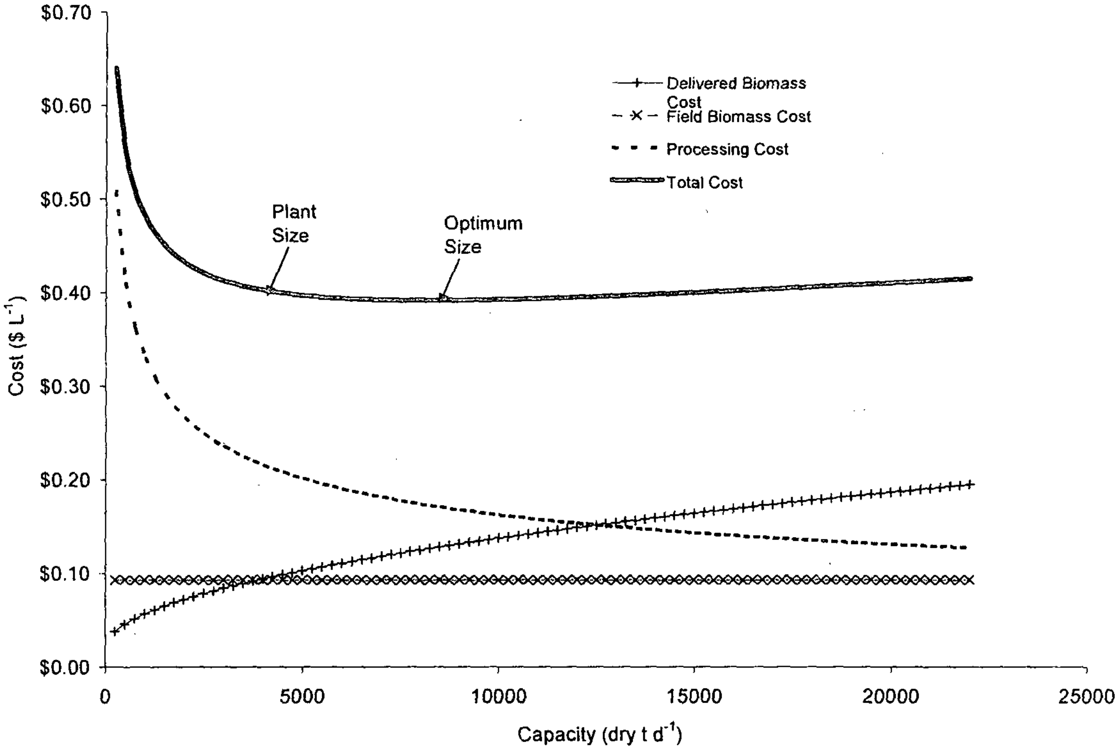


Figure 3.4. Determination of optimum plant size for enzymatic hydrolysis of straw.

From Figure 3.4, the technical optimum plant size for enzymatic hydrolysis is 8250 dry t d^{-1}. This size of plant corresponds to an ethanol production of 859 ML yr^{-1}, a collection distance of 203 km, and a cost of \$0.391 L^{-1} ethanol. However, the curve flattens out well before that point, and a smaller plant size was chosen. This reflects the expectation that an actual investor in a commercial ethanol plant would want to reduce capital investment (therein reducing risk), and would accept a less than optimum scale provided the cost impact was small. As discussed above, the criteria applied in this study is a product cost 3% higher than the theoretical minimum cost. At 4000 dry t d^{-1}, at which point on the total cost curve has almost plateaued, the total unit cost is 3% higher than the cost at 8250 dry t d^{-1}, \$0.22 L^{-1}. This size of plant corresponds to an ethanol production of 416 ML yr^{-1}, a collection distance of 152 km, and a transport cost of \$0.094 L^{-1}. The purchase (field) cost of straw available in bales with a moisture content of 15% is \$25 actual t^{-1}, or \$0.093 L^{-1}. Hence the overall production cost of ethanol at 4000 dry t d^{-1} is \$0.40 L^{-1}.

3.3 Lignocellulosic Ethanol GHG Emissions

The carbon contained in a lignocellulosic crop is not counted as making a net contribution to GHG emissions because the regrowth of the crop will remove the same amount of carbon from the atmosphere (see, for example, Wyman 1999, Levelton 2000, Sheehan *et al.* 1998, Spatari *et al.* 2005, Sheehan *et al.* 2004, Mann and Spath 1997, Larson *et al.* 2006). Hence, LCA analyses of carbon emissions can track lignocellulosic carbon, but if this approach is adopted this amount is then subtracted from emissions in calculating the net impact of the project. In effect, the contributors to GHG from lignocellulosic ethanol arise from the fossil fuel GHG emissions from recovering the crop, transporting it to the plant, using fossil fuels if any in processing it, and any net carbon emissions related to life cycle of the equipment used in these steps.

As discussed in Chapter 1, equipment related emissions, i.e. those associated with the construction and ultimate salvage of the ethanol plant and related field and transport equipment, are ignored, for two reasons. First, their impact is small relative to the impact of emissions arising from harvesting and transportation the crop (Mann and Spath 1997, Tyson 1993), which as will be shown below are themselves very small relative to the overall carbon displaced by using a renewable carbon energy source instead of a fossil fuel. Second, the construction of an ethanol plant, and, for example, the pipelines and trucks to deliver ethanol or ethanol blended fuel to its ultimate point of sale simply displace investment that would otherwise occur for fossil fuels.

3.3.1 Emissions from the Processing of Biomass to Ethanol

Tyson (1993) did a detailed analysis of emissions from a lignocellulosic ethanol plant using 1800 dry t d^{-1} of grasses and short rotation trees to produce 300 ML yr^{-1} of denatured ethanol and 17 MWe of power for export to the grid from combustion of the lignin fraction. Overall emissions of fossil CO_2e are very small compared to the CO_2e of the produced ethanol, 1940 g L^{-1} (Tyson 1993, Kadam 2002, and the European Council for Automotive R&D 2006). Tyson's values are shown in Table 3.2. Similar results were found by Spatari *et al.* (2005), Sheehan *et al.* (2004) and the European Council for Automotive R&D (2006). All these studies found CH_4 and N_2O emissions to be negligible, as did Beer *et al.* (2002), Sheehan *et al.* (1998) and Furuholt (1995). Kadam (2002) reported a similar value for CO_2 emissions for ethanol production from sugar cane, but a tenfold higher level of methane emissions, while Fu *et al.* (2003) showed CO_2 emissions about twice as high for the production of ethanol from balsam fir. MacLean *et al.* (2004) note that ethanol has many alternative production options (feedstocks and conversion processes), and therefore the precision of results for an LCA analysis is less precise than for gasoline. Note, however, that fossil CO_2 emissions from the production of ethanol are in the order of 1% of the value of CO_2 emissions from gasoline, so the uncertainty is not significant.

Table 3.2. Air emissions from the production of ethanol via enzymatic hydrolysis (Tyson 1993).

Stressor	Air Emissions ($g\ L^{-1}$ ethanol)	Equivalent Emissions ($g\ L^{-1}$ ethanol)
CO_2	26.9	26.9
CH_4	0.00272	0.0571
N_2O	0	0
Total Fossil CO_2e ($g\ L^{-1}$ ethanol)		*27.0*

3.3.2 Emission Credit for Export of Power

Ethanol plants that combust lignin and other residual solids produce more power than is used in the plant. Table 3.1 shows the net export of power per liter of produced ethanol for five studies of enzymatic hydrolysis ethanol plants.

In the Province of Alberta, grid average emissions are 761 g CO_2e kWh^{-1} (Tampier *et al.* 2004). However, a "must run" power plant associated with a processing plant is contributing base load power, and would have the effect of displacing future base load capacity, which in the Province of Alberta is supplied by coal fired power plants. Average emissions from a standard pulverized coal fired power plant are 987 g CO_2e kWh^{-1} (Kumar *et al.* 2003). The most recent technology for coal power plants in Alberta is supercritical boilers for which emissions are 90% of standard sub-critical pulverized coal boilers (EPCOR 2007).

Two studies have noted that fossil fuel emissions from a biomass power plant are very small relative to a coal fired power plant. Spath and Mann (2004) evaluated many cases of coal and biomass power, and cite that fossil fuel usage is reduced by 99% for a biomass power plant relative to a coal fired power plant. Kumar *et al.* (2003) note that a biomass power plant burning straw has fossil emissions of 5% of coal, but all of that comes from the production, harvesting and transport of the biomass; the amount arising from the power plant itself is negligible. Since the production, harvesting, and transportation emissions for the lignocellulosic ethanol plant have already been attributed to the ethanol in this LCA, the contribution of fossil emissions from burning lignin and other residual solids is negligible and can be treated as zero. Hence in this study renewable net base load power exported to the grid from a lignocellulosic power plant is credited with 888 g CO_2e kWh^{-1} arising from avoided emissions from a base load coal fired power plant. Emissions from biomass power plants are discussed in more detail in Section 5.3.

3.4 *Gasoline GHG Emissions*

As per the US EPA (2007) regular gasoline has a carbon content of 640 g L^{-1}.

CO_2 emissions from a liter of regular gasoline from consumption:

= 640 g C L^{-1} * (44/12) = 2,350 g CO_2 L^{-1} gasoline

These values are within 5% of the values found by $(S\&T)^2$ Consultants inc. *et al.* (2008) using GHGenius and GREET models.

3.4.1 GHG Emissions from Extraction, Transportation and Refining

Several studies have reported values for GHG emissions from extraction, transport and refining of petroleum products (Fleming *et al.* 2006, Furuholt 1995, Tyson 1993 (reformulated gasoline), Sheehan *et al.* 2004, $(S\&T)^2$ Consultants Inc. (2008) *et al.*, and Choudhury *et al.* 2002). Furuholt (1995) presented CO_2 emissions from the production of gasoline, however did not consider CH_4 or N_2O emissions. This omission is consistent with past studies which also found the impact from CH_4 or NO_x emissions to be negligible (Beer *et al.* 2002, Sheehan *et al.* 1998, Furuholt 1995). $(S\&T)^2$ Consultants Inc. *et al.* (2008) reported CH_4 and N_2O CO_2e emissions from gasoline production to be less than 3% of the emissions resulting from fuel combustion. As discussed below, the impact of specific refining process or gasoline type is not significant within the overall precision of the LCA (see Lewis 1997, for example).

Furuholt (1995) found the CO_2 emissions to be 200 g L^{-1} gasoline, and CH_4 and N_2O emissions to be negligible. Pierru (2007), Facanha and Horvath (2007), and Choudhury *et al.* (2002) found CO_2 emissions to be 180.8 g L^{-1} gasoline (using European numbers), 134.7 g L^{-1} gasoline (based on American data), and 455 g CO_2e L^{-1}gasoline, respectively. European Council for Automotive R&D (2006) found emissions from gasoline production in Europe to be 402.5 g CO_2e L^{-1}, while Hu *et al.* (2004) found gasoline production emissions to be 560 g CO_2e L^{-1}. Lewis (1997) found emissions from the production of gasoline to be 321 g CO_2 L^{-1}, 0.567 g CH_4 (which is negligible as compared to the CO_2 emissions), and N_2O to be negligible. The GHG emissions found by $(S\&T)^2$ Consultants Inc. *et al.* (2008) using GHGenius and GREET models gave an average of 292 g CO_2e L^{-1} for crude oil production, 460 g L^{-1} for crude oil refining, with a total of 750 g CO^2e L^{-1} gasoline. In this study we use an average value of these studies, 376 g CO_2e L^{-1}. Note that this value is small compared to the emissions resulting from burning the fuel (2350 g CO_2e L^{-1}). Table 3.3 shows average gasoline production emissions (including extraction and processing, crude oil transport, and refining).

Table 3.3. GHG emissions from the crude oil production (including extraction), crude oil transport to the refinery, and refining to produce regular gasoline presented in g CO_2 L^{-1} gasoline.

Stressor	Air Emissions ($g\ L^{-1}$ gasoline)	Equivalent Emissions ($g\ L^{-1}$ gasoline)
CO_2	376	376
CH_4	negligible	negligible
N_2O	negligible	negligible
	Total Fossil CO_2e ($g\ L^{-1}$)	*376*

3.5 *Fuel Equivalency and Net GHG Impact of Ethanol vs. Gasoline*

As noted above, there is no evidence that a vehicle 's travel distance will vary per unit of energy using ethanol as a fuel vs. gasoline; distance traveled is related to energy content of the fuel (Maclean *et al.* 2000). Values for gasoline, diesel, and ethanol are shown in Table 3.4.

Table 3.4. Energy densities (in LHV) of selected transport fuels (ORNL 2007).

Fuel	Energy Density ($MJ\ L^{-1}$)
Gasoline	32.0
Diesel	36.4
Ethanol	21.1

Based on these values, one liter of ethanol has the equivalent ability to propel a vehicle as 0.66 L of gasoline. Using this relationship, the net impact of using one liter of ethanol from straw vs. gasoline is shown in Table 3.5.

3.6 *GHG Emissions Summary*

Table 3.5. Summary of the net impact of using one liter of ethanol produced from straw to replace on liter of gasoline produced from fossil fuels, presented in g CO_2e L^{-1}. Note that 1 L ethanol = 0.66 L gasoline.

	Gasoline	**Gasoline * 0.66**	**Ethanol**	**Difference (Gas – Ethanol)**
Production & Harvesting of Biomass	NA	NA	264	-264
Transport of Biomass	NA	NA	26.0	-26.0
Extraction, Transport, and Refining of Oil	376	250	0	250
Production of Ethanol	NA	NA	27.0	-27.0
Consumption of Fuel	2,350	1,550	0	1,550
Production of Electrical Power	NA	NA	-576	576
Total	2,730	1,800	-260	2,060

From Table 3.5, consuming one liter of ethanol prevents 2,060 g CO_2e emissions from entering the atmosphere.

3.7 *Value of Carbon Credit Required to Support an Ethanol Plant*

The carbon credit is the ratio of incremental cost of producing lignocellulosic ethanol over producing gasoline, and the reduction in CO_2e emissions resulting from producing the ethanol over producing gasoline from fossil fuels. The value of the carbon credit required to support a straw ethanol plant with a return of 12% on total capital will decrease with increasing oil (and hence wholesale gasoline) prices. We define a low and high case corresponding to an oil price of \$65 and \$90 bbl^{-1}, and a wholesale pretax gasoline price of \$0.54 and 0.71 L^{-1}, respectively (using the model developed herein to find the corresponding gasoline price from oil price). In addition Figures 3.5a and b show the carbon credit as a function of gasoline and oil price. The low scenario led to a required carbon credit of \$22.2 t^{-1} CO_2, and the high scenario led to a carbon credit of -\$32.2 t^{-1} CO_2. Note that a negative value for the carbon credit means that the project can achieve more than a 12% return on capital with no social subsidy in the form of a carbon credit. Note that there is some uncertainty in any relationship between the price of crude oil and the price of gasoline since other factors also affect price, including local supply demand factors. See Appendix for further discussion.

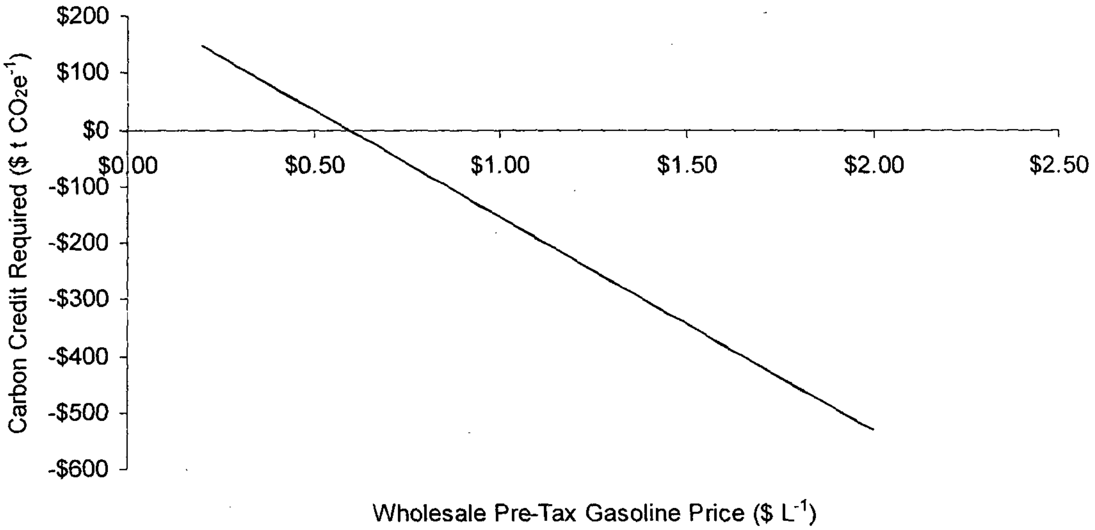


Figure 3.5a. Relationship between the wholesale pre-tax cost of gasoline and value of the carbon credit required for enzymatic hydrolysis of straw. Note that when the wholesale pre-tax cost of gasoline reaches \$0.61 L^{-1}, no carbon credit is required.

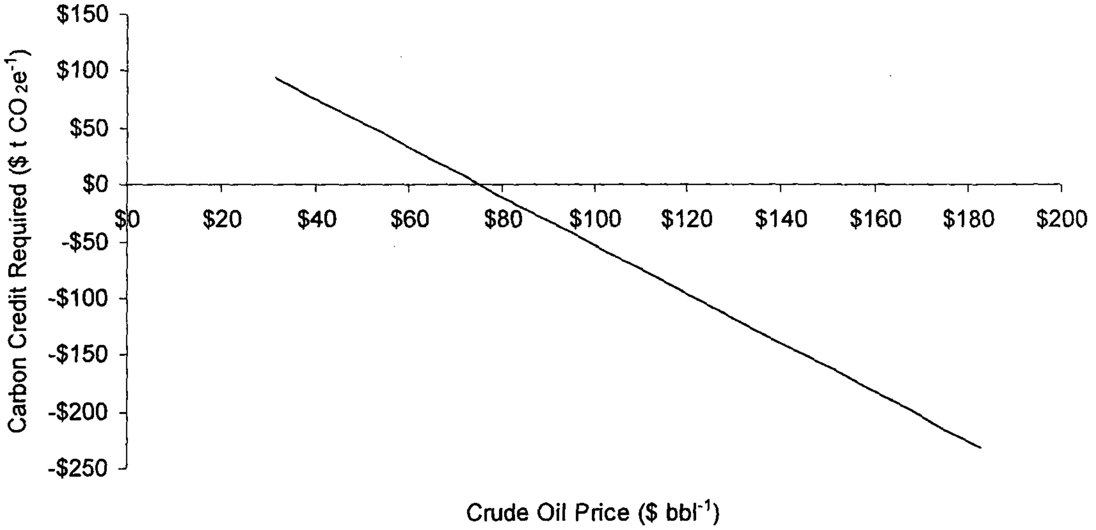


Figure 3.5b. Relationship between required carbon credit and crude oil price for ethanol. When the oil price is \$74.8 bbl^{-1}, there is no carbon credit required.

3.8 *Sensitivity Analysis*

Table 3.6. Impact of changing various parameters on the value of the required carbon credit for ethanol (\$ t^{-1} CO$_2$e), with the percentage change indicated below. The base case is for a plant size of 4000 dry t d^{-1}, with a biomass availability of 75% and a carbon credit from the low oil price scenario of \$22.2 t^{-1} CO$_2$. Note that the delivered cost of biomass is the sum of field cost and transport cost.

	Base Case	**-10%**	**+ 15%**	**+ 30%**	**+50%**	**+100%**	**+150%**
Field Cost of biomass	\$0.093 L^{-1} \$25 actual t^{-1}	17.7 -20%	29.0 30%	35.8 61%	44.9 102%	67.5 204%	90.2 306%
Transport Cost of Biomass	\$0.094 L^{-1} \$29.77 dry t^{-1}	17.6 -21%	29.1 31%	36.0 62%	45.2 103%	68.1 206%	91.0 309%
Delivered Cost of Biomass	\$0.187 L^{-1} \$54.77 dry t^{-1}	13.1 -41%	35.9 61%	49.6 123%	67.8 205%	113.4 410%	159.0 615%
Processing Cost	\$0.22 L^{-1} \$69.71 dry t^{-1}	11.7 -47%	38.0 71%	53.8 142%	74.9 237%	127.6 474%	180.3 711%
Wholesale Pre Tax Gasoline price	\$65 bbl^{-1} oil (approx.[a] gas price: \$0.541 L^{-1})	39.7 79%	-3.9 -118%	-30.0 -235%	-64.9 -392%	-152.1 -784%	-239.2 -1176%
Emissions from Production of Ethanol[b]	320 g L^{-1} ethanol	21.9 -1%	22.8 3%	23.3 5%	24.1 8%	26.3 18%	28.9 30%
Emissions from Gasoline Production[c]	376 g L^{-1} gasoline	22.5 1%	21.8 -2%	21.4 -4%	20.9 -6%	19.8 -11%	18.8 -15%

[a] Predicted with model

[b] Includes emissions from harvesting, biomass transport and conversion, and not including the electricity emissions credit

[c] Includes emissions from extraction, transport and refining

From Table 3.6 it is clear that the carbon credit is most sensitive to changes in gasoline price and processing cost. Given the recent high degree of volatility in oil price, it is very difficult to link a fixed carbon credit to the cost of producing lignocellulosic ethanol. This is compounded by the relatively high uncertainty in capital cost for a lignocellulosic ethanol plant, since no data is available from actual plants at commercial scale. It is important to update this type of calculation as more accurate data on ethanol plant processing cost is obtained, and a clearer picture of the long term oil price emerges. The certainty is improved, however, by several detailed cost analyses done for lignocellulosic ethanol plants.

LCA studies show some degree of variance in calculated emissions from the production of ethanol and the extraction, transport and refining of gasoline. Table 3.6 shows that this uncertainty has very low impact on the calculated required carbon credit. The low sensitivity to emissions emphasizes that it is not critical to invest enormous amounts of time in obtaining the utmost accuracy in emissions for the renewable alternatives.

4 Diesel Production via FT Synthesis

Syndiesel from biomass is a renewable transportation fuel usable in the present day transportation sector (Hamelinck *et al.* 2004). There is some imprecision in commonly used words for diesel fractions produced from biomass, from a variety of processes, e.g. syndiesel, biodiesel, bio-oil, pyrolytic bio-oil, and synthetic bio-oil. In this study syndiesel will mean hydrocarbons from C_9 - C_{20} produced from Fischer Tropsch (FT) synthesis. A synthesis gas, or syngas, is used in FT synthesis to produce liquid hydrocarbon fuels. In this study, we will examine the economics of and GHG emissions from producing the syngas from oxygen gasification of biomass, followed by passing the syngas through a FT reactor designed to optimize the production of diesel. A schematic of FT diesel production is shown in Figure 4.1.

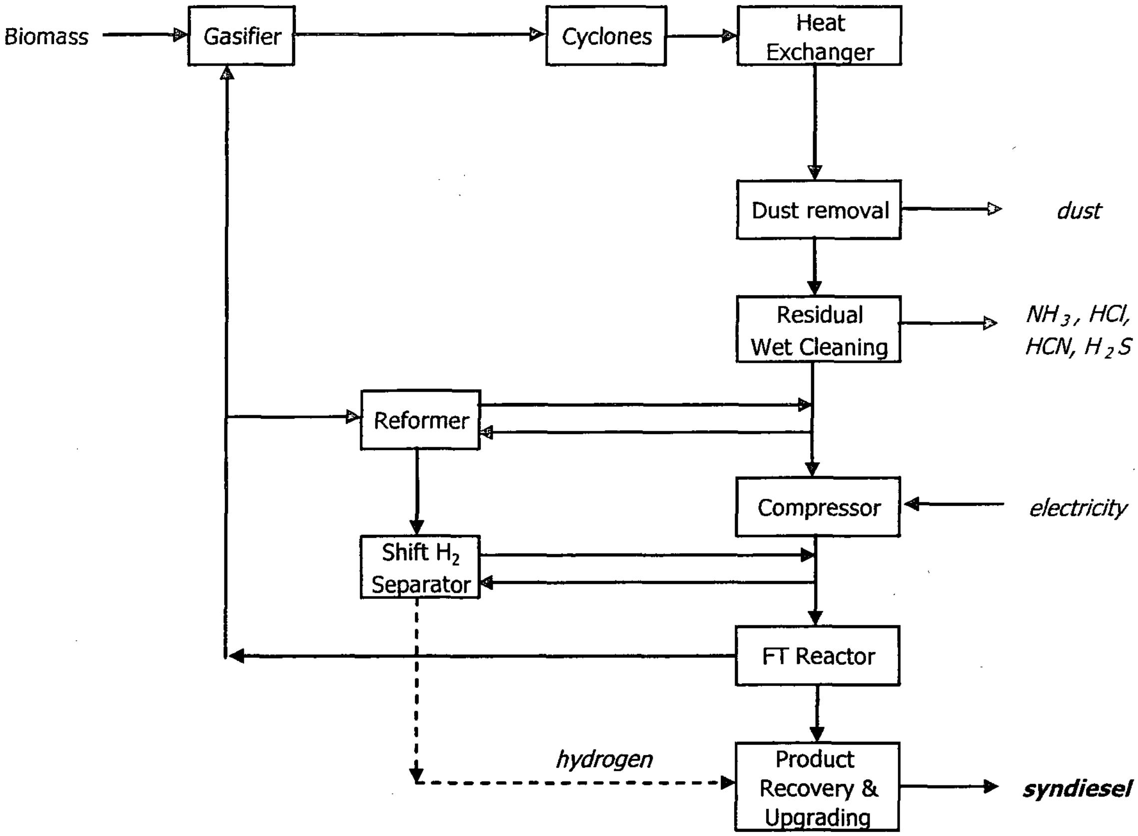


Figure 4.1. Schematic of FT diesel production modified from Hamelinck *et al.* (2004).

4.1 *Technical Summary*

The biomass is first pretreated which generally consists of screening, size reduction, magnetic separation of tramp metal, and drying if required (generally with steam, as significant amounts of low-quality steam are generated in the FT process, or with flue gas) to a moisture content below 15% (Rodrigues *et al.* 2006, Craig and Mann 1996, Tijmensen *et al.* 2002, Prins *et al.* 2004). The biomass is gasified to produce syngas composed of CH_4, CO_2, H_2O, H_2, and CO, of which the latter two are required for FT synthesis. The heat content of syngas is variable, and depends on variety and MC of the gas, as well as the gasification process used. When air is used to gasify a material, the resulting gas has a gross caloric value of 4 - 7 MJ Nm^{-3} (Rodrigues *et al.* 2006, Rollins *et al.* 2002, Craig and Mann 1996) and is called producer gas or low heating value gas. Syngas is based on using O_2 separated from air to produces a gas with a gross caloric value of 10 - 18 MJ Nm^{-3} (Tampier *et al.* 2004, Rao *et al.* 2004). The simplified FT reaction equation is as follows:

$$n\,CO + (2n+1)\,H_2 \Rightarrow C_nH_{2n+2} + n\,H_2O$$

The reaction is highly exothermic, and rapid removal of heat through heat exchangers is a major consideration in the design of suitable reactors to prevent fast temperature increases in the catalyst bed, which would increase production of undesired CH_4 and carbon deposition (Dry 1996, Prins *et al.* 2004).

There are many types of gasifiers, including fixed bed, bubbling bed, and fluidized bed (both static and circulating). Entrained flow gasifiers used to gasify finely pulverized coal have limited application for raw biomass because of the difficulty of pulverizing biomass, although Choren has applied these to process a gas, tar (condensable organic compounds) and ground char mixture from biomass (Kawulka 2007). Fixed bed biomass gasifiers encounter one of two difficulties, depending on whether they are updraft or downdraft. Updraft gasifiers in which the oxidant flows countercurrently to the solid achieve a high conversion rate but the gas has a high tar content that requires subsequent treatment, typically in a subsequent vessel called a tar cracker. Downdraft gasifiers in which the oxidant flows concurrently with the solid can crack tars in the hot bottom zone of the gasifier, but have a lower conversion efficiency since not all carbon is converted to gas, and there is a significant char fraction (see, for example, Balat 2008). Bubbling and fluidized bed gasifiers have high heat transfer and reaction rates, and hence can process a higher amount of biomass per unit of reactor volume, but they too must have a process to convert produced tars (Cifemo and Marano 2002, Hamelinck *et al.* 2004). Note that pyrolysis of biomass by thermal cracking, producing a vapor stream, is sometimes also referred to as a gasification process but does not involve oxygen; heat is usually provided by a circulating medium such as a sand stream that is reheated outside the reaction vessel (Tijmensen *et al.* 2002). Also note that in pyrolysis, the products of interest are the char and liquids produced, as opposed to the byproduct gas stream (Balat 2008).

Air compression and oxygen separation are expensive processes, and with one exception gasification processes intended to produce a fuel gas for subsequent combustion use air as the reactant. The one exception is where a process is intended for capture of carbon dioxide for subsequent sequestration (Mills 2006). However, in the case of FT processing of syngas, oxygen separation is economically justified because the lower volume of syngas, due to the absence of nitrogen, leads to smaller equipment (reactors and gas cleanup) downstream, and this more than offsets the cost of oxygen separation (Hamelinck *et al.* 2004, Hamelinck and Faiij 2001, Prins *et al.* 2004).

This study is based on atmospheric pressure gasification. An alternative is pressurized gasification, with more complicated systems to feed in solids to the reactor and a more expensive gasification vessel but less need for compression after the reactor. Also, atmospheric gasification decreases methane formation, which does not participate in syndiesel production and can therefore reduce overall selectivity to liquids (Prins *et al.* 2004). Biomass gasification has only been performed to date at pilot scale and the relative merits of pressure vs. atmospheric gasification are still under debate (Hamelinck *et al.* 2004, Tijmensen *et al.* 2002). Regardless of the pressure of the gasifier, gas cleanup is required to remove contaminants prior to the FT catalysts (Boerrigter *et al.* 2002). The reliability of hot high temperature vs. cold (wet) gas cleaning methods is also a matter of debate.

Once the contaminants are removed, the gas is processed to obtain an optimum ratio of H_2 to CO (generally about 2:1 H_2:CO, Prins *et al.* 2004) for FT synthesis to avoid hydrogen concentration being the limiting factor on conversion to hydrocarbons. A number of techniques can be used to modify this ratio (Yamashita and Barreto 2004, Wilhelm *et al.* 2001, Filippis *et al.* 2004, Boerrigter *et al.* 2002, Boerrigter and Zwart 2004, Tijmensen *et al.* 2002), including conversion of methane to hydrogen and CO_2 and the water gas shift reaction; both of these process steps were included in all of the studies referenced in this work.

An important parameter of FT synthesis is the chain growth probability, α, which is the probability that a hydrocarbon chain continues growing during synthesis. With a higher probability of chain growth, a higher amount of longer hydrocarbon chains are obtained in the process (Yamashita and Barreto 2004, Tijmensen *et al.* 2002, Prins *et al.* 2004), which is desirable. The selectivity depends primarily on the type of catalyst, the ratio of H_2 and CO in the gas fed to the FT reactor, temperature, pressure, and reactor type (Yamashita and Barreto 2004). The presence of non-reactive gases (CO_2, CH_4, N_2, light hydrocarbons) does not directly influence the selectivity, other than by decreasing the partial pressure of H_2 and CO and consequently decreasing the selectivity (Hamelinck *et al.* 2003). Although some studies looked at removing CO_2, its removal requires a lot of energy, and the increased energy use has been found to outweigh the increase in FT selectivity caused by removal of CO_2 (Prins *et al.* 2004, Yamashita and Barreto 2004).

There are many options for FT design. Plants can be designed to maximize liquid production by making high molecular weight hydrocarbons, with the longest being subsequently cracked to form transportation fuels. They can be designed to make liquids in a one pass system, with combustion of unconverted gases to produce power. They can be designed to produce liquids with a methanation step for unconverted gases, to produce pipeline grade natural gas, or to produce methyl tert-butyl ether (Tijmensen *et al.* 2002, Boerrigter *et al.* 2002). Three reactor types can be used, fluidized bed, fixed bed (the most common), and slurry (Larson *et al.* 2005, Tijmensen *et al.* 2002). Many catalyst types are available, with differences in cost and chain growth probability (Spath and Dayton 2003, Boerrigter *et al.* 2002, Dry 1996, Gradassi 1998). This study is based on a full conversion FT to maximize high molecular weight hydrocarbons, achieved by recycle of non-converted CO and H_2, with subsequent hydrocracking of FT product to form diesel fuel.

The hydrocarbon recovery plant recovers a C_{5+} naphtha, distillate, and wax fraction for further processing. The waxy part (C_{20+}) of the raw synthesis product is cracked to the desired middle distillate products C_{10-20}. Simultaneously, the product is treated to improve flow properties, and subsequently fractionated in a conventional distillation column (Hamelinck *et al.* 2004). Table 4.1 shows an example of the products retrieved from a FT reactor for a case where unreacted syngas is used to produce electricity, and another case where FT liquids production are optimized.

Table 4.1. Products (GJ GJ^{-1} biomass feed unless otherwise noted) retrieved from a FT reactor with $\alpha = 0.95$, cracking of wax, and unconverted syngas made into electricity (Larson and Jin 1999).

	Full Recycle	**Once Through**
kg syngas kg^{-1} biomass feed	0.932	
GJ syngas GJ^{-1} biomass feed	0.727	
Process electricity demand	0.0373	0.0251
Electricity produced (gross)	0.0373	0.197
Naphtha	0.125	0.067
Kerosene	0.246	0.132
Diesel	0.123	0.0658
Net hydrocarbon conversion	0.494	0.265
Overall HHV efficiency[a]	0.494	0.437

[a] Includes electricity production, less the biomass input in HHV that would be necessary to generate required electricity from a standalone IGCC power plant

The maximum size of a single biomass gasifier is a matter of debate. Hamelinck *et al.* (2004) cite 100 MW_{th} input as the maximum size of a single biomass gasifier. Nieminen (2007) presents a concern about operating stability and reliability for larger sized atmospheric gasifiers, and noted that gasifiers using oil as a feed are typically operating at pressure, which enables larger size. The Institute of Gas Technology and Batelle Columbus Laboratories have indicated that single vessel biomass gasifiers can be constructed with a capacity of up to 2000 dry t d^{-1}, over 400 MW_{th} input (Rodrigues *et al.* 2003). It is worth noting that single boiler coal fired power plants operate at atmospheric pressure at far higher thermal input rates (over 1 GW_{th} in Alberta, and over 2 GW_{th} in Japan), and one single boiler biomass power plant operates in Finland at a input of 550 MW_{th} (Flynn and Kumar 2005). In this study, when working with the data of Hamelinck *et al.* (2004) we incorporate that study's maximum single gasifier size of 100 MW_{th}, but we anticipate that larger biomass gasifiers can be built in the future.

It should be noted that syndiesel and petroleum diesel are not identical and have some different properties, in large part due to the tendency of syndiesel to form straight chains (see, for example, Greene 1999, Prins *et al.* 2004, Laohalidanond *et al.* 2006, Abbott *et al.* 2006). For example, syndiesel does not contain sulfur and has lower NOx emissions than petroleum diesel. However, the LHV for syndiesel and petroleum diesel overlap (ORNL 2007, Laohalidanond *et al.* 2006; Abbott *et al.* 2006), and syndiesel can be used in a conventional diesel engine (Hamelinck *et al.* 2004). Blending of FT diesel into the product from an existing refinery may reduce the need for treatment to achieve required diesel properties.

4.2 Economics

Costs for syndiesel production were derived from five separate reports. Estimates were based on the use of O_2 as an oxidant and direct-fired circulating fluidized bed gasifiers, with the exception of Yamashita and Barreto (2004) who used a bubbling fluidized bed gasifier.

The Hamelinck *et al.* (2004) study gave a list of system components with their respective base system cost, scale factor for the component (ranging from 0.6 to 1), the base scale, installation factor, and maximum size, if applicable, and numerous process variations were included. Options included gasification pressure (the FT reactor was assumed to be at 1.3 bar), oxidant (air, enriched air, or oxygen), power generation, and in optimization of FT liquids or towards a product mix of FT liquids and electricity (the former was chosen), as the system was selected to be consistent with other studies examined. The two facility sizes, 2000 and 4408 dry t d^{-1}, were selected to be consistent with the enzymatic hydrolysis studies previously examined. This study forecasted a 70% conversion efficiency per pass in the FT reactor, and included detailed technical information. The cited accuracy of the estimates is +/- 30%.

The Boerrigter and Zwart (2004) data is for very large-scale projects, intended for a centrally-located biomass conversion facility in Europe. This study gave component costing including minimum, expected, and maximum values for each component. The cost analysis was done based on the biomass throughput size noted in the report of 81,000 dry t d^{-1}. The authors had assumed that 55% of the syngas (C_1 - C_4) would be used to produce natural gas through methanation, under the assumption that co-production results in higher biomass-to-fuel efficiencies, lower biomass requirements, and more favorable economics. (Note that this study was intended to assess the feasibility of replacing 10% of Dutch natural gas consumption with synthetic natural gas and 10% of Dutch petroleum consumption with syndiesel.) Therefore, for this analysis the natural gas stream was eliminated and only the FT reactor and associated components were examined. Four different gasification options were presented, including pressurized, indirect, entrained flow, and atmospheric oxygen-blown CFB, the latter of which was used in the study. As this study was intended as a comparison of five different methods of generating transportation fuels and natural gas, the solids handling cost for each were considered to be equal and therefore not included. The solids handling costs would be a significant portion of the costs, and therefore that data was omitted from the determination of the scale factor.

Larson *et al.* (2005) produced an extensive study, including a detailed mass and energy balance, and component costing. Larson *et al.* outlined several production scenarios, including three FT cases, three dimethyl ether cases, hydrogen, and methyl acetate. We selected the FT scenario to be consistent with other reports studied. The size of the facility for the cost estimate for this study was selected based on a scenario detailed in the report. Some syndiesel yield information was extracted from Larson and Jin (1999), as the 2004 report had a large power generation component, which made yield calculations difficult. Larson *et al.* (2005) notes +/- 30% accuracy in economic data.

Yamashita and Barreto (2004) looked at FT production with the option of electricity co-production for the medium term, as well as the option of removal of CO_2 (either followed by sequestration or just removing CO_2 in an attempt to increase FT liquid yield). Scenarios presented include direct-fired gasification with either air or oxygen, and indirect-fired circulating fluidized bed gasification. The auto thermal reformer (ATR), which breaks down CH_4 emitted from the gasifier into H_2, CO, and CO_2 since CH_4 will not form higher hydrocarbons in the reactor, was optional. However, as it significantly increases the syndiesel yield, it was included for this analysis. Note that the study found the ATR to have a positive effect on the project economics. Yamashita and Barreto compiled the component costs from a variety of suppliers and studies. Not every information source contained costing information on each component, and certain components had more sources than others. The reference systems were of various capacities, and therefore to extract information for this study, the capacity was plotted against the component cost to achieve a scale factor, which was then used to cost the component for this report.

When component costs from Yamashita and Barreto (2004) were plotted and curve fitted, the component costs for the FT system do not yield consistent scale factors and one cannot make much sense of their randomness. However looking at the scale factors for the entire FT system, the values fall within the reasonable range expected of a refinery or power plant. The O_2 FT gasifiers do not tend to follow an exponential curve as expected, but this may be due to the limited size of the data set. The plant cost for air fed direct heated gasifiers are consistently higher than for indirect fed. The two Yamashita and Barreto facility sizes used, 2000 and 4408 dry t d^{-1}, were chosen to be consistent with the Hamelinck *et al.* (2004) study.

Bechtel Corporation conducted a study for the US DOE Federal Technology Center on eight FT production scenarios, each emphasizing different end products (i.e. diesel, gasoline, propane, butane, and/or natural gas) and various technologies (including liquefaction and co-production) and upgrading scenarios. The scenario selected was such to be consistent with the previous studies, and was considered by Bechtel to be the baseline case. Bechtel presented component costs for the FT diesel broken down into three areas: syngas production from coal (which was omitted), FT synthesis loop, and product upgrading and refining. Therefore, the component costs up to syngas cleaning were cleaved and calculated from another study, namely that of Mann (1995). Mann provided the component costing for gasifying biomass, and also included mass and energy balances. Three plant sizes were examined by Mann: 30, 300, and 1000 dry t d^{-1} of biomass, and the largest size was scaled based on the scale factor of 0.7, which was extracted from the report.

Choren is a German company, partially owned by Shell, that has developed a unique gasification process for biomass. The process generates tars and char in an initial gasification step, removes the char which is then ground, and the char dust is reinjected with the tar containing gas stream into a second entrained flow gasifier operating at very high temperature, in which all tars are cracked. Shell has expertise in Fischer Tropsch technology, and their process is used in a natural gas to liquids plant in Malaysia (Shell 2007). Choren is proposing a 1 Mt yr^{-1} biomass gasification and FT plant in Lubmin, Germany, with a projected construction commencement in 2008 (Kawulka 2007). Information regarding this project was limited due to confidentiality issues and appeared to be biased on the low end, and for both reasons was not included due to lack of detail.

Due to the variety of end products, including methane and electricity as well as FT gasoline and diesel, a significant amount of manipulation was required to bring the data from the five studies for which meaningful data was available to a common and consistent basis. As with the ethanol studies, all costs were restated in 2006 USD, the plant operating factor was set at 90%, and capital cost recovery was based on a 12% pre-tax return on investment. Feedstock costs were removed from each study to allow a calculation of processing cost. The annual maintenance cost was taken to be 3.0% of the total capital investment, which was the average maintenance cost found in the studies. Table 4.2 shows the cases developed in this study from the various data sets; two of the studies provided enough information to allow cost estimates to be prepared at more than one plant size.

Table 4.2. Summary of costing information sources for FT diesel production from biomass.

Author	Feedstock	Dry t d^{-1}	m^3 diesel yr^{-1}	No. passes	Catalyst	FT Reactor
Hamelinck *et al.* 2004	Wood	2000	160,000	Multiple	Cobalt	Gas/solids phase
		4408	350,000			
Yamashita & Barreto 2004	Wood	2000	160,000	Multiple	Cobalt	Gas/solids phase
		4408	350,000			
Boerrigter & Zwart 2004	Logs & forest residues	81,000	6,480,000	Single	Cobalt	Gas/solids phase
Larson *et al.* 2006	Switchgrass	4545	268,700	Single[a]	Iron	Slurry phase
Bechtel 1998 & Mann	Wood[b]	32,393	2,822,000	Multiple	Iron	Gas/solids phase
Choren 2007	Wood	2740	200,000	?	?	?

[a] The slurry phase reactor is designed to have high efficiency (80% conversion) over a single pass.

[b] Dried to 11% moisture using low pressure steam

Table 4.3 shows a summary of results from the analysis of the five studies.

Table 4.3. Summary of FT capital cost and processing data.

	Hamelinck et al.	Yamashita et al.	Hamelinck et al.	Yamashita et al.	Larson et al.	Bechtel & Mann	Boerrigter & Zwart	Choren
Feedstock	Wood	Wood	Wood	Wood	Switchgrass	Wood	Logs & forest residues	Wood
Feedrate (dry td^{-1})	2000	2000	4408	4408	4545	32393	81000	2740
Diesel Production (ML yr^{-1})	160	160	350	350	338	2822	6480	200
Total Capital Investment (M)	$ 676,730	$ 595,867	$ 1,251,914	$ 1,024,746	$ 678,711	$ 2,884,262	$ 3,756,822	$ 503,360
Capital Recovery (M)	$ 86,283	$ 75,973	$ 159,619	$ 130,655	$ 86,536	$ 367,743	$ 478,995	$ 64,178
O&M + Cap Recovery (M)	$1,249,180	$ 99,808	$ 234,947	$ 171,645	$ 127,259	$ 482,129	$ 635,636	Unavailable
(O&M + Cap Recov)L^{-1}	$ 0.78	$ 0.62	$ 0.67	$ 0.49	$ 0.37	$ 0.17	$ 0.10	Unavailable

Capital costs range from $596 million to $3.76 billion, and processing costs ranged from $0.10 to $0.78 L^{-1}. The huge range is attributed to the gross difference in scale of the two plants, where Boerrigter and Zwart is 40 times the capacity of Hamelinck *et al.*, and the fact that Boerrigter and Zwart do not include solids handling costs. The Hamelinck *et al.* costs are higher than the Yamashita and Barreto for both processing and capital, in part because Yamashita and Barreto used a different kind of gasifier than the other studies. Both costs were higher due to Hamelinck *et al.* citing higher equipment costs. For example, pre-treatment, gasifier, gas cleaning, and syngas processing costs were approximately twice that listed by Yamashita and Barreto. Note that the largest equipment cost items are the air separation unit, syngas manufacturing, and FT synthesis (Boerrigter 2006).

Results were broken down into two components: gasification (up to and including gas cleaning) and FT synthesis, and a plot of all the cases is shown in Figure 4.2.

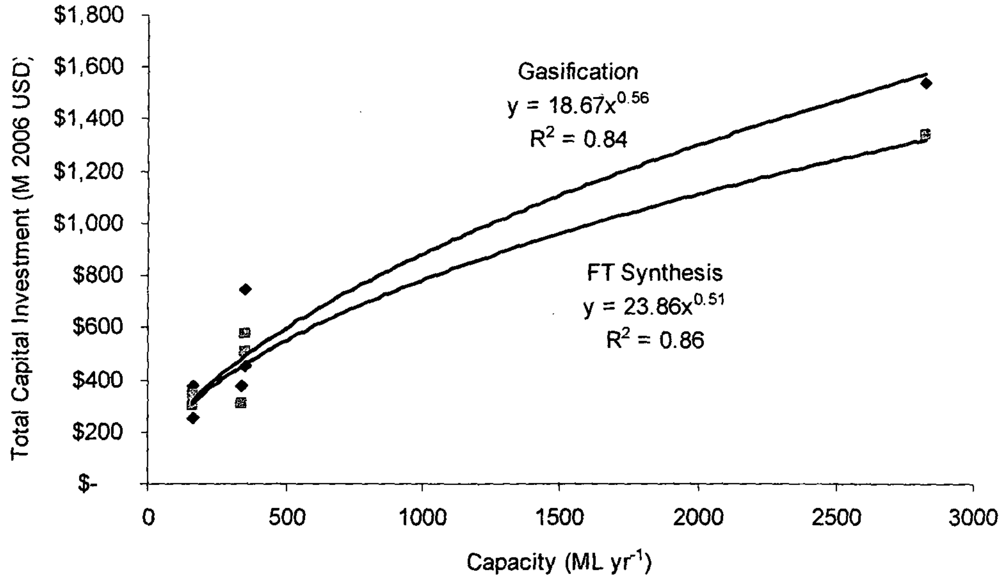


Figure 4.2. Relationship between total capital investment and plant capacity for FT synthesis from biomass, with gasification and FT synthesis shown separately.

The best fit approach to determining a scale factor from Figure 4.2 in effect places an overemphasis on the large scale study by Bechtel and Mann. Figure 4.3 shows the data set with the very large scale plants removed. There is high scatter in the data and a low correlation for the implied scale coefficients. The scale factors implicit in the data, 0.76 for gasification and 0.60 for FT synthesis, are more consistent with typical values for thermal reaction and chemical synthesis (Park 1984).

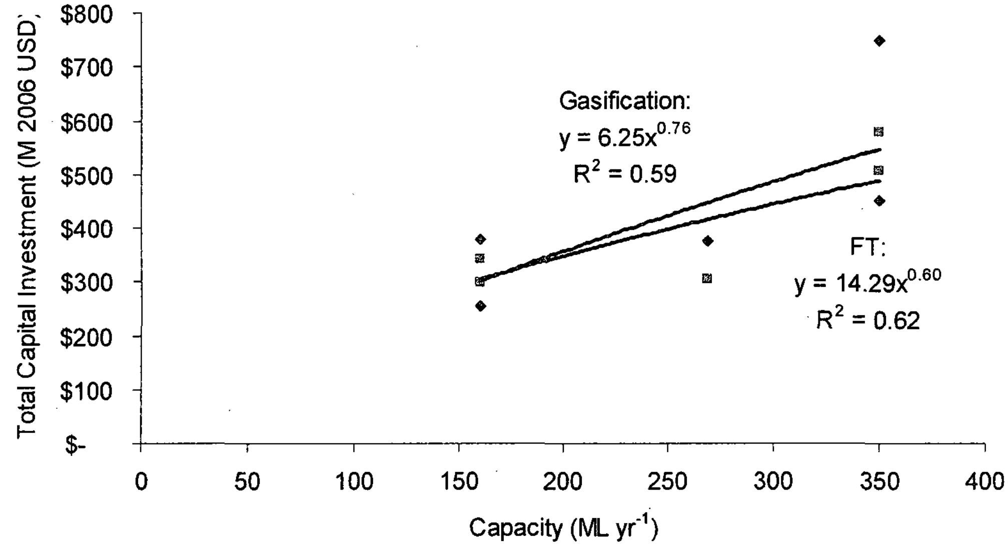


Figure 4.3. Relationship between total capital investment and plant capacity for FT synthesis from biomass, with gasification and FT synthesis shown separately, excluding Bechtel and Mann and Boerrigter and Zwart.

Figure 4.4 shows the total operating cost, including capital recovery, for all of the cases included in this study. As with Figure 4.2, the best fit line is being heavily influenced by the large scale case. The scale factor implied from Figure 4.4, 0.51, is inconsistent with historical data for chemical, refinery and power plants (Park 1984).

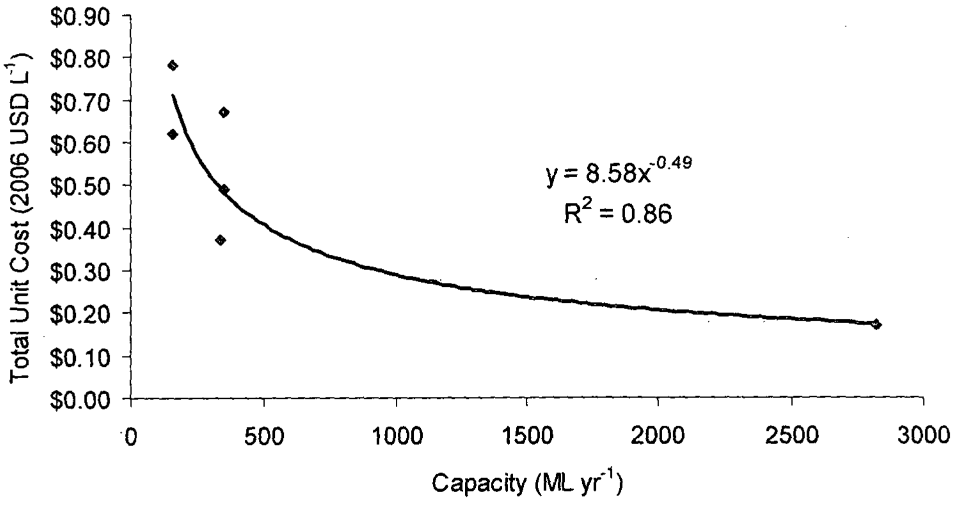


Figure 4.4. Relationship between total unit processing cost and annual plant capacity for FT synthesis (including both gasification and FT components).

Figures 4.5 and 4.6 show the processing data with the two large cases removed, as a function of tonnes of biomass feed and liters of syndiesel produced. The plots are different because reported yields in the various studies are not identical. The best fit scale factors, 0.65 and 0.70, are more consistent with expected values. In this study we use the data from Figure 4.6 to estimate FT cost as a function of scale; the overall scale factor for total production cost is 0.70.

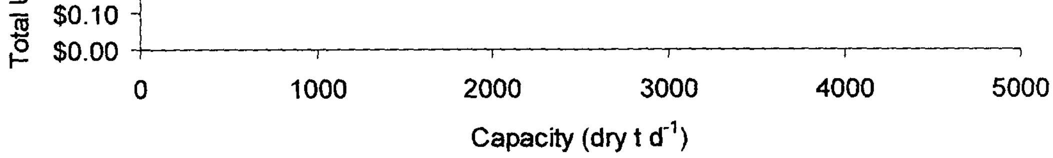


Figure 4.5. Relationship between processing cost and annual plant capacity in dry tonnes per day for FT synthesis.

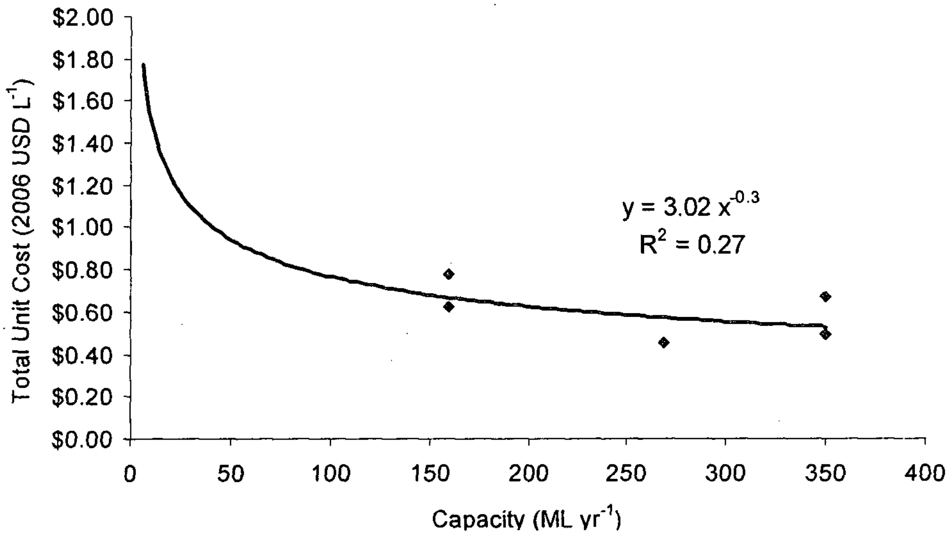


Figure 4.6. Relationship between processing cost and annual plant capacity in millions liters of FT production for FT synthesis.

The very low regression coefficient in Figure 4.6 of 0.27 is a reflection of the scatter in data available on producing FT syndiesel using biomass. There are many reasons for the scatter, including the fact that there are very few commercial scale FT plants of any kind, and there is very limited cost information available. As well, there are many different ways to configure a FT facility (for example, optimizing for the production of methane and other light hydrocarbons, diesel, or power, or any combination therein) and significant manipulation was required. While research on lignocellulosic ethanol has tended to converge on a yield of 25% on a mass basis; data on FT yields is less consistent, and the same is true for FT equipment costs. With this in mind, the scale factor that is extracted from Figure 4.6 is consistent with what would be expected from this type of energy facility (Park 1984).

Hamelinck *et al.* (2003) assumed a scale factor of 0.82 for equipment, and estimated an overall scale factor including direct and indirect capital costs, working capital and start up costs of 0.78. This study identified maximum equipment sizes for some components and assumed that no economy of scale for those components would be realized above that size. Tijmensen *et al.* (2002), in a study that was a precursor to Hamelinck *et al.* (2004), looked at individual equipment and for scales between 100 and 400 MW_{th} estimated an overall scale factor in capital costs of 0.74. When capacities go beyond 400 MW_{th}, they estimated that the average scaling factor increases to 0.91. Mann assumed the scale factor for capital cost to be 0.7, while Wright and Brown (2007) cited 0.7 as the scale factor for thermochemical platforms. Larson *et al.* used a capital cost scale factor of 0.67. The overall scale factor in this study of 0.67 is for capital and operating cost.

Boerrigter (2006) suggested that a staggered scale factor should be employed. For plants with a capacity between 1000 and 5000 bbl d^{-1} (53 - 263 ML yr^{-1}), a scale factor of 0.5 was recommended, and a scale factor of 0.6 suggested for scales between 5000 and 20000 bbl d^{-1} (263 - 1050 ML yr^{-1}). For scales between 20,000 and 60,000 bbl $^{-1}$ (1000 - 3000 ML yr^{-1}), the scale factor of 0.7 was applied. For larger scales, diminishing returns are encountered and there is less of a benefit to increasing the plant size, and therefore a scale factor of 0.9 is applied.

Studies of the cost of producing syndiesel via oxygen gasification and FT synthesis are at an earlier stage of definition, and the accuracy and consistency is therefore lower. If the Choren plant is built, it would significantly add to the knowledge of FT synthesis, including capital and operating cost. The scatter in the data from existing studies, when placed on a consistent basis, suggests that claims of estimating accuracy of +/-30% are exaggerated.

4.2.1 Other Economic Data

FT cost data presented below was not included above as the data was either too general, the system configuration was inconsistent with above configurations (i.e. they were not designed to optimize diesel production), or the feedstock was not biomass. The economics of biomass-to-liquid plants differ from that of gas-to-liquids plants due to alterations in technology required to accommodate the difference in feedstock. For biomass-fed systems, more extensive feedstock preparation and handling is required, as well as a higher oxygen demand, higher gas cleaning costs to remove the higher amount of gas impurities, and finally the application of an entrained flow gasifier which is more expensive than a natural gas reformer when solids handling is considered (Boerrigter 2006). Biomass differs from coal as well, as biomass requires significant pretreatment to allow stable feeding into the gasifier without excessive inert gas consumption (Boerrigter 2006). All values are in 2006 USD, unless otherwise noted.

Greene (1999) listed several existing or proposed FT production facilities, all of which use either natural gas or coal as a feedstock. Exxon had a pilot plant in Baton Rouge, Louisiana to demonstrate a new natural gas to liquid transportation fuel process. Exxon, along with the Qatar General Petroleum Corporation, proposed to build an 8,000,000 to 16,000,000 L d^{-1} (50,000 to 100,000 bbl d^{-1}) facility using this process in Qatar. Exxon's feasibility study for this project reportedly estimated the capital cost to range from \$1.45 to \$2.9 billion, depending on plant size, or about \$182 L^{-1} d^{-1} (\$29,000 bbl^{-1} d^{-1}).

British Petroleum along with Kvaerner AS, Oslo announced an alternative plant design that reportedly cuts the capital cost of syngas production by 50% by reducing heat accumulation in the catalyst bed and developing a new cobalt catalyst (Greene 1999). BP expects the capital cost of such a plant to be approximately \$152 L^{-1} d^{-1} (\$24,200 bbl^{-1} d^{-1}).

The Syntroleum Autothermal Reforming process eliminates the need for O_2 separation by using air gasification, and then passes the nitrogen-diluted syngas through the FT reactor. Because the gas is not recycled, nitrogen does not build up as it would in a conventional FT process. Syntroleum has developed several alternative gas-to-liquid process designs and catalysts to be used under differing circumstances (Greene 1999). According to Syntroleum, its syndiesel process can operate economically at 800,000 L d^{-1} (5,000 bbl d^{-1}) and, in some cases, as low as 400,000 L d^{-1}. The company believes that small-scale plants can be constructed at a cost of \$91 to \$250 L^{-1} d^{-1} (\$14,500 to \$32,600 bbl^{-1} d^{-1}) (Greene 1999).

Gray and Tomlinson (1997) presented three gas-to-liquid scenarios, one from coal and two for natural gas. The coal-based facility used 18,000 t d^{-1} of feedstock, producing a total of 8,000,000 L d^{-1} (50,000 bbl d^{-1}) of a gasoline (48%), diesel (49%) and minor amounts of liquid petroleum gas (LPG). Gray and Tomlinson estimated the capital cost using existing literature to be \$4,007,000,000, and the net operating cost was estimated at \$380,000,000 yr^{-1}. Using 76 GJ hr^{-1} natural gas as a feedstock and cobalt as a catalyst, 8,456,000 L d^{-1} liquid product was produced, approximately half gasoline and half diesel, along with 4 MW power. The capital cost was \$2,223,000,000 with a net operating cost of \$796,000,000 yr^{-1}. An iron-based catalyst system was also presented, but assumed a large power generation component.

A natural gas-to-liquids study that estimated costs using a computer simulation was presented by Gradassi (1998). 8,000,000 L (50,000 bbl) were produced per stream day, using 270 m^3 natural gas bbl^{-1} liquids. The capital cost was \$204 L d^{-1} (\$32,400 bbl^{-1} d^{-1}).

Boerrigter (2006) conducted a study to find the optimum FT plant size, and it was concluded that the optimum FT biomass-to-liquids scale is between 2000 to 4000 MW_{th}, or 16,000 to 32,000 bbl d^{-1} (800 - 1600 ML yr^{-1}). This study assumed a pressurized O_2 entrained flow gasifier at 91% availability, and that plants were constructed on site near existing refinery infrastructure, and included CO_2 removal. For smaller scales (i.e. below 20,000 bbl d^{-1}), they stated that their assumption of a scale factor of 0.7 would likely underestimate the TCI costs, as a smaller scale factor of 0.5 - 0.6 would be more realistic. Boerrigter gave two cost numbers: an "off the record" capital cost for the Sasol FT plant presently operating in South Africa, and an estimate for an upcoming slurry-phase, Sasol-Chevron FT in Nigeria, both using natural gas as the feedstock. The costs given were \$39,000 bbl^{-1} d^{-1} and \$69,000 bbl^{-1} d^{-1}, respectively, both at a scale of approximately 1700 ML yr^{-1}. These costs are biased on the low end, as they did not include pretreatment or synthetic fuel upgrading costs. As well, Boerrigter (2006) included a relation between cost data from natural gas FT plants to projected costs for biomass based FT plants by applying a 60% increase to capital costs.

Wright and Brown (2007) found from previous studies that FT diesel total unit production costs range from \$0.29 - 1.08 L^{-1} diesel when cellulosic biomass is used as a feedstock (note that the cost found in Section 4.2.2 was \$0.74 L^{-1}). The paper gave a plant capacity of 132 ML yr^{-1}, with a capital cost of $382,100,000. The annual operating and management cost was $49,080,000 yr^{-1}.

Table 4.4. Summary of other economic data for FT synthesis, ordered by increasing capital cost. Operating cost includes maintenance, operations, administration, taxes, and other annual costs, and was not available from all sources.

Feed	Capital Cost ($L^{-1} d^{-1})	Operating Cost ($L^{-1} yr^{-1})	Capacity (kL d^{-1})	Source
Coal	91 - 250	NA	400 - 800	Greene 1999 (Syntroleum)
Coal	152	NA	NA	Greene 1999 (BP)
Natural Gas	182	NA	8,000 - 16,000	Greene 1999 (Exxon)
Natural Gas	204	NA	8,000	Gradassi 1998
Natural Gas	262	0.287	8,456	Gray & Tomlinson 1997
Natural Gas	392	NA	5,140	Boerrigter 2006
Coal	501	0.144	8,000	Gray & Tomlinson 1997
Coal	536	0.091	7,550	US DOE 2007
Coal	611	0.242	1,450	US DOE 2007
Biomass[a]	692	NA	5,140	Boerrigter 2006
Coal, Switchgrass	762	0.115	1,140	US DOE 2007
Woody Biomass	794	7% TCI[c]	2,420	Boerrigter 2006
Straw	850	0.14	1,770	Searcy[b]
Biomass	950	0.37	402	Wright & Brown 2007
Woody Biomass	1588	5% TCI[c]	4,835	Boerrigter 2006

[a]Boerrigter (2006) concluded that these changes would result in a 60% increase in capital cost of BTL plants over GTL facilities. Therefore, capital costs of plants using natural gas as feedstock in Table 4.4 were increased by 60 % prior to being plotted in Figure 4.7 below.
[b]Data calculated at the plant size of 8000 dry td^{-1}determined in Section 4.2
[c]Initial total capital investment

We can see from Table 4.4 that there are a range of cost values for FT synthesis. One would expect that FT production from coal would be more expensive than from natural gas due to the higher cost of solids handling, however that is not always the case. Similarly, coal-fed facilities would be expected to be less expensive per unit output than biomass based facilities, but this is not consistently true from Table 4.4. The results in Table 4.4 along with biomass-based data are plotted in Figure 4.7.

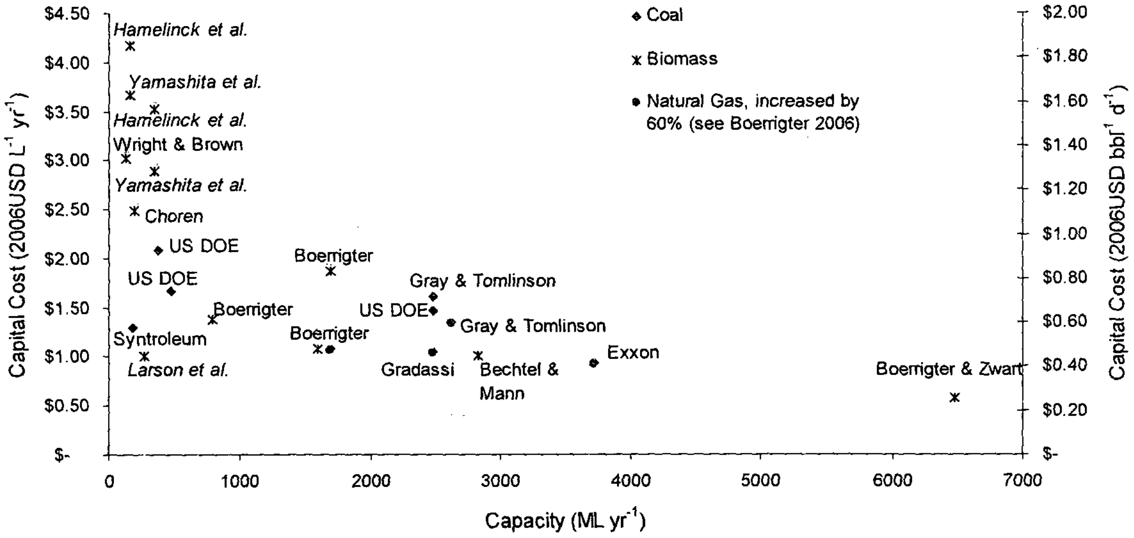


Figure 4.7. Capital cost of Fischer Tropsch syndiesel plant as a function of plant scale.

Figure 4.7 shows the capital cost per liter per year of capacity from studies of FT processing of coal, biomass, and natural gas. There is a high degree of scatter in the data, reflecting in part the fact that no large scale biomass oxygen gasifier has ever been built and in part the variability in FT configuration discussed above. Figure 4.7 suggests biomass-based capital cost estimates at small scales are on the high end. Although there is much scatter in the data, there is still a general exponential trend of decreasing capital cost per unit with increasing plant scale.

4.2.2 Optimum Plant Size

Optimum plant size was determined for the FT syndiesel production scenario, based on the equation presented in Figure 4.6.

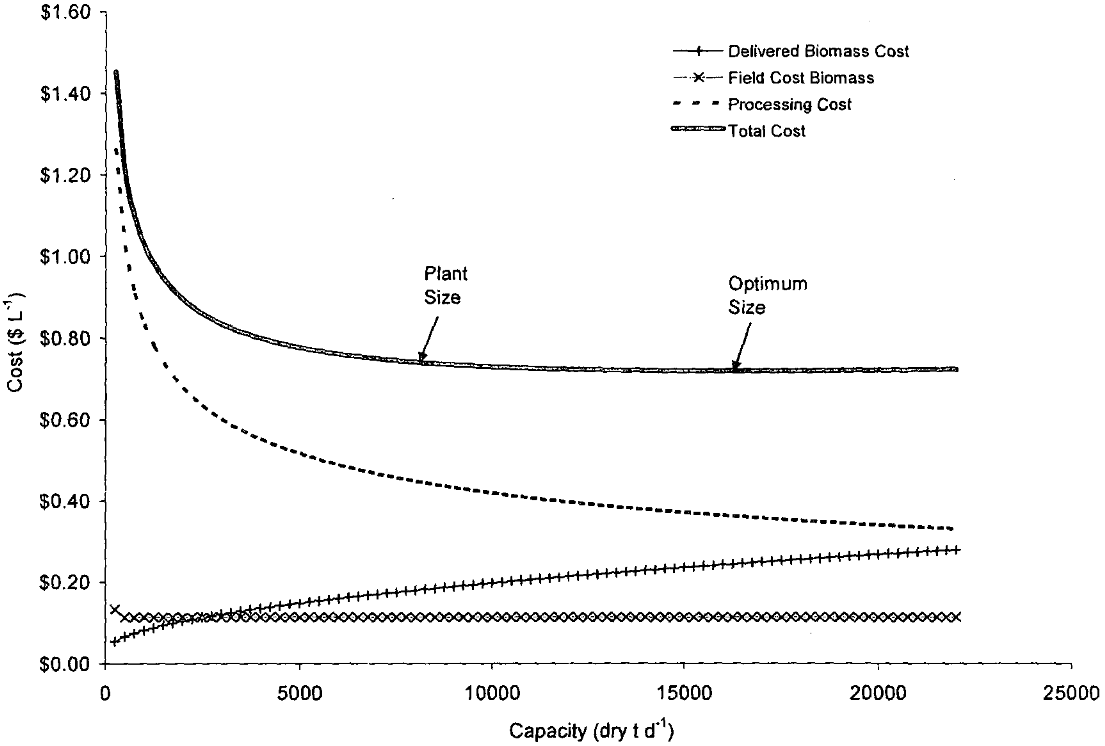


Figure 4.8. Determination of FT optimum plant size using straw from southern Alberta as a feedstock

From Figure 4.8, the technical optimum plant size for FT syndiesel production is 16250 dry t d^{-1} biomass input, which corresponds to a syndiesel production of 1181 ML yr^{-1}. Note that this size is within the optimum size range of 800 to 1600 ML yr^{-1} diesel found by Boerrigter (2006) for a biomass-based FT production facility. At 1181 ML yr^{-1} the biomass draw area is 290 km and the total production cost is $0.72 L^{-1} syndiesel, of which $0.24 L^{-1} is from the delivered cost of biomass, $0.11 L^{-1} is from the field cost of the biomass, and $0.36 L^{-1} is from the processing cost. The higher field cost per liter over ethanol reflects the lower volume yield of syndiesel derived from biomass. The curve begins to flatten before the minimum total production cost is reached (i.e. the optimum size), and therefore a smaller plant size was chosen in an effort to reduce capital investment. The plant size of 8000 dry t d^{-1} biomass input, corresponding to a total production 3% higher than that at optimum size ($0.74 L^{-1} syndiesel), was selected. This smaller plant size yields 581 ML yr^{-1} syndiesel, a biomass draw area of 203 km, and a transport cost of $0.18 L^{-1}. The purchase (field) cost of straw available in bales with a moisture content of 15% is $25 actual t^{-1}, or $0.11 L^{-1}. Hence when the processing cost of $0.45 L^{-1} is added, we get the overall production cost of syndiesel at 8000 dry t d^{-1} is $0.74 L^{-1}.

4.3 *Fischer-Tropsch GHG Emissions*

There are fewer studies of syndiesel production than of ethanol fermentation, and as a result there is less data available on emissions. $(S\&T)^2$ Consultants (2006) studied syndiesel production from wood; from their data total emissions were 322 g CO_2e L^{-1}, a value that included biomass harvest and transport. Imported power consumption during production and the production process itself had emissions of 91 g CO_2e L^{-1}. Abbott *et al.* (2006) studied a 75,000 bbl d^{-1} FT plant using a natural gas feedstock. From their data the value for emissions from the FT production step, including imported power, were 231 g CO_2e L^{-1}. Finally, data from a study by The European Council for Automotive R&D (2007) was adjusted to increase the emissions associated with power generation to reflect an Alberta average grid emissions level of 761 g CO_2e kWh^{-1} (Tampier *et al.* 2004), higher than the value in the European study that assumed a significant amount of nuclear power in the generation pool. This leads to a calculated emission of 339 g CO_2e L^{-1} from the FT production process, including imported power. In this study we use a value of 220 g CO_2e L^{-1}, the average of the above values; we note again that the variance in values for emissions from FT production is small in relation to the fossil CO_2 released by combustion of diesel from oil.

The carbon emissions for FT production are much higher than for ethanol, however the power used to produce ethanol is obtained from carbon-neutral lignin, whereas grid-sourced coal is used for power generation in FT synthesis. The FT synthesis process could be designed such that there was sufficient power generated to have a carbon-neutral power source, however this would involve decreasing the amount of FT syndiesel produced (by by-passing some of the unconverted synthesis gas from going into the recycle process). This is not the case for ethanol, wherein the lignin cannot be converted into fuel and would be wasted if not converted to power.

4.4 *Diesel GHG Emissions*

As per the US EPA (2007) low sulfur diesel has a carbon content of 734 g L^{-1}.

CO_2 emissions from combustion of a liter of diesel:

$= 734 \text{ g} * (44/12) = 2{,}690 \text{ g } CO_2 \text{ } L^{-1}$ diesel

4.4.1 GHG Emissions from Extraction, Transportation and Refining

There is a very high variance in reported emissions for the production of diesel, as noted by Fleming *et al.* (2006). CO_2 emissions in g L^{-1} are reported as 120 (Furuholt 1995), 165 (Sheehan *et al.* 1998), 381 (Choudhury *et al.* 2002), 429 (Beer *et al.* 2002), 481 (European Council for Automotive R&D 2006), 560 (Singh *et al.* 1998) and 612 (Fleming *et al.* 2006).

Some but not all studies report methane emissions, in g L^{-1} and g CO_2e L^{-1}, of 1.3 and 27.3 (Beer *et al.* 2002), 1.46 and 30.7 (Sheehan *et al.* 1998) and 8.30 and 174.3 (Singh *et al.* 1998). Only Sheehan *et al.* (1998) reports N_2O emissions, which were 0.0485 g L^{-1}, equivalent to 15.0 g CO_2e L^{-1}. The US GREET model developed by the Argonne National Laboratory gives emission of 525 g CO_2 L^{-1} low sulfur diesel using a US energy mix, and again CH_4 and N_2O emissions are negligible compared to CO_2 emissions. We use a blended value in this report of 400 g CO_2e L^{-1} for diesel transport and refining, shown in Table 4.5, noting that the variance in values for refining is small in relation to the fossil CO_2 released during combustion. Table 4.5 shows an average of emissions presented in several studies for the production of petroleum diesel.

Table 4.5. Average air emissions for petroleum diesel production (g L^{-1}), including crude oil production (including extraction), transport of crude oil to the refinery, and refining.

Stressor	Air Emissions (g L^{-1} diesel)	Equivalent Emissions (g L^{-1} diesel)
CO_2	400	400
CH_4	Negligible	Negligible
N_2O	Negligible	Negligible
	Total Fossil CO_2e (g L^{-1})	*400*

Emissions for the exploration and discovery of oil are negligible compared to the emissions from diesel fuel usage (which are 2,690 g CO_2 L^{-1}), which are far higher than emissions during refining and transport. As referenced above, Fischer Tropsch diesel is sufficiently close in properties to diesel from petroleum that no significant differences in GHG emissions during combustion would occur.

4.5 *Summary of Emissions*

Table 4.6 presents a summary of emissions data for feedstock production and transport, as well as the conversion emissions for fossil fuel diesel and FT syndiesel production.

Table 4.6. Summary of GHG emissions from fossil fuel and FT syndiesel in g CO_2e L^{-1}.

	Diesel	FT Syndiesel	Difference (Diesel – FT)
Production and Harvesting Biomass	NA	380	-380
Transport of Biomass	NA	49.7	-49.7
Extraction, Transport and Refining of Oil	400	NA	400
Production of FT Syndiesel	NA	220	-220
Consumption of Fuel	2,690	0	2,690
Total	3,090	650	2,440

From Table 4.6, consuming one liter of syndiesel prevents 2,440 g CO_2e emissions from entering the atmosphere.

4.6 *Value of Carbon Credit Required to Support an FT Syndiesel Plant*

The carbon credit for FT synthesis was determined for low and high oil price scenarios, corresponding to an oil price of \$65 bbl^{-1} (\$0.59 L^{-1} diesel using the model we developed for oil price/diesel price conversion) and \$90 bbl^{-1} (corresponding to \$0.75 L^{-1} diesel using the model). The low and high oil prices yield \$59.6 and -\$4.7 t^{-1} CO_2 as the carbon credit for Fischer Tropsch syndiesel, respectively. Figure 4.9a shows the relationship between carbon credit and the wholesale pretax price of petroleum diesel.

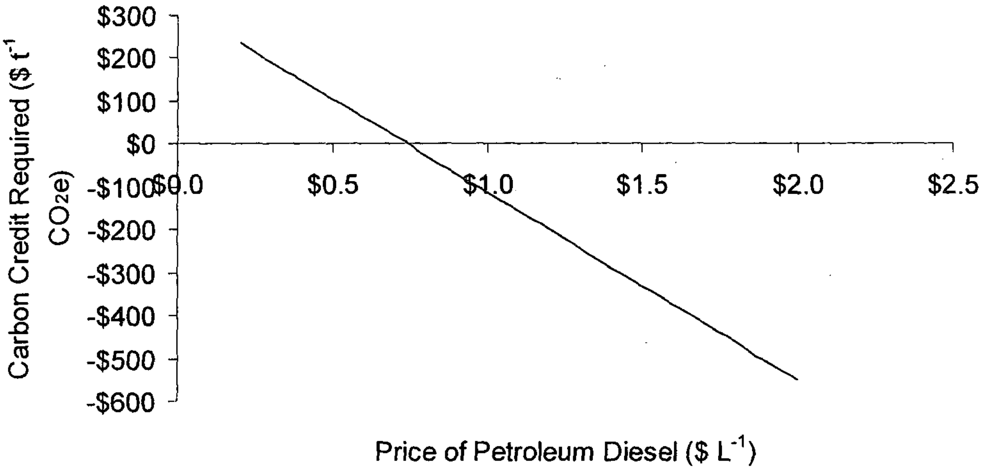


Figure 4.9a. Relationship between the wholesale pre-tax cost of petroleum diesel and the value of the carbon required for FT syndiesel production to be competitive with petroleum diesel.

As per Figure 4.9a and previous discussion, when the wholesale pre-tax cost of petroleum diesel reaches $0.74 L^{-1}, the costs of FT syndiesel and petroleum diesel are equal, and therefore no carbon credit is needed.

The carbon credit required to make FT syndiesel competitive to petroleum diesel was also related to the price of crude oil using the model presented in Appendix, as shown below in Figure 4.9b.

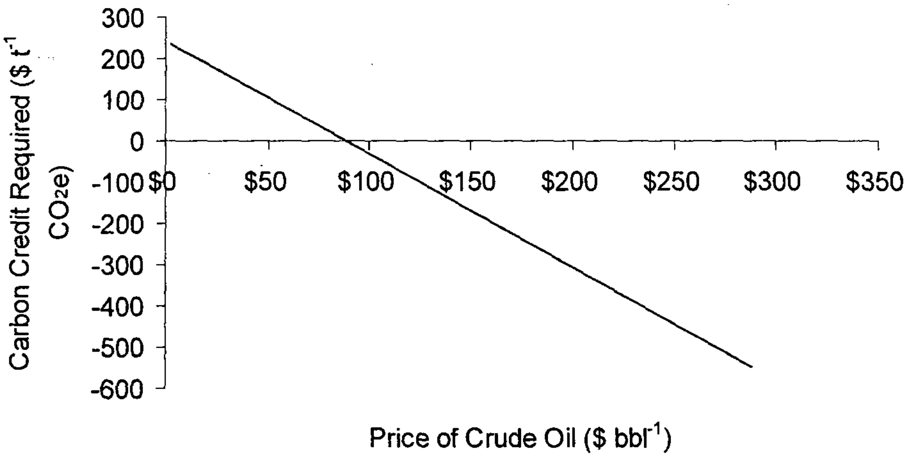


Figure 4.9b. Relationship between required carbon credit for FT syndiesel and crude oil price.

From Figure 4.9b, the oil price at which point there is no longer a carbon credit required is \$84.37 bbl^{-1}.

4.7 *Sensitivity Analysis*

Table 4.7. Demonstration of the sensitivity of the Fischer Tropsch carbon credit (\$ t^{-1} CO_2e) for the low oil price scenario, with the percentage change indicated below. The base case is for a plant size of 8000 dry t d^{-1}, with a biomass availability of 75% and a carbon credit of \$59.6 t^{-1} CO_2e. The delivered cost of biomass is the sum of field cost and transport cost.

	Base Case	**-10%**	**+ 15%**	**+ 30%**	**+50%**	**+100%**	**+150%**
Field Cost of biomass	\$0.113 L^{-1} \$25 actual t^{-1}	55.0 -8%	66.6 12%	73.5 23%	82.8 39%	105.9 78%	129.1 117%
Transport Cost of Biomass	\$0.18 L^{-1} \$39.60 dry t^{-1}	52.3 -12%	70.6 18%	81.6 37%	96.3 62%	133.0 123%	169.7 185%
Delivered Cost of Biomass	\$0.292 L^{-1} \$64.6 dry t^{-1}	47.6 -20%	77.6 30%	95.5 60%	119.5 100%	179.3 201%	239.2 301%
Processing Cost	\$0.45 L^{-1} \$99.53 dry t^{-1}	41.3 -31%	87.1 46%	114.6 92%	151.3 154%	242.9 307%	334.7 461%
Wholesale Pre Tax Diesel price	\$65 bbl^{-1} oil (approx.[a] diesel price: \$0.59 L^{-1})	83.9 41%	23.1 -61%	-13.4 -122%	-62.1 -204%	-183.8 -408%	-305.5 -612%
FT Syndiesel Emissions[b]	650 g CO_2e L^{-1}	58.1 -3%	62.1 4%	64.8 9%	68.8 15%	81.3 36%	99.3 67%
Petroleum Diesel Production Emissions[c]	400 g CO_2e L^{-1}	60.6 -2%	58.2 2%	56.8 5%	55.1 8%	51.2 14%	47.8 20%

[a] Estimated using model presented in Appendix

[b] Includes emissions from harvesting, biomass transport and conversion

[c] Includes emissions from extraction, transport and refining

Note that a negative carbon credit indicates that the renewable technology would give a higher return than 12%. As there is substantially less information available on FT synthesis than the other technologies, the certainty in the information is much lower. Therefore it is quite possible that the processing cost would be 100% higher than predicted, even after compensating for recent changes in construction and labor costs. As with ethanol production, the largest impact comes from changing the price of petroleum, followed by a change in processing cost. However, for FT the percent change is lower for a similar alteration in ethanol primarily due to a lower initial production cost of ethanol. As was the case for ethanol production, changes in emissions have the smallest impact on the value of the carbon credit. This is of particular note, as it emphasizes that it is not critical to invest enormous amounts of time in obtaining the utmost accuracy in emissions for the renewable alternatives.

5 Power Production via Direct Combustion

Direct combustion is by far the oldest and most common method of energy production using biomass. Direct combustion is used to a limited extent for residential space heating, however in this study we focus on the production of electrical power from direct combustion and a steam cycle. This is a proven technology being applied at large scale today. The average biomass power plant size in the US is 20 MW (the largest is 80 MW) and average efficiency is 20% (Bain *et al.* 2003), however the largest biomass combustion plant in the world is operated by Alholmens in Pietersaari, Finland, and has a gross capacity of 240 MW_e. When any fuel is used to produce electricity via a steam cycle, 60% or more of the energy is lost as waste heat unless that heat, contained in flue gas and from exhaust steam or the condensing of steam, can be used for another purpose (for example, in an industrial process or to heat a building) (US DOE 2006). Larger plants achieve higher efficiencies.

5.1 *Technical Summary*

In direct combustion, biomass enters the boiler where it is combusted to generate heat, which is used to produce steam through coils in the boiler. The steam is converted into mechanical energy to drive the turbine shaft, which powers a generator to produce electricity. A cyclone is usually used to reduce particulate emissions, along with other emission control devices. Boiler efficiency, which is the percentage of energy in the biomass converted to heat and absorbed by the water or steam, is usually between 80 and 90%, while a total efficiency defined as the ratio of electrical power out to thermal energy in of approximately 30 - 40% (LHV) can be expected for larger facilities (Bain *et al.* 2003, Castleman 1995, Caputo *et al.* 2005, Kumar *et al.* 2003, Flynn and Kumar 2005). A schematic of direct combustion is shown in Figure 5.1.

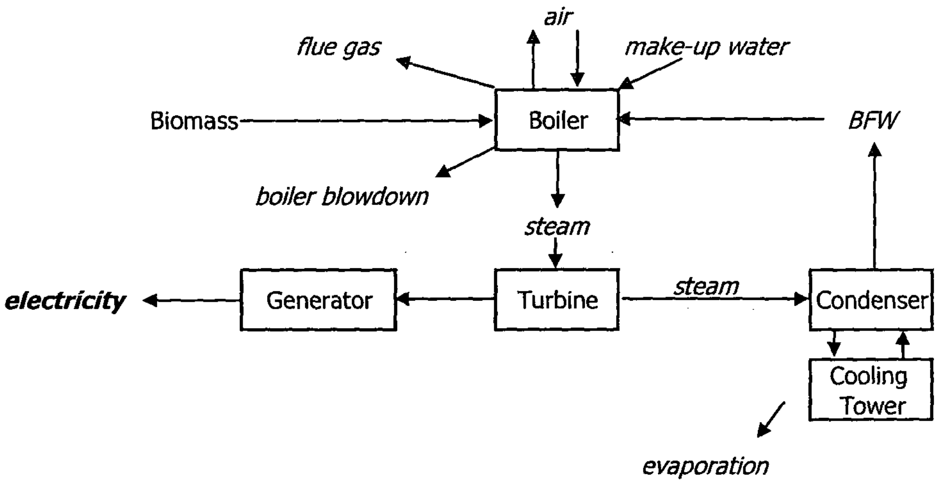


Figure 5.1. Schematic diagram of direct combustion of biomass.

As with all alternative energy technologies, numerous options exist for converting biomass into electricity through combustion. Boiler alternatives include fixed, entrained flow, or fluidized bed (which has further divisions including circulating vs. bubbling bed), and atmospheric or pressurized combustion. Biomass fuel alternatives include using modified biomass (for example, densified and/or dried) as opposed to using biomass as received. Fluidized bed designs are becoming highly favored due to lower NO_x emissions (Caputo *et al.* 2005). The Alholmens biomass power plant uses circulating fluidized bed combustion, and that technology is the basis of this study.

For some boiler designs another option for combustion is to co-fire the biomass, where normally around 5 – 15% biomass by energy input is directly fed into the furnace with either coal or natural gas. In some boilers this amount of biomass can be tolerated by the system without modification or significant effects on the combustion equipment (Tampier *et al.* 2004, Bain *et al.* 2003, Ramsgaard-Nielsen 2004), and prevents undesired changes in ash composition (Nussbaumer 2003). After minor adjustments, there is little or no loss in total efficiency, while there is an 18% reduction in GHG emissions when replacing 15% of the energy with biomass (Bain *et al.* 2003). Note that there would also be additional investment costs for the biomass pretreatment (cutting, drying, metal separation, and grinding). However, opportunities to retrofit for co-firing of biomass are limited.

In the combustion chamber of a circulating fluidized bed system, the biomass is fluidized with a bed of solid granular particles (either sand or limestone) suspended by an upward flow of air in the combustion. Both the particles and air are introduced into the lower section of the combustion chamber, and a perforated grid plate or nozzles distribute the air uniformly. Heat transfer occurs from the bed material to the boiler tube surface, and turbulent mixing of air and fuel at temperatures above the ignition point of the fuel causes combustion to occur (Castleman 1995). The air to fuel ratio is kept low in the feed zone to reduce the initial combustion temperature to minimize NO_x emissions. Secondary air is introduced at higher elevations to complete combustion. Castleman (1995) noted that sizing of fuel is very important, as fine particles can become entrained and pass through the unit unburned and may not be caught by the cyclone, while larger particles can cause fluidization problems. Neither of these problems have been observed in the Alholmens plant (Flynn and Kumar 2005). In a circulating fluidized bed the fluidized medium, typically sand, and incompletely burned biomass are separated from flue gas in a cyclone and returned to the combustion zone. Flue gas from the boiler passes through the steam generation and economizer (combustion air preheat) sections and is filtered through electrostatic precipitators or bag houses to remove fly ash. Boilers can include catalytic or non-catalytic reduction of NOx if required to meet local air quality standards.

The steam is superheated in the boiler and expanded through a multi-stage steam turbine that drives the turbine shaft used to turn an electric generator; three stages are typical (Castleman 1995). Low pressure steam from the turbine exhaust is cooled to water in a condenser using air or water as a cooling medium.

The world's largest straw-fired power plant is a 38 MW_e direct combustion facility located in the Ely Industrial Business Park near Sutton, Cambridge, in the United Kingdom. With commercial operation beginning in September 2000, the main fuel is straw from grains such as wheat, oat, barley, and rye, with alternative fuels of natural gas and wood chips. The plant consumes 630 t d^{-1} of straw bales daily, and net plant efficiency is above 32%. Problems due to fouling and corrosion of the heating surfaces of the steam boiler are prevented by unspecified design measures. The plant has an availability above 93%, and unmanned operation is possible (Bioener Aps 2007).

Common combustion problems with biomass include erosion, corrosion, and fouling by sticky deposits in the boiler that reduce heat transfer rates and corrode metal. Molten slag can form at relatively low temperatures and hence molten deposits can condense on boiler tubes. Corrosion and fouling problems are higher for agricultural residues like straw because of higher levels of salts, especially KCl, and silicates (Jenkins *et al.* 1996, Jenkins 1998)

A 25 MW straw-power generating plant in Spain which consumes 160,000 t yr^{-1} (440 t d^{-1}) of straw was involved in a research study aimed at improving the fuel quality of straw by a reduction in K and Cl ion content (Allica *et al.* 2001). Leaching with water, either through natural precipitation or under controlled conditions, extracts most of K and Cl (Allica *et al.* 2001, Jenkins *et al.* 1996). It should be noted that the MC after washing was from 82 - 88% (Jenkins *et al.* 1996); drying is required after washing because at these moisture levels LHV heat content is negligible. Similarly, a study by Jenkins (1998) found that leaching with water might reduce 80 % or more alkali and over 90 % Cl which reduces corrosion and Cl facilitation of ash deposition.

5.2 *Economics*

Five sources were used to compile the direct combustion costing, ranging in capacity from 36 MW_e to 450 MW_e gross, and the parasitic load was estimated to be 8% (Flynn and Kumar 2005).

Kumar *et al.* (2003) compiled data of cost components and operating parameters from several sources, including van den Broek *et al.* (1995), US DOE (1997), Wiltsee (2000), Williams and Larson (1996), Bain *et al.* (1996), and Zundel *et al.* (1996), on biomass direct combustion. Industry consultation and discussions with leading researchers were also used. Kumar focused on forest biomass as the energy source, and found forest harvest residue combustion plants to have an optimum size of 137 MW_e, while whole forest biomass has a much larger optimum plant size of 900 MW_e. The small optimum size for a forest harvest residue plant is due to the dispersed nature of the biomass. Kumar *et al.*

used a scale factor of 0.75 from 20 to 450 MW_e, and assumed a maximum plant size of 450 MW_e and an efficiency of 34% on a LHV basis. Kumar *et al.* noted that many biomass plants constructed to date are demonstration units and therefore one would expect a higher capital cost than for a mature technology. For a mature plant they predicted a plant cost 40% higher than comparable capital costs for large scale coal fired boiler/power plants in western Canada. Factors contributing to a higher cost for biomass boilers include the higher mass flow rate of solid fuel because biomass has a lower heating value than coal, lower flame temperature, and more corrosive ash, although the authors note that these factors do not appear to justify the large increase in biomass boiler cost relative to coal (Kumar 2004). However, Kumar *et al.* (2007) later noted that cost estimates made using this logic were significantly higher than the reported actual cost for the Alholmens biomass power plant in Finland.

Caputo *et al.* (2006) performed a component-based cost estimate of a fluidized bed combustion system, followed by a steam turbine cycle power generation. Applicable plant sizes were 5 to 50 MW_e. Components, including equipment, piping, electrical, and civil works, each had a coefficient, which was multiplied by the plant size in MW_e raised to a scale factor. Component scale factors ranged from 0.199 to 0.955 and had an average of 0.5, which is inconsistent with most literature (see, for example, Park 1984).

Castleman (1994) produced a study on the cost of combustion of wastes, including agricultural residues. The study included detailed descriptions of system components, as well as supplier costs of several different sized systems ranging from 18 to 250 MW_e, and 2 different types of combustors, bubbling and circulating fluidized bed designs. The 250 MW_e biomass combustion unit was cited as being the largest used in biomass applications, and the capacity is limited due to the height of the combustor and the size of the cyclones. For this study, only circulating fluidized bed costs and the largest system were used. Throughput calculations were based on straw as a feedstock, which resulted in a feed rate of approximately 3900 dry t d^{-1} at 250 MW_e.

The Radian Corporation (1991) prepared a report for NREL on the biomass to energy cycle, including costing information on the combustion system used to convert lignin into energy. Six scenarios were cited, including those from various areas of the US using different conditions including higher temperature, with and without biomass drying, and various pressures. The base case was used for this analysis, which included a dryer for the rather wet biomass (sludge in this case). The capacity of the system was 36 MW_e, corresponding to a biomass input of 790 dry t d^{-1}. Note that this study has a somewhat different biomass, a wet sludge feedstock that requires extracted steam for drying.

Uddin and Barreto (2007) performed an economic analysis on estimates of various biomass-fired systems, including BIGCC and direct combustion with and without carbon capture and storage, and with and without cogeneration. Natural gas combined cycle was also considered. For consistency, carbon capture and storage was omitted from the costing in this study and the condensing scenario was selected. One system size was provided for a direct combustion condensing cycle, which had capital and operating costs provided for a 200 MW_e plant, corresponding to a feed rate of 2660 dry t d^{-1} of logging residues.

The Alholmens power plant produces 240 MW_e (gross) of power, as well as exporting some process steam low quality heat for district heating (OPET Finland 2007). Detailed capital cost information was not available for the Alholemns power plant; a range of numbers were cited in the press, 700 to 850 € kW^{-1} (year 2004). An average of these estimates retrieved from Kaverner Power Inc. (Kumar *et al.* 2008) gives a capital cost of approximately $250,000,000 (2006 USD). It is not clear whether these numbers are total cost or cost after capital cost support from the European Union. The plant can operate entirely on biomass, entirely on coal, or any combination therein. The boiler was designed and manufactured by Kvaerner Pulping Finland to optimize the burning of biomass, and is about double the size of the average solid biomass fueled boilers. The boiler has a capacity of 600 MW_{th}, and has a thermal efficiency of 92%. NO_x emissions are controlled by air staging and ammonia injection. Some slagging and fouling problems were encountered in early years of operation, but have not been a long term problem.

As with the ethanol and FT studies, all costs were restated in 2006 USD, the plant operating factor was set at 90%, and capital cost recovery was based on a 12% pre-tax return on investment. Feedstock costs were removed from each study for the calculation of processing cost. The annual maintenance cost was considered to be 2.5% of the total capital investment, which was the average value of the studies examined. Caputo *et al.* (2006) cited a wide range of efficiencies in their study; in working with this study we set the electrical efficiency at 25%, consistent with smaller biomass power plants (Kumar *et al.* 2008). Table 5.1 shows the cases developed in this study from the various data sets.

Table 5.1. Summary of biomass direct combustion costs.

	Radian	Caputo	Uddin & Barreto	Castleman	Kumar	Alholmens
Net Capacity (MW_e)	33.1	46	184	230	414	220.8
Capacity (dry t d^{-1})	794	1119	2661	3856	5753	3900
Total Installed Capital Cost (M)	$ 99,352	$ 91,289	$ 319,792	$ 366,404	$ 593,113	$ 249,240
Cap Recovery (M)	$ 12,667	$ 11,639	$ 40,773	$ 46,716	$ 75,622	$ 31,778
Cap Recovery MWh^{-1}	$ 48.51	$ 32.09	$ 28.11	$ 25.76	$ 23.17	$ 18.26
Total O&M (M)	$ 6,199	$ 3,972	$ 15,176	$ 18,320	$ 24,123	Unavailable
Total Op + Cap Recov (M)	$ 18,866	$ 15,611	$ 55,949	$ 65,037	$ 99,745	Unavailable
(Total Op + Cap Recov) MWh^{-1}	$ 72.25	$ 43.05	$ 38.57	$ 35.87	$ 30.56	Unavailable

Figure 5.2 shows the capital cost from four of the five studies; the data for the Alholmens plant was considered to be too uncertain for inclusion. The best fit scale factor for capital cost, 0.76, is slightly higher than those used by engineering firms that design and build power plants, 0.7 (Cameron *et al.* 2007).

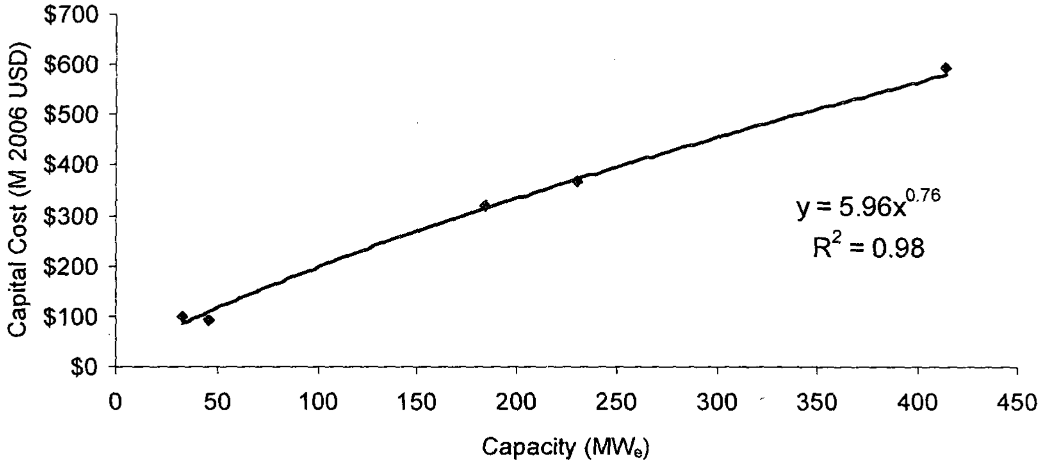


Figure 5.2. Relationship between total capital cost and plant capacity for direct combustion, excluding the Alholmens data point.

Figure 5.3 shows the processing cost from four of the five studies. The data for the Alhomens plant cannot be considered because no operating cost data is available for this plant. The Caputo *et al.* (2006) study has a lower processing cost than the best fit line. The Radian plant processing cost is higher than the best fit line, which may be a consequence of the need to substantially dry a sludge based fuel. Despite the small number of data points and the discrepancy at small sizes, the best fit line has a reasonable scale factor, rounded to 0.7, consistent with the work of Kumar *et al.* (2003), and fits well the larger scale plant studies by Kumar *et al.* (2003) and Castleman (1993).

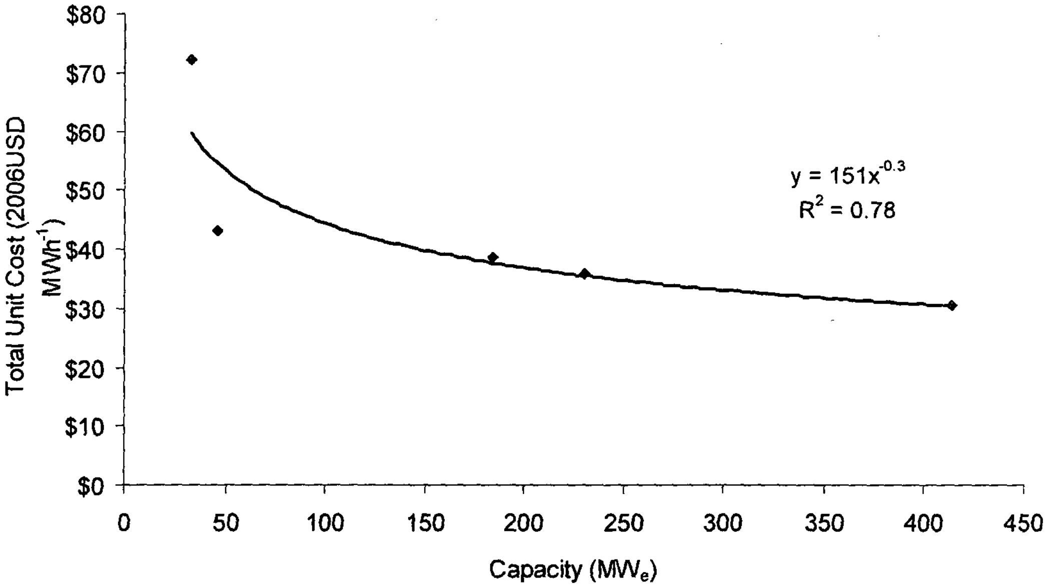


Figure 5.3. Relationship between processing cost and capacity for direct combustion of biomass.

5.2.1 Fossil Plant Costs

As a check on the reasonableness of biomass capital cost estimates, we compare them to coal fired power plants. Figure 5.4 shows the relationship between capital cost and net MW of capacity for each of the biomass direct combustion studies presented above, as well as reference data on the capital cost of coal fired power. Note that gross power produced by the plant is higher than net power by the amount of parasitic power usage, i.e. power consumed by the plant itself. Parasitic power use is assumed to be 8% of gross power production for both direct combustion and BIGCC (Kumar *et al.* 2003, Flynn and Kumar 2005). Italicized points in Figure 5.4 were used in the analysis of biomass power generation cost.

Scale also has a significant impact on the conversion efficiency (gross power output, MW_e, per unit of energy input, LHV MW_{th}) of a direct combustion plant, with small boilers having an efficiency as low as 20%, while large plants such as Alholmens achieve an efficiency of 38.5% (Cameron *et al.* 2007, Flynn and Kumar 2005).

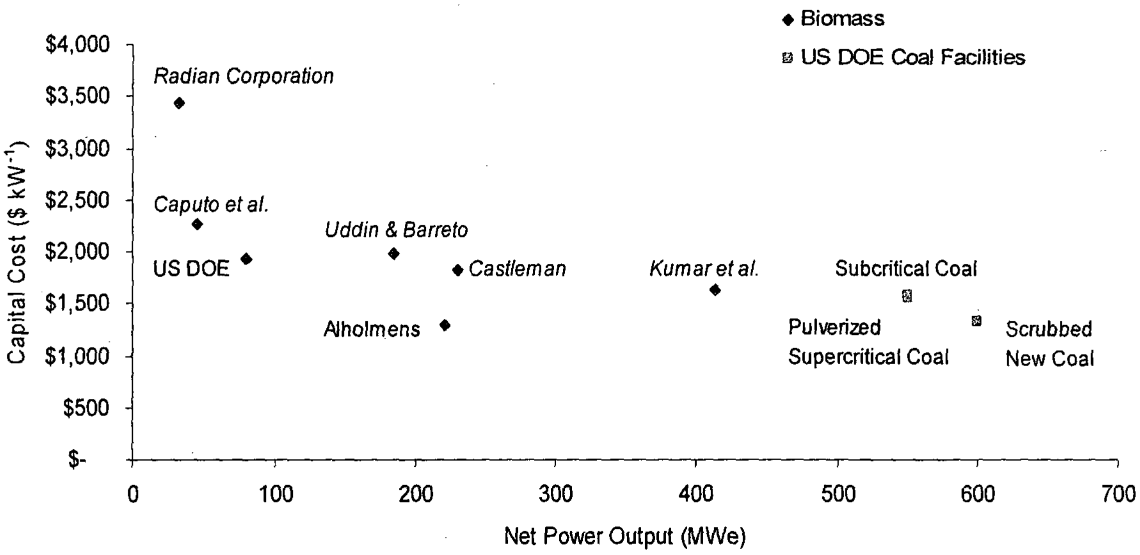


Figure 5.4. Capital cost of biomass direct combustion power plants and coal combustion plants as a function of plant size.

5.2.2 Efficiency of Direct Combustion Power Plants

Most direct combustion biomass plants in the world are small scale; the Alholmens plant in Finland at 600 MW_{th} is an exception. Small biomass direct combustion plants face two challenges that reduce their efficiency for electrical power generation. First, ambient heat losses as a percentage of total energy input increase as plant size decreases, due to higher unit surface area. Second, small plants struggle to limit capital cost, which is high because of the poor economies of scale. One means of controlling costs is to reduce steam temperature, allowing cheaper metallurgy, but a lower steam temperature and pressure reduces the generation efficiency. The result is that many plants have a generation efficiency below 25%, and some below 18% (Craig and Mann 1996, Williams and Larson 1996, Liscinsky *et al.* 2003). This contrasts to the Alholmens plant, which achieves a generation efficiency of over 38% (Flynn and Kumar 2005).

The conversion efficiency is a factor that impacts optimum size for direct combustion plants. Conversion efficiencies were staggered in this study to reflect the increase in efficiency associated with an increased plant size, starting at 20% of LHV at 250 dry t d^{-1}, and increasing to 38.5% LHV at 3000 dry t d^{-1} (corresponding to a gross capacity of 209 MW$_e$) and up (Cameron *et al.* 2007, Flynn and Kumar 2005, van den Broek *et al.* 1995, Matvinchuk 2002, Stennes and McBeath 2005). The variation in conversion efficiency also causes the field cost of biomass per MWh power output to be higher at low plant scale.

5.2.3 Direct Combustion Optimum Plant Size

The optimum plant size was determined for direct combustion of straw, and is shown in Figure 5.5.

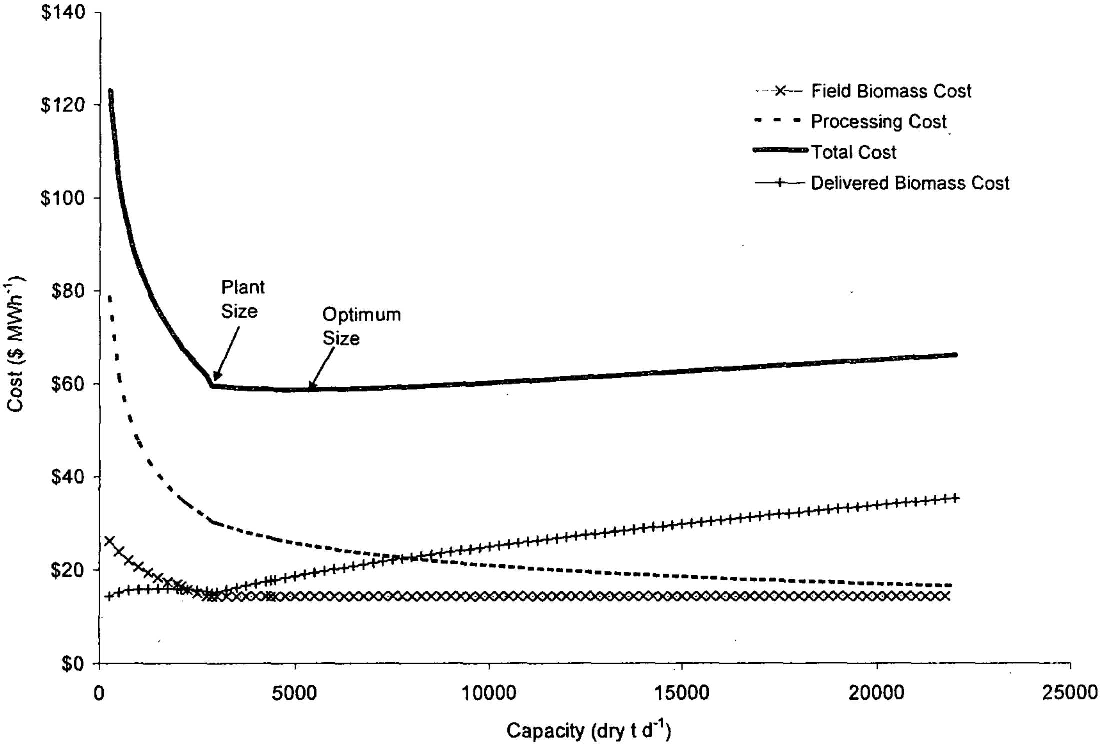


Figure 5.5. Determination of direct combustion optimum plant size using straw.

From Figure 5.5, it was determined that the optimum plant size for biomass combustion of straw was 5250 dry t d^{-1}, corresponding to a gross capacity of 383 MW$_e$. The draw distance for this size is 165 km, resulting in a transport cost of biomass of $19.72 MWh^{-1}.

When this value is combined with the field cost of biomass (\$14.29 MWh^{-1}) and the processing cost (\$24.68 MWh^{-1}), the total production cost of \$58.69 MWh^{-1} is attained. To reduce capital investment and therein reduce investment risk, the total unit cost at optimum size was increased by 3%, and the corresponding plant size of 2875 dry t d^{-1} (209 MWe gross) was used in subsequent analysis. At this scale the biomass is transported over 122 km, giving a transportation cost of \$14.96 MWh^{-1}, and the \$25 t^{-1} field cost of straw results in \$14.29 MWh^{-1}. When these two values are combined with a processing cost of \$30.38 MWh^{-1}, we get a total cost of \$59.63 MWh^{-1}.

5.3 *Coal Power Generation GHG Emissions*

Kumar *et al.* (2003) reported that emissions from a 450 MWe coal-fired boiler in Alberta are 968 g CO_2e kWh^{-1}. This value includes coal bed methane and other surface mining emissions, and assumes that the plant is at the mine mouth resulting in negligible transport emissions from the coal. Supercritical coal-fired burners have 0.9 times the emissions of a conventional coal plant (EPCOR 2007), and therefore the emissions were adjusted to 886 g CO_2e kWh^{-1}.

The European Council for Automotive R&D (2006) found emissions from a state-of-the-art conventional coal combustion facility to be 873 g CO_2e kWh^{-1}, which is within 1.5% of that presented by Kumar *et al.* The emissions cited in Kumar *et al.* fit within the emission factor set out by Natural Resources Canada (2006) for coal power production, which is a range between 729 and 919 g CO_2e kWh^{-1}, and that set out by the IPCC for sub-bituminous coal, which is approximately 830 - 900 g CO_2e kWh^{-1} (IPCC 2006). From 1998 - 2005, coal mined via sub-bituminous surface mining in Alberta had an emission factor of 836 g CO_2e kWh^{-1} according to Environment Canada (2007). Spath *et al.* (1999) found the emissions from a New Performance Source (i.e. with a higher efficiency (35%) than conventional plants (32%)) coal combustion plant in the US to be 941 g CO_2e kWh^{-1}, assuming the coal was surfaced mined. This number is again very close to the value presented by Kumar *et al.*

5.4 *Direct Combustion GHG Emissions*

Most studies consider emissions relating to the production of power from delivered biomass to be negligible or zero (see, for example, Kumar *et al.* 2003; Larson *et al.* 2006; European Council for Automotive R&D 2006). Spath and Mann (2004) cite fossil fuel usage in a biomass direct combustion power plant as 1% that of a coal fired plant. Mann and Spath (1997) developed a highly detailed analysis of a BIGCC power plant assuming future improvements in technology, and from this study we can conclude that there are only negligible incremental GHG emissions directly resulting from plant operation, as compared to supercritical coal power generation. We follow the practice of most studies and treat emissions from power production from biomass as negligible relative to coal fired power plant emissions.

5.5 *Summary of Emissions*

Table 5.2. Summary of GHG emissions from the production and transport of feedstock, and from the conversion of feedstock into power using direct combustion of coal or straw at a plant size of 2875 dry t d^{-1} in g CO_2e kWh^{-1}.

	Coal	**Biomass Direct Combustion**	**Difference (Coal – Biomass)**
Production and Harvesting of Biomass	NA	45.3	-45.3
Transport of Biomass	NA	3.57	-3.57
Extraction, Transport, and Power Production from Coal	886	NA	886
Biomass Power Production	NA	0	0
Total	886	48.9	837

5.6 *Value of Carbon Credit Required to Support a Straw Direct Combustion Plant*

Two wholesale power prices were assumed in calculating sample carbon credits required for power generation via direct combustion of straw: \$60 MWh^{-1} for the low case and \$75 MWh^{-1} for the high. The net power output from the biomass plant at the plant size of 2875 dry t d^{-1} was multiplied by the wholesale price of power, and from this the annual production cost (total cost of biomass direct combustion gross power production) was subtracted. This difference was divided by the emissions from the gross power output to get the carbon credit required for direct combustion at \$60 MWh^{-1} and \$75 MWh^{-1} power, which was \$5.3 t^{-1} CO_2e and -\$11.2 t^{-1} CO_2e, respectively. Figure 5.6 shows the relationship between required carbon credit for direct combustion and wholesale power price.

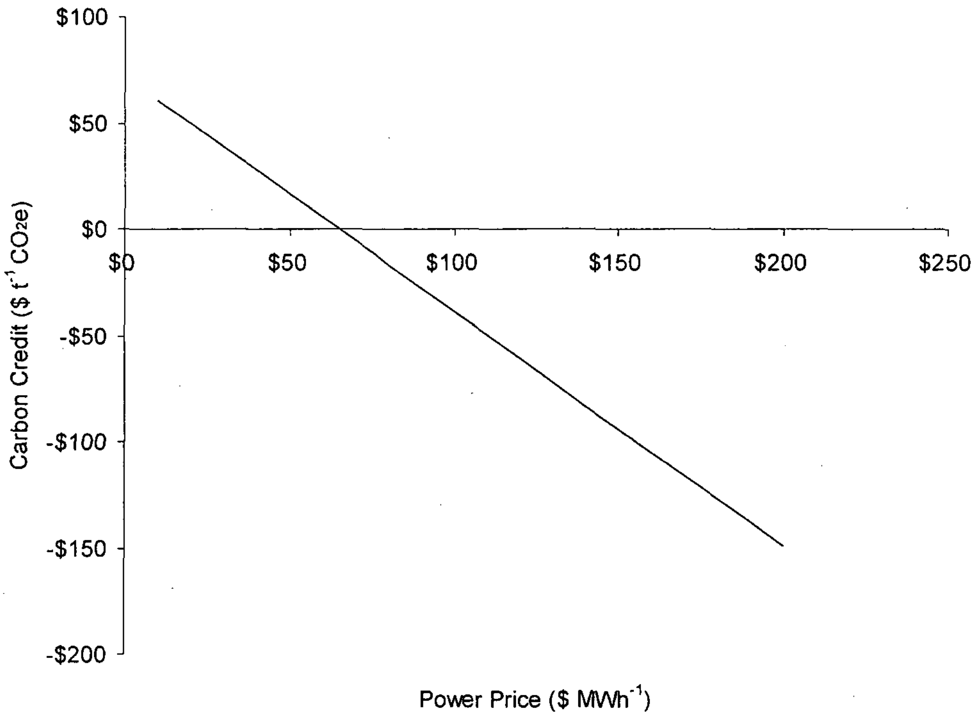


Figure 5.6. Relationship between the wholesale power price and the carbon credit required for direct combustion to be economical. Note that the power price at which point no carbon credit is required is $64.8 MWh^{-1}.

5.7 Sensitivity Analysis

Table 5.3. The impact of changing various parameters on the direct combustion carbon credit (t^{-1} CO_2e) for the low power price case (power price is \$60 MWh^{-1}), with the percentage change indicated below. The base case is for a plant size of 2875 dry t d^{-1}, with a biomass availability of 75% and a carbon credit of \$5.3 t^{-1} CO_2e. The delivered cost of biomass is the sum of field cost and transport cost.

	Base Case	**-10%**	**+ 15%**	**+ 30%**	**+50%**	**+100%**	**+150%**
Field Cost of biomass	\$14.29 MWh^{-1} \$25 actual t^{-1}	3.6 -32%	7.9 49%	10.4 96%	13.8 160%	22.4 323%	30.9 483%
Transport Cost of Biomass	\$14.96 MWh^{-1}	3.5 -34%	7.9 49%	10.7 102%	14.2 168%	23.7 347%	32.1 506%
Delivered Cost of Biomass	\$29.25 MWh^{-1}	1.8 -66%	10.5 98%	15.8 198%	22.8 300%	40.2 658%	57.7 989%
Processing Cost	\$30.38 MWh^{-1}	1.7 -68%	10.7 102%	16.2 206%	23.4 342%	41.6 685%	59.7 1026%
Wholesale Power price	\$60 MWh^{-1}	11.9 125%	-4.6 -187%	-14.5 -347%	-27.7 -623%	-60.6 -1243%	-93.6 -1866%
Direct Combustion Emissions[a]	48.9 g CO_2e kWh^{-1}	5.3 -1%	5.4 1%	5.4 2%	5.5 3%	5.6 6%	5.8 10%

[a]Includes emissions from harvesting, biomass transport and conversion

Unlike the other alternative technologies presented herein, there are several large-scale biomass-fired combustion facilities, and therefore the economic and emissions data for this technology is considered to be of highest relative confidence. However, it is possible that the economic estimates would be off by as much as 30%, and the wholesale power price (which is the factor of highest sensitivity) could vary widely based on various market conditions. Also, see Section 7.6 for a discussion on recent changes in construction costs.

The carbon credit required for direct combustion to be competitive with conventional technology is the most sensitive to changes in power price, followed by changes in processing cost. The changes in direct combustion emissions had very little impact on the overall value of the carbon credit, emphasizing that accuracy in GHG emissions from direct combustion is not crucial for the purposes of this study.

6 Power Production via BIGCC

Combined cycle power plants use the gas from gasification at high pressure in a turbine for the first cycle, and then recover remaining heat in a heat recovery steam generator (HRSG), with the steam then being used in a second cycle. Biomass cannot be injected directly into a turbine, and therefore must be gasified first. The resulting process is called BIGCC: biomass integrated gasification and combined cycle. BIGCC can potentially achieve significantly higher generation efficiencies, which depend on the net heating value of the biomass, which in turn is highly influenced by moisture content. Value of 45% to as high as 59% LHV are cited (Craig and Mann 1996, Cameron *et al.* 2007, Kumar 2004), making it the most energy-efficient power generating cycle on the market today (Williams and Larson 1996, Filippis *et al.* 2004, Mann and Spath 1997, US DOE 2006). As with direct combustion, scale can be expected to have a significant impact on the conversion efficiency (gross power output, MWe, per unit of energy input, LHV MW_{th}) of a BIGCC plant (Flynn and Kumar 2005, Uddin and Barreto 2007).

6.1 *Technical Summary*

As with other conversion technologies, BIGCC has many potential design variations, such as pressure, gasifier type, oxidant type (air, enriched air, or oxygen), single or double shaft, i.e. one generator with a gas turbine and steam turbine driver, or two generators, one per driver), and flow rate to name a few. BIGCC combines the extensively proven advanced gas turbine power generation or co generating cycles with biomass gasifiers, which can be designed similarly to gasifiers already developed for using coal (Liscinsky *et al.* 2003). Gasifier types have been described in Section 4.1. A schematic of BIGCC is shown in Figure 6.1.

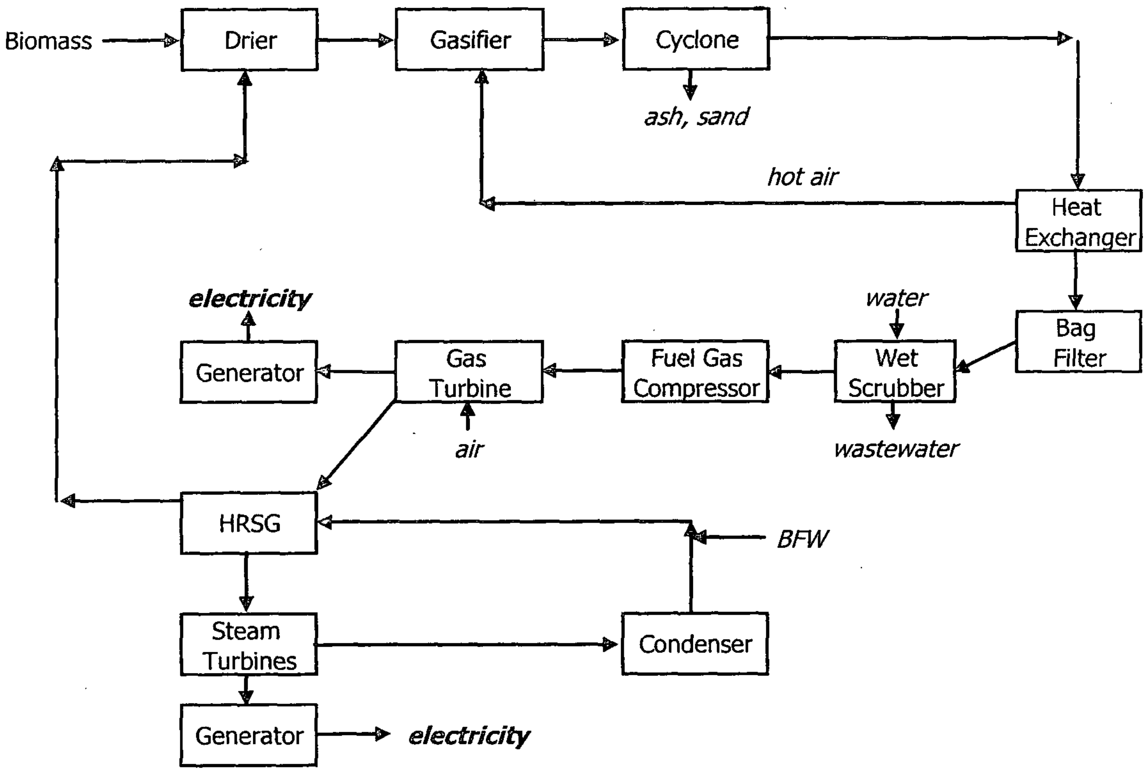


Figure 6.1. Schematic of BIGCC, modified from Craig and Mann (1996). BFW indicates boiler feed water. Air added to the gas turbine is compressed by the turbine.

The gas turbine achieves higher efficiency than combustion because the peak cycle temperature of modern gas turbines (as high as 1260 °C) is far higher than for steam turbines (approximately 540 °C) (Williams and Larson 1996). The US Department of Energy recommends a fluidized bed gasifier for BIGCC, as it has greater fuel size flexibility than entrained flow or fixed bed gasifiers, and has uniform temperature distribution which minimizes production of tars and oils (Liscinsky *et al.* 2003). This study will look at atmospheric direct-fired fluidized bed gasifiers, using air an oxidant.

Preheated air enters the gasifier near its base; hot gas exiting the gasifier passes through a cyclone that removes the majority of particulates which could foul the fuel gas cooler, plug the fabric filters, and increase wastewater treatment loads from the gas scrubber if left in the gas stream (Craig and Mann 1996). The gas then flows through a series of heat exchangers that drop the temperature to accommodate the baghouse filter and wet scrubber (Liscinsky *et al.* 2003, Rodrigues *et al.* 2006). The heat is recovered to enhance steam generation, to preheat the air fed to the gasifier, to preheat the synthesis gas before it enters the gas turbine, and to preheat the feedwater for the boiler (Rodrigues *et al.* 2006).

After cooling, a baghouse filter or candle (solid ceramic) filter removes the particulates and remaining contaminants are removed in the wet scrubber (Rodrigues *et al.* 2006, Craig and Mann 1996). Following this step, the gas may also be washed with a dilute sulfuric acid stream to further remove ammonia from the flue gas (Craig and Mann 1996). The fuel gas is sent to the gas turbine combustor where it is combusted causing expansion resulting in a decrease in the gas temperature. After this expansion, the exhaust goes to a HRSG where a supplemental fuel may be added to increase temperature. Some steam is returned to a reheater in the fuel gas stream where it is very highly superheated, while some of the steam is sent to the gasifier (Liscinsky *et al.* 2003).

BIGCC usually uses air as an oxidant as opposed to pure oxygen, which is expensive to separate; the exception would be if capture of CO_2 for sequestration was an objective. The fuel gas from air gasification of biomass is called producer gas, and has a lower heating value as much as ten times lower than that of natural gas (Rodrigues *et al.* 2006). Commercial "off the shelf" gas turbines, which were designed for operation on natural gas, must run in off design mode when using biomass which de-rates the output of the turbine.

6.2 *Economics*

For this study five BIGCC economic analyses were examined with capacities ranging in size from 42 to 200 MW_e gross (corresponding to 434 and 4521 dry t d^{-1}, respectively), and the parasitic load was considered to be 8% (Flynn and Kumar 2005).

Rollins *et al.* (2002) working with the Electric Power Research Institute completed a detailed multi-stage study of renewable energy including some cases with carbon capture and sequestration. Several scenarios were outlined, including various pressures of gasification, different oxidants (air, enriched air, or oxygen), a size was specified for each scenario. The study used wood as a feedstock with a feed rate of 434 dry t d^{-1}, generating 42 MW_e. The gasifier scenario from Rollins *et al.* evaluated in this study was an air-fed atmospheric fluidized bed type.

Uddin and Barreto (2007) performed an economic analysis on estimates of various BIGCC systems with and without carbon capture and storage, and with and without cogeneration. For consistency, carbon capture and storage was omitted from the costing in this study and the condensing scenario was chosen. There was costing given for one condensing BIGCC plant scenario, namely for a capacity of 100 MW_e with a logging residue feed rate of 1150 dry t d^{-1}.

Liscinsky *et al.* (2003) works with the United Technologies Research Center, and the study was conducted alongside other organizations including Pratt and Whitney Power Systems and the University of North Dakota. The team carried out a detailed economic and environmental analysis of a BIGCC system. The primary feedstock evaluated was refuse-derived fuel (paper, cardboard, plastic film (grocery bags, for example) with minor amounts of glass, wood, dense plastic, and metals), and was dried from a MC of

30% to 12% using waste process heat. The biomass is fed at a rate of 1058 dry t d^{-1}, and the plant has a generation capacity of 85 MW_e. Their study described various types of gasifiers and their benefits/disadvantages, as well as various potential feedstocks including municipal solid waste, refuse-derived fuels, forest residues, sawmill and other wood manufacture residues, among others. The report cited a confidence of +/- 20% for many system components.

Craig and Mann (1996) of NREL compiled a detailed cost and performance analysis of BIGCC power systems. The report gave details on three gasifiers, namely high-pressure air-blown, low-pressure indirectly-heated, and low-pressure air blown and capital and operating costs were assessed for each. Cost information was provided on installation, piping, instrumentation, buildings and structures, among other details. System components were described in detail and process flow diagrams were included. In this study we used data from Craig and Mann for an air blown low-pressure CFB. The gasifier was fed with 1297 dry t d^{-1} of wood, dried to 15% MC with waste system heat, and had a power generation capacity of 105 MW_e.

Rodrigues *et al.* (2003) provided component costs for a base scale of 30 MW_e, as well as the scale factors for each component such that the data could be scaled to determine costs for any size atmospheric air-blown CFB BIGCC plant between 20 and 300 MW_e. In this study we use the data of Rodriques *et al.* at 200 MW_e, which corresponds to a feed rate of 2541 dry t d^{-1}. The reference feedstock was bagasse (sugar cane residue), which was dried to 15% MC using flue gas from the HRSG. Cost information was also provided for transportation and natural gas co-firing with scenarios of 10, 30, 50, and 70% natural gas.

The data from the five studies was manipulated such that all cost information was on a common and consistent basis for comparative purposes and to determine the scale factor implicit from the various studies. Costs associated with carbon sequestration and storage were removed, and all currencies were converted to 2006 USD. Costs associated with the purchase and delivery of feedstock were removed from all of the studies due to regional variation and to compare the processing costs independent of feedstock cost. A 12% pre tax return on investment was applied to all studies, and a plant availability of 90% was applied to all cases. The annual maintenance expense was considered to be 3.0% of the total capital investment, which is the average of all of the studies. Rollins *et al.*, Licsinsky *et al.*, and Craig and Mann each provided a component cost breakdown for the size scenario in their respective studies, and Rodrigues *et al.* provided sufficient detail to determine capital and operating costs from any scale between 50 and 450 MW_e. The total capital cost and cost of production of each study are summarized in Table 6.1, and are plotted in Figures 6.2 and 6.3 below.

Table 6.1. Project economics for the five BIGCC systems examined.

	Rollins et al.	Uddin & Barreto	Liscinsky et al.	Craig & Mann	Rodrigues et al.
Feedstock	Wood	Logging Residues	Refuse-Derived Fuel	Wood	Sugar Cane Residue
Feedrate (dry t d^{-1})	555	1149	1058	1297	3040
MWe Net	38.5	92	78.2	96.6	200
Total Capital investment (M)	$ 96,768	$ 148,764	$ 122,834	$ 218,709	$ 232,648
Annual Cap Recovery (M)	$ 12,338	$ 18,967	$ 15,661	$ 27,885	$ 29,663
Total Annual O&M costs (M)	$ 5,595	$ 8,452	$ 11,182	$ 13,598	$ 13,959
Cap Recov + O&M (M)	$ 17,933	$ 27,420	$ 26,843	$ 41,483	$ 43,621
(Cap Recov + O&M) MWh^{-1}	$ 59.06	$ 37.80	$ 43.54	$ 54.47	$ 27.66

Capital cost estimates for the five cases are summarized in Figure 6.2. Two mid range values, from Liscinsky *et al.* (2003) and Craig and Mann (1996) stray from the best fit curve. Liscinsky *et al.* have a significantly lower cost for the gasifier and gas clean up components relative to Craig and Mann; these studies, relative to the others in the group, appear low and high respectively. The scale factor from the best fit of the data, 0.56, is low relative to values typically used for power generation plants. Both the study by Craig and Mann (1996) and that by Rollins *et al.* (2002) cite a scale factor of 0.7, and according to Cameron *et al.* (2007), scale factors for this technology range from 0.59 to 0.89.

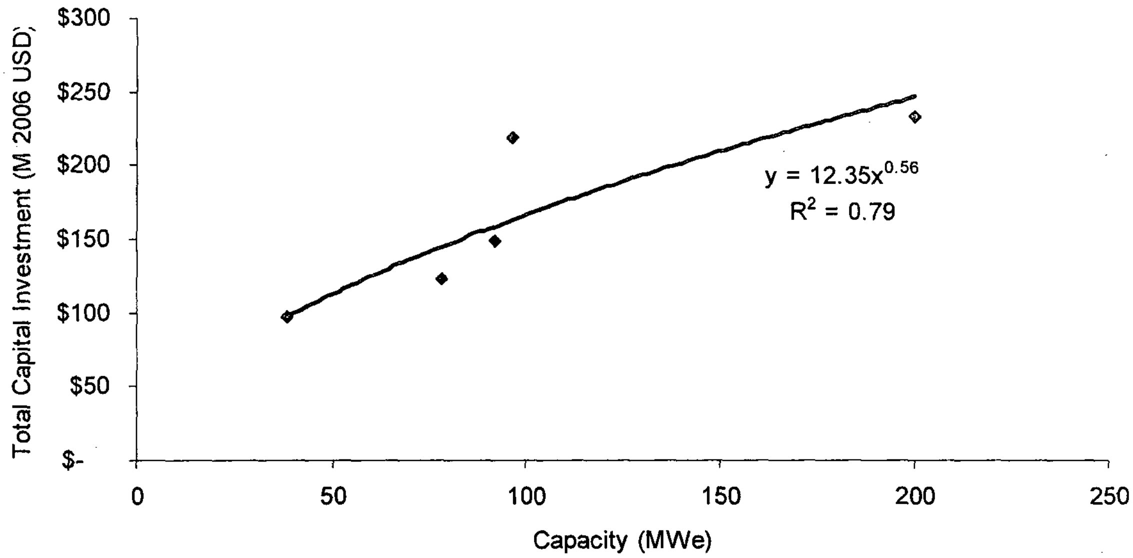


Figure 6.2. Relationship between total capital investment and power generating capacity for BIGCC.

Processing cost, including capital recovery and operating cost for the five BIGCC cases, is plotted against generation capacity in Figure 6.3 below. Again, the mid range points of Liscinsky *et al.* and Craig and Mann deviate from the best fit line. The best fit line has an uncharacteristically low scale factor, 0.56, and this number would not be considered representative of such a technology, as mentioned above. The low scale factor can be attributed to the small data set, and modifying any one of the data points, or adding another point, may significantly impact the scale factor.

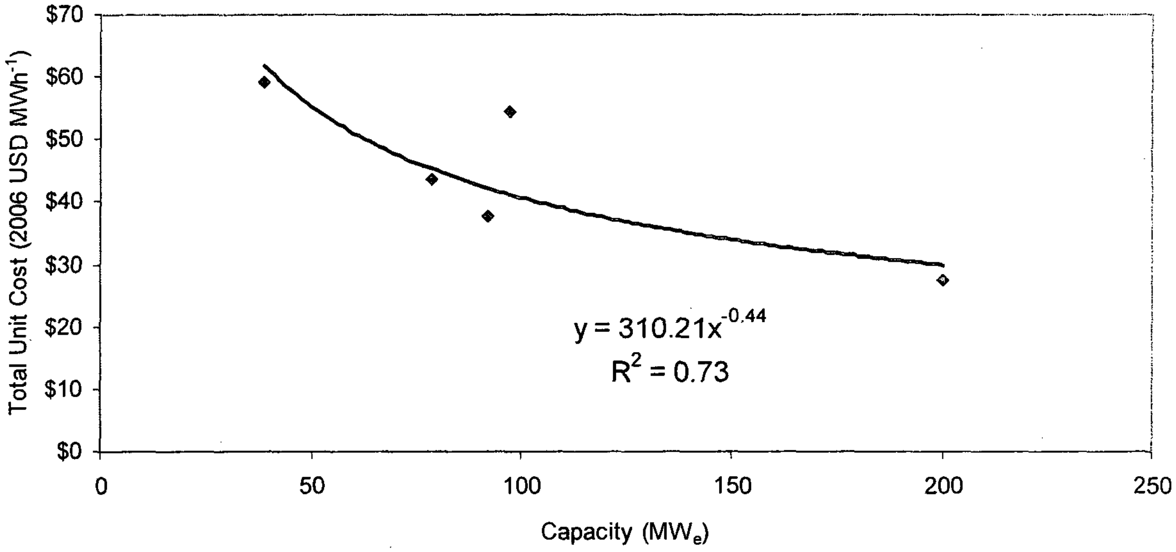


Figure 6.3. Relationship between processing cost and power generation capacity for BIGCC.

A more representative scale factor of 0.7 was selected. The coefficient of the processing cost curve was determined by best fit minimizing the regression of the data points from an equation of the form $y=ax^{-0.3}$ (reflecting a scale factor of 0.7), solving for a. The coefficient was found to be 169.95, and the comparison of the revised curve to the best fit curve from the data is shown in Figure 6.4. The equation used herein for processing cost of BIGCC power is $y = 170\ x^{-0.3}$.

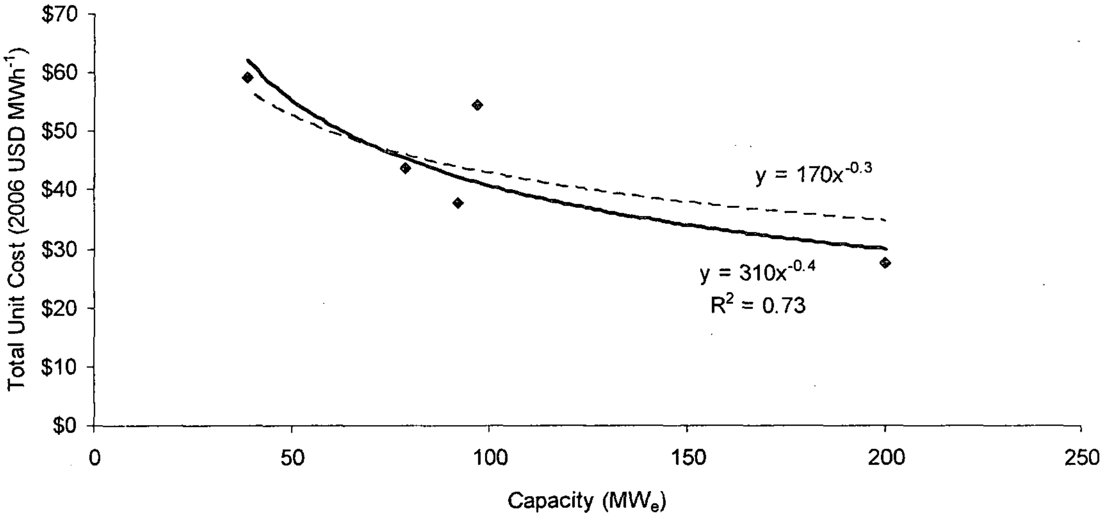


Figure 6.4. Best fit curve produced using literature data (solids line) compared to the curve produced using a scale factor characteristic of BIGCC (dashed line).

The equation in figure 6.4 produced from fitting a scale factor of 0.7 yields unit cost values lower than the corresponding direct combustion equation. In particular, the increase in capital cost relative to direct combustion, 1.13, is less than the increase in efficiency, 1.22, which would suggest that BIGCC would always be favored relative to direct combustion. However, this is not the case for coal fired power plants, where in the absence of emission constraints developers have consistently chosen direct combustion over coal IGCC. For that reason we place a particular emphasis on an analysis of coal IGCC costs, which have been analyzed in greater detail than BIGCC.

6.2.1 Fossil IGCC Plant Costs

Integrated air gasification and production of power via combined cycle has been applied to coal to increase power production per unit of fossil carbon emissions. Previous studies have noted that production of power via gasification gives a lower overall power cost for more expensive fuels (Cameron *et al.* 2007). Unlike direct combustion, however, there are no large scale BIGCC plants in operation, and capital and operating cost estimates are therefore less certain. Figure 6.5 shows capital cost per MW capacity for five studies of BIGCC listed above and also includes values for coal IGCC from a recent US DOE study (US DOE 2007). In Figure 6.5 we show a line that fits the US DOE study of coal IGCC capital costs and a second line that best fits the BIGCC studies, with a scale factor set to 0.7 for both lines. The capital cost for BIGCC is 59% of the coal IGCC data, whereas one would expect BIGCC to have a higher capital cost than coal IGCC because of the more difficult nature of biomass as a solid fuel in gasification. Given the low state of commercial development of BIGCC we consider the actual IGCC cost data to be the more accurate predictor of future BIGCC costs.

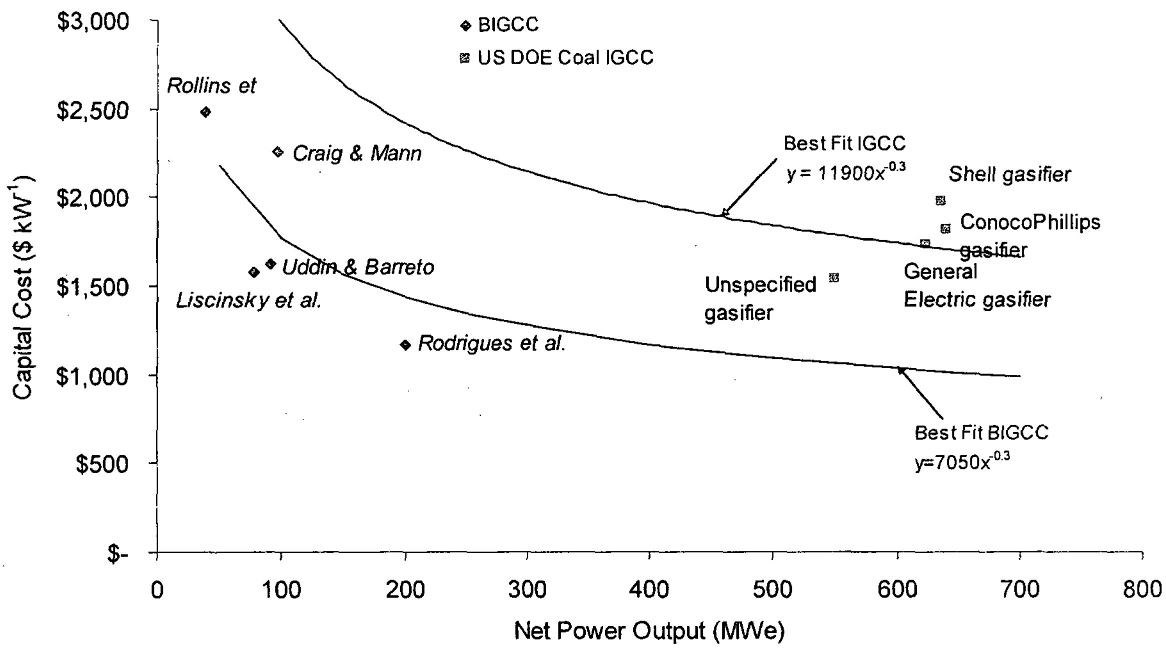


Figure 6.5. Capital cost of BIGCC and IGCC as a function of plant size.

The cost numbers used herein for BIGCC were extracted from Figue 6.5, and are represented by:

Processing Cost, USD MWh^{-1} = 297 (Plant Size, MW)$^{-0.3}$

When the BIGCC cost numbers from the literature were increased upon considering coal IGCC cost numbers, the cost of BIGCC power relative to direct combustion will be higher for low delivered cost of biomass. However for high values of the delivered cost of biomass the higher efficiency of BIGCC relative to direct combustion will eventually lead to a lower power cost. Hereafter we use an adjusted BIGCC cost value to compensate for the discrepancy between IGCC and BIGCC values, and we therefore increased BIGCC cost numbers by a factor of 1.75. This value is slightly higher than the 1.7 increase of the coal IGCC literature values over the BIGCC literature costs. The slight increase compensated for the increase cost of using biomass as a power source over coal.

6.2.2 BIGCC Optimum Plant Size

The optimum plant size was determined for the production of power from BIGCC using straw as a feedstock (Figure 6.6).

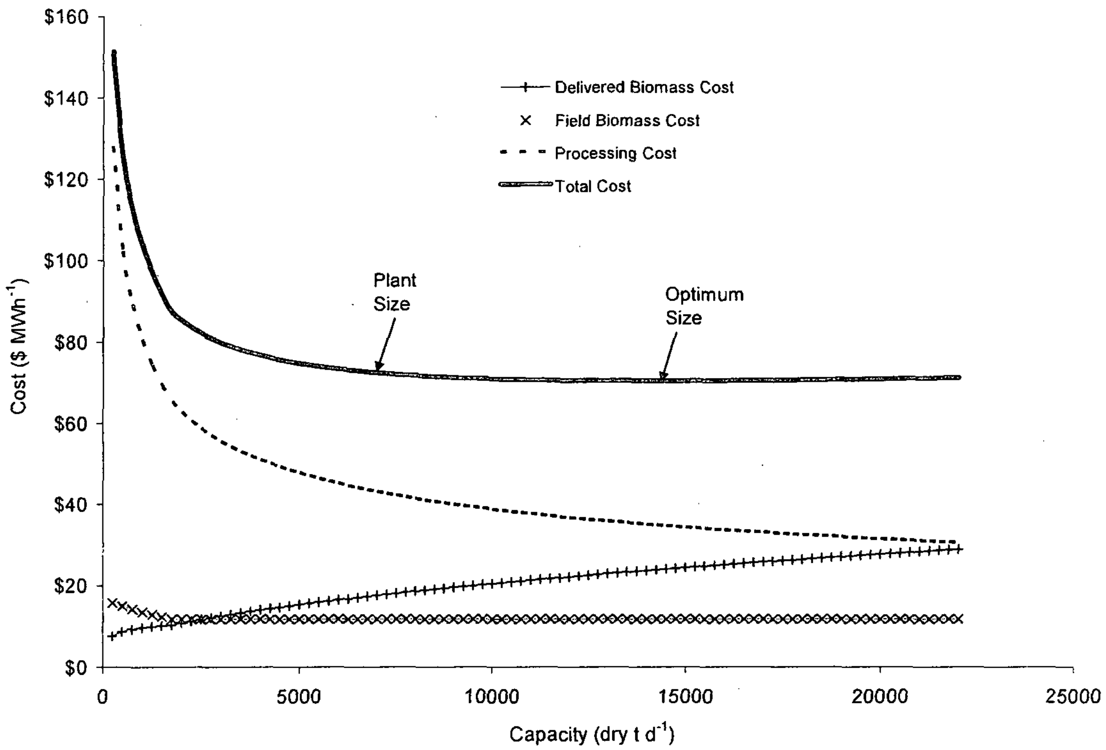


Figure 6.6. Determination of optimum plant size for BIGCC using straw. Note that the BIGCC cost numbers extracted from the literature were increased by a factor of 1.75 after considering actual construction cost of IGCC plants.

From Figure 6.6, the optimum plant size for power production from BIGCC is 14250 dry t d^{-1}, corresponding to a power production of 1270 MW_e. To reduce capital investment, a plant size corresponding to a total unit cost 3% higher than that at optimum size was used. Therefore, the plant size for BIGCC was 7000 dry t d^{-1}, which corresponds to a gross plant size of 623 MW_e. This plant size has an average collection distance of 190 km, which results in a transport cost of biomass of $17.53 MWh^{-1}. The field cost of biomass would be $11.71 MWh^{-1}, and the processing cost would be $43.16 MWh^{-1}, giving a total production cost of $72.40 MWh^{-1}.

6.3 BIGCC GHG Emissions

Most studies consider emissions relating to the production of power from delivered biomass to be negligible or zero (Kumar et al., 2003; Larson et al., 2006; European Council for Automotive R&D, 2006). Mann and Spath (1997) developed a highly detailed analysis of a 113 MW_e BIGCC power plant (1334 dry t d^{-1} of wood) assuming future improvements in technology, and from this study we can conclude that there are only negligible incremental emissions directly resulting from plant operation, as compared to supercritical coal power generation. We follow the practice of most studies and treat emissions from power production from biomass as negligible relative to coal fired power plant emissions, as shown in Table 6.2.

Table 6.2. Summary of emissions from the production of the power via BIGCC of biomass (Mann and Spath 1997).

Stressor	Air Emissions (g kWh^{-1})	Equivalent Emissions (g kWh^{-1})
CO_2	Negligible	Negligible
CH_4	0.00027	0.00567
N_2O	0	0
	Total CO_2e (g kWh^{-1})	Negligible

As per Mann and Spath (1997), 96% of the system N_2O emissions are from feedstock production, with the majority coming from diesel combustion during farming operations (58%), and therefore negligible amounts were generated during power production. In this study emissions from the production, harvesting and transportation of straw are accounted for separately from straw processing.

6.4 Emissions Summary

Table 6.3. Summary of emissions from the production and transport of feedstock, and the conversion of feedstock into power for coal combustion and BIGCC of straw (g CO_2e kWh^{-1}) at a scale of 7000 dry t d^{-1}).

	Coal[a]	BIGCC	Difference
Production and Harvesting of Biomass	NA	39.2	-39.2
Transport of Biomass	NA	5.15	-5.15
Extraction, Transport and Power Production from Coal	886	NA	886
Power Production from Straw	NA	0	0
Total	886	44.3	840

[a] Determination of coal emissions summarized in Section 5.3.

6.5 Value of Carbon Credit Required to Support a BICGG Plant

The net power output from the BIGCC plant at 7000 dry t d^{-1} was multiplied by the wholesale price of power ($60 MWh^{-1} and $75 MWh^{-1} for the low and high case, respectively), and from this the annual production cost (total cost of BIGCC gross power) was subtracted. This difference was divided by the emissions from the gross power output to get the carbon credit required for direct combustion to be competitive with super critical coal power. Using the low value yields $20.5 t^{-1} CO_2, while the high value yields a carbon credit of $4.0 t^{-1} CO_2.

Figure 6.7. shows the relationship between required carbon credit and power price. The power price where a carbon credit is no longer required is of $78.7 MWh^{-1}.

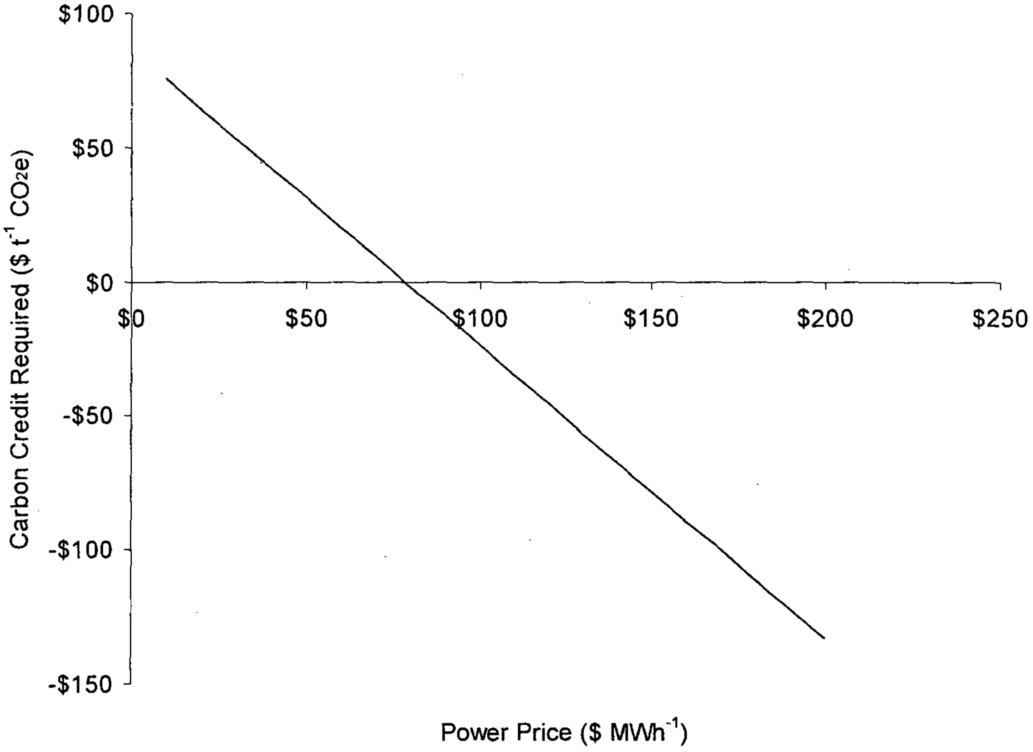


Figure 6.7. Relationship between carbon credit and power price for BIGCC.

6.6 Sensitivity Analysis

Table 6.4. Impact of changing various parameters on the required BIGCC carbon credit (t^{-1} CO$_2$e) for the low case (power price is \$60 MWh^{-1}), with the percentage change indicated below. The base case is for a plant size of 7000 dry t d^{-1}, with a biomass availability of 75% and a carbon credit of \$20.5 t^{-1} CO$_2$e.

	Base Case	**-10%**	**+ 15%**	**+ 30%**	**+50%**	**+100%**	**+150%**
Field Cost of biomass	\$11.71 MWh^{-1} \$25 actual t^{-1}	19.1 -7%	22.6 10%	24.7 20%	27.5 34%	34.5 68%	41.4 102%
Transport Cost of Biomass	\$17.53 MWh^{-1}	18.4 -10%	23.6 15%	26.8 31%	30.9 51%	41.4 102%	51.8 153%
Delivered Cost of Biomass	\$29.24 MWh^{-1}	17.0 -17%	25.7 25%	30.9 51%	37.9 85%	55.4 170%	72.8 255%
Processing Cost	\$43.16 MWh^{-1}	15.4 -25%	28.2 38%	35.9 75%	46.2 125%	71.9 251%	97.7 377%
Wholesale Power price	\$60 MWh^{-1}	27.1 32%	10.6 -48%	0.8 -96%	-12.4 -160%	-45.3 -321%	-78.2 -481%
BIGCC Emissions[a]	47.05 g CO$_2$e kWh^{-1}	20.4 -1%	20.7 1%	20.9 2%	21.1 3%	21.7 6%	22.4 9%

[a] Includes emissions from harvesting, biomass transport and conversion

Much of the information used in the economic and emissions analyses herein is based on estimates derived from conventional gasification plants. As there are no commercial scale facilities, the information is of lower certainty than that for direct combustion and enzymatic hydrolysis. Also, inconsistencies in biomass based literature data with conventional IGCC plant cost estimates have resulted in further assumptions on costing not made in the other renewable technologies examined. The wholesale power cost is again the main influence on the value of the carbon credit, followed by the processing cost. See Section 7.6 for comments on recent increases in construction costs. The magnitude of the changes in carbon credit are lower than for direct combustion due to the higher base case value of the BIGCC required carbon credit.

Also of note is the small change in carbon credit with changing BIGCC emissions, emphasizing that an accurate emissions value is less crucial than accuracy in other areas.

7 Choosing a Processing Technology

Previous chapters detailed the steps taken in estimating total unit cost and emissions for the production of power via BIGCC and direct combustion, and the production of vehicle fuels via enzymatic hydrolysis and FT synthesis. Capital and operating costs were extracted from the literature, and brought to a consistent basis by adjusting currency values, applying a fixed rated of return (12%) over a common 25 year plant life, and applying a common standard for maintenance cost. Once optimum size and plant size were determined, all technologies were analyzed for a common feedstock. Section 7.1 considers results for two specific conventional price scenarios, and Section 2.7 analyzes the social cost of renewable energy over a continuous range of pricing.

7.1 Summary of Results

The economic and emissions results for the four renewable technologies are summarized in Table 7.1.

Table 7.1. Summary of results. Biomass availability is 75% (gross yield = 0.32 t gross ha^{-1}), and a field cost of biomass of \$25 t^{-1}. "Conventional" refers to the fossil alternative (i.e. oil or grid power).

	Ethanol	**FT Syndiesel**	**Direct Combustion**	**BIGCC**
Optimum Size (dry t d^{-1})	8250	16250	5750	14250
Plant Size (dry t d^{-1})	4000	8000	2875	7000
Output	416 ML yr^{-1}	581 ML yr^{-1}	209 MW$_{gross}$	623 MW$_{gross}$
Total Product Cost	\$0.40 L^{-1}	\$0.74 L^{-1}	\$59.6 MWh^{-1}	\$72.4 MWh^{-1}
Total Product Cost (\$ t^{-1} dry biomass input)	127	164	110	145
Total Production Emissions[a] (g CO$_2$e)	-260 L^{-1}	650 L^{-1}	49 kWh^{-1}	44 kWh^{-1}
Avoided Emissions (g CO$_2$e)	2,060 L^{-1}	2,440 L^{-1}	837 kWh^{-1}	840 kWh^{-1}
Avoided Emissions (g CO$_2$e t^{-1} dry biomass input)	650	540	1550	1680
Conventional Sale Price- Low Case	\$65 bbl^{-1}, \$0.54 L^{-1}	\$65 bbl^{-1}, \$0.59 L^{-1}	\$60 MWh^{-1}	\$60 MWh^{-1}
High Case	\$90 bbl^{-1}, \$0.71 L^{-1}	\$90 bbl^{-1}, \$ 0.75L^{-1}	\$75 MWh^{-1}	\$75 MWh^{-1}
Carbon Credit @ Plant Size, Low Case (t^{-1} CO$_2$e)	\$ 22.2	\$ 59.6	\$ 5.3	\$ 20.5
High Case (t^{-1} CO$_2$e)	-\$32.2	-\$4.7	-\$11.2	\$4.0
Conventional Price Where No Carbon Credit is Required	\$75 bbl^{-1}	\$84 bbl^{-1}	\$65 MWh^{-1}	\$79 MWh^{-1}
Relative Certainty	Medium	Low	High	Medium/Low

[a] includes production, transport, and conversion

Optimum size increases with increasing capital cost, and therefore as expected FT has the largest optimum size, followed by BIGCC, ethanol production, and direct combustion. Increasing plant size increases capital investment. In an effort to decrease capital investment, a consistent small relaxation in the minimum cost criterion was applied to all technologies to determine the plant size to be used in this study. This reflects our belief that actual project developers would accept some increase in processing cost in order to reduce plant size and thereby reduce the amount of capital at risk.

Looking at the total product cost on a per dry biomass input basis, we can again see that direct combustion is the lowest cost option, followed by ethanol production, BIGCC, and finally FT synthesis. For emissions, the clear driver is the level of emissions from the conventional technology, as the renewable alternatives have low emissions in comparison. On the basis of per dry tonne biomass input, the power alternatives have much higher avoided emissions, because of the higher energy conversion efficiency of the power alternatives over the transportation fuel options and because the starting fuel is coal, with a higher carbon density.

The carbon credit, which is the incremental cost per unit avoided emissions, represents the cost and benefit of adopting a renewable energy technology. Combining the economic and emissions data, the technology with the lowest carbon credit for the low conventional price scenario is direct combustion, followed by BIGCC, ethanol production, and FT synthesis. For the high conventional price scenario, the technology requiring the lowest carbon credit is ethanol, followed by direct combustion, FT synthesis, and BIGCC. In the high case, BIGCC is the only technology for which the conventional price does not exceed the price where a carbon credit is no longer required to achieve a 12% return on total capital. Said another way, BIGCC is the only technology where the carbon credit is still a positive value. (The impact of energy price on carbon credit is discussed in further detail in 7.2.) A summary of the sensitivity analyses is shown in Table 7.2.

Although the values depend on assumptions (see Section 8.0 for comments on study limitations), the carbon credits for the power generation technologies in Table 7.1 were compared to that found in literature. Of particular impact are the assumed local power price, the business as usual power generation technology, and assumed feedstock cost.

Kumar *et al.* (2008) estimated the carbon credit required for a 300 MW direct combustion plant burning damaged wood to be below \$15 t^{-1} CO_2, assuming a business as usual coal power source. Van den Broek *et al.* (2001) compared the carbon credit required for the direct combustion of energy crops in Nicaragua (displacing fuel oil based electricity), Ireland (displacing peat based electricity), and the Netherlands (displacing coal based electricity). Each country had different power and land costs, and different biomass availabilities. The carbon credits required were higher than that found for the direct combustion scenario in the study: Nicaragua required \$14 t^{-1} CO_2, Ireland required between \$22 and 52 t CO_2^{-1}, and the Netherlands required between \$55 and 85 t^{-1} CO_2. The higher values are in partial reflection of higher biomass costs and the low assumed efficiency (20%) of biomass direct combustion plants due to small size. Spath and Mann (2004) estimated the required carbon credit for the large-scale direct combustion of urban waste wood, without and with carbon capture and sequestration. Using coal-fired power as the business as usual power course, the values with and without sequestration were \$48 t^{-1} CO_2 and \$44 t^{-1} CO_2, respectively. Using natural gas combined cycle power as the business as usual power case, the values without and with sequestration were \$44 t^{-1} CO_2 and \$19 t^{-1} CO_2, respectively.

Gustavsson and Madlener (2003) compared 50 – 100 MW wood-fed BIGCC systems in Sweden to natural gas-based power production, with and without sequestration. The carbon credits varied between \$50 and 300 t^{-1} CO_2, and the carbon capture scenarios required a higher credit. Moomaw and Moreira (2001) considered the same technologies and cited a range of required carbon credits from \$60 to 224 t^{-1} CO_2. A higher biomass cost and lower business as usual emission contribute to the higher value of carbon credit values. Walter and Overend (1999) looked at BIGCC using sugar cane bagasse using natural gas combined cycle as the business as usual power course, and found that a carbon credit below \$30 t^{-1} CO_2 was required. Spath and Mann (2004) estimated the required carbon credit for gasification via BIGCC of urban waste wood, with and without carbon capture and sequestration. Using coal-fired power as the business as usual power course, the values without and with sequestration were \$38 t^{-1} CO_2 and \$22 t^{-1} CO_2, respectively.

Table 7.2. Comparison of sensitivity analyses of the carbon credit required at plant size considering the low case price of conventional output (an assumed oil price of \$65 bbl^{-1} and power price of \$60 MWh^{-1}). For each scenario, the lowest carbon credit is bolded, and the units are \$ t^{-1} CO_2e.

	Ethanol	**Fischer Tropsch**	**Direct Combustion**	**BIGCC**
Highest Sensitivity	Gasoline Price	Diesel Price	Power Price	Power Price
Base Case	*22.2*	*59.6*	5.3	*20.5*
150% Increase in Field Cost of Biomass	90.2	121.1	**30.9**	41.4
150% Increase in Transport Cost of Biomass	91.0	169.7	**32.1**	51.8
150% Increase in Delivered Cost of Biomass	159.0	239.2	**57.7**	72.8
150% Increase in Processing Cost	180.3	334.7	**59.7**	97.7
150% Increase in Renewable Emissions	28.9	99.3	**5.8**	22.4
30% Increase in Conventional Fuel Price	**-30.0**	-13.4	-14.5	0.8
50% Increase in Conventional Fuel Price	**-64.9**	-62.1	-27.7	-12.4
100% Increase in Conventional Fuel Price	-152.1	**-183.8**	-60.6	-45.3

With the exception of modifying the conventional fuel cost, direct combustion always results in the lowest required carbon credit, even when parameters are increased by 2.5 times. The variable that has the greatest impact on the magnitude of the carbon credit is the value of the conventional replacement, i.e. gasoline, diesel, or power price. When the power price/oil price is increased by 30% (corresponding to a power price of \$78 MWh^{-1} and an oil price of \$84.5 bbl^{-1}), ethanol becomes the lowest carbon credit alternative. When we again increase the cost of the conventional alternative to 50% above the base case scenario (corresponding to a power price of \$90 MWh^{-1} and oil price of \$97.5 bbl^{-1}), ethanol is still the lowest but the value of the carbon credit is very close to that of FT. Fischer Tropsch has the lowest carbon credit when the conventional fuel price is doubled.

Increasing the emissions from the renewable energy processing has a much bigger impact on the percent change in carbon credit for the transportation fuels than for the power production alternatives. This is a reflection of the increased emissions savings (relative to cost) in power production over transportation fuel production; processing biomass to produce power has negligible emissions while processing to transportation fuel has some. The impact of renewable energy emissions uncertainty is low for all cases except FT. For FT, the impact is significant, but note that the degree of uncertainty in Table 7.2 is very high, 2.5 times the base case.

7.1.1 Certainty of Carbon Credit

As noted above, there is a degree of uncertainty in both the cost estimates and LCA emissions estimates. Cited values for cost estimates are often 25% to 30%; we consider these to be low for technologies which have not been operated at a demonstration scale (BIGCC and FT), and perhaps low for ethanol since cost data from the plants under construction at commercial scale are not yet available. LCA emissions estimates often have a cited accuracy of 25% to 30%, although considering that the majority of the emissions credit arises from substitution of the fuel, and the relative impact of emissions during processing is low, the actual accuracy of the total avoided emissions may be less than 25%. Regardless of the absolute accuracy, it is clear that the carbon credit calculation combines two uncertain numbers and has a high degree of uncertainty. However, the level of uncertainty in choices between technologies is lower than the uncertainty in the absolute value of the carbon credit because some of the uncertainty, for example the impact of recent rises in equipment cost, would affect all technologies.

7.2 Implications for Technology Selection

Figures 3.5b and 4.9b, and 5.6 and 6.7 showed the plots of carbon credit vs. oil price or power price for each of the technologies, and were combined to produce Figures 7.1 and 7.2. At all power prices the carbon credit required to sustain a direct combustion power plant is less than that for BIGCC; this is a function of the gross availability of straw/stover, discussed further in Section 7.4.2.

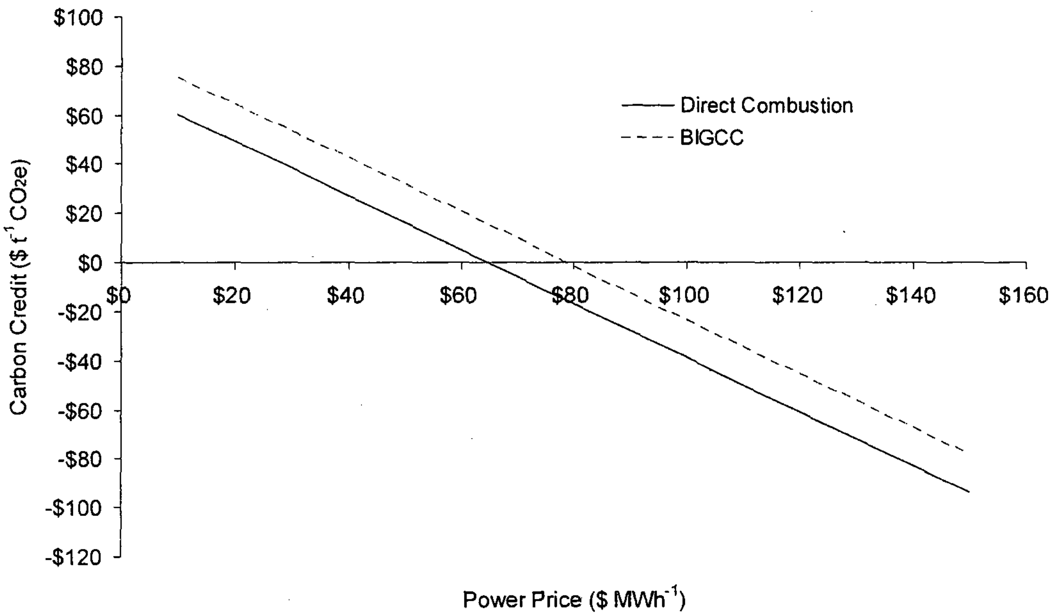


Figure 7.1. Carbon credit required for a 12% pre-tax return on total capital for power production via direct combustion and BIGCC from straw/stover.

Figure 7.2 shows that when we look at a combined plot of carbon credit vs oil price for ethanol and FT, there is a crossover point, and when the oil price increases beyond this point it is more economical to produce syndiesel than ethanol. Recall ethanol production is prorated to a gasoline equivalency based on an energy equivalency: 21.1 GJ L^{-1} of ethanol vs. 32.0 GJ L^{-1} for gasoline (ORNL 2007), based on the premise that vehicle distance traveled is proportional to energy content (MacLean et al. 2000).

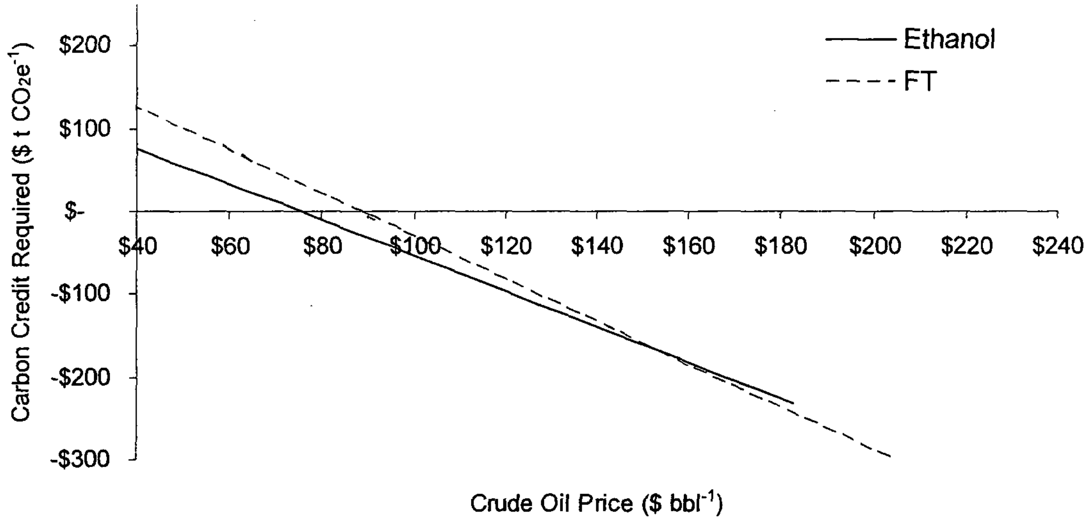


Figure 7.2. Carbon credit required for a 12% pre-tax return on total capital for ethanol production and FT synthesis from straw/stover.

The point of the crossover in Figure 7.2 is dependant on the relationship between oil price and gasoline or diesel price. As discussed in the Appendix, this relationship is not precise for many reasons, and involved using a "best fit", shown in Figure 7.3a, which gives a marginal value for gasoline (the slope) significantly in excess of that for diesel. This may reflect specific supply demand factors for the two fuels during the time period analyzed. We therefore presented a second scenario in Figure 7.3b, where we fixed the slope of the two regression curves to be proportional to the energy content of the two fuels, 32.0 MJ L^{-1} for gasoline and 36.4 MJ L^{-1} for diesel (ORNL 2007), and use a best fit technique to set the intercept.

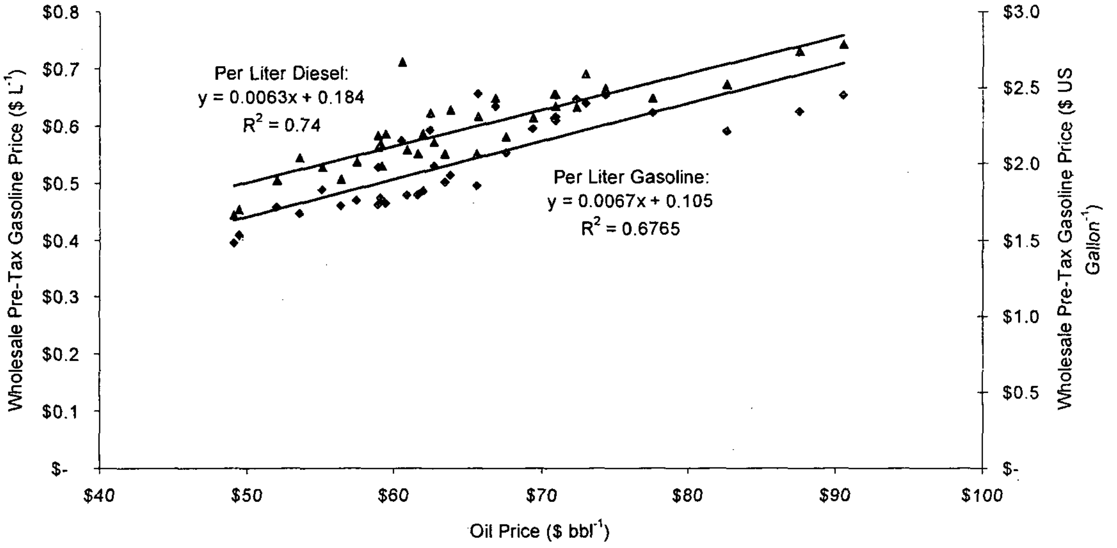


Figure 7.3a. Relationship between oil price and gasoline/diesel price as determined by a best fit model.

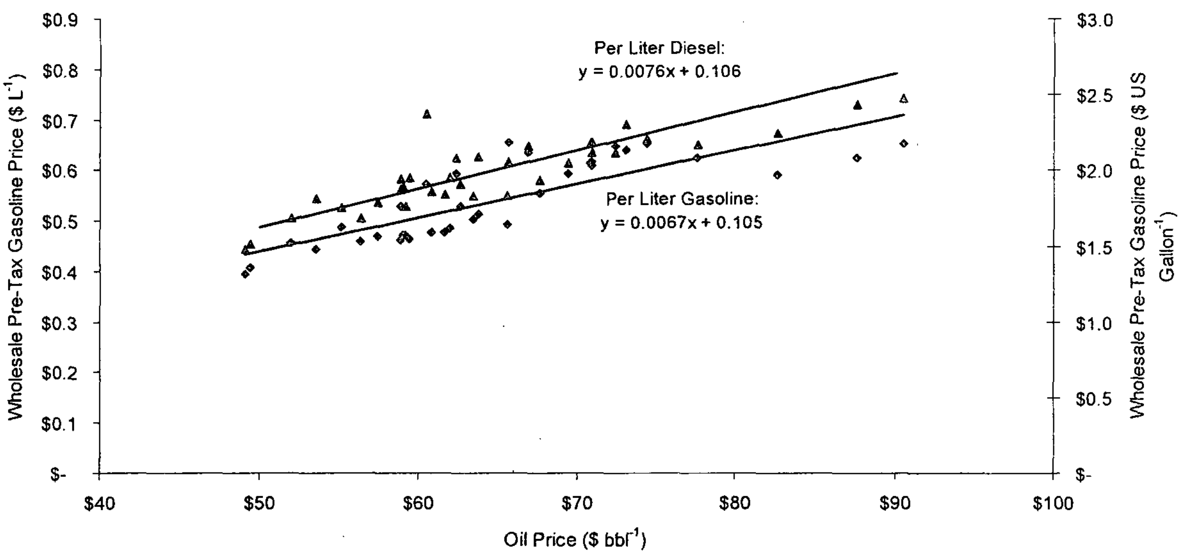


Figure 7.3b. Correlation between oil and gasoline price by best fit with a slope proportional to the energy content of diesel vs. gasoline .

We use the relationships in Figure 7.3b to determine the required carbon credit for the two transportation fuel alternatives as a function of oil price, shown in Figure 7.4.

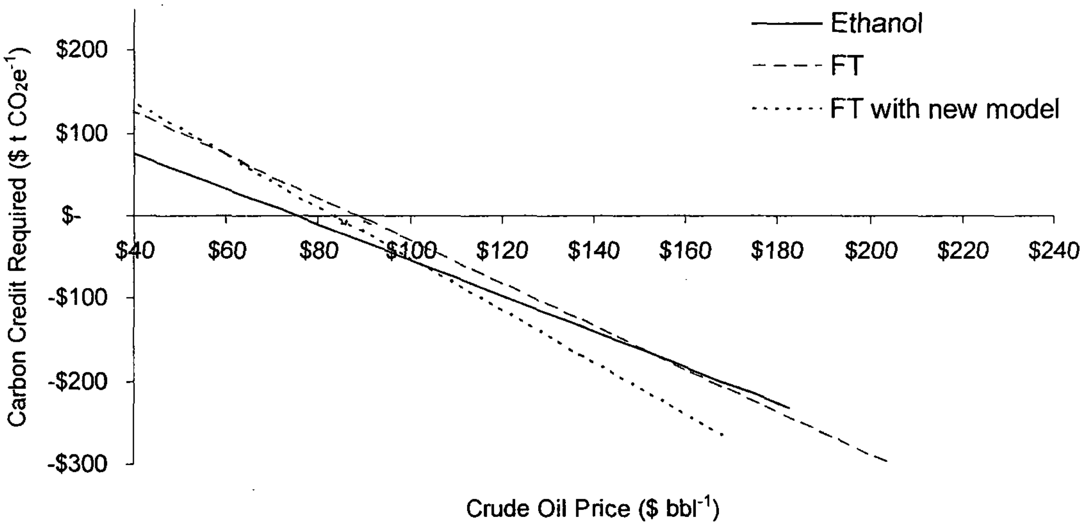


Figure 7.4. Carbon credit required for a 12% pre-tax return on total capital for two straw/stover transportation fuel alternatives. The results of two different models used for the relationship of gasoline and diesel to oil price are shown.

Note that the slope of the carbon credit required for power production by direct combustion and BIGCC is virtually identical, because the annual production volume per annual avoided emission is very close for the two processing technologies. This is a result of very low CO_2e emissions from the biomass processing, with the slight difference in this study between direct combustion and BIGCC arising from slightly different emissions from transportation of biomass. The slope for producing gasoline and diesel is not identical because the LCA emissions avoided per unit of production are different for the two processes. The difference in emissions results largely from the power source: while FT depends on grid power, the ethanol plant generates carbon-neutral energy from lignin. For all power costs, at a gross availability of 0.32 dry t ha^{-1} the social payment required to support direct combustion and the power cost at which no social payment is required is lower than for BIGCC. At this availability of straw/stover, power via direct combustion has a lower social cost than BIGCC, and is the favored technology. For oil prices up to a range of \$100 to \$150 bbl^{-1}, depending on the correlation of oil price to gasoline and diesel price, the production of ethanol is favored over Fischer Tropsch production of diesel, for the same reason.

The selection between two processes that make different end products, in this study electricity and transportation fuel, depends on the relative pricing of the two products. Figure 7.5 shows the line for oil and power price at which the calculated carbon credit for lignocellulosic ethanol and power production by direct combustion are equal. In the region above the line production of ethanol has a lower social cost, and below the line power production does. The point at which no social subsidy of renewable energy is required is also identified. Figure 7.5 also shows the approximate values of oil and power in North America for several time periods, showing that the selection of the end use form of energy to achieve a minimum social input per unit of avoided carbon dioxide would depend on relative energy pricing far into the future.

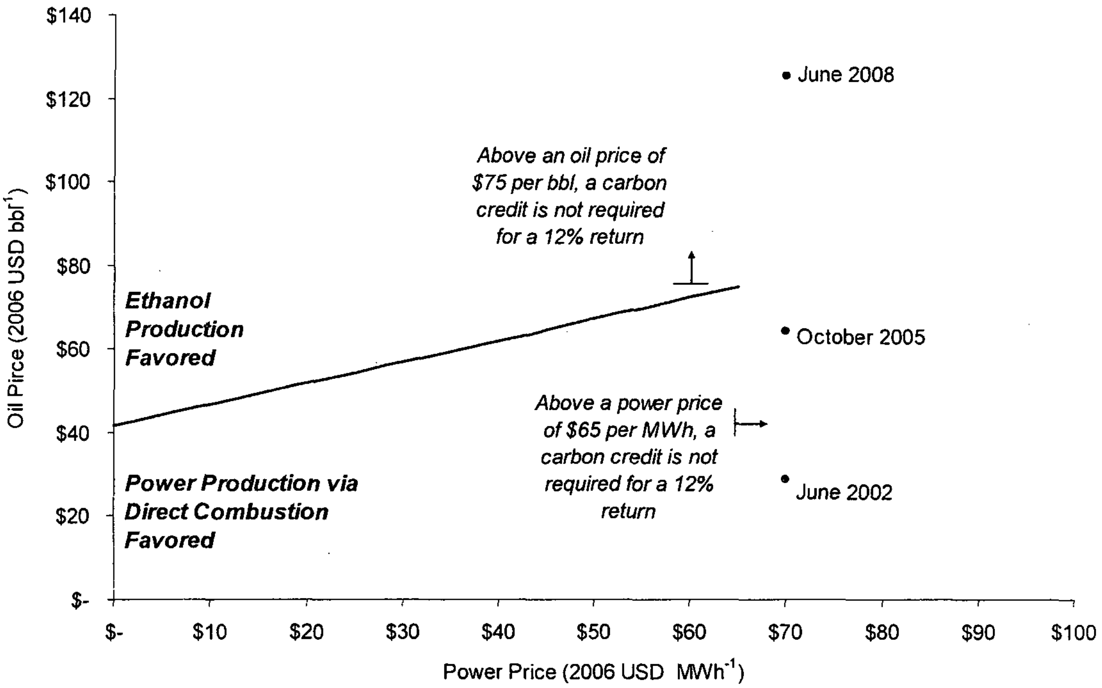


Figure 7.5. Oil and power price at which the carbon credit required for a 12% pre-tax return on total capital for the production of lignocellulosic ethanol and electricity from straw/stover are equal.

If the objective of a society is to reduce the accumulation of GHG in the atmosphere then for straw/stover at a yield expected in major grain and corn growing areas it is better to make electricity by direct combustion than BIGCC and better to make ethanol as a transportation fuel than FT syndiesel. "Better" is measured as having a lower cost to society, either the consumer or taxpayer, for the benefit received: a reduction in GHG. This study further concludes that for a typical North American wholesale power price of $70 MWh^{-1}, if the long term oil price is below about $75 bbl^{-1} then production of electricity would have a lower social cost per unit of avoided GHG emissions.

This study illustrates an approach to technology selection by applying it to one feedstock only. Good social decisions about selection of renewable energy technologies would calculate incremental cost per unit of avoided emissions for all processing alternatives. This would give a basis for sorting through the myriad of alternatives for renewable energy and identifying a subset of desirable processes. To illustrate this, consider the generation of power from the anaerobic digestion (AD) of manure. AD is a well demonstrated technology, but a previous study calculated that it would require a carbon credit well in excess of $100 t^{-1} CO_2 to achieve a 12% pre-tax return on total capital investment (Ghafoori *et al.* 2007). Pursuing AD as a form of green energy has a high cost to achieve a minimal reward. AD of manure may sometimes be warranted to deal with an agricultural problem, such as odor, pathogen or phosphate control, but pursuing AD purely for its renewable energy benefit is a poor social decision.

7.3 Recent Increases in Capital Costs

In recent years, there has been a large increase in construction costs worldwide. Between January 2004 and January 2007, Chupka and Basheda (2007) reported that the cost of steam-generation plant, transmission projects, and distribution equipment rose by between 25 - 35% (compared to an 8% increase in the GDP deflator). The cost of new power plant construction (specifically coal, gas, wind, and nuclear) in North America increased 27% from February 2007 to 2008, and 19% between August and February 2008, reaching a level 130% higher than in the year 2000 (Chupka and Basheda 2007). Excluding nuclear plants, costs have risen 79% since the year 2000 (CERA 2008). The same report stated that a surge that began in 2005 has pushed costs up 76% in the past three years, and that unless there is a sudden and dramatic change in the industry, activity and market pressures should keep costs at these level, if not higher, for the next 12 - 18 months. After that, there may be a rebalancing of the industry with either fewer active projects or a greater amount of delivery capacity available, or both. Anecdotal evidence in Alberta suggests even higher cost increases due to a very high rate of development of energy projects.

According to Boerrigter (2006), contractor costs have increased in recent years due to increased demand caused by the large number of large-scale projects internationally. Chupka and Basheda (2007) attribute the increase to dramatically increased raw materials prices (particularly steel, aluminum, copper), primarily due to high global demand for commodities and manufactured goods, higher production and transportation costs (partly due to higher fuel costs), increased energy costs in mineral extraction, processing, and transport, and weakening US dollar. Another, smaller factor is increased labor costs, although the impact of this may increase in the future partly due to growing backlog of construction project contracts.

This increase, of course, would have a major impact on the capital cost of all new projects. However, as each of the four alternative energy technologies has a different proportion of the processing cost that is attributed to capital cost, it impacts different technologies differently. These recent changes would also have a large impact on the certainty of the absolute magnitude of processing costs (as opposed to relative value). Note that transportation costs used herein are recent enough that no such consideration is needed, and similarly for field cost of biomass.

Table 7.3. Portion of processing cost attributable to capital cost.

Technology	Processing Cost @ Plant Size	Percent Capital Cost
Enzymatic Hydrolysis	\$0.22 L^{-1}	56.4%
FT Synthesis	\$0.45 L^{-1}	60.8%
Direct Combustion	\$30.38 MWh^{-1}	53.6%
BIGCC[a]	\$43.16 MWh^{-1}	59.6%

[a]Using numbers increased according to Section 6.2.1.

Based on the magnitude of unit cost and avoided emissions, the preferred alternatives are ethanol and direct combustion. These technologies have approximately the same contribution from capital (within the accuracy of the study) and therefore would be impacted equally by changes in construction costs.

7.4 Factors Influencing Technology Selection

7.4.1 General Factors

Two cautions must be voiced about the quality of cost data in this study. First, as noted above, the four processes analyzed in this study are at significantly different stages of commercial development. The uncertainty in the cost estimates for BIGCC and FT are far higher than for direct combustion and lignocellulosic ethanol. We note, however, that further commercial development of a process more frequently increases the estimate of capital and operating cost than decreases it. Therefore the conclusion of this paper that direct combustion and lignocellulosic ethanol are preferred over BIGCC and FT for typical North American agricultural residue availability is not likely to be altered by additional data on the cost of BIGCC and FT. A second caution is that the production cost formulae used in this study were drawn from studies using cost estimates prior to 2005. Anecdotal evidence supports that equipment cost, and hence total capital cost, went through a significant increase in the period 2005 through 2008 (see Section 7.3). The significance of this is that the estimates of carbon credits in this study, and the power and oil price at which no carbon credit is required for the renewable energies to achieve a 12% pre-tax return on total capital, are more likely to be biased low than high. Note again, however, that this would not likely affect the relative screening of the four processes, since an increase in capital cost would affect all four processes. Further, BIGCC and FT are more capital intensive processes than direct combustion and ethanol.

The United States has long cited a goal of reducing the import of oil, and more recently concerns have emerged in Europe about the extent of dependence on natural gas from Russia. In this study we calculate cost against the single social benefit of reduced CO_2e in the atmosphere. A social choice of technology would also be influenced by secondary goals related to energy dependency. In the US this would bias process selection towards transportation fuel, while in Europe it might well bias the decision towards power production with heat recovery (co-generation), or a different process to produce a gaseous fuel from biomass.

The carbon credit required to sustain a renewable technology depends on the gross availability of biomass. We tested the impact of this by looking at a lower availability of straw/stover, 0.21 t ha^{-1} (corresponding to a 50%/25% availability of straw/stover) rather than 0.32 t ha^{-1} (75/37.5%) that is the basis of the results presented in this study. As expected, the required carbon credit for each of the four processes is lower as biomass availability increases, because the cost of transport of biomass decreases. However, there is negligible impact on the line that defines equal carbon credit for the production of power and ethanol, because the impact on carbon credit runs in tandem for the four processing alternatives.

7.4.2 Impact of Changing Field Cost of Biomass

The delivered cost of biomass consists of two components, the field cost of biomass and the cost of transportation to a processing plant. Field cost depends on payments to owners; one factor is the alternate value of the biomass. Field cost can be positive (for example compensation paid to a farmer for nutrient replacement) or negative (such as avoided disposal cost of mill residue). Since some forms of biomass such as straw or corn stover have other uses, for example soil conservation and animal bedding, the second critical factor is what fraction of the biomass gross density is actually available to a processing plant, referred to here as gross yield. Transportation cost will depend on gross density (the amount of biomass per total area in a region), gross yield, and the cost of transportation. Transport cost is influenced by average transport distance, load size, fuel cost and average driving speed. The result is that the delivered cost of biomass can have a wide range, from a negative value to a very high delivered cost.

Figure 1.1 illustrated the concept of competition between transportation and processing cost, assuming that biomass is available in the field for a fixed cost throughout the area from which the processing plant draws feedstock. From Figure 1.1 it is evident that a lower gross yield of biomass will shift the cost of delivered feedstock up, shifting the optimum size lower. Note that if one assumes that the cost of biomass at the field is independent of size, e.g. all farmers are willing to sell straw or corn stover for a similar price regardless of their distance from a processing plant, then the field cost of biomass at its point of origin has no impact on optimum size of a processing plant. Only feedstock costs that vary with distance, e.g. the distance variable component of trucking cost, impact optimum size.

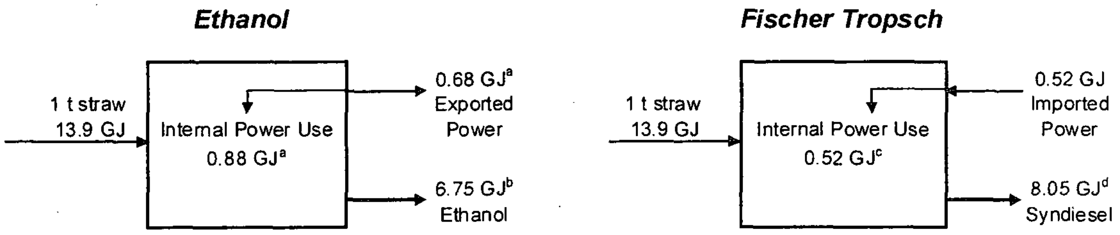
The processing technology with the lowest unit product cost can depend on the delivered cost of biomass (Cameron *et al.* 2007). Consider two processes, with one having a higher product yield and a higher processing cost. If the increase in yield is a higher percentage than the increase in processing cost, the more expensive process will always be more economic. However, if the increase in yield is a lower percentage than the increase in processing cost, as the delivered cost of biomass increases it reaches a point where it justifies a more expensive process for the gain in efficiency. This occurs because the more efficient process requires less biomass feedstock per unit of output, or alternately produces more saleable product per unit of biomass input. In the extreme, if biomass is free then there is no economic incentive to be efficient; if biomass is very expensive one cannot afford an inefficient process.

Impact on Selecting Power Generation Technology

We explored the impact of biomass delivered cost on power cost from direct combustion and BIGCC by holding the biomass gross yield constant at 0.21 dry t ha^{-1} and increasing the field cost of biomass, which in effect holds the optimum size constant. As biomass delivered cost increased the power cost from BIGCC became lower than from direct combustion. The feedstock cost above which power from BIGCC had a lower product cost than from direct combustion was \$330 dry t^{-1}, which resulted in a power cost of \$175 MWh^{-1}. Using a higher availability (for example, 75%) would decrease the power cost at the crossover; the reduced transportation cost would be conducive to a larger plant size and a lower unit production cost. As noted above, the crossover occurs because for BIGCC the ratio of increase in processing cost relative to direct combustion is higher than the ratio of efficiency increase; the reduced usage of biomass per unit of power output becomes more significant as delivered cost of biomass increases. Note that using the BIGCC cost number from the literature (i.e. not adjusted to reflect the IGCC information in Figure 6.5), there is no crossover: BIGCC produces power at a lower cost at any delivered cost of biomass, because the processing cost increment is less than the efficiency gain. However, if the adjusted BIGCC estimates are valid then BIGCC is not economic relative to direct combustion unless the delivered cost of biomass, and hence the cost of produced power, is very high, e.g. \$270 MWh^{-1} for a plant processing 4500 dry t d^{-1}. Given that BIGCC is not economic until the delivered cost of biomass is relatively very high, with a resulting power cost well above typical wholesale power costs of \$50 to \$80 MWh^{-1}, direct combustion is the preferred technology for turning straw/stover into electric power. Clearly, resolving the uncertainty around BIGCC capital and processing cost is critical to any decision about its selection relative to direct combustion. Note that higher biomass gross yields and higher capital cost increase the plant size at which the minimum production cost is realized, and therefore the BIGCC plant size would be substantially larger than that for direct combustion. Similarly, a FT plant would be larger than an ethanol plant.

Impact on Transportation Fuel Selection

We calculated the delivered cost of straw/stover at which the production of syndiesel has a lower liquid product cost per GJ than lignocellulosic ethanol for the same values of biomass gross availability, 0.21 t ha^{-1}, and for plants at optimum size. Note that a liter of ethanol has an LHV of 21.1 MJ, vs. values used in this study of 32.0 MJ for gasoline and 36.4 MJ for diesel (ORLN 2007). The efficiency analysis for liquid transportation fuel is more complex than for power generation, since lignocellulosic ethanol produces electrical power for export while FT configured to maximize diesel production imports power. Figure 7.6 shows the yield values used in this study based on LHV. The net energy efficiency of FT is 7.53 GJ dry t^{-1} of straw/stover input with 13.9 GJ t^{-1}, vs. 7.43 GJ dry t^{-1} for ethanol production. However, FT has a higher energy yield of liquid transportation fuel.



[a] Derived from values reported in Aden *et al.* 2002, McAloon *et al.* 2000, and Wooley *et al.* 1999.

[b] Aden et al. 2002

[c] Larson and Jin 1999

[d] Consistent with Wright and brown 2007, Larson *et al.* 2006, Prins *et al.* 2004, and Hamelinck *et al.* 2004

Figure 7.6. Energy yield for the production of ethanol and FT syndiesel from a dry ton of straw/stover.

We fixed the price of electrical power at \$60 MWh^{-1} and calculated the cost of producing one GJ (LHV) of transportation fuel at optimum size while increasing the field cost of biomass due to a higher acquisition cost.

Figure 7.7 shows the product cost as a function of the delivered cost of biomass. At a field cost of biomass above approximately \$80 dry t^{-1} FT syndiesel has a lower net production cost than ethanol. The cost of syndiesel and ethanol at the crossover point is \$28 GJ^{-1}, which is equivalent to a wholesale price of \$0.98 L^{-1} of gasoline and \$1.01 L^{-1} of diesel. This range of gasoline and diesel wholesale price would occur with an oil price of about \$130 bbl^{-1}. Note that the crossover occurs not because the overall FT process is more energy efficient than ethanol, but rather because it produces more liquid transportation fuel.

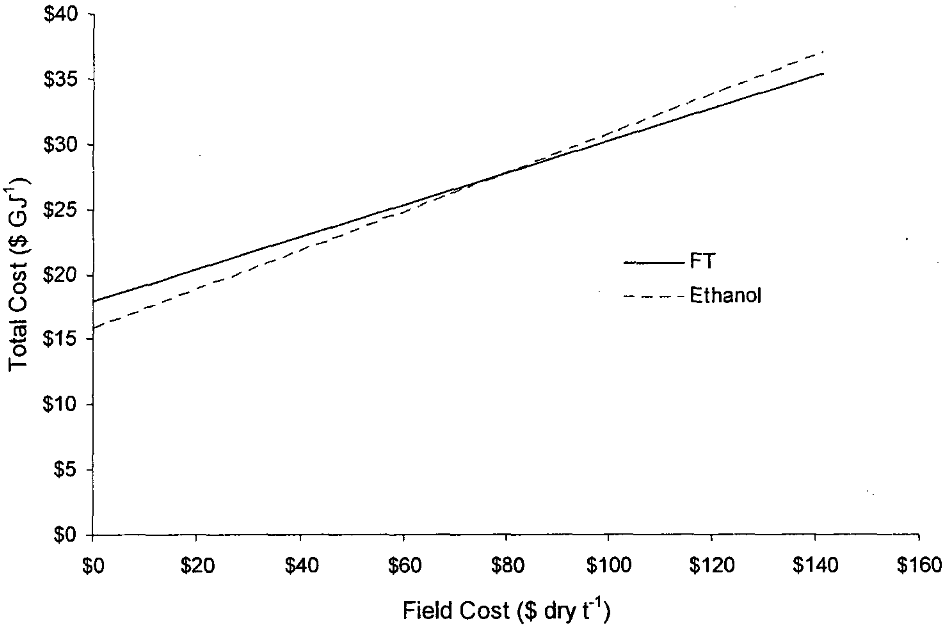


Figure 7.7. Cost of ethanol and FT syndiesel as a function of the field cost of biomass.

Although there is uncertainty in the costs of producing transportation fuels using biomass, the underlying point will not likely change: at some delivered cost of biomass FT syndiesel will have a lower production than ethanol because it has a higher energy yield of liquid transportation fuel. Another factor of note is that for a high capital cost process such as FT the optimum size is very large, and might well exceed either the availability of biomass in a region or the financial capacity of an investor.

We note that a crossover between the net present value of FT and ethanol occurs with rising oil price only because the cost of electricity does not rise proportionally. Based on current yield data lignocellulosic ethanol and FT produce virtually the same amount of energy per unit of straw/stover input, but FT produces more energy as liquid fuel. Long term average power price has not shown the high volatility that has occurred for oil. A rise in oil price that is not matched by a rise in power price would cause FT to have a higher NPV than ethanol.

8 Conclusions and Future Research

Conclusions from this study were broken down into three sections: first conclusions relating to emissions are listed, followed by those relating to the economics of the processes, and finally the implications of combing these values.

LCA

- Higher amounts of GHG emissions result in a larger environmental impact.
- Data on emissions from renewable energy is of varying quality.

- Emissions resulting from the production, harvesting, and transportation of biomass have little impact on the total level of avoided emissions.
- The level of accuracy of emissions from the conversion of biomass into product has little impact in determination of carbon credit, as shown by the sensitivity analyses.
- By far the most significant contributor to the avoided emissions of a renewable technology is the amount of emissions from combustion of the conventional alternative. Were a less carbon-intense power generation alternative (such as natural gas combined cycle) used as the business as usual case, the required carbon credit would decrease, and vice versa.

Economics

- A slight relaxation in the minimum cost criterion (i.e. using a plant size resulting in a 3% higher unit production cost over optimum size) substantially reduces initial capital investment by reducing plant size by approximately 50%.
- There is a lot of inconsistent information on the cost of production of renewable energy, and the data is of varying quality.
- There have been recent increases in construction and labor costs that would significantly impact the magnitude of capital costs from before 2005, however the relative impact of these increases would not have a major impact on the conclusions of this study.

Carbon Credit

- Minimum carbon credit in \$ t avoided CO_2e^{-1} is an appropriate criterion for selecting a renewable energy processing technology, as it reflects society's goal of achieving the most GHG reduction per unit of social cost .
- For availabilities of straw/stover that are representative of North American grain and corn growing regions, production of electricity by direct combustion is favored over BIGCC, and production of lignocellulosic ethanol is favored over FT syndiesel.
- Increasing the delivered cost of biomass (either through increased field cost of biomass, increased transportation cost, or both) creates a higher incentive for a higher capital investment in order to gain a more efficient plant.
- For a power price in the range of \$60 to \$70 MWh^{-1}, the carbon credit required by a direct combustion power plant is less than ethanol production for oil prices lower than about \$80 bbl^{-1}.
- Specific calculations of required carbon credits will change with improved capital and operating cost estimates. Enhanced estimating data will have a lesser impact on the relative ranking of process alternatives.
- Technologies were the most sensitive to changes in conventional power price, followed by changes in processing cost.
- Technology selection is dependant on the price of the conventional technology that would be replaced (i.e. grid-purchased power, gasoline, or diesel).

- The production of power by direct combustion has the lowest total product cost on a biomass input basis, the highest amount of avoided emissions on a biomass input basis, and this results in the lowest carbon credit. It also has the highest level of certainty in the estimations. Therefore, under the conditions of this study, the lowest social cost of GHG emission reduction is achieved using power production via direct combustion.

Policy Implications

- The selection of technologies should be based on the criterion of minimum social cost for the desired objective. In the case of GHG reduction, renewable energy technologies should be screened on the basis of minimum incremental cost per unit of CO_2e reduction.
- Plants being built below half of the theoretical optimum size should not be encouraged by policy decisions (for example, providing a higher subsidy for small plants).

This study demonstrated a methodology effective in selecting a renewable energy technology using a given feedstock. The selection process achieved the most widely sited goal of renewable energy, namely the maximum reduction of greenhouse gas emissions at minimum social cost. The methodology was transparent and considers variables that may impact the technology choice.

Study Limitations

The accuracy of the study is limited by the accuracy of the studies used to compile the cost and GHG emissions estimates. In particular, there is much uncertainty in the processing costs for the renewable technologies. Recent increases in capital costs add to this uncertainty, and if a pre-tax return other than 12% was desired, results would have to be adjusted. As well, transportation costs were determined prior to a large increase in oil price and were determined assuming truck transport. Although oil price is a small component of transportation costs, it would have an impact of the certainty of the transport costs. Field cost of biomass can be verified, however again this value will vary with market conditions.

Technology selection was demonstrated in this study using a single feedstock: straw at an availability of 75%. Results and potentially study conclusions will vary depending on the delivered cost of biomass.

The magnitude of the carbon credit is heavily dependant on the selection of the business as usual technology. For example, natural gas combined cycle has lower emissions than supercritical coal power, and if the former were selected as the comparative technology for GHG emissions, the required carbon credit would increase. Other study assumptions, including maintenance cost, operating cost, plant availability, product yields, and straw properties impact the magnitude of the carbon credit.

In this study the major contributor to the reduction in emissions of CO_2e arises from the use of the biomass, a renewable fuel, compared to the use of a fossil fuel. Relative to this impact, the emissions calculated for processing of biomass or refining of oil, for which studies report a wide variation, are minor. Note, however, that this conclusion may not apply to all cases of renewable energy substitution, and a case by case assessment of the source of emissions and the impact of uncertainty in emissions is required.

Although the best cost and emissions data available was used, the studies cited for each technology are not in reference to identical certain processing schemes. For example for ethanol production there are different enzymes used in different referenced studies, which result in slightly different costs and yields. For FT synthesis different catalysts and reactor types are used in different studies, resulting again in different costs and liquid yields. Note that this introduces an error that is small relative to the uncertainty in system costs.

Opportunities for Future Research

The cost of alternative technologies is a major determinant of what technology we choose to pursue. In this study GHG emissions were considered in an effort to represent an area of environmental impact. As we get closer to the stage where a plant is actually going to be built, other factors would have to be considered. For example, a complete environmental impact assessment would be necessary to obtain a permit to build the plant. This assessment would consider such environmental stressors as additional air pollutants (for example, volatile organic compounds, particulate emissions, NH_3, SO_2, H_2S, HCl, SO_2, NO_x, NH_3, HF), as well as other environmental factors including water consumption and pollution (considering such things as BOD, COD, dissolved matter, tars, suspended matter, ammonia, metals, and chlorides), solid waste generation, resource depletion (particularly fossil fuels, minerals and ores, land use and water), and socioeconomic factors (including noise pollution, increased truck traffic, labor availability, and odors). The impact of many of these parameters on human health may also be considered.

As well, the impact of water vapor as a GHG could be further explored. Does the level of water vapor that the atmosphere can hold increase with an increased level of water vapor from GHG contributions, or from modified agricultural practices to supply biomass? The optimum amount of straw that can be removed from an Alberta field while minimizing erosion should be explored. Another possible area of research is the estimation of the extent of nitrate loss through denitrification and quantification of the extent to which nitrogen is lost as N_2O rather than N_2. This research may clarify the emissions associated with biomass production, as well as the amount of fertilizer that is required.

8.1.1 Update Estimates with Increased Research and Development

The technologies examined all have alternative process configurations described in each section. Each of these variations could lead to a separate cost estimate and separate LCA. As future advancements are made, the studies could be revised. For example, improvements in the enzymes used for enzymatic hydrolysis could lead to large decreases in production costs and increases in ethanol yields, which may warrant a new cost analysis. For FT synthesis, the development of ceramic membranes for the removal of CO_2 could potentially have large impacts on yields, therein changing process economics.

8.1.2 Extend Work to Include Carbon Sequestration

Other areas could include investigation into the impact of adding carbon capture and storage technologies, which would make the net carbon releases for biomass energy conversion negative when also considering sequestration from growing the biomass. Presently, CO_2 sequestration technologies are expensive due to compression costs; with new developments, such as decreased cost and/or energy requirements, the options could be re-assessed.

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Appendix: Relationship Between Oil Price and Gasoline/Diesel Price

Canadian Data

Gasoline

In an effort to correlate wholesale pre-tax gasoline price to the price of crude oil, the monthly average of Canadian gasoline price was plotted against the monthly average of Canadian crude oil price over 36 months from January 2005 to December 2007, taken from the Natural resources Canada Fuel Focus website. The results are shown in Figure A1. The gasoline price was staggered by one month from the crude oil price (i.e. the January 2005 crude oil price was matched with the February 2005 gasoline price, and so on) and by two months to see if time in inventory during refining and distribution had an impact on the regression number, however the strongest correlation was found without any staggering. It is clear from Figure A1 that factors other than the price of crude oil affect the gasoline price, however the approximation is useful as a reference.

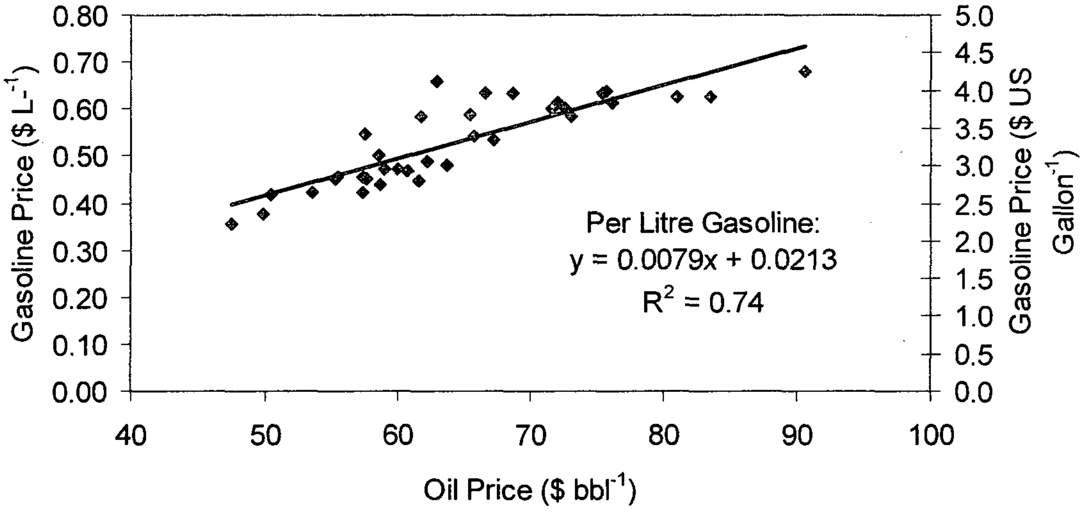

Figure A1. Relationship between Canadian crude oil price and the price of gasoline.

Although the price of crude oil is a major determinant of gasoline prices (McCool 2007, Conference Board of Canada 2001), there are several other factors including the changing demand for gasoline, refinery capacity in North America that has not expanded at the same pace as the demand for gasoline, a declining trend in gasoline inventories, and regulatory factors, such as national air quality standards, resulting in the switch to special gasoline blends in some states (McCool 2007). According to the Conference Board of Canada (2001), crude oil and taxes make up about 84% of the average price of a liter of regular unleaded gasoline. The remaining 16% covers the costs of refining, marketing, and the retailer's operational and fixed costs. As an illustration, in mid-November 2000 when the gasoline price was $ 0.79 L^{-1} Cdn, the refining, marketing, and retailing components influenced over $ 0.119 L^{-1} Cdn, and retailers influence only about $ 0.045 L^{-1} Cdn of the pump price of gasoline. The Conference Board of Canada (2001) also noted that the gasoline price in Canada and the United States, excluding taxes, is very similar, and is among the lowest gasoline prices in the world largely due to a highly competitive retail sector and competition with the United States.

The y intercept in Figure A1, 0.0213, is the price of gasoline when the oil price is zero. Said another way, this value partially represents the capital cost of refining. However, it is on the low end; based on past data, one would expect the refining costs to be higher than $ 0.02 L^{-1}. According to Natural Resources Canada (2007), in 2004 the refining cost was $ 0.163 L^{-1} (20 % of selling price of gasoline), in 2005 the refining cost was $ 0.160 L^{-1} (17.3 % of selling price of gasoline), and $ 0.192 L^{-1} in 2006 (19.6 % the selling price of gasoline).

Petroleum Diesel

To create a quick conversion reference and as was done for gasoline, the wholesale pre-tax diesel price was related to the price of crude oil using the monthly average of Canadian diesel price and the monthly average of Canadian crude oil price over 36 months from January 2005 to December 2007, taken from the Natural resources Canada Fuel Focus website. The results are shown in Figure A2. Again similarly to gasoline (shown in Figure A1), diesel price was staggered by one month from the crude oil price (i.e. the January 2005 crude oil price was matched with the February 2005 diesel price, and so on), and then by two months to see the impact this had on the regression number, however the strongest correlation by far was found without any staggering. The correlation coefficient for the relationship between diesel and oil price is much higher than for gasoline and oil.

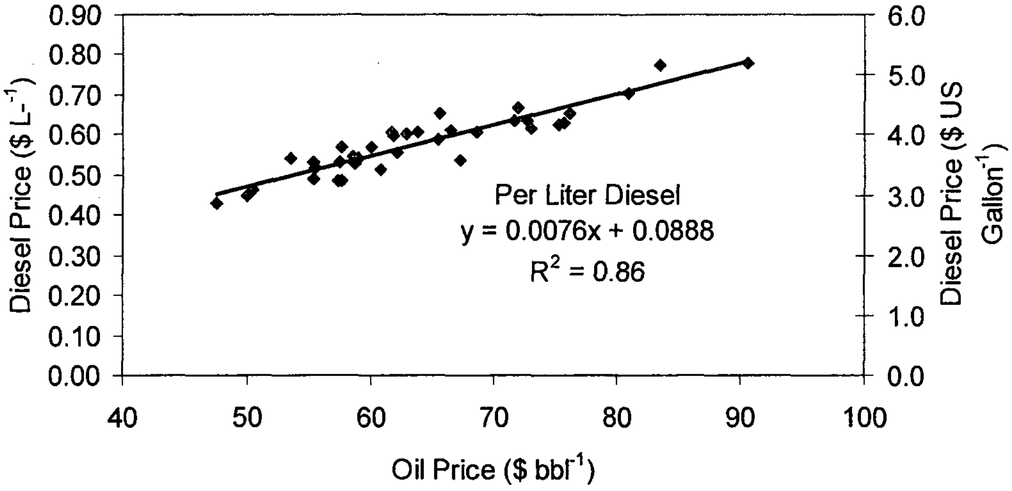

Figure A2. Relationship between Canadian crude oil price and the price of diesel.

Again, the refining cost shown in Figure A2 (represented by the y intercept of 0.09) is lower than what would be expected from past data.

US Data

Gasoline

The wholesale pre-tax gasoline and crude oil price was retrieved from the US Energy Information Administration website. Daily crude oil prices were used to get a monthly average price, and weekly gasoline prices were averaged to get a monthly gasoline price. The results are shown in Figure A3.

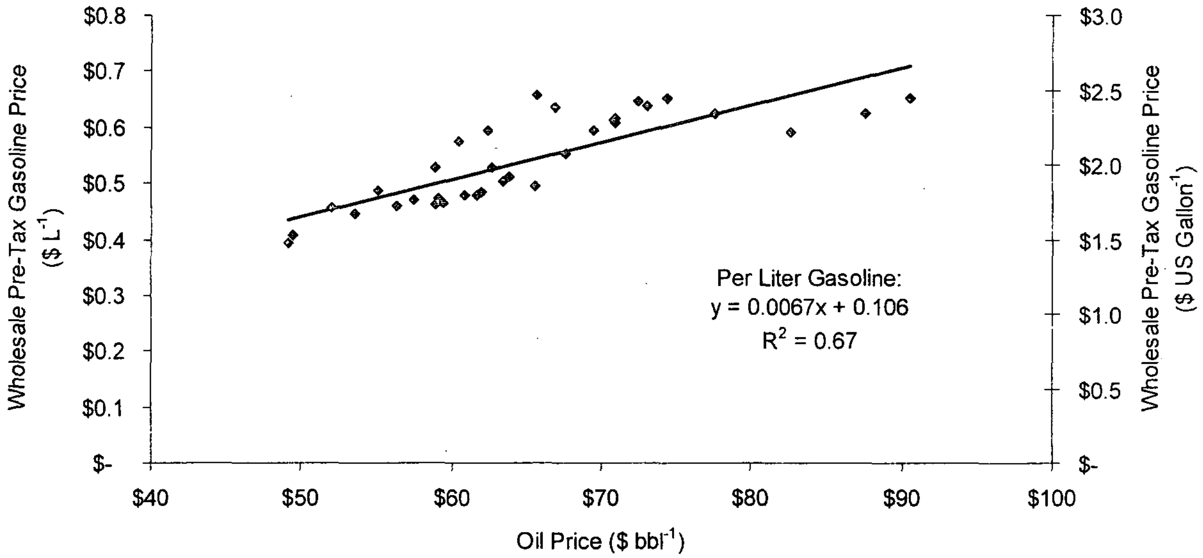

Figure A3. Relationship between American crude oil price and the wholesale pre-tax price of gasoline. The equation shown is calculated using the oil price in barrels and gasoline price in liters.

The y intercept of $ 0.17 L^{-1} is a far better reflection of refining costs than was taken from Figure A1, and therefore we used this data in our analyses.

Petroleum Diesel

The wholesale pre-tax petroleum diesel and crude oil price was retrieved from the US Energy Information Administration website. Daily crude oil prices were used to get a monthly average price and those were combined with monthly diesel prices. The results are shown in Figure A4.

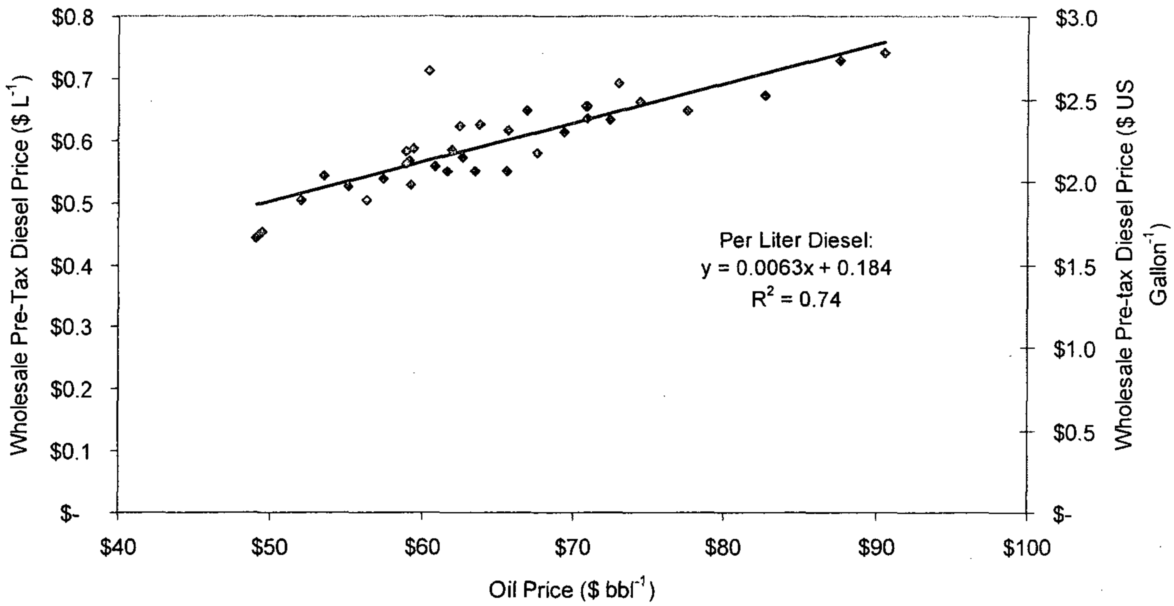

Figure A4. Relationship between American crude oil price and the wholesale pre-tax price of petroleum diesel. The equation shown is calculated using the oil price in barrels and diesel price in liters.