University of Alberta

The Economics of Biomass for Power and Greenhouse Gas Reduction

by

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List of Abbreviations

AFUDC	Allowance for Funds Used During Construction
BIGCC	Biomass Integrated Gasification Combined Cycle
C	Celsius
CHP	Combined Heat and Power
DFC	Distance Fixed Cost
DVC	Distance Variable Cost
ENFOR	Energy From Forest
EPC	Engineering Procurement Construction
FERIC	Forest Engineering Research Institute of Canada
g	Gram
GHG	Greenhouse Gas
GJ	GigaJoule
GL	GigaLiter
ha	Hectare
HHV	High Heating Value
hr	Hour
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
K	Kelvin

List of Abbreviations (cont'd)

kg	Kilogram
km	Kilometer
kW	Kilowatt
kWh	Kilowatt Hour
LHV	Low Heating Value
M	Million
m	Meter
MJ	Mega Joule
MW	Megawatt
MW_e	Megawatt Electricity
MWh	Megawatt Hour
NREL	National Renewable Energy Laboratory
NSERC	Natural Sciences and Engineering Research Council of Canada
Odt	Oven Dried Tonnes
ORNL	Oak Ridge National Laboratory
PMH	Productive Machine Hour
SMH	Scheduled Machine Hour
SSF	Simultaneous Saccharification and Fermentation
STS	Simultaneous Transportation and Saccharification
TPS	Termiska Processor Sweden

Chapter 1

Introduction

1.1 Research motivation

The buildup of greenhouse gasses (GHG's) in the atmosphere is widely believed to have the potential to increase the temperature of the earth and greatly disrupt the climate. Many jurisdictions, including Canada, are looking for ways to slow the buildup of GHG's. Some of the solutions include: reduction of energy use, sequestration of atmospheric GHG's, and substitution of renewable energy for fossil fuels.

Currently in western Canada the cost of producing various commodities can be estimated with great precision. The cost of producing electricity from various fossil fuels, the cost of upgrading heavy oil fractions, the cost of making chemical intermediates are all well known. However, if GHG's are thought of as a commodity (often expressed in tonnes of CO_2 equivalent) one finds that the production of that commodity, or alternatively the cost to avoid production, cannot be estimated with great precision. This lack of information makes it difficult for businesses to make investment decisions and it makes it difficult for governments to make funding and policy decisions. A business may wonder, "Do we still build a coal plant if we are required to offset 50% of the GHG emissions?" A government may wonder, "How do we best allocate our budget between wind, ethanol, solar, and other renewable projects?" This thesis is intended to provide a cost of producing the GHG reduction commodity through utilization of agricultural residues as a fuel.

1.2 Research focus

Biomass such as wheat or barley straw is considered to be a GHG neutral fuel, i.e. as the straw is burned the next crop soon absorbs the CO_2 released into the air from the burning. If the straw were left to rot in the field a similar amount of CO_2 would be released into the atmosphere. When straw replaces a fossil fuel in a process such as the generation of electricity, the buildup of CO_2 in the atmosphere is slowed and a GHG reduction commodity is created.

Western Canada is rich in two types of biomass: agricultural residues from cereal straws such as wheat and barley, and forest biomass. This research is intended to provide the cost of producing electricity from a conventional direct combustion straw-fired power plant in western Canada. The difference between the cost of straw-fired electricity and the market price of electricity is then used to calculate the cost of the GHG reduction commodity. The use of forest biomass for the same purpose in western Canada was studied simultaneously by a colleague and has been included for comparison.

The cost of biomass-fired power plants around the world is much higher per kW than the cost of fossil fuel plants. Much of this cost difference is due to the small size of biomass power plants and the economies of scale enjoyed by the large fossil fuel plants. To date, no straw-fired power plant has been built in the world larger than 36 MW, while coal-fired units of 450 MW have been built in Alberta and another of that size is currently under construction. In the rest of the world unit sizes of 600 MW are common, and units as large as 1050 have been built (Tachibana-wan Power Station). In order to determine an accurate cost of straw-fired electricity the plant must be built at an economic scale. However, unlike many fossil fuel plants, the cost of the fuel increases with plant size for a biomass-fired plant due to the transportation cost of the biomass. Hence, determining the optimum size that balances economies of scale against increasing transportation costs is essential for the research.

1.3 Research methodology

The cost of producing power from straw in western Canada was built up from a variety of sources:

- The costs of harvesting were estimated using methods provided by Alberta Agriculture and compared to the literature.
- The cost of transportation to the plant was determined by contacting custom haulers in Alberta and compared to the literature.
- The cost of nutrient replacement was calculated using straw compositions and current fertilizer costs.
- The capital cost of the plant was estimated by using the cost of European demonstration plants and scaling the cost up to an optimum size.

- The cost of operating the plant was estimated by myself and my supervisor, Peter Flynn, using our experience in the power generation industry.

The optimum size of the power plant was determined by finding the lowest power cost while varying the plant size. The maximum unit size was limited to 450 MW as that is the largest unit that the local power grid currently accepts. Above that size the plant would have two identical units.

After determining the optimum plant size, power cost from straw, and resulting cost of GHG credit, the research focus shifted from determining costs to reducing costs. A major component of power cost from biomass is the delivered cost of the biomass fuel, notably fuel transportation cost. We investigated reducing fuel transportation costs through slurry pipelining, however the biomass (straw in particular) soaks up too much of the carrier fluid, lowering the net heating value of the biomass. This makes pipelining of biomass unsuitable for combustion applications. However, this lead into the research of pipelining corn stover for ethanol applications, since uptake of water is not deleterious to a fermentation process, which is aqueous based.

Another method of reducing fuel transportation costs is to improve the efficiency of the power plant. (This reduces all fuel related costs.) Gasification with integrated combined cycle increases the capital cost of the plant, but the higher efficiency reduces the fuel related costs. The effect on fixed and variable fuel costs on both the decision of which technology to use and the size of power plant to build was examined, and a least cost alternative for many combinations of fuel costs was determined.

Cofiring was investigated as a method of reducing capital costs. As part of an Industrial-NSERC (Natural Sciences and Engineering Research Council of Canada) a case study was conducted for the EPCOR coal-fired Genessee power plant. The cost from the literature of retrofitting various types of cofiring to EPCOR's plant was combined with local costs for straw and coal. This allowed the determination of the cost of reducing GHG's by directly displacing coal in an existing plant. In addition, the possible improvements in GHG emissions intensity (a measurement used by the province for the plants operating license) was calculated.

1.4 Arrangement of the thesis

This thesis is paper-based. Chapters 2, 4, and 5 are each from papers that have been accepted for publication in an academic journal. Chapter 3 is from a report prepared for EPCOR Inc. Chapter 6 is from a conference publication. All papers have been standardized to year 2000 US dollars.

Chapter 2 is a comprehensive study of the cost of producing electrical power at optimum plant size using straw in a conventional direct-fired boiler in western Canada. Appendix A contains a summary of the discounted cash flow model used for calculating electricity cost. Also included in Chapter 2 are the costs of producing a GHG credit at various market prices for electricity. In addition, sensitivities to key cost elements are calculated. The cost of producing electricity from whole forest woodchips and from forest harvest residues is included for comparison purposes and because many of the cost elements from chapter 2 are used in chapters 4, 5, and 6.

Chapter 3 is a case study focusing on three types of co-firing straw with coal at the Genesee power station. This was requested by EPCOR to determine the suitability of co-firing as an "in house" solution to their legislated commitment to reduce the GHG impact from their newest coal-fired unit. GHG reduction costs are examined on an emissions intensity basis as well as a cost per tonne of CO_2 abated. These costs are compared to the GHG reduction costs of a stand-alone plant from Chapter 2.

Due to the high cost of transporting biomass, pipelining biomass was examined in Chapter 4. Straw was quickly eliminated because our tests showed (and the literature confirmed) that the straw absorbed too much water too quickly to have any lower heating value (LHV) left for a combustion application. However, the research was continued for the cost of pipelining wood chips in both water and in oil. Appendix B contains formulas used in calculating the pumping power for pipelining as well as cost elements used in the economic analysis.

Chapter 5 continues the research in pipelining biomass. In this chapter pipelining corn stover to an ethanol plant is considered. The break from combustion applications was undertaken because pipelining is most suited to ethanol production due to its aqueous process where the absorbed water does not create the same problems as it does in combustion applications. Appendix C contains the capital costs, as well as the technical and economic parameters used in chapter 5.

Chapter 6 presents a methodology for comparing different energy conversion technologies based on their efficiencies, capital costs, and the makeup of the fuel costs. In this chapter a new capital cost for direct combustion is developed, based not on actual biomass plants, but rather based on the well known capital cost of a direct combustion coal-fired plant in western Canada. The anticipated differences between a commercial scale coal-fired plant and a biomass-fired plant are listed and their costs estimated. The cost of power from this method is compared to the cost of power estimated using a Biomass Integrated Gasification Combined Cycle (BIGCC) plant. The cost elements of the biomass fuel affects both the size of the plant built and the technology chosen (direct combustion vs. BIGCC). These relationships are explored.

A summary of the research work is contained in Chapter 7. In addition, a recommendation for future research work is provided.

References

Tachibana-wan Power Station; see, for example, www.jpower.co.jp/english/news_release/news/news126.htm (Accessed May 5, 2004).

Chapter 2

Biomass power cost and optimum plant size in western Canada*

2.1 Overview

Biomass usage, specifically capturing energy from biomass that would otherwise decay, is one of many options available to mitigate the impact of the buildup of greenhouse gas (GHG) emissions from fossil fuel utilization. In some locations, including western Canada, good data on the cost of using biomass is not available, and this leads to a high degree of uncertainty in the cost of GHG credits that would be required to support such a facility. Western Canada, in particular the Province of Alberta, is a particularly relevant place to evaluate the economics of generating power from biomass for three reasons. First, Alberta has a growing power demand and is an area of active development of new coal based power plants, with one project of a single 450 MW unit and a second project of two 450 MW units approved and under construction. Second, the region has abundant biomass resources, both agricultural and forest. If all the straw in Alberta were used to make electricity it could amount to 2,000 MW, or about 25% of the electricity made in the province. In central Alberta black soil zones 3.4 million tonnes of straw are produced annually. If 75% of this was recovered and used in a direct fired power plant this would support 450 MW of electricity generation.

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* A version of this chapter has been published. Kumar, Cameron, and Flynn 2003. Journal of Biomass and Bioenergy. 24: 445-464.

Third, the region has a large oil and gas resource that is being exploited for industrial, domestic and transportation fuels, and continued development of this resource may well depend on developing effective GHG offsets. The combination of these three factors makes western Canada an ideal location for implementing power from biomass at a full commercial scale.

The purpose of our research has been to estimate the cost and evaluate the cost sensitivities for major biomass utilization projects located in the Province of Alberta. Our research has focused on major biomass resources located within western Canada that are available in significant quantities for future power generation. Specifically, three such sources were identified: agricultural residues, forest biomass from harvesting of the whole forest, and the residues from harvesting forests for lumber and pulp. Each of these sources is discussed below in more detail. Mill residues from processing of lumber and pulp (for example, bark and sawdust) were not evaluated, because these are widely utilized today and recent volatility in the cost of natural gas has led to intensive development of additional projects based on this resource.

Our research has focused on a common end use for biomass: power generation from direct combustion. Holding end use constant for the three biomass sources allows an assessment of the relative value of these three biomass resources. It is also key to assessing the comparative economic optimum size of a biomass power generation facility, which is fuel specific. In generating power, biomass fuels differ from coal: the variable cost of fuel per unit capacity depends on the capacity of the facility using the biomass, whereas for coal fired plants, whether mine mouth (i.e. the power plant is located at the coal mine) or remote, the variable fuel cost is either negligible or virtually independent of capacity. The variable component of biomass fuels is related to their transportation cost. Because biomass has a significant variable fuel cost component that varies with plant size and coal does not, the economic optimum size characteristics are quite different for the two fuels.

Our research is based on existing techniques of harvesting biomass and commercially proven direct combustion technologies for its utilization. Alternate technologies can be used to generate power (for example, gasification vs. direct combustion), and alternate end uses can be identified (for example the production of liquid fuel byproducts). These technologies are at the demonstration or research stage. If power from biomass were implemented on a large scale in western Canada, specialized techniques and equipment might emerge that would reduce harvest costs; examples include simultaneous collection of straw and grain and simultaneous chipping of forest residues at the time of timber/pulp harvest. The potential impact of such future improvements is not factored into this study.

Power from biomass is not economic today in western Canada, where power is generated from a large base of hydroelectric, gas fired, and base-load mine-mouth coal fired plants. Hence, one key measure of cost of biomass is the carbon credit (as \$ $tonne^{-1}$ CO_2 abated) required to equalize the cost of power from a biomass plant with current alternatives. In effect, this is the "premium" associated with the mitigation of GHG. Because coal based power projects are under active development and represent the current marginal power plant fuel of choice, GHG credits are calculated in comparison to a new coal based power plant using conventional combustion supercritical boiler technology.

Previous studies have assessed biomass economics from the perspective of general models (Jenkins, 1997; Nguyen and Prince, 1996; Overend 1982; Larson and Marrison, 1997; McIlveen-Wright et al., 2001). Dornburg and Faaji (2001) have developed a detailed study of small to medium scale biomass plants in a Dutch setting. This study applies the general methodology to western Canada. Good regional data is available on the cost of harvest and transport of biomass, including costs of loading and unloading that have not always been considered in previous studies. Western Canada is also the site of both recent and current major energy projects, and good data is available on construction costs for both developed and remote locations. Hence, this study draws on actual data to determine the cost difference for substituting biomass for coal at an optimum plant size in a region of active coal power development.

2.2 Biomass sources and nutrient replacement

2.2.1 Agricultural residues

The largest concentrated source of field-based agricultural residues in western Canada is straw from crops such as wheat and barley. Note that some barley is grown as "green feed", i.e. it is harvested whole and used as silage for animal feed. However, where wheat or barley is threshed, straw is a byproduct that is typically laid back on the field during the combining process. Some of this straw is subsequently collected for use as bedding or a feed supplement, but most is left to rot on the field. Except in cases of highly sloped soils or unusually high wind areas, straw cover on fields does not impact erosion control if proper stubble height is maintained (Saskatchewan Agriculture and Food Fibre Opportunity Agronomy Committee, 2001). Based on published yield data (Carcajou Research Limited, 1988), the Province of Alberta alone could support 2000 MW of power generation from currently uncollected straw.

A key study demonstrated that in black soils in western Canada repetitive straw recovery did not reduce soil carbon levels (Hartman, 1999), presumably because the contribution of residual stubble and roots to soil carbon offsets losses. Hence, the carbon credit available from recovery of straw in these areas is not partially offset by loss of carbon sequestered in the soil. Agricultural records for six years for three districts in central Alberta with black soil showed a range of grain production per gross hectare from 0.42 to 0.81 tonnes (Carcajou Research Limited, 1988). Note that gross hectares include all area within the district, including towns, roads, and land cultivated to non-grain uses. For this study an average grain yield of 0.52 tonnes of grain per gross hectare was used, equivalent to the lower quartile of yields during the period for which data was recorded. Straw production for these areas ranged from 0.75 to 1.05 units of dry straw[1] per unit of as-delivered grain (Hartman, 1999; Canada Grains Council, 1999); in this study an average value of 0.80 was used. Hence, for this study a straw production density of 0.416 tonnes of dry straw per gross hectare in a district was used.

Agricultural residues contain nutrients that return to the soil during the decomposition process. Wheat/barley crops in Alberta are fertilized today, but recovery of residues for usage as fuel would require a higher application rate of fertilizer, which is included as a cost in this study. Prairie soils are glacial till, with abundance of calcium and usually of trace minerals, so nutrient replacement costs are factored only for nitrogen, phosphorous, potassium and sulfur.

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[1] Note that for all biomass in this chapter the reported yields or weights are on a dry weight basis, except as noted, i.e. actual wet yields are adjusted to zero moisture content (the forestry industry refers to "bone dry wood", which we treat as identical to a dried tonne). Estimated actual moisture content is 16% for straw, 50% for whole forest chips, and 45% for forest harvest residue chips. These estimated actual moisture levels were used in calculating transportation costs and net heat yields from combustion. The heat of combustion of biomass per dried tonne varies with species; in this study a blended value for each biomass fuel is used.

Agricultural residues are used today as a fuel for heat and combined heat and power plants in Europe (da Silva Pinto, 1999; Larsen, 1999; Caddet 1988a; Caddet 1988b; Caddet 1988c). In some cases these plants are economical because the recovery of straw is required for agricultural reasons and is produced in great excess to its needs as an animal bedding material or feed supplement. For these cases use of the straw as fuel is a means of waste disposal as well as energy recovery, and the straw collection costs are a sunk cost not charged to the power generation cost.

In this study, agricultural residue cost is based on full replacement of removed nutrients at cost plus full recovery by the farmer of all costs associated with harvesting straw, including labor and capital recovery for equipment usage. In addition, a market premium of \$4 dry tonne^{-1} is placed on biomass, as discussed below. The resulting value for straw at the field used in this study is about 150% of the current value of market value of straw in western Canada. Security of fuel supply is a major concern of any developer of a power plant, and steps that would help address this risk are discussed below.

2.2.2 Whole forest biomass

The second source of biomass in this study is whole forest biomass from a dedicated forest plot, with the power plant located centrally within the plot. Note that in the Province of Alberta the majority of forested areas are owned and controlled by government, and these in turn have been committed to existing forestry operations (pulp and lumber) under long term management agreements. Hence, in theory there is no available uncommitted forest area that could be specifically harvested for biomass. However, the alignment of forest processing plants (e.g. pulp mills and lumber operations) and forest reserves is inexact, and it is likely that some excess forest capacity will emerge particularly if faster growing hybrid species are replanted after harvesting.

Northern forests in Alberta are boreal; two types of sub-region are the most common: mixed hardwood and spruce. The basis of the whole forest biomass case is a medium yield site (Alberta Energy and Natural Resources, 1985). Our assumption is that good yield site would be reserved for timber and pulp operations; however sensitivity cases for both good and fair yield site are included. Biomass yields from mature stands of medium yield for mixed hardwood and spruce are 94 and 74 dry tonnes per net hectare respectively (Alberta Energy and Natural Resources, 1985), and these have been blended in this study to an assumed forest biomass yield of 84 dry tonnes of biomass per hectare. Large contiguous areas of mixed hardwood and spruce are available in Alberta, and could support a large power plant for a 30+ year life without having to harvest or leap over low yield bog areas, hence an aggregated biomass yield based on the two sub-regions is warranted. The study is based on selective clear-cut logging throughout the dedicated forest plot, resulting in a constant transportation distance to the power plant over the life of the plant.

This study draws on regionally specific detailed studies of the costs of recovering forest biomass performed by the Canadian Government, by the Forest Engineering Research Institute of Canada, from other literature, and from personal discussions with researchers and equipment suppliers (Puttock, 1995; Hudson and Mitchell, 1992; Hankin et al., 1995; Hudson, 1995; Perlack et al., 1996; Zundel and Lebel, 1992; Hall et al., 2001; LeDoux and Huyler, 2001; McKendry, 2002; Zundel et al., 1996; Silversides and Moodie, 1985; Zundel, 1986; Mellgren, 1990). In addition to these sources we have built a detailed model of chipping costs for both forest cases in this study. For the whole forest case, whole trees are cut and skidded to a 50/48 Morbark chipper, which prepares chips suitable for direct combustion that are loaded into a waiting chip van. The large-scale chipper is assumed to operate 5000 hours per year, and is fed by a dedicated grapple. Based on this specific case, a whole forest chipping cost of \$2.40 dry tonne^{-1} is calculated. This is considerably lower than other reported values in the literature, which range from \$8.23 to \$14.54 dry tonne^{-1} (Desrochers, 2002; Morbark, 2002; Wiksten and Prins, 1980; Bowater, 1983; Folkema, 1989; Favreau, 1992; Spinelli and Hartsough, 2001; Asikainen and Pulkkinen, 1998). The lower value in this study arises from the large scale of the chipper (100 green tonnes hour^{-1}) and the high number of operating hours per year compared to chippers in (Desrochers, 2002; Morbark, 2002; Wiksten and Prins, 1980; Bowater, 1983; Folkema, 1989; Favreau, 1992; Spinelli and Hartsough, 2001; Asikainen and Pulkkinen, 1998). In pulp operations the transport of whole trees is an alternative, but in the case of using forest biomass for power generation the limbs and tops (that are left at roadside in pulp or lumber harvesting) are also recovered, requiring the transport of chipped material.

Nutrients are not restored in most existing Alberta forest operations, most of which are occurring in areas of first cutting. Branches and tops are left in the forest in current harvesting, however the distribution of these is usually not uniform. About 80% of harvest operations in Alberta skid whole trees to roadside, where they are delimbed and topped. The leaves / needles in this trimmed material contain a large portion of the nutrients, especially nitrogen. The limb and top residue is piled by the side of the logging road, and typically burned at the end of the harvest, which results in a loss of the nitrogen to atmosphere. Return of phosphorous, potassium and other trace nutrients in the ash is very limited at best, since ash distribution is rare. Hence, in current forest harvesting operations virtually all nutrients in the forest biomass are lost, and are not replaced.

Since the current forestry practice in Alberta, based on first cut, is not to replace nutrients, in this study the base case does not include a provision for nutrient replacement. However, this is evaluated as a sensitivity since it is a key cost factor if included. For the nutrient replacement sensitivity, nitrogen, phosphorous and potassium are replaced. Calcium is not replaced since it is abundant in boreal forest soils in western Canada. Ultimately, as long-term forest management in European countries has demonstrated, nutrient replacement is necessary regardless of the end use of the forest biomass. First cut operations take advantage of the initial bounty of nutrients in the soil, but this is eventually depleted with sustained harvesting.

Costs for construction of logging roads, and silviculture costs (replanting, plus nutrient application in the sensitivity case) are included for harvesting the whole forest; these are a significant component of overall cost.

Whole forest biomass cost in this study is thus based on full recovery of all costs associated with harvesting and chipping, including capital recovery, but without nutrient replacement. As with agricultural residues, an additional market premium of \$4 dry $tonne^{-1}$ is placed on the biomass, but note that this market premium is at the low end of the range of royalty payments (stumpage fees) realized from the sale of timber cutting rights. Hence traditional pulp and lumber operations could, in most market conditions, compete for access to the forest biomass. As a region rich in forest and fossil fuel resources that will likely require GHG offsets, interesting tradeoffs arise: is the forest worth more as a low royalty fuel supply that enables parallel development of high royalty fossil fuel projects, as compared to its value for pulp and lumber? Note that for the whole forest case, security of fuel supply is readily addressed by the granting of cutting rights, which are controlled in western Canada by the Provincial Governments that have retained ownership of the forests.

2.2.3 Forest harvest residues

Given that forest resources have a value as fiber in pulp or lumber, an alternative is to recover harvest residues. In theory, one could harvest brush and deadfall as well as limbs and tops, but in practice this would require a major modification of forest harvesting, since current practice is to cut and skid trees to roadside where they are delimbed and topped, whereas brush and deadfall is left in place in the forest. Hence the basis of this study is the recovery of limbs and tops from the side of logging roads. These residues range from 15 to 25% of the total biomass in the forest. In lumber based operations there is a growing emphasis on "cut to fit" in the field, i.e. trimming logs to the economic length in the field so as to avoid transporting waste material to the mill. This practice pushes harvest residues to the 25% range, whereas in some pulp operations it is as low as 15%. 20% residue from a good yield site has been used as the basis of this study, since current lumber and pulp harvesting draws from such sites. This is equivalent to a blended yield of 24.7 dry tonnes of residue per net harvested hectare (Alberta Energy and Natural Resources, 1985). However, the forest in Alberta is harvested on a planned average rotation of 80 to 120 years, due to poor soil conditions and a northern climate. In this study, a rotation of 100 years is assumed, giving a yield of forest harvest residues of 0.247 dry tonnes of residue per gross hectare.

Residue material is piled (consolidated from small roadside piles into larger piles), chipped in the field and transported to the power plant by chip van truck. Chipping of branches and tops is less efficient than chipping whole trees, and requires different equipment. As with the whole forest case, the literature reports a wide range of chipping costs for residues, from \$2.00 to 28.78 per dry tonne (Desrochers, 2002; Morbark, 2002; Wiksten and Prins, 1980; Desrochers et al., 1993a; Desrochers et al., 1993b; Desrochers et al., 1995; Hunt, 1994; Richardson, 1986). For forest residues a specific case using pilers, loaders and high capacity Nicholson WFP3A chippers with a capacity of 48 green tonnes hour^{-1} operating at 5000 hours per year gives a total cost of \$9.42 dry tonne^{-1} to recover residues left by the sides of logging roads. Note that for forest residues the limit to throughput is the ability to feed the material into the chipper, and for this reason a smaller capacity chipper is used.

Costs for construction of logging roads and silviculture are not attributed to the cost of power from harvest residues, since the roads and silviculture costs are required regardless of the disposition of the residues.

In most existing forestry operations in Alberta, nutrients are not replaced, and the nutrients from harvest residues end up being concentrated at roadside or dispersed in the atmosphere and hence are not available to fertilize regrowth, as discussed above. Hence, the base case for use of harvest residue does not include a cost for nutrient replacement.

Forest harvest residue cost in this study is thus based on full recovery of all costs associated with harvesting and chipping, including capital recovery, but without nutrient replacement. An additional market premium of \$4 dry tonne^{-1} is placed on the biomass, which would result in a direct gain by the company that held the timber cutting rights. In theory a government could require long term access to forest harvest residues without a premium as a condition of granting cutting rights, thereby reducing the cost of forest harvest residues and addressing long term security of supply.

2.3 Scope and cost

Note: all currency figures in this thesis are expressed in US \$ and are in base year 2000 unless otherwise noted. Conversion between Canadian and US \$, where required, has been done at the rate of \$1 US = \$ 1.52 Cdn. Costs from the literature have been adjusted to the year 2000 using historical inflation rates; an inflation rate of 2% per year is assumed for the future.

The scope of this study is a dedicated power generation plant operating for 30 years using biomass. Fuel properties are shown in Table 2-1. Cost factors are developed for each element of the scope and are included in detail in Table 2-2, 2-3 and 2-4. Note that for costs affected by scale factor, the costs are reported for a plant capacity of 450 MW. Some cost factors warrant further comment:

- Field purchase of biomass: A flat charge of \$4 dry tonne^{-1} of biomass is assumed, regardless of the heating value of the fuel. Since straw has about 90% of the heating value of the chipped forest biomass on a dry basis, it has a slightly higher charge for biomass per unit of power generated, but the impact on power cost is not significant. Note that \$4 dry $tonne^{-1}$ is equivalent in the whole forest case to \$3.50 Canadian dollar m^{-3} of recovered lumber or pulpwood; as noted above, this is comparable to the lower end of existing royalty (stumpage) fees in the Province of Alberta.

- Gathering of biomass in the field: Capital costs for harvesting equipment are not estimated in this study but rather treated as an operating cost that includes capital recovery. This is equivalent to assuming that the power plant operator contracts out harvesting.
    - For agricultural residues, we assume that farmers harvest the residues, deliver them to roadside as large bales and cover these with tarps to limit moisture ingress. The power plant operator would be responsible for arranging pickup of the bales (tarps would be left by roadside for reuse by the farmer). The cost of straw harvesting includes an allowance for both equipment and labor, i.e. in addition to the purchase of biomass the farmer harvesting straw is paid \$10 $h^{-1}r$ for his time spent in gathering the straw on a separate pass over the field.
    - For whole forest biomass, we assume that contract harvesting rates cover cutting, skidding, and field chipping of whole trees. For forest harvest residues, we assume that limbs and tops are stacked and chipped. As noted above, chipping of limbs and tops is less efficient than chipping whole trees, and a higher chipping cost is factored into the forest harvest residues case.

- Nutrient replacement: The agricultural residue case includes a payment to the farmer for replacement of the nutrient content of the straw, while nutrient replacement is not included in the base case for forest biomass, as discussed above. Note that the farmer is already fertilizing grain crops, so the nutrient payment is for incremental fertilizer only and does not include an application cost. For whole forest, the cost of nutrient replacement is assessed as a sensitivity case, in which the cost of applying the fertilizer is included.
- Transport of biomass to the power plant site: For agricultural residues, biomass transport is over existing publicly maintained roads. For forest harvest residues, this is over existing forest roads from pulp and lumber operations that generate the residues. For whole forest biomass, the cost of road building is charged to the project since there is no existing road infrastructure. As noted biomass projects have a transportation cost that varies with plant capacity. This arises because the area from which biomass is drawn is proportional to plant capacity, and the haul distance is proportional to the square root of area. Biomass economics are thus sensitive to biomass yield: higher yields per unit area reduce the area required to sustain a given project size. We explore this effect in a sensitivity.
- Processing of biomass at the plant site: A small reserve of biomass is stored on site (equivalent to about two weeks operation) to sustain the power plant when roads are impassible. Straw is chopped at the plant site.
- Combustion of the biomass in a boiler, with use of the steam solely for power generation: Full capital costs are calculated for power generation, and are

adjusted for capacity by a scale factor. Note that co-generation, the use of low-pressure steam exhausted from turbo generators for heating, requires a customer for the steam and the economics would be project specific. Hence co-generation is not considered in this study.

- Scale factor: The base case unit scale factor used in this study was 0.75, where scale factor is an exponent for adjusting the cost of a power generation unit from one capacity to another (i.e. $Cost_2 = Cost_1 \times (Capacity_2 / Capacity_1)^{Scale\ factor}$). Scale factors for single boiler biomass power plants from the literature range from 0.7 to 0.8 (Bain et al., 1996; Office of Power Technologies, 1997; Marrison and Larson, 1995); similar values are reported for coal (Williams, 2002; Silsbe, 2002). Actual cost data is available for a number of straw based plants, although comparison is difficult because the plants use the steam for heat and power, and the relative mix of these varies from plant to plant (Larsen, 1999; Caddet, 1988a; Caddet, 1988b; Caddet, 1988c). After manipulating the data to adjust for scope, the scale factor is estimated at 0.8, but this reflects plants built in a variety of locations that are always "new" to that location and that are small and built as demonstration units. For that reason, we have assumed that in a mature large scale facility the scale factor would be lower. Previous studies have shown some disagreement on appropriate range of scale factors; Jenkins (1997) has explored a wide range, from zero to 1.0, while Dornburg and Faaji (2001) argue for a narrower range. Based on discussions with firms that have built major energy facilities, we explore the impact of scale factor in the range of 0.6 to 0.9 for a single unit up to 450 MW size. Over 450 MW, a step change in scale factor occurs: the cost of an additional identical unit is assumed to be 95% (Silsbe, 2002) of the first unit cost, i.e. the cost of building an incremental identical unit saves 5% on the incremental unit only. This is close to Jenkins' assumption that scale factors approach unity as project sizes get very large.

- Maximum Unit Size: In this study we have assumed that the maximum unit size for a biomass fired boiler is 450 MW_e. For any capacity over 450 MW, two or more identical sized units are built, e.g. at 500 MW two units of 250 MW would be built. This assumption reflects two qualitative factors: a judgment re comfort in scale up of existing biomass combustion units, and the maximum unit size that is acceptable in relation to the size of the electrical power market. We note that the three coal fired units being built in the Province of Alberta are all sized at 450 MW, although larger coal fired units have been built in other locations, e.g. (Gibson Steam Generating Plant). The assumption of maximum unit size is critical for two cases in this study, where the optimum plant size is found to be one or more of the maximum sized units. This is discussed further below.
- Capital cost: Data were drawn from a variety of actual plant costs and literature sources, and show a wide variability (Larsen, 1999; Caddet,

1988a; Caddet 1988b; Caddet 1988c; Broek et al., 1995). Actual data for straw fired units, built for a mix of heat and power, appeared after manipulation for scope and size to be about 20% higher than wood based biomass units. Values used in this study are \$1300 kW^{-1} for straw, and \$1184 kW^{-1} for wood and forest residues at a size of 450 MW; comparable values for new coal-fired plants in Alberta are \$850 kW^{-1}. We make two notes on these values. First, many biomass plants built to date have been demonstration units, for which higher capital costs would be expected than would be realized with a mature technology. Second, boiler/power plant costs for straw and wood are 50% and 40% higher than comparable capital costs for large coal fired boiler/power plants in western Canada (which has low sulfur coal that does not required sulfur removal from flue gas). Several factors contribute to a higher cost for burning biomass, including higher mass flow rate of solid fuel, lower flame temperature (and hence larger convective to radiant ratio in the boiler) and a more corrosive ash (Miles et al., 1996), but these factors do not readily equate to such a large difference in cost as compared to coal. We are not able to justify the large premium in capital cost compared to coal, and hence the biomass capital cost values may be conservative (high). Capital cost of the boiler and power plant is thus a source of uncertainty; we have run sensitivities on capital cost to explore the impact of this uncertainty.

- <u>Location:</u> Alberta has a cold winter, but also has a workforce and construction industry well used to working productively in cold weather. Hence, no capital cost penalty was applied for climactic conditions. However, in all cases the plants are sufficiently remote from major population centers that construction labor would be housed in a camp, and a provision of $13 million was provided for the camp and for workforce transportation costs at a 450 MW capacity, and adjusted for scale (Williams, 2002). The whole forest power plant is built in a remote location away from existing infrastructure, and would have additional costs during construction such as access roads, higher freight costs, higher contractor mobilization and demobilization costs, and a longer construction staff cycle (for example, two weeks in and one week out rather than the traditional five day work week). To account for this, capital costs are escalated by 10% for this case (Williams, 2002).

- <u>Disposal of ash:</u> Evidence from two Canadian plants is that once a biomass power plant starts up, a demand develops for ash, in that farmers and foresters will remove ash from the plant at zero cost, and spread it on fields (Matvinchuk, 2002). However, since this takes some time to develop, in this study we have taken a more conservative approach: ash is hauled to fields at an assumed average haul distance of 50 km, and spread, all at full cost to the power plant. For this scenario, spreading cost is 74% of total ash disposal cost. Ash content varies for the three fuels, affected in part by the dirt content of the fuel.

- Connection of the power plant to the existing transmission grid:
    - In the case of agricultural and forest harvest residues, the collection areas for biomass are large, and there is some flexibility in the location of the power plant, which is assumed in this study to be at or very near to an existing community and to an existing transmission line. In Alberta, the likely location of an agricultural or forest harvest residue power generation plant is also in a power load consuming area, so that there would likely be no transmission penalty assessed. Hence, no net transmission cost is assigned to the generation facility.
    - For the whole forest biomass case, the basis of the study is a remote forest plot located 300 km from existing transmission lines, which requires a dedicated transmission line to connect to the existing grid. This transmission line is assumed to have 3% line loss. The cost of the line is recovered as a transmission charge; at the optimum sized whole forest biomass plant, the charge to recover the cost of the transmission line is \$1.52 MWh^{-1}. The scale factor for the remote transmission line is 0.5 rather than the 0.75 figure used for power generation equipment; the 0.5 factor is based on actual estimates for transmission lines at various scales, and reflects that clearing of the right of way is required regardless of line capacity.

- Operating costs: For the agricultural and forest harvest residue plants, assumed to be located in an existing small urban setting, power plant staff compensation is estimated at \$27 $hour^{-1}$ to cover salary plus benefits. For the remote whole forest case, a premium of 20% on all labor is applied.
    - Direct operating labor: A single boiler unit requires eight operators per shift, and each additional unit requires an additional four operators (Broek et al., 1995; Matvinchuk, 2002). These levels are slightly higher than comparable coal plants, and reflect expected difficulties in the receipt and processing of biomass fuel.
    - Administration costs: The biomass power plant is assumed to be a stand-alone company, and an administration staffing level of 26 is assumed for each case. In the whole forest case, these staff are sited at the remote location. If a larger firm owned and operated the biomass power plant, savings in administration costs would be possible. However, these are not a significant cost factor in the overall cost of power.
    - Maintenance costs: Maintenance is a major source of uncertainty in evaluating biomass plant operating cost. Existing power plants in Alberta that pulverize and fire high ash coal have maintenance costs in the range of \$1.25 to \$1.75 MWh^{-1}. Various studies of biomass units show values that are 7 to 10 times higher (Bain et al., 1996; Broek et al., 1995). After some manipulation of actual data from a small demonstration straw fired power plant, we estimated maintenance

costs at about $13 MWh^{-1} (Caddet, 1997). We cannot explain this wide range in terms of difficulty of processing fuel or expected problems in the boiler, and we attribute them in part to the startup and demonstration nature of existing plants. In this study we have assumed that maintenance costs (parts plus labor) are 3% of the initial capital cost of the plant, which gives a maintenance cost in the range of $4.93 to $6.20 MWh^{-1}. Actual maintenance costs in large-scale biomass facilities are a critical issue in overall economics of biomass usage.

- <u>Plant reliability and startup profile:</u> Biomass plants have operating outages that are often associated with solids handling problems. In this study, a plant operating availability of 0.85 is assumed, which is less than levels of 0.90 to 0.95 routinely achieved in coal-fired plants. Startup of solids based power generation is rarely smooth, and this is accounted for by assuming a plant availability of 0.70 in year 1 and 0.80 in year 2. In year three and beyond the availability goes to 0.85 (Wiltsee, 2000). The plants are assumed to be based loaded, which is a reasonable assumption in Alberta where plants with a higher net marginal cost (fired by natural gas) provide non-base load power.
- <u>Reclamation:</u> A site recovery and reclamation cost of 20% of original capital cost, escalated, is assumed in this study, spent in the 30^{th} year of the project. Because the charge occurs only in the last year, it is an insignificant factor in the cost of power.

- Return: Power cost is calculated to give a pre-tax return of 10%. The impact of rate of return is assessed in a sensitivity case. This value is consistent with a plant with a publicly guaranteed return on investment. An alternate case is run at 12%.

2.4 Key inputs

Table 2-1: Fuel properties

Characteristics	Straw	Whole forest	Forest residues
Moisture content (%)	16	50	45
Heating values (MJ dry kg^{-1}, HHV)	18[a]	20[b]	20[b]
Fuel density during transport (dry kg m^{-3})	140[e]	350[c]	350[c]
Nutrient content (%)			
• Nitrogen	0.66[d]	0.31[f]	-
• Phosphorus	0.09[d]	0.05[f]	-
• Potassium	1.60[d]	0.15[f]	-
• Sulphur	0.23[d]	-	-
Ash (%)	4[g]	1[g]	3[h]

a – (Prairie Agricultural, 1995), b – (Woodchip Combustion), c – (Desrochers, 2002), d - (Hartman, 1999), e – (Balers), f – The data given is for white spruce-subalpine fir forest in Canada (Kimmins, 1987). It has been generalized for the boreal forest, g - (Environment Manual Database, 1995), h – (Broek et al., 1995).

Table 2-2: Production and delivery of biomass

Factor	Value	Source / Comments
Straw		
Cost of straw recovery (baling and roadsiding) excluding nutrient replacement ($ $tonne^{-1}$)	8.86	The data is made up of two sources: baling (Ashmead, 1996) and tarping (Bakker-Dhaliwal et al., 1999). The cost estimate for straw supply assumes baling and trucking the bales directly from farm to power plant. The cost does not include raking the straw before baling or stacking the straw at the farm.
Straw loading and unloading cost ($ green $tonne^{-1}$)	4.00	This value is the sum of the loading and unloading costs. It is a blended value of costs taken from the literature (Ashmead, 1996; Bakker-Dhaliwal et al., 1999) and quotes from Alberta based custom straw haulers.
Straw transport cost ($ green $tonne^{-1}$ km^{-1})	0.11	This is a blended value of costs taken from the literature (Ashmead, 1996; Bakker-Dhaliwal et al., 1999) and quotes from Alberta based custom straw haulers.
Nutrient spreading cost ($)	0	It is assumed that there are no spreading costs for agricultural residues because the additional nutrients lost to residue removal can be replaced during existing fertilizing operations.
Whole forest		
Whole forest harvest cost including skidding to roadside ($ m^{-3}) • Felling • Skidding	 $0.9177V^{-0.5963}$ $0.9936V^{-0.3676}$	In the formula V stands for mean merchantable volume of per stem. Average merchantable volume is assumed to be 90% of the gross volume per stem. Skidding distance is assumed to be 150 m. Value of V is assumed to be 0.26 m^3 per stem based on the yields of the hardwood and spruce in the boreal forest (Favreau, 1992).
Chip loading, unloading and transport cost ($ m^{-3})	$0.7585*(2.30 + 0.0257D)$	D is the round-trip road distance from the forest to the receiving plant (Favreau, 1992). In this study the cost has been converted to green metric tonnes. The transport cost for the chips in the whole forest case and forest residue case is the same.

Factor	Value	Source / Comments
Road construction and infrastructure cost (\$ m^{-3})	0.7585 + (379.24/VT)	VT is the mean merchantable volume per hectare, where T is the mean number of merchantable stems per hectare. Value of VT has been assumed to be 185.4 m^3 ha^{-1} for the boreal forest. The construction cost of roads is \$379.24 ha^{-1} represents the tertiary road network used only during the year of the harvest. Infrastructure cost of \$0.7585 m^{-3} depends on the amount of labor and machine, and possibly the merchantable volume per hectare (Favreau, 1992).
Silviculture cost (\$ ha^{-1})	151.69	Many Canadian provinces require that silviculture treatments be performed shortly after harvesting, so that cut areas are returned to a productive state (Favreau, 1992).
Nutrient Spreading Cost (\$ ha^{-1})	73.00	(Borjesson, 2000)
Chipping cost for whole tree (\$ dry $tonne^{-1}$)	2.40	Based on detailed study of Morbark (2002) 50/48 whole tree chipper.
Premium above cost of fuel that is paid to owner as an incentive to collect and sell the fuel (\$ dry $tonne^{-1}$)	4.00	Note that US\$ 4 dry $tonne^{-1}$ of whole forest biomass is approximately Cnd\$ 3.50 m^{-3} of recovered lumber or pulp wood. This is comparable to the lower end of existing royalty (stumpage) fees in the Province of Alberta.
Forest residues		
Chipping cost of forest residues (\$ dry $tonne^{-1}$)	9.42	The cost of chipping for forest residues includes forwarding and piling.
Chip loading, unloading and transport cost (\$ m^{-3})	0.7585*(2.30 + 0.0257D)	D is the round-trip road distance from the forest to the receiving plant (Favreau, 1992). In this study the cost has been converted to green metric tonnes. The transport cost formula for the chips in the whole forest case and forest residue case is the same.

Table 2-3: Power plant characteristics and costs

Factor	Value	Source / Comments
Plant life (years)	30	
Net plant efficiency (LHV) (%)	34	Internal plant use of power is assumed at 10% of gross (Office of Power Technologies, 1997; Broek et al., 1995; Wiltsee, 2000).
Plant operating factor: • Year 1 • Year 2 • Year 3 onwards	 0.70 0.80 0.85	
Operating staffing excluding maintenance staff: • 450 MW or below • Above 450 MW, for each additional unit	 8 4	Staffing levels are derived from the literature (Broek et al., 1995; Wiltsee, 2000; Williams and Larson, 1996), and discussions with personnel in the power generation industry. For a plant up to 450 MW, operators per shift are fuel receiver (1), fuel handlers (2), control room (2), ash handling plant (1), and other power plant tasks (2). For each additional unit we add one fuel handler, one ash handler, and two staff for other power plant tasks. The assumed staffing is five shifts (10,400 hours per shift position per year), which allows for vacation coverage and training.
Power Generation Capital Cost ($ kW^{-1} at 450MW) • Straw plants • Wood plants	 1,300 1,184	This is for a 450 MW direct combustion biomass power plant determined from the literature (Bain et al., 1996; Broek et al., 1995), existing straw plants, (Larsen, 1999; Caddet 1988a; Caddet 1988b; Caddet 1988c) and existing wood plants (Office of Power Technologies, 1997). Note that this figure is more than 50% higher than comparable figures for coal based power generation; the source of this discrepancy is not obvious and the cost for biomass power generation is considered conservative, i.e. high.
Average annual labor cost including benefits ($ hr^{-1}) • Operators • Administration staff	 27.00 27.00	

Factor	Value	Source / Comments
Ash disposal cost		Hauling distance for the ash is assumed to be 50 kms for the three cases.
• Ash hauling cost ($ dry $tonne^{-1}$ km^{-1})	0.114	(Zundel et al., 1996)
• Ash disposal cost ($ dry $tonne^{-1}$ ha^{-1})	15.90	(Zundel et al., 1996)
• Amount of ash disposal (dry tonnes ha^{-1})	1	(Zundel et al., 1996)
Transmission charge for remote location ($ MWh^{-1})	2.16	The transmission charge for the whole forest case has been calculated assuming 300 km of dedicated lines carrying 900 MW at a total capital cost of $97 million at 10% capital recovery plus an operating cost of $408,000 excluding line loss. The cost is for the power plant running at full load at a capacity factor of 0.85.
• Capital cost	2.08	
• Operating cost	0.08	
Spread of costs during construction (%)		Plant startup is at end of year 3 of construction.
• Year 1	20	
• Year 2	35	
• Year 3	45	

Table 2-4: General assumptions

Factor	Value	Source / Comments
Scale factor		
• Total power plant capacity 20 to 450 MW	0.75	(Bain et al., 1996; Office of Power Technologies, 1997)
• Transmission line capital cost.	0.49	0.49 is based on fitting a curve to estimates of 300 km transmission lines through remote boreal forest at various capacities. This value is an exponent.
• Transmission line operating cost.	0.50	0.5 is an exponent for operating costs and is an estimate based on consultation with the electrical industry.

Factor	Value	Source / Comments
Cost of an additional equal sized power plant unit relative to the first	0.95	0.95 is based on conversations with Engineering Procurement Construction (EPC) contractors. This value is not an exponent. It states that additional identical power plant units only cost 95% as much as the first unit (Silsbe, 2002).
Factor to reflect capital cost impact for remote location	1.10	1.1 is based on discussions with EPC contractors regarding construction of a power plant in a remote location (Williams, 2002).
Transmission loss for remote location	3% of generated power	The value has been estimated based on consultation with the electrical industry for a base load 300 km line.
Annual maintenance cost	3% of initial capital cost per year	The value has been assumed based on blending data from existing coal-fired units and from studies of biomass power plants (Bain et al., 1996; Broek et al., 1995; Caddet, 1997).
Labor surcharge for remote location.	1.20	
Aggregate pre-tax return on investment (blend of debt plus equity)	10 %	
Site recovery and reclamation costs	20% of initial capital cost	The reclamation cost is escalated and is assumed to be in the 30th year of operation.
Nutrient cost ($\$ kg^{-1}$) • Nitrogen • P_2O_5 • K_2O • Sulfur	 0.62 0.41 0.22 0.26	(Hartman, 1999; Hursh, 2001) The nutrient costs are given in cost per unit of fertilizer. To determine the cost of nutrient replacement one must multiply by the amount of nutrient per unit of fertilizer. K_2O is 83% potassium. P_2O_5 is 44% Phosphorous.

2.5 Study results and discussion

2.5.1 Economic optimum size of power plant

For the three sources of biomass, the economic optimum size of power plant, the power cost and the geographical "footprint" from which biomass is drawn are shown in Table 2-5.

As expected, the economic optimum size of power plant based on biomass fuel increases with increasing biomass yield per unit area. Figure 2-1 shows the power cost as a function of plant capacity for the three cases.

Table 2-5. Economic optimum size of power plant for Alberta based biomass

Biomass source	**Biomass yield (dry tonnes per gross hectare)**	**Optimum size (MW)**	**Project area from which biomass is drawn (km^2)**	**Power cost ($\$ MWh^{-1}$)**
Agricultural Residues	0.416	450	61,000	50.30
Whole Forest Biomass	84	900	19,000	47.16
Forest Residues	0.247	137	764,000	63.00

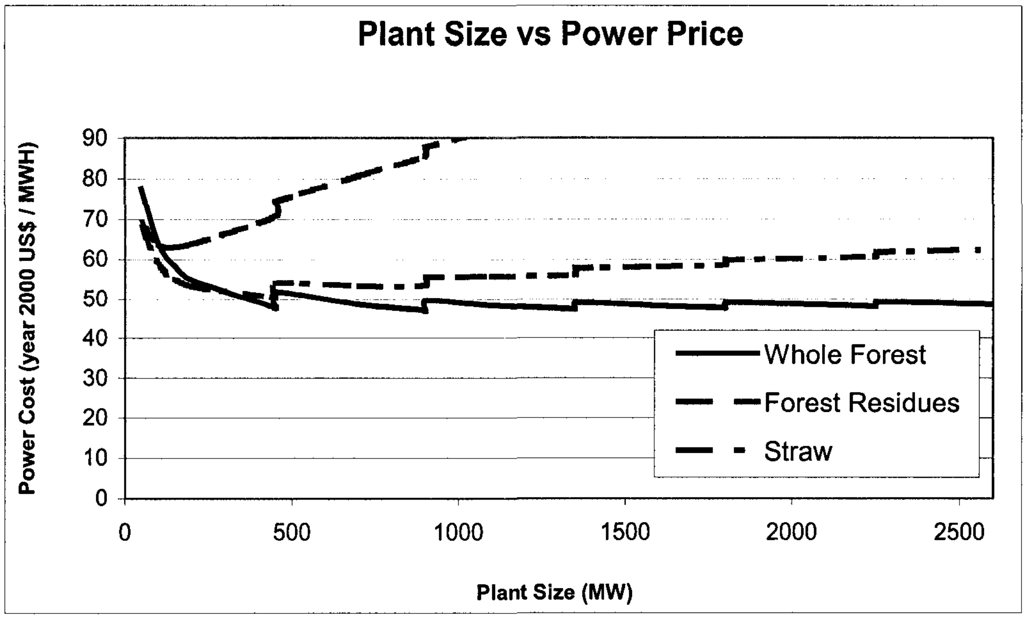

Figure 2-1. Power cost as a function of capacity for three biomass fuels.

These curves have two characteristics worth noting:

- The profile of power cost vs. capacity is flat: In biomass projects, two cost factors compete: fuel transportation costs rise in approximate proportion to the square root of capacity, while capital costs per unit capacity decrease. Because the variable component of fuel transportation cost becomes a significant cost factor as biomass yields drop, the result is a very flat profile of cost vs. capacity. This result is consistent with previous studies of optimum size (Jenkins, 1997; Nguyen and Prince, 1996; Overend, 1982; Larson and Marrison, 1997; McIlveen-Wright et al., 2001). The flatness of cost vs. capacity for biomass is different than coal projects, where "bigger is better", and the size of a unit is often determined by either the largest available capacity or the largest increment of power generation that the power market can accommodate. The result is that biomass to power projects can be built over a wide range of capacities without a significant cost penalty. For example, the economic optimum sized biomass plant for whole forest is 900 MW (two maximum sized units), but the range of capacity for which the power cost is within 10% of the optimum value is 250 MW to more than 4000 MW. While the calculated optimum size for a forest biomass plant is 900 MW, in practice significant road congestion would occur at this scale, and the far more likely plant size would be one 450 MW unit.

- <u>The assumption of maximum unit size drives the determination of the optimum size:</u> The assumption that the largest single biomass unit that can be built is 450 MW puts a discontinuity in power cost at any multiple of that size, as is seen in Figure 2-1. This occurs because at 451 MW, two identical 225.5 MW units are built rather than a single unit. For the straw and whole forest cases, the optimum size is found to be a multiple of the maximum size of a single boiler. In the case of straw, we looked at the optimum size of plant without the assumption of a maximum unit size of 450 MW, and in this case the optimum power plant size is 628 MW. However, as noted above, the flatness of the curve suggests that straw based power plants could be built in any scale from 145 MW to 900 MW with an output power cost predicted to be within 10% of the optimum power cost.

2.5.2 The composition of power cost from biomass

Table 2-6 shows the makeup of power cost per MWh for the three biomass cases. Note that costs are for the first year of operation at full capacity (year 3), but are deflated back to the base year 2000.

Table 2-6. Cost of power from biomass, year 2000 US$ MWh^{-1}, at full capacity (year 3) and optimum size

Cost element	Whole forest	Forest harvest residue	Agricultural residue
Capital Recovery	16.97	20.72	16.32
Transportation	6.74	23.93	12.47
Harvesting	6.74	5.41	6.05
Maintenance	5.09	6.20	4.93
Operating	0.59	2.50	0.63
Administration	0.24	1.30	0.39
Field Cost of Biomass	2.45	2.30	2.29
Silviculture	1.39	-	-
Road Construction	5.19	-	-
Nutrient Replacement	-	-	6.64
Transmission	1.52	-	-
Ash disposal	0.25	0.64	0.57
Total	**47.16**	**63.00**	**50.30**

2.5.3 Other important points

Several points are worth noting:

- Life cycle emissions of carbon: Table 2-7 shows the relative CO_2 emissions per kWh for the three biomass cases used in this study and a new Alberta coal fired power plant located at the mine. The table uses the values of Spath et al. (1999) for the construction of the power plant and the harvesting of biomass, and incorporates average haul distances for biomass transportation.

Transportation of coal has a negligible carbon emission factor because in western Canada the power plant is located adjacent to the mine. Emissions from transporting biomass are based on average haul distances for each specific case. Note that even in the forest harvest residue case, transportation emissions are less than 5% of the emissions of a coal fired plant, per unit of power. Emissions associated with mining coal are included, for both the energy required to move the overburden and recover the coal, and the release of methane. Methane emissions from open pit coal mines reflect not only the methane contained in the mined coal but also methane from the seam near the edge of the pit is released to the atmosphere. The approach of Hollingshead (1990) was modified to reflect the large size of a mine supporting a 450 or 900 MW coal fired power plant. Methane released from the coal seam is estimated at three times the methane contained in the actual mined coal. From Table 2-7 it is clear that this assumption does not significantly affect the total estimated carbon credit.

Table 2-7: Life cycle emissions (g kWh^{-1}) from the power plants

	Production	Trans-portation	Construction and De-commissioning	Energy Conversion	Total Emissions
Forest Residues	28.0[a]	35.5[b]	12.0[a]	0	75.5
Whole Forest	28.0[a]	6.4[b]	12.0[a]	0	46.4
Straw	28.0[a]	8.9[b]	12.0[a]	0	48.9
Coal	11.6[d]	0[b]	5.0[e]	968.0[c]	984.6

a – (Mann and Spath, 1999)

b - based on truck transportation for a distance of 329, 52 and 123 kms for forest residues, whole forest and straw respectively, assuming the energy input of 1.3 MJ $tonne^{-1}$ km^{-1} by truck and a release of 3 gC GJ^{-1} km^{-1} (Borjesson, 1996). Most of the coal power plants in western Canada are at a mine, so the transportation distance is very small. The emission during transportation would be negligible as compared to the other components. Hence it has been neglected in this case.

c - The emission factor is calculated based on characteristics of Alberta coal and the new 450 MW coal power plant.

d - For Genesee, Alberta coal-field, (Hollingshead, 1990). It includes the contribution from methane emission and also the emission during the mining of coal.

e – (Spath et al., 1999)

- Cost of biomass power: None of the biomass cases are directly competitive with coal based power in western Canada, which has a power cost (including return on capital) in the range of \$30 per MWh. Hence, in the absence of an emission credit biomass power will not be developed. From Table 2-7, the difference in emissions is used to calculate the carbon credit required to make biomass power competitive with incremental power from a new coal fired plant, assuming a coal power cost of \$30 MWh^{-1}. A carbon credit of \$18.30 $tonne^{-1}$ of CO_2, \$21.70 $tonne^{-1}$ of CO_2, and \$36.20 $tonne^{-1}$ of CO_2 would be required to equalize against an incremental coal plant for each of forest biomass, straw and forest harvest residue. The Alberta power market was fully deregulated in 2000, and since that time monthly average power price has ranged from less than \$16 MWh^{-1} to more than \$165 MWh^{-1}. Figure 2-2 shows the carbon credit that would be required to make the biomass cases economic in Alberta as a function of power price. These values could be used to calculate a variable incentive for a publicly supported biomass power plant.

Such an incentive would be tied to actual power price rather than the cost of power from a displaced fossil fuel plant i.e. by a new coal fired plant.

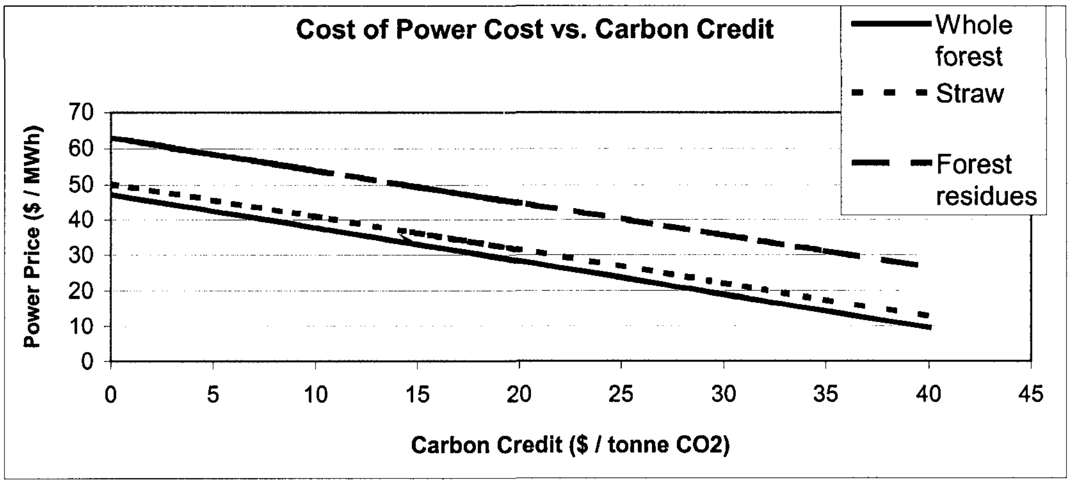

Figure 2-2. Carbon credit required to make biomass power economic in western Canada as a function of average power price.

- Whole forest biomass: Harvesting the whole forest for power generation has the highest biomass yield per gross hectare and the lowest power cost. However, the cost is lowest only because nutrients are not replaced. Had the basis been nutrient replacement, the cost of whole forest biomass would be comparable to power from straw. The variable transportation cost is low, due to the high biomass yield per hectare. Construction of roads is a major cost factor for power from biomass; the other two cases utilize existing roads. This cost would disappear for a second generation power plant based on harvesting replanted forest. The remoteness of the assumed location for this plant is also a significant penalty, giving a higher construction and operating cost and adding both transmission cost and line loss. If the whole forest plant were in a non-remote location, the cost of power would drop to \$43.29 MWh^{-1}.

- Forest harvest residues: Forest harvest residues give the most expensive power of the three cases. The major cost penalty is the high cost of biomass transportation, which exceeds the cost of capital recovery. The slow growth of the Northern Alberta forest leads to a long rotation period, which in turn gives a very low yield of residues per gross hectare. Areas that have shorter rotation periods would have more favorable economics for these residues.
- Agricultural residues: Power from straw is close to whole forest utilization despite straw's low yield of biomass per gross hectare. Transportation costs are high, but there is no cost for road infrastructure and the setting is not remote.
- Ash removal: Ash removal cost is based on the conservative assumption of no credit for the nutrient value of the ash; as noted above, there is evidence that once a biomass plant starts operation that a demand for the ash emerges and that growers will haul it away at no charge to the plant. This is evaluated in a sensitivity case.

2.6 Sensitivities

Some key sensitivities are shown in Table 2-8.

Table 2-8. Key sensitivities for power from biomass

Factor	Power Cost ($ MWh^{-1})	Cost Impact (%)	Optimum Size Impact (MW)
Capital cost of power plant is 10% lower			
• Agricultural Residues	48.17	- 4.2	No Change
• Whole forest	44.96	- 4.7	No Change
• Forest residues	60.30	- 4.3	128
Pretax return on capital is 12% rather than 10%			
• Agricultural residues	53.71	+ 6.8	No Change
• Whole forest	50.70	+ 7.5	No Change
• Forest residues	67.27	+ 6.8	151
Efficiency increased from 34% to 35% (LHV)			
• Agricultural residues	49.37	- 1.8	No Change
• Whole forest	46.46	- 1.5	No Change
• Forest residues	61.77	- 2.0	142
Largest unit size for boiler is unconstrained: Agricultural residues (straw) case	50.03	- 0.5	628
Whole forest biomass location is not remote	43.29	- 8.2	450
Scale factor is 0.6 rather than 0.75			
• Agricultural residues	44.66	- 11.2	No Change
• Whole forest	41.14	- 12.8	No Change
• Forest residues	59.20	- 6.0	168
Scale factor is 0.9 rather than 0.75			
• Agricultural residues	58.42	+ 16.1	No Change
• Whole forest	55.52	+ 17.7	No Change
• Forest residues	66.47	+ 5.5	95
Biomass yield is 25% higher per gross hectare	49.29	- 2.0	No Change
• Agricultural residues	60.71	- 3.6	152
• Forest residues			
Whole forest biomass from			
• Good Site (124 dry tonnes	43.50	- 7.8	No change
gross $hectare^{-1}$)	53.33	+ 13.1	No change
• Fair Site (53 dry tonnes gross $hectare^{-1}$)			

Factor	Power Cost ($\$ MWh^{-1}$)	Cost Impact (%)	Optimum Size Impact (MW)
Biomass harvesting cost is 25% lower	48.78	- 3.0	No Change
• Agricultural residues	45.47	- 3.6	No Change
• Whole forest	61.64	- 2.2	No Change
• Forest residues			
Staffing cost reduced by 25%			
• Agricultural residues	50.04	- 0.5	No Change
• Whole forest	46.95	- 0.4	No Change
• Forest residues	61.98	- 1.6	124
Ash disposal at zero cost			
• Agricultural residues	49.72	- 1.2	No Change
• Whole forest	46.90	- 0.6	No Change
• Forest residues	62.35	- 1.0	No Change
Nutrient replacement, whole forest case	51.58	+ 9.4	No Change

2.7 Other technologies and cost factors

This study is based on production of electrical power from the direct combustion of biomass. Other technologies warrant comment and future assessment:

- Use of low pressure steam for heating purposes helps the economics of any thermal power plant project, i.e. biomass, fossil fuel or nuclear. However, the potential for developing such a co-generation application is higher for the agricultural residues (where heat might be used in a food processing application) and the forest harvest residues (where the plant has such a large draw area that it might be economically located near a pulp or lumber operation). For a remote whole forest biomass, such a co-gen application is less likely.

- In all cases of use of biomass fuel, water content of the fuel reduces efficiency. This study does not include an assessment of field drying of wood chips or the use of very low quality heat, such as flue gas, for drying of fuel.
- Even though straw is passed through a combine as part of the threshing operation, it is dispersed back onto the ground and then gathered up on a second pass over the field. This practice simply reflects past agricultural needs rather than technological limits. Dispersing straw on the field creates two problems: there is extra cost for a second pass and the efficiency of straw collection is lower, since some of the straw, including virtually all of the chaff, is not recovered on the second pass.
- For forest residues, a major cost is the forwarding (consolidation) and piling of residues prior to chipping. If forest residue power projects were implemented on a large scale, delimbing and topping of trees could be integrated with chipping of the limbs and tops in a single operation.
- This study assumes that biomass fuel is sold at a premium over cost of $4 dry tonne^{-1}. An alternative for each of the fuels in this study is to require their availability at cost, as a condition of access to Provincially owned timber in the case of forest harvest residue biomass, and as a condition of agricultural support programs in the case of agricultural residues. Such an approach would presumably reflect a growing social concern re the need to mitigate GHG. It would also address a critical issue for the power plant operator, security of fuel supply. Failure to address reliability of fuel

supply would leave the power plant operator hostage to biomass price increases once the plant is built. This kind of concern in the power industry is normally addressed by long term fuel supply contracts, which might work for forest biomass but would be unlikely to work for agricultural residues coming from a wide number of farmers. We believe that some social intervention will be necessary to address security of fuel supply. For whole forest biomass, a key question is the value of the wood as fuel vs. the value of the wood as fiber (lumber or pulp).

- This study assumes truck delivery of fuel. We note that no other power generation facility of significant size relies on highway truck delivery of fuel. Alternate transport mechanisms, includes rail and pipeline, from hubs within the area from which biomass is drawn.
- Direct combustion of biomass has a lower efficiency and lower heat rate than other technologies, notably gasification. Gasification of wood can be achieved at significantly lower temperatures (and hence cost) than for coal (Williams and Larson, 1996).

2.8 Conclusions

Electrical power from biomass in western Canada is not economic in its own right, but may become so if a system of trading GHG credits emerges. Whole forest biomass and straw can generate power for \$47 and \$50 MWh^{-1} at their optimum size. Forest biomass likely requires a remote location with dedicated transmission, but has low transportation cost due to the high biomass yield per gross hectare. Straw has a lower biomass yield and hence a higher transportation cost, but this is partly offset by a non-remote location and access to public road infrastructure. Forest harvest residues have a very low yield per gross hectare because of the long rotation and low cutting density in the boreal forest; transportation costs are of the same scale as capital recovery in this case, and the cost of power is \$63 MWh^{-1} and optimum plant size is the smallest, at 137 MW. Nutrient replacement was factored into the straw case, but not into the forest biomass cases since first cut operations in Alberta do not practice nutrient replacement. However, repeated forest harvesting ultimately requires nutrient replacement, and this is a significant cost factor for the whole forest case (\$4.42 MWh^{-1}). Inclusion of nutrient replacement makes forest biomass comparable to power from straw.

All biomass cases show a region of flat profile of power cost vs. plant capacity, which occurs because the reduction in capital cost per unit capacity with increasing capacity is offset by increasing fuel transportation cost as the area from which biomass is drawn increases. This means that smaller than optimum plants can be built with only a minor cost penalty.

Biomass yield per gross hectare is a major factor in the cost of power from biomass, and forest harvest residue usage would be more economic in areas with shorter rotations. The assumption of maximum unit size for a biomass boiler drives the optimum capacity for the straw and whole forest cases, but the flatness of the cost vs. capacity curve means this is not a critical factor.

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Chapter 3

Cofiring straw with coal to reduce greenhouse gas emissions at the Genesee power station*

3.1 Overview

The primary driver for this project is that cofiring at the Genesee power station may provide a local, "in-house", method to help EPCOR meet its commitment to offset GHG emissions to the level of a natural gas combined-cycle facility (Public disclosure document, 2002). Using biomass in a stand-alone plant offsets 909 – 938 grams of carbon dioxide per kWh when the power replaces conventional coal-fired generation (Kumar, Cameron and Flynn, 2003). While the offset generated from cofiring will not be exactly the same as in a stand-alone plant, it is expected to be slightly higher due to the reduced capital construction required and higher combustion efficiency. Hence 909 g kWh^{-1} can be used as a conservative estimate to evaluate the CO_2 reduction potential of cofiring.

Three methods of cofiring were considered: simple mixing of the biomass with the coal in the fuel yard, separate injection of sized biomass into the boiler, and gasification of biomass with the gas directly fired in the boiler. Technology under development includes gasification of biomass with the gas fired in its own turbine, and using the waste heat in the existing coal-fired steam cycle. This was

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* A version of this chapter has been published. Cameron 2003. EPCOR Inc. internal report.

not considered in detail because the technology is not mature and might not be ready to implement in the near future. In addition it has much higher capital costs than the other methods considered.

3.2 Methods of cofiring

3.2.1 Simple mixing

Simple mixing of biomass in with the fuel is the blending of fuels before they are put into the boiler, usually in the fuel yard or along one of the coal conveyors. For instance sawdust or chopped straw could be deposited on top of the coal as it travels along a conveyor from the crusher into the plant. This blending of biomass is lower in cost than other methods of cofiring (Hughes, 2000; Tillman, 2000) but it has several limitations.

Due to the fact that the density of straw is much lower than the density of coal, a 1% straw input on a thermal basis results in a 5% - 10% straw input on a volumetric basis. The density of the straw input depends on the preparation of the straw. The 5% volumetric input corresponds to a finely chopped straw (90% < 1/16"). Unchopped straw has a much lower density and correspondingly lower preparation costs. The large volume of straw required (relative to coal) for a given heat input leads to a limitation on the proportion of straw that can be co-fired with simple mixing due to capacity issues in the coal feed system. In particular simple mixing of straw with coal in a large pulverized coal plant reaches the practical limit for the coal mills at a co-firing level of 2% straw on a thermal basis (Hughes, 2000).

Another limitation of the simple mixing method of cofiring is the lack of immediate control of the straw portion of the fuel mix. When the straw is added to the coal in the fuel yard, it will often take at least 12 hours before a change in the straw proportion reaches the boiler depending on the coal stored in the bunkers. In addition, while the coal straw mix is in the bunkers the straw may intensify existing material bridging and holdup problems, especially if the straw is not finely chopped.

Finally, the NOx reduction potential of the straw is limited by simple mixing due to two factors. The amount of straw able to be co-fired is well below the optimal amount of 15% required for maximum NOx reduction (Hein and Bemtgen, 1998). In addition, because the straw is mixed evenly with the coal only a small portion of it is being injected into the optimum NOx reducing zone.

3.2.2 Separate injection of sized biomass

Separate injection of sized straw involves a parallel fuel delivery system of preparing, feeding, and injecting the straw separate from the coal system. In a pulverized coal boiler there are three methods of straw injection that have been demonstrated:

- installing new row(s) of straw burners,

- converting coal burners to fire straw,
- At the Strudstrup power station in Denmark one row of existing coal burners was modified to feed straw through the oil lance located in the center of the burners (Wieck-Hansen et al., 2000) while continuing to feed coal through the outer portion of the burner.

Separate injection has a capital cost (both total cost and per kW cost) that is higher than simple mixing, however it allows for higher proportions of straw co-firing, it provides nearly immediate control over the amount of straw co-fired, and does not impact the coal feed system. On the contrary, it may even allow operators to avoid a derate when the plant output would otherwise be limited by the coal feed (such as an unplanned pulverizer outage).

With separate injection the feeding system is no longer the limitation on the amount of straw that can be co-fired. The limitation then shifts to boiler chemistry/corrosion due to the presence of KCl and silicates in the straw. The limit on the amount of straw that can be co-fired is then raised (relative to simple mixing) to as much as 20% based on boiler temperatures and acceptable levels of corrosion. At cofiring levels of up to 10% there is no appreciable corrosion increase for boilers with steam temperatures in the 540 – 580 C range (Wieck-Hansen et al., 2000). At higher temperatures corrosion can increase by up to 2 times (Hein and Bemtgen, 1998). At cofiring levels of 20% corrosion in the superheaters may increase 1.5 to 3 times for boilers using a low corrosive coal, however the corrosion rate is still low compared to a medium corrosive coal

(Wieck-Hansen et al., 2000). In addition, at cofiring levels of 20% there is increased slagging (which requires increased sootblowing compared to normal operation) (Wieck-Hansen et al., 2000).

The increased operational control of separate injection also provides the advantage of dispatchability. With simple mixing, the proportion of straw co-fire is set in the fuel yard. With direct injection, the operators have control over the amount of co-fire at any given time. This means that they can alter the straw/coal ratio at any time for reasons of flame control, NOx control, or "Green Power" contract commitments. Unlike other renewables such as wind and solar power, straw power is storable and in the case of separate injection it is dispatchable. Actually, straw can compliment wind or solar power as it could be dispatched when the wind or the sun do not cooperate and scaled back again when the wind or solar is back to full capacity.

3.2.3 Gasification

Gasification of biomass refers to an endothermic reaction of biomass in a vessel with hot air (or supercritical water) which produces a combustible gas comprised of N_2, CO, CO_2, CH_4, C_2H_6, H_2, and H_2O, as well as some condensable tars and solid char. This gas can then be fired directly in a main coal boiler.

Another method of using gasification is to use in a separate gas turbine with waste heat recovery. After the biomass is gasified the produced gas is cooled, filtered, and fired in a turbine. This may not sound like cofiring, but by using the waste heat from both the gas cooler and the turbine exhaust in the existing steam cycle, coal usage is reduced, with a corresponding reduction in carbon emissions. On an emissions intensity basis, this is the most attractive cofiring option because electricity production is increasing in addition to reducing fossil fuel usage.

Gasification in either form has the highest capital cost of the three alternatives considered (Tillman, 2000), however gasification with indirect cofiring (the second method) is much more capital intensive than gasification with direct cofiring. The primary advantage of gasification with indirect cofiring is that it produces incremental electricity as well as reducing coal usage.

In addition to high cost, gasification has a process disadvantage as well. It is not readily dispatchable like the separate injection of sized biomass. A gasification process has a relatively long startup and shutdown period and only a moderate turn-down ratio.

One advantage of gasification compared to the other types of cofiring is the separation of ash. Many jurisdictions have not approved the use of biomass derived ash for the production of concrete. This is a significant disadvantage to simple mixing and separate injection of sized biomass, because the bioash is mixed with the coal ash, with the potential of severely limiting ash sales.

Another advantage of gasification is the flexibility of input fuel. In addition to straw, gasification plants can handle a wide range of refuse derived fuels. The Kymijarvi gasification plant in Lahti, Finland accepts sawdust, wet wood residues from lumber operations, dry wood residues from the woodworking industry, plastics, paper, cardboard, and even tire derived fuel (Raskin et al., 2001).

Finally, there is essentially no limit to the amount of biomass that can be cofired using gasification. Therefore the size of the gasifier would be determined based on economic optimum size (for injection into the boiler of the produced gas), the amount of carbon dioxide abatement desired, and thermodynamic considerations. For this study an upper limit of 50% biomass was considered. Beyond that amount it would make more sense to research adding coal to an existing straw-fired plant.

3.3 Discussion

3.3.1 Economics

Cofiring biomass has economic advantages and disadvantages when compared to stand-alone biomass power plants. Typically the capital cost of retrofitting an existing power plant to cofire a certain amount of biomass is much lower than building a stand-alone biomass plant of the same biomass capacity. In addition unlike mine mouth coal, the cost of biomass fuel is not a constant with respect to plant size. As the amount of biomass fuel required increases, so does the collection area, the transportation distance and the average cost of the biomass fuel. Cofiring allows biomass to be used in smaller quantities and yet still be used in a large, efficient power plant (small stand-alone biomass plants have overall efficiencies as low as 20% compared to >30% for a 450 MW coal plant) (Overgaard et al., 2002).

The primary disadvantage of cofiring in this case is that it displaces existing electricity generation capacity, whereas a stand-alone biomass power plant is assumed to displace the construction of a new fossil fuel power plant. The economic difference is that in the case of a stand-alone plant there are two products for sale from the biomass combustion: a GHG credit and a unit of electricity. With co-firing no incremental electricity is generated, hence only a GHG credit is created (plus small savings in coal fuel costs). On the other hand, there is some ambiguity as to what a stand-alone biomass power plant replaces; does it replace a coal plant, a combined cycle natural gas turbine, or a solar panel? Clearly the GHG credit created in each of these three cases in not equal. Cofiring eliminates this ambiguity because the biomass is directly substituted for coal in an existing coal fired plant, resulting in the largest CO_2 credit.

Using values from the literature and chapter 1 on biomass in western Canada, the Table 3-1 was constructed to show the cost and quantity of CO_2 credits available using biomass in a 450 MW coal unit in Alberta.

Table 3-1: CO_2 abatement cost

Description	Capital Cost used, range (US$/kW)*	Straw Cost (US$/ tonne) **	Scale, % biomass	Credits generated (tonnes/year) based on 90% availability	Abatement cost (US$/ tonne CO_2)
Stand alone plant	$1517, $1250 - $1920	$38.11	450 MW, 100%	3,100,000	$11 - $21***
Simple mixing	$76, $51 - $101	$26.68	9 MW, 2%	61,000	$21
Separate injection (small, low impact)	$185, $169 - $202	$39.00	45 MW, 10%	305,000	$26
Separate injection (large)	$169, $169 - $202	$30.76	90 MW, 20%	610,000	$27
Gasification-direct injection (small)	$311	$29.00	45 MW, 10%	305,000	$29
Gasification-direct injection (large)	$211	$34.91	225 MW, 50%	1,550,000	$32

Notes on Table 3-1:

- The incremental cost of coal usage was assumed to be $5 US per tonne with an LHV of 18 MJ $tonne^{-1}$.
- Capital costs were recovered at 15% per year.
- The capital cost for large gasification-direct injection was scaled from the small gasifaction-direct injection using a scale factor of 0.75.

* Capital costs were taken from the following references: (chapter 1; Hughes, 2000; Spliethoff and Hein, 1998; Battista et al., 2000; Cameron et al., 2002; Dasappa et al., 2003)

** Straw cost is a blend of collection cost, transportation costs, nutrient replacement, and a payment to the farmer (owner). The straw cost increases with the amount of straw needed due to increasing transportation distances. The cost was calculated using the methods described in chapter 1.

*** Because a stand alone biomass power plant generates new electricity as well as a CO_2 credit, the cost of the abatement is a range that depends on the payment received for the electricity. The range in abatement costs reported represents a power price of $30 MWh^{-1} - $40 MWh^{-1}.

As table 3-1 illustrates, even the lowest cost of CO_2 abatement through cofiring straw is more expensive than even the highest cost of building a stand alone straw fired power plant (although it is much less risky due to a lower capital investment and better security of fuel supply). Note also that $22 US is well above the $15/tonne Cdn price cap that the Canadian government has guaranteed.

Another way of looking at the cost of cofiring is by examining the decrease in emissions intensity for each of the options, and the corresponding increase in the cost of producing power. This method of analysis is particularly suited to EPCOR because its operating license for Genesee 3 depends on meeting an emissions intensity target. Table 3-2 illustrates emissions intensity vs. increase in power cost for biomass cofiring at the Genesee power station.

The primary reason that the methods of cofiring analyzed are uneconomic is that the straw fuel is expensive (relative to coal) and that there is no incremental electricity generation. There are some savings in the incremental cost of coal, but these savings are dwarfed by the cost of the straw fuel. Because EPCOR owns its coal resource, its cost of coal is a mix of fixed costs and variable costs. This is in contrast to many European and American coal plants which purchase coal that is delivered by rail or ship from a third party. In addition to having typically higher coal costs, for these plants the entire cost of coal is variable, making the coal fuel savings from cofiring more attractive. In addition, some coal plants are in some way fuel limited (TransAlta's Wab4 recent pulverizer limitation is an example). For these plants cofiring can actually increase the electricity generated, which increases revenues and makes cofiring more attractive. However, the Genesee units are not fuel limited and hence cofiring biomass does not produce incremental power.

Table 3-2: Reduction of emissions vs. increase in power cost

Description	Genesee 1, 2			Genesee 3		
	Emissions intensity	New Emissions Intensity*	Change in power cost	Emissions intensity	New Emissions Intensity*	Change in power cost
Simple mixing	992.5 kg/MWh	973.6 kg/MWh	+$0.51/ MWh	891 kg/ MWh	874 kg/ MWh	+$0.51/ MWh
Separate injection (small, low impact)	992.5 kg/MWh	898.1 kg/MWh	+$3.09/ MWh	891 kg/ MWh	807 kg/ MWh	+$3.13/ MWh
Separate injection (large)	992.5 kg/MWh	803.7 kg/MWh	+$6.46/ MWh	891 kg/ MWh	723 kg/ MWh	+$6.57/ MWh
Gasification-direct injection (small)	992.5 kg/MWh	898.1 kg/MWh	+$3.09/ MWh	891 kg/ MWh	807 kg/ MWh	+$3.49/ MWh
Gasification-direct injection (large)	992.5 kg/MWh	521 kg/MWh	+$18.63/ MWh	891 kg/ MWh	470 kg/ MWh	+$18.93/ MWh

Notes on Table 3-2:

*48.9 kg MWh^{-1} was used as the life cycle emissions for straw fired generation (Kumar, Cameron and Flynn, 2003).

3.3.2 Other benefits

The use of biomass as a fuel is currently driven by a desire to reduce CO_2 emissions. However, that has not always been the case; looking at some of the previous reasons for using biomass highlights the secondary benefits of cofiring biomass.

Biomass for district heat and electricity was implemented in Europe and studied in the US extensively in the 1970's as a method to help ensure a secure fuel supply during times of uncertain fossil fuel prices. EPCOR's Genesee power station does not have a concern around fuel security, but it is worth noting that the substitution of biomass for a portion of the coal fuel would prolong the life of the coal mine.

Biomass has also been studied as a method of NOx reduction. Because of its high volatility, straw (and other forms of biomass) ignites more rapidly but also decrease furnace exit temperatures, which causes less thermal NOx to be formed (Hus and Tillman, 2000). When the biomass is staged properly, it can also create a localized area of oxygen deficiency and drive a reverse-Zeldovich reaction, which is considered the main path of NOx destruction (Harding and Adams, 2000). Genesee is not above its mandated NOx emissions and currently in Alberta there is no economic incentive to reduce NOx further. However in several jurisdictions emissions trading would allow a plant that was well under its limits to sell the unused portion to other plants.

Biomass-fired power plants are also used in Alberta and around the world as a method of waste disposal. In Alberta this consists primarily of the combustion of mill residues at pulp mills and saw mills. However it is expanding to include burning "produced gas" in the oilfield and burning methane produced from composting urban waste. Around the world biomass waste is burned in many applications including bagasse at sugar processing plants, rice hulls, urban wood waste, and in certain areas (E.g. Denmark) excess straw that cannot be left on the field. One of the disadvantages to cofiring straw in Alberta is that waste straw does not need to be removed from the field for agronomic reasons. This means that the full cost of straw collection (and related nutrient replacement) is born by the electricity generator. Whereas in an area like Denmark the farmers are removing the straw from the field anyway, the electricity generator only pays for the transportation cost from the farm to the plant.

3.4 Conclusions

- Cofiring straw at the Genesee power station as a means of GHG reduction is not currently economic compared to a stand-alone biomass plant. A stand-alone biomass plant would be a lower cost option per unit of GHG abated despite having a much higher capital cost.
- Cofiring of straw (or other biomass) might become economic at the Genesee power station if one of the following conditions were satisfied:

  i. The coal available limited the life of the power plant. Then the biomass would have a secondary economic effect of extending the life of the coal plant.

  ii. The coal feed system limited the output of the plant. Low quality coal, or continuing pulverizer problems (such as occurred with the TransAlta

Wabamun 4 plant) could make separate injection of biomass an alternative to upgrading the coal feed system.

iii. A reduction in NOx emissions was a tradable credit (As is the case in parts of the US), or if NOx emissions were currently above legislated limits. In that case biomass cofiring may compete favorably with other NOx control methods.

iv. The cost of the biomass fuel was greatly reduced (as is the case with mill wastes; the biomass fuel has a negative cost).

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Chapter 4

Pipeline transport of biomass[*]

4.1 Overview

Carbon based power generation facilities do not typically rely on delivery of fuel by highway truck. Oil and gas fired plants rely on pipelines, and coal based facilities typically are either located at mine mouth or rely on rail or ship for fuel delivery. The reason for this is the high cost and high congestion that would be associated with delivery of large tonnages of fuel to modern large sized power plants.

Numerous biomass power plants are small and utilize truck delivery of fuel. However, in chapter 1 it was noted that optimum size for straw and wood based biomass power plants in a western Canadian setting were 450 MW or greater for straw and wood from harvesting the whole forest, and that cost of power increased sharply at sizes below about 200 MW. For forest harvest residues (limbs and tops), which are more widely dispersed, the optimum size was 137 MW.

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[*] A version of this chapter has been published. Kumar, Cameron, and Flynn 2004. Journal of Applied Biochemistry and Biotechnology. 113(3): 27-40.

A 450 MW biomass power plant burning 2.1 M dry tonnes per year of wood chips would require 17 truck deliveries per hour at 20 tonne per truck capacity (Cameron et al., 2002). Highway transportation of fuel is a significant cost element, contributing, at optimum power plant size, 25, 14 and 38% of the total cost of power generation from direct combustion of straw, wood from harvesting the whole forest, and forest harvest residues, respectively (Kumar, Cameron and Flynn, 2003). In this chapter pipeline delivery of biomass to a power generation plant is evaluated to avoid road congestion (and likely resistance by nearby residents), and to reduce overall fuel transportation cost.

Two carrier mediums are considered for biomass: water and oil. We review the inherent economics of truck vs. pipeline transport, and then evaluate a case of field delivery of biomass by short haul truck to a pipeline terminal. The impact of water and oil absorption by the biomass fuel is also evaluated. The prospects for pipeline transport of biomass are discussed.

4.2 The inherent economics of truck and pipeline transport

Truck delivery of material has a fixed cost associated with the time required to load and unload the truck, and a variable cost that is related to the time the truck is being driven and/or the distance driven. For most biomass delivery applications, truck speed is relatively constant over the route; thus, for example, a truck picking up straw would average about 80 km/hr on rural and district roads, and a truck picking up wood chips in a forest would average about 50 km/hr on logging roads. Only if the wood chips had a significant drive over highways would there be a second higher speed portion of the trip; this effect is ignored here. Figure 4-1A and 4-1B show cost data per km for truck transport of wood chips in a typical western Canadian setting (Favreau, 1992; Evashiak, 2003); the intercept of the lines is the fixed cost of loading and unloading, and the slope is the incremental variable cost per km.

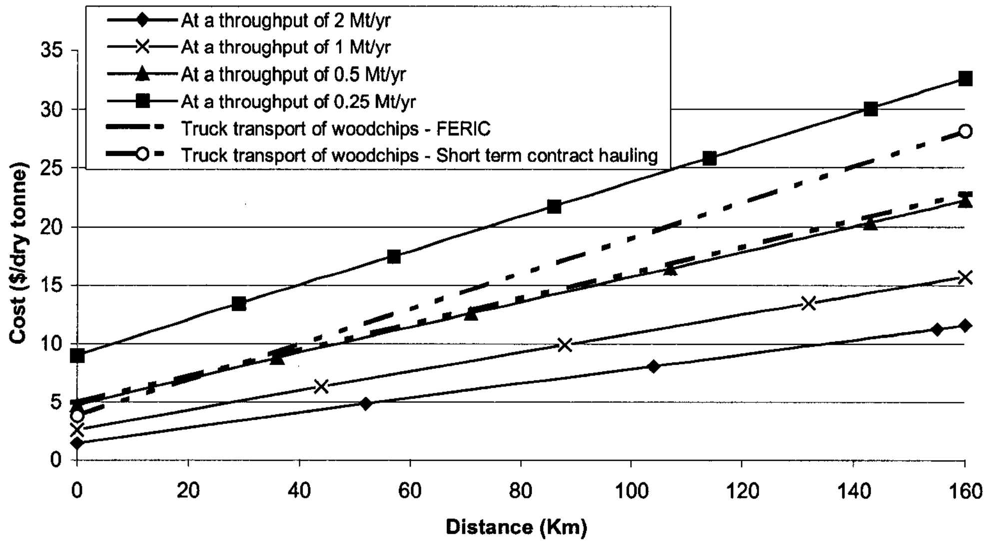

Fig. 4-1A. Pipeline transport cost of wood chips without carrier fluid return pipeline.

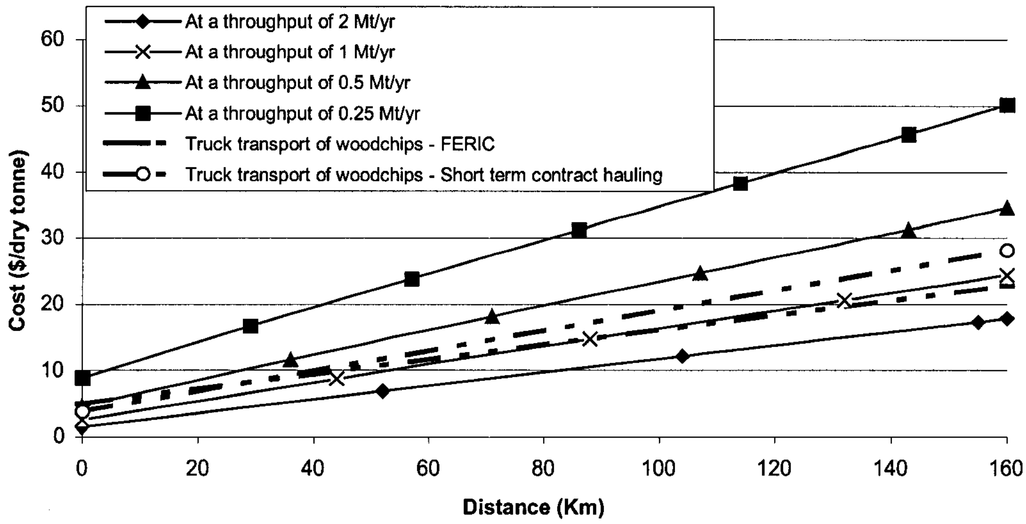

Fig. 4-1B. Pipeline transport cost of wood chips with carrier fluid return pipeline.

Table 4-1 shows the equations for transport costs, including straw. Figure 4-1 is adjusted to dry tonnes of biomass to make comparison with pipeline costs easier; pipeline costs are discussed below. Typical field moisture levels for straw and wood in western Canada are 16% and 50% respectively. The range of costs for truck transport of wood chips comes from two different types of estimate: the lower bound is from a Forest Engineering Research Institute of Canada (FERIC) study of chip transport costs from a long term dedicated fleet, while the upper bound is based on current short term contract hauling rates. The FERIC data is more representative of steady biomass supply to a long term end use such as a power plant. Note that there is no change of cost with scale for any biomass application of interest, i.e. the amount of biomass moved fully utilizes multiple trucks and no savings occur with larger throughput.

Table 4-1

Formulae for truck and pipeline costs as a function of distance

Cases	Cost, \$/dry tonne (d is distance in km)	Distance between slurry pumping stations, km
Two-way pipeline transport cost of a water wood chip slurry		
At 2 Mt/yr capacity	0.1023d + 1.47	51
At 1 Mt/yr capacity	0.1355d + 2.65	44
At 0.5 Mt/yr capacity	0.1858d + 4.80	36
At 0.25 Mt/yr capacity	0.2571d + 9.05	29
One-way pipeline transport cost of a water wood chip slurry		
At 2 Mt/yr capacity	0.0630d + 1.50	51
At 1 Mt/yr capacity	0.0819d + 2.63	44
At 0.5 Mt/yr capacity	0.1088d + 4.80	36
At 0.25 Mt/yr capacity	0.1473d + 9.07	29
Truck transport cost of wood chips (50% moisture)	0.1114d + 4.98	-
FERIC (long term hauling)	0.1309d + 4.76	-
Short term contract hauling		
Truck transport cost of straw (16% moisture)	0.1524d + 3.81	-

Note that unlike truck transport there is an economy of scale in slurry transport of materials, since larger throughputs benefit from an economy of scale in construction of the pipeline and associated equipment, and in lower friction losses in larger pipelines.

Pipeline transport of wood chips was studied in the 1960's. Brebner (1964), Elliott (1960), and Wasp et al. (1967) looked at solids carrying capacity and pressure losses, and Wasp et al. (1967) did a cost analysis for a 160 km pipeline with one-way transport, i.e. no water return. These studies were focused on the supply of wood chips to pulp mills, and hence water uptake by chips did not have a downstream processing impact. More recently Hunt (1976) did an extensive analysis of friction factors in wood chip slurries in water; in this work, we utilize his formula for the friction factor. More recently Liu et al. (1995) completed an analysis of two phase pipelining of coal logs (compressed coal cylinders) by pipeline. In this paper we draw on the work of Wasp et al. (1967), Liu et al. (1995), and discussions with a Canadian engineering contractor (Williams, 2003) to develop pipeline cost estimates for transporting water slurries of wood chips; these costs are also shown in Figures 4-1A and 4-1B, and in Table 4-1.

Delivery of material by slurry pipeline has a similar shape of curve to truck transport. The fixed cost is associated with the investment in the material receiving and slurrying equipment at the pipeline inlet, and the separation and material transport equipment at the terminus. The slope of the curve comes from the operating cost of pumping, and the recovery of the incremental capital investment in the pipeline and booster pumping stations plus associated infrastructure such as power and road access, all of which increase linearly with distance. Technically, pipeline costs would have a slight "sawtooth" shape, with a slight discrete increase in overall cost occurring when an additional pumping station is required. Practically, most of the incremental capital cost is in the pipeline rather than pumping stations, and the sawtooth effect can be ignored. (In our analysis the pipeline component of the total capital cost is 85% at 50 km, and 94% at 500 km).

One key element in the pipeline scope and estimate is whether a return line for the carrying fluid is provided. This would be required in virtually all circumstances if the carrying fluid were a hydrocarbon, e.g. oil, and would be required for water if upstream sources were not available, as might occur in a forest cut area, or if downstream discharge of separated water was prohibited. Appendix B shows the scope and cost estimate included in a two-way pipeline, i.e. one with return of the carrier fluid. Key elements at the upstream end are materials receiving from trucks, dead and live storage, slurrying, and pipeline initial pumps. Key elements along the pipeline are the slurry and return pipeline and booster pumping stations. Key elements at the discharge end are slurry separation and drainage of the wood chips, and material transport to the biomass processing facility. As noted above, pressure drops, pumping requirements, and the overall estimate are based on water as the carrier fluid.

Figure 4-2 compares the total transport costs of wood chips by truck and by pipeline, in $/dry tonne km, for an arbitrary fixed distance of 160 km. The basis of the cost estimate is a wood chip concentration of 27% by volume at the inlet end and 30% by volume at the outlet end. The close agreement between the estimating formulae of Liu et al. (1995) and the results of Wasp et al. (1967) for a one-way pipeline is evident. The one-way pipeline cost estimates were cross checked against a recent estimate of two short large diameter liquid pipelines in western Canada (Williams, 2003) with good agreement. Figure 4-2 shows the impact of scale on pipeline costs, as compared to the cost of truck transport which is independent of scale. (The formulae of Liu et al. (1995) and the data from Bantrel (Williams, 2003) suggest a capital cost scale factor for pipelines of 0.59 to 0.62; the data of Wasp et al. (1967) is not specific enough to calculate a comparable figure). Figure 4-2 also shows the significantly higher cost for a two-way pipeline that returns carrier liquid to the inlet end.

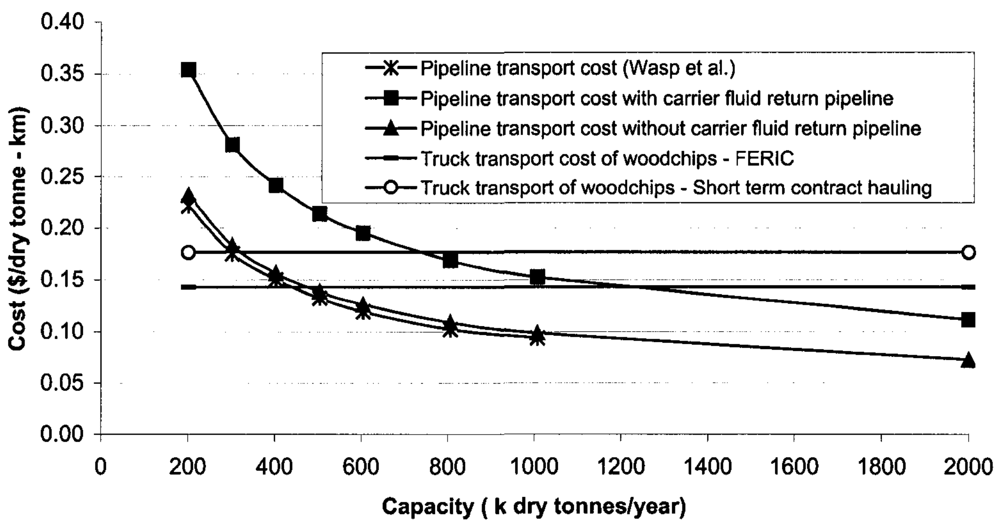

Fig. 4-2. Pipeline and truck transport cost of wood chips at a fixed distance of 160 kms.

From Figures 4-1 and 4-2 it is clear that the marginal cost of transporting biomass by pipeline at a concentration of 30% is higher than truck transport at capacities less than 0.5 M dry tonnes per year (one way pipeline) and 1.25 M dry tonnes per year (two way pipeline) at a distance of 160 km. The implications of this are discussed in the next section.

4.3 Practical application: integrated truck / pipeline transport of biomass

Any real application of pipeline transport of biomass from a field location (as opposed to mill residue) will normally require an initial truck haul to get the biomass to the pipeline inlet. This means that the fixed costs associated with both truck and pipeline transport are incurred. Thus, for example, truck hauling of 2 M dry tonnes per year of biomass to a pipeline inlet at an average haul distance of 35 km (Kumar, Cameron and Flynn, 2003), as might occur in a whole forest harvest operation, with further transport of biomass by one or two way pipeline, would have cost curves as shown in Figure 4-3. The alternative of transport by truck alone is shown by the dashed line.

Since by inspection of Figure 4-1A and 4-1B all pipelines with a capacity of less than 0.5 M dry tonnes per year (one way) or 1.25 M dry tonnes per year (two-way) have a higher incremental cost (slope) per km than the alternative of hauling by truck, it is clear that pipelines below this capacity cannot compete with the alternative of leaving the biomass on the truck for the extra distance. In the example illustrated in Figure 4-3, at 2 M dry tonnes per year the minimum pipeline distance to recover the fixed costs of the pipeline as compared to truck haul are 75 km for a one way pipeline (in addition to the initial 35 km truck haul to the pipeline inlet), and 470 km for a two way pipeline (again in addition to the initial truck haul); pipeline distances lower than this are less economic than continued hauling by truck. Hence, pipelining of truck delivered biomass at a concentration of 30% can only make sense at both large capacity and medium to long distances.

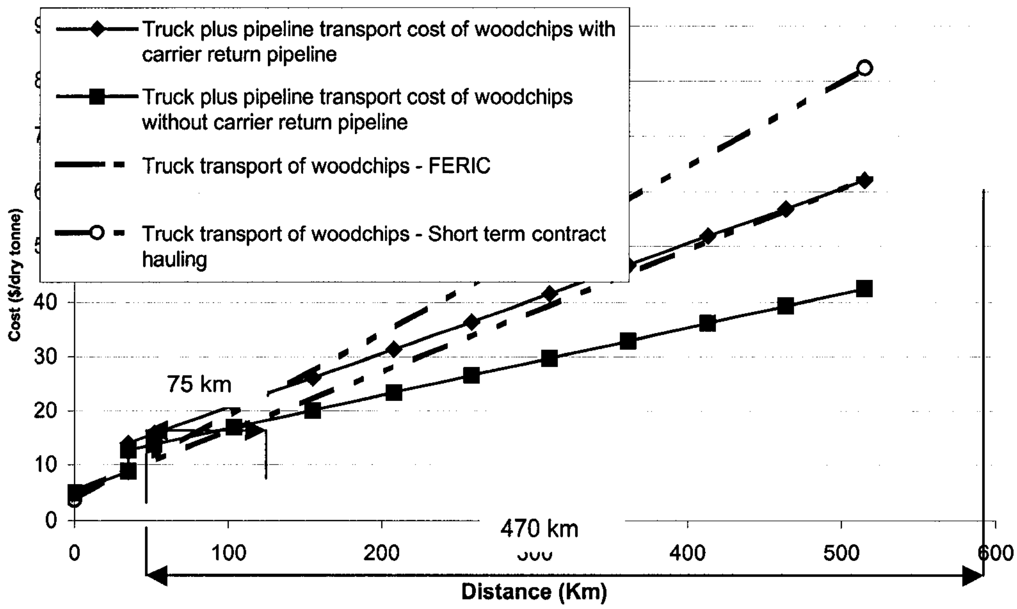

Fig. 4-3. Comparison of integrated pipeline/truck transport versus truck only transport of wood chips at 2 M dry tonnes/year capacity.

4.4 Absorption of carrier fluid by the biomass

We performed a series of simple experiments to explore the uptake of carrier fluid by biomass. Fresh wood chips, both hardwood (aspen) and softwood (spruce), were kept sealed and cool until immersion in room temperature water or oil; they were drained and dried to determine moisture level. Dry matter loss from the woodchips (from leaching) was not measured. Water drainage was brief, about 1 minute, although one test of a longer drainage period showed negligible impact of longer drain times. The oil used in this study is a heavy gas oil fraction from Syncrude Canada Ltd., with a nominal boiling range of approximately 325 to 550 °C and a viscosity of 1.3 Pas at 20 °C. This type of oil is typical of an industrial grade furnace oil. Wood chips were drained of oil for one hour before weighing. Figure 4-4 shows the carrier fluid content of wood chips after exposure to carrier fluid for varying periods of time. Note that immersion time can be related to pipeline distance because at a typical slurry velocity of 1.5 m/s the slurry would travel 5.4 km/hr.

The choice of an oil carrier requires a tradeoff between the viscosity of the carrier, which drops with lower boiling range of the oil fraction, and the value of the carrier, which increases with lower boiling range. At one extreme, a diesel fraction would have low viscosity but has such a high value as a transportation fuel that its use as a thermal fuel would be cost prohibitive. At the other extreme, a residuum fraction would have low value but such a high viscosity that transport of the slurry would likely be prohibitive in operating (pumping) cost. In this study, we have arbitrarily selected a heavy gas oil as the balance between these competing considerations.

During water immersion 1 kg of mixed spruce and aspen wood chips at an average 50% water content would pick up an additional 0.51 kg of water, and reach a terminal moisture level of about 67%. Water uptake is quick; even after immersion for three hours moisture levels exceed 63%. This is similar to the findings of Brebner (1964) and Wasp et al. (1967), who report saturated wood values of 65%. We conducted two experiments with straw and found that moisture level moved from 14% as received to more than 80% after exposure of 3 hours. This is similar to the findings of Jenkins et al. (1996) for rice straw from California.

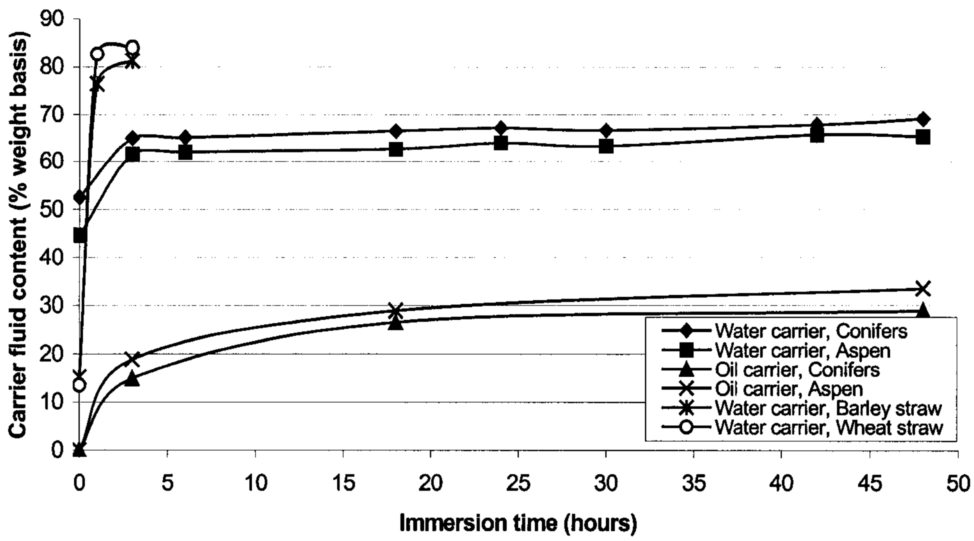

Fig. 4-4. Carrier fluid content of wood chips after different hours of immersion in carrier fluid.

Absorption of water has serious implications for any process such as direct combustion that converts absorbed liquid water in the fuel to emitted water vapor in the flue gas, in that it reduces the lower heating value (LHV) of the biomass and requires more biomass per unit of heat released by combustion, an effect also noted by Yoshida et al. (2003). Figure 4-5 shows the loss in LHV and the corresponding increase in biomass that must be delivered to a direct combustion based biomass operation; at 67% moisture level. Werther et al. (2000) note some other problems with increasing moisture in the direct combustion of biomass: reduced combustion temperature, delay of release of volatiles, poor ignition, and higher volumes of flue gas. These secondary impacts on efficiency and operability of a direct combustion unit are not considered in Figure 4-5.

One can conceptually break down biomass utilization into three component costs:

A. Field harvest of biomass.

B. Transportation from the field to the biomass processing site.

C. Cost of processing / conversion.

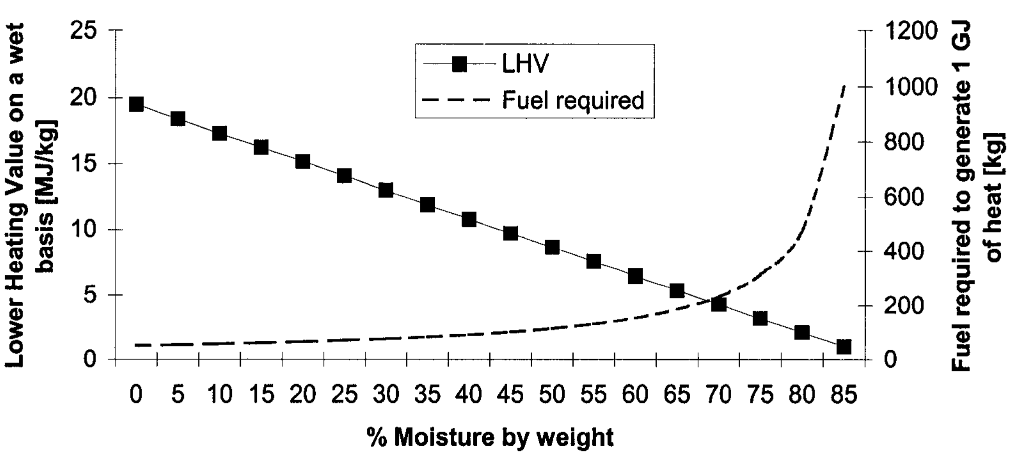

Fig. 4-5. Moisture content vs. LHV and fuel requirement of wood chips.

For direct combustion of truck transported biomass from harvesting of the whole forest in western Canada at or near optimum scale, the percentage and cost per

MWh for category A is: 33.4%, 15.77 \$ MWh^{-1}; B: 14.3%, 6.74 \$ MWh^{-1}; and C: 52.3%, 24.65 \$ MWh^{-1} (Kumar, Cameron and Flynn, 2003). Since, from Figure 4-5, changing the moisture level of wood chips from 50% to 67% increases the requirement for field biomass in direct combustion by 78% for a given output of heat and power, it is evident that water based pipelining of wood chips cannot be economical for direct combustion, since the increase in field harvest cost associated with the higher biomass requirement is larger than any possible transportation cost saving. For straw, so much water is taken up that the LHV is effectively zero; pipeline transport of straw to a direct combustion application would destroy the heating value of the fuel.

This impact is not true for a fuel process such as supercritical water gasification of biomass (Antal et al., 2000; Matsumura et al., 1997a; Matsumura et al., 1997b) that does not produce water vapor from absorbed water, since the HHV value of the biomass is effectively realized by countercurrent exchange of heat between products and feed that results in condensation of produced water. The impact of absorbed water is also not an issue for fermentation of biomass, since this is a water based process. Pipelining of biomass to fermentation processes offers the promise of larger scale more economic processing of ethanol, chemicals, and byproducts such as lignin. However, the pipeline design would require more detailed assessment since saccharification in the pipeline would be a logical processing alternative, and this would require elevated temperature in during pipeline transport. This more detailed assessment is addressed in chapter 5.

During oil immersion for 48 hours 1 kg of mixed conifer and aspen wood chips at an average 50% water content would pick up an additional 0.45 kg of oil, and reach a oil level of 31%. Comparable figures for 124 hours are an uptake of 0.52 kg to reach an oil level of 34%. Direct combusting wood chips delivered in a heavy gas oil can be thought of as co-firing a mix of about 2/3 of oil and 1/3 of wood on a thermal basis. Pipeline cost would increase because of additional pumping; the increase would depend on the viscosity of the oil fraction that was selected as the transport carrier fluid.

4.5 Discussion

Pipeline transport of oil and natural gas is clearly far more economic than truck transport, even in relatively small pipelines. Three factors combine to make the transport of energy in the form of biomass far less economic:

- The density of energy in the pipeline is far lower for biomass than for oil. This work is based on 30% biomass by volume in a carrier liquid. Wasp et al. (1967) based their work on 22% biomass. Brebner (1964) and Elliott (1960) indicated that at about 47% concentration by volume a slurry of wood chips and water can not flow. Given the low heat content of wood per unit volume relative to oil and the low concentration of wood chips in water, the energy density in a 30% wood chip slurry is about 8%

compared to oil, even based on HHV, and hence far larger pipelines are required to transport the same amount of energy.

- The pressure drop in the pipeline is high for suspended solids in a carrier fluid. For example, Wasp et al. (1967) indicate that at 30% concentration of wood and a velocity of 1.4 m/s, a wood chip slurry in a 214 mm diameter pipeline has a pressure drop that is 3 times larger than for water alone.
- Recycle of the carrier fluid will often be required in biomass transport by pipeline, both because large quantities of water will not be available at the inlet end and discharge of water that has carried the biomass will, in some jurisdictions, be prohibited. This requires a second pipeline and set of pumping stations be constructed.

In addition to these cost elements, transport of biomass for a direct combustion application by water creates a prohibitive drop in the LHV of the fuel because of absorbed water.

These issues limit the application of pipeline transport of biomass to large applications that:

- Use oil as a carrier medium, or
- Supply a process for which the heat content of the fuel is not degraded by the requirement to remove absorbed water as vapor, e.g. a supercritical water gasification process.

Transport of wood chips by oil precludes firing a high percentage of biomass due to high oil uptake by woodchips. We consider it unlikely that a 2/3 oil and 1/3 wood fuel mixture would have high interest today as a power plant fuel, since even a heavy gas oil fraction has too high a value as a transportation fuel precursor to be diverted into power generation.

4.6 Conclusion

We conclude from this study that:

- Pipeline transport of truck delivered wood chips is only economic at large capacities and medium to long distances. For a one way pipeline, the minimum economic capacity is >0.5 M dry tonnes per year. For a two way pipeline, the minimum economic capacity is >1.25 M dry tonnes per year.
- At 2 M dry tonnes per year, the minimum economic distance for a one way pipeline without carrier fluid return is 75 km, and for a two way pipeline with carrier fluid return is 470 km.
- Water transport of mixed hardwood and softwood chips causes an increase in moisture level to 65% or greater, which so degrades the LHV of the biomass that it cannot be economic for any process, such as direct combustion, that produces water vapor from water contained in the biomass. The impact on straw is greater, in that moisture levels are so high that LHV is negative. Pipeline transport of biomass water slurries can only be utilized when produced water is removed as a liquid, for example from supercritical water gasification.

- Oil transport of mixed hardwood and softwood chips gives a fuel that is more than 30% oil by mass and is 2/3 oil and 1/3 wood on a thermal basis.

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Chapter 5

Pipeline transport and simultaneous saccharification of corn stover*

5.1 Overview

Fossil fuel based plants do not generally depend on highway truck delivery of fuel. Plants using oil or gas typically receive fuel by pipeline, and coal based facilities are usually either located at the mine mouth or rely on rail or ship for fuel delivery. A large-scale facility cannot depend on truck delivery of fuel because of high cost and the problem of high truck congestion.

Biomass utilization requires the transport of a fuel with a lower energy density than fossil fuels, and problems of truck delivery to large scale facilities would be even greater than for a fossil fuel plant (Atchison et al., 2003). The desire for low transport distances and low congestion has favored smaller biomass processing plants, while traditional issues of economy of scale have favored larger scale facilities.

The production of ethanol from corn stover exemplifies these problems. A plant using 2 M dry tonnes of corn stover per year to produce up to 960 M liters/year at full theoretical yield (Kadam et al., 2003; Sokhansanj et al., 2002) would require

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* A version of this chapter has been accepted for publication. Kumar, Cameron, and Flynn 2004. Bioresource Technology (in press).

approximately 15 highway trucks (20 tonne capacity) per hour. However, this size of ethanol plant is very small compared to a typical modern oil refinery. At this scale significant diseconomies of scale occur, for example in the utilization of byproducts such as lignin (Wallace et al., 2003) and in the distillation of the ethanol.

Larger ethanol plants would increase truck congestion and transportation cost. Several studies have indicated that transportation cost is between 20 and 45% of the delivered cost of corn stover at plant capacities of less than 1 M dry tonnes/year (Aden et al., 2002; Perlack et al., 2002) and hauling distances of 50 to 80 km (Glassner et al., 1998).

The initial stage of transport of biomass from the field is always by truck. One possible means of shifting the balance between truck congestion/transport cost vs. larger plant size is the use of multiple pipelines to feed a large ethanol-processing complex. Trucks would deliver biomass to many local pipeline inlet stations, which would then transport the biomass as a slurry to a processing plant. This approach has limitations for any biomass application involving combustion, due to uptake of the carrier fluid by the biomass (Kumar, Cameron and Flynn, 2004). However, there is no processing penalty for water transport of biomass for ethanol production via fermentation since the process itself is aqueous. Pipeline transport of corn stover to an ethanol plant can be thought of as relocating the initial processing steps (washing, shredding, slurrying, and possibly pretreatment) from the plant to the pipeline inlet.

In this work we estimate the pipeline transportation cost for corn stover using one way (without carrier fluid return) and two way (with carrier fluid return) pipelines, with water as the carrier fluid. Pipeline capacity, distance and solids loading are key determinants of cost. Pipeline transport costs are compared to estimates of truck transport cost, which show a high degree of variability. Pipeline transport costs have a high economy of scale, while truck transport costs have a negligible economy of scale. Hence, we determine the capacity above which pipeline costs less than trucking of corn stover, which depends on the solids loading in the pipeline.

A major processing step in an ethanol plant is enzymatic saccharification of cellulose to sugars through treatment by enzymes; this step requires lengthy processing and normally follows a short term pretreatment step. We evaluate the potential for simultaneous transport and saccharification (STS) within the pipeline.

5.2 Truck transportation

Truck transport cost of biomass consists of a fixed cost and a variable cost relative to distance, which we refer to hereafter as distance variable cost. Note that the distance variable cost includes the depreciation and return on investment in capital assets. For trucking, the fixed cost is based on the time required for loading and unloading; the distance variable cost depends on the driving time, which is linearly related to the distance since haul speeds are nearly constant. Hence truck transport cost as a function of distance is linear, with the intercept representing the fixed costs independent of distance and the slope representing the distance variable costs per km of transport.

The literature shows a wide range in estimates of North American truck transportation costs, as shown in Table 5-1. (Figures from other geographical regions are available, for example wood chips in Brazil (Marrison et al., 1995) and Sweden (Hankin et al., 1995) and mixed agricultural and forest residues in Thailand (Junginger et al., 2001). However, these costs are not included in Table 5-1 because differences in fuel taxation have the potential to create a geographical variation in transportation cost). The range in North American costs is so high that it significantly impacts any conclusion about the relative costs of truck vs. pipeline transport. In this work, we have identified four representative estimates of truck haul costs for corn stover like material: a very high estimate, based on the work of Marrison et al. (1995) on switchgrass bales, a high range based on the work of Jenkins et al. (2000) and Kumar, Cameron and Flynn (2003) on straw bales, a mid estimate based on an actual corn stover bale collection project in Harlan, Iowa, USA, reported by Glassner et al. (1998) of the US National Renewable Energy Laboratory (NREL), and a low estimate based on a theoretical study by Perlack et al. (2002) of the US Oak Ridge National Laboratory (ORNL) on corn stover. The distance variable cost component for the four estimates adjusted to dry tonnes is \$0.1984, \$0.1328, \$0.1167, and \$0.0527 /dry tonne/km. Note that the high and mid estimates are close, and the very high and low estimate are significantly above and below these. The ORNL study assumes a much higher load size of corn stover per truck than the other studies, which are based on current practice.

5.3 Pipeline transport of corn stover

Pipeline transport of wood chips was studied in the 1960's by Brebner (1964), Elliot (1960) and Wasp et al. (1967). Hunt (1976) carried out a detailed analysis of friction loss during the transportation of wood chips. Liu at al. (1995) developed a detailed cost estimate of transportation of coal logs (compressed coal cylinders). In this chapter the work of chapter 4 is extended to corn stover. We utilize Hunt's formula for friction losses, originally developed for wood chips.

Slurry pipelines sometimes provide for the return of all or a portion of the carrier fluid from the outlet to the inlet end; this is accomplished by installing two parallel pipelines. We refer to such pipelines as two way pipelines; a one way pipeline would discharge or use the carrier fluid at the downstream end. In the case of transport of corn stover, for example in the US Midwest, it is likely that one way pipelines would be chosen, since there are sufficient rivers to be sources of water, the water is used in the ethanol plant for processing, and a large ethanol plant would have water treatment capability that would likely enable discharge of water after processing. However, two way pipeline costs are calculated in this study, and would apply in cases where either water was not available in sufficient quantities at the upstream end of the pipeline or discharge of treated process water from the ethanol plant was not permitted.

Table 5-1: Distance variable and fixed cost of biomass transportation by truck in North America

Biomass	Moisture content (%)	Distance Variable Cost ($/dry tonne/km)	Fixed Cost ($/dry tonne)
Straw (Jenkins et al., 2000)	11	0.1348	4.43
Straw (Kumar, Cameron and Flynn, 2003)	16	0.1309	4.76
Wood chips – long term supply (Kumar, Cameron and Flynn, 2004)	50	0.1114	4.98
Wood chips – short term supply (Kumar, Cameron and Flynn, 2004)	50	0.1524	3.81
Corn stover (Aden et al, 2002; Glassner et al., 1998)	-	0.1167	6.76
Corn stover (Jose et al., 2001)	-	0.1045	0
Corn stover (Perlack et al,	-		
2002)		0.0527	5.91
• Round bales		0.0596	5.84
• Rectangular bales			
Switch grass (Marrison et al., 1995)	-	0.1984	3.31

Cost of delivery of material by pipeline in which the material is drained at the receiving end (for example, for a combustion application) has a similar shape to the truck transportation curve. The cost of facilities at the inlet and outlet end of the pipeline represent fixed costs independent of distance, while both the capital recovery charge (depreciation and return) for the pipeline and pump stations and the ongoing operating and maintenance cost are distance variable costs that increase linearly with distance for all but very short pipelines. Fixed costs of inlet and outlet facilities are typically low compared to the pipeline cost; at a distance of 50 km, investment in inlet and outlet facilities is less than 15% of total investment (Kumar, Cameron and Flynn, 2004). The operating cost of a pipeline mainly arises from electrical power to operate the pumps.

In the case of pipelining biomass to a fermentation process, most of the costs at the inlet end of the pipeline displace costs that would otherwise be incurred at the plant if the biomass were delivered to the plant site, e.g. the cost of washing, sizing and slurrying. If the biomass is transported in the pipeline at about the same concentration as the processing stage, the material leaving the pipeline would flow directly into the fermentation process. Hence, for pipeline transport of corn stover to an ethanol plant the transport cost can be modeled as only the distance variable cost component.

All biomass starts its trip from the field on a truck, and the key question is whether it is economical to remove the material from the truck at some intermediate gathering point and move it by pipeline to a processing plant. Hence for corn stover being transported to an ethanol plant, pipelining will cost less when the distance variable cost of pipelining is less than the distance variable cost of trucking. Table 5-2 shows the distance variable cost of pipelining corn stover at various solids concentrations and capacities.

Table 5-2: Distance variable cost for one way and two way pipeline transport cost for corn stover at different solids concentration

Solids concentration (%)	Capacity (M dry tonnes/yr)	Diameter of pipeline (m)	Distance variable cost, d is distance in km ($/dry tonne/km)		Distance between slurry pumping stations (km)
			One way	Two way	
30					
	2	1.028	0.0892d	0.1370d	48
	1	0.727	0.1140d	0.1801d	42
	0.5	0.514	0.1486d	0.2411d	35
	0.25	0.363	0.1978d	0.3294d	29
25					
	2	1.126	0.0946d	0.1491d	59
	1	0.796	0.1212d	0.1964d	51
	0.5	0.563	0.1583d	0.2633d	43
	0.25	0.398	0.2112d	0.3600d	35
20					
	2	1.259	0.1018d	0.1653d	75
	1	0.890	0.1312d	0.2186d	64
	0.5	0.629	0.1724d	0.2937d	54
	0.25	0.445	0.2298d	0.4013d	44
15					
	2	1.453	0.1140d	0.1906d	101
	1	1.028	0.1480d	0.2527d	85
	0.5	0.727	0.1942d	0.3394d	70
	0.25	0.514	0.2595d	0.4622d	56

Appendix C shows details used in developing the cost estimates. Note that at 2 M dry tonnes/yr and a concentration of 20%, 67% of the distance variable cost of pipelining is recovery of invested capital, and 33% is operating cost, of which the overwhelming largest component is electrical power for pumping. Figure 5-1A and 5-1B compare the pipeline distance variable transportation cost of corn stover for one way and two way pipelines at 20% solids concentration to the distance variable cost of truck transport. Technically the pipeline transport curve would have a slightly "sawtooth" shape, with a slight increase in overall cost occurring when an additional pumping station is required. In practice, the cost impact of an incremental pumping station is negligible compared to the overall pipeline cost, and the sawtooth effect can be ignored (Kumar, Cameron and Flynn, 2004). From Figures 5-1A and 5-1B, it is clear that pipeline transport costs less than trucking at some higher capacity; the capacity at which this occurs depends on the distance variable cost of trucking.

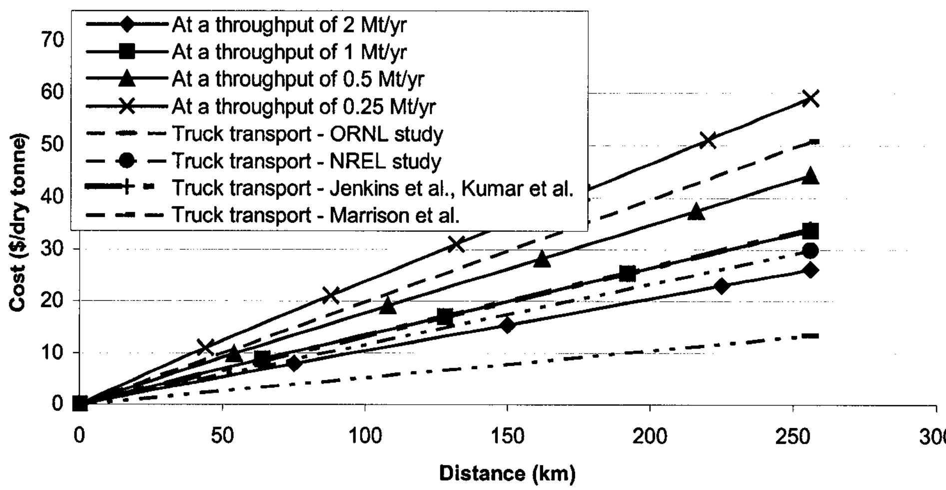

Figure 5-1A: One way (without water return pipeline) distance variable pipeline transport cost of corn stover at 20% solids concentration compared to truck distance variable cost.

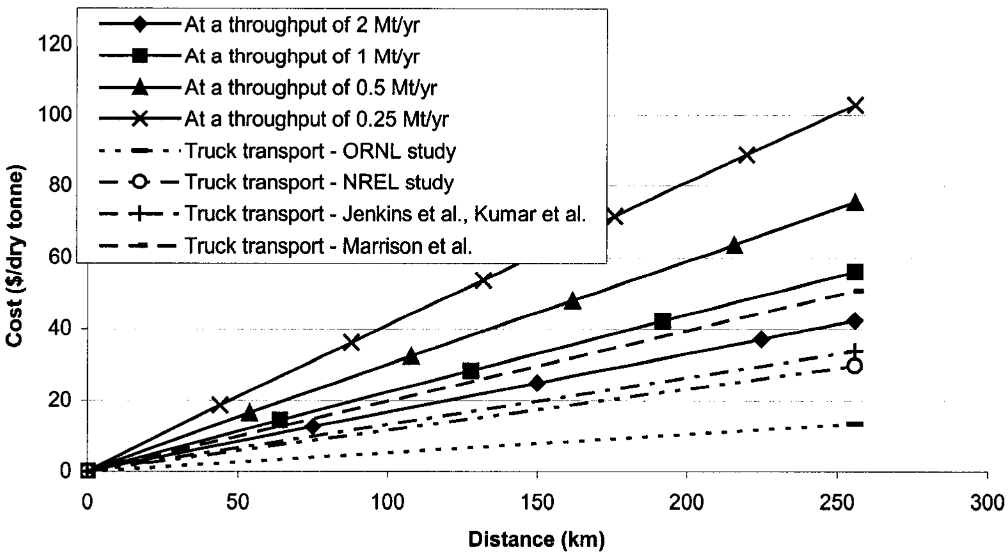

Figure 5-1B: Two way (with water return pipeline) distance variable pipeline transport cost of corn stover at 20% solids concentration compared to truck distance variable cost.

5.4 Cost crossover for pipeline vs. truck transport of corn stover

Truck transport of biomass is effectively independent of scale; more biomass requires more trucks, and the relationship is linear. Pipelines have an economy of scale that arises from both the equipment and the construction cost. Previous work calculated a scale factor of 0.59 to 0.62 for a biomass pipeline (Kumar, Cameron and Flynn, 2004). Figures 5-2A and 5-2B show the distance variable cost of transport by truck and pipeline (one way and two way) as a function of capacity and solids concentration; note the different capacity scale on Figure 5-2B. Pipeline transport cost decreases with increasing solids concentration and capacity. The point at which pipelining becomes less costly than trucking depends strongly on the distance variable cost of trucking. Figure 5-3A shows the cost crossover at which the cost of using a one way pipeline is less than trucking as a function of solids concentration for the four ranges of truck distance variable cost. Note, however, that the comparison between pipelining and trucking is based on transportation costs only, and does not factor in any savings in the ethanol fermentation plant that might arise from economies of scale from a facility served by multiple pipelines. Economics of pipelining would require an analysis in a specific project to factor in any cost savings from increased fermentation plant size.

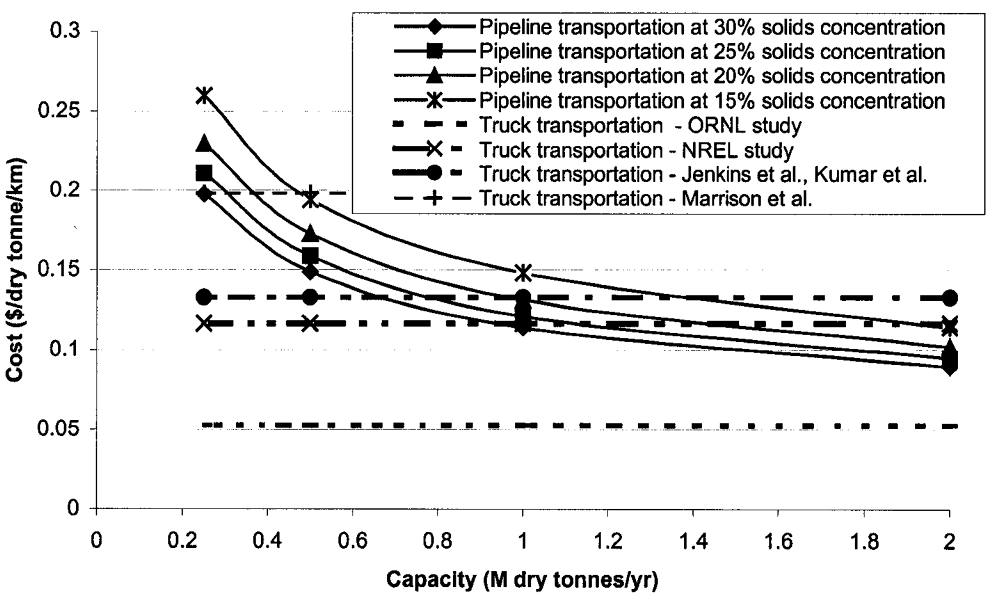

Figure 5-2A: One way pipeline and truck distance variable cost of corn stover at different concentrations.

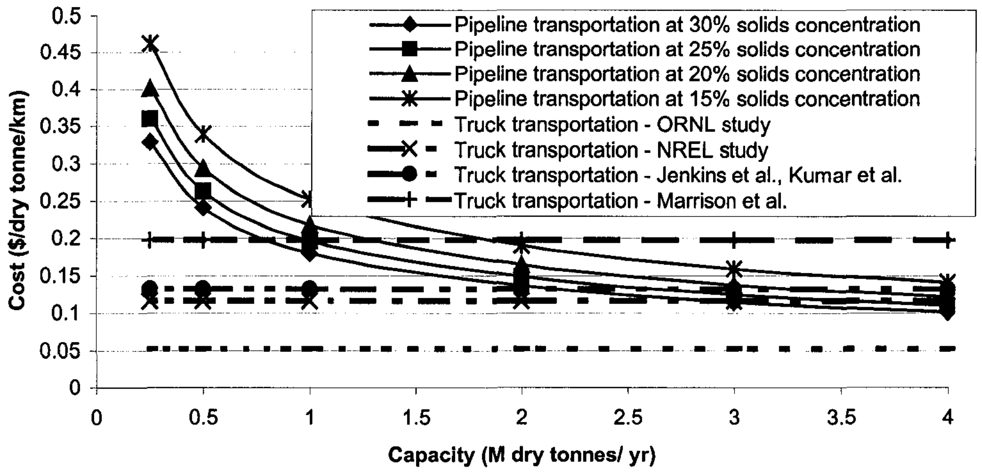

Figure 5-2B: Two way pipeline and truck distance variable transport cost of corn stover at different concentrations.

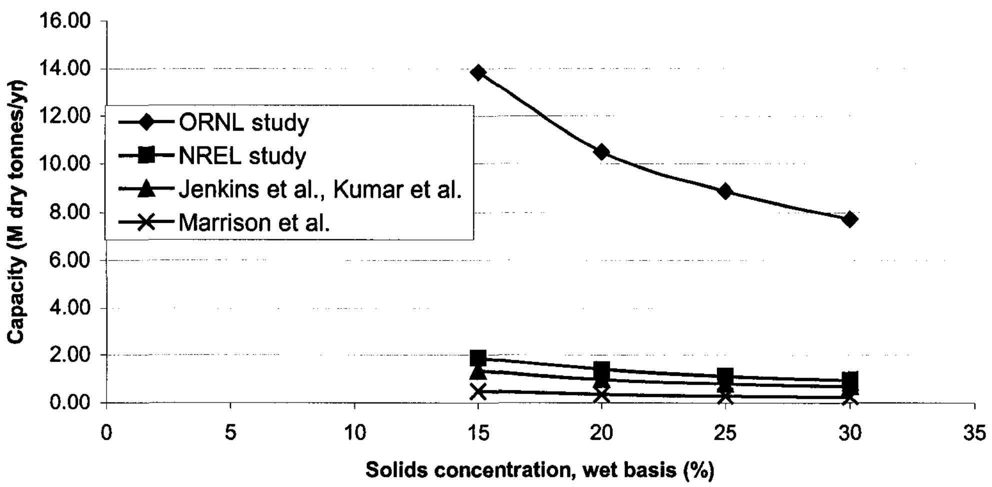

Figure 5-3A: Cost crossover above which one way pipelining has a lower distance variable cost than trucking (no credit for economies of scale in the fermentation plant).

Figure 5-3B shows the comparable cost crossover between pipelining and trucking for a two way pipeline. Note the difference in scale between Figures 5-3A and 5-3B. Only in the case of the very high estimate of trucking cost is a two way pipeline lower cost than trucking capacities less than 2 M dry tonnes/yr. Given the likelihood of 2 M dry tonnes/yr being a congestion limit on field receipt of biomass, we focus on one way pipelines in subsequent discussion of results.

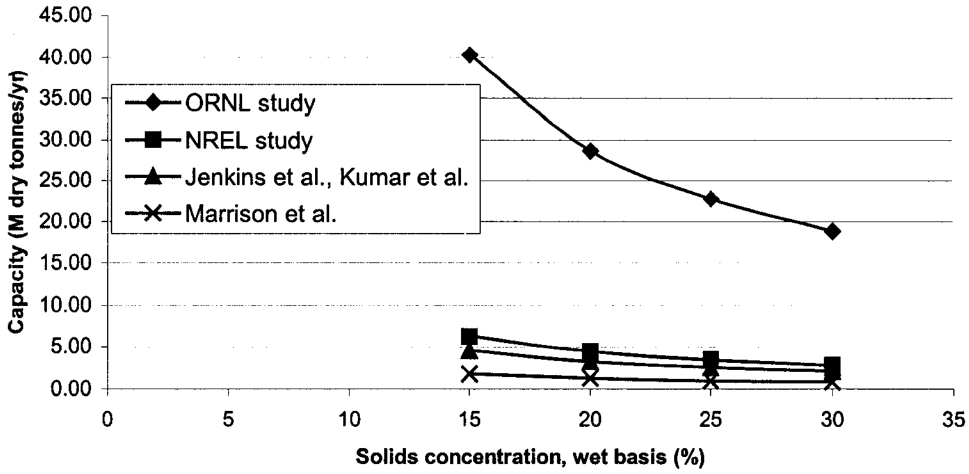

Figure 5-3B: Cost crossover above which two way pipelining has a lower distance variable cost than trucking (no credit for economies of scale in the fermentation plant).

These results make clear that an accurate estimate of trucking distance variable cost is critical to an assessment of the capacity of a biomass pipeline at which cost of transport is less than trucking. The high and mid range estimates of truck transport cost from Glassner et al. (1998), Jenkins et al. (2000) and Kumar, Cameron and Flynn (2003) are close, and based on these estimates, one way pipelining of biomass at a scale of 1 to 2 M dry tonnes/year costs less than trucking. The ORNL study (Perlack et al., 2002) estimates a far lower truck variable transportation cost, and based on this estimate one way pipelines at 20% solids, for example, are more costly than truck transport at capacities below 10.5 M dry tonnes/year. The ORNL study is based on a theoretical analysis, with truck loadings that have not been implemented in any trial to date. However, a commitment to a long term biomass processing facility would no doubt stimulate the trucking industry to try to achieve lower costs. At the other extreme, Marrison et al.'s (1995) estimate of the distance variable cost of hauling switchgrass bales is significantly higher than trucking costs from actual current operations, but if their estimate proves to be realistic then pipelining is highly competitive with trucking even if two way pipelines are required. Accurate identification of distance variable truck costs for corn stover will be critical to any future assessment of transportation modes.

5.5 Simultaneous saccharification of corn stover in a pipeline

Saccharification or hydrolysis is the process of conversion of starch into sugars, normally in the presence of enzymes. Production of ethanol from corn stover uses saccharification of cellulose to glucose using the cellulase enzyme (Aden et al., 2002). In a conventional process of production of ethanol from corn stover, saccharification is carried out in a tank and glucose produced during saccharification is fermented to produce ethanol in a separate fermentation tank.

More recently research is being done on simultaneous saccharification and fermentation (SSF) (see for example (Aden et al., 2002; Varga et al., 2003)).

Pipeline transport of biomass gives the potential to perform the saccharification step in the pipeline by simultaneous transportation and saccharification (STS). (Any required treatment before saccharification, such as acidification, would be conducted at the pipeline inlet facilities). The NREL design (Aden et. al., 2002) for ethanol fermentation uses enzymes that require a low pH (4 to 5) in the saccharification process. This pH is unsuitable for carbon steel pipelines, but a stainless steel pipeline would not be economic. This research is based on the economics of a carbon steel pipeline, assuming that current enzyme development will progress to the point where high yield cellulases are usable at a more neutral (higher) pH

Contact time and temperature are critical factors in saccharification. For example, Varga et al. (2003) notes that a temperature drop from 50 to 40 °C increases the reaction time for saccharification from 24 to 72 hours. Work from NREL suggests a saccharification temperature of 65 °C at a contact time of 36 hr (Aden et al., 2002).

In a corn stover slurry pipeline velocity would be about 1.5 m/s or 5.4 km/hr; distances of 200 to 400 km correspond to residence times of 36 to 72 hr, typically required for adequate saccharification. Temperature is more critical for two reasons:

- A significant cost impact arises if the slurry is heated from ambient temperature to 40 to 65 °C. In a typical ethanol plant heating of inlet slurry is done with waste heat. In case of pipeline delivery of corn stover, unless waste heat is available near the pipeline inlet (say from a gas pipeline compression station or a thermal electric power plant), the fuel cost for heating the slurry would be significant. We estimate that the fuel cost for heating slurry water by 40 °C using natural gas at $5/GJ would cost more than 5 cents/liter of produced ethanol even at maximum theoretical yield of ethanol.
- Elevated temperatures might require insulated pipelines, depending on pipeline size and soil type. For larger capacity pipelines in typical clay prairie soils, this is not the case. The estimated temperature drop over 400 km in a 1.26 m buried pipeline carrying 2 M dry tonnes/yr of corn stover through clay soil with a thermal conductivity of 0.85 W/m/K is about 5 °C for a slurry inlet temperature of 50 °C and a soil temperature of 10 °C (Stewart, 2003). However, smaller capacity pipelines buried in soils with higher thermal conductivity might require insulation to sustain temperature, adding cost to the pipeline. We estimate that insulating a 1.09 m pipeline carrying 1.5 M dry tonnes/yr with 1 inch of foam insulation would increase the installed cost of the pipeline by 15%, and would increase the distance variable cost of pipeline transport of corn stover by 10%.

Whether insulation is required in a specific pipeline would require more detailed modeling of both the reaction kinetics and the heat loss from the specific pipeline geometry and routing.

Three approaches could aid in reducing the cost of saccharification in pipelines:

- Co-location of a biomass pipeline inlet with a source of low quality heat, such as a power plant. Using once through untreated cooling water from a power plant as a source of pipeline slurry water would eliminate the cost of raising the temperature of the slurry and save investment in cooling facilities at the power plant.
- The development of enzymes that are active at typical pipeline temperatures of 0 to 25 °C. This is not a trivial problem, and there is no indication today that this goal is achievable.
- Higher enzyme loading. Note, however, that enzymes are a significant cost factor; an NREL study estimates that even after significant development the cellulase cost will be about 10% of the total cost of ethanol (Aden et al., 2003); hence increased enzyme loading will be very expensive.

In STS of corn stover, since saccharification takes place in the pipeline a separate saccharification tank, agitator and other related accessories in the plant are not required. This results in a capital savings in the plant; this savings is scale dependent. Figure 5-4 shows the calculated credit for eliminating saccharification equipment from the fermentation plant, drawing on the work of Aden et al. (2003) of NREL.

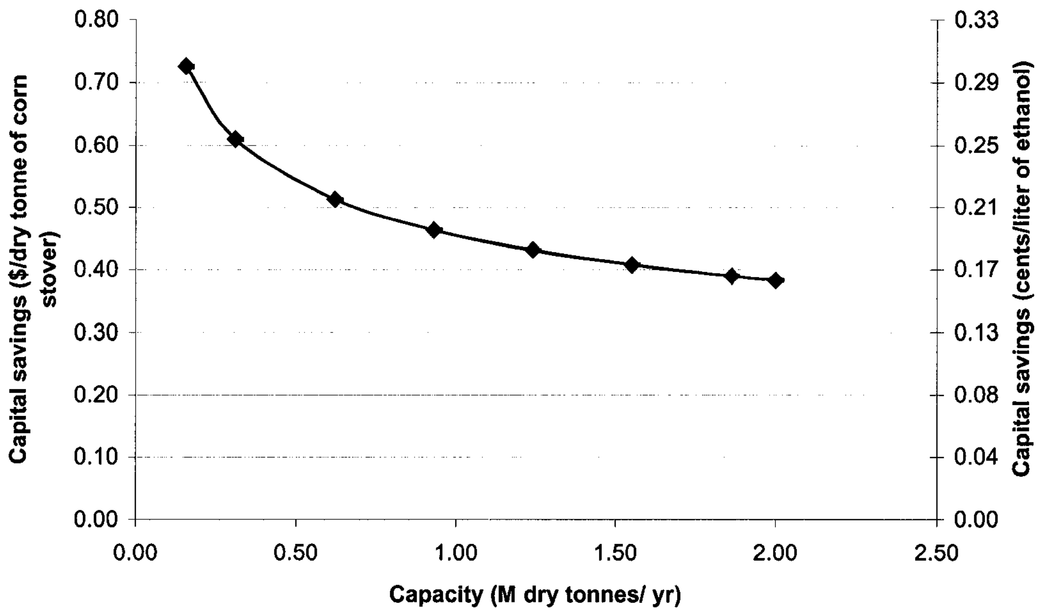

Figure 5-4: Capital credit from eliminating the saccharification step from an ethanol processing plant due to simultaneous transportation and saccharification (STS) of corn stover.

5.6 Discussion

The incentive for pipelining of corn stover is that it enables the development of a much larger biomass refinery for the production of ethanol fuels. In the absence of pipelining of corn stover, plant size will likely be limited to 1 to 2 M dry tonnes/yr due to truck congestion; it is hard to imagine community acceptance of a plant that required more than 15 truck deliveries/hour. NREL (Aden et al., 2002) base their detailed cost estimates on 0.7 M dry tonnes/yr. At this capacity, much of the equipment in the ethanol facility is significantly below optimum size. A typical modern oil refinery has a liquid product capacity of more than 25 GL/yr, more than 50 times the fuel output from an ethanol plant processing 1 M dry tonnes/yr of corn stover. Wallace et al. (2003) noted in particular the cost penalty of burning lignin to produce power and heat at this small scale, but similar diseconomies would occur in other processing steps such as distillation.

Pipelining of biomass to an ethanol refinery would overcome the feedstock delivery issues associated with a much larger facility. For example, one could locate 10 or more local corn stover receiving facilities with a capacity of 1 to 2 M dry tonnes/yr throughout a corn growing region, and use a one way pipeline from each of these facilities to a central ethanol refinery. The corn stover slurry could enter the ethanol processing facility directly, i.e. no adjustment would be required in solids water ratio at the plant. At a scale of 10 to 40 M dry tonnes/yr, ethanol fermentation and distillation and lignin processing economics would be substantially enhanced, and the recovery of significant quantities of higher value byproducts could also be considered. Produced ethanol could also be transported by a liquid pipeline of economic scale to non-corn growing regions for addition to the gasoline pool.

One critical issue in evaluating the economics of pipeline vs. truck delivery of biomass is an accurate value for the cost of truck transport. As noted above, there is a very wide range of estimates of truck delivery of corn stover. If current costs, as reflected in the studies by Glassner et al. (1998), Jenkins et al. (2000), and Kumar, Cameron and Flynn (2003) are realistic, then pipelining is directly cost competitive with trucking at reasonable scales even without consideration of the improved economic efficiency of the fermentation plant. If the cost forecast of Perlack et al. of ORNL (2002) is achievable, then pipelining of corn stover cannot directly compete with trucking at reasonable scales, although full cycle analysis of the cost of the transport and processing might still confirm that pipelining is in aggregate more economic than trucking due to economies of scale achieved in the fermentation plant. The distance variable cost estimated by Marrison et al. (1995) seems very high in comparison to actual current costs for trucking baled agricultural residues.

Two way transport of biomass by pipelines that return carrier fluid to the inlet of the pipeline is significantly less economic than one way transport. Only if the cost estimates of Marrison et al. (1995) are realistic would two way pipelining be cost competitive against trucking at scales compatible with field receipt of truck delivered biomass.

The location requirement for a pipeline inlet is access to significant amounts of water to slurry the corn stover; the water requirement per dry tonne of corn stover is 24 m^3. As noted above, if simultaneous transport and saccharification is contemplated, an ideal location would have access to warm water or a source of low quality waste heat. The location requirement for a large scale ethanol processing plant is the same as for smaller plants: a watercourse to accept discharged treated water. In many jurisdictions, transfer of water from one watershed to another is problematic, hence an ideal configuration would draw and discharge water in the same major drainage basin.

This work has applied a friction factor calculation derived for wood chips to corn stover, since experimental data for corn stover slurries is not available. We have tested the sensitivity of this assumption in the range of friction factors that are 50% lower to 100% higher than calculated using the model of Hunt (1976). In this range, the distance variable cost of pipelining corn stover in a one way pipeline is 16% lower to 31% higher. This sensitivity does not invalidate the conclusions of this study, but precise determination of the friction factor of corn stover slurry would be a valuable contribution to the future evaluation of pipelining of corn stover.

Pipelining of fossil fuels is commonly practiced at scales far smaller than those identified as cost competitive in this study. Reasons for the difference include a higher friction factor for pipelining slurries and a far lower energy density for slurried biomass. Crude oil, for example, has an energy density of 35.65 GJ/m^3, while a 20% slurry of wet corn stover has an energy density of 0.732 GJ/m^3 (HHV basis), about 2% that of oil.

5.7 Conclusions

We conclude from this study:

- Traffic congestion is a factor limiting the size of ethanol plants processing corn stover delivered by truck. A plant processing 2 M dry tonnes/yr would require a truck delivery every four to eight minutes; capacities larger than this are likely above community acceptance levels.
- The capacity at which pipelining biomass costs less than trucking depends on slurry concentration and on the cost of trucking of corn stover. There is a very wide variation of reported and forecast trucking costs for corn stover.
- One way pipeline transportation of corn stover at 20% solids loading costs less than trucking at a capacity of 1.4 M dry tonnes/yr when compared to a mid range of variable trucking cost of $0.1167 /dry tonne/km. Note that savings in the ethanol processing plant due to economies of scale are not factored into this calculation.
- Two way pipeline transportation costs less than trucking only at higher capacities and higher solids concentration. At 20% solids concentration, it is economical (again, without consideration of potential savings in the ethanol fermentation plant) only at capacities greater than 4.4 M dry tonnes/year when compared to a mid range of variable trucking cost of $0.1167 /dry tonne/km. As noted, this capacity is likely larger than the ability of a single receiving facility to accept corn stover delivered by truck from the field.
- Pipelines could be used as a reactor for carrying out simultaneous transport and saccharification (STS). At 2 M dry tonnes/year capacity, STS result in a

capital credit of 38 cents per dry tonne of corn stover or 0.2 cents/liter of ethanol due to reduced costs in the ethanol plant.

- One key issue with STS is the need to maintain elevated temperature in the slurry during pipelining. Heating of the slurry, which in a normal ethanol plant occurs from waste heat, by 40 °C by firing natural gas would cost more than 5 cents/liter of produced ethanol. One alternative is to locate a pipeline inlet near a source of low quality waste heat; the use of once through cooling water from a power plant, for example, would be an ideal slurry medium for corn stover. Insulation is not likely required for large diameter pipelines in typical clay soils of the prairies: a 1.26 m pipeline carrying 2 M dry tonnes/yr would experience a temperature drop about 5 °C over a distance of 400 km with a temperature drop (pipeline inlet to soil) of 40 °C. Smaller pipelines or soil of high thermal conductivity might require insulation of the pipeline. Adding insulation to a 1.09 m pipeline carrying 1.5 M dry tonnes/yr of corn stover would increase the installed cost of the pipeline by 15% and increase the cost of pipelining of corn stover by 10%.
- Transport of corn stover through multiple pipelines to a large ethanol plant offers the potential to overcome problems of economy of scale in the production of ethanol.

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Chapter 6

Power from biomass: the economics of gasification vs. direct combustion*

6.1 Overview

If the full potential of biomass to mitigate GHG is to be realized, biomass applications must be developed in their most economical form. For a given source of biomass three factors have a strong impact on the cost of biomass utilization: the end product (e.g. power, heat, ethanol), the technology of conversion, and the scale. In this work we look at one end product, electrical power, and evaluate the impact of scale for two technologies.

Biomass power projects have typically been developed at small scale; with the exception of a Finnish plant (near Pietarsaari) at 240 gross MW, all are below 80 MW and many are much smaller. Many authors have noted that biomass utilization is below economic optimum size in this range. Two factors have contributed to the small size of existing biomass power projects. First, biomass supply is limited in some plants, as often occurs when using mill residues such as bark or sawdust. Second, many projects are of a demonstration nature and often supported from limited public funds.

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* A version of this chapter has been published. Cameron, Kumar, and Flynn 2004. 2nd World Conference and Technology Exhibition on Biomass for Energy, Industry and Climate Protection, Rome, Italy.

In this chapter the focus is on a biomass source for which availability is high in comparison to plant size. This is true for many agricultural residues (e.g. corn stover in the US Midwest, grain straw in parts of Europe and North America, and wood and forest harvest residues in large forested areas. In such areas the correct selection of biomass power plant size will have a strong impact on overall cost of power. The analysis in this paper will apply in concept to any abundant biomass source, but is specifically developed from a cost model for wood chips from chapter 1.

Biomass optimum plant size is a tradeoff between competing costs. One cost is a portion of the total delivered cost of biomass fuel cost, i.e. the component that varies with the distance that biomass is transported, which we refer to as distance variable cost (DVC). This component is mainly transportation cost, and increases approximately with the square root of plant size. The competing cost is plant operation, including capital recovery, per unit of output, which decreases with increasing plant size. In actual application the determination of optimum project size varies by technology and is strongly influenced by the number of parallel trains required in the plant. Note that DVC has an impact on scale, but the fuel costs that are not dependent on distance, such as acquisition and harvesting costs, which we refer to as distance fixed costs (DFC), do not affect optimum plant size.

6.2 Power from biomass

Two technologies studied in this research are high-pressure biomass integrated gasification combined cycle (BIGCC) and direct combustion. Gasification and direct combustion have different maximum sizes of single units. If sufficient fuel were available there is no evident reason why direct combustion power plants utilizing biomass could not be developed to 500 MW of net output (the maximum size evaluated in this study) and perhaps higher. Coal fired direct combustion plants have been commonly built in this size range, and more recently have been developed up to sizes of 1050 MW (Tachibana-wan Power Station). This contrasts to gasification processes, where materials constraints on turbine size in the combined cycle plant currently limit the maximum size of a single turbine unit firing low heating value gas to 250 MW of output. Above 250 MW, the design would change to two parallel gas fired turbines supplied by two gasifiers, with a common heat recovery steam generator (HRSG) and steam turbine.

Maximum unit size is a critical factor in assessing relative economics because the economy of scale typically changes at the point that a maximum unit size is reached. Scale factor for large projects is a matter of some dispute. Many studies have used a scale factor for biomass plants of 0.7 (Craig and Bain, 1995; Faaiji and van Ree, 1998). Jenkins (1997) has contended that the scale factor approaches unity for projects in excess of 100 MW. Larson et al. (1997) use a formula for capital costs that in effect equates to a scale factor near unity at power plant sizes in excess of 250 MW. Both believe that more of the benefit of scale is realized in the size range up to 250 MW than between 250 and 500 MW. However, engineering firms that routinely build power plants and classical cost estimating analysis hold the view that a scale factor of approximately 0.7 applies up to and even above 500 plant size for power plants (Jones, 2004; Williams, 2002; Page, 1996). The behavior of firms that own and operate plants would seem to support this view: coal power plants are routinely in the 450 to 500 MW range in North America (where grid stability considerations also limit plant size), and units as large as 1050 MW have been built in Japan (Tachibana-wan Power Station). Engineering firms estimate on the basis that a second identical unit built at the same time and site (i.e. a second train) costs 95% of the initial unit (Silsbe, 2002). In this study actual detailed design data were used by an equipment supplier to estimate gasification capital costs up to 500 MW. For direct combustion, costs are developed by a variety of techniques, one of which assumes a relatively conservative scale factor of 0.75 operating up to a range of 500 MW. We note, however, that the key conclusion of this work is valid regardless of whether the approach of Jenkins and Larson or engineering and operating companies is adopted. In this study we explore scale over the range of very small plants to a maximum of 500 MW, which is one train for direct combustion and two trains for gasification. This maximum is based on an assumed congestion limit for truck delivered biomass. Note that once the optimum size for gasification reaches 250 MW, the incremental benefit from economy of scale for a larger plant is less for gasification than for direct combustion, because in the size range of 250 to 500 MW there are two gasification trains and only one direct combustion plant.

A second factor other than scale also influences the relative return for gasification vs. direct combustion: the delivered cost of biomass fuel to the plant. Gasification has a higher capital cost per input of fuel and output of power than direct combustion; this higher cost is offset by a higher efficiency, i.e. more electrical power is produced per unit input of fuel. At one extreme, if biomass delivered to the plant site were free and available in unlimited supply it would make no economic sense to spend the premium on gasification; the economically preferred choice would be a direct combustion plant producing the same amount of power from a larger amount of free fuel. At the other extreme, if the delivered cost of biomass were very high then the efficiency gain that allowed the purchase of less biomass for a given electrical output would be favored economically. Thus both scale and delivered biomass fuel cost are key factors in the relative economics of gasification vs. direct combustion. In this work we systematically explore the impact of DVC on optimum size for gasification and direct combustion of boreal forest wood chips, and then identify the combination of DVC and DFC that determines where gasification is economically favored over direct combustion for an optimally sized plant.

6.3 Methodology

This study uses the model from chapter 1 that studied in detail the cost factors for the collection and transportation of wood chips in western Canada. In this study plant costs for BIGCC are drawn from recent information provided by a supplier of IGCC plants for plant sizes of 20, 40, 250, and 500 MW capacities. Although BIGCC has not been commercially developed on a large scale, detailed designs have been completed and as well, all of the components are well known: gasification is a well established technology, and combustion of low heating value gas in turbines is already practiced, for example with coke oven gas. Calculated scale factors from BIGCC supplier data are 0.59 in the range up to 250 MW, and 0.89 for 500 vs. 250 MW since two gas turbines but only one HRSG and steam turbine are required in that case. Total plant cost per kW at 250 and 500 MW is \$1,447 and \$1,330. We used a thermal efficiency for BIGCC of 45% on an LHV basis as compared to 34% for direct combustion. Boreal forest wood chips have a moisture content of 50%, and the equivalent HHV efficiency for BIGCC is 36.5%.

We use three approaches to define a range of plant cost estimates for direct combustion of biomass. First, existing plant data for total plant costs at small scale (not including the 240 MW Finnish plant) are extrapolated to larger scale with a scale factor of 0.75 (Kumar, Cameron and Flynn, 2003). Many biomass combustion plants are demonstration units, "first of a kind" in a particular area. The use of these cost figures and a relatively high scale factor gives an estimated plant cost of $1,223 per kW at a scale of 500 MW, that we believe is likely a high estimate for a mature biomass plant. We develop a lower estimate, $880 per kW at 500 MW, by looking at the total plant cost of large-scale coal power plant excluding flue gas desulphurization (Bohachuk, 2004). Reported cost figures for the Finnish biomass plant, even adjusted for assumed internal consumption of power, are near this lower value; the plant is a mixed heat and power plant built on an existing industrial site, so exact comparison to a stand alone pure generation plant is difficult. We also develop an estimated cost based on considering the design differences between a large scale plant using biomass instead of coal, and applying an adjustment to reported values for stand alone coal power plants. Table 6-1 shows a breakdown of the total plant cost of a power plant using a low sulfur sub-bituminous coal, the expected differences in scale for biomass vs. coal, and the adjustments based on a scale factor of 0.75 to build an estimate for a biomass plant based on a mature coal technology. This gives a value of 1,062 per kW at 500 MW. We refer to this third estimate as the "nth plant" estimate, since it is developed in comparison to a mature coal power plant.

Table 6-1. Biomass direct combustion power plant cost based on adjustment from coal plant cost

	Cost ($/kW)	% of plant cost	Size adjustment	Nth plant ($/kW)
Boiler	172	20.2	3x larger	392
Ash handling	95	11.2	15x smaller	12
Fuel handling	28	3.4	3x larger	65
Other equipment	556	65.3	same	556
AFUDC* (4.5% per year)	28			36
Total plant	880	100.0		1,062

*Allowance for funds used during construction

6.4 Results

For each assumed yield of boreal forest wood chip biomass, there is a unique optimum size. As yield increases biomass haul distances decrease (lowering DVC), and optimum plant size increases. For gasification, this increase is smooth until the constraint of maximum unit size of 250 MW is reached, at which point there a large range of yields for which 250 MW remains the optimum size. Finally, as yield increases even more, there is a jump to two turbine units (500 MW). Note that two units at a size less than 250 MW are not optimal at any yield and that at very low yields the optimum plant size is larger for gasification than for direct combustion. In effect, the economy of scale benefit for a higher capital intensity justifies drawing biomass from a larger area. Figure 6-1 shows optimum size as a function of distance variable cost; in this case, there are some values of DVC for which there are two optimum sizes. When optimum plant size jumps from one unit to two, as occurs for gasification, distance variable cost increases because of the increased haul distances needed to supply the larger plant. The dashed lines in Figure 6-1 are lines of constant yield. Capital cost values for direct combustion are based on the "n^{th} plant" cost estimate.

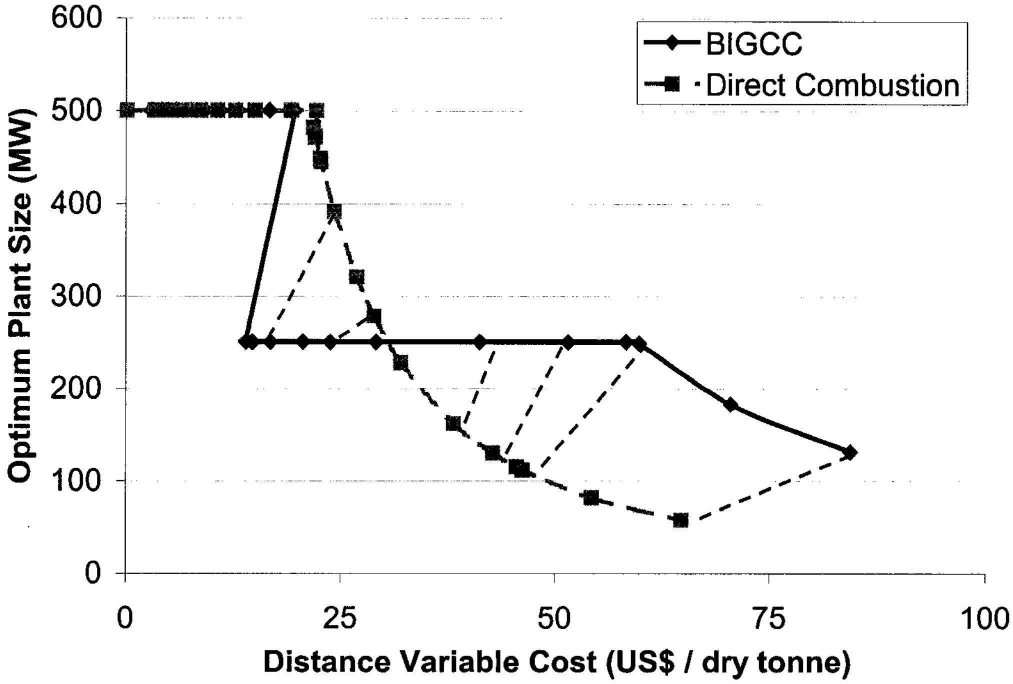

Figure 6-1: Optimum plant size as a function of biomass distance variable cost (DVC).

Figure 6-2 shows three planes: the total cost of power from direct combustion and from gasification in a one turbine (capacity 250 MW or less) and two turbine (500 MW) plant.

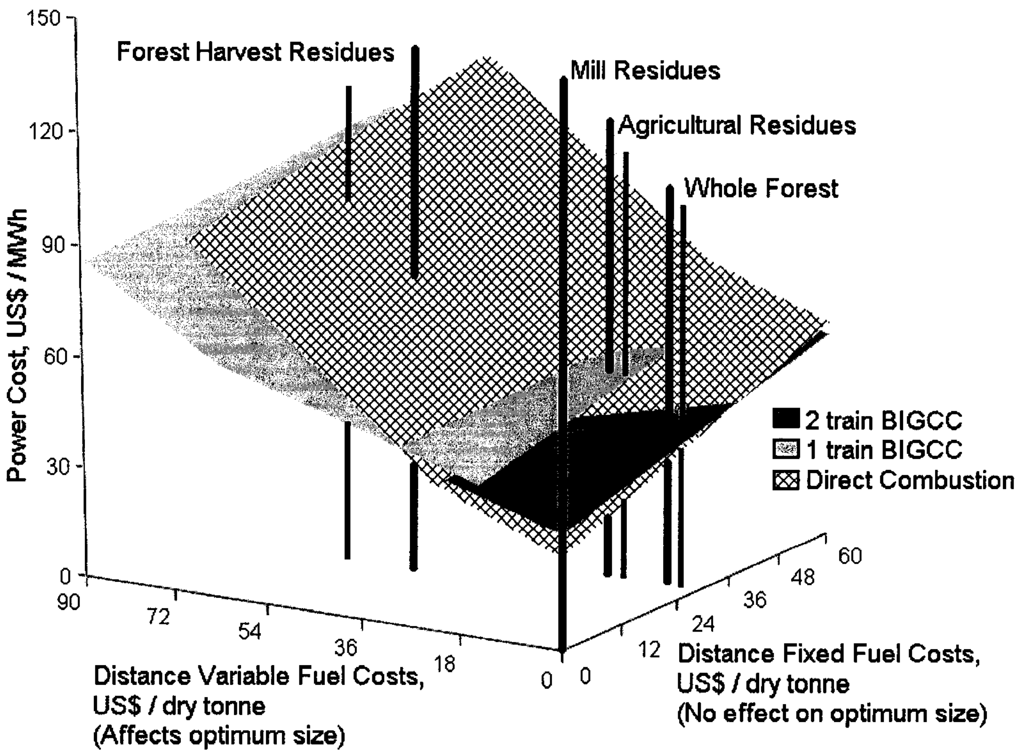

Figure 6-2: Power cost at optimum size for direct combustion and gasification in a one and two train plant of biomass as a function of distance variable and fixed fuel cost.

Note that along the DVC axis optimum plant size is decreasing, while along the DFC axis there is no change in optimum plant size. Power cost rises linearly with any increase in DFC; it rises more rapidly with an increase in DVC, since the optimum plant size is decreasing as DFC increases, and capital efficiency is being lost as well. Several observations can be made from Figure 6-2. The rise in power cost as DVC and DFC increase is lower for gasification than for direct combustion; this occurs because of the higher efficiency of gasification. However, at lower biomass fuel costs direct combustion gains over gasification from two factors. First, the higher efficiency of gasification saves little because the fuel is worth little. Second, once the optimum size of gasification reaches 250 MW there is a long plateau in which no incremental capital economy of scale is realized until two trains are justified; this plateau is not reached until 500 MW or higher for direct combustion.

When gasification shifts from an optimum size of 250 MW to 500 MW, the reduction in capital cost per unit output is relatively small, 7%, because a second gas turbine train is being added.

The region in which single train gasification is less economic than direct combustion is not symmetric: a greater increase in DFC can be accommodated with direct combustion remaining economically favored because it does not change optimum plant size, whereas any change in DVC is also causing a change in optimum plant size. Consider a DFC of zero: since DVC has the impact of reducing the optimum size of a direct combustion plant in the region from $15 to $62 per dry tonne but the economically favored size of a gasification plant remains at 250 MW, the increase in direct combustion power cost is greater for a change in DVC than for DFC. This asymmetry, in which an increase in DVC more quickly shifts the balance in favor of gasification than DFC, occurs when the scale of one technology is changing but the scale of the other is not. It does not occur initially for a two train gasifier vs. a 500 MW coal fired plant because initially the increase in DVC does not cause the optimum size of plant to change for either technology, which can be observed by inspection of Figure 6-1: initially, the plant size for each technology is 500 MW as DVC increases, up to a value of DVC of $20 per tonne.

For reference, the estimated cost of power from a new 450 MW mine-mouth coal fired plant in western Canada is about $35 to $40 per MWh.

Four costs of fuel are illustrated in Figure 6-2 for the two technologies: mill waste, and western Canadian costs for wood chips from harvesting the whole boreal forest, wood chips from boreal forest harvest residues (limbs and tops of trees harvested for pulp and lumber), and straw from wheat and barley. Mill waste is shown as having zero DVC and DFC (which assumes it is being converted to power at the site at which it is generated), while in fact it may often have a negative cost, in that if it is not burned it must be disposed of by landfill, a net cost to the owner. Note that the lines for a given fuel are different for gasification (thin line) vs. direct combustion (thick line) because the optimum plant size, which impacts DVC, is different for each technology. One can see that gasification is strongly favored for forest harvest residues (a very low yield fuel), slightly favored for straw, and that direct combustion would be favored for mill wastes, if available in large quantities, and for wood chips from the boreal forest. While this would appear to suggest that gasification would never be selected for mill residues, we note that this analysis is based on optimum plant size, and mill residues are often available in amounts far below that required for an optimum size. Hence, there may be circumstances of constrained supply that favor gasification.

Figure 6-3 shows the area of DVC and DFC in which direct combustion, one train or two-train gasification is favored for the three values of direct combustion power plant cost discussed above.

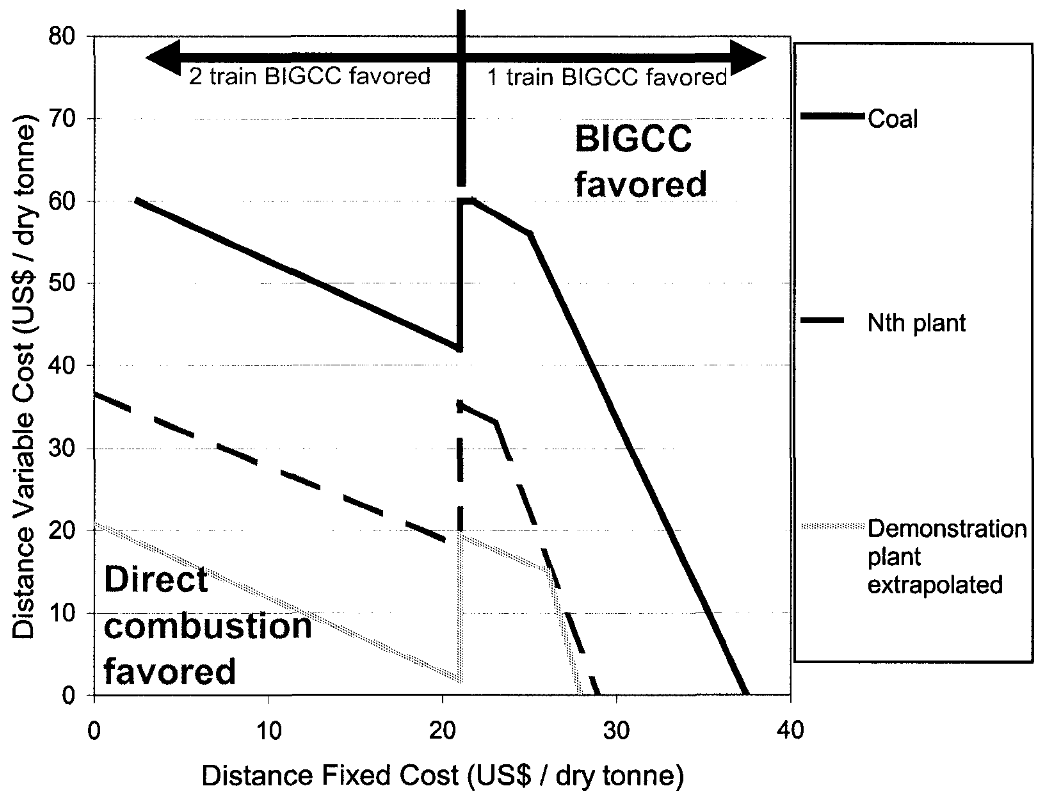

Figure 6-3: Impact of capital cost of biomass direct combustion plant on selection of gasification vs. direct combustion.

For each of the three capital costs, the region below the line favors direct combustion. The region above and to the right of the line favors gasification.

Even at the highest range of capital cost estimates for direct combustion there is a region of low biomass fuel cost where direct combustion is favored over gasification. In general, low cost fuels with wide availability are not economical to gasify.

6.5 Discussion

It is evident from this work that the relative economics of gasification vs. direct combustion depend on fuel cost and scale, and hence will be case specific. For low fuel costs, direct combustion will always be more economic than gasification as long as investment cost in gasification per unit of power output is less than direct combustion. Direct combustion is a simpler technology than BIGCC. The additional equipment used in BIGCC achieves a higher efficiency of generation per unit of fuel input, but today the capital cost per kW is still higher for gasification than for direct combustion. Some have speculated that technical developments may bring the cost of gasification below direct combustion per unit output; we note that all technologies involved in both processes are relatively mature. Hence we anticipate that for some time direct combustion will remain a lower capital cost alternative that will continue to make sense for abundant low cost fuels. If the boreal forest were harvested for fuel, gasification would not be economic, while if a more disperse fuel such as forest harvest residues were used then gasification would be economic because of the higher biomass fuel cost, which in turn arises from the longer haul distances to an optimum sized plant.

Note that reported cost figures for the one large scale plant designed to process biomass or coal are comparable to the lowest range of cost estimates for direct combustion used in this study. This supports the general conclusion that there is a region of fuel cost in which direct combustion is favored. This is different than the conclusion of previous studies that gasification of biomass was always more economical than direct combustion (Craig and Bain, 1995; Larson and Marrison, 1997).

One can identify regions of fuel cost in which gasification is more economic than direct combustion, but we note that these regions have a relatively high corresponding power cost. One can expect that the initial efforts to utilize abundant biomass fuels will focus on sources that can be delivered at low overall cost, a situation that may well favor direct combustion. This research has focused on biomass sources that are available in abundance relative to the size of a single processing plant. We note that the general conclusion for such sources, i.e. that gasification is only economic at higher fuel costs, may not apply when the supply of fuel is constrained. In this case, highly specific project factors must be considered in an economic evaluation.

6.6 Conclusions

Power cost from direct combustion or gasification of boreal forest wood chips is affected differently by DVC and DFC. At low values of DVC and DFC direct combustion is favored over gasification, because the higher capital cost paid for the higher efficiency of gasification is not justified in savings due to the low fuel cost. At high values of DVC and DFC the high fuel cost more than justifies the extra capital investment in gasification. These results can be extrapolated to any biomass fuel that is available in sufficient amount to support an optimum sized plant, for example straw and corn stover in regions where these crops are widespread and wood harvest residues in large forested areas.

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Chapter 7

Conclusions and future research

7.1 Conclusions

The economic optimum size of a straw-fired direct-combustion power plant in western Canada is 450 MW, an order of magnitude larger than current straw-fired power plants. Even at optimum size a straw-fired power plant produces electricity at a cost of \$50 MWh^{-1}. This is slightly more than the cost of electricity from whole forest biomass (which does not currently require nutrient replacement) but substantially less than the cost of electricity from forest harvest residues. It should be noted that all of the forests available for harvest in western Canada are currently allocated for pulp or lumber and hence a whole forest power plant would have to displace a pulp or lumber operation. Straw-fired power generation is not competitive in its own right. However, it might become more economic if:

- Renewable power were subsidized by the government or rate based.
- A system of carbon trading emerged and a long-term demand for CO_2 credits arose. At a power price of \$40 MWh^{-1} a carbon credit of \$11 per tonne would make straw-fired generation economic.
- The market price of electricity increased relative to the cost of the biomass plant and fuel collection costs. This could come about as the result of an increased demand for electricity, a tax on nonrenewable electricity, or an increase in the price of fossil fuels.

I believe the capital cost of existing straw-fired power plants reflects the fact that they are demonstration plants and often "first in kind." A comparison to coal-fired plants suggests that if a number of commercial scale plants were built, the capital cost might drop significantly.

Cofiring straw in an existing boiler with coal offers the opportunity to reduce GHG's with a much smaller capital investment than a stand-alone biomass power plant. In addition, cofiring allows straw to be burned in a large scale plant without the large transportation distances required for a large scale biomass-only plant. However, in a plant that is not limited by fuel input the straw displaces coal but does not create any incremental electricity. The price of the GHG credit must cover the difference in the cost of straw vs. coal, which is quite large (in part due to the abundance of cheap coal in western Canada). As such the cost of a GHG credit from cofiring is not economic compared to a GHG credit from a stand-alone biomass plant.

Cofiring may be economic in cases where the plant is fuel limited or where a reduction in NO_x represents an economic benefit to the owner/operator of the coal plant. In addition, cofiring may be competitive with stand-alone straw plants in situations where the cost of coal is higher.

The transportation cost for biomass is a major component of power cost. Pipelining can reduce the cost of transporting woodchips at large capacities and medium to long distances. For a one way pipeline, the minimum economic capacity is >0.5 M dry tonnes per year. For a two way pipeline, the minimum economic capacity is >1.25 M. dry tonnes per year. At 2 M dry tonnes per year, the minimum economic distance for a one way pipeline without carrier fluid return is 75 km, and for a two way pipeline with carrier fluid return is 470 km.

Straw absorbs so much water that its LHV is negative and it is unsuitable for combustion applications. Woodchips absorb water to a level of 65%, which makes pipelining uneconomic for combustion applications. Oil transport of mixed hardwood and softwood chips gives a fuel that is more than 30% oil by mass and is 2/3 oil and 1/3 wood on a thermal basis.

Absorption of the carrier fluid is not a problem if the biomass is to be used in an aqueous process such as the production of ethanol. Due to the wide variation in trucking costs it is difficult to tell if pipelining corn stover to an ethanol plant is less costly than trucking. At a mid range of trucking cost pipelining without carrier fluid return would be less costly for plants larger than 1.4 M dry tonnes per year. Pipelining with carrier fluid return would be less costly than a mid-range trucking cost for plants larger than 4.4 M dry tonnes per year. Multiple pipelines offer the opportunity for an ethanol producer to take advantage of economies of scale because they would not be limited by truck congestion related to the delivery of biomass.

If a source of waste heat is available at the source of a pipeline, saccharification of the corn stover can be economically carried out in the pipeline. This saves capital investment in the ethanol plant and reduces the cost of ethanol production by 2 cents per litre.

The choice of whether or not to use higher capital cost, higher efficiency electricity production processes (such as BIGCC) requires a good understanding of the makeup of fuel costs. Higher fuel costs favor BIGCC over direct combustion, however a high distance variable cost can have more effect than a high distance fixed cost. This is because distance variable costs lowers the optimum size of the plant and BIGCC plants are more competitive at smaller sizes due to a smaller maximum unit size.

7.2 Recommendations for future research

The author believes that the small scale of current biomass projects puts them at an unfair disadvantage against fossil fuels. However, the capital cost of large-scale direct combustion biomass power plants is not well understood, which discourages investment in such a plant. A detailed plant design and corresponding capital cost estimate is essential before any business or government would consider biomass as an option for a large-scale power plant costing hundreds of millions of dollars.

The cost of straw transportation depends on the assumption that continued removal does not adversely affect soil quality and carbon content if proper stubble height is maintained and the nutrients in the straw are replaced. While this has been demonstrated for black soil zones in western Canada, the potential for straw usage could be greatly increased if continued removal was researched in other soil types.

Currently the straw is left on the field when the grain is harvested. Collecting straw requires an extra pass over the field, requiring extra labor and fuel. Simultaneous collection of grain and straw offers the potential to reduce labor and fuel costs. In addition, simultaneous collection can increase yield and reduce foreign material (dirt and rocks). Simultaneous collection would require new machinery and new harvesting procedures but this is worth researching because lowering the cost of the biomass fuel is a key step towards making electricity from biomass and the resulting GHG credit less costly.

A critical issue in the evaluation of trucking vs. pipelining biomass is the wide range of trucking costs in the literature. A more detailed understanding of these costs would be necessary before making the decision whether or not to invest in a slurry pipeline.

Supercritical water gasification is not as well developed as many other biomass utilization technologies and it is not clear that it would have the same economies of scale that direct combustion or other gasification technologies have. However, as supercritical water gasification research progresses, the potential for very large scale plants (>2 M dry tonnes of biomass per year) should not be ignored. Pipelining woodchips offers a solution to the high transportation costs and traffic congestion associated with very large biomass plants.

Chapter 5 extends the work of wood chip pipelining to corn stover and explores a wide range of friction factors. A precise determination of the friction factor of corn stover slurry would contribute to the future evaluation of pipelining corn stover. The large-scale ethanol facility made possible by multiple pipelines may offer the opportunity to recover potentially valuable byproducts in significant quantities. These byproducts and their economic potential should be quantified.

Appendix A

Table A1: Summary of discounted cash flow for straw-fired power plant in western Canada at an optimum size of 450 MW

Year	Capital Cost	Operation Cost	Maintenance Cost	Administrative Cost	Harvest and Handling Costs	Transp. Cost	Nutrient Replacement	Premium to fuel owner	Ash Disposal	Total Costs	pv of total costs at 10%	MWH produced	Price required for 10% return	revenue required for 10% return	pv of revenue at 10%
	($'000)	($'000)	($'000)	($'000)	($'000)	($'000)	($'000)	($'000)	($'000)	($'000)	($'000)		($)	($'000)	($'000)
-2	116,915	0	0	0	0	0	0	0	0	116,915	141,468	0			
-1	204,602	0	0	0	0	0	0	0	0	204,602	225,062	0			
0	263,059	0	0	0	0	0	0	0	0	263,059	263,059	0			
1	0	2,246	17,537	1,404	9,489	32,398	20,226	6,992	2,009	92,303	83,911	2,759,397	49.65	137,001	124,547
2	0	2,291	17,888	1,432	10,845	39,705	23,116	6,469	2,050	103,795	85,781	3,153,597	50.64	159,705	131,987
3	0	2,337	18,246	1,461	11,522	44,031	24,561	8,490	2,091	112,738	84,702	3,350,697	51.65	173,080	130,038
4	0	2,384	18,611	1,490	11,753	44,912	25,052	8,660	2,132	114,993	78,542	3,350,697	52.69	176,542	120,580
5	0	2,432	18,983	1,520	11,988	45,810	25,553	8,833	2,175	117,293	72,830	3,350,697	53.74	180,072	111,811
6	0	2,480	19,363	1,550	12,228	46,726	26,064	9,010	2,218	119,639	67,533	3,350,697	54.82	183,674	103,679
7	0	2,530	19,750	1,581	12,472	47,661	26,585	9,190	2,263	122,031	62,621	3,350,697	55.91	187,347	96,139
8	0	2,580	20,145	1,613	12,722	48,614	27,117	9,374	2,308	124,472	58,067	3,350,697	57.03	191,094	89,147
9	0	2,632	20,548	1,645	12,976	49,586	27,659	9,561	2,354	126,961	53,844	3,350,697	58.17	194,916	82,663
10	0	2,685	20,959	1,678	13,236	50,578	28,213	9,753	2,401	129,501	49,928	3,350,697	59.34	198,814	76,652
11	0	2,738	21,378	1,712	13,500	51,589	28,777	9,948	2,449	132,091	46,297	3,350,697	60.52	202,791	71,077
12	0	2,793	21,805	1,746	13,770	52,621	29,352	10,147	2,498	134,733	42,930	3,350,697	61.73	206,847	65,908
13	0	2,849	22,242	1,781	14,046	53,673	29,939	10,349	2,548	137,427	39,808	3,350,697	62.97	210,983	61,114
14	0	2,906	22,686	1,816	14,327	54,747	30,538	10,556	2,599	140,176	36,913	3,350,697	64.23	215,203	56,670
15	0	2,964	23,140	1,853	14,613	55,842	31,149	10,768	2,651	142,979	34,228	3,350,697	65.51	219,507	52,548
16	0	3,023	23,603	1,890	14,905	56,959	31,772	10,983	2,704	145,839	31,739	3,350,697	66.82	223,897	48,727
17	0	3,084	24,075	1,927	15,203	58,098	32,407	11,203	2,758	148,756	29,431	3,350,697	68.16	228,375	45,183
18	0	3,146	24,556	1,966	15,508	59,260	33,055	11,427	2,814	151,731	27,290	3,350,697	69.52	232,943	41,897
19	0	3,208	25,048	2,005	15,818	60,445	33,717	11,655	2,870	154,765	25,305	3,350,697	70.91	237,602	38,850
20	0	3,273	25,549	2,045	16,134	61,654	34,391	11,888	2,927	157,861	23,465	3,350,697	72.33	242,354	36,024
21	0	3,338	26,060	2,086	16,457	62,887	35,079	12,126	2,986	161,018	21,758	3,350,697	73.78	247,201	33,404
22	0	3,405	26,581	2,128	16,786	64,145	35,780	12,369	3,045	164,238	20,176	3,350,697	75.25	252,145	30,975
23	0	3,473	27,112	2,171	17,122	65,428	36,496	12,616	3,106	167,523	18,709	3,350,697	76.76	257,188	28,722
24	0	3,542	27,655	2,214	17,464	66,736	37,226	12,868	3,169	170,873	17,348	3,350,697	78.29	262,331	26,633
25	0	3,613	28,208	2,258	17,813	68,071	37,970	13,126	3,232	174,291	16,086	3,350,697	79.86	267,578	24,696
26	0	3,686	28,772	2,303	18,170	69,432	38,730	13,388	3,297	177,777	14,916	3,350,697	81.45	272,930	22,900
27	0	3,759	29,347	2,350	18,533	70,821	39,504	13,656	3,362	181,332	13,832	3,350,697	83.08	278,388	21,235
28	0	3,834	29,934	2,397	18,904	72,237	40,294	13,929	3,430	184,959	12,826	3,350,697	84.75	283,956	19,690
29	0	3,911	30,533	2,444	19,282	73,682	41,100	14,208	3,498	188,658	11,893	3,350,697	86.44	289,635	18,258
30	0	3,989	31,144	2,493	19,667	75,156	41,922	14,492	3,568	285,963	16,388	3,350,697	88.17	295,428	16,931

Table A2: Discounted cash flow model inputs

Capacity of power plant (MW)	450
Capital cost without camp cost. for 50 MW ($/kw)	2200
Cost of 50 MW plant with camp cost	$112,501,851
cost (with camp cost) per kw	2,250
Scale Factor	0.75
Cost per Installed kw	$1,299
Price of Power in year 1 (for 10% IRR)	$46.79
Inflation	0.02
Inflation Index (from 1992 to 2000)	1.1561
Inflation Index (from 1996 to 2000)	1.059
Canadian dollar/US Dollar (2000)	0.65606
Average fuel yield (tonnes/ha)	0.47
Area requirement per year (ha)	
Year 1	4427461.3
Year 2	5059955.8
Year 3 onwards	5,376,203
Premium above cost of fuel that is paid to owner as an incentive to collect and sell the fuel ($/ton)	4.00
Site recovery and reclamation costs (as % of capital cost)	20
Power cost (2000 US$/MWhr)	32.80
Capacity factor	
Year 1	0.7
Year 2	0.8
Year 3 onwards	0.85
Maximum Unit Size (MW)	450
Number of units	1
Unit size	450.00
Maintenance cost (assumed 3 % cap. Cost)	0.03
Efficiency of plant	0.34
Calorific value of dry straw (HHV) (MJ/kg)	18.3
Percentage moisture of fuel	16
percentage hydrogen of fuel	4.8
Calorific value at given moisture content (HHV) (MJ/kg)	14.041
Energy produced (MJ/yr)	
Year 1	9.934E+09
Year 2	1.135E+10
Year 3 onwards	1.206E+10
Spread of costs during construction (%)	
Year 1	20
Year 2	35
Year 3	45
Fuel required (tonnes/yr)	
Year 1	2,080,907
Year 2	2,378,179
Year 3 onwards	2,526,815
Harvesting cost (2000 US$/tonne)	4.56
No. of operators required	
For 0 - 450 MW	8
For each additional 450 MW	4
No. of administrative staffs required	26
Operating and administrative labour cost ($/hr)	27
Nutrient Cost per tonne of fuel	0
Percentage of Ash in straw	4
Ash Hauling cost ($/odt/km)	0.105
Cost of application of ash ($/odt/ha)	14.63

Appendix B

1. Formula for calculating the friction factor in wood chip water slurry pipeline (Hunt, 1976):

$$(F_m/F) - 1 = 197 \left(\frac{D^{0.970} * g^{1.312} * \upsilon^{0.342}}{V_m^{2.964}} \right) [C/(1-C)]^{[0.838 + \{0.930 * \ln(1-k)\}]}$$

F_m – Darcy-Weisbach friction factor for mixtures of wood chips and water, dimensionless
F – Darcy-Weisbach friction factor, dimensionless
D – internal diameter of pipe, m
g - gravitational acceleration, 9.81 m/s^2
υ – kinematic viscosity of carrier water, m^2/sec
V_m – mean velocity of mixture flow, m/sec
C – concentration of solids in mixture (decimal fraction), dimensionless
k – ratio of characteristic chip dimension to pipe diameter, d_c/D, dimensionless

2. Formula for calculating the friction factor in water pipeline

Colebrook equation:

$$f = a + b * Re^{-c}, \text{ if } Re > 10^4 \text{ and } 10^{-5} < k < 0.04$$

$a = 0.094 * k^{0.225}$

$b = 88 * k^{0.44}$

$c = 1.62 * k^{0.134}$

$Re = d*g*D/\mu$

$k = e/D$

f – Darcy – Weisbach friction factor, dimensionless
Re – Reynolds number, dimensionless
d – density of fluid, kg/m^3
D – internal diameter of pipe, m
g - gravitational acceleration, 9.81 m/s^2
μ – viscosity, Pa.S
e – Roughness of pipe, m

3. Formula for calculating the head loss

Darcy – Weisbach equation:

$$h_f = f * L * V^2 / (2 * g * D)$$

h_f - head loss, m
f - Darcy-Weisbach friction factor
L – length of the pipe, m
V – velocity of fluid, m/s
g - gravitational acceleration, 9.81 m/s^2

4. Formula for pipeline cost (Liu et al., 1995)

$$C = 132 * D^{1.34} + 104 * D^{0.87} + 24 * D + 20$$

C – capital cost for constructed pipeline capital cost ($1000) per mile, which include steel pipe, construction (excavation, welding and insulation), coating, wrapping, valves and the right of way (cost in $1994)
D – nominal pipe diameter in feet

5. Formula for pump cost (Liu et al., 1995)

$$C = 1.15 * (H_p)^{0.8056}$$

C – cost for pump ($1000), cost in 1994 dollars
H_p – pump power in horsepower

Table B1 : Capital costs for inlet, outlet and booster station facilities (two-way pipeline, 819 mm slurry, 606 mm water, 2 M dry tonnes/year, 104 kms)

Item	Cost ($ 1000)	Remark
Inlet facilities		
Land for inlet facility	19.7	Estimated
Access roads	39.9	(RS Means, 2000)
Conveyor belt	245.3	(Peters et al., 1991)
Mixing tank (water and chips)	61.3	(Peters et al., 1991)
Piping	405.1	(Liu et al., 1995)
Foundation for pump area	100.0	Estimated
Storage tank for water	769.3	Peters et al. (1991)
Auxiliary pump (with one redundant pump)	137.1	(Liu et al., 1995)
Power supply line and sub station	400.0	Estimated
Communication lines	40.0	Estimated
Building	236.8	Estimated
Road along the pipeline	266.0	(RS Means, 2000)
Fire suppression system	65.8	Estimated
Mobile stacker for dead storage	100.0	Estimated
Main pump for wood chips and water mixture transport	2,678.8	(Liu et al., 1995)
Pipeline for wood chips transport to plant	58,863.9	(Liu et al., 1995)
Total capital cost at inlet	**64,389.2**	
Outlet facilities		
Building	236.8	Estimated
HVAC system to blow air	48.6	(Peters et al., 1991)
Conveyor belt	490.6	(Peters et al., 1991)
Filteration tank	3.4	(Peters et al., 1991)
Water intake tank	769.3	(Peters et al., 1991)
Water supply lines from a water source	42.6	(Liu et al., 1995)
Auxiliary pump (with one redundant pump)	137.1	(Liu et al., 1995)
Main pump for water return	2,262.3	(Liu et al., 1995)
Return water pipeline	41,897.2	Estimated
Total capital cost at outlet	**45,887.9**	
Booster station facilities		
Substation	400.0	Estimated
Booster pump for mixture	1,283.0	(Liu et al., 1995)
Booster pump for water	1,017.5	(Liu et al., 1995)
Building	19.7	Estimated
Access roads	4.0	(RS Means, 2000)
Land	0.7	Estimated
Foundation for pump area	100.0	Estimated
Total capital cost at booster station	**2824.9**	

Table B2: O/M cost for inlet, outlet and booster station facilities
(two-way pipeline, 819 mm slurry, 606 mm water, 2 M dry tonnes/year, 104 kms)

Item	Cost ($ 1000)	Remark
Inlet facilities		
Electricity	1,775.9	
Maintenance cost	423.0	
Salary and wages	1,080.0	*4 per shift*
Total O/M at inlet	**3,278.9**	
Outlet facilities		
Electricity	1,448.0	
Maintenance cost	331.1	
Salary and wages	540.0	*2 per shift*
Total O/M at inlet	**2,319.1**	
Booster station		
Electricity	2,627.7	
Maintenance cost	38.5	
Total O/M at inlet	**2,666.2**	

Table B3: General economic and technical parameters

Item	Values
Life of pipeline	30 years
Contingency in cost	20% of total cost
Engineering cost	10% of total capital cost
Discount rate	10%
Operating factor	0.85
Power cost	$50 per MWh
Velocity of the slurry	1.5 m/s
Velocity of water in the water return pipeline	2.0 m/s
Maximum pressure	4100 kPa
Pump efficiency	80%
Scale factor applied to inlet, outlet and booster station facilities excluding pumps	0.75

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Appendix C

Table C1: Capital costs for inlet and booster station facilities (one way pipeline, 1259 mm slurry, 2 M dry tonnes/year, 150 kms, 20% solids concentration)

Item	Cost ($ 1000)	Remark
Inlet facilities		
Main pump for wood chips and water slurry transport	5223.7	(Liu et al., 1995)
Pipeline for wood chips transport to plant	139,613.8	(Liu et al., 1995; Williams, 2003)
Total capital cost at inlet	**144,837.5**	
Booster station facilities		
Substation	400.0	Estimated
Booster pump for mixture	2,592.7	(Liu et al., 1995)
Building	19.7	Estimated
Access roads	4.0	(RS Means, 2000)
Land	0.7	Estimated
Foundation for pump area	100.0	Estimated
Total capital cost at booster station	**3,117.1**	

Table C2: O/M cost for inlet and booster station facilities (one way pipeline, 1259 mm slurry, 2 M dry tonnes/year, 150 kms, 20% solids concentration)

Item	Cost ($ 1000)
Inlet facilities	
Electricity	3,608.5
Maintenance cost	966.4
Salary and wages	100.0
Total O/M at inlet	**4,674.9**
Booster station	
Electricity	3,611.4
Maintenance cost	77.8
Total O/M at inlet	**3,689.2**

Table C3: General economic and technical parameters

Item	Values
Life of pipeline	30 years
Contingency in cost	20% of total cost
Engineering cost	10% of total capital cost
Discount rate	10%
Operating factor	0.85
Power cost	$50 /MWh
Velocity of the slurry	1.5 m/s
Velocity of water in the water return pipeline	2.0 m/s
Maximum pressure	4100 kPa
Pump efficiency	80%
Scale factor applied to inlet, outlet and booster station facilities excluding pumps, saccharification tank	0.75
Capital cost of saccharification tank and related accessories at a plant capacity of 2000 dry tonnes of stover per day	$ 3,000,000

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