IDENTIFYING ENVIRONMENTALLY PREFERABLE USES FOR BIOMASS RESOURCES

STAGE 1 REPORT:
Identification of Feedstock-to-Product Threads

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TABLE OF CONTENTS

Introduction

Canada is richly endowed with significant biomass resources. For example, the estimated thermal energy content of the annual biomass harvest in Canada is 5.1 Exajoules (1 Ej =10^{18} joules or 1.4 x 10^6 GWh). This annual harvest is equal to 62% of the thermal energy derived from fossil fuel combustion (BIOCAP 2003). The development of this biomass resource, not just for energy but a variety of end uses, presents Canada with an opportunity to not only develop new and innovative industries but sustainable energy and raw material supplies while also reducing our reliance on non-renewable fuels and our greenhouse gas emissions

This Phase 1 report builds on past studies to summarize the size of Canada's major biomass resources (forestry, agricultural, and municipal residues, landfill gas and energy crops) and for each sector identifies a number of possibilities and technologies that could be applied to this resource for energy and other potential commercial purposes. It also provides some initial information on regional concentrations of biomass. That information is required to select suitable feedstock-to-product processes or "threads" for analysis during the second phase of this work. Each thread will describe the processing steps to convert a biomass feedstock to a product that can be used for transport fuel, electricity, heat, fertilizer, and other products.

Reference to particular companies or specific processes in this report does not mean that the authors necessarily recommend these processes or companies or that they are commercially viable at current energy prices or greenhouse gas credit values. Rather, they are presented to demonstrate that such companies and processes exist and that literature is available for further investigation.

Five main ways to utilize biomass were identified:

1. **Biochemical Transformation** – this includes: fermentation to form alcohols such as methanol or ethanol; anaerobic digestion to produce methane (landfill gas); or chemical treatment of fats and oils to produce biodiesel. Biodiesel can be produced from vegetable crops, wood residue, and from liquid forms of waste biomass, such as animal fat or used cooking oil, as well as from wood (bio-oil, see point 3).

2. **Combustion** – this process uses the biomass directly to generate thermal energy, which can in turn be used to provide process heat, space heat, or can be used in a boiler system with a turbine to drive a power cycle to generate electricity. Combined heat and power units will deliver both useful heat and electricity and achieve a high degree of conversion efficiency.

3. **Pyrolysis** – this process produces a bio-oil liquid from which chemical products can be extracted, or which can be used as a transportation fuel or as a fuel for stationary engines.

4. **Gasification** – this process partially combusts biomass to produce a mixture of gases referred to as syngas in this report. This syngas can in turn be refined to yield hydrogen, converted into methanol, converted into various other chemical products, or it can be used to displace or replace fossil fuels to generate power in an engine, turbine, or boiler.

5. **Material uses** – this includes all of the other non-energy uses for biomass in addition to the energy and thermal conversions mentioned above. For example using the raw biomass, the extracted fibres and other compounds to produce: starch-based plastics, building materials (e.g. .wood products, MDF or strand board); pulps and papers, yarns, fibres and fabrics; fertilizers, soil improvers and compost.

Research is on-going towards the so-called "biorefinery" concept, i.e. the extraction of multiple specialty chemicals from biomass. While these can improve overall process economics, making some of the above five options more viable, they have minimal impacts on climate change issues, and are therefore treated as a side aspect in this examination.

Figure I-1 traces the conversion of biomass through basic processes and intermediary forms to final energy products for combustion, gasification, and pyrolysis. There may be numerous intermediate products or energy forms but they are temporary in the cycle of source-to-energy use. Two of the noted final products, charcoal and coke, are intermediary forms themselves as they can both be used in further processing. In fact there are only three final products with respect to energy-related uses of biomass: electricity, heat and kinetic energy for transportation.

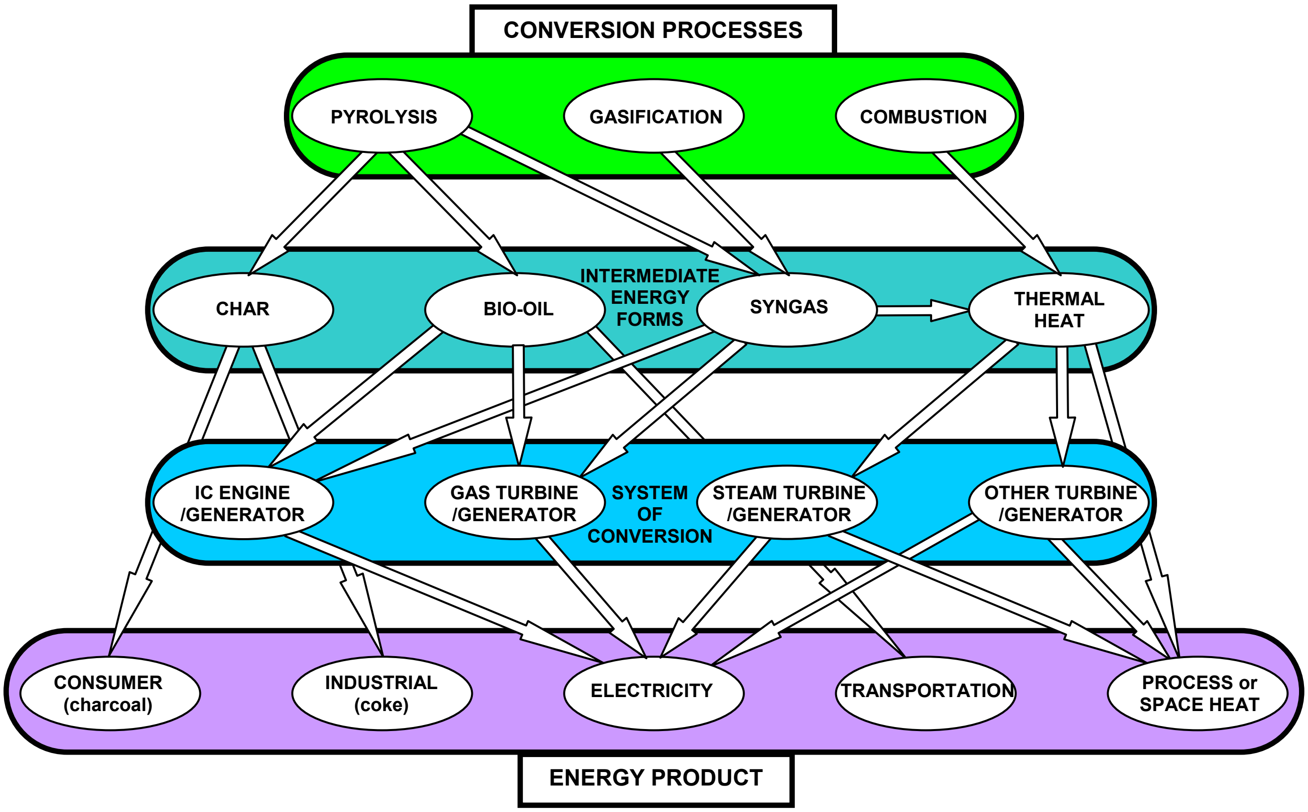


Figure I-1 Thermal Conversion Processes

Biomass contains a great deal of energy. Its energy density is lower than that of fossil fuels, but far higher than that of other "green" energy sources, such as wind, wave and solar. In addition, biomass is transportable and available for use on demand, i.e. it can be used as a firm power source, as opposed to intermittent renewable resources.

During the last century, electrical power production from biomass has been implemented in locations where high concentrations of available biomass allow for large systems to be built, as smaller, decentralised units could not reach the necessary economies of scale. In particular, pulp mills have become "integrated" to not only use recovery boilers to minimize chemical requirements but also to use hog fuel boilers to create additional steam and electrical power to minimize electricity purchases. However, much of Canada's more dispersed biomass is not being utilized productively. This has sparked interest to develop new technologies for biomass utilization that yield higher-value products than just steam and electricity, reduce costs, thus becoming viable for smaller quantities of biomass.

Many biomass conversion options are technically defined but are not commercially viable. In some cases, the market for the product is minor while in other cases the technology is too complex to compete with other sources. Some of the processes are relatively simple (i.e. the use of biomass as a soil improver or residential space heating) and others, such as gasification and subsequent chemical treatment, can be quite complex. **Figure I-2** illustrates the many ways in which syngas produced from biomass can be transformed, into a variety of process streams that can be used to replace petroleum-based products. Although the composition and therefore the treatment options for all biomass sources are at one level similar, the different physical and chemical structures, locations, and distributions of the various resources tend to favour feedstock-specific processes and uses.

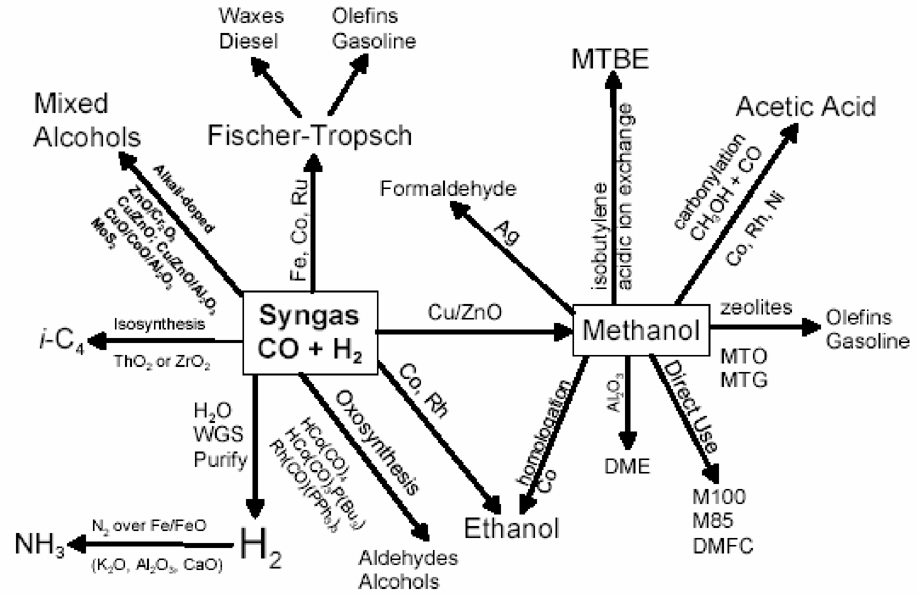


Figure I-2 Selection of Options to Use Syngas and Methanol for Products
[NREL 2003, p.14]

Feedstock	Treatment 1	Step 1 Product	Treatment 2	Step 2 Product
Wood	Combustion	Heat		
Corn stover	Fermentation	Power	Steam	Hydrogen
Switchgrass	Composting	Ethanol	reforming	
Landfill gas	Shredding	Biodiesel		Methanol
Solid waste	Mixing	Pyrolysis oil	Catalytic	
Rape seed	Separation/	Syngas	conversion	Biobased
Etc.	cleaning	etc.	etc.	chemical product
	etc.			

Figure I-3 1-Step and 2-Step Feedstock-to-Product Threads

Figure I-3 shows that the production of biomass-based products can take one or two processing steps: in the case of electricity production, biomass is burned in one step, possibly with some pre-treatment, such as shredding or sorting. Other products, such as hydrogen, are produced in a two-step process – and yet others could even require a third step. Each step will require additional energy and possibly other inputs which can reduce overall resource efficiency. It should be noted that for fuels, such as hydrogen and methanol, engine efficiencies must be taken into account when comparing them to fossil alternatives.

A large number of "threads" were identified. By recognizing the modularity of different processing steps we can break down the "threads" into several processing steps, making the comparison of various options and feedstocks possible. Whereas many options to use biomass are presented here, a large number of initiatives and research projects are underway to use biomass in yet different ways, extract specialty chemicals, and to improve existing technologies to become more efficient and economically attractive. The field of biomass utilization is evolving rapidly, and new developments are published almost daily.

The **Phase 2** report of this study will not only relate to Canada's particular situation, but will also extrapolate the results to other jurisdictions, concentrating on the U.S., Mexico and Western Europe. The situation in each country or region will differ, depending on the fossil fuels that biomass can replace and the specific emissions assigned to them, the electricity generation portfolio, and the availability of resources. For example considering wood, **Table I-1** shows that the use of wood as a fuel in Europe, North America and Mexico amounts to a few percent of overall energy use. However, per capita use of wood as a fuel is lowest in Europe and highest in Canada, indicating that the harvest of fuel wood is already high here as the resource is abundant. On the other hand, limited resources may be the reason for lower harvesting rates in much of Europe and Mexico. It is of interest to Canada that Finland used biomass to fill as much as 19.5% of its energy needs in 1991 [ARC 2003(1), p.26].

Table I-1 Use of Wood for Energy Purposes in North America and Europe
[IEA 1998, p.135ff.]

Country/ Region	Timber demand	Wood fuels demand		Ratio wood/ all energy	Per capita wood energy demand	Sources of Wood Fuels (FAOSTAT, in 1000 m^3 of fuel wood)			
	1000 m^3	1000 m^3	PJ	%	m^3 per capita/yr	Fuel wood	Char-coal	Resi-dues	Black Liquor
Canada	182,388	34,538	345	4	1.17	5,319		600	30,673
USA	408,948	237,900	2,379	3	0.90	90,362	4,482		115,000
Mexico	6,060	32,775	328	6	0.35	15,574	840		634
Western Europe	145,377	91,310	913	2	0.25	28,377	1,268	18,025	15,636

Figure I-4 compares the current use of biomass in the supply of energy needs for North America and Europe. As can be seen, the USA and Europe have the lowest share of biomass in their energy portfolios, whereas Mexico covers more than 9% of its total energy needs from biomass (1998 data). Biomass has a large potential and it is estimated that it could cover as much as 20% of Europe's energy needs, and in Canada, residual biomass alone could provide about 25% of the energy now obtained from fossil fuels [BIOCAP 2003].

Several scenarios may be necessary to provide a true picture of the environmental impacts of replacing fossil fuels with biomass in each country or region. As **Figure I-5** shows, the electricity background mix is very different for the three North American countries, as well as for Western Europe. There are also differences which also occur within each of the countries (e.g. the fuels used for electricity production vary between Canadian provinces). This variation needs to be taken into account when making recommendations for the best use of biomass and may result in different results of the analysis with respect to emission reduction benefits.

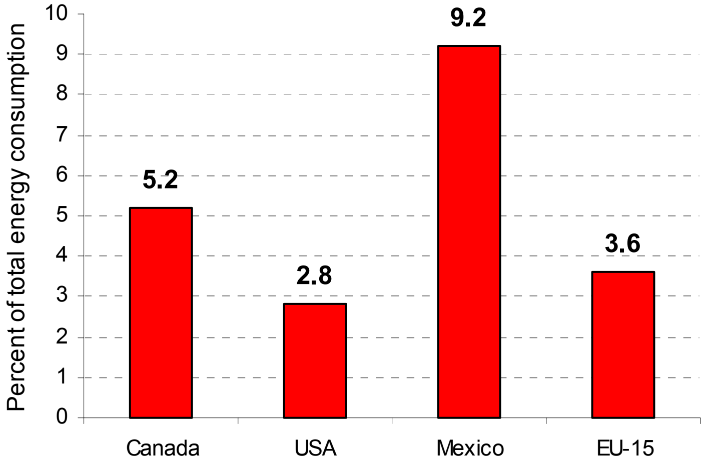
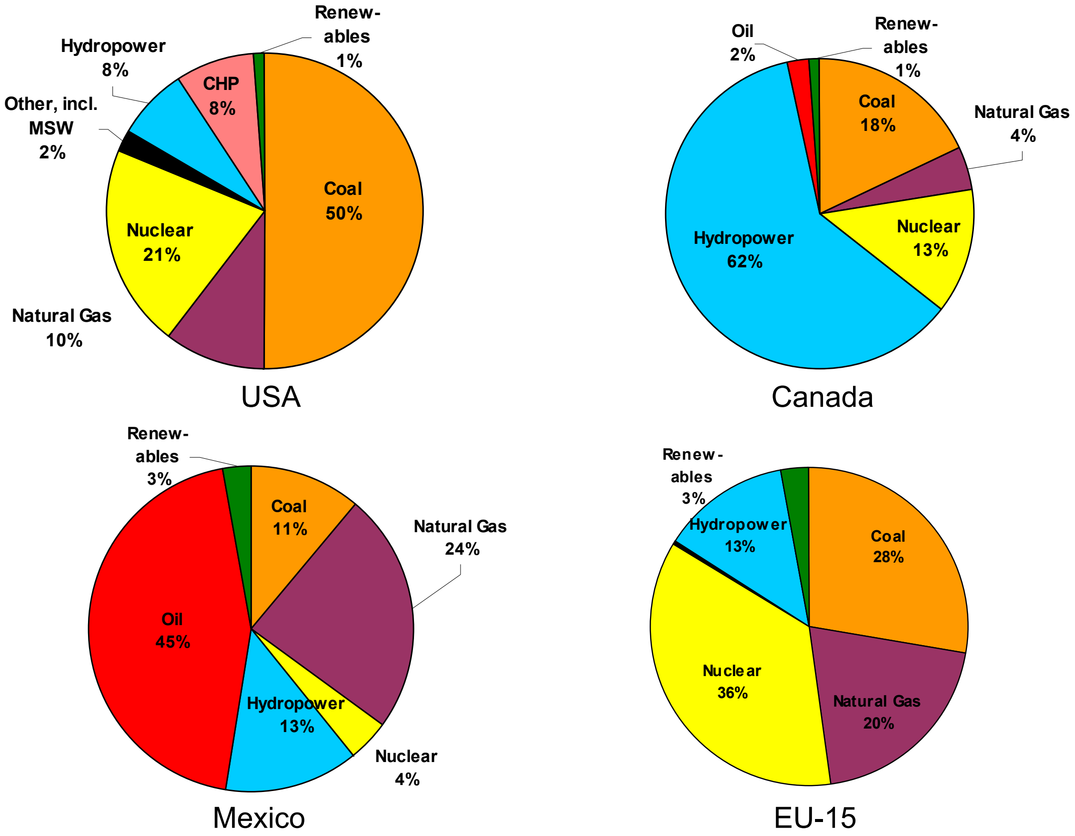


Figure I-4 Share of Biomass-Derived Energy in Overall Energy Consumption [IEA 2002(1)]



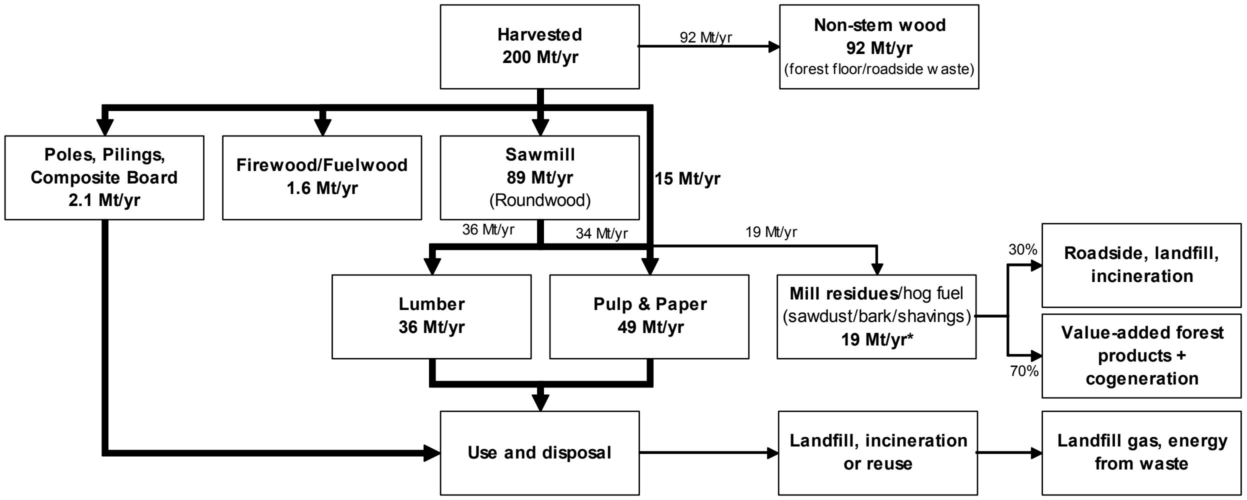
CHP = Combined Heat and Power; MSW = Municipal Solid Waste

Figure I-5 Electricity Production by Source in the U.S., Canada, Mexico and Europe [IEA 2002(2)]

Chapter 1 Forestry Residues

1.1 Forest Biomass in Canada

Each year, Canada's forestry sector harvests more than 100 Mt of roundwood, and more than 90 Mt of non-stem biomass (treetops, branches and leaves which are left behind at or near the sites where the roundwood is harvested because it is uneconomical for use in sawmills). This harvest of roundwood and non-stem biomass alone has an energy content of about 3.1 EJ/yr, or approximately 36% of the current Canadian energy consumption provided from fossil fuels.



Based on Table 2.6 of BIOCAP 2003; 1 m^3 of wood = 0.54 tons ODT

* the number in literature is generally somewhat smaller, i.e. 17-18 Mt/yr [CFS 1999]

Figure 1.1 Annual use of harvested forest biomass in Canada

Figure 1.1 shows how harvested forest biomass is currently being used. So far, most of the non-stem wood is not being used in North America although some is used to produce mulch for reclamation of logging landings. Some trial programs to collect this resource are currently being conducted in Europe, as preliminary estimates suggest that overall carbon emissions could be reduced by as much as 4-6% through its use [PA0923 2003]. A significant portion of the non-stem biomass could be available in Canada. Its energy content is 1.44 EJ/yr or about 17% of Canada's current fossil fuel energy consumption [BIOCAP 2003, p. 16]. The non-stem wood category could be expanded to include other non merchantable forest biomass, such as tree thinnings (for disease control, scrub forest reclamation or forest fire mitigation), partially-burned/ fire-damaged wood left after forest fires, diseased wood (bugwood affected by pine beetles), inferior tree species, and wood from community interface zones (a belt of about 3 km around inhabited areas to prevent forest fires from reaching settlements), and dry land sort wood waste[1] (an important stream of biomass, mainly bark, from sorting operations off rivers used for transporting wood) that could also be added to this category. According to the BC Ministry for Sustainable Resource Management, about 15 million m^3 of bugwood are expected to be

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[1] Contamination of this material with rock and grit is typically a challenge to its successful use as a fuel or use as a feedstock for another product.

available over the next ten years in the province [BCSRM 2003]. However, no estimates for the recoverable amounts from these sources have been found for this study.

Figure 1.1 also shows that much of the “hog fuel”, i.e. residues from milling operations, is already being used for energy generation. The hog fuel is mostly used wherever it occurs in sufficient quantities to make its economic utilization possible, i.e. at large saw and pulp and paper mills, where it is often used for combined heat and power generation. However, some 30% of this resource is still being landfilled, incinerated (sometimes in beehive or silo burners) without energy recovery, or simply left to decompose near roadside landings. All three ways of handling forest residues mentioned raise significant concerns: wood landfills have been shown to have a leaching problem that introduces pollutants into the environment. Incineration in uncontrolled beehive and silo burners produces excessive particulate and smoke emissions. Leaving residues in the forest “near the roadside” interferes with ecosystems, encourages insect infestations and can present a wildfire hazard. In addition, each of these practices has associated greenhouse gas emission profiles that can be improved.

This biomass is distributed and meaningful applications often require local utilization at the biomass production site to limit transportation costs. Some of the biomass is stockpiled, with some highly localized concentrations. For example, Saskatchewan has about 4 million tons of wood residue in landfills [AGB 2001, p.20] and BC has various woodwaste landfills. Technologies to utilize these resources need to be able to handle fuel with a high moisture content (50-60%).

Another resource derived from forest products is tall oil. Tall Oil Products such as Crude Tall Oil, Distilled Tall Oil and Tall Oil Fatty Acids are derived from Pine trees. They are by-products of the manufacture of paper and could be turned into bioenergy products, such as biodiesel. The Canadian tall oil production is estimated to be roughly 180 thousand tonnes per year [GCSI 1998, p.15]. Pulp and paper mills will often burn this residue in black recovery boilers to produce energy.

1.2 Geographical Distribution of Forest Biomass

Based on the National Atlas of Canada, sawmills can be found across the nation, with most activity going on in British Columbia, Northern Alberta, Eastern Ontario, Southern Québec and across the Maritimes (see Figure 1.2).

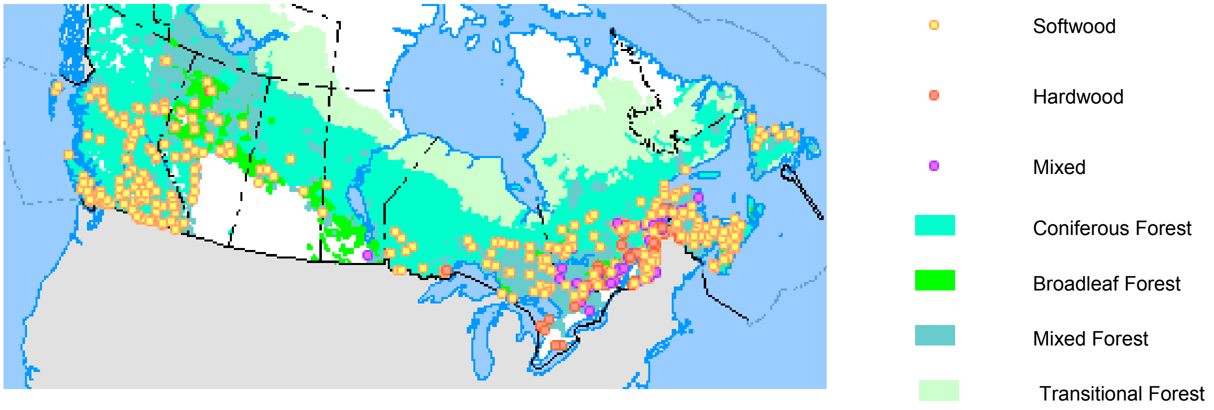


Figure 1.2 Location of Sawmills Across Canada [NAC 2003]

Apart from sawmills, pulp & paper mills and plywood mills will also be points where biomass residue can be found concentrated. Plywood production in Canada in 1999 was 1.9 million cubic metres, and 80 per cent of the total Canadian production came from British Columbia. With nearly half of Canadian softwood production also coming from BC, the province clearly has the largest wood and woodwaste resource among Canadian provinces. For pulp & &paper mills, the picture is somewhat different: only 31.5% of pulp and 15.2% of paper were produced in BC in 1999 [COFI 2000]. Canada has 102 paper and board mills and 44 pulp mills. The paper and board production capacity is 22 million tons and the market pulp production capacity 12 million tons. Most of the pulp and paper mills are located in the Atlantic Provinces, Ontario and Quebec. [HUT 2002]

Table 1.1 Unused Mill Residues in Canada [CFS 1999]

Province/Country	**Surplus** [million BDt]
British Columbia	2.06
Alberta	0.90
Saskatchewan	0.05
Manitoba	0.02
Ontario	0.45
Québec	1.64
New Brunswick	0.18
Nova Scotia	0.06
Prince Edward Island	n/a
Newfoundland	0.02
Canada	**5.4**

The next map (Figure 1.3) shows concentrations of timber productive land use, an indication of where Canadian forests are harvested most intensively. Therefore, the most intensely harvested forest biomass areas in Canada are located in:

Ontario: along the St. Lawrence River, north of Greater Sudbury and the Thunder Bay
Alberta: north and south of the Athabasca River and,
BC: from the Columbia River valley up to the Prince George Area, the Queen Charlotte Islands and the western part of Vancouver Island in BC.

Local availability of biomass will depend on different factors. For example, if forestry is to be intensified for energy needs, areas that are currently not used extensively may be utilized. If forest residues are to be used, the highest quantities of non-stem wood will be available where forestry is most intensive. As a starting point for this project, it is important to account for current uses of forest biomass. Sawmill residues are already being used in some areas, and Table 1.1 shows the available amounts of all mill residues in each province. Their availability is highest in British Columbia, followed by Québec and then Alberta. Ontario, for example, seems to be using most of its mill residues already.

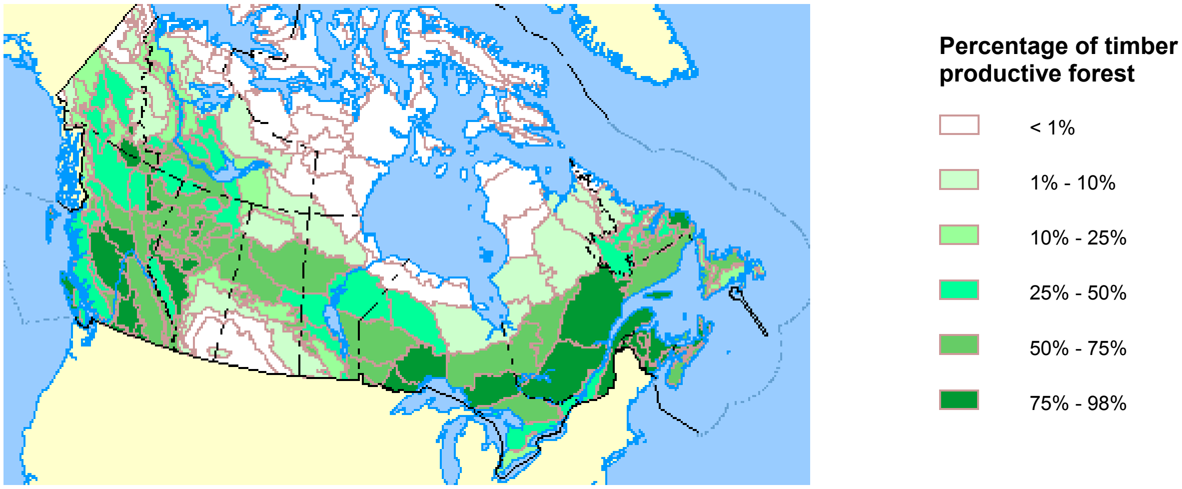


Figure 1.3 Timber Productive Forest [NAC 2003]

1.3 Possible Uses of Forest Biomass

1.3.1 General

There have been a number of developments of equipment designed specifically to combust biomass more completely and reduce fly ash emissions. These systems were developed because even the best large grate boilers showed significant inefficiencies. These boilers expelled carbon in the bottom ash as well as carbon, carbon monoxide and unburned hydrocarbons in the flue gas. These components represent unconverted potential biomass energy.

Combustion systems designed to fully convert biomass have generally followed one of several approaches: high temperature combustion systems use a refractory that reflects and re-radiates the combustion heat back onto the fuel bed to maintain temperature and ensures a complete burnout. Two-stage combustion systems use a gasifier chamber followed by a second refractory lined chamber where high temperatures complete the combustion. With lower moisture biomass the secondary combustion can be maintained by a scroll burner (or a similar system) without the need for the second chamber. (Gasification is also used by some systems to produce a syngas as an engine fuel, as will be discussed later.) Combustion systems are either operated at high temperatures to ensure full burn-out or they used a secondary "catalyst" to ensure full biomass exposure to sufficient heat. Refractory-lined combustion chambers are an example of the former. Fluidized bed combustors are an example of the latter, with hot sand acting as a "catalyst" to ensure the intimate mixing of the biomass fuel and full contact with high temperatures to ensure complete combustion.

High temperature combustors are an effective way to maximize the thermal energy produced from biomass while reducing unwanted emissions. To obtain the desired effects the combustion chamber must be refractory lined to capture the heat and maximize combustion temperature. This means that heat recovery must all be done from the hot flue gases and not from boiler tubing on the walls. Such combustors will typically minimize/eliminate carbon in the ash and flue gas. The particulate emissions are reduced, but not sufficiently to meet environmental regulations.

Gasifier two-stage combustion systems operate functionally similar to high temperature combustors. The partial combustion of biomass on the bed is desired for its reduced air supply, velocity and ash carrying ability. The potential advantage of gasifier two-stage combustion over high temperature combustion is reduced particulate emission.

Fluidized bed combustors have been shown to combust biomass very completely and also reduce/eliminate carbon. Both bubbling bed and travelling bed designs can be implemented. One advantage of bubbling fluidized bed boilers is that they can operate with boiler wall tubes in a design similar to traditional grate boilers. There are several disadvantages that are operationally significant. Some of the ash produced in the sand bed will fuse into clinkers which can be removed during operation. However, all of the remaining ash as well as worn sand particles (as they become small in size) are carried off with the flue gas. The fly ash loading often becomes greater than traditional boilers. In addition the worn sand particles that are carried in the flue gas, being silica, are abrasive. These two conditions put added operational stress on fluidized bed combustors.

Conversion of biomass using two-stage or high-temperature combustion systems is commercially used to produce heat to displace fossil fuels. These units can vary in size from small residential fireplaces, to medium size units capable of converting all the biomass waste of a sawmill. They can be configured to convert all the hog fuel generated in several sawmills, and through heat recovery steam generators (HRSGs) to produce process steam in a pulp mill. Generation of heat from biomass is the least technology intensive conversion technology.

1.3.2 Electricity Production

a) Large Combustion Systems. Traditional biomass conversion to electricity uses large scale boiler systems to create steam and turbine/generator systems to produce electricity. The reference to "large scale" is relative to the quantity of biomass consumed compared to quantities of biomass normally available in given locations. In fact traditional biomass boilers are considered "large scale" in the 35-MWe to 80-MWe range whereas traditional coal-fired boilers are an order of magnitude larger at 100-MWe to 1500-MWe.

Industrial biomass boilers are typically large cavity, "water-walled" combustion chambers with superheater, boiler and economizer tube banks in the outlet flue gas stream. The boiler section consists of a natural circulation design with a steam drum, mud drum and several boiler tube circuits. The wet-wall sides of the boilers, under-grate tubes and direct flue gas boiler tubes are all interactively connected in a relatively complex circulation pattern. Burning is done within the combustion cavity with a bed of biomass at the bottom fed with air from below. Typically the control strategy does partial combustion in the biomass bed with volatiles being driven off into the cavity. Over-fire air in one or more stages is used to complete combustion. Several grate systems have been implemented within this fundamental boiler design approach. Newer bubbling fluidized bed systems generally follow this same fundamental design. Travelling fluidized bed systems are less common and have design aspects more specific to their operational needs.

For production of electricity these boiler systems are integrated into power generation systems using steam turbines directly driving generators at line frequency. The fundamental power conversion uses steam in a Rankine cycle. In such a cycle the bulk of the energy is lost as unrecoverable latent heat of the steam which limits the thermal efficiency. The steam must be expanded to vacuum conditions to maximize the energy recovery and the result is very large equipment to handle both the high volume flow and the low pressure drop requirements. Typically the overall efficiency of large steam systems is limited to about 20%, electricity output from gross fuel energy content. With the addition of some added boiler efficiency enhancers, such as combustion air pre-heaters, the overall efficiency can be enhanced to exceed 25%.

Steam systems require operation by highly qualified and regulated personnel. This adds significantly to the operation cost and the cost of power generated. Handling of biomass fuel requires greater effort, storage area and equipment size compared to fossil fuels. In addition, heat rejection must be considered separately. Unless a source of cooling water (e.g., direct river water use) is readily available, heat must be rejected to the atmosphere. Due to the low temperatures of reject heat required to maximize cycle efficiency, evaporative cooling towers or cooling ponds must be employed. Such systems are large, require notable pumping energy, require maintenance support and are weather dependent.

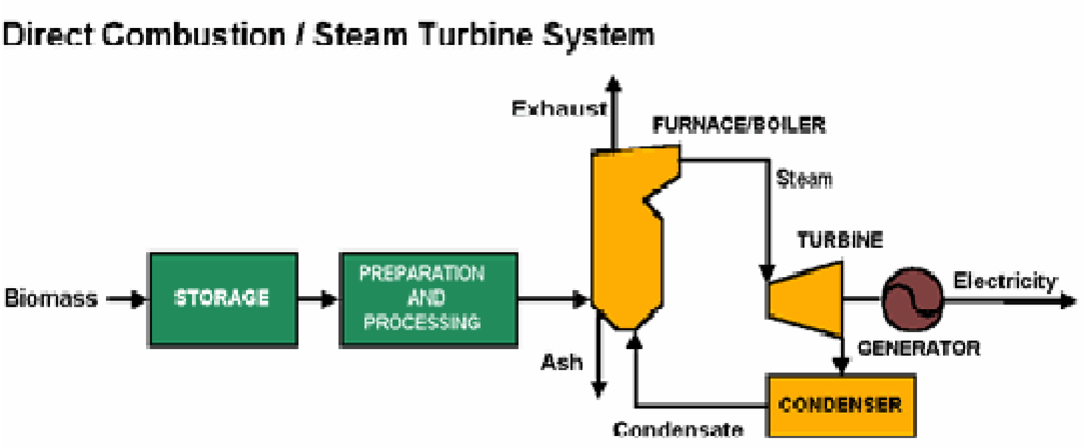


Figure 1.4 Generic Flow Diagram of a Direct Combustion System [Trillium 2002, p.22]

b) **Small Combustion Systems.** Biomass is a distributed source of moderate energy content. There are only few situations where biomass is sufficiently concentrated to support large-scale boilers. Quantities that would combust to produce less than 100 MW_{th} (or 25-MWe) are generally insufficient to be converted to electricity economically when using traditional equipment. Concentrations of forest biomass, such as waste from roadside landings, log yards, land clearing, bush chipping, mill log yards, pulp mill woodrooms, sawmills and wood product plants, are generally smaller than what is required for a large-scale plant. In addition there are sources of biomass suitable only for energy production but located where large power generators would have no market. Such sources include bugwood from pine beetle infested forests, scrub forests and fire killed areas.

It has long been recognized that power generation from forest biomass on a small scale would open significant opportunities. Benefits could be realized in environmentally preferred methods of waste disposal, new power generation, displaced fossil fuel use, reduced greenhouse gas emissions and reduced particulate emissions. This has sparked efforts to address this potential market.

A number of attempts have been made to produce small biomass power systems using a steam Rankine cycle. Scaling effects and practical engineering requirements reduce the overall efficiency of such systems by a factor of two. As a result, the unit capital cost increases and makes this approach uneconomical. In addition, the requirement for highly qualified operating personnel makes the unit power cost of production prohibitive. Small steam systems on the market are generally project-designed with available equipment, rather than purpose-designed. Small co-generation systems are more accepted as the heat benefits enhance project economics.

A second approach has been presented using a closed Organic Rankine Cycle (ORC) that appears to be technically successful. An advanced version of the ORC offered by a European company (Turboden, srl) uses a synthetic oil working fluid and results in greater electrical conversion efficiency than the small steam approach. The coolant is rejected at a temperature sufficiently high for cogeneration purposes (80°C). A specific design feature of this system is an independent thermal oil loop to transfer heat from the flue gas to the working fluid. This bypasses the requirements for registered steam operators in most jurisdictions, reducing the unit power cost of production. It also imposes a second heat transfer loop in series and reduces the heat extraction from the flue gas. The complexity of the system, the specially designed multi-stage turbine and the limited ability to extract flue gas heat results in a system that has a higher unit capital cost than large steam systems. However, the reduced operator qualification requirements reduce the operating cost significantly.

A third approach is being promoted using a new and currently unpublished power cycle. This system uses a Rankine cycle adaptation named the entropic cycle for a simplified small biomass power system. The implementation uses a single working fluid loop requiring only three heat exchangers and a power module. An expansion ratio less than 3:1 allows for a very small single stage turbine impeller. Coolant is typically used at 60°C and rejected at 90°C, making it fully available for cogeneration purposes. The system uses a heater/super-heater rather than a boiler, so avoiding the need for registered steam operators. It produces slightly better electrical conversion efficiency than the European ORC system and recovers more energy from the flue gas, lowering the temperature sufficiently to allow direct baghouse cleaning. The fundamental benefit is a unit capital cost comparable to a large steam system and a reduced operating cost. A commercial unit of this system has not yet been implemented.

c) **Gasification systems:** Syngas is generated through gasification and reduction processes. Biomass, such as wood, wood by-products or municipal waste, is converted to a synthetic gas in a high temperature, oxygen deficient environment. Volatile gases created are largely carbon monoxide, hydrogen and methane. There is typically also a significant quantity of non-volatile gases that include carbon dioxide, water vapour and nitrogen. In addition, there are particles of ash, char, tar and alkali compounds. These particles must be filtered from the syngas before it can be used as a fuel in an internal combustion (IC) engine or gas turbine. The filtering process, the need to remove water and the application in engines require that the syngas is cooled, resulting in an energy loss. Both IC engines and gas turbines require a relatively clean fuel for operation. Both engine types compress the fuel in operation, which causes a large temperature rise. To prevent uncontrolled detonation, the fuel must not be excessively hot initially.

The heat content of syngas varies greatly with the species and moisture content of the fuel feed and the conversion process employed. The common process uses air and results in a gas mixture of low gross calorific value (4-7 MJ/Nm^3 dry). Special processes using pure oxygen would result in a gas mixture of medium gross calorific value (10-18 MJ/Nm^3 dry). An exotic approach is being promoted using a plasma arc discharge gasification of biomass to produce a gas of even higher calorific value (20 MJ/Nm^3 dry). However, this system uses 1 kWh of electricity to produce the energy equivalent of 1.93 kWh in the syngas, which would convert back to only 0.63 kWh of electricity. For comparison, natural gas has a calorific value of 35 MJ/Nm^3.

Subsequent utilization of syngas is dependent on its production method, fuel properties and fuel consistency. Cooling and filtering is required to prepare it for use. Syngas can also be converted to methanol and other intermediary products. The low energy content of syngas affects the size of engines required to convert this energy. Generally, the physical size of an IC engine operating on syngas must be significantly larger than an equivalent fossil-fuelled engine. Larger engines are less efficient and more expensive to purchase, operate and maintain.

A technical extension of gasification is the Integrated Gasification Combined Cycle (IGCC) system intended to produce a syngas to be fired in a gas turbine. Waste heat recovered from the turbine exhaust is input into a steam Rankine cycle. The intent is to increase the overall conversion efficiency over direct combustion, large steam systems. The capital and operating costs are intended to be mitigated by the increased efficiency. Such systems are most applicable to large sizes required to amortize capital and operating costs, although demonstration plants are in the 10-MWe size. IGCC gasification will continue for some time to be classified as a developing stage technology [Trillium 2002, p.24].

More information: http://future-energy.np.def6.com/Silvagas.asp

Many companies in Canada are developing new gasifier concepts. For example, Enerkem in Québec offers a gasification concept. The company claims their BIOSYN technology can process a variety of feedstocks, including sorted municipal solid waste, urban wood, agricultural residues, forest thinnings, sludges, as well as wastes from various industries, such as sawdust and pulp mill residues, spent oils, plastic-rich residues and rubber-containing wastes. Other companies like Nexterra, Modern Organics, Home Tech Farms, Gasifier, Vadir and SunGas are also developing small-scale gasifiers to convert biomass wastes into heat and power at the local scale. Some of these gasifier companies intend to produce syngas for engine applications and others perform an immediate combustion of gases to produce heat.

More information: http://www.enerkem.com/

d) In coal **co-firing**, a portion of the coal used in a coal-fired plant is substituted with 5% to 15% biomass. This level of biomass can typically be tolerated by a coal-fired system without significant effects on the combustion process. The Oak Ridge National Laboratory, a DOE research and development laboratory, estimates that this biomass can be added at a cost less than US$.005/kWh. Co-firing biomass is less expensive compared to dedicated biomass systems because no new or additional technology is needed to incorporate the biomass with the coal. Many large coal-fired boilers could benefit from co-firing by reducing their net greenhouse gas emissions (displacing fossil coal with green biomass) and/or increasing power production beyond current regulation limits. In addition, biomass acts as a reburning fuel and decreases NOx emissions by up to 40 to 60%. With a lower sulphur content than coal, co-fired biomass also decreases sulphur emissions. Two Florida coal-powered boilers use biomass for co-firing. A pilot plantation with an area of 130 acres growing eucalyptus and cottonwood trees, which can be harvested every one to three years, has produced the target 55 green tons/acre of energy crop. The premium for this energy crop met the test target of $1.76/million Btu compared to the current cost for coal of $1.50 to $1.75/million Btu. More than 10 demonstration projects in the U.S. have shown that NOx emissions can be considerably reduced by co-firing biomass in the reburning zone. NREL estimates that co-firing biomass in U.S. coal plants will generate 20 to 30 GW by 2020 [FPT 1998].

1.3.3 Cogeneration and Combined Heat & Power (CHP) with Biomass

Cogeneration refers to the use of biomass-derived energy for multiple purposes. Probably the best example is in pulp and paper mills where biomass boilers produce a high pressure steam. The pulping and papermaking processes require this steam at a much lower pressure in a near saturated state. Reducing the high pressure boiler steam to process levels can be done through a turbine/generator. Thus the original fuel “co-generates” both electricity and process steam. In many mills excess steam is produced and expanded through condensing turbines to maximize power production and allow more efficient control in meeting process steam needs. These applications are viewed more in terms of "extra benefit" from power generation than overall efficiency since the primary process steam needs must be satisfied independently of efficiency considerations.

Combined Heat and Power (CHP) is a specific implementation of cogeneration. It is recognized that many opportunities exist where both power generation and thermal energy is required. A single system used to meet both needs can show very high overall conversion efficiency. It should be recognized that electrical power generation is reduced to allow the cycle to reject heat at a higher temperature for thermal use. The loss of electrical conversion efficiency is significant but is accepted to create an increased overall efficiency of biomass energy utilization.

The first limitation of CHP systems is the amount of heat that can be recovered from the original biomass energy. In biomass combustion systems this is directly related to the outlet temperature of the flue gas. The second limitation is the energy loss associated with the conversion cycle. All conversion systems have associated parasitic and often unrecoverable heat losses. The final limitation is the form and temperature of the reject heat from the conversion cycle. Hot gases are the most inconvenient form of heat and have few direct economical uses. Saturated steam is a very useful form of thermal energy if it has sufficient temperature. However, steam must be used in close proximity to where it is generated as it cannot be "pumped". Hot liquid is a useful form of heat if it has a sufficient supply temperature and a sufficiently high return temperature. The benefit of hot liquid is the ability to pump it distances for district heating purposes.

1.3.4 Conversion to Bio-Oil and Charcoal

Bio-oil is produced by condensing gases produced by pyrolysis. Generally the large, carbon based molecules produced by pyrolysis will condense along with water vapour while lighter hydrocarbon and carbon-oxygen molecules will remain vapour. Furthermore it has been found that large molecules will tend to break down to smaller non-condensable molecules if they are held at high temperature. Recognizing this, several groups have developed "fast pyrolysis" systems in which the pyrolysis gases are cooled and condensed quickly (<2 seconds) soon after being formed. Fast pyrolysis will maximize the yield of bio-oil and change the constituent molecules as compared to slow pyrolysis. Yields of bio-oil will vary with different technology systems, operating conditions and fuel feeds. Reviewing four alternate commercial systems shows similar production outputs for fast pyrolysis processes and a different output profile for slow pyrolysis.

Significant parasitic heat and power is consumed to dry and size the fuel in preparation for pyrolysis, as bio-oil production requires a fuel feed of very low moisture content. Any moisture in the fuel feed is captured as water content in the resulting bio-oil. Excessive water in bio-oil will reduce the heat content of the bio-oil, alter the combustion properties and cause separation into light and heavy phases. Bio-oil processes require a feed of <10% moisture, which is significantly below the moisture content of almost all available forest biomass. Even with this low level of moisture in the feed, the conversion process results in approximately 25% moisture content in the bio-oil. Most of this is due to the same amount of water being included in a lesser total volume of product. Some is due to the formation of water molecules from hydrogen and oxygen present molecularly within the original fuel.

The chemical mixture of bio-oil is relatively complex. There has been discussion concerning the extraction of useful, high-value chemicals from this mixture. However, with the exception of "wood smoke" flavouring chemicals and some glue precursors, there has been little progress made on finding useful applications. Both of these products appear to have limited market potential. At this time it appears that heat energy conversion is the most promising application of bio-oil.

As a liquid with reasonably dense energy content, bio-oil appears to be suited as a transport fuel. On a volumetric basis, bio-oil has 55% of the volumetric energy content of diesel oil (40% on a weight basis). Contrary to diesel fuel, bio-oil does not produce SOx emissions during combustion and produces approximately half the NOx emissions in comparison with fossil fuels. However, combustion concerns include its acidic nature, particulate content and flame stability. The lower heat energy content requires larger equipment, especially for IC engines, for the same power output as fossil fuelled machines. Larger engines are less efficient and more expensive to purchase, operate and maintain. The high water content of bio-oil means the energy output is reduced as more energy is consumed in evaporation.

The unburned char from the process may have commercial applications. Non-condensable gases are recycled and produce approximately 75% of the energy required for the pyrolysis process.

More information: www.dynamotive.com - similar systems: www.ensyn.com; www.renewableoil.com

1.3.5 Ethanol and Lignin

Ethanol is produced by the fermentation of biomass, using bacteria, yeasts and enzymes. The carbohydrates of biomass are broken down and alcohol is formed. This process has been applied mainly to crops like corn that are rich in starch. The Iogen process is an enzymatic hydrolysis process for converting lignocellulosics (plant matter) to ethanol. The unique aspects of the technology include the steam explosion pre-treatment that was pioneered by Iogen, and the proprietary enzymes developed, manufactured, and marketed by Iogen. The block diagram for the Iogen process is shown in Figure 1.5.

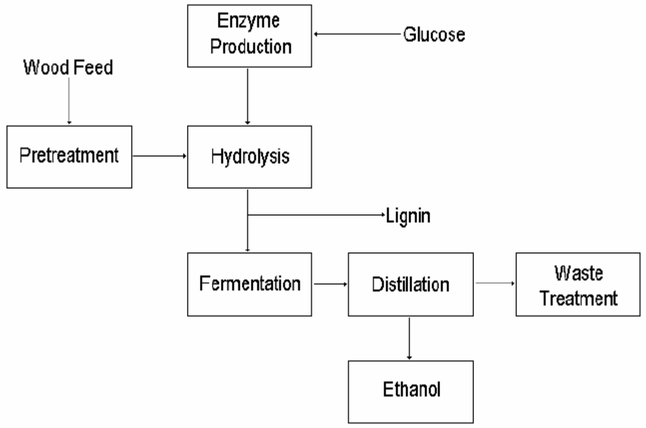


Figure 1.5 Iogen Enzymatic Process

The Iogen process is currently suitable for agricultural residues such as wheat straw and corn stover. Hardwood residues are also a suitable feedstock. A single step pre-treatment process for agricultural and hardwood residues can produce a material that can be efficiently hydrolyzed by the enzymes. However, the pre-treatment process is not as effective for separating the lignin of softwoods – a very interesting feedstock in British Columbia - from the cellulosic material and thus the enzymes are not as effective. Much higher levels of enzymes are required and the production and capital costs are also much higher. The development of a pre-treatment process that produces both cellulose and hemi-cellulose that could be enzymatically hydrolyzed economically would allow the remainder of the Iogen process to be commercialized for softwoods.

The process will produce lignin as a co-product. The relatively mild pre-treatment process employed should provide a lignin that can be utilized as a starting material in other processes. If the lignin cannot be used in commercial applications, the alternative is to utilize lignin as a fuel to produce steam or electricity. This use yields a very low price for the lignin, no more than 5 cents per kilogram. Iogen Corp. has built a $40-million pilot plant, and expects the technology to be fully matured with the first commercial facility to be operational in 2007.

Lignol Innovations Corp., together with BC Research, is commercializing a proven proprietary technology for refining many forms of woody biomass into their constituent chemical components. Their initial focus is on the production of ethanol and natural lignin from wood residues, such as sawdust & shavings. Lignol use a solvent (ethanol) to dissolve the lignin and then use an enzymatic process to convert the cellulose and hemi-cellulose into sugars. The key advantage of the Lignol process is that the lignin from this process remains natural and is not affected by the process. It can therefore be more readily used a substitute for industrial glues, such as phenol formaldehyde, than the lignin from the Iogen process. If a stable market for such products can be developed, this may improve overall process economics.

By a different process, ethanol can also be made from biomass through gasification. Figure I-1 in the Introduction identifies this process. Some argue this process bears the potential to be more cost-effective than the enzymatic routes discussed above [Klass 1998].

More information: www.iogen.ca www.lignol-innovations.com

Other concepts: BC International Corporation; Arkenol (Southern California); ACOS (Acid Catalyzed Organosolv Saccharification process; Dr. Laszlo Paszner of the Faculty of Forestry at UBC); a wood gasification system is offered by Brightstar Synfuels Company of Texas and a biological syngas to ethanol process was developed by Bioengineering Resources, Inc. (BRI) of Arkansas.

Fermentation routes to fuel ethanol have been used in most research studies and commercial developments to date. However, an alternative approach is gasification: the biomass material is gasified to a mixture of carbon monoxide and hydrogen. In the presence of the appropriate metallic catalyst, this mixture is converted to ethanol. This approach can utilize biomass materials such as bark, which are not suitable for ethanol production by fermentation methods. In Canada, this route has been explored by Ethopower (Kelowna, BC), in conjunction with the University of British Columbia, and by the Saskatchewan Research Council [CARC 2003, p.54f.]. Ethopower no longer exists, but the gasification concept is still being pursued by Nexterra in Vancouver, as well as Draco Energy Systems, in conjunction with Hybrid Fuels Inc. (geared towards animal waste). The technology is still at a conceptual stage, with a suitable catalyst being the main challenge for ethanol production.

More information: http://www.hybridfuels.com/html/080903.html

1.3.6 Methanol

Most of the methanol produced in the United States today is made from natural gas. But methanol can also be produced from other feedstocks including coal, biomass, and residual oil. Biomass for the production of methanol includes crop residues, forage crops (grasses), forest residues, short-rotation tree crops, and more than half of the municipal solid waste and industrial waste streams. An important opportunity for Canada seems to exist in terms of the large amounts of black liquor produced in the pulp & &paper sector, which could also be used to make methanol. From presently 24 million tonnes of black liquor generated annually in Canada methanol could be produced in the same order of magnitude as current ethanol production in Canada (see Table 5.2) [CARC 2003, p.55].

A thermochemical conversion process can be used to produce fuels like methanol, ETBE and MTBE. The first conversion step to produce Methanol from biomass is gasification. The biomass is subjected to elevated temperatures and pressures (in some processes) to form a synthesis gas (syngas). The syngas, composed mainly of carbon monoxide and hydrogen, is conditioned to remove impurities such as tars and methane, and to adjust the hydrogen to carbon monoxide ratio to 2:1. In a second step, the syngas reacts over a catalyst at elevated temperatures and pressures to form methanol.

Methanol is a liquid transportation fuel that can be produced from fossil or renewable domestic resources. In the United States, it is most commonly used as a chemical feedstock, extractant, or solvent, and as a feedstock for producing methyl tertiary butyl ether (MTBE), an octane-enhancing gasoline additive. It can also be used in pure form as a gasoline substitute, or in gasoline blends such as M85 (85% methanol and 15% gasoline). Pure methanol can be used in existing vehicles; however, engine modifications are required to facilitate cold starts and to replace materials that can be corroded by methanol and M85. Methanol has a higher octane rating than gasoline, which helps reduce engine “knock.” It can also deliver greater fuel efficiency if the engine’s compression ratio is properly adjusted [NREL 1995]. Because methanol carries more hydrogen by weight than liquefied hydrogen, it is also seen as a possible synthetic fuel for fuel cells.

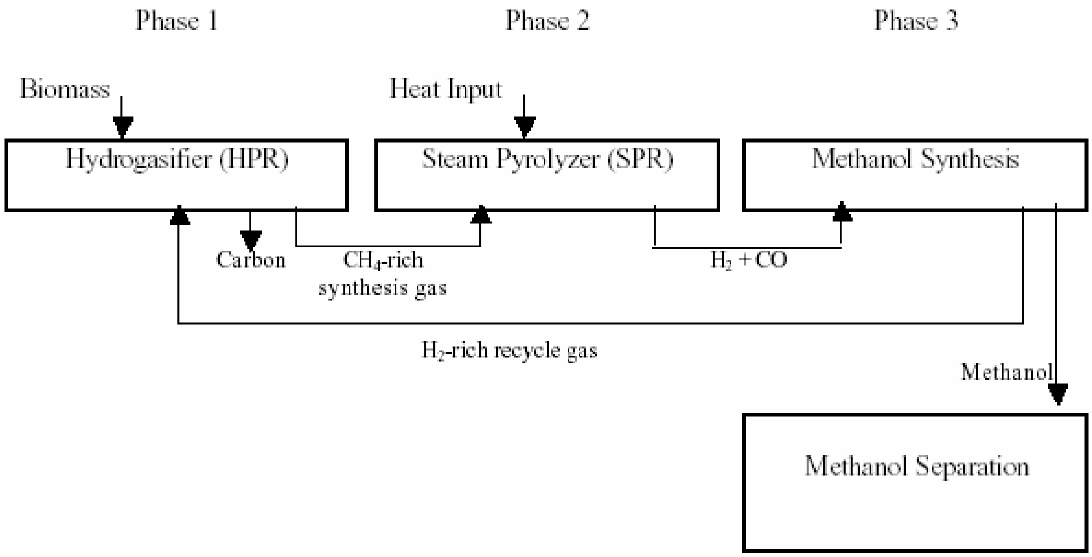


Figure 1.6 Hynol Process Flow [EPA 2000]

One of the concepts considered for the production of methanol is the Hynol Process. It originated at the Department of Energy’s Brookhaven National Laboratory as a method for increasing the yield of fuel from conversion of biomass. Originally conceived to operate with a coal feedstock, the process has been adapted to biomass. The process produces methanol with a carbon conversion efficiency of 87%. Unconverted biomass is withdrawn from the reactor with ash in the form of char, which can be used as fuel or sequestered.

The Hynol Process involves three phases: (1) Reaction of biomass in a hydrogasifier, also referred to as a hydropyrolizer (HPR); (2) Steam pyrolization of the resulting gas, which produces a synthesis gas; and (3) Methanol synthesis, which leaves a recycle gas that can be returned to the HPR and waste heat that can be returned to the steam pyrolizer.

1.3.7 Hydrogen

In addition to the direct production of hydrogen from gaseous hydrocarbon feedstocks, such as gasified coal or natural gas, hydrogen can be produced from liquid energy carriers such as ethanol and methanol as well as from ammonia. Methanol reforming ($CH_3OH + H_2O \leftrightarrow CO_2 + 3H_2$) is practised in Japan and to a small degree in Europe where there are no economical sources of syngas. Currently, there are about a dozen companies that are involved in building plants to produce hydrogen from methanol or ammonia. [NREL 2003, p.19]

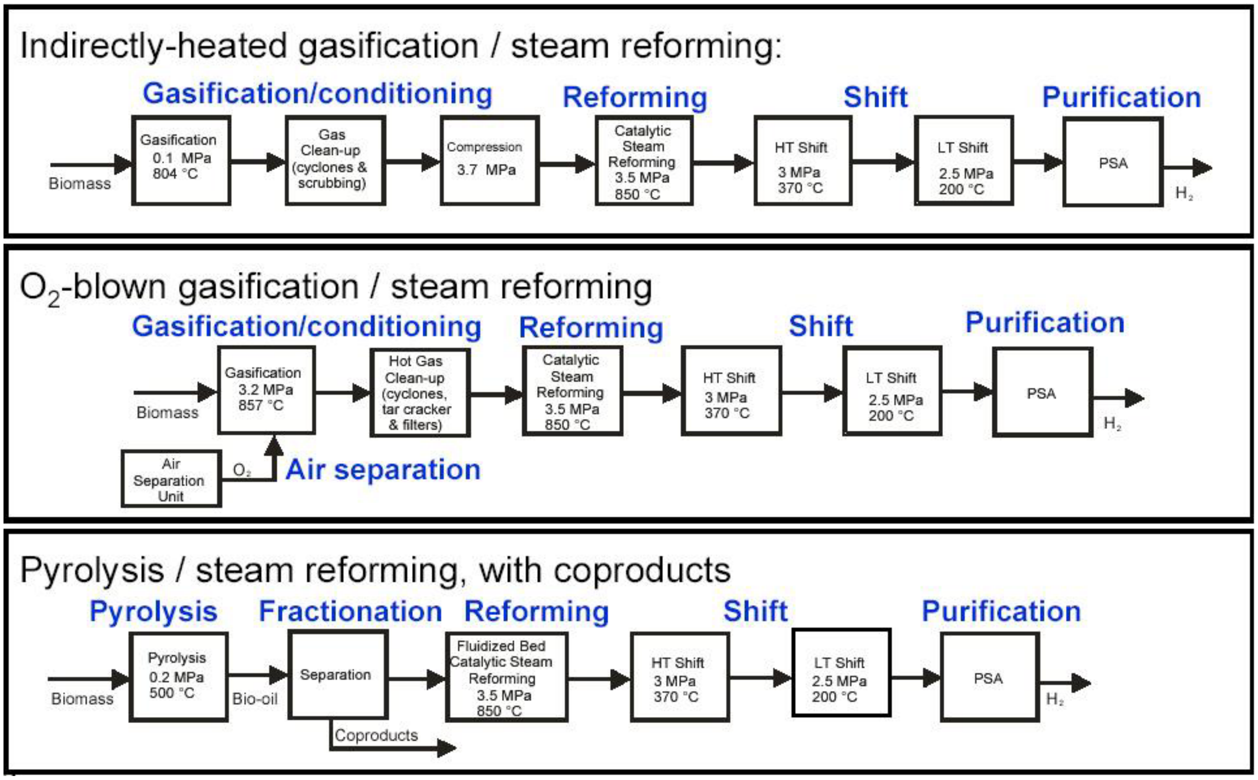


Figure 1.7 Flow Diagrams for Biomass-to-Hydrogen Pathways [NREL und.]

The production of hydrogen from biomass follows the same general process as that of coal to hydrogen. The biomass is first gasified, the gas is treated to increase the hydrogen content and then the hydrogen is purified. The syngas produced from biomass gasification can contain a number of contaminants including particulates, tars, sulphur, and chlorine compounds. The syngas may also contain significant quantities of methane, which must be reformed to more syngas, depending on the composition of the feedstock and the type of gasifier used. A report prepared for the US Department of Energy identified bubbling fluid bed gasifiers as the technology of choice to make hydrogen from biomass [E2S 2002]. Apart from gasification, pyrolysis is also being explored as a pathway to hydrogen from biomass (see Figure 1.7).

Merchant hydrogen prices vary considerably depending on the volume and form of delivery. For large volume users, pipeline is the most economical followed by bulk liquid hydrogen delivery. For gaseous hydrogen produced from natural gas at a large-scale, central production facility at a pressure of around 400 psi, the plant gate price is about $5-$8/GJ. In general, contract prices for delivered hydrogen are not publicly available and they vary a great deal depending on the type of delivery, quantity required, and delivery distance. SRI International, a California research institute, states that liquid hydrogen list prices have been around $45/GJ, but that the average transaction prices are considerably below this. A typical price range for large-volume, bulk liquid consumers is $18-$24/GJ. [NREL 2003, p.23]

1.3.8 Composting

Composting is an aerobic treatment of biomass. Whereas CO_2 is produced through partial decomposition of the biomass during the process, no methane is produced, as would ensue if the biomass was landfilled and allowed to decompose under anaerobic conditions. The resulting compost can be rich in nutrients and displace artificial fertilizer, which in turn leads to emission reductions from the fertilizer production process and its bacterial decomposition in the field, which results in N_2O emissions.

Composting wood residues poses two challenges: 1) the particle size must be reduced if too large (1/8 inch diameter) in order for the micro-organisms to access it as a substrate, and 2) a nitrogen source must be added. Conversely, the best potential use for woody debris is to mix it with other residues. For example, wood can be used as a bulking agent for nitrogen-rich and water-rich feedstocks, such as manure, biosolids, food waste, or grass. The potentially large particle size can help increase pile porosity and aeration.

Most wood residues, apart from sawdust and wood shavings, have to be shredded in order to facilitate composting. A tub grinder is most often used for shredding or grinding woody materials destined for composting. A tub grinder is a hammer mill with a round rotating hopper (tub) which feeds the materials into a hammer chamber. The composting process takes about six weeks. [CERWA 1998]

Chapter 2 Agricultural Residues

2.1 Crop Production Residues

2.1.1 Availability in Canada

Agricultural crops can be classified as [BIOCAP 2003, p.19]

a) starch crops (cereal grains: wheat, barley, oats, rye; and grain corn): represent 54% of total dry tonnage produced in Canada
b) Seed oil crops (canola, soy beans, flaxseed): represent 9% of dry tonnage produced in Canada
c) Forage crops (tame hay and fodder corn): represent 36% of dry tonnage in Canada.

Forage crops are harvested nearly intact, and hence are considered to have a harvest index of 100%, meaning that only unused portions of it are available for other uses (estimated to be about 5%). In contrast, reported harvests of cereal grains and seed crops represent only about 50% of the total plant mass. The difference between the whole plant yield and the crop yield is considered to be crop residue, consisting of straw and chaff of cereal crops, stover of corn and unused fodder crops [BIOCAP 2003, p.20].

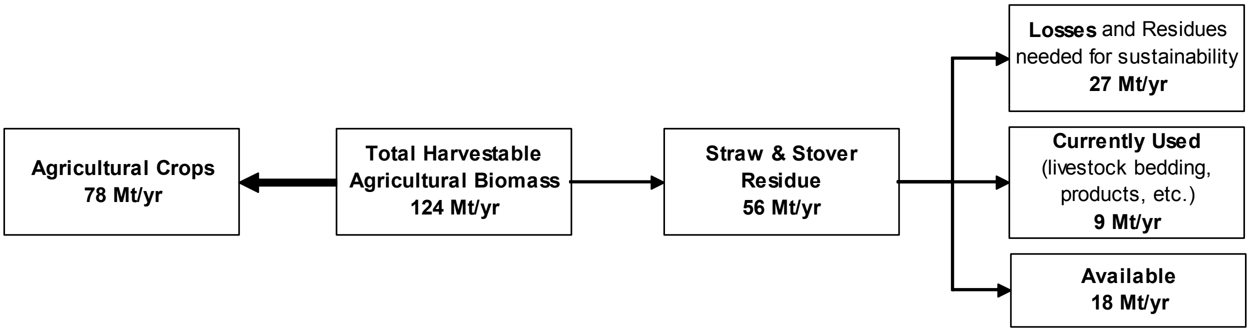


Figure 2.1 Agricultural Biomass from Field Crops in Canada

Figure 2.1 shows the mass flows of agricultural biomass for Canada. About 45% of agricultural biomass is available as residue and thus potentially available for energy and other uses. However, to warrant soil fertility and the sustainability of agricultural operations, a minimum of 20% of crop residues should be left on-site [STUMBORG 1996]. In addition, not all remaining residues can be harvested due to technical limitations (e.g. weather). Discounting amounts that are already being used for other purposes, such as straw needed as livestock bedding, insulation, mulching, etc. leaves about 15% of agricultural biomass available for the purposes discussed here.

2.1.2 Geographical Distribution

Table 2.1 shows the regional availability of agricultural biomass throughout Canada. The totals based on the REAP 2002(1) report are somewhat higher than those given in BIOCAP 2003, which confirms them as fairly conservative. Figure 2.2 shows the same facts graphically, agricultural activity is concentrated in the Prairies, mainly in Eastern Alberta, Saskatchewan and Western Manitoba, with additional, but smaller, activity in Northwest Alberta, Southern Ontario and in Québec, along the St. Laurence River.

Table 2.1 Availability of Agricultural Residues in Canada, in tonnes x 1,000 [based on REAP 2002(1), Table 1]

	BC	AB	SK	MB	ON	QC	Atlantic	Total
Corn Stover	-	-	-	110	1,900	1,115	6	3,131
Straw*	23	6,218	9,246	2,940	615	310	125	19,477
Hay	-	~220	~220	~220	220	210	52	482
Canola straw	11	627	833	463	14	-	-	1,948
TOTAL	**35**	**6,845**	**10,079**	**3,513**	**2,749**	**1,635**	**183**	**25,039**

Data for western provinces extrapolated from Ontario data, based on annual yield data as given in [PP 2002, Table C2] and [CCoC 2003] for canola. REAP 2002(1) assumes that 20% of straw, 50% of corn stover and 29% of canola residues remain on the field to maintain sustainability. Of the sustainably recoverable residues, a large proportion is already allocated to other uses, such as straw for livestock bedding. 35% of the recoverable straw, 100% of corn stover, 5% of hay and 100% of canola is left for other uses, such as energy production. These are the numbers given in this table.

* The long-term total of straw available in ON was estimated to be about 1.4 million tonnes per year, after harvesting and storage losses. How much of this would be available for energy purposes depends on alternative uses, such as bedding, it price (to be $50 or less a tonne to be economically viable), and how much can actually be collected from farms. REAP Canada estimated that only 20% could be collected, which would result in a total of only 230,000 tonnes, as opposed to the above 615,000 tonnes [AAFC 2004].

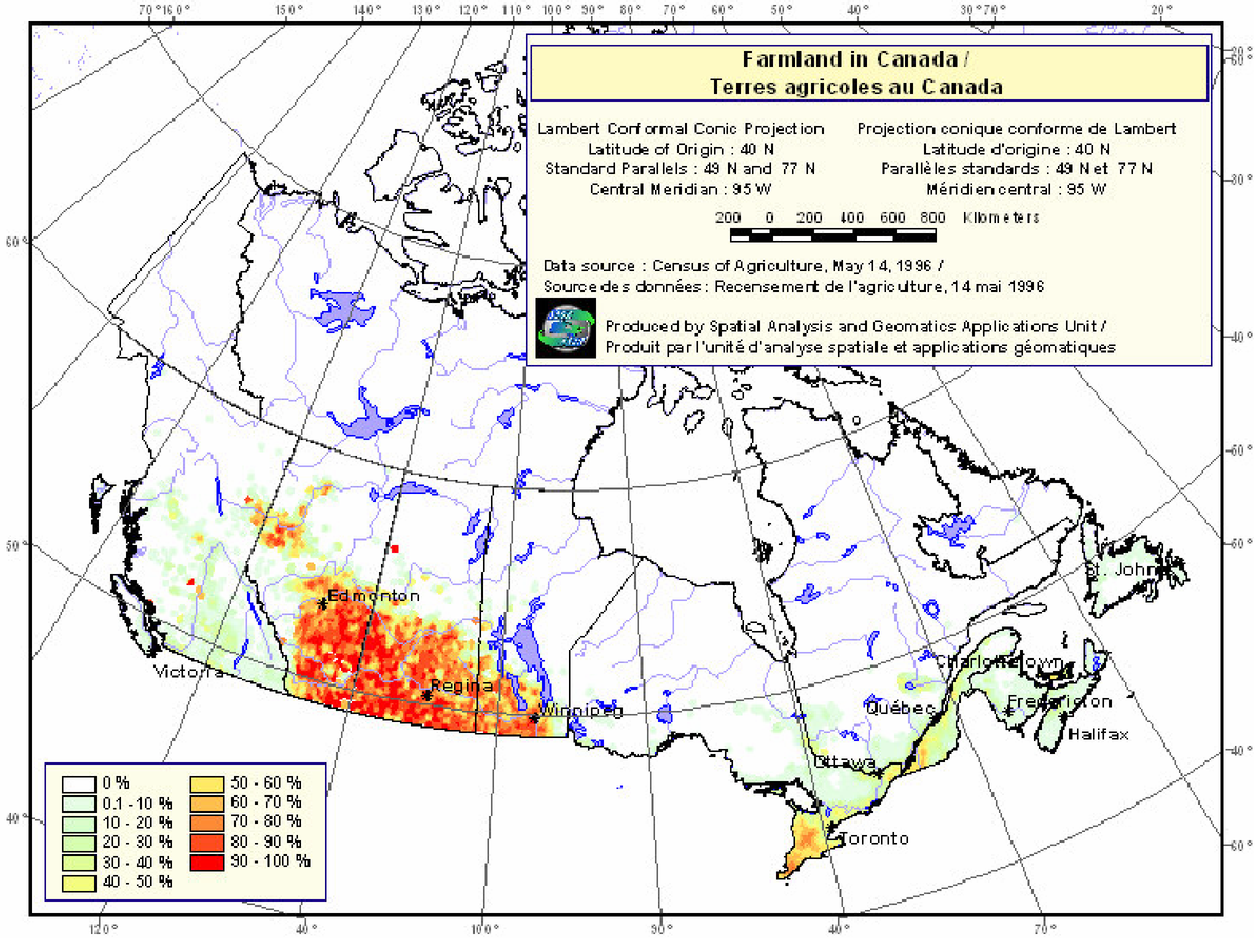


Figure 2.2 Concentration of Farmland in Canada [Statcan 2001, App. D]

2.1.3 Possible Uses for Field Crop Residues

Current Usage

In Eastern Canada, approximately 65% of straw residues supply existing markets, but the distribution of usage is very different in the Western provinces. In Manitoba for example, 93.5% of barley straw is committed to livestock bedding, but only 6.7% of wheat straw is used for livestock bedding. A further 6% of the straw is used for the production of strawboard in the Elie plant just west of Winnipeg. By comparison, there is virtually no demand for the 600,000 tonnes of oat straw produced per year. Only 25.8% of the total 4.7 million tonnes of straw available in Manitoba supplies dedicated usage, and burning in the field eliminates a considerable fraction. [BIOCAP 2003, p.21]

Ethanol, Distiller's Grain, and CO_2

Conventional ethanol production involves fermenting the starch-derived sugar from grain like wheat and corn. Research is now being conducted to produce ethanol from products that are now considered waste, like the sludge from pulp and paper production, waste paper, grass, straw (Iogen Process, see chapter 1.3.4), leaves and other solid landfill wastes that contain cellulose, or plant fibres.

Ethanol is a high-octane, water-free alcohol that is usually produced from renewable resources such as corn, wheat, straw and other biomass. Only the starch component of the grain is converted to ethanol leaving the fibre, protein, minerals, carbon dioxide (CO_2) and vitamins. Traditionally, grain-based plants produce two products in addition to ethanol – distiller's grain, either wet or dry, and CO_2. Wheat distiller's grain is high-protein, palatable by-pass protein, and high fibre that improves gut health in pigs and poultry. Sale of distillers' grain and CO_2 in addition to ethanol can result in production plant savings of 4 cents a litre. [AGRI 2003]

Total ethanol production in Canada is about 238 million litres a year, with most being used as fuel and the rest going to industrial uses. Industrial ethanol is used as a solvent in products such as toiletries, cosmetics and medications for external use. In Saskatchewan, the PoundMaker ethanol plant at Lanigan has a production capacity of about 13 million litres per year. This plant is integrated with a feedlot. Beef cattle are fed the distiller's grain, which is a by-product of the ethanol production process. Ethanol production in the United States is considerably higher - about 6 billion litres are produced each year.

Ethanol made from wheat is created through the process of fermentation. Fermentation is a series of biochemical reactions, using micro-organisms like yeast, which yields ethanol. Several different types of wheat can be used, including durum, hard red spring and hard red winter wheat. The process begins with cleaning and milling of the whole wheat kernel. Then a special enzyme (a naturally occurring substance), which can withstand high temperatures, is added, and the wheat is cooked at 95ºC. This process of enzyme treatment and cooking breaks down the starch in the wheat. Then the mash is cooled to 30ºC, the temperature at which fermentation can take place. Another enzyme, called amyloglucosidase, is added, along with yeast (Saccharomyces cerevisiae).

The enzyme and the yeast work together to ferment the wheat mash. The enzyme slowly releases glucose, a sugar. The glucose is immediately used by the yeast, and the process of fermentation occurs. The fermentation is usually complete in 56 hours. Ethanol is recovered through distillation. Water is removed from the ethanol, either through filtration or treatment with a chemical. The mash that is left over from the fermentation process can be fed to beef cattle as distiller's grain. Use of the by-product in this way reduces the need for cattle feed production, reduces the cost of ethanol production and helps produce a valuable consumer product. [Agwest 1998]

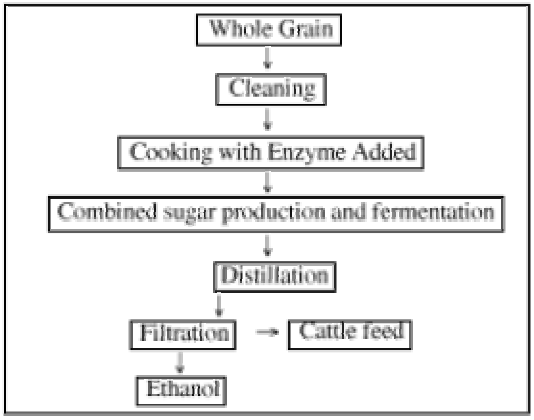


Figure 2.3 **Production of Ethanol from Grain** [Agwest 1998]

Many ethanol production technologies are currently experimental and have not yet been demonstrated on a large scale. This would include the production and collection of some of the feedstocks as well as the production of ethanol from lignocellulosics, like wood [Levelton 2000].

Biomass Fractionation into Cellulose, Hemicellulose and Lignin

PureVision in Lupton, Colorado, pursues the separation of the major components of biomass, converting these into cellulose, hemicellulose and lignin. The feedstock can be agricultural crop residues (wheat straw, corn stover and sugarcane bagasse), small diameter trees and forest thinnings, energy crops (switchgrass, hybrid poplar, willow, etc.) or other wastes, including organics and paper from municipal solid waste and paper mill and municipal sewage sludges. The process includes three steps (see Figure 2.4):

1. Pre-treatment;
2. Production of a purified cellulose product and separated wash streams containing the lignin and hemicellulose from biomass; and
3. Preparation of the purified cellulose fraction for enzymatic conversion into sugar, which can then be converted to ethanol.

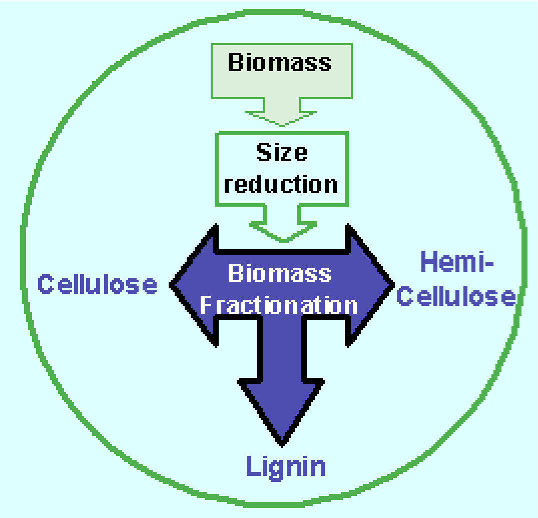


Figure 2.4 **PureVision Fractionation Process** [PV 2003]

The PureVision technology uses enzymes to convert diverse biomass feedstocks into sugar streams, a process known as enzymatic hydrolysis. Both xylose (a 5-carbon sugar, from hemicellulose) and glucose (a 6-carbon sugar, from cellulose) are produced from renewable biomass in the PureVision process. The technology has been proven at bench-scale and provides a critical process to effectively convert cellulose and hemicellulose into sugars in biorefineries. Once the cellulose, hemicellulose and lignin are separated in the fractionation process, they become feedstocks for producing a wide range of bio-products for many industries, including but not limited to energy, transportation, agri-business, textiles, building products, pharmaceuticals, bio-plastics and paper industries. Table 2.2 provides an overview of the numerous possibilities for use of the three output streams from the fractionation process.

Potential markets for the fibres include substitutions for wood pulp, non wood pulp and synthetically processed cellulose pulp in commercial applications. These pulps are used in all forms of papers as well as a wide range of other materials including dissolving pulps for producing rayon, lyocell and cellulose acetate fibres used in both textile and technical applications, fibre for automotive composites, and building products. The lignin fraction can be combusted in a boiler to produce electricity. Higher value applications could include the use of lignin as an asphalt binder or in construction materials.

Table 2.2 Utilization Options for Output Streams of the PureVision Process [PV 2003]

Output from Process	Primary Market	Products
Cellulose to glucose, then fermented into alcohol	Fuel ethanol for transportation markets	Transportation applications include oxygenates added to gasoline in blends of 10%, 20%, and 85%, aeroplane fuel and fuel cells.
Cellulose converted into glucose	Glucose processed into speciality chemicals for food and health care industries.	Fermentation sugars, gluconic acid, glucose, mannitol, sorbitol.
Hemicellulose	Fermentation sugars and/or conversion to methane in a bio-reactor to feed co-generation	Fermentation sugars for producing ethanol, xylose, xylitol, furfural, furfuryl alcohol, furan, bioplastics, etc.
		Energy
Purified cellulose fibres	Pulp for paper making and fibre filler in the building/ construction and automotive industries.	Bio-based cellulose derivatives include fibre and pulps for paper and building products, rayon, cellophane and cellophane flake.(delete colon here)
Lignin	Fuel for co-generation (energy)	Combustible fuel
		Future uses include making adhesives

More information: www.purevisiontechnology.com; see also: http://www.oit.doe.gov/agriculture/factsheets/fractionation.pdf

Manufacture of Composite Board

Dow BioProducts Ltd. produces “Wood Stalk” fibreboards from agricultural residues in its factory in Elie, MB. The fiberboard is made from harvested wheat straw fibre and a formaldehyde-free polyurethane resin. Before being offered the alternative of selling the straw, many Manitoba farmers were burning off the straw in the field.

Other products, such as particleboard or MDF, are often made from both waste wood and whole tree resources. Another traditional material, Lauan plywood, is commonly made from trees harvested from tropical rainforests.

Wood Stalk is used in the same applications as traditional fibreboards, and have some superior features, such as lighter weight, moisture resistance, and reduced tool wear.

More information: http://www.cargilldow.com/corporate/index.asp

2.2 Livestock Residues

2.2.1 Availability in Canada

Livestock manure from dairy, beef, poultry and swine is a readily available source of waste biomass in Canada. It is an under utilized resource, with most manure currently landspread with little or no pre-treatment. The Alberta Research Council estimated that 780 MW of electricity and 1040 MW of thermal energy could be produced in Canada from the wastes of the livestock industry [ARC 2003(1), p.28]. The utilization of manure for energy purposes would also alleviate other problems associated with direct application of manure to soils including bacterial contamination of surface and groundwater supplies, over-enrichment of soils with nitrogen or phosphorus and nuisance odours. In addition, manure produces methane gas and nitrous oxide, two potent greenhouse gases.

Not all livestock manure can be used for energy purposes. For example, manure from field grazed animals is considered lost due to difficulties in collection (but has a useful purpose to fertilise the soil). The numbers in Figure 2.5 represent a conservative Canadian average, but actual recovery rates could be much higher on individual farms.

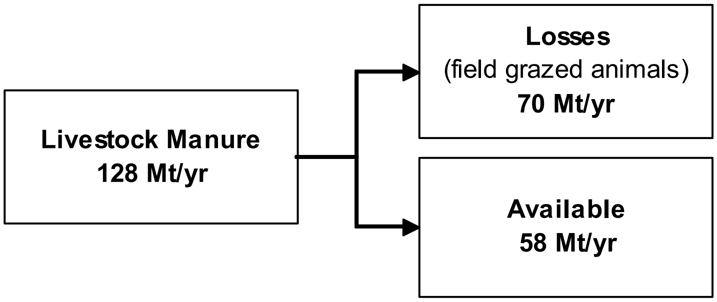


Figure 2.5 Availability of Livestock Manure in Canada

2.2.2 Geographical Distribution

Table 2.3 shows the regional availability of livestock manure throughout Canada. The totals based on the REAP 2002(1) report (close to 80 million tonnes a year) are somewhat higher than those given in BIOCAP 2003 (58 million tonnes a year), which confirms the latter as fairly conservative.

Figure 2.6 provides a graphical view of livestock concentrations in Canada. Although overall livestock numbers are also highest in the Prairies, the highest local livestock concentrations can actually be found in British Columbia (various locations) and along the St Lawrence River in Québec, as well as in Southern Ontario. This means that transport distances to central facilities may be higher in the Prairies, which could influence decisions to utilize these resources for energy production purposes.

Table 2.3 Availability of Livestock Manure in Canada, in tonnes x 1,000 [based on REAP 2002(1), Table 1]

	BC	AB	SK	MB	ON	QC	Atlantic	Total
Dairy	1,913	2,167	641	1,106	8,205	8,636	1,367	24,035
Beef	2,062	14,022	8,810	4,199	3,037	1,236	462	33,828
Swine	199	2,694	1,593	3,154	4,338	4,991	499	17,468
Poultry	475	288	98	137	939	684	210	2,830
Turkey	79	63	29	48	307	168	46	739
Sheep	3	9	5	3	11	10	2	43
TOTAL	**4,730**	**19,243**	**11,177**	**8,646**	**16,837**	**15,725**	**2,586**	**78,943**

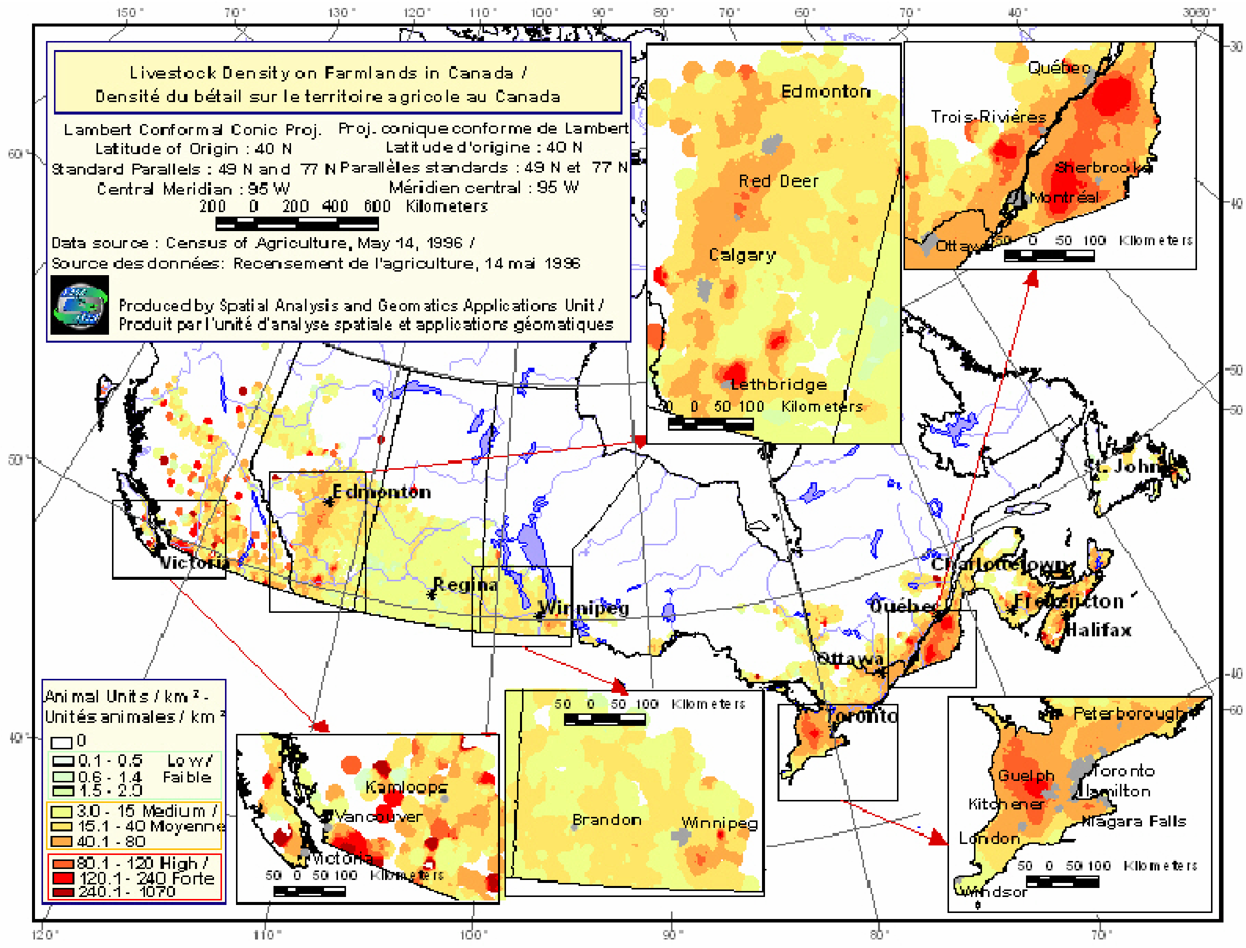


Figure 2.6 Livestock Density in Canada (1996) [Statcan 2001, p.13]

2.2.3 Manure Utilization Options

Power, Heat and Fertilizer (anaerobic digestion)

The treatment of manure in anaerobic digestion systems, with simultaneous biogas production, could meet typical household electrical demands of an average dairy farm, while also producing a nutrient-rich fertilizer and providing a renewable energy resource.

In a digester, anaerobic bacteria break down or "digest" organic material in the absence of oxygen and produce '"biogas" as a waste product. Biogas produced in anaerobic digesters consists of methane (50%-80%), carbon dioxide (20%-50%), and trace levels of other gases such as hydrogen, carbon monoxide, nitrogen, oxygen, and hydrogen sulphide.

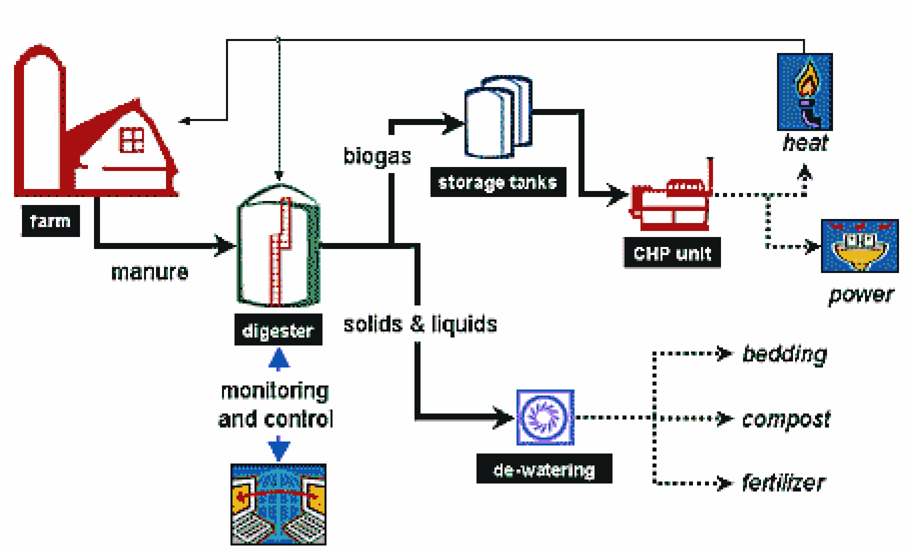


Figure 2.7 Anaerobic Digester Facility [Microgy 2003]

There are two basic types of digesters: batch and continuous. Batch-type digesters are the simplest to build. Their operation consists of loading the digester with organic materials and allowing it to digest. The retention time depends on temperature and other factors. Once the digestion is complete, the effluent is removed and the process is repeated.

In a continuous digester, organic material is constantly or regularly fed into the digester. The material moves through the digester either mechanically or by the force of the new feed pushing out digested material. Unlike batch-type digesters, continuous digesters produce biogas without the interruption of loading material and unloading effluent. They may be better suited for large-scale operations and have been commercially successful in Europe, where they were developed.

To optimize the digestion process parameters in the digester need to be controlled: the digester must be kept at a consistent temperature, as rapid changes will upset bacterial activity; digester pH and rapid changes in temperature can upset bacterial activity in the digester. In Canada, digestion vessels require some level of insulation and/or heating. The trade-offs in maintaining optimum digester temperatures to maximize gas production while minimizing expenses are somewhat complex. Studies on digesters in the north-central areas of the country indicate that maximum net biogas production can occur in digesters maintained at temperatures as low as 72°F (22.2°C).

Biogas can be used for heating and to operate an internal combustion engine or microturbine for electric power. For engine applications, it may be advisable to scrub out hydrogen sulphide (a corrosive and toxic gas). Very large-scale systems/producers could sell the gas to natural gas companies, but this may require scrubbing out the carbon dioxide. More frequently, the electricity generated from biogas is sold into the public power grid. In Brooklyn, New York, fuel cells are being used to convert digester gas into electricity: the New York Power Authority has installed eight 200 kW fuel cells that will use digester gas from local biosolids treatment plants as the feedstock to produce electricity.

The material drawn from the digester is called sludge, or effluent. It is rich in nutrients (ammonia, phosphorus, potassium, and more than a dozen trace elements) and is an excellent soil conditioner. It can also be used as a livestock feed additive when dried. Any toxic compounds (pesticides, etc.) that are in the digester feedstock material may become concentrated in the effluent. Therefore, it is important to test the effluent before using it on a large scale. This is important for low temperature digesters, which may not be as effective in killing all the pathogens.

The availability of inexpensive fossil fuels has limited the use of digesters solely for biogas production. However, the waste treatment and odour reduction benefits of controlled anaerobic digestion are receiving increasing interest, especially for large-scale livestock operations such as dairies, feedlots, and slaughterhouses. Where costs are high for sewage, agricultural, or animal waste disposal, and the effluent has economic value, anaerobic digestion and biogas production can reduce overall operating costs. Biogas production for generating cost effective electricity requires manure from more than 150 cows.

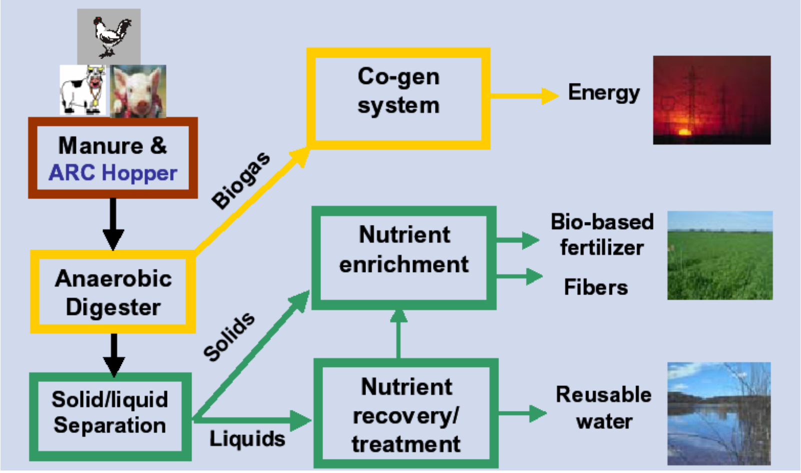


Figure 2.8 IMUS Digester Concept [ARC 2003(3)]

Highmark Renewables and the Alberta Research Council are working on a digester concept to turn manure into energy, bio-based fertilizers and reusable water. The technology, called Integrated Manure Utilization System (IMUS), will be tested at pilot scale in Vegreville, producing one megawatt of electricity from the manure of 7,500 head of cattle. It is scheduled for completion in June 2004. Figure 2.8 shows the process flow of the plant. The temperature of the anaerobic digesters is maintained at 53°C to 55°C in order to create optimal thermophilic bacterial growth. Under these conditions hydraulic retention time is shortened, over 99 per cent of pathogens present in the raw material are destroyed, and biogas production is maximized. The unique nutrient recovery system treats the centrifuged liquid through physical and chemical processes to recover nitrogen and phosphate and produce reusable water. The solid, combined with a nutrient enrichment process, is used to produce solid bio-based fertilizer with balanced nutrients [ARC 2003(2)]. A low temperature plug-flow type digester is being demonstrated in Manitoba (BioTerre).

More information: http://www.arc.ab.ca/whatsnew/newsreleases/imus.asp

Superior Fertilizer (aerobic biotransformation)

Agronix Inc. is a US-based company that has developed an aerobic treatment process for manure and other organic waste. The process is an accelerated composting process, but has the advantage of preserving many of the fertilizer values of the organic material, as opposed to a normal composting process, which will lose much of the nitrogen.

The BCR (Bio-Conversion Reactor) system takes organic residues such as animal manures, sewer sludge and industrial food production waste and converts them through a natural process into fully bio-converted high quality agri-products like organic fertilizer and growth substrates. The conversion is completed in 12-14 days in a scientifically controlled in-vessel system. Through the combination of different kinds of manure, rather than just one (e.g., cow manure, as in the case of decentralised digesters), the composition and value of the end product as a fertilizer is improved. The fertilizer is pelletised and can be applied like inorganic fertilizer. All pathogens are eliminated during the treatment process. As the nutrients are bound up into an organic matrix, they are not leached from the fertilizer and can be absorbed by the plants to 100% - whereas a large percentage of inorganic fertilizer is lost due to leaching and bacterial denitrification.

The plant is a centralised facility and would regroup the organic residues from several farm operations, including livestock manure, slaughterhouse residues, or agricultural residues. The process prevents the loss of nutrients that are lost through leaking or evaporation of ammonia and methane in other processes and produces a more consistent product with defined, stable features, and nutrient contents. The process also transforms any heavy metals present in the biomass into oxides, which radically reduces their toxicity and bioavailability.

The BCIR (Bio-Chemical Integrated Recycling) system is a more specialised version of the BCR process and is in its final commercialization stage of process engineering. The process involves a step-wise sequence of controlled chemical reactions designed to extract whatever end-product(s) are desired from the manure or other biomass. The process has undergone intensive laboratory testing on a wide variety of organic residues. Although it is not an organic process, it has near zero environmental impact, according to Agronix.

It can transform all organic wastes including sewer sludge into more than 1,000 identified chemical commodities. At present, Agronix has successfully extracted 65 chemical commodities for use by industry as polymers, surfactants, lubricants, de-icers, adhesives, alternative fuels, agro-chemicals and fertilizers. Some more recent testing has been focused on the extraction of alternative fuels (ethanol) from various organic wastes and for the paper industry, long-fibre cellulose from bagasse (sugar cane waste).

More information: http://agronixinc.com/GO.html#BCR

Manure and Animal Residues to Bio-Oil

A University of Illinois research team is working on turning pig manure into a form of crude oil that could be refined to heat homes or generate electricity. The thermochemical conversion process uses intense heat and pressure to break down the molecular structure of manure into oil. It's much like the natural process that turns organic matter into oil over centuries, but in the laboratory the process can take as little as a half-hour. The process is currently only working in small batches, but further development could lead to an oil product that could be used to fuel smaller electric or heating plants, or to make plastics, ink, or asphalt.

A similar process is being used at a plant in Carthage, Missouri, where tons of turkey entrails, feathers, fat, and grease from a nearby Butterball turkey plant are converted into a light crude oil.

More information: http://www.age.uiuc.edu/faculty/yhz/index.htm

Chapter 3 Landfill Gas

3.1 Resource Availability

In Canada, most waste disposal on land occurs in well over 10,000 municipally managed or privately owned landfills [Levelton 1991]. The generation of methane from landfills has increased since 1990. However, more landfill gas is now being captured and combusted. Residential, institutional, commercial, industrial, construction and demolition wastes are disposed of in MSW landfills [EC 2003]. About 23.5% of Canada's methane emissions come from landfills. As such, landfills are Canada's fifth largest source of CO_2 equivalent greenhouse gas emissions.

Wood waste landfills are privately owned and operated by forest industries, such as saw mills and pulp and paper mills. These industries use the landfills to dispose of surplus wood residue such as sawdust, wood shavings, bark and sludges. Landfill gas capture increased by almost 40% between 1990 and 1999, but is not practised at wood waste landfills [EC 2003].

Landfill gas, which is composed mainly of methane (55%) and carbon dioxide (45%), is produced by the anaerobic decomposition of organic wastes. The first phase of this process typically begins after waste has been in a landfill for 10 to 50 days. Although the majority of the methane and carbon dioxide is generated within 20 years of landfilling, emissions can continue for 100 years or more.

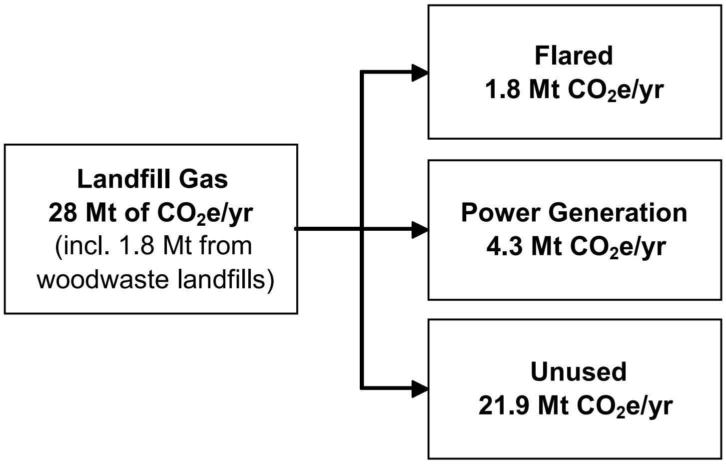


Figure 3.1 Current Usage of Landfill Gas Emissions in Canada [EC 2002]

In Canada, 5% of waste is centrally composted and the balance is landfilled. At the landfill, 7% of the landfill gas is captured and flared and a further 17% is captured and used as an energy source [Woodrising 1999].

3.2 Possible Uses of Landfill Gas

3.2.1 Flaring

24% of landfill gas in Canada is captured, but not all of it is currently being used in generators for power production. In some cases, the low calorific value of the gas or erratic volumetric flow rates does not make energy recovery economical. Pumping of the gases can entrain air, which could lead to spontaneous combustion in the landfill. About 7% of landfill gas is flared, which turns methane (a potent greenhouse gas) into carbon dioxide, reducing greenhouse gas emissions. Carbon dioxide emissions from biomass in landfills are not counted as emissions under the Kyoto Protocol, as it is assumed that they are derived from non-fossil plant matter, which is constantly regrown such that the same amount emitted through landfills is sequestered again.

As methane is is 21 times as potent as carbon dioxide as a greenhouse gas, a large reduction in emissions can be achieved by flaring. Further reductions would be possible if the energy were used to heat buildings or as process heat, or to produce electricity. However, landfill gas capturing systems are expensive and are currently only installed on the larger landfill sites.

3.2.2 Power and CO_2 Production

The anaerobic decomposition of biomass in landfills produces methane, which can be used as an energy source. Wells can be drilled to release the methane from the decaying organic matter. Then pipes from each well carry the gas to a central point where it is filtered and cleaned before burning.

Methane can be used as an energy source in many ways. Most facilities burn it in internal combustion engines to produce electricity. Two new ways that are being explored include the use of microturbines and fuel cells. Microturbines have outputs of 25 to 500 kilowatts. About the size of a refrigerator, they can be used where there are space limitations for power production. Methane can also be used as "fuel" for a fuel cell. Even low BTU gas from landfill sites can be used in a modified microturbine. The fuel is premixed and the use of a catalyst allows it to continue making power from low-quality gas.

A major barrier to widespread commercial utilization of landfill gas (LFG) is reliable, economic removal of contaminants. Ohio company Acrion markets a process to remove contaminants from landfill gas using liquid carbon dioxide obtained directly from LFG [Acrion 2003]. A stream of contaminant-free methane and CO_2 is produced. Contaminants are concentrated in a separate small stream of CO_2 for incineration in the landfill flare. The contaminant-free methane and CO_2 stream can be used as medium Btu fuel gas, as a hydrogen source for the fuel cell or as feedstock for chemical synthesis, for example to produce methanol. Alternatively, it can be further processed to separate CO_2 from methane to produce pipeline methane or transportation fuel (compressed or liquefied), and liquid CO_2. Natural gas fleet vehicles are a potential steady market for methane recovered from LFG.

The resulting stream of methane is pure enough to be used in fuel cells instead of a generator in order to produce electricity.

Acrion’s technology also allows for the commercial use of most of the CO_2 in landfill gas. The CO_2 not used for the wash is drawn off as a 99.99 percent pure liquid CO_2 stream that can be used in a variety of commercial applications, from making dry ice to carbonating soft drinks. One option Acrion is examining is to pipe the CO_2 to Burlington County's R&D Greenhouse and Resource Recovery Complex, where "Jersey Fresh" tomatoes and other plants would benefit from the CO_2-enriched environment. Acrion is also providing samples of the pure liquid CO_2 to distributors and consumers for analysis and testing in commercial applications.

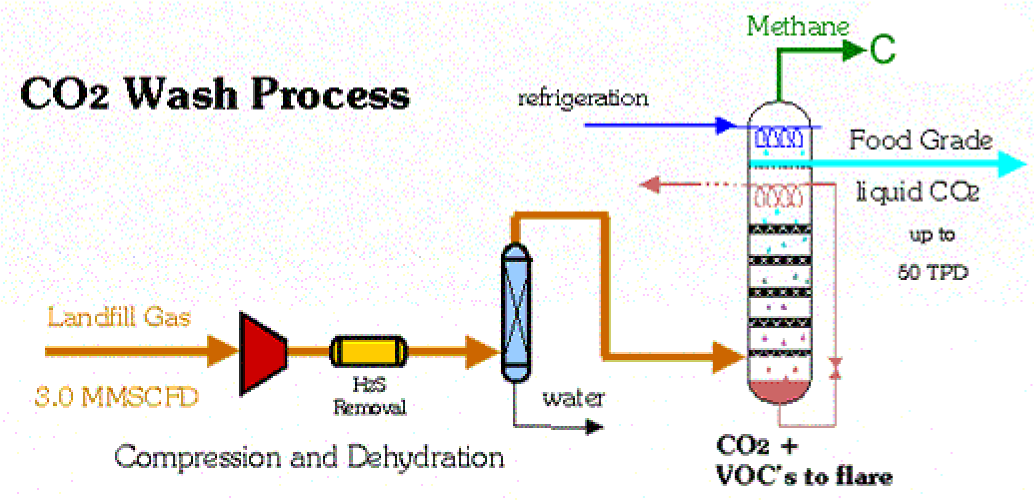


Figure 3.2 The CO_2 Wash Process [Acrion 2003]

More information: www.acrion.com.

3.2.3 Methanol and CO_2

Figure 3.3 shows the treatment of landfill gas in the Acrion process in order to obtain methanol. A small, modular add-on “refinery” produces methanol from landfill gas, using a stream of methane that is also produced on-site using the CO_2 Wash Process.

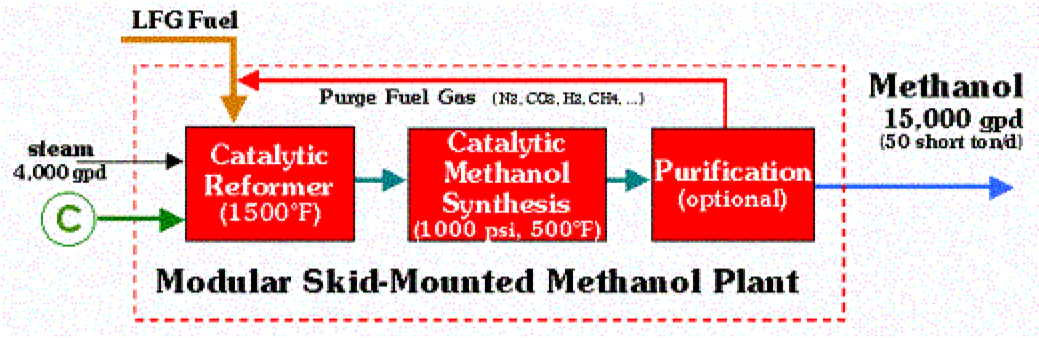


Figure 3.3 Acrion’s Modular Methanol Synthesis Process [Acrion 2003]

3.2.4 Hydrogen and CO_2

Instead of methanol, the landfill gas can also be turned into hydrogen in a shift reactor.

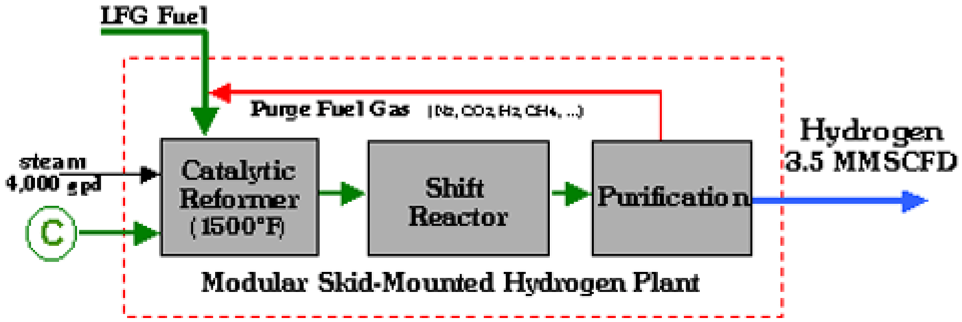


Figure 3.4 Acrion's Modular Hydrogen Synthesis Process [Acrion 2003]

Chapter 4 Municipal and Industrial Residues

4.1 Organic Waste Resources

4.1.1 Municipal Solid Waste

Municipal solid waste (MSW) may be considered to fall into three categories:
- urban or residential wastes - generally picked up at the curb or transported directly by the producer to landfill;
- industrial, commercial, and institutional (I, C & I) wastes - from commercial enterprises, temporarily stored on-site in bulk-lift containers before haulage; and
- demolition, landscaping and construction (DLC) wastes - usually trucked directly to landfill.

In Canada, approximately 1 tonne per person of municipal solid waste is generated each year, about a quarter of which is recycled [BIOCAP 2003, Tables 4.1 & 4.2]. Of the 25 million tons per year total, 1.2 million tons are incinerated with energy recovery [NRCan 2002, p.17]. The remainder is either recycled or landfilled.

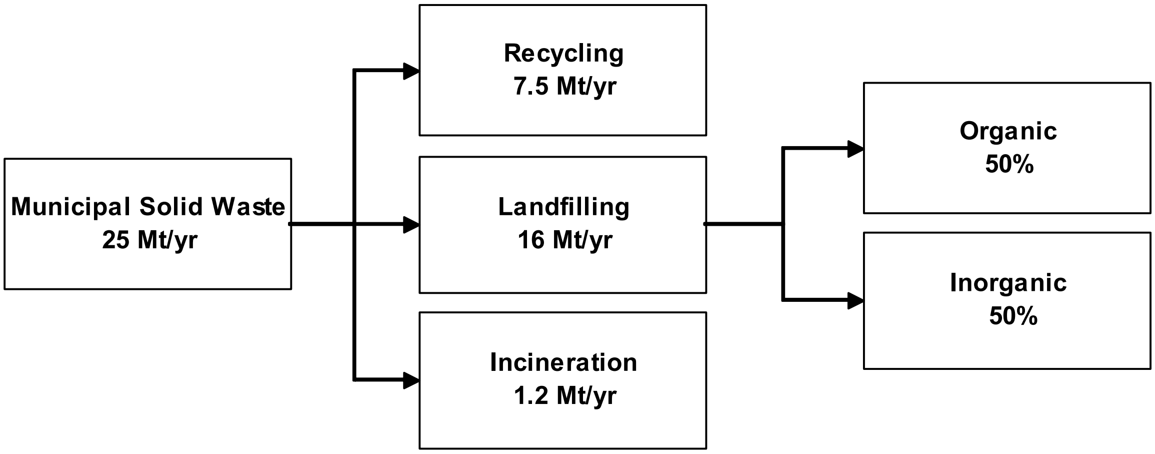


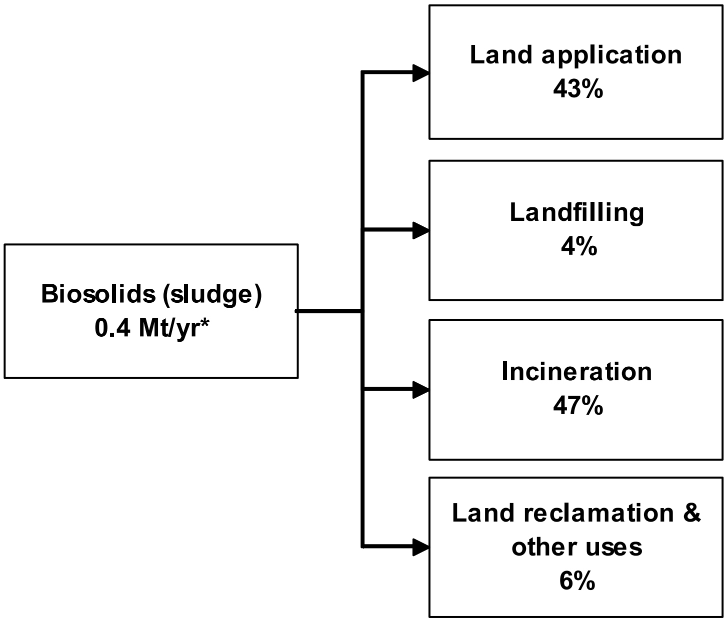
Figure 4.1 Municipal Solid Waste Management in Canada

MSW contains on average 85% combustible materials from which energy may be derived by a variety of methods. This would include plastics and other artificial materials derived from fossil fuels. No definitive analysis over the organic content of landfilled waste could be found, but it can be safely assumed that it is at least 50%. Combustion, pyrolysis, gasification and the production of biogas through aerobic or anaerobic fermentation are methods to derive energy from waste. Pyrolysis and gasification require pre-drying of the waste, but offer great potential both for the capture of energy and the production of specific bio-products.

4.1.2 Sludge

Municipal sewage sludge, or biosolids, from wastewater treatment does contain biomass and can be used for energy and other purposes. In Canada, approximately 388,700 dry tonnes of biosolids are produced every year. About 43% are applied to land, 47% are incinerated and 4% are sent to landfill, with the remainder used in land reclamation and other uses. Land application has been increasing in recent years as many municipalities move away from incineration and landfill disposal due to environmental concerns with these processes. By comparison, the United States and Europe apply approximately 60% and 34%, respectively, of their biosolids to agricultural land. [EMS 2001]

The usage of biosolids varies substantially from province to province. In BC, 90% of municipal biosolids are land applied (land reclamation: 70%, agriculture: 25%, compost: 5%). Most wastewater facilities in Manitoba use holding lagoons, some of which are only pumped out every nine years. Biosolids in Manitoba can be land applied at a one time use of 55 tonnes per hectare. In Québec (1999), 80% of biosolids were incinerated, 12% landfilled and 8% or 0.5 million tonnes were either land applied or composted. In Alberta and Saskatchewan, regulations specify a maximum biosolids application rate of 25 tonnes per hectare. Biosolids cannot be applied to land used for root crops, vegetables, tobacco or dairy grazing. [ES&E 2000].



* dry tonnes

Figure 4.2 Current Uses of Biosolids from Water Purification in Canada

Unlike forest residues, chemical conversion of biosolids offers several challenges irrespective whether combustion (incineration), gasification, or even pyrolysis is used. Heavy metals contained in the biosolids can be transported with the flue gas and filtered out if the proper air pollution equipment is in place; some heavy metals can remain in the ash. The ash must then be disposed of accordingly.

4.1.3 Animal Fat and Liquid Organic Waste, Canola Oil

Fats and oils have high energy contents and can be transformed into transport fuels (biodiesel). West Coast Reduction of Vancouver has a virtual monopoly on the prairies in terms of the commercial collection and rendering of yellow grease (used cooking oil), beef tallow and pork lard. This appears to be particularly the case for yellow grease. In the case of tallow and lard, the large animal processors manage and process most of their own material. [IAG 2002, p.6]

Most of Canada's exportable canola supplies are purchased by Japan. The remainder of the crop is crushed for domestic consumption or export, primarily to the United States. Biodiesel production in Canada would require displacement from higher priced food uses. There is potential for the use of lower quality canola oils from seed that was overheated during storage without any ill affects on the quality of the biodiesel. However, the amounts of heat damaged seed available each year varies greatly, and ranged from 100 tonnes to 3,200 tonnes per year between 1996 and 2000 [IAG 2002, p.9]. This volatility in supply makes rape seed at best a supplementary feedstock in addition to more stable source of supply, such as yellow grease.

4.2 Clusters of Animal Fat and Liquid Organic Waste in Canada

4.2.1 Municipal Solid Waste

Table 3.1 provides an overview of waste generation per province in Canada. Solid organic waste can be expected to occur where large agglomerations of people are present, i.e. in the big urban centres of Canada. Waste is often transported over hundreds of kilometres to remote landfills, which implies significant emission reductions if the waste can be used in the vicinity of large cities.

Table 3.1 Disposal of waste[1] by province and territory (Preliminary estimates for 2000) [Statcan 2002]

	1996	1998	2000	1996	1998	2000
	Waste disposed			Waste disposed per capita		
	Metric tonnes			Kilograms per capita		
Canada	**20,673 903**	**20,840,883**	**23,109,369**	**690**	**688**	**750**
Newfoundland and Labrador	372,324	366,280	409,599	670	671	760
Prince Edward Island	x	x	x	x	x	x
Nova Scotia	553,638	502,577	432,487	590	537	460
New Brunswick	505,957	468,571	472,612	670	623	630
Quebec[2]	5,491,000	5,537,465	6,912,000	750	755	940
Ontario	6,913,786	6,988,157	7,615,923	620	612	650
Manitoba	947,884	964,726	938,624	840	848	819
Saskatchewan	900,210	848,408	828,359	880	827	811
Alberta	2,435,884	2,527,817	2,750,004	880	869	910
British Columbia	2,413,528	2,458,484	2,592,191	620	614	640
Yukon, Northwest Territories and Nunavut	x	x	x	x	x	x

[x] Confidential to meet secrecy requirements of the *Statistics Act*.

[1] Total amount of waste disposed of in public and private waste disposal facilities. Does not include wastes disposed in hazardous waste disposal facilities or wastes managed by the waste generator on site.

[2] Figures are derived from the results of surveys conducted by the province.

Note: Figures may not add up to totals due to rounding.

4.2.2 Yellow Grease

As yellow grease originates in food frying operations, most of this grease can be collected in Canada's metropolitan areas, such as Toronto, Montréal, Vancouver, Calgary and Edmonton. A commercial-size biodiesel manufacturing plant with a capacity of 20-30 million litres a year could be run in virtually any province (see Table 3.2).

Table 3.2 Annual Production of Biodiesel Feedstocks in Canada, million litres (extrapolated from Alberta data [IAG 2002, p.10])

Feedstock	BC	AB	SK	MB	ON	QC	Atlantic	Canada
Yellow grease[1]	24	**18**	6	7	70	43	13	180
Beef tallow[2]	12	**90**	41	22	31	20	4	221
Pork Lard[3]	1	**11**	7	15	20	24	2	79
Canola oil*	0.06	**3**	5	2.5	0.05	-	-	11
TOTAL	36	**123**	59	47	121	86	19	491

* Based on 2003 Canola Harvests [CCoC 2003]

[1] Based on population statistics (Statcan, 2003)

[2] Based on heads of beef per province (Statcan, 2003); a number of 200,000 tonnes per year is also confirmed in [GCSI 1998, p.15]

[3] Based on heads of hogs per province (Statcan, July 1, 2003)

NOTE: According to [CARC 2003, p.v], yellow grease production in Canada is 240,000 tonnes per year, and animal fat production is 640,000 tonnes, which exceeds the above extrapolated values considerably. However, the report then goes on to say that only a small fraction of these amounts is available for new uses, such as biodiesel production.

4.2.3 Animal Fat

Table 3.4 identifies high-density livestock regions in Canada. Table 3.2 already shows that Alberta, Saskatchewan, Ontario and Québec are the provinces with the highest production of beef tallow and pork lard. For beef tallow, the best regions would be the Central St. Lawrence, Upper South Saskatchewan, North Lake Erie and East Lake Huron. For pork lard, the best regions are the Central St. Lawrence, Lower St. Lawrence and North Lake Erie. This indicates that the regions in Québec and Ontario probably have the best overall resources, as they combine both beef tallow and pork lard.

Table 3.4 High Livestock Density Areas (May 1996) [Statcan 2001, p.14]

Province	Sub-Basin	Cattle (Animal Units)	Pigs (Animal Units)
Quebec	Central St. Lawrence	270,347	170,570
Ontario	North Lake Erie	237,669	89,400
Ontario	East Lake Huron	231,890	40,952
Quebec	Lower St. Lawrence	183,828	98,346
Alberta	Upper South Saskatchewan	253,058	10,347
B.C.	Fraser	126,393	13,407
Alberta	Red Deer	102,567	8,454
Alberta	Battle	76,759	6,723
Ontario	Lake Ontario	13,808	2,150

4.2.4 Canola

Significant rape seed (Canola) harvests are brought in only in the Prairies, with Saskatchewan having the largest share, followed by Alberta and then Manitoba.

4.3 Utilization Options

4.2.5 Animal Fat, Sub-food-grade Vegetable Oil and Cooking Oil to Biodiesel and Glycerine

Animal fats are used in lipo-chemistry, for energy production, instead of gas or mineral oil, and also in the production of biodiesel. Biodiesel is a methyl diester product made by a chemical reaction between methanol and either vegetable oils (e.g. substandard vegetable oil or recycled cooking oil) or animal fats. Currently three common types of biodiesel production technologies are available, and the selection will depend on feedstock quality and the state-of-art of a facility. Commercially used processes for biodiesel production are as follows:

- Base catalyzed transesterification with refined oils
- Base catalyzed transesterification with low free fatty acid greases and fats
- Acid esterification followed by transesterification of low or high free fatty acid greases and fats.

Each of these processes typically utilizes methanol (ethanol has been considered as well) in the presence of a base catalyst such as sodium or potassium hydroxide to produce mono-alkyl ester-based oxygenated fuel (methyl or ethyl esters) commonly known as biodiesel, and glycerine as a by-product.

Canadian biodiesel technology has focused on the hydro-treating method using a conventional refining process similar to the petroleum industry. This method produces cetane (used as a booster for diesel fuel), naphtha (used as a gasoline supplement), and other products (usable as power burner fuels). The high cetane portion (super cetane), when blended about 5 to 10 percent by volume with diesel, enhances engine performance in diesel the way octane does in gasoline. Super cetane may find a potential market as a replacement for commercial nitrate-type diesel fuel additives [CRFA 2003(1)]. A German biodiesel plant blends its animal fat-based biodiesel with rape seed oil for better lubricity during the cold months [Render 2002].

In Canada, since May 2001, Biox Corp. is using new technology to run a 250,000 litre per year pilot plant in Oakville, Ontario, which can handle any feedstock, with yellow grease provided by a Canadian renderer as the primary stock. The BIOX Process is a new commercial scale biodiesel production process in which fatty acids and triglycerides are sequentially converted to methyl esters by acid catalysed esterification and base catalysed transesterification. Dr. David Boocock, Past Chairman of the Chemical Engineering and Applied Chemistry Department, University of Toronto, has transformed the production process using inert co-solvents, such as tetrahydrofuran or methyl tertiary butyl ether, to achieve the reaction at low pressure in one phase and increase the rate of methanolysis reaction. The reaction is over 99% complete in seconds at ambient temperatures, compared to previous processes which required several hours. Continuous processes are now feasible and proven.

Most of the solvent can be recycled, and so the enhanced performance results in lower costs – Biox wants to produce ASTM D6751 grade biodiesel at a cost of 7 cents CAD per litre, plus the cost of capital and feedstock, thereby making biodiesel cost competitive with petroleum diesel. BIOX plans to commission its first commercial scale biodiesel production facility (60 million litres per annum) in Toronto during Spring, 2004.

More information: www.bioxcorp.com

Whereas biodiesel production will most likely not grow to cover the entire diesel consumption in Canada (to compare, all U.S. soy crops could only cover 13% of U.S. diesel consumption), using biodiesel as an additive may result in emission reduction benefits: the addition of 1% biodiesel to diesel fuel increased fuel efficiency by 5% - 13% [CRFA 2002]. With Canada's annual diesel consumption of 22.6 billion litres, 1% addition of biodiesel as a fuel additive could reduce CO_2 emissions by 2.8 to 5.6 Mt of CO_2. Reductions as a result of fuel savings would close 1.1% to 2.3% of Canada's Kyoto gap of 240 Mt.

The CANMET Energy Technology Centre in Ontario, Canada, has proven at lab scale a process to convert yellow grease and/or tallow and/or poultry fat into a valuable low-sulphur, high cetane premium diesel blending stock. The process used is based on a refining technology called hydrotreating. Figure 4.3 describes the necessary equipment and the material flows. The principal output is a diesel blending stock called AGTANE (for AGricultural ceTANE, or also SuperCetane) in English speaking countries (e.g. Australia, United Kingdom, United States, etc.), and BIOZOLE in French speaking countries. Production could be readily implemented in major urban areas where large rendering operations are located within 50 miles of petroleum refining facilities

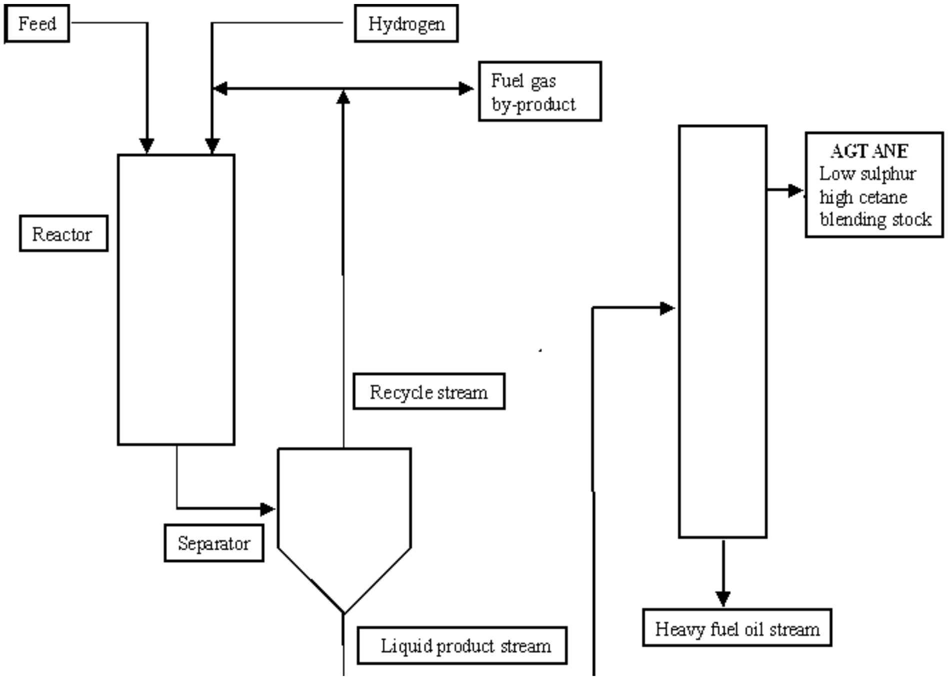


Figure 4.3 AGTANE Process Flow Chart

AGTANE, a collection of long-chained paraffins, is a premium diesel blending stock - it is not biodiesel (biodiesels are esters). Conservative economic models indicate that for mass production plants (>750,000 gallons/year), yellow grease can be profitably converted to AGTANE. AGTANE blended diesel will not require fuel suppliers to increase the use (and cost) of algae and/or bacteria killers (biodiesel blends typically require more algae and/or bacteria-killing additives than regular diesels). Being a collection of long-chain paraffins, AGTANE has a field tank storage life equal to or superior to currently commercialised diesel fuels. Modern fuel injection diesel engines were designed to burn fuels that include paraffins, which are included in AGTANE but no in conventional biodiesel fuels. AGTANE has been repeatedly shown to have cetane values of over 100, before blending, and have excellent physical and chemical characteristics that make it an ideal blending stock. Typically, biodiesels have cetane values between 50 and 60. Unlike biodiesel, there are no engine emission trade-offs. No water is needed to produce AGTANE (water is needed to make biodiesel).

More information: http://www.mhr-viandes.com/en/docu/docu/d9000137.htm or
http://www.canren.gc.ca/tech_appl/index.asp?CaID=2&PgId=1083

4.2.6 Land Application of Sludge

In Canada, a large portion of biosolids (43%) are currently used in agriculture because they contain high concentrations of essential crop nutrients, primarily nitrogen and phosphorous. The nutrients are recycled into crop production and are used in place of inorganic fertilizers [EMS 2001]. Similar direct uses of sludge include its application to fertilise forests, in land reclamation projects, or the revegetation of mine spoils.

The main concerns about land application of biosolids are their content of contaminants, including heavy metals, and pathogens. For this reason, many municipalities incinerate the sludge in order to eliminate pathogens.

Composting is a possibility of pre-treatment for sludges. The sludge is dewatered to increase the solids content to around 20%, and is then mixed with a high-carbon organic material, such as sawdust. This mix is composted under aerobic conditions at temperatures of at least 131°F for several days during the composting process. This also eliminates some of the pathogens.

4.2.7 Anaerobic Treatment – Methane and Biosolids

Anaerobic treatment in digesters is one of the most widely used methods to treat water purification sludge. The sludge is held in the absence of air for 15 to 60 days at temperatures of 20°C to 55°C. Anaerobic bacteria feed on the sludge, producing methane and carbon dioxide. In some treatment plants, the methane is collected and burned to maintain the treatment temperature.

An example of an anaerobic process is the U.S. ODI 2PAD System (see Figure 4.4). It separates the acid and methane-forming digestion phases (acidogenesis and methanogenesis), increasing the efficiency of both, and combines this with high temperature, destroying pathogens to below detectable limits. The system has been proven during a two-year pilot study.

An anaerobic sludge treatment facility in Tampa, Fl recovers about US$700,000 worth of electricity each year from the methane produced. This is equivalent to approximately US$65 of net electricity per dry ton of volatile biosolids removed from the digester. Tampa also uses the heat removed from the electrical generators to provide more than 95% of the warmth needed for the digesters. All but 10-15% of Tampa's digested biosolids are heat-dried and marketed for between $85 and $120 per dry ton. The balance is being land applied in dewatered form [EPA 1994, p.17].

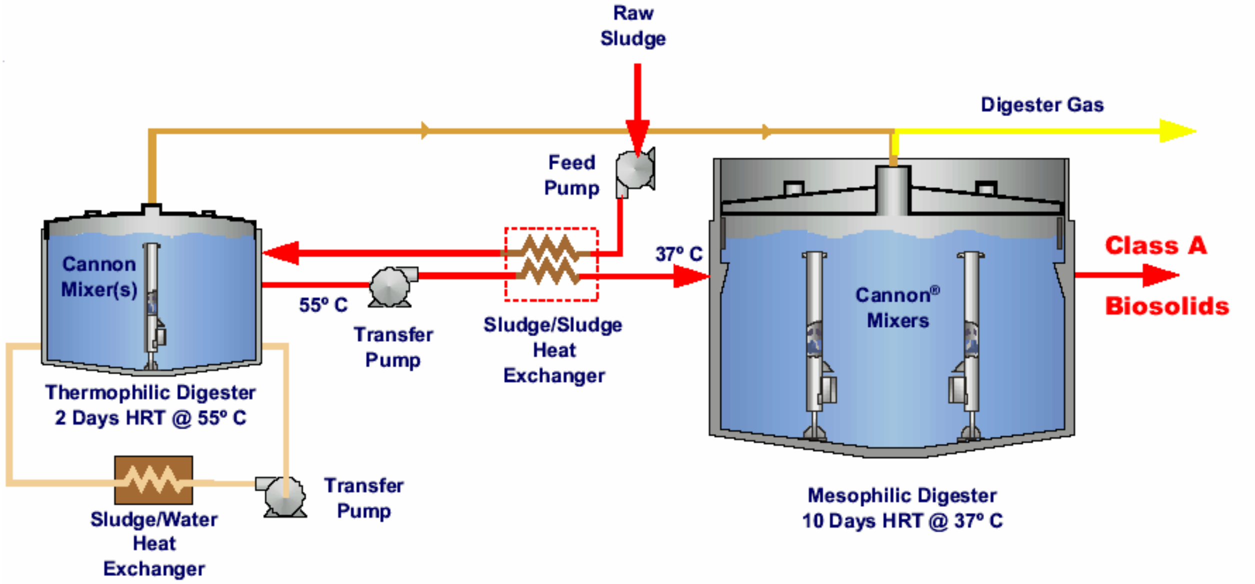


Figure 4.4 Two-Phase Digestion Process (ODI 2PAD System) [ONDEO 2002]

As an option for further improvement of the digestion process, a fuel cell can be used to generate electricity. A fuel cell at the Columbia Boulevard Wastewater Treatment Plant in Portland, Oregon, already converts digester gas into electricity. The digester gas is first cleaned to remove impurities and then enters the phosphoric acid fuel cell. Impurities are principally hydrogen sulphide, halogens (fluorine, chlorine and bromine), moisture, bacteria and solids. Biogas also contains carbon dioxide, which cannot be removed easily. The gas-cleaning system at Columbia Boulevard uses a potassium hydroxide impregnated activated carbon filter to remove the hydrogen sulphide. The fuel cell began producing power in July 1999 and produces an estimated 1,400,000 kilowatt-hours of electricity each year.

More information: www.energy.state.or.us/biomass/FuelCell.htm

4.2.8 Incineration

Sewage sludge incineration reduces the volume of the material to be disposed of, completely destroys pathogens, decomposes most organic chemicals, and recovers the small amount of heat value contained in sewage sludge. Figure 4.5 shows the incineration technology by Danish company Krüger as an example. The residual ash is a stable, relatively inert, inorganic material that has just 10 to 20% of the original sludge’s volume. Most trace metals in the sewage sludge become concentrated in the ash (a five- to tenfold increase in concentration). This material most commonly is landfilled, although it potentially could be used in construction materials. Incineration can release volatile pollutants, such as cadmium, mercury, lead, or dioxins into the atmosphere. Incinerator operation requires sophisticated systems to control temperature, residence time, and the removal of fine particulate matter (fly ash) and volatile pollutants from stack gases. This makes incineration one of the more expensive options for sewage sludge disposal. As with landfilling, the potential benefits from organic matter and plant nutrients in sewage sludge are lost. [PSU 1999]

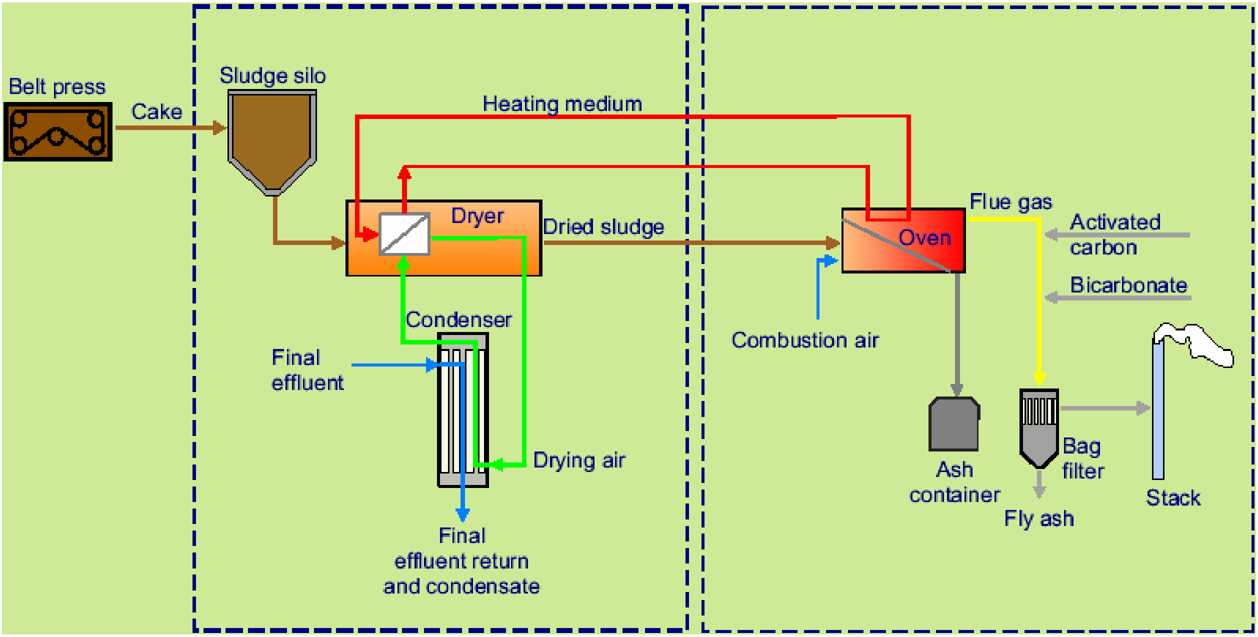


Figure 4.5 BioCon System for Sludge Incineration [Vivendi]

4.2.9 Pyrolysis: Waste to Liquid Fuel

Pyrolysis is almost exclusively applied to the manufacture of liquid-fuel end products like ethanol and bio-oil. Pyrolysis occurs when biomass is heated in the absence of oxygen. Through this process, the biomass is converted into a liquid called pyrolysis oil (bio-oil), which has a heating value nearly half that of a conventional fuel oil – typically 16–18 MJ/kg, and a pH of 2.5. The density of the liquid is very high at around 1.2 kg/litre, compared to light fuel oil at around 0.85 kg/litre. This means that the liquid has about 42% of the energy content of fuel oil on a weight basis, but 61% on a volumetric basis [PYNE 1999]. A biopower system that uses pyrolysis oil is currently being commercialised.

Fast pyrolysis, while related to the traditional pyrolysis processes for making charcoal, is an advanced process, which is carefully controlled to give high yields of liquid. It is a high-temperature process in which biomass is rapidly heated in the absence of oxygen. As a result it decomposes to generate mostly vapours and aerosols and some charcoal. Cooling and condensation forms a dark brown mobile liquid, the pyrolysis oil, also termed “bio-oil”.

The essential features of a fast pyrolysis process are:

- Very high heating and heat transfer rates, which usually requires a finely ground biomass feed with a low moisture content.
- Carefully controlled pyrolysis reaction temperature often exceeding 500°C in the vapour phase, with short vapour residence times of typically less than 2 seconds.
- Rapid cooling of the pyrolysis vapours to condense out the bio-oil product.

Bio-oil is obtained in yields of up to 80% by weight on dry feed, together with by-products char and gas, which may be used within the process, eliminating waste streams. While a wide range of reactor configurations have been operated, fluid beds are the most popular configurations due to their ease of operation and ready scale-up. Canadian company Dynamotive has a 50 kg/h demonstration unit (see also section 1.3.3). Circulating fluid beds and transported bed reactors have been developed to commercial status by Ensyn and are used in the USA for food flavourings and related products in several plants of 1 to 2 t/h. [PYNE 1999]

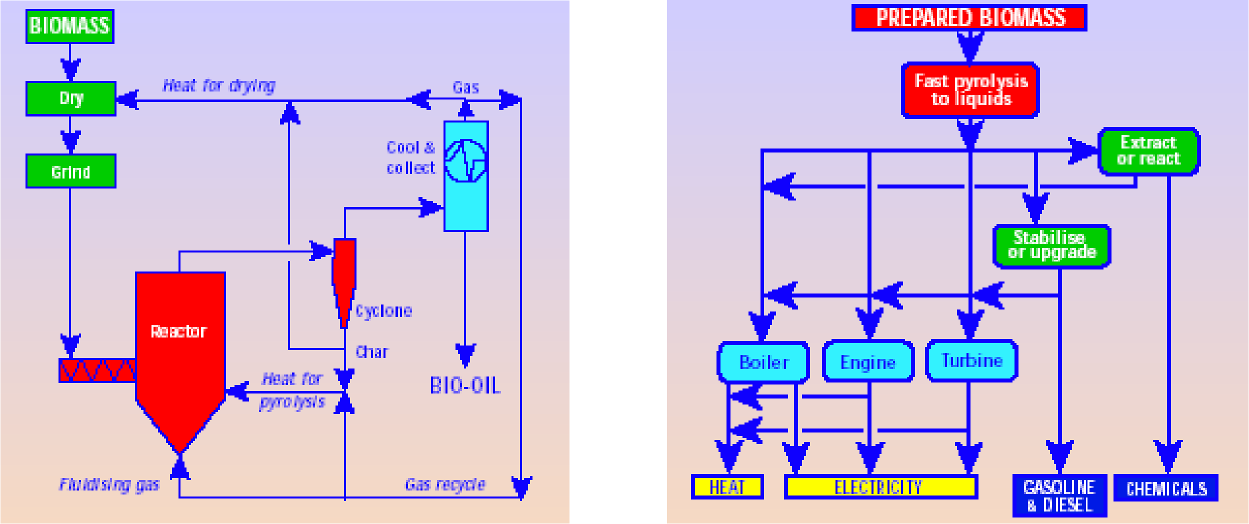


Figure 4.6 Generic Pyrolysis Process Flow Chart and Possible Uses of Oil [PYNE 1999]

Bio-oil has the potential to substitute for fuel oil or diesel in many static applications including boilers, furnaces, engines and turbines for electricity generation, although the lower pH of the bio-oil and its high water content must be taken into account. The possibilities are summarized in Figure 4.6. There is also a range of chemicals that can be extracted or derived including food flavourings, specialities, resins, agri-chemicals, fertilizers, and emissions control agents. Upgrading bio-oil to transportation fuel quality is feasible but currently not economic [PYNE 1999].

Due to its high moisture content, waste biomass usually needs to be dried before it can be converted to bio-oil. As discussed in chapter 1.3.4, this reduces the amount of useful energy that can be extracted, and negatively affects process economics.

More information: Biomass Pyrolysis Network - http://www.pyne.co.uk/pyne/

4.2.10 Waste to Ethanol

Feedstocks that can be used to produce ethanol include waste sludge from pulp and paper mills, waste paper, grass, straw, leaves and other solid landfill wastes that contain cellulose, or plant fibres.

The process of making ethanol from pulp and paper sludge is similar to the process used in making ethanol from wheat (see Figure 4.7). The sludge is pre-treated to further break down the cellulose. Enzymes are added to convert the cellulose to glucose. Then yeast or, in some cases, genetically altered bacteria, are added to create the fermentation process. The mixture is then distilled to produce ethanol.

A Japanese team has also developed a process to make ethanol from waste construction wood. A factory producing 3.7 million litres of ethanol from 30,000 tonnes of waste wood is to be operational in Osaka by 2007. The process consists of acid pre-treatment and subsequent fermentation, and is being developed by a group of five organisations, including Marubeni and Tokyo Board Industries.

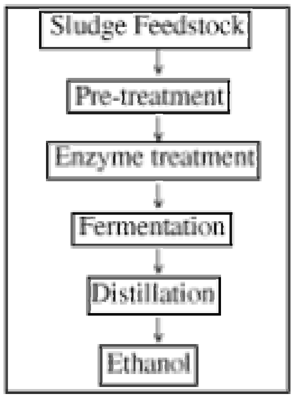


Figure 4.7 Fuel Ethanol Production from Pulp and Paper Waste

4.2.11 Gasification

Gasification can also be applied to biomass waste. It is a process that chemically and physically changes biomass through the addition of heat in an oxygen-starved environment. The end products of gasification include solid ash, slag, and synthesis gas, or syngas, which can be used for electricity production or be turned into other, higher-value chemical products (see Figure 1.2). The gas has a calorific value, or heat content, equivalent to less than 25% that of natural gas if ambient air is used or 40% if oxygen enriched air is used. Gasification can be applied to various biomass waste feedstocks, including Municipal Solid Waste, sludges, bagasse, sugarcane, corn fibre, rice straw and hulls, nutshells, tree clippings, animal wastes, process sludges, industrial biomass residues, etc.

Although several gasification systems have been designed and constructed in the past two decades, most have been demonstration and laboratory-scale systems. Large-scale demonstration plants in the U.S. experienced technological problems and are no longer operating. There are currently no commercial-scale solid waste gasification systems operating in the United States [BREDL 2002]. Canadian company Enerkem does promote a biomass gasification concept (see section 1.1.1).

4.2.12 Fractionation into Fibre and Lignin

The PureVision process allows several biomass waste streams to be split up into lignin and fibre. Possible feedstocks include pulp from paper mills, municipal biosolids, and the organic and paper fraction of municipal solid waste (see section 2.2.2).

4.2.13 Composting of Separated Fractions

Methane is formed in landfills due to the decomposition of organic materials in landfills. Diverting the organic fraction of waste to composting will reduce the organic residue in landfills, and therefore methane emissions as well. In addition to that, large-scale composting has other climate change benefits, including:

- reduced N_2O emissions, since compost use reduces the need for fertilizers; and

- reduced CO_2 emissions, since compost use increases soil moisture retention and thus reduces the amount of energy needed for irrigation. [Woodrising 1999]

The challenges in waste composting is its separation from other waste items, especially those containing contaminants, such as heavy metals, and the control of salt content from food waste.

Chapter 5 Energy Crops and Biochemicals

5.1 Canada's Potential

5.1.1 Overview

There is no official estimate with respect to how large Canada's potential for energy crops would be. Issues to be addressed would include competing land uses, e.g. growing energy crops vs. afforestation to obtain carbon credits for Canada's offset system, or utilization of existing crops for energy purposes instead of current uses.

However, there is a strong policy drive towards energy crops in the U.S. and the EU, and also the Canadian government has made $100 million available for the furtherance of the ethanol industry within its 2003 budget for climate change-related measures.

A variety of biomass crops can be used for energy purposes. Table 5.1 shows a few examples of the most typical ones. Some provinces have started analyzing their potential to use biomass crops for the production of biodiesel and ethanol. In Manitoba, as well as in many other jurisdictions, the addition of 10% ethanol to gasoline is encouraged with tax breaks. Expanding this to all gasoline sold in the province would create a market for 140 million litres of ethanol that would require approximately 420,000 tonnes of wheat, the crop seen with the most near-term potential for conversion to ethanol [AGRI 2003].

Table 5.1 Energy Crops and Their Uses [OEKO 2000]

Energy Crop	Products
Sugar beets, potatoes, corn, grain	Bioethanol
Rape seed	Biodiesel or heating oil
Wood, grass, straw, grain, miscanthus	Heat, steam, power

5.1.2 Switchgrass

Switchgrass is a high-yielding species that can be planted on marginal agricultural lands. Ontario alone has 1.5 million hectares of such areas, which could yield biomass equivalent to 17 million litres of ethanol [Levelton 2000, p.14]. However, switchgrass only grows well in Ontario and Manitoba, with yields in Manitoba somewhat reduced from 8-10 t/ha to only 5–6 t/ha, but with a larger surface available for its production. So, about the same annual yield as for Ontario can be assumed. Further West and East of Ontario, either willow or other kinds of grass could be grown instead of switchgrass [AAFC 2002]. The potential yield can be assumed to be as high as Ontario's for Alberta, Saskatchewan, Quebec and the Atlantic Provinces together, leaving out BC because of its small arable land surfaces [REAP 2002(2)]. The overall potential yield of grass crops on marginal land in Canada has been estimated to about 6.8 million tons per year [PP 2002, p.193].

5.1.3 Oil Seeds

In Canada, the 2003 production of canola was 6.3 million tonnes. Soybean seeds were projected at 2.5 million tonnes [Agnews 2003]. Due to exports, Canada only processed about 1.3 million tonnes of these seeds (1996 figure). Assuming 10% of Canada's canola and soy oil potential was used for biodiesel production, 277 million litres of biodiesel could be produced per year [GCSI 1998, p.15]. This amounts to only about 1.5% of the Canadian diesel consumption of approximately 19 billion litres per year. However, as mentioned in chapter 4.1.3, the use of oil seeds for biodiesel production is not likely as long as other uses promise much higher returns.

5.1.4 Wheat, Corn and Sugar Beets

Ethanol is already being made from bioenergy crops: as Table 5.2 shows, several plants with a combined output of 212 million litres per year are in operation in Canada. Both wheat and corn are currently being used as feedstocks, although the use of sugar beet is also employed, especially in Europe. Additional ethanol plants are proposed for Ontario and Québec [CRFA 2003(2)]. As part of the Climate Change Plan for Canada, the government created an Ethanol Expansion Program funded with $100 million over three years in 2003, to support the construction of ethanol plants. From this program, Suncor has been awarded $22 million to build a 200 million tonne ethanol plant in Sarnia, ON, in February 2004.

Table 5.2 Ethanol Production in Canada [CRFA 2003, corrected acc. To CARC 2003]

Producer	Location	Capacity	Other Information
Mohawk Oil, Canada, Ltd.	Minnedosa, Man.	10 million litres	Wheat-based
Pound-Maker Agventures, Ltd.	Lanigan, Sask.	12 million litres	Wheat-based Partnered with a cattle feedlot
Commercial Alcohols, Inc.	Tiverton, Ont.	23 million litres	Corn-based
Commercial Alcohols, Inc.	Chatham, Ont.	150 million litres	Corn-based
Tembec	Temiscaming, Qué.	17 million litres	Forestry product-based

The Government of Canada's Future Fuel Initiative has the objective to increase bioethanol fuel use in vehicles from the current 212 million litres per year to over 1.3 billion litres per year by 2010. This volume is based on bioethanol achieving 35% market penetration of gasoline blends formulated with 10% bioethanol (E10) [ARC 2003(1), p.31]. This is equivalent to 3.5 million tonnes of wheat, at an average yield of 370 litres of ethanol per tonne processed. E10 is more realistic as a near-term target, as blends with 85% bioethanol (E85) cannot be used in most vehicles [CCC 2003, p.6].

From 1992-1996, about 2.9 million tonnes per year of all wheat classes were designated as (inferior) feed quality. Together with 1.8 million tonnes of "Canadian Prairie Spring Red" and 0.4 million tonnes of "Canadian Prairie Spring White" – both low-protein varieties that have less value for human consumption - the total available feedstock for ethanol production would amount to 4.6 million tonnes per year, surpassing the 3.5 million tonnes required to meet the national 35% E10 fuel target. This does not include the use of Eastern Canadian corn, the largest feedstock for current ethanol production. [CCC 2003, p.7]

It is also likely that wheat production would be increased if a large ethanol market existed. The number of acres of land used in wheat production has declined steadily for the past decade or more. If more land were to be used for wheat production, reaching the volume required for a 10% ethanol blend in 35% of all gasoline would be even more easily attained. It is estimated that Saskatchewan alone could increase production of ethanol grade wheat by some 1.3 million tonnes per year by using half of the current summer fallow land. This could represent an additional 480 million litres of ethanol per year [CCC 2003, p.7]. Of course, increased wheat production could reduce opportunities to grow other energy crops, such as switchgrass, for energy purposes.

Canada only has one sugar beet plant, located in Taber, Alberta. Sugar beets have been successfully grown in Québec and Ontario, but the Prairie provinces have proven to be the most ideally situated for economic production. Sugar beet harvests have declined in recent years and the area planted has decreased from 18,000 hectares in 1998 to 11,700 hectares in 2001. With a 2001 yield of 46.5 tonnes per hectare, the total harvest was 544,000 tonnes, virtually all in Alberta [AAFC 2003]. Based on an estimate for Australian sugar beet (ethanol yield of 4,500 litres/hectare), the 2001 harvest represents a potential 53 million litres of ethanol [Weeden 2000]. If the decline in areas used for sugar beets in Alberta were reversed, then the 6,300 extra hectares would yield another 28 million litres of ethanol, or about 22,000 tonnes per year (specific weight of ethanol: 0.79 kg/l). Acreages for growing sugar beets could be significantly increased across Canada, and would be able to yield ethanol in the same order of magnitude as grains or corn.

5.2 Utilization Options for Energy Crops and Biochemicals

5.2.1 Use as Heating Fuel

A furnace is the simplest combustion technology. Biomass is burned in a combustion chamber, converting it to heat energy. The released hot gases contain about 85 percent of the energy contained in biomass. Commercial and industrial facilities use furnaces to directly or indirectly heat facilities or processes through a heat exchanger in the form of hot air or water.

Densified (pelletised) biomass fuels can be transported and used in wood pellet stoves. This technology is apparently being explored by tobacco farmers in southwestern Ontario looking to use switchgrass pellets instead of natural gas for heating their tobacco dryers. Currently, Canada produces about 350,000 tonnes of pellet fuels per year. Approximately 100,000 tonnes of pelletised wood residues are being exported annually to Scandinavia from Canada, but the market within Canada remains underdeveloped [ECS 2001, p.8]. Gasifier pellet stoves are being produced and sold in Canada that are burning moderately high ash pellets and grains at 80-85% efficiency [REAP 2004]. Numerous attempts have been made in both Canada and USA to develop a wood pellet market but have met with limited success.

Heating with biomass is also being proposed for homes. A biomass-fed furnace offered by a U.S. company can heat houses using fuels such as corn, rye, pellet fuel or even cherry pits.

More information: http://www.ja-ran.com/superior.html

5.2.2 Lactic Acid from Starch

Biodegradable plastics are gaining market momentum in Europe as a result of government regulations promoting the composting of biodegradable materials. The EU market for bioplastics in 2000 was 10,000 tonnes (40% of world market) and it is expected to grow to 60,000 tonnes by 2005. The main product markets are food packaging, compost bags, paper coatings, dishes and cutlery. Other commercial applications for starch biopolymers include loosefill packaging; sheets, shaped and blocked packaging for electronics; injection moulding; films and fillers; and children’s toys. Long term market opportunities for bioplastics in the EU are estimated to be about 300,000 tonnes by 2010 [CARC 2003, p.84].

Cargill Dow LLC’s facility for the production of polylactic acid (PLA) in Blair, Nebraska, has a capacity of 140,000 metric tons/year. The plant began operations in the fall of 2001. At present, the products include polymers for packaging, polymers for fibres and lactide as a source of chemical intermediates. These materials replace conventional plastics made from fossil fuels.

The corn wet milling process converts corn into several fractions, the largest of which is starch. The starch is then converted in an enzymatic process into dextrose. Dextrose is combined with appropriate nutrient sources and minerals and is converted via fermentation and purification to lactic acid. An anaerobic fermentation using either Bacillus or Lactobacillus species is used to prepare the crude broth, maintaining a neutral pH with the addition of lime. The lactic acid can be either of two isomers, or a mixture, depending on the organism used for the fermentation. The crude broth is then purified by acidulation, precipitation, or ion exchange and then evaporated to the final concentration. Conversion of lactic acid to lactide follows, which is blended to the desired isomer content, polymerized and finished to form the various grades for a variety of products.

The life cycle assessment of the overall process and the component pieces, including farm inputs, transportation, power generation demonstrates that use of PLA can result in a 25-55% reduction in fossil fuel and significantly reduced greenhouse gas emissions, compared to the incumbent petroleum-based polymers. [IC 2003]

Cargill Dow is further developing the fermentation process to operate on sugars from biomass feedstock and agricultural wastes rather than more expensive food-grade corn sugars. As the cost of fermentable sugars is reduced and production volumes increase, PLA will become more price competitive with commodity plastics such as polystyrene and should experience expanding markets [ARC 2003(1), p.58].

More information: http://www.cargilldow.com/corporate/index.asp

5.2.3 Switchgrass to Polyhydroxyalkanoates

Polyhydroxyalkanoates (PHA) are a family of polyester polymers that can be biosynthesized in bacteria and plants. U.S. company Metabolix Inc. is using nuclear transformation to introduce PHA-encoding genes into switchgrass and tobacco. To recover PHA from biomass, solvent extraction techniques using green solvents such as ethanol and ethyl acetate are used, as well as hydrolytic enzymes to facilitate aqueous extraction of PHA from biomass. In 2002, Metabolix announced it had demonstrated the feasibility of high yield commercial scale manufacturing of PHA with costs projected at under $US 1 per pound. [ARC 2003(1), p.58]

5.2.4 Corn to Bulk Chemicals and Chemical Intermediates

1,3-Propanediol

Genencor International, with Dupont, genetically engineered a micro-organism which combines the needed metabolic pathways from bacteria and yeast to make 1,3 propanediol (bio-PDO) by fermentation of corn-based sugars. PDO is used to produce polytrimethylene glycol terephthalate (3GT), which Dupont is marketing as a new fabric polymer called Sorona™, displacing polyester in applications such as clothing, carpets, packaging and automobile interiors. 3GT has enhanced fabric properties compared to traditional polyester, including improvements in fit and comfort, softness of touch, dyeability, resilience, and stretch recovery. Other high performance bioplastics and fabrics could also be made using bio-PDO and 3GT as technology platforms.

The production of PDO involves a costly petroleum-based synthetic process, which makes the process too expensive so far. DuPont and Tate & Lyle are jointly developing the bio-PDO manufacturing process. Once bio-PDO can be produced more cheaply than petroleum-based PDO, 3GT could penetrate more of the polyester market. [ibid., p.50]

α,ω-Dicarboxylic Acids

These dicarboxylic acids are chemical intermediates used in the production of nylon polymers, lubricants and plasticizers. The production of succinic acid derivatives from corn sugars has been explored in the U.S. – where the market for these chemicals is 450,000 tonnes per year. [ibid., p.51]

Biobased Solvents

Cargill-Dow Polymers can produce ethyl lactate, through the fermentation of corn sugars. Other esters can be made from soy or citrus peels. [ibid., p.52]

Alcohols

Fusel oil, a by-product of ethanol production, is a mixture of various higher alcohols which have a potentially high market value. [ibid., p.53]

Biolubricants

Vegetable oils can be used to make a broad range of lubricant products, including: machinery oils, chain bar lubricants, gear and transmission fluids, hydraulic fluids, farm tractor oils, drilling oils, outboard marine two-stroke engine oils, metal cutting oils, etc. Although the performance of biolubricants is sometimes lower than that of petroleum-based oils, their lesser ecotoxicity and better biodegradability opens up great market opportunities. In Europe, biolubricants already gained a market share of 20%, whereas in Canada they only hold a very small margin of the market [CARC 2003, p.120].

5.2.5 Fractionation into Fibre and Lignin

The PureVision process can split up various biomass crops, such as switchgrass, hybrid poplar and willow, into lignin and fibre (see section 2.2.2).

Flax and hemp fibres are replacing glass fibres in applications, such as cement and composites. The use of fibres is becoming more and more important in composites for the automotive industry, increasing recyclability, reducing vehicle weight – and therewith fuel consumption – and reducing the energy required for the production of composites by 80%. In Europe, the glass fibre market has a size of 600,000 tonnes, whereas 100,000 tonnes of plant fibres were used already in 1999. In North America, their application is less advanced. [CARC 2003, p.108ff.]

5.2.6 Other Options

In essence, the technologies and options to use biomass crops are the same as for the previous sections. They can be summarized as follows:

- Switchgrass and other lignocellulosics (poplar and willow trees, switchgrass, elephant grass, prairie bluestem, etc.) to ethanol and CO_2 (fermentation)
- Canola and soy beans to biodiesel (transesterification)
- Biomass to syngas and then electricity or biobased products (gasification)
- Switchgrass or forest biomass to electrical power
- Forest biomass to charcoal for co-firing or other applications
- etc.

Chapter 6 Results from Stage I and Recommendations

6.1 Biomass Availability in Canada

Table 6.1 summarizes the findings of the previous chapters. It becomes evident that the largest sources of biomass are the ones current forest practices leave behind unused, agricultural residues, and municipal waste. Black liquor was included as a major resource, although it is already being used for energy purposes. However, applying alternative technologies may increase the emission reduction benefits from black liquor use in the pulp and paper industry.

It is also striking that there is a very large potential for both switchgrass and also wheat and corn. Most of the other waste-related resources, such as yellow grease, do occur in important amounts, but still an order of magnitude less than the aforementioned resources. Without taking energy crops into account, BIOCAP has calculated that biomass residues alone have an energy content equivalent to between 18 and 27% of Canada's annual energy consumption [BIOCAP 2003, p.2].

Table 6.1 Summary of Canada's Biomass Resources

Biomass from …	Specific Type	Availability [Mt/year]	Appr. Energy Content in Dry Biomass [PJ]
Forestry Residues	Non-stem wood	92	1440
	Mill residues	<5.7	<117
	Tall oil	0.18	7
	Black Liquor	24	282
Agricultural Residues	Straw & Stover	18-25	277-385
	Livestock manure	58-79	65-88
Landfill Gas	(in tonnes of CO_2e)	21.9	
Municipal and Industrial Residues	MSW (50% of total)	8	132
	Municipal water purification sludge	0.4	7
	Yellow grease*	0.16	6
	Beef tallow*	0.20	8
	Pork Lard*	0.07	3
	Canola oil* (from low-quality canola only)	0.01	0.4
Energy Crops (Potential)	Switchgrass and other grass	6.8[1]	107
	Canola and soy beans (10% of harvest)	0.23	9
	Grains (wheat and corn; enough for a national E10 standard)	>4.6	89

* assumed density: 0.91 kg/l

[1] REAP Canada assessed Canada's potential eight times higher, to 55 million tonnes for perennial grass yields. This is based on an available surface of 23.4 million acres, which would not affect food production in Canada (about 13%) [REAP 2004]. The lower estimate above is based on the assumption that Ontario would have 282,000 acres available for growing perennial grasses, and that Canada's overall yield could be three times that of Ontario.

The above Table does not contain data on wood from Reduction of Fuel Loading in the forest. This initiative is underway in the U.S. in order to prevent forest fires, and may also yield additional wood in Canada if implemented here. However, it is a forest treatment that is only appropriate for ecosystems which naturally have fire as a regular part of the cycle but from which fire has been excluded for the past 100 years or more. This includes the ponderosa pine ecosystems of the western US, extending into the Southern Interior of BC. Most of the forests of Canada are in the boreal forest zone, however, where wildfire is also part of the regeneration cycle (though on a much longer cycle than in ponderosa pine) but which have continued to experience periodic fires in historic times. However, thinning, particularly pre-commercial thinning (at an early age before any regularly merchantable wood can be extracted) is good silvicultural practice throughout the boreal forest, improving the growth of the rest of the stands, and an energy market for the thinnings would make the practice more viable economically [CanBIO 2003]. The quantities available from fuel loading reduction and thinning may be significant, but at the moment, no such program has been decided on in Canada. It can be treated the same way as non-stem wood, as it mainly concerns thinning out smaller trees. More forest biomass may be derived from fire management, bugwood and other sources (see section 1.1).

6.2 Selection of Threads to be Analysed in Phase 2

The following matrix summarizes the findings from the first few weeks of research into biomass in Canada and its possible uses. 19 of the threads identified in this table are further analysed in the Phase II Report, selected based on the preferences of the funding partners. Envirochem has highlighted further threads that seem to be relevant and that it recommends for being examined further on a life-cycle basis (marked “nf” for “not funded”).

The following feedstock-to-product threads were selected for a full life-cycle study during Phase 2:

- a comparison of the use of non-stem wood residues for power production as opposed to gasification, and with fast pyrolysis of sawmill residues, and proposed technologies for CHP;
- a comparison of landfill gas use for electricity production as opposed to simply flaring it, as well as municipal waste incineration and increased recycling of biomass;
- an examination of the use of yellow grease for biodiesel production as opposed to making it from energy crops, such as canola (Ontario)
- production of ethanol from straw and stover residue as opposed to from field crops (Prairies)
- the use of switchgrass for power production as opposed to hydrogen generation (Prairies)
- a comparison of local small power systems versus larger centralized systems for forest residues (not marked in Table 6.2);
- comparison of land-use options (afforestation and energy crops) against “business as usual” or the “do nothing” alternative.

The Phase 2 research was carried out in “modules”, which means that feedstock-to-product threads were examined in several steps: harvesting/transportation – first processing step – second processing step – distribution - consumption. Some of these steps may be identical for several biomass feedstocks: for example, any feedstock that can be gasified can also be used for hydrogen production. This modular approach allows the application of information about certain common end products like hydrogen to several feedstocks. For example, once the “hydrogen module” has been put together, it can then be applied to several feedstocks, enriching the results flowing from this study and making more comparisons possible without multiplying the work.

Table 6.2 Biomass Resources and Possible Uses

	Feedstock / Product	Fertiliser (aerobic)	Burning/Flaring	Heat (direct comb.)	Electricity (direct comb.)	Heat/Electricity (Biogas)	Syngas/Electricity	Methanol	Hydrogen	Bio-Oil and Charcoal	Biodiesel	AGTANE Diesel Addit.	Heating Oil	Ethanol	Polylactic Acid	Bulk Chemicals	Fibre and Lignin	Composite Board
Forest Biomass	Non-stem wood, bugwood, etc.	x			**f**		x	x	x	x				x*			x	
	Sawmill residues	x		**nf**	**f**	**nf**	x	**nf**	**f**	**f**				x*			x	
	Tall oil										x	x						
	Pulp liquor			x	x		x							x				
Agricultural Biomass	Straw & stover residue	x	x	x	x		x	x	x	x				**f**	(x)		x	x
	Manure	**nf**		x	x	**nf**								x				
Waste	Landfill gas		**f**		**f**			x	x					x				
	Municipal solid waste	**f**		x	**f**	**f**	**nf**	x						x			x	
	Waste wood			x	x		x	x	x	x				x			x	x
	Yellow grease						x				**f**	**nf**						
	Beef tallow										**f**	x						
	Pork lard										**f**	x						
	Canola oil waste										**f**	x						
	Biosolids/municip. and ind. sludges	**nf**	x	x	x	**nf**	**nf**										x	
Energy Crops	Corn													**f**	x	x		
	Grain													**f**	(x)			
	Sugar beets													x				
	Canola & soy										**f**	x	x					
	Switchgrass			**nf**	**nf**		x	**nf**	**f**					**f**			x	
	Willow			x	**nf**		x	x	**f**								x	

* hardwood only; f: funded within existing budget; nf: suggested, but additional funding needed

Chapter 7 What Is "Sustainable Biomass"?

The use of biomass for energy production has been common practice for thousands of years. Yet, its large-scale use is controversial for a number of reasons, and the inclusion of biomass-based power generation in "green labelling" and renewable energy policies is highly contentious. Some of the main arguments brought forth against large-scale use of biomass are:

- **Energy crops:** the displacement of other activities, such as agriculture for food-related crops
- **Energy crops:** the need for fertilizer and transport, which can undo much of the emission benefits hoped for
- **Forest residues:** unsustainable harvest of additional biomass could harm ecosystem balances
- **Agricultural residues:** centralised treatment can prevent valuable nutrients from being returned to the field
- **Municipal waste:** using waste for energy is unsustainable; organic residues should be separately collected and composted
- **Landfill gas:** waste-related energy sources are not "green" (per definition)
- **Co-firing:** the combustion of biomass in coal-powered stations supports the use of coal, a fossil fuel with the highest greenhouse gas and other emissions
- **Biomass (general):** the combustion of biomass creates air particulate emissions

To make a judgement about the sustainability of biomass use, several questions need to be answered. For example, energy crop production depletes soils of minerals and, in an intensive farming scenario, requires replenishment of essential minerals through artificial fertilizers. The collection and transport of biomass must be done in a manner that does not cause excessive emissions so that possible benefits from biomass use are undone. The combustion of biomass is often seen as polluting, for example due to increased particulate emissions as compared to fossil fuels. However, abatement technology can be used to prevent such emissions, and biomass-derived power will reduce net carbon dioxide emissions, as biomass is considered "carbon cycle neutral". The direct combustion of biomass, emitting carbon dioxide, has less GHG impacts than its natural decomposition, which produces methane gas; a 21 times more potent greenhouse gas. It is clear that electricity production from biomass causes air pollution and that the only emission that is clearly reduced by regrowing the feedstock is carbon dioxide. This must be weight against the notion that biomass is the only renewable energy that if not used productively can be detrimental to the environment. Natural occurring decomposition systems to convert accumulation of biomass residue from agricultural and industrial activity can be shown to produce more environmental damage than many conversion technologies used to harness product and power.

Internationally, there is no consistent approach to defining "sustainable biomass", and a variety of definitions exist under various labelling and legislative support schemes (see Table 7.1). To address sustainability issues, the North American forest industry has created "sustainable management" protocols, which can be used to sell wood products as certified under Canadian Standards Association or Sustainable Forestry Initiative® Standards.

An exhaustive examination of sustainability must incorporate more than just carbon dioxide emissions. This study can help determine which uses of biomass should be preferred as it describes energy payback, life-cycle carbon emissions and also includes information on other air pollutants, as well as financial aspects. However, the final decision whether a biomass technology or project is sustainable or not will also depend on issues not related to air emissions, including community involvement and acceptance, the possible competition between resource uses (e.g., agriculture for food as opposed to agriculture for energy crops), and other changes induced by the increased use of biomass for energy purposes.

Table 7.1 Types of Biomass Included in Various Renewable Energy Schemes

	Wood waste	Agricultural and forest residues	Energy crops	MSW	Landfill Gas	Sewage gas	Co-firing	Other
Canadian Low Impact Electricity Guideline (draft)	Un-treated	x	x	An-aerobic	x	x		Management, social and environmental pre-assessm't requirements; air emission limits
Green-e	x	x	x	(x)	x			MSW not allowed in some regions; air emission limits
North American RPS definitions	15	13	7	10, some "no"	19	4		out of 27 RPS examined [CEC 2003]
Australian Renewable Energy Act	x	x	x	x	x	x		bagasse co-generation, black liquor, food waste
EU Renewable Energy Directive	Un-treated	x		x				Cork waste
Netherlands (groencertificaten)	x	x		50%	x	x	No	
German OK Power label	Un-treated	Wood from certified forestry operations	Organic only				x	
EUGENE	Un-treated	x Certified wood only	x	No		x	x	Specifications concerning consumer in-formation and additionality
EKOENERGIA (Finland)	Un-treated	x	x		x	x		

x = included

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IDENTIFYING ENVIRONMENTALLY PREFERABLE USES FOR BIOMASS RESOURCES

STAGE 2 REPORT:
Life-Cycle GHG Emission Reduction Benefits of Selected Feedstock-to-Product Threads

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Table of Contents

Executive Summary

In this study, we examined the greenhouse gas emission reduction effects of several of the biomass feedstock-to-product threads that were identified in the Stage 1 report. Based on life-cycle GHG emission analysis, the emissions from growing, collecting, and processing biomass were assessed and weighed against the displaced emissions from fossil fuels. The overall results are presented on a per (metric, dry) tonne of biomass input basis and also per hectare of land used for energy crops.

Additional analysis was carried out with respect to the technology readiness and the cost of various biomass technologies. The amount of fossil fuel that could be displaced by each option was determined. Findings from this additional analysis were considered in the final recommendations.

General Approach: This study centered on answering two questions based on the analysis of the twenty-nine threads listed below. The initial question was: If a tonne of biomass is available, which use would deliver the most GHG emission reductions and would therefore be preferred from an environmental point of view (changes in other emissions were not the subject of this report, but are considered qualitatively as well)? This question was further refined, as there are two categories of biomass: waste material (e.g., sawmill residues and the organic fraction of municipal waste) and new material (i.e. energy crops specially grown to be used as a biomass feedstock for energy or fuel production).

Waste material is biomass that is linked to another economic activity. Determining benefits on a per-tonne of waste basis allows for the most beneficial uses to be identified and promoted. The same can be done for energy crops. For example, switchgrass can show different benefits if it is used to make ethanol, space heat, electricity, or hydrogen. However, this raises a second question in the context of energy crops: "How can one optimize emission reductions for a given land surface?"

Biomass threads examined: The following 29 threads were included:

1. Corn to ethanol
2. Wheat to ethanol
3. Corn stover to ethanol
4. Wheat straw to ethanol
5. Hay to ethanol
6. Switchgrass to ethanol
7. Soy beans to biodiesel
8. Canola oilseed to biodiesel
9. Canola oil-based biodiesel as an additive
10. Waste oil and animal fat to biodiesel
11. Yellow grease and tallow to biodiesel
12. Wood to hydrogen
13. Wood waste to hydrogen
14. Corn ethanol to hydrogen
15. Switchgrass ethanol to hydrogen
16. Wood waste to bio-oil and electricity
17. Wood waste to electricity (gasification)
18. Wood waste to electricity (large steam)
19. Wood waste to electricity (small steam)
20. Wood waste to electricity (Brayton cycle)
21. Wood waste to CHP (small steam)
22. Wood waste to CHP (Turboden cycle)
23. Wood waste to CHP (Entropic cycle)
24. Municipal waste – open landfilling
25. Municipal waste – landfilling with gas collection and flaring
26. Municipal waste – landfilling with gas collection and power generation
27. Municipal waste - Composting
28. Municipal waste – Digestion and composting
29. Municipal waste - Incineration

In addition to the above threads, land use options were also compared to carbon sequestration through afforestation. Forest sequestration was compared to other options (i.e. large steam electricity, small CHP (Entropic cycle), or hydrogen production).

Because sustainably harvested biomass is not considered to create net greenhouse gas emissions, (based on the assumption that the CO_2 released from the conversion of biomass is recaptured by the following crop cycle), the aim of the analysis was to determine whether there were significant differences in the emission reduction benefits from different biomass and land use options.

Results:

A) Energy crops

1. **Yields are the decisive factor in terms of GHG emission reductions.** The main effect in terms of emission reductions per hectare is created by the amount of carbon in plant matter. Emissions due to the transportation of biomass are marginal. Process emissions can be significant, but are still secondary compared to those displaced from fossil fuels through the use of biomass fuels. If the amount of biomass harvested per hectare is small, then the overall emission reduction benefits are small as well. This could be shown for several crops, including wheat for ethanol, canola oilseed and soy beans for biodiesel, and corn for ethanol.
2. **Displacement of GHG emissions from fossil fuels is the other main criterion.** A preference is noted for ethanol or combined heat and power (CHP) over electricity only. Electrical power often only displaces low-emission sources or natural gas on the grid. This limits the achievable emission reduction benefits. In an overall national strategy to minimise GHG emissions, biomass uses should either displace transportation fuels, such as gasoline, or electricity and natural gas or heating oil when used to fuel a combined heat and power plant. Another option resulting in considerable GHG emission reductions is co-firing of biomass in coal-based power stations, where biomass directly displaces the use of coal.
3. **Afforestation should always be considered.** Planting trees may be the least cost option to gain GHG emission benefits in the medium term. Such benefits may taper off in the future, but over a 50-year term, they can be as large as or larger than those from using land in other manners. Actual benefits will depend on locally achievable growth rates for a given tree species.

B) Biomass waste

Forest residues: The first type of biomass waste examined was forest residues. This includes sawmill and pulp mill residues (saw log waste and black liquor), as well as roadside slash. **Displacement of GHG emissions from fossil fuels is the main criterion.** A preference is noted for hydrogen or combined heat and power (CHP) over electricity only. Electrical power often only displaces low-emission sources or natural gas on the grid. Another option resulting in considerable GHG emission reductions is co-firing of biomass in coal-based power stations, where biomass directly displaces the use of coal.

Municipal Solid Waste: The second type of biomass waste examined was the organic fraction of municipal solid waste (MSW). It consists largely of residential food waste, commercial biowaste, green waste from gardening etc., paper, and construction waste. The waste can be treated together with inorganic waste, or selectively collected and treated in a composting or digestion facility. **Minimisation of methane emissions is the main criterion.** Pockets of methane form in composting facilities and cause considerable GHG emissions, possibly even beyond those of open landfills. Incineration consumes the organic fraction of MSW, but also causes the emission of all carbon in biomass as CO_2. On the other hand, landfilling with gas collection, if done effectively (75% of methane or more can be captured), assures little methane is emitted from the landfill, and has additional carbon sequestration benefits as much of the biomass remains intact inside the landfill body. If less than about 50% of methane is captured over the whole lifetime of a landfill, incineration becomes preferable over landfilling in terms of GHG emissions. However, lower landfill gas capture efficiencies may qualify if the plastics fraction in MSW is taken into account, as the carbon in plastic materials is not oxidised to CO_2 but remains in the landfill. The sequestration benefits of landfills are most marked for the non-paper fraction of biomass waste, whereas they only slightly outweigh the GHG impacts of incineration if the whole biomass fraction of MSW is considered (including paper).

Waste oil and fat: This third type of biomass waste includes yellow grease (waste cooking oil), animal fat (e.g., pork lard), beef tallow, as well as sub-market quality canola oil. All these feedstocks can be converted to biodiesel. **The main criterion for GHG emission reductions is the fuel efficiency and displacement effect of biodiesel on transport fuel.** If it is used in high quantities (10-20% mixed into conventional diesel), biodiesel will displace conventional diesel and associated production emissions. However, there are some concerns about using biodiesel in quantities higher than 5% in transportation, due to its higher viscosity. This can lead to cold start problems during the winter. On the other hand, some trials with passenger vehicles have shown considerable fuel efficiency increases if biodiesel is used as an additive in small quantities (0.5% mixed into conventional diesel). Biodiesel increases lubricity of the fuel thus compensating for the increasingly aggressive action of diesel on engine parts as the sulphur content is reduced. If these fuel efficiencies can be confirmed in large-scale trials, biodiesel made from waste oil and fat could be used to make this fuel additive for Canada's entire diesel fleet, with sharply increased GHG emission reduction benefits over using biodiesel in higher percentages.

Recommendations: Based on the findings in this study, the following recommendations with respect to biomass utilization can be made:

1. If biomass is specifically grown to produce energy, avoid using low-yielding energy crops. Wheat, canola, or corn should not be used as energy crops, as they require considerable energy inputs in the form of fertilizer etc., take up prime farmland, and deliver small yields per hectare. Switchgrass or wood from short-rotation forestry (e.g., poplar or willow) should be used to produce energy. This brings into question current thinking in both Canada and the U.S., where corn and wheat are increasingly promoted as ethanol feedstocks.
2. Use biomass waste and energy crops where they displace fuels with high carbon content. Combined heat and power, or the production of either ethanol or hydrogen are preferred over electricity-only options.
3. Landfilling and incineration are the best options to minimize GHG emissions from MSW. While landfilling with efficient gas collection (capturing at least 50% over the lifetime of a landfill) wins out in the medium term, the best long-term solution may still be incineration, as there is no possibility of methane emissions from the MSW biomass once it has been incinerated. If the cost of these options is too high due to long transport distances, the separate collection of biowaste and treatment in digesters seems to be the second best option. Composting is not recommended due to the considerable methane emissions from pockets of anaerobic activity.

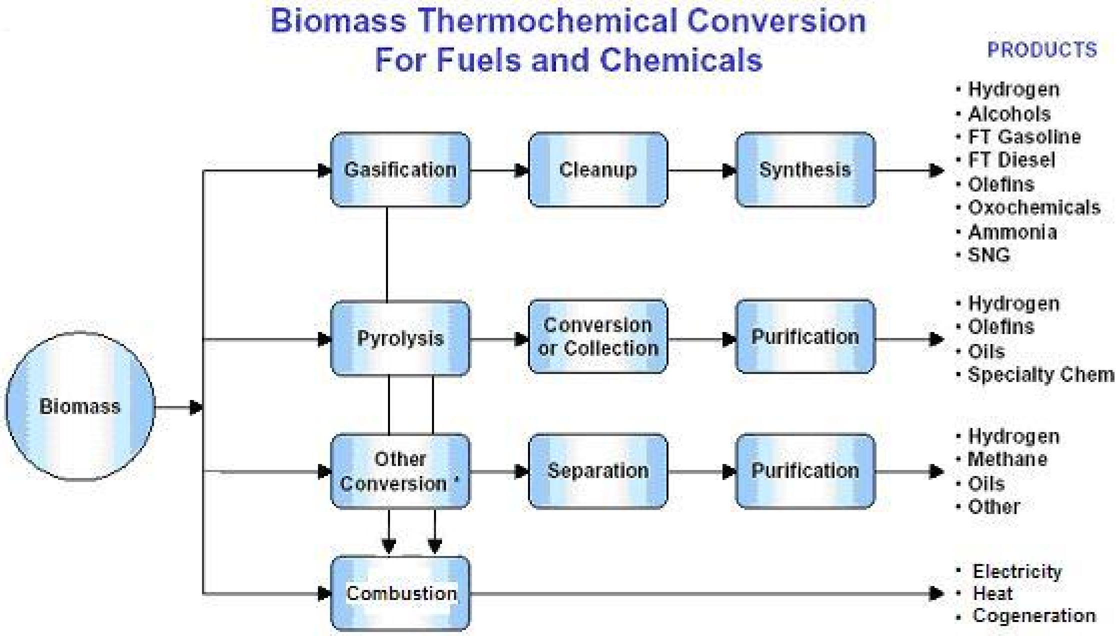
4. Do not produce biodiesel from virgin vegetable oils. Available land can be used more efficiently by growing other crops for energy purposes. However, waste oil and fat should be used to make either biodiesel, or a diesel additive, if the positive fuel efficiency impacts of small quantities of biodiesel in conventional diesel can be confirmed.
5. If the ultimate goal is to displace a maximum quantity of fossil fuels, CHP is the preferable biomass use option.
6. The impact of the national or regional electricity background mix on the results is minimal, except for power-only options.

Limitations: Several important feedstock-to-product threads could not be examined in this study. This includes heat only options, hydrogen from switchgrass, ethanol from wood, electricity and CHP from switchgrass, and emerging biorefinery options, among others. These threads should also be examined to further clarify the best uses of biomass to minimize GHG emission reductions.

No other environmental effects than GHG emissions were assessed in detail in this analysis. However, other emissions and environmental effects are discussed qualitatively. In general, biofuels have been found to be very similar to fossil fuels in terms of criteria air pollutants, acidification, summer smog, and human toxicity. However, the use of fertilisers causes an increase in eutrophication when compared to fossil fuels. On the whole, the literature indicates that changes in other environmental impacts are not a consideration that would clearly determine decisions for or against using biomass instead of fossil fuels.

Introduction

This report presents the results of the Stage 2 research carried out to determine "Environmentally Preferable Uses of Biomass". Stage 1 identified existing and emerging technologies and pathways to transform various biomass feedstocks into an energy or non-energy product. Each pathway is called a "thread" in this study. The figure below shows some of the possible threads that can be pursued in order to convert biomass to a commercial product.



Biomass Feedstock-to-Product Threads [adapted from NREL 2004]

This Stage 2 report provides information on threads selected by the funding partners. The main emphasis is on the Greenhouse Gas (GHG) emission reduction benefits of each thread, based on life-cycle GHG analysis. Regions in Canada were selected to present case studies, and the results obtained were then extrapolated to other regions within and outside Canada by varying the background electricity mix, which to a large extent determines the overall impact of both the biomass conversion process itself, and the displacement of fossil fuels through the biomass product.

The following questions that this report tries to answer are all related to how GHG emission benefits from biomass can be maximized:

1. How does afforestation compare to other land uses, such as agricultural uses to produce bioproducts?
2. How do alternative uses of biomass (e.g., combustion to produce electricity, production of liquid biofuels, etc.) compare in terms of GHG emission reductions achieved?
3. Given that biomass resources are limited in quantity, which biomass use options should be preferred as a function of environmental concerns, economic and technical feasibility, and energy security concerns?

The answers to these questions will provide crucial guidance for policies and programs, as well as management decisions, on how to use biomass in a carbon-constrained world.

Chapter 1 Methodology

1.1 Methodological Considerations and Approach

The methodology for this work is based on Schlamadinger 1997, which reflects the recommendations of the International Energy Agency's Task 38 (Greenhouse Gas Balances of Biomass and Bioenergy Systems). Existing life-cycle analyses were used as much as possible. To be sure that correct values were used the following guiding principles were used:

- numbers from contradictory studies, if available, were compared and an attempt to explain the differences was made; where indicated, a sensitivity analysis was conducted to assess the impact of using different data or assumptions;
- values for transport distances given in underlying studies used as sources were adjusted to reflect the actual case discussed here. In order to derive more general conclusions that would apply to different scenarios from those in the case study examined, transport distances were also varied for a sensitivity analysis;
- the background electricity generation mix was varied according to the values in Table 1.1 (see section 1.3). This means that results from underlying studies were modified to reflect these values;
- electricity displaced by using biomass in the process (e.g., for process energy in the case of ethanol production) was treated the same way as if the electricity was displaced by a separate power plant run on that biomass. This means, instead of having surplus electricity displace natural gas-based power generation or another power source at the margin, all electricity from biomass is seen as displacing the average background power mix, in order to maintain consistency between different uses of biomass;
- results are presented as reduced emissions per metric dry tonne of biomass input, to allow comparisons of different usage options for a given feedstock.

Key assumptions that were made include:

- Carbon storage in ecosystems is affected by the removal of biomass for energy production (e.g. the planting and harvesting of energy crops). Carbon stocks could be lowered, for example, through the removal of non-stem wood from forests. They could be increased through intensified pre-commercial thinning, the conversion of fields to forests, or the replacement of food crops with perennial energy crops. Changes in biomass management can lead to a new soil carbon equilibrium at somewhat lower or higher levels. However, these changes are considered negligible in the long term when compared to the amounts of carbon that are sequestered and removed for energy and other uses over time. Thinning forests to prevent forest fires can also improve long-term carbon storage, although carbon is removed in the short term. Such changes of stored carbon stocks were therefore not included in this analysis;
- Biomass fuels have higher GHG emission intensities than many fossil fuels, such as oil and natural gas. However, this is only relevant when biomass fuels are derived from unsustainable land-use practices, i.e. the carbon cycle is not closed. For this report, it was assumed that sustainable land-use practices are applied;
- The production, transport and conversion of biomass fuels requires inputs of energy and causes emissions, which must be taken into account. Likewise, production, transport and conversion of displaced fossil fuels have to be accounted for;
- Bioenergy can be a by-product of other processes. For example, when certain compounds are extracted before using the remainder for energy purposes. In this case, emissions and offsets of both products must be taken into account;

- Biomass is examined in the context of Kyoto Protocol rules and definitions. Consequently, the conversion of carbon contained in biomass to CO_2 is considered carbon neutral, assuming that the carbon cycle is closed over the complete life-cycle of a biomass feedstock. This means only secondary emissions from processing, transport, etc. from biomass are considered, whereas for fossil fuels, carbon contained in the feedstock itself is also counted as an emission;
- Energy needed to produce transportation or conversion facilities is not included in this analysis. This is due to the fact that a) the energy content of facilities for fossil fuels and for biomass can be assumed to be very similar, and b) the energy throughput is two to three orders of magnitude larger than the energy contained in the facility, and is therefore negligible for the overall analysis, the mistake being smaller than 1% [Schlamadinger 1997, p.367];
- In Canada, diesel fuel is a blend sourced from heavy oil, off-shore oil and so-called 'synthetic' oil (derived from oil sands), the composition of which varies across the country [IJLCA 2003]. Although life-cycle GHG data on Canadian diesel was used in this study, the error or variation introduced when using alternative data on diesel fuel emissions is not considered significant, as transportation generally only represents a small percentage of overall emissions of biomass usage threads;
- Process fuels were assumed to be fossil fuels (or electricity produced with the existing background mix of power plants), and no biomass was assumed to be used. This reflects that the purpose of this study is to determine the best use of biomass. Using it for process heat would reduce overall CO_2 emissions, but would also conceal the actual benefits of its use as a process feedstock. In addition, biomass availability is reduced if it is used for both running the process itself and as a feedstock. This would diminish the overall yield per hectare in the case of energy crops, for example. Where process residues could be used as secondary fuels (for example, char), this was accounted for in the analysis, but without specifying whether these would be used to power the process itself or elsewhere.

1.2 System Boundaries

Figure 1.1 shows how system boundaries were set for this analysis. Whereas most data and analysis comes from pre-existing life-cycle studies on various feedstock-to-product threads, some refinement or additional assumptions had to be made in order to obtain comparable results. This was especially true for, transport distances and background electricity mix emissions which had to be adjusted, in some, cases to better reflect the realities of the case studies examined.

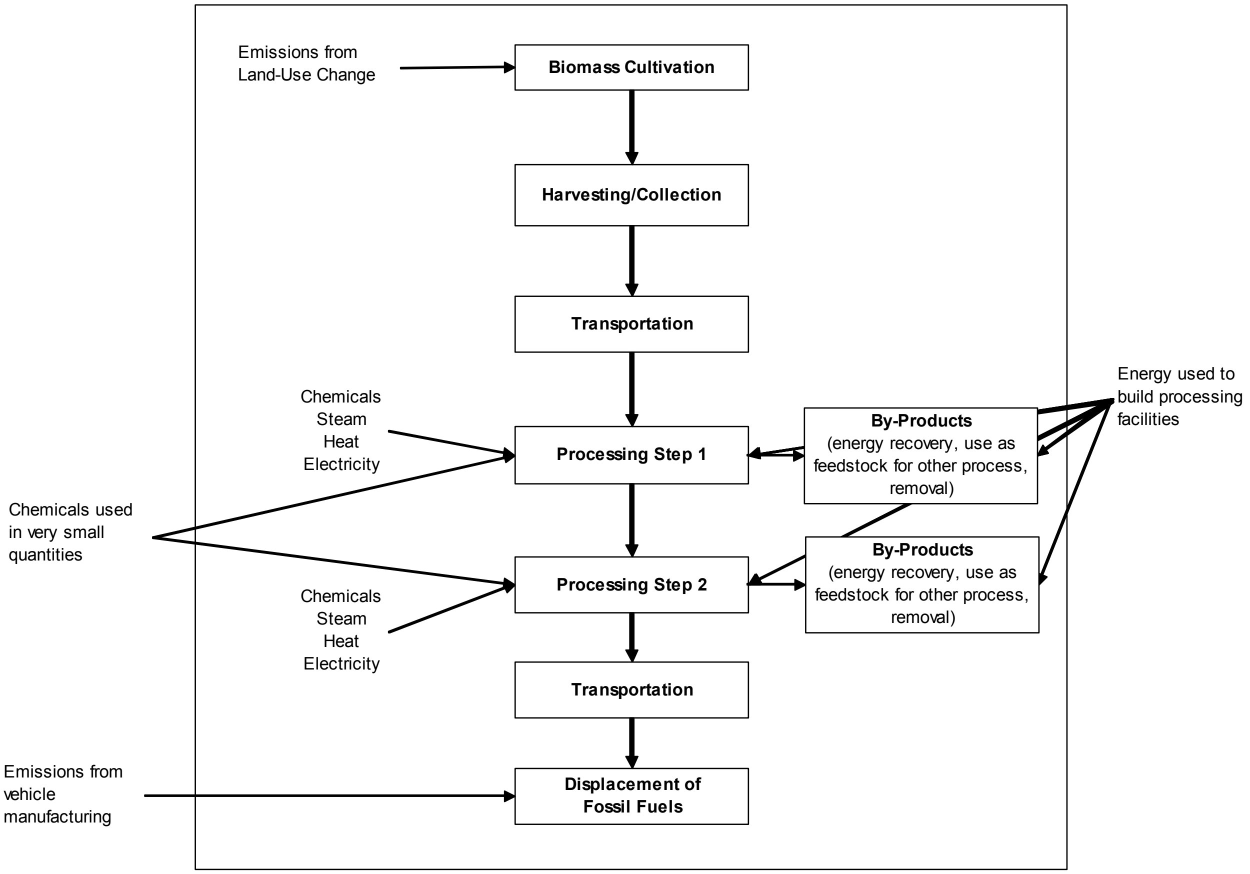
The following items are included in the analyses:

- Biomass cultivation and harvesting (Including: fertilizer and emissions from fertilizer production and use; nitrous oxide from bacterial decomposition in the field; pesticides; and energy for irrigation and machinery);
- Emissions resulting from land-use changes (see chapter 1.1), unless data was not relevant or readily available;
- All transportation steps including life-cycle transportation emissions (i.e. emissions from fuel consumption and fuel evaporation), transportation of secondary process ingredients, distribution of the product to where fossil fuels are displaced, and the removal of residues, if any;

- Processing, including secondary process ingredients (chemicals, etc.) plus all heat, electricity and steam (secondary chemicals used in very small quantities are omitted);
- Processing and energy recovery from by-products of the primary process (i.e. from burning lignin or char that is created when processing biomass); and
- Displacement effects from reduced usage of fossil fuels.

The following items are excluded from the analysis:

- For biomass residues - all preceding production steps. Feedstocks are assumed to be available emission-free, and all emissions until transportation of the residue to a processing facility starts are excluded;
- Emissions from the manufacture of biomass processing facilities, as well as the manufacture of vehicles for the transportation of biomass;
- Effects on electricity distribution, for example through distributed power generation with biomass;
- The life-cycle emissions of vehicles that use biofuels, as biofuels only displace emissions during the actual use of the vehicle, but not during production.



Note: Items outside the box were not included in the analysis

Figure 1.1 System Boundaries for Life-Cycle Analysis

1.3 Sensitivity Analysis

The sensitivity analysis comprises three aspects: technology improvements, electricity generation background mix, and transport distances. In order to capture potential future increases in process efficiencies and other improvements that could reduce overall energy consumption or emissions from the biomass conversion process, target data from U.S. Department of Energy, Canadian research plans and roadmaps, or manufacturers data were used.

The electricity background mix was varied to obtain four different scenarios, as shown in Table 1.1. These scenarios do not replace detailed analysis for a given country, as they represent typified data and not real data taken from an existing dataset. However, they do represent the main cases that will be encountered throughout OECD countries, and will provide insight into the effect of various modes of electricity generation.

Table 1.1 Scenarios Used to Model the Effect of Typical Electricity Generation Background Mixes in Various Regions

	Description	Emissions per kWh	Typical Regions
Scenario 1	Low carbon intensity power generation: 90% of nuclear or large hydropower; 10% natural gas	CO_2: 52 g	Québec, British Columbia, Manitoba; France; Norway; Sweden
Scenario 2	Moderate carbon intensity power mix: 65% nuclear/large hydro 25% coal 10% natural gas	CO_2: 288 g	Canadian average; Ontario; Atlantic Canada; Austria; Belgium
Scenario 3	High coal/oil content in power production (50%); nuclear/large hydro: 25%; natural gas: 25%	CO_2: 588 g	United States average, Denmark; Germany; Mexico; Spain; U.K.
Scenario 4	Very high coal/oil content: 75% nuclear/large hydro: 15% Natural gas: 10%	CO_2: 761 g	Alberta, Saskatchewan, central U.S.; Greece; Ireland; Netherlands

For transport distances, the Canadian case study selected for this report is the base case. The influence of transport distances is then discussed in more detail, describing the effect of multiplying or reducing them on the complete life-cycle GHG emissions.

1.4 General Explanations

Energy Balance: The energy balance is presented in two ways for each process. First, an output-based energy balance is based on a value often found in underlying studies, e.g. one million BTU energy content in a fuel produced from biomass. All energy inputs during the life-cycle of the feedstock-to-product thread are presented in relation to the energy contained in the end product. If the energy going into the process exceeds the energy contained in the end product, the process is very energy intensive. If the output-based energy balance is 1, as much energy as is contained in the fuel will be used for its production. In other words, twice as much energy is consumed in the production and combustion of a litre of fuel, for example, as is contained in it. This does not mean that the process is not viable, as most biomass resources have a much higher water content than fossil fuels, and will require extra energy (often delivered by part of the biomass feed) for drying. However, a high energy balance shows that the process is less resource intensive and therefore more desirable.

The second way of looking at energy balances is based on energy input. The input-based balance ignores the way biomass was made and starts at the plant gate. Whereas the output-based energy balance tends to ignore biomass lost "on the way" – for example, when part of the biomass input is consumed for energy purposes inside the process – the input-based energy balance will uncover such losses as it starts with the energy contained in the biomass as it enters the transformation thread. It will show more clearly whether a process can be called a "renewable" energy process, or whether so much extra external energy is required that it does not deserve to be called renewable. Electricity and natural gas inputs, as well as energy inputs in the form of chemicals or fossil fuels consumed by machinery, will heavily depend on fossil fuels. If the input-based energy balance approaches zero, or becomes negative, it is highly questionable whether a process is still renewable.

Higher Heating Value: For energy balances, either the lower or the higher heating value can be used. The lower heating value represents the energy obtained from burning a fuel without recovering the heat contained in water, which is generally formed as a by-product of combustion. For example in engines, condensation of such water is not likely to occur, and the energy contained in water vapour is therefore lost. This suggests that energy balances should be based on the lower heating value. However, some life-cycle analyses have used the higher heating value. In the end, results do not differ very much, as long as either one or the other heating value is used consistently.

Process steps: Definitions of process steps were often adopted from underlying studies used for this report. The following is a list of terms and their associated activities:

- *Fertilizer manufacture:* energy/emission related to the production of fertilizers and pesticides used for feedstock production, including raw material recovery, transport and manufacturing of chemicals.
- *Feedstock recovery:* recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, upstream processing prior to transmission, and mining.
- *Land use changes:* Emissions associated with the change in the land use in cultivation of crops, including N_20 from application of fertilizer, changes in soil carbon and biomass, methane emissions from soil, and energy used for land cultivation.
- *Feedstock transport:* pumping, compression, leaks, fugitive emissions, and transportation from point of origin to the fuel refining plant. Import/export transport distances and the modes of transport are considered.
- *Fuel production* (as in production from raw materials): conversion of the feedstock into a saleable product. Includes: process emissions (direct and indirect), combustion emissions for process heat/steam, electricity generation, fugitive emissions, and emissions from the life cycle of chemicals used for ethanol fuel cycles.
- *Storage and Distribution:* storage and handling of fuel products at terminals, bulk plants and service stations. Includes: storage, electricity for pumping, space heating and lighting.
- *Evaporation:* transfer of the fuel at a service station from storage to vehicles. Includes: electricity for pumping, fugitive emissions, and spills.

- *Emissions displaced by co-products*: Emissions displaced by electricity, a co-product of ethanol production, equal to emissions from electricity production displaced from other sources. Other co-products are calculated on the same displacement method.

Life-cycle data: Only the results from underlying studies or the authors' expert estimates for life-cycle data were included in this report. Some assumptions and key data are provided in the following chapters. More detailed information about input data and assumptions can be gained from the original studies and from an appendix to this study in EXCEL format, which can be obtained from the authors.

Moisture content: In order to obtain comparable results, all life-cycle GHG emission data are related to bone-dry (0% moisture) tonnes of biomass feedstock. For most processes, biomass will require some pre-drying. For example, fresh wood will contain about 50% moisture and needs to be dried to about 15% for gasification. Switchgrass will arrive at the plant gate with a 15% moisture content and may have to be dried to 7.5%. In some cases, drying can be achieved through adequate storage (e.g. seasoning for wood) or using heat, possibly combined with chipping or grinding. All such energy inputs have been included in the energy balances, as have related direct or indirect emissions of greenhouse gases.

Process impacts and displacements from other processes: A biomass-based product displaces both the manufacturing and the combustion fossil fuels, and related greenhouse gas emissions. For the example of biodiesel, the growth of canola plants sequesters carbon dioxide out of the air. When biodiesel is combusted later on, there are no emissions from the fuel itself as regrowing the canola sequesters the same amount of carbon dioxide that is set free in the combustion process. In addition, the manufacturing of conventional diesel also requires large energy inputs, which are displaced as well. On the other hand, any emissions from the cultivation, harvest, transport, and processing of canola oilseed diminish the amount of greenhouse gases displaced by using biodiesel (see Figure 1.2). Finally, any useful by-products, such as canola meal and glycerine (in the case of biodiesel made from canola oilseed), displace other products, which cause greenhouse gas emissions during their production. These emissions are also displaced by the biodiesel process and are credited back to biodiesel, offsetting part of the emissions caused during the cultivation and processing steps.

Emissions displaced by biodiesel = **Emissions from burning conventional diesel** + **Emissions from conventional diesel manufacture** – **Cultivation & land use emissions from canola agriculture** – **Emissions from biodiesel production and related transport** + **Emission displaced by by-products** (Canola meal and glycerine)

Figure 1.2 Determination of GHG Emission Reduction Benefits of Biodiesel

Chapter 2 Life-Cycle GHG Analyses of Selected Feedstock-to-Product Threads

2.1 Ethanol from Corn and Lignocellulosic Feedstocks in Southern Ontario

2.1.1 Underlying Studies and Assumptions

Ethanol can be made from starch contained in grain and corn, from sugar (sugar beets) and from lignocellulosic feedstocks, such as grass. In North America, corn is one of the main feedstocks used to produce bio-ethanol. In Canada, corn is mainly grown in Ontario and Québec. Levelton Engineering carried out a detailed life-cycle analysis of ethanol production from corn in Southern Ontario. This analysis is based on a model that is used today by NRCan in a modified version, called GHGenius. A second study from the same authors covers the lifecycle of corn stover, switchgrass, hay, and wheat straw [Levelton 1999]. This chapter is mainly based on this work.

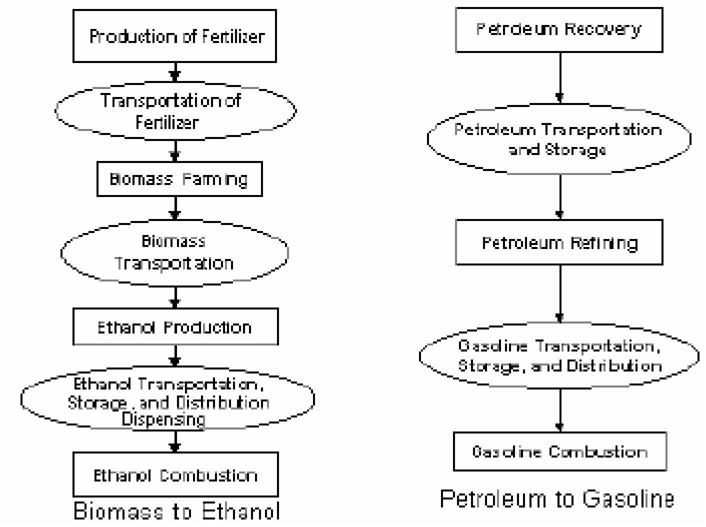


Figure 2.1.1 Fuel Cycles for Gasoline and Ethanol Production [Levelton 1999]

Figure 2.1.1 compares the fuel cycle for ethanol and gasoline, which is displaced by increased use of ethanol as a transportation fuel. The Levelton study makes some basic assumptions to assess overall energy consumption and greenhouse gas emissions:

Corn: Ethanol from corn is assumed to be produced through a continuous fermentation and distillation process, as used in the Chatham plant in Ontario. Emissions from nitrogen fertilizer use attributed to corn ethanol, are reduced by 30% due to the intense use of manure in Ontario. Corn yields are given as 123 bushels per acre (7.76 t/ha). Due to the use of distiller's grain as cattle feed, no surplus biomass is available to power the process, and external energy sources (electricity, natural gas) are used to make ethanol from corn.

Lignocellulosics: Corn stover, wheat straw, hay and switchgrass are assumed to be processed in a plant based on the Iogen concept, which is using enzymatic hydrolysis to produce ethanol. Emissions from fertilizer use are attributed to lignocellulosics either based on actual fertilizer use in cultivation, if any, or on the need to replace nutrients, that are removed together with the crop residues, with artificial fertilizer.

By-products: By-products of the corn-based process are CO_2, which is captured and sold, and distiller's grain, which is sold as animal feed. Emission credits are attributed to the use of distiller's grain, assuming that it is used partly to replace fodder corn and partly as cattle feed, displacing corn and soybean meal. The by-products of the enzymatic hydrolysis process are acetic acid (60 lb per tonne of feedstock), unfermented pentose (25% of total pentose produced), and non-fermentables (lignin), which are used for energy generation in order to deliver heat and electricity for the conversion process. The use of lignin for other purposes with a higher economic value could become feasible in the future, which would lead to different values for the energy/emissions balance of the process than those presented here.

Ethanol blend: Only the E10 (10% ethanol blended with 90% gasoline) case is examined here, as most of today's automobiles do not allow for the use of high-percentage ethanol blends. The E85 or E100 cases are also not likely to be implemented Canada-wide as the feedstocks available for ethanol production are limited. A national switch to ethanol as a transportation fuel would not be possible, although a 10% target could probably be exceeded (see chapter 5.1.4 of Stage 1 study).

Transportation: For lignocellulosic feedstocks, a 150 km transport distance to the plant was modelled. Transport distances for delivery of the ethanol were taken as 80 km for corn derived ethanol and 32 km for truck transport of wheat ethanol.

Process energy: Only the overall process energy needed for the Iogen process (100% obtained from burning the residual lignin) is known from the Levelton 1999 study. The exact split between electricity and heat was not reported. This information is proprietary and could not be obtained for this study. Knowledge of the split between heat and power is necessary to better compare the processes (i.e. the distortion in terms of reduced greenhouse gas emissions could be excluded from the use of process residues in the Iogen process) and model the influence of different electricity background mixes.

We assumed that the Iogen process is similar to the U.S. National Renewable Energy Laboratory (NREL) system, for which the split between heat and power use is publicly available [ECN 2001]. Thus, the boiler capacity is 95 MWth of steam, all of which is consumed in the production plant. The plant's electricity generation capacity is 44 MWe of electricity, of which 33 MWe (75%) is required internally, mainly for the blowers in the cellulose production section (18 MWe), and 11 MWe is available for export to the public grid. With an annual production of 156 million litres, this would represent 5.33 kWh_{th} of heat, 1.85 kWh of process electricity and 0.62 kWh of surplus electricity per litre (2.35 kWh per gallon), i.e. a split of 95/33, or 74%/26%, between thermal and electric energy used in the plant.

Of the total process energy given in Table 2.1.2, some is due to electricity, heat, and the chemicals used in the process. A range of between 30 and 38% of feedstock remains unused as lignin residue, extra biomass from unfermented sugars/ yeast and cell mass from enzymatic digestion [Levelton 1999]. As some of the energy consumed in the process plant is due to the chemicals added, we assumed that the portion of energy use attributable to process electricity and steam can be represented by taking 38% of feedstock input as the residue from processing corn stover and wheat straw, and 41% as the residue from processing hay and switchgrass.

The energy content of the residue is given as 9,250 BTU/lb [Levelton 1999, p.23], which amounts to 1,006,300 BTU/MMBTU (38% of 129.86 kg of feedstock) in the case of corn stover and a little more for wheat straw. We used 1 million BTU for corn stover and wheat straw, and 1.2 million BTU for hay and switchgrass, which have a higher process energy consumption. According to the Levelton study, 1.52 kWh of surplus electricity is created per gallon of ethanol when corn stover or wheat straw is used as feedstock, and 1.9 kWh if hay or switchgrass is used. This would indicate a slightly higher electricity consumption of the Iogen process vs. the NREL process. The percentage split between heat and electricity is therefore adjusted to 72%/28% in the case of stover or straw, and 73%/27% in the case of hay or switchgrass. Table 2.1.1 summarizes the assumptions made with respect to the heat/electricity split (1 kWh = 3,413 BTU).

The CO_2 emission credits for surplus electricity have been corrected to reflect the average Ontario power mix (instead of natural gas), in line with the methodology laid out in Chapter 1. In contrast to the original Levelton data, the process energy for lignocellulosics is first assumed, like that for ethanol from corn, to come from grid electricity and natural gas. Subsequently, credits are given for the use of biomass for heat and electricity, as well as surplus electricity.

Table 2.1.1 Split between Electricity and Heat Used in Ethanol Production Plants

Feedstock	Natural Gas Consumption	Electricity Consumption	Surplus Electricity
Corn [Levelton 1999b]	638,021 BTU/MMBTU	35 kWh/MMBTU	None
NREL numbers (corn stover/wheat straw)	720,000 BTU/MMBTU	82 kWh/MMBTU	18 kWh/MMBTU
Hay/Switchgrass	876,000 BTU/MMBTU	95 kWh/MMBTU	22 kWh/MMBTU

Note: Values for lignocellulosics were estimated based on NREL design.

2.1.2 Life-Cycle GHG Emissions

The background electricity mix used by Levelton was the regional mix for Ontario. We therefore assumed that the carbon intensity of electricity production can be taken as equivalent to the value given for Scenario 2 in Table 1.1 above.

Table 2.1.2 represents life-cycle GHG emissions from all steps of the ethanol production process: cultivation and harvesting, including energy inputs from diesel for agricultural machinery, fertilizer production, etc.; the production process within the ethanol factory, with all its inputs of steam, electricity and chemicals, feedstock and ethanol transport, and emissions due to evaporation. Land-use change emissions were also included, and reflects a loss in soil carbon through switching agricultural activity to growing corn, as well as methane emissions from well fertilised soils.

On the other hand, the use of ethanol emission reductions at several instances, which are accounted for as “credits” in the analysis: as it was assumed that natural gas and grid electricity were used for lignocellulosic feedstocks for the first part of Table 2.1.2, emissions from power and steam production are credited back to the process in the second part, as due to the use of process residues for power and heat generation, no net GHG emissions result at this level. In addition, surplus electricity is generated, which displaces electricity from the grid and associated emissions. Corn and grain residues are sold as animal food, where they displace other animal food that must otherwise be grown, i.e. the emissions associated with the cultivation, harvesting and distribution of these replacement grains (corn and soy) are credited here. Due to the calculation methodology, the emissions from the displaced gas in the E10 mix were credited back to the ethanol production process. A 10% ethanol fuel improves fuel efficiency, which is conservatively assumed to be 1%, which creates further emission reductions. The carbon contained in the ethanol itself was first sequestered from air (i.e., captured as CO_2 out of the air by the plant and turned into living biomass) and according to accounting rules laid down in the Kyoto Protocol, these emissions are not counted and are therefore also credited. Finally, credits were given for process improvements within the gasoline refinery due to the higher octane value of ethanol, as well as for reduced leakage and flares from displaced gasoline production ("other credits"). Figure 2.1.1 compares the emission reductions per tonne for each of the feedstocks, without and including the credits for by-products (all other credits are included for both datasets).

Table 2.1.2 CO_2e Emissions from Ethanol Production, in Grams Per Tonne of Feedstock Input (modified from Levelton 1999)

	Starch Crops		Lignocellulosics			
Process Step	**Corn**	**Wheat**	**Corn Stover**	**Wheat Straw**	**Hay**	**Switch-grass**
Cultivation & Harvesting	164,017	162,930	107,753	124,622	93,313	94,820
Land Use	7,810	171,920[1]	20,204	36,527	-33,752	-52,454
Transport to plant	15,360	6,537	33,448	34,164	33,553	34,095
Processing	342,875	387,422	522,833	502,972	548,967	547,644
Transport & Distribution	15,621	13,066	13,469	12,892	11,912	12,105
Evaporation	1,412	1,256	1,218	1,165	1,077	1,094
Sub-total	547,096	743,130	698,925	712,342	655,071	637,304
Biomass-to-energy credits	-	-	-478,609	-458,495	-505,884	-513,952
Distiller's grain	-117,155	-407,192[1]	-	-	-	-
Surplus Electricity	-	-	-70,174	-67,202	-75,603	-76,845
Displaced emissions from gas	-243,162	-227,914	-209,670	-200,684	-185,435	-188,430
1% fuel efficiency gain	-36,448	-34,163	-31,428	-30,081	-27,795	-28,244
Carbon sequestered in ethanol	-622,225	-583,205	-536,521	-513,527	-474,508	-482,172
Other credits	-263,990	-247,436	-227,629	-217,873	-201,318	-204,570
TOTAL	**-492,723**	**-528,865**	**-645,436**	**-574,837**	**-630,038**	**-668,480**
Per litre of ethanol	-1,231	-1,410	-1,871	-1,799	-2,137	-2,227

[1] Due to a different methodology used for the ethanol from wheat study, these numbers differ very much, but partly cancel each other out in the end result.

As can be seen from Figure 2.1.2, the by-product credits have a large impact on the absolute amount of GHG emission reductions. If the lignin residue from lignocellulosic feedstocks were used in an application that yields a higher monetary value than its energetic use, as is being explored by promoters of the process, lesser emission reductions might ensue, which would make the lignocellulosic process more similar in its effects to starch or sugar-based ethanol production.

As the CO_2 data are given per tonne of feedstock input - with different inputs required because of varying ethanol yields per tonne - they cannot be compared to each other. Our aim is to compare GHG emission reductions per tonne of feedstock in different applications in a subsequent analysis, when all chapters are evaluated in a synopsis (see Chapter 3). The last line of Table 2.1.2 therefore specifies GHG emissions per litre of output to allow for a comparison of the performance of different ethanol feedstocks.

* Large difference to corn due to changes in methodology between original studies

Figure 2.1.2 Absolute CO_2 Emission Reductions per Tonne for Ethanol Feedstocks, Comparing E10 to the Use of 100% Gasoline

The studies used for ethanol from grain and corn used different methodologies to calculate some of the emissions and emission credits; on the whole, however, both ethanol from corn (Ontario) and from grain (Saskatchewan) produce very similar emissions and emission displacements. Feedstock recovery for wheat is expected to emit more GHG because of longer distances and lower feedstock densities around the ethanol plant, whereas wheat distiller's grain will create slightly higher emission credits due to its higher protein content. The fuel production process and fertilizer inputs for wheat require higher energy inputs, which creates a somewhat better energy/GHG balance for corn than for wheat in the end.

The difference in GHG emissions between corn and lignocellulosic feedstocks is mainly due to the fact that the Iogen process uses feedstock residue to generate all its process electricity and heat. If biomass was likewise used to power the ethanol-to-corn process, GHG emissions could be expected to decrease to similar levels as those of lignocellulosic feedstocks. This can be seen from the sub-totals, which are all in the same range. Only when the emission reductions due to the use of biomass as an internal energy source are given, the Iogen process has lower emissions. If lignin was otherwise used, life-cycle GHG emissions might increase for the Iogen process. To explain the differences among lignocellulosics, wheat straw has a high nutrient content, which must be restored to the ground by adding extra fertilizer, hence the somewhat higher emissions from this thread. Hay and switchgrass have the lowest life-cycle GHG emissions – despite their lower ethanol yields – because they sequester additional carbon in the ground, assuming they are grown on unimproved pasture land.

2.1.3 Energy Balance

Table 2.1.3 shows the energy balance of ethanol production from several feedstocks. The higher heating value (84,700 BTU/gallon) was used by Levelton for this analysis. It reflects the energy gain including the recondensation of water contained in the exhaust gas, which cannot occur under the conditions in an internal combustion engine. However, corrections could not be made to correct for the lower heating value of ethanol (76,000 BTU/gallon), as all other inputs would have had to be changed as well. It is generally accepted that, although the lower heating value is probably more adequate, the end result does not differ much, whatever value is used throughout the life-cycle analysis.

Table 2.1.3 Energy Inputs as BTU per Million BTU Contained in Ethanol [Levelton 1999, S&T 2002]

	Starch Crops		Lignocellulosics			
Process Step	**Corn**	**Wheat**	**Corn Stover**	**Wheat Straw**	**Hay**	**Switch-grass**
Cultivation & Harvesting	198,000	237,300	138,149	116,301	125,995	133,801
Transport to plant	12,100	5,800	35,238	37,910	40,921	40,252
Processing	595,900	556,100	1,152,910	1,110,317	1,441,695	1,394,865
Transport & Distribution	15,500	15,400	17,283	17,283	17,283	17,283
Sub-total	821,500	814,600	1,344,597	1,381,820	1,625,893	1,586,199
Distiller's grain	-156,250	-125,400	-	-	-	-
Acetic acid & surplus electricity	-	-	-114,725	-117,155	-137,000	-136,100
Improved fuel efficiency	-141,600	-141,600	-141,600	-141,600	-141,600	-141,600
Refinery savings	-40,500	-40,500	-40,500	-40,500	-40,500	-40,500
TOTAL	**483,150**	**507,100**	**1,036,722**	**1,071,533**	**1,295,761**	**1,256,967**

In line with the methodology discussed in chapter 1, by-products are included in the analysis. The energy credits attributed to the ethanol production process stem from

a) the energy saved by the use of distiller's grain as cattle feed (displacement of soy and corn meal) for corn as a feedstock; for other feedstocks, the value of the residue in producing surplus electricity, as well as avoided energy use for the production of acetic acid, only counting the chemical energy contained in the acid;

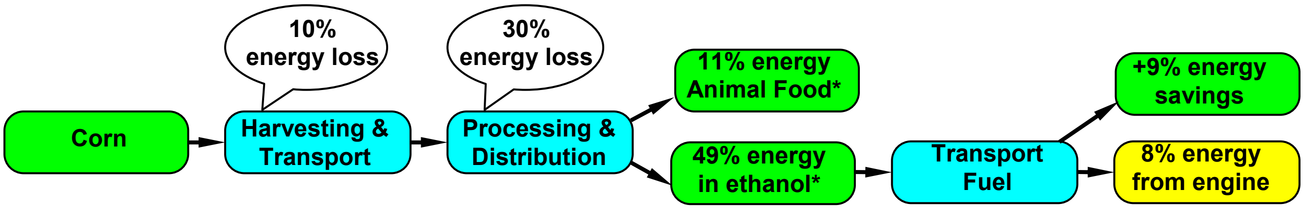
b) a 1% improved energy-specific fuel efficiency of E10 fuel;
c) energy savings during the refining process due to ethanol's octane value.

Table 2.1.4 provides an overview of energy payback (energy contained in ethanol per process energy inputs), showing that the energy balance of lignocellulosic feedstocks is close to 1, or even negative (i.e., smaller than 1) for hay and switchgrass. The energy payback "after credits" adds the energy credits to the energy contained in the ethanol, leading to slightly higher overall results.

Table 2.1.4 Energy Payback of Feedstocks for Ethanol Production [BTU/BTU]

Feedstock	Before Credits	After Credits
Corn	1.22	1.63
Wheat	1.23	1.61
Corn Stover	0.83	0.96
Wheat Straw	0.81	0.94
Hay	0.69	0.81
Switchgrass	0.70	0.83

Part of the difference between corn and lignocellulosic feedstocks is caused by the high rate of manure use in Southern Ontario, for which the original analysis was made. Manure provides one-third of the nitrogen for corn, whereas the fertilizer requirements for all lignocellulosic feedstocks were calculated based on synthetic fertilizers only. It is therefore to be expected that the energy balance for lignocellulosics would be slightly improved if manure was used to the same extent, or that the corn-to-ethanol energy balance would be less favourable if only artificial fertilizer was used to grow corn. The higher ethanol yield from corn (470 l/t vs. 305-345 l/t for lignocellulosics) also contributes to its better energy balance.



* 49%: actual ethanol energy content. Energy content in cattle feed by-product was increased to reflect chemical energy content as opposed to life-cycle energy displacement

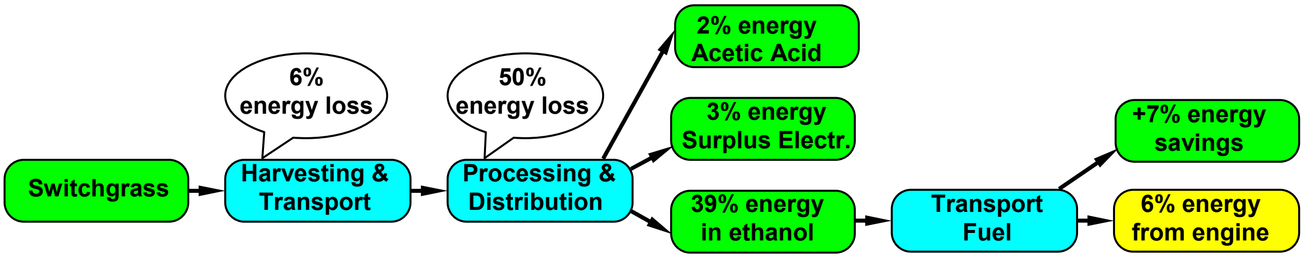


Figure 2.1.3 Energy Balance of Ethanol from Corn (above) and from Switchgrass (below)

The main factor influencing the energy balance of lignocellulosic ethanol is, however, the about twice as high energy input required for the enzymatic hydrolysis process compared to the fermentation process used to make ethanol from corn and grains. This is also shown in the input-based energy balance represented in Figure 2.1.3, which illustrates the energy balance in a slightly different way, clearly distinguishing between the energy contained/displaced in each of the process outputs. For these flow diagrams, the chemical energy contained in the feedstock was set as 100%, and energy used during subsequent handling and processing steps is given as a percentage of the original energy content in the feedstock. Some of the feedstock energy ends up in by-products, either as chemical energy contained in them, or as energy displaced from their production by other means. The energy balance for corn shows that in the end, assuming an engine efficiency of 17%, only 8% of the thermal energy contained in corn ethanol will actually be available as kinetic energy. For lignocellulosic ethanol, only 6% of the original feedstock energy is available for transportation. Energy savings occurring in the refinery and due to better fuel efficiency are shown in a separate box, as they represent a secondary effect of ethanol use that is not directly related to the ethanol production process.

The energy balance for ethanol from softwood is likely to be very similar to other lignocellulosic feedstocks, with a yield of 320 litres of ethanol per tonne of feedstock input [IJLCA 2003, Figure 1]. For sugar beets, the energy balance tends to be slightly better than for wheat and corn [KIWE 2003].

2.1.4 Discussion of Input Values Used in the Underlying Study

There is a great deal of controversy over whether or not the overall energy balance of ethanol production from starch-based and lignocellulosic feedstocks is positive or negative. This discussion comes down to how by-product credits are treated in the calculations, but also which amounts of fertilizer and other energy are used in the cultivation of corn.

The energy input data were taken over from the Levelton 1999 study, as these were verified and adapted for Canada. They are displayed in the left column of Table 2.1.5. In the middle, Sigurdson's data for Manitoba are given, and values from a British study are included in the right column. Extremely high yields are observed in the U.K. (possibly due to much better moisture and soil conditions), and both Sigurdson and the U.K. study assume higher diesel fuel inputs than the study used for the present analysis. Chemicals (biocides) inputs are assumed to be twice as high in the U.K. study than the values used here, and Sigurdson assumes even higher inputs, based on cost.

Table 2.1.5 Comparison of Input Data for Wheat-Based Ethanol

	S&T 2003	Sigurdson 2003	SHU 2003
Wheat yields	40 bushels/acre	36 bushels/acre	119 bushels/acre[1]
Nitrogen input	48 lbs/acre	70 lbs/acre	46 lbs/acre
Diesel fuel input	12 litres/acre	22 litres/acre	44 litres/acre
Chemicals input	$4.5/acre (4.4 kg/ha)	$32.00/acre	8.4 kg/ha

[1] One bushel of wheat = 60 lbs

Putting these differences into perspective, a doubling of the energy inputs required for wheat cultivation in Canada would still result in an overall positive energy balance (see Table 2.1.3 above), and would also still deliver GHG emission benefits from using wheat ethanol, although these would be much smaller than those from lignocellulosic feedstocks (see Table 2.1.2).

However, as can be seen from Table 2.1.3, the energy balance for ethanol from lignocellulosics is very close to 1, and negative for all feedstocks if by-product credits for energy are not included in the calculation. This means that slight improvements in efficiencies of gasoline production, a bad harvest, or other variables can undo the slight energy gains from ethanol production shown for some feedstocks, and the overall energy balance will only remain positive if important credits from the use of by-products and from other energy savings still exist.

These credits can be assumed to be rather safe in all cases, as the use of distiller's grain as animal food and also the use of residual biomass for process energy in the Iogen process will continue to exist. On the other hand, the dependence on by-product shows that the production of ethanol is an energy-intensive process with a low energy payback, suggesting that other biomass uses may present larger energy returns.

The transport distances and related emissions used for this analysis assume that feedstocks are cultivated close to the ethanol plant. If grains, such as corn, were imported from the U.S., as is being discussed in the context of expanding ethanol production in Manitoba, for example, these distances may become much longer. Sigurdson suggests 600 miles of truck transport for corn imported to Manitoba from the U.S. [Sigurdson 2003] – this would indeed undo any GHG reduction benefits from the ethanol produced.

2.1.5 Economic Aspects

In the current fuel market, ethanol is not competitive with gasoline. The average cost of production for a litre of ethanol from corn (starch) in the large-scale Chatham plant, net of the co-product value, amounts to about $0.45 per litre. By comparison, Ontario's 12-month average wholesale price for gasoline on December 16, 2003 was $0.36 per litre [FF 2003]. At the same time, gas prices are highly volatile (see Figure 2.1.4), which increases economic uncertainty for ethanol as a competing fuel. This means that even with generous tax exemptions granted to ethanol, such as the Canada-wide excise tax exemption of $0.10/litre of ethanol mixed with gasoline, market breakthroughs cannot be expected.

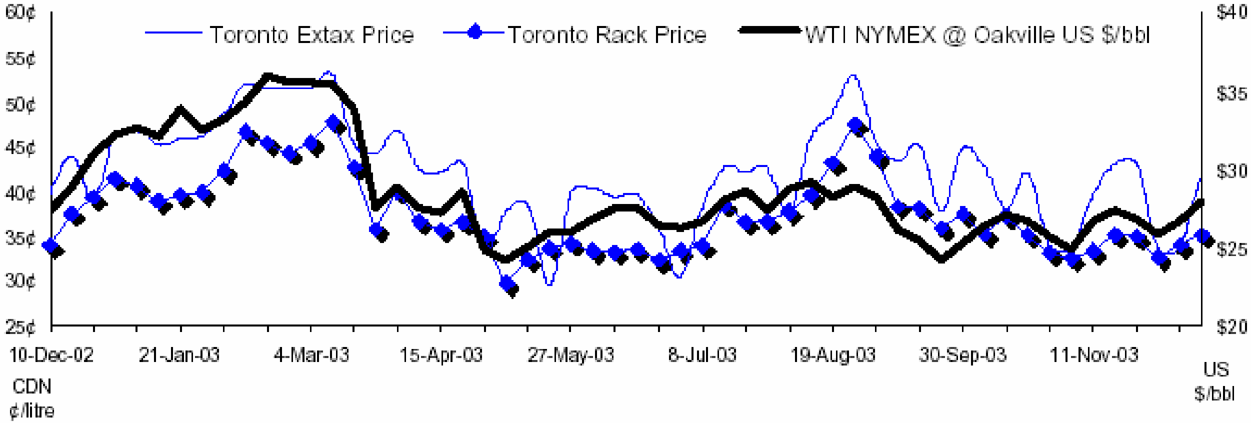


Figure 2.1.4 Price Volatility of Gasoline in Ontario [FF 2003]

Six Canadian provinces provide additional tax exemptions ranging from 9 ¢/l to 20.4 ¢/l [CCC 2003, p.9]. However, uncertainty about the continuation of these exemptions, and simply the disincentive to blend ethanol with gasoline due to reduced profits for the oil industry from this practice (with 10% of profits going to ethanol producers in the case of an E10 blend) has prevented a significant ethanol industry from being created in Canada. A government-mandated E10 standard, as being pursued in Saskatchewan and Manitoba, would remove market impediments and could create stable demand for ethanol.

The projected costs for large-scale ethanol production from lignocellulosic biomass residues are C$0.42 per litre because feedstocks generally are agricultural residues and can be obtained more cheaply than corn. Through technological improvements, the cost of ethanol from lignocellulosics may be further reduced to about C$0.29 per litre in the longer term [ECN 2001], which would bring the price below the current average for gasoline. However, the lower energy content of ethanol results in somewhat lower value-for-money per litre, which may have to be taken into account for such assumptions.

Cost improvements for ethanol from lignocellulosics are likely to occur in the future, as research and process improvement can be implemented. Work is on-going to reduce the cost of the enzymatic hydrolysis step by a factor 3 to 10, as this step causes about half the production cost [ECN 2002]. The hydrolysis of hemicellulose results in the generation of pentose sugars, which cannot be turned into ethanol by the enzymes currently used. If processes can be developed to make additional ethanol from these sugars, process economics would be further enhanced. Although corn yields are increasing each year, it is expected that lignocellulosic feedstocks have the potential to become the cheaper ethanol resource due to their significantly lower cost, which may be equal to transport cost in the case of agricultural waste. The National Renewable Energy Laboratory expects the cost of bio-ethanol to reach US$1.07 per gallon by 2010, and $0.7 per gallon by 2025, making it competitive with gasoline on a BTU basis, based on a crude oil price of US$25 per barrel [NREL 2004]. Increasing crude oil prices could therefore make bio-ethanol competitive even earlier.

2.1.6 Other Environmental Aspects

When using energy crops, certain tradeoffs have to be taken into account. Some of these tradeoffs are difficult to include in life-cycle analysis, or even when quantified, need to be evaluated in a greater context to make a judgement concerning the sustainability of a feedstock-to-product thread.

For example, micro-elements needed to restore the minerals base in a field from which additional residual biomass has been removed have not been included in the life-cycle GHG analysis. Other aspects, such as increased erosion due to the removal of biomass, water consumption of the ethanol production process, and the changed exhaust emissions profile all have an impact on the overall sustainability of ethanol production and use. The gross water consumption when making ethanol using the enzymatic hydrolysis process is high (28-54 litres per litre of ethanol, compared to 10-15 litres for ethanol from corn or grain), although it can be reduced by recycling some of the process water [ECN 2002].

Ethanol use reduces particulate emissions from motor vehicles by between 25% and 32% percent, depending on the vehicle [MEO]. Particulates have been fingered as a cause of respiratory ailments. Ethanol also displaces the uses of toxic gasoline components such as benzene - a carcinogen.

Ethanol plants use large amounts of fresh water, producing large amounts of nutrient rich wastewater. There may be odour problems close to ethanol plants, and ethanol causes aldehyde and alcohol emissions, which are carcinogens.

2.1.7 Sensitivity Analysis and Extrapolation to Other Regions

Figure 2.1.5 shows the relative importance of each production step for ethanol's energy balance. It follows that improvements to transport efficiency will only have marginal impacts on the overall energy balance of ethanol production. More efficient cultivation and harvesting may yield better results, especially if artificial fertilizer was replaced by organic fertilizer, which requires less energy inputs. By far the most important factor when trying to improve the energy balance is process efficiency.

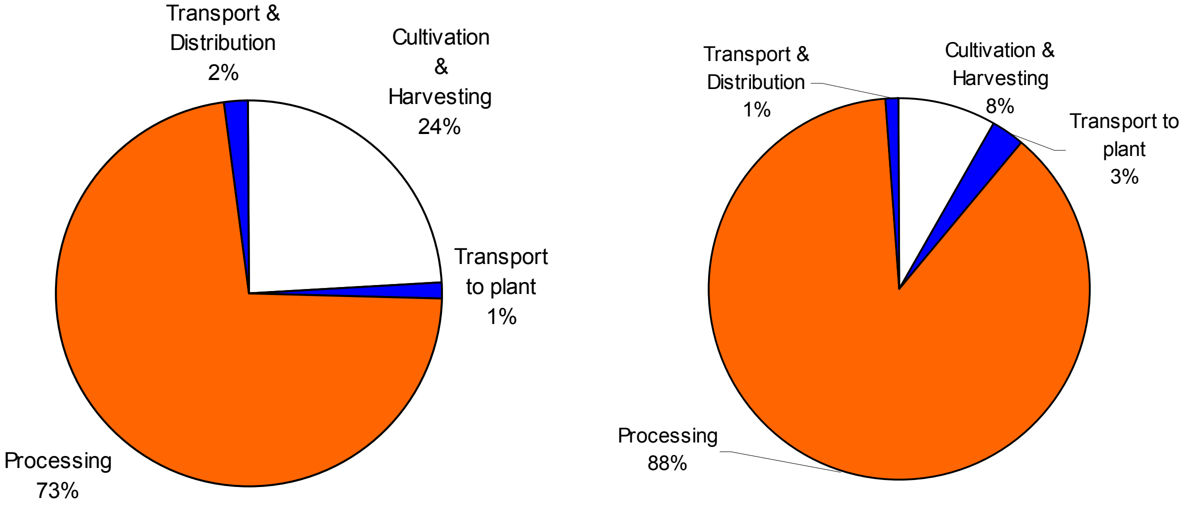


Figure 2.1.5 Energy Consumption for Ethanol from Corn (left) and from Switchgrass (right)

Technology improvements: Process efficiencies can be improved through energy efficiency measures, or by increasing harvests and ethanol yields. Levelton 1999 lists possible ethanol yield increases of between 1% for corn and 21-22% for all lignocellulosic feedstocks. However, these gains are counteracted slightly by a loss in surplus electricity production because less residue is produced. For ethanol from corn, significant energy efficiency improvements of 15-20% are expected [Levelton 1999b, p.24]. Corn yields also increased steadily over the past decades. On the whole, these improvements could lead to significant improvements, as shown in Figure 2.1.6. By 2010, energy requirements for ethanol production are expected to decrease significantly. Ethanol from corn will be made at an energy cost less than half of its energy content, and even ethanol from switchgrass could be produced with a smaller energy input than the energy contained in the ethanol product (if by-products are included).

Other possible improvements are the replacement of the acid hydrolysis pre-treatment (currently using sulphuric acid) by another process. One promising options seems to be the use of carbonic acid, using CO_2 produced on-site from the fermentation process, possibly combined with mild steam pre-treatment. This method has high sugar yields, low inhibitor formation and produces no waste [ECN 2002]. The use of a Biomass-Integrated-Gasification/Combined-Cycle system (BIGCC) is expected to increase the overall energetic conversion efficiency, mainly due to a higher power production efficiency. However, the economic advantage of increased surplus electricity generation comes at the price of relatively high specific investment costs of the BIG/CC [ECN 2001]. Based on the NREL system analysed, ECN 2001 models surplus electricity production to increase about five-fold. Due to the somewhat higher assumed electricity consumption for the Iogen process and the possibility that pentose sugars will also be turned into ethanol, we simply assume that the electricity output of 1.4 kWh per gallon in 2010 will increase fivefold to 7 kWh through the use of BIGCC, which is modelled for figure 2.1.6. It should be noted that improvements to the heat and steam generation system could also be implemented for corn as a feedstock, but these have not been modelled here.

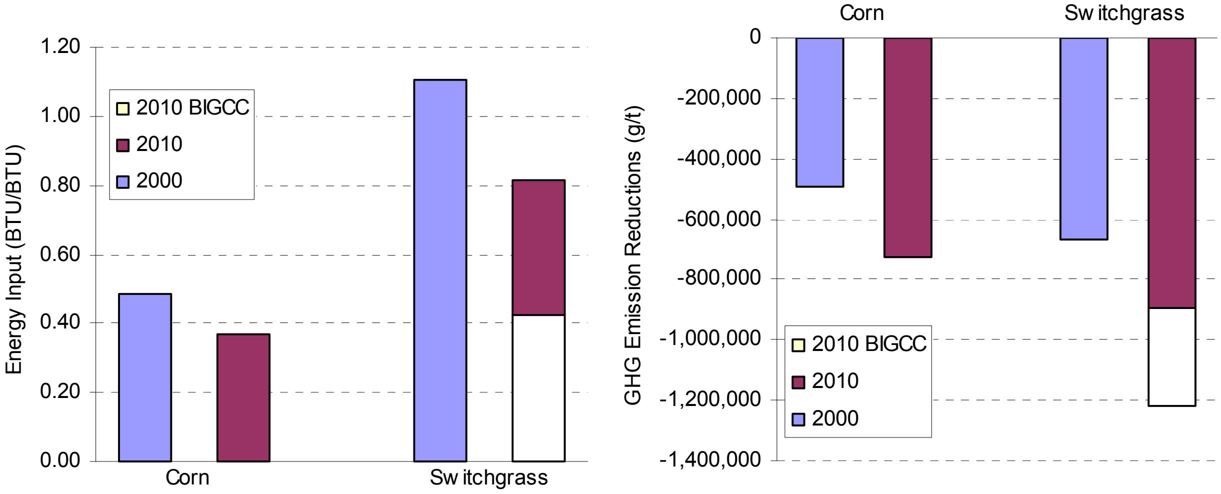


Figure 2.1.6 Comparison of Energy Balances (left) and GHG Emissions (right) for the years 2000 and 2010, for Corn and Switchgrass as Feedstocks

To model 2010 CO_2 emissions, new assumptions had to be made as to the split between electricity and heat production from switchgrass, representative of all lignocellulosic feedstocks. Process energy consumption decreases significantly, and ethanol yields grow from 310 l/t in 2000 to 375 l/t in 2010, which reduces total process energy requirements to 965,000 BTU/MMBTU [Levelton 1999, p.33]. We assume again that part of this is due to process chemicals and reduce the energy used for process heat and electricity to 880,000 BTU/MMBTU, i.e. 642,400 BTU for heat (73%) and 237,600 BTU (70 kWh/27%) for electricity, and an additional surplus of 1.4 kWh per gallon, or 18.4 kWh/MMBTU ethanol output. The Levelton study assumes an increase in fossil fuel-based electricity generation in Ontario[1], which was modeled as Scenario 3 emissions, absent any specifications provided on the 2010 electricity generation mix used in the original study.

Both ethanol from corn and ethanol from switchgrass (also representing other lignocellulosic feedstocks) are expected to experience significant improvements to their life-cycle energy and greenhouse gas emission profiles. The more efficient BIGCC option for switchgrass has a major additional positive impact on both the energy balance and CO_2 emissions, due to the large credit from feeding more electricity to the grid (based on Scenario 3 emissions for 2010 in Ontario, in line with the original assumptions of the Levelton study).

Influence of transport distances: The average transport distance modeled by Levelton for corn was 72 km (45 miles), and 150 km for lignocellulosics. The energy required for feedstock transport is 2.4% of the total after credits for corn and 3.2% for switchgrass. We have modelled a tripling of these distances, in order to reflect larger plants requiring larger areas for growing feedstocks, or more European circumstances, where agricultural surfaces represent a smaller

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[1] This assumption seems no longer valid, as the current government has committed to phasing out coal-based generation by 2007, replacing it by nuclear, natural gas and renewable energy.

share of land use than in sparsely populated North American regions. The distance from the ethanol plant to the gasoline plant is assumed to remain the same.

As Figure 2.1.7 illustrates, the influence of transport distances is small. A threefold increase only raises the life-cycle energy consumption by 5-6%. Likewise, the impact on greenhouse gas emissions is small – the largest impact being a 10% reduction of the emission reduction benefits from switchgrass if the transport distance is tripled to 450 km. These findings are confirmed by the literature: Schlamadinger 1997 summarises several studies and states that harvesting and transport of straw or logging residues usually makes out 4% of overall energy required for biomass energy systems. Increasing the distance from 50 km to 1000 km (most of this by ship or train) only raises this share to 7% [Schlamadinger 1997, p.366].

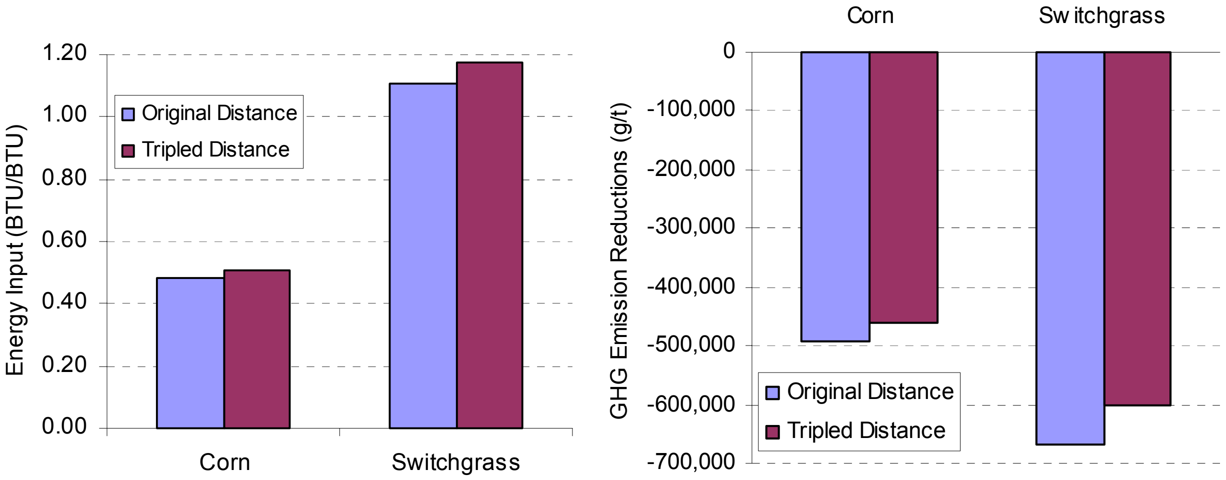

Figure 2.1.7 Comparison of the Influence of Tripling Initial Feedstock Transport Distances on Energy Balance (left) and GHG Emission Reductions (right), for Corn and Switchgrass as Feedstocks

Influence of electricity background mix: To determine which influence the background mix has on the emissions displaced by bio-ethanol made from corn and from switchgrass, the indirect emissions were calculated for each of the scenarios defined in Table 1.1. The default scenario used above was Scenario 2 (representing average emissions from Ontario's power mix). Only the influence of electricity used in the ethanol plant was modelled, which was determined to be 313 kWh per tonne of corn. In the case of switchgrass, the plant generates 155 kWh of surplus electricity per tonne of switchgrass, and the power mix does have no influence on emissions from electricity used at the plant as all electricity needs are covered by the combustion on lignin. However, the surplus electricity will displace different amounts of emissions, depending on what the background power mix is.

Electricity consumption in the ethanol production plant (0.074 kWh/l[2] of ethanol) has little influence on the overall GHG emissions of ethanol production from corn. Figure 2.1.8 shows that greenhouse gas emissions would only be reduced by an additional 1% if a Scenario 1 (low-emission) background mix was used instead of Ontario's average emissions (modelled as Scenario 2). Emission reductions would be reduced by only 3% under Scenario 4 (high coal scenario). For switchgrass, the differences are much more visible, but the values change in the

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[2] This value was corrected to 0.12 kWh in a subsequent study [S&T^2 2003], but this will still have little influence on overall emission reduction effects.

opposite way, as surplus electricity is generated. Under Scenario 4, emission reductions would be increased by 11%, but in all cases the performance of switchgrass is better than that of corn ethanol if lignin is used to produce process energy.

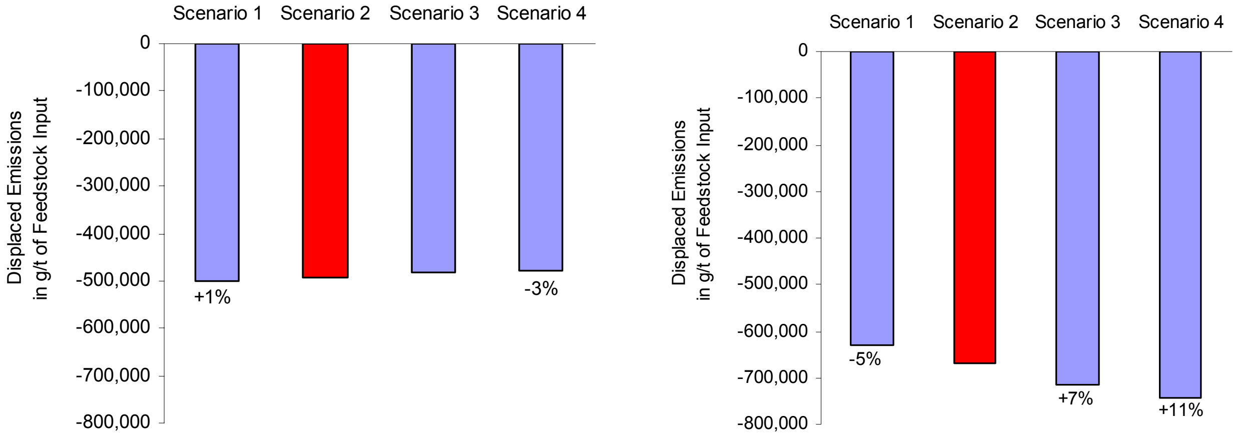

Figure 2.1.8 Influence of Electricity Background Mix on Life-Cycle GHG Emissions for Corn as a Feedstock (left) and for Switchgrass (right)

Regional differences: Levelton 1999 also models the difference between Eastern and Western Canadian wheat straw. This difference is mainly due to the fact that Western Canadian straw contains less nutrients, meaning that fertilizer requirements are two-thirds lower. In addition to that, land use changes are modelled as less significant in Western Canada. Per tonne of feedstock input, these parameters reduce life-cycle GHG emissions of ethanol production by 14%, such that life-cycle CO_2 emission reductions are 17% lower. The intense use of manure in Southern Ontario, replacing 30% of artificial nitrogen fertilizer [Levelton 1999, p.25], is another regional irregularity. However, seen the share of fertilizer in overall energy use, this reduction does not have a major impact on the results. The soil's capacity to sequester carbon and soil fertility, irrigation requirements and vegetation periods will also influence the overall result.

Updated GHGenius Data: Natural Resources Canada provided updated data currently used in the GHGenius model. These data show reduced emissions from the ethanol lifecycle for both corn ethanol (25% of value used here) and wheat ethanol (between 10 and 25% of value used here). These reduced values are mainly due to increased emission displacements attributed to the animal feed by-products. For corn ethanol, these new values would result in about 37% increased emission reductions. While these variations are considerable, they depend on how by-product credits are weighted in the overall analysis and show that there are still some uncertainties with respect to by-product credits and their contribution to overall emission reductions. For wheat ethanol, the updated values are about the same that were used in this analysis.

2.1.8 Summary and Analysis

Figure 2.1.9 provides an idea of the ranges that life-cycle GHG analysis results can take if certain key parameters are changed, the "main" scenario being the one modelled in Tables 2.1.2 and 2.1.3. Whereas regional differences pertaining to fertilizer requirements as discussed above for wheat straw were left out, the graph shows the impact that electricity background mix, technology improvements and transport distances can have.

As Figure 2.1.9 shows, results can be greatly influenced by the input parameters. While the "worst case" energy scenario is mainly influenced by increasing transport distances, which has a small effect, technology and background mix changes together can have major impacts on greenhouse gas emissions, both in the positive and negative direction. However, none of the options modelled completely cancel out the emission displacement benefits of ethanol.

The influence of using biomass as a feedstock when producing ethanol from corn would also have a major impact. It must be clearly understood that the Levelton study compares one process the residue of which is used as cattle feed, with another process the residue of which is used to generate energy for the process itself, greatly reducing greenhouse gas emissions.

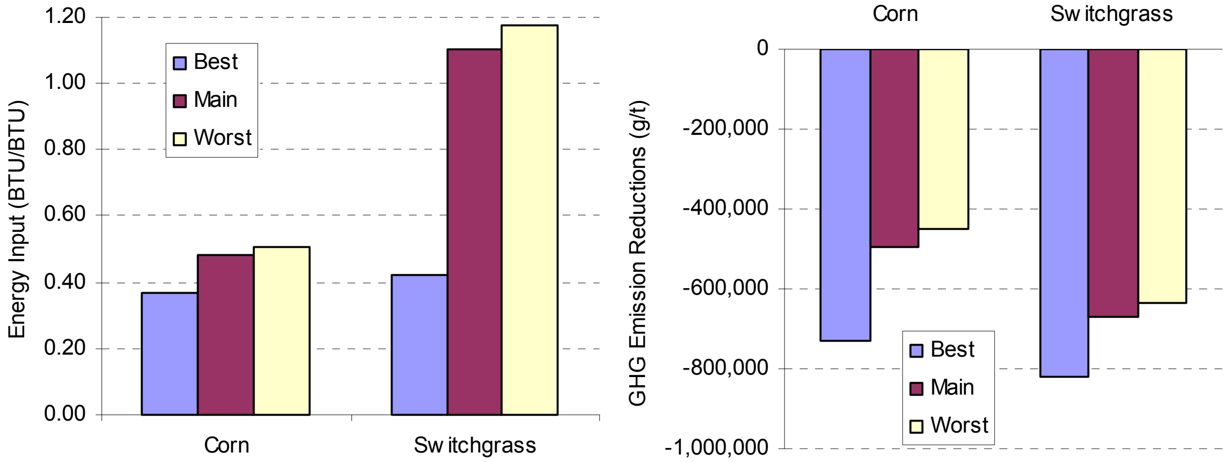

Figure 2.1.9 Combined Influence of Transport Distance, Electricity Background Mix and Technology Improvements on Energy Balance (left) and GHG Emission Reductions (right), for Corn and Switchgrass as Feedstocks

2.2 Biodiesel from Canola and Waste Oil and Fats in Alberta

2.2.1 Underlying Studies and Assumptions

Canola is mainly cultivated in the Prairies, although it is grown throughout Canada. This chapter is based on work carried out be Levelton Engineering to update the Canadian GHGenius Model [Levelton 2002a]. The study assumes extraction of the oil using hexane as a solvent, which is also current practice for edible canola production in Canada [EC 2004]. We also drew upon a study assessing the potential for producing biodiesel in Alberta [IAG 2003] for feedstock availability data and the economic analysis.

Conventional diesel fuel: Biodiesel is assumed to displace emissions from ultra-low sulphur diesel, as the first such plants have already been built in Canada, and because federal legislation makes this quality mandatory by 2006. As biodiesel has a higher viscosity than conventional diesel, it cannot be used in very cold temperatures as they occur in Canadian winters throughout most of the country. We assumed therefore that biodiesel would be blended with conventional diesel, as B10 or B20 (10 or 20% biodiesel)[3]. The amount of biodiesel mixed in has no impact on the emission benefits of each unit of biodiesel produced, as emission reductions are proportional to the share of biodiesel in the blend [NREL 1998].

Biodiesel as an additive: Several test runs with a VW beetle with a 1.9 litre turbo diesel engine and a Ford 2 litre diesel engine carried out between 1997 and 2000 have shown a significant increase in fuel efficiency through the addition on 0.1 to 1% of biodiesel to conventional diesel. It was shown that biodiesel significantly improves lubrication, with and average of a 40% reduction in engine wear. A VW "New Beetle" showed a fuel economy improvement of between 1.9% and 13%, with an average of 5.8%, when 0.5% biodiesel was added to the fuel [Hertz 2001]. This means that one unit of biodiesel displaced about ten units of conventional diesel and related emissions, which is a very significant opportunity for using biodiesel if the results of these trials can be confirmed at a larger scale. This options was therefore also modelled (assuming a 5% better fuel economy when adding 0.5% biodiesel) to show the significant potential of using biodiesel as an additive to conventional diesel.

Transesterification process: The process to produce biodiesel from vegetable oils is assumed to be base catalyst (usually caustic soda) transesterification of the oil with methanol. 100 kg of oil react with 10 kg of methanol to 100 kg of diesel and 10 kg of glycerine. Most of the methanol is recovered from the process. Some of the hexane solvent will remain in the animal feed. The underlying technology is assumed to be the Lurgi Process for virgin soybean and canola oil, and the BIOX Process for waste oils and animal fat as feedstocks. BIOX is a Canadian concept that is proven at laboratory stage and allows for the continuous processing of feedstock, instead of in batches, due to the reduced reaction times (30 minutes in total). The BIOX process tolerates up to 15% of free fatty acids, which makes it more suitable for used cooking oils.

By-product credits: Animal feed (soybean or canola meal) is produced when making biodiesel from agricultural crops. The allocation of credits was modified from the approach chosen for the ethanol chapter: the soybean meal credit is calculated as
1.61 x emissions from soybean milling – 0.73 x emissions from canola milling
and likewise, the credit for canola meal is determined as

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[3] Trials in Montréal showed not more than 5% of biodiesel can be added for buses to be able to start without being heated overnight [Coxworth 2004].

1.21 x emissions from canola milling – 0.55 x emissions from soybean milling.
The canola meal yield is given in the Levelton study as 16.28 lb/gallon of biodiesel. This number can be converted to 685 kg/tonne of canola oilseed – too high a number, seen that 400 kg of biodiesel must also come from the same tonne. The credit for canola meal was therefore reduced to reflect a yield of only 600 kg pr tonne of oilseed.

Glycerin is another by-product of biodiesel production and accounts for about 10% of animal fats and vegetable oils. The amount of glycerine producer for each litre of biodiesel displaces 4134 BTU of energy otherwise required to produce glycerine from fossil feedstocks. Canola straw and other plan residues that are not used in the process were not included in the analysis, other than recognising the nitrogen contained in crop residues. This nitrogen is assumed to be available for the following crop, reducing fertilisation requirements.

Transport distances: The Levelton study assumes mean transport distances of 50 miles for feedstock transport by truck for 90% of the feedstock, and 100 miles by train for 10% of the feedstock. 50 miles are also assumed to be the transport distance for biodiesel by truck (already mixed as B10, or as an additive, with conventional diesel). An American study on biodiesel from soy oil assumes a transport distance of 120 km (75 miles) for the feedstock, 914 km for the soy oil to the biodiesel plant and 160 km (100 miles) for biodiesel transport [NREL 1998]. As can be seen from Figure 2.2.1, most of Alberta's canola comes from Southern and some from Northern Alberta.

Figure 2.2.1 Canola Growth Regions in Canada [CC 2004]

A commercial-size plant for 60 million litres of biodiesel would require a little over 60 million litres of crude canola oil, or about two and a half times as much oilseed (150,000 tonnes). Only about 3 million litres of off-grade canola oil are available in Alberta each year [IAG 2003, p.10], which would imply that most of the canola oil would have to come from increased cultivation. For a plant located in Edmonton, assuming that most of the extra oilseed would come from Northern Alberta, we therefore assume a transport distance for the feedstock of 400 km. Edmonton is close to three of Alberta's refineries, which would mean that biodiesel transport could be as little as 50 km to the refinery, where it would be blended with conventional diesel. This distance could be zero if the biodiesel plant were on the same site as an existing diesel production plant. We therefore modified the energy inputs and emissions related to transport to match the aforementioned assumptions for an Alberta refinery in Edmonton.

For waste vegetable oil and fat, we have assumed a mean transport distance of 320 km to the plant, which is a conservative estimate if these oils are mainly collected in urban centres. Alberta produces about 120 million litres of animal fats and yellow grease per year [IAG 2003, p.10], which is more than enough for a commercial-size plant. Overall diesel consumption in Alberta was four billion litres in 2001 [ibid., p.11]. To achieve a 10% biodiesel target, 400 million litres would be required. This could, however, only be achieved using additional canola oil from dedicated energy crops and/or additional waste oil from outside the province.

Background power mix: As in the previous chapter, Levelton is assuming the Ontario background mix for the calculation of indirect emissions. This has been corrected to Scenario 4 emissions, which are more representative for Alberta. Electricity consumption data is given for all process steps, and based on those numbers, indirect emissions were adjusted.

Biodiesel from waste oil and animal fats: Like virgin canola oil, used canola and other vegetable oils can also be purified and then transformed into biodiesel, by the same transesterification process. The steps covering cultivation, drying, storage and refining of vegetable oil included in the analysis of canola oil as a feedstock are omitted from the analysis for recycled oil. Likewise, by-product credits for canola meal were also left out of the analysis. On the other hand, the rendering process to produce fat from animal waste, and the purification of waste oil for biodiesel production, are included. By-product credits were also given to bone meal produced from the animal waste rendering process, and again for glycerine produced during the actual esterification step. It is assumed that the collected oil has to be transported over 320 km (diesel consumption the same as for transportation of the biodiesel product), and that distribution parameters are the same as for biodiesel from canola oilseed.

Soil carbon and nitrous oxide emissions: Changes in soil carbon and emissions from microbial fertilizer decomposition in the field contribute significant amounts of greenhouse gases to the production of biodiesel from canola, and even more so from soy beans. It is assumed that for each kg of nitrogen applied as fertilizer 0.01125 kg of nitrous oxide is formed, which is a potent greenhouse gas. Emissions of ammonia and nitrogen oxides can also form nitrous oxides after atmospheric deposition, and about 15% of fertilizer applied is estimated to be lost through leaching or surface runoff in Canada.

Nitrogen fixation: Soy beans fix nitrogen out of the air, which reduces fertilizer requirements to only 10% of those required for canola. Levelton assumed that 92% of nitrogen in the crop is fixed and that most (90% of plant nitrogen) of this is in the plant. Canola does not fix nitrogen, but a small amount of nitrogen is returned to the soil through the decomposition of straw left behind after harvesting.

2.2.2 Life-Cycle GHG Emissions

Table 2.2.1 compares life-cycle CO_2 emissions for biodiesel production based on soy beans, canola oilseed, a mix of animal waste and yellow grease, and yellow grease by itself. In addition, a quantification of the fuel efficiency effect of using biodiesel as an additive is also shown. While the underlying process for biodiesel from canola and soy is the German Lurgi Process, biodiesel from animal waste and yellow grease is assumed to be made using the Canadian BIOX Process.

Land-use changes have a major impact on overall emissions from biodiesel made from virgin oils. This is a very large factor for soy beans as it is assumed that these are mainly cultivated in Ontario or Québec and that this cannot be done on marginal agricultural land, but requires transformation of other land to farmland, which entails high soil carbon losses. This is not the case for canola if it can be grown on existing farmland. The actual esterification process is not highly energy or emission intensive, which causes a marked difference to ethanol production (see previous chapter). By-product credits for GHG emissions were given for canola and soybean meal and glycerine. The credits for soy bean meal are very high due to their protein content and also due to the calculation methodology, which assumes that canola and soy meal displace each other in the marketplace. A special case is biodiesel produced from animal waste:

the rendering process is more emission-intensive than the other processes, but as a large amount of the original biomass ends up as bone meal, much of the emissions is later subtracted through giving a by-product credit for the production of bone meal. The by-product credits are far smaller for yellow grease because only glycerine is produced here and no other products.

Table 2.2.1 CO_2e Emissions from Biodiesel Production, in Grams Per Tonne of Feedstock Input

Process Step	Lurgi Process			BIOX Process	
	Soy Beans	Canola Oilseed	Fuel Additive (Canola)	Waste Oil and Animal Fat	Yellow Grease and Tallow
Cultivation & Harvesting	175,225	218,021	218,021	-	-
Fertilizer Production	38,888	164,204	164,204	-	-
Land Use	523,879	250,731	250,731	-	-
Transport to plant	90,160	81,232	81,232	124,330	43,688
Processing	122,096	171,542	171,542	416,972	300,037
Transport & Distribution	9,450	23,844	23,844	21,009	21,009
Sub-total	959,698	909,473	909,473	562,311	364,735
Glycerine	-656,204	-339,150	-339,150	-369,607	-31,644
Canola/Soy Meal					
Bone Meal					
Displaced emissions from diesel	-144,239	-320,235	-320,235	-320,235	-320,235
Credit for carbon in fuel from sequestered CO_2	-455,333	-1,011,617	-1,011,617	-1,011,617	-1,011,617
Credit for increased fuel efficiency of 0.5% biodiesel additive	-	-	-10,116,170	-	-
TOTAL	-295,979	-761,528	-10,877,698	-1,139,148	-998,761
Grams per litre of biodiesel*	-1,447	-1,675	-23,931	-2,506	-2,197

* for waste oil and fats: artificially based on the same amount of dry biomass as biodiesel from canola oilseed

When comparing the data in Table 2.2.1 it is important to note that everything is input-based and therefore not immediately comparable. For example, the emission reductions per tonne of soy beans are lower than those per tonne of canola oilseed. A large factor accounting for this difference is the fact that about twice as much oil is extracted per tonne of canola than can be gained from soy beans. If the analysis was based on a standard amount of oil instead of on the original biomass input, the number for both would therefore look very similar. This can also be seen at the bottom of the table, where the displaced amounts of CO_2 per litre are given. Here, numbers for canola and soy are very similar. On the other hand, no useful comparison would be possible with waste-based biodiesel if the waste oil was used as the initial biomass input. For this analysis, we therefore artificially set the biomass input to equal one bone-dry tonne of canola oilseed. In other words, as 400 kg of oil is made from canola oilseed, the comparison is made for 400 kg of waste oil, instead of 1 tonne. It is therefore now possible to compare the data for biodiesel from waste products with that made from virgin canola oil – but not with that made from soy beans, as a different biomass input was used here.

After credits, emission reductions from waste oil-based biodiesel are markedly higher than those from canola-based biodiesel – an immediate effect of emissions from cultivation and land use changes. Suffice to say in this context that a diverging approach could attribute some of these emissions for the production of the original vegetable oil, or from enteric fermentation emissions from raising feedstock, could be attributed to waste oil and fat due to it having a market value and a useful purpose in biodiesel production. Such an approach would of course narrow the gap between waste and virgin oils in terms of reduced emissions. Due to the strong fuel economy improvement suggested by the findings of a number of field trials as mentioned above, the emission reduction benefits are more than ten times higher if biodiesel is used as an additive.

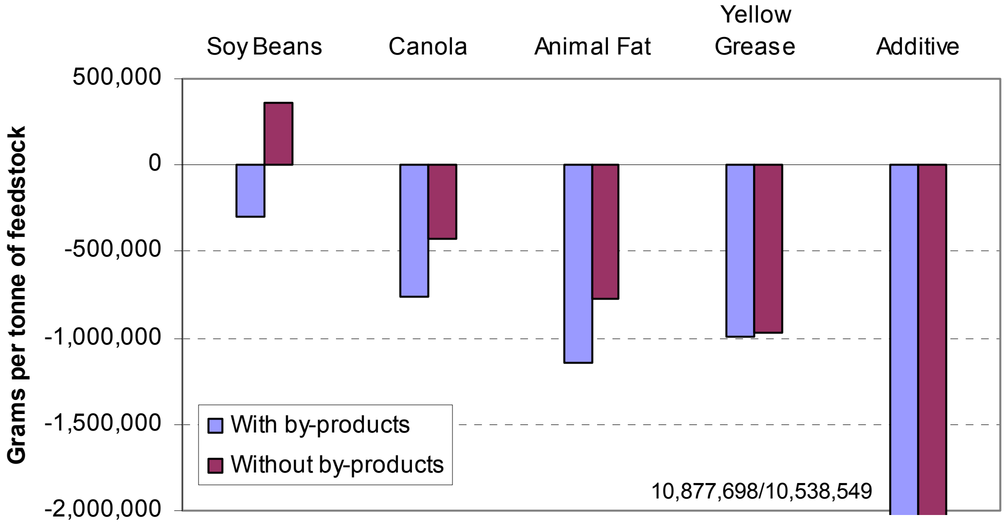

Figure 2.2.2 Absolute CO_2 Emission Reductions per Tonne for Biodiesel Feedstocks

Figure 2.2.2 shows the CO_2 emission reductions for all feedstocks, with and without by product credits. The graph has been cut as showing the full scale of emission reductions caused by the use of biodiesel as an additive dwarfs all other approaches. What is important to see is that the by-product credits are quite important for the virgin oil products: soy bean-based biodiesel does not even create emission benefits by itself, but only after by-product credits are included there is an overall emission reduction. If there was no use for the by-products (mainly soy bean meal), the overall emission benefits would be negative. Due to the high market value of the meal as animal feed, this is, however, not a case to be expected in reality.

2.2.3 Energy Balance

Table 2.2.2 shows the energy balances of biodiesel production using each of the feedstocks that were examined. For the fuel additive option, the energy saved from the production of conventional diesel from crude oil was subtracted as an energy credit, virtually making this option a "perpetuum mobile", as indeed lost of energy can be saved if ten times the fuel volume is displaced by the addition of 0.5% biodiesel. As for the greenhouse gas analysis, the Lurgi Process was assumed for the virgin oil feedstocks and the BIOX process for the waste feedstocks. The electricity and steam requirements for the BIOX process are markedly higher than for the Lurgi process, which appears in the higher energy consumption in the production step.

Cultivation and fertilizer production are the largest contributors to energy consumption for biodiesel from virgin oil, whereas the production of biodiesel is more energy intensive for the waste feedstocks. As can be seen from the left column of Table 2.2.3, the energy payback is between about 2 and 4 times the energy that was used to produce biodiesel. The energy payback "after credits" adds the energy credits to the energy contained in biodiesel, increasing the payback to between about 2.6 and 4. In the case of biodiesel use as an additive, nine times the energy invested in the process is gained, if the displaced energy from conventional diesel production is taken into account. The same co-product credit was applied for bone meal as for soy meal. The result in an overall energy gain from the process, suggesting that bone meal displaces another product the production of which is more energy intensive.

Table 2.2.2 Energy Inputs as BTU per Million BTU Contained in Biodiesel [Levelton 2002a]

Process Step	Lurgi Process			BIOX Process	
	Soy Beans	Canola Oilseed	Fuel Additive	Waste Oil and Animal Fat	Yellow Grease and Tallow
Cultivation & Harvesting	206,600	113,500	113,500	-	-
Fertilizer Production	82,900	171,600	171,600	-	-
Transport to plant	95,000	43,000	43,000	66,000	23,200
Processing	156,300	96,200	96,200	362,900	223,600
Transport & Distribution	13,200	15,200	15,200	13,200	13,200
Sub-total	554,000	439,500	439,500	442,100	260,000
Glycerine	-443,500	-290,702	-290,702	-442,400	-15,700
Canola/Soy Meal					
Bone Meal					
Credit for increased fuel efficiency of 0.5% biodiesel additive	-	-	-2,728,364	-	-
TOTAL	**110,500**	**148,798**	**-2,579,566**	**-300**	**244,300**

Table 2.2.3 Energy Payback of Feedstocks for Biodiesel Production (BTU/BTU)

Feedstock	Before Credits	After Credits
Soy Beans	1.81	2.60
Canola Oilseed	2.28	2.94
Canola Oilseed/Additive	2.28	9.14
Animal Waste and Grease	2.26	3.26
Yellow Grease and Tallow	3.85	3.91

Based on the total energy content in canola oilseed (15 million BTU/tonne, combined calorific energy content of oil and meal) and the by-products, Figure 2.2.3 shows the input-based energy balance graphically. All energy flows represent the calorific value of by-products, and the energy that can be ascribed to the biodiesel product if there are all subtracted (the actual chemical energy in biodiesel is of course higher). For biodiesel made from canola oilseed, more energy is consumed by the process, and contained in by-products, than is contained in the original oilseed. This makes the input-based energy balance negative – even more so when considering that less than a quarter of the fuel is converted to kinetic energy in the car (diesel engine efficiency: 23%). This shows that the calorific value of by-products is very high, i.e. if these were combusted to provide process energy, the energy balance would look better for biodiesel. However, the use of by-products for other purposes has a much higher economic value, and as greenhouse gas emissions are avoided through their use elsewhere, the over LCA results are still positive for biodiesel production from canola.

The calorific energy content of Methanol, which is added for the esterification process, was credited back to the balance as its energy ends up in the final products. For waste oil, the balance is positive, and less by-products are produced. This suggests that the abundant availability of waste vegetable oil and especially animal fat in Alberta should be used first to make biodiesel before cultivating canola specially for this purpose.

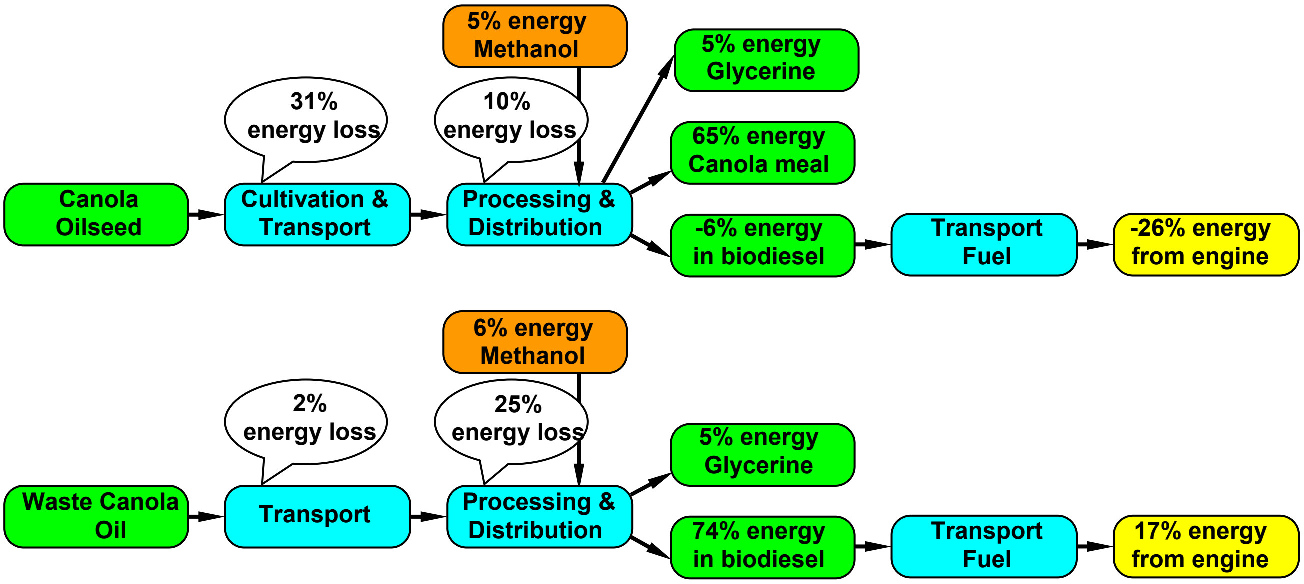

Figure 2.2.3 Energy Balance of Biodiesel from Canola Oilseed (above) and from Waste Oil and Tallow (below)

2.2.4 Discussion of Input Values Used in the Underlying Study

An American study carried out in 1998 found a negative output-based energy balance[4] (0.81) for biodiesel from soy bean oil [NREL 1998]. The main difference is that this study assumed a very high energy demand for the esterification process, which was based on an existing low-efficiency U.S. plant. If biodiesel production in Canada were implemented at a large scale,

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[4] A negative energy balance (smaller than 1) does not mean that the process is uneconomical or not worthwhile. Actually, the same study determined the energy balance for the production of conventional diesel fuel to be in the same range (0.83).

higher efficiencies are more likely. On the other hand, the NREL study uses smaller energy inputs for the agricultural part of the life-cycle. The average U.S. nitrogen application rate for soybean agriculture was determined to be 11.1 kg/ha (9.89 lb/acre) – nine times less than what was assumed for canola in the base case modeled here. As soy fixes nitrogen out of the air, fertilizer inputs are much lower than for canola. This fact would explain most of the difference between these inputs.

A British study on life-cycle emissions from biodiesel made from rapeseed oil [DEFRA 2003] found about twice as high energy inputs, and related emissions, for the hexane extraction and esterification process. These data are based on a 1997 study carried out in Germany, whereas the Levelton data are based on Lurgi company prospects. Seen that Canada can be expected to use state-of-the-art equipment if it was to expand it's biodiesel production, the more optimistic assumptions of the Levelton study are more like to apply to Canada's situation. Actually, Levelton show even more energy efficient plant data, which have not been used for the base case, for soybean crushing equipment (assumed to be similar to canola oilseed crushing), so that the values used in this LCA seem to be much closer to reality.

2.2.5 Economic Aspects

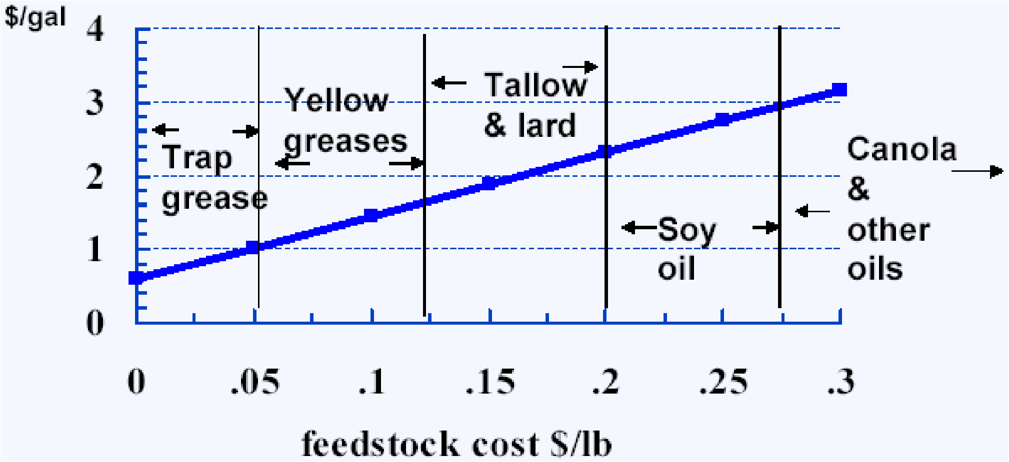
The economic feasibility of biodiesel production will depend on the price of feedstocks, including their transport to the plant, capital and operation costs, the price of conventional diesel fuel, and market values of by-products, such as glycerine, canola meal and straw, and possibly also on the sale of emission reduction credits.

Glycerine: Commercial-scale biodiesel production would increase the availability of glycerine, possibly leading to lower market prices. The total Canadian market for glycerine equals approximately 6,000 tonnes annually. Seen that a single commercial-size biodiesel plant (60 million litres per year) would produce about the same amount of glycerine per year, the increased offer can be expected to reduce market prices for glycerine significantly. Export markets would have to be found to find a market for the glycerine output of more than one such plant in Canada. Currently, the demand for glycerine is rising, as new uses are found and the economies of developing countries grow. Increases in supply have been unable to match increases in demand. As a result, prices for both crude and refined glycerine are now very high. Today, crude glycerine sells for approximately CDN $1.50/kg. In the recent past, crude glycerine prices have been as low as CDN $0.22/kg [AAFC 2003]. Levelton assumes a glycerine sales revenue of 10 cents per litre of oil, i.e. based on a price of $1 per litre.

To avoid the glycerine by-product, unprocessed vegetable oils can be used in modified diesel engines. Such engines are in limited production and are therefore more expensive, although their numbers are increasing in Europe. This usage would reduce energy use and emissions from biodiesel production and would not produce any glycerine [CRFA 2004]. This was not one of the threads selected by the funding parties for research in this report so the possibility has not been further assessed. It is also likely to be a very limited market in Canada at this point in time.

Waste oils and tallow: The price of yellow grease has dropped since 1997 where it reached a peak of US$0.20 per pound (CDN$0.73 per litre) to about US$0.08 per lb (CDN$0.29 per litre) in January 2002. Beef tallow cost about US$0.10 per lb. (CDN$0.37 per litre) in 2002. It has been dropping steadily since 1997 as well. Two factors are probably causing the lower prices: environmental concerns regarding the use of beef tallow as animal feed, and/or supply of yellow grease and tallow being higher than demand [AB 2002, p.17]. In Canada, prices for beef tallow vary across the country: 2002 prices in Montréal were 26 cents, whereas Vancouver and Toronto prices were 44 cents per kg [Levelton 2002a].

Canola oil: Prices for canola oil have fallen more or less steadily since 1995, but are still far higher than those of waste oil and tallow [AB 2002, p.18]. Figure 2.2.3 provides an idea of feedstock prices in U.S. dollars. The price of canola oil also fluctuates heavily in Canada. In 2001, it was C$452 per tonne, and in 2003 it was C$946 (83¢/l). 53 cents have been suggested by AB 2002, but much higher prices have been observed in the market since 2004. It is not known what effect an increase in demand for canola oil for diesel production, and therefore enhanced production of canola, would have on canola oil prices.



Total cost at plant gate for 3 million gallons a year plant.
Does not include transportation and handling.

Figure 2.2.3 Biodiesel Feedstock Prices in U.S. Dollars per Gallon [EERE 2003]

Production and capital costs: Production costs for biodiesel were calculated to be $0.59 per litre for the Lurgi process, and only $0.32 for the continuous and faster BIOX process. The capital cost for plants with annual biodiesel production of 60 million litres is approximately $0.04 per litre of annual production (based on 20-year payback of a $19 million investment, plus interest) [Levelton 2002a]. Feedstock transportation costs to a plant in Calgary from the two major beef tallow producers would average about $0.015 per litre [AB 2002, p.17]. We will assume that this price is very similar for a plant in Edmonton, situated closer to existing diesel manufacturing.

Table 2.2.4 Per-Litre Costs of Biodiesel Production from Beef Tallow and Canola Oil, in Canadian Dollars [based on AB 2002]

Costs	Beef tallow (BIOX)	Canola Oil (Lurgi)
Feedstock costs	0.37	0.53
Feedstock transport	0.02	0.05*
Capital Cost	0.03	0.04
Operating Cost	0.32	0.59
Overhead	0.06	0.06
Glycerine sales	-0.10	-0.10
TOTAL	0.70	1.17

* crude estimate, suggesting greater transport distances and larger tonnage for canola oilseed

Analysis: The wholesale rack price for conventional diesel is currently about $0.35 per litre. This price will fluctuate significantly with changing crude oil prices: in January 2002, the rack price was only $0.25 per litre, whereas in April 2004, bulk diesel was offered for $0.57 in Ontario, including a 14.3 cents tax exemption [MFAC 2004]. The cost of producing biodiesel from virgin oil is about 50% higher than that of tallow or yellow grease-based diesel, and is still significantly higher than that of conventional diesel. With increasing prices for conventional diesel, which are projected to stay at high levels for the foreseeable future, tax exemptions such as the one in Ontario can at least bridge the cost for biodiesel from waste products. If fossil fuel prices continue to rise, and production costs for biodiesel from virgin oil can be reduced further, biodiesel could become an interesting alternative to the fossil fuel-based economy. It is also remarkable that neither in the environmental and energy analysis nor in the economic analysis, transport is a major factor.

SuperCetane from tall oil: A hydrogenation process can be used to produce a hydrocarbon fuel from tall oil, a by product from the Kraft pulping process in the pulp and paper sector. The production cost for this product, also called SuperCetane, including the capital and operating costs in a large scale plant is estimated at only 10 to 12 cents per litre. The cost of the tall oil as raw material could vary from 8 to 20 cents per litre of SuperCetane. Thus the total cost of this product could range between 18 to 32 cents per litre [GCSI 1998, p.12], which brings it into the same range as conventional diesel fuel, or even lower if current pricing trends continue. About 180,000 tonnes of tall oil are produced in Canada each year, which is enough for several commercial-size plants. Assuming a conversion efficiency of close to 100%, this amount could yield close to 200 million litres per year, or about 1% of Canada's annual diesel consumption (19 billion litres). This process could compete with biodiesel as a fuel, and could be included in a future expansion of this present report.

2.2.6 Other Environmental Aspects

Biodiesel reduces a number of other emissions in addition to greenhouse gases. The following numbers are taken from NREL 1998:

- Compared to conventional diesel, CO and particulate matter emissions are reduced by one-third,
- SOx emissions were assessed to decrease by 8% on a life-cycle basis, although tailpipe SOx emissions are completely eliminated because biodiesel does not contain sulphur. As the underlying study used the U.S. background power mix and assumed very high energy consumption for the production process, the SOx emission reduction for Canadian biodiesel production would probably be more significant.

On the other hand,

- NOx emissions increase by about 13% (biodiesel exhaust has a higher NOx content than conventional diesel). This result is disputed by another study (IEA 1994), which found no such increase if the engine is correctly tuned, but is confirmed by another American study [EPA 2002].
- Hydrocarbon emissions rise by about one-third.

If biodiesel is made from energy crops, additional environmental impacts can be expected from agriculture, such as eutrophication of groundwater or surface waters, water consumption for irrigation, the use of pesticides, etc. The German IFEU Institute has compared various environmental impacts of biodiesel production to the use of conventional diesel and came to the conclusion that the impacts are significant for both products, such that it is a political, not an environmental, question as to which fuel should be preferred. Figure 2.2.4 illustrates this finding: each bar reflects the use of biodiesel over a distance of 100 km. The energy balance of biodiesel is better than that of conventional diesel, reflected in savings equivalent to the energy required to make 8 litres of conventional diesel, per 100 km. Likewise, GHG emissions are reduced. However, emissions causing acidification, eutrophication, and ozone-depleting substances are far higher – up to an equivalent of 119 litres per 100 km in the case of ozone depletion. These emissions are caused by microbial activity that releases part of the fertilizer used to grow canola into the air as nitrous oxide (N_2O), which is an ozone-depleting substance, as well as a GHG. 50% of the IPPC guidance value for N_2O emissions from fertilizer were used by IFEU, based on fertilizer application of 180 kg N/ha [IFEU 2003, p.10].

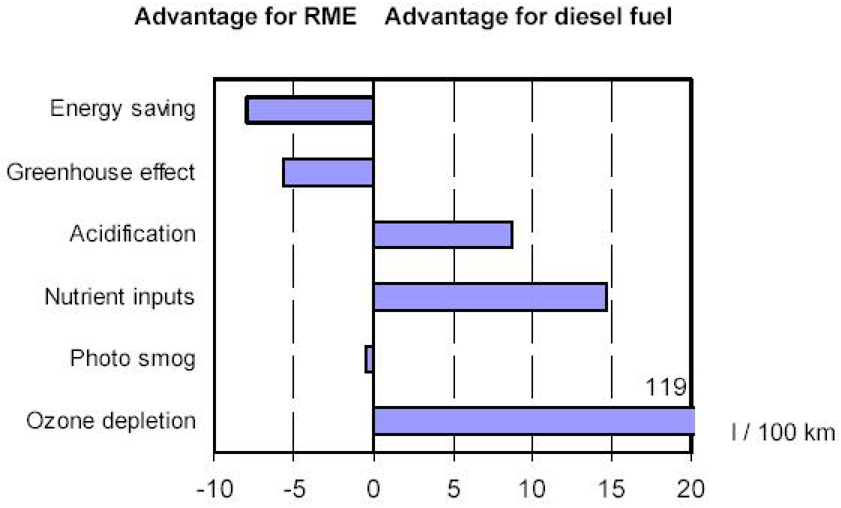


Figure 2.2.4 Comparison of Several Environmental Impacts of Biodiesel and Conventional Diesel Fuel [IFEU 2003, p.7]

However, biodiesel has some interesting positive features when used as a fuel [BfL 1999]:

- It is easily biodegradable and does therefore not bear the same risks of soil contamination as fossil fuels;
- biodiesel lubricates the engine and can be used in low-sulphur diesel, which would otherwise require additives to increase lubrication.

2.2.7 Sensitivity Analysis and Extrapolation to Other Regions

Figure 2.2.5 illustrates the energy consumption shares of each successive step in the life-cycle for biodiesel production from canola oilseed and from waste vegetable oils and tallow. This highlights where improvements to the life-cycle performance of each feedstock could be made. Transportation is not a major factor, but agricultural energy consumption for both cultivation and the production of fertilizer is important in the canola oilseed life-cycle. Energy for processing is the major factor for waste oil and fat, and is also important for canola oilseed.

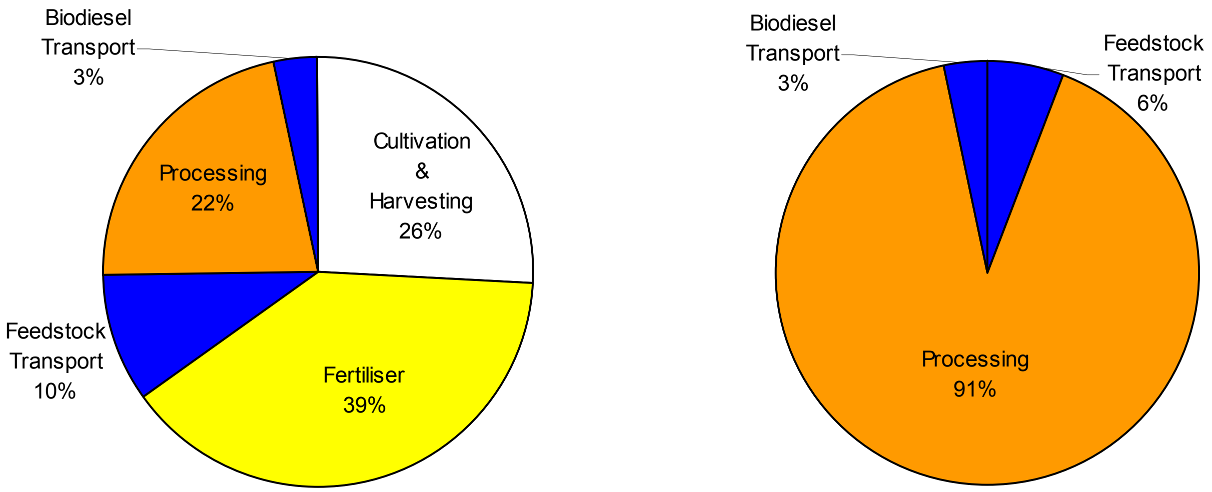


Figure 2.2.5 Energy Consumption for Biodiesel from Canola (left) and from Waste Oils and Fats (right)

Technology improvements: Esterification, hexane extraction and agriculture are the process steps that contribute most to both greenhouse gas emissions and energy consumption of the biodiesel life-cycle. Microwave extraction is a new process being researched that is expected to reduce energy requirements/CO_2 through hexane [EC 2004]. This process would ultimately also replace propane or butane for hexane, which may further reduce energy use and emissions, but has not been modelled here as it is still at the experimental stage. Improving agricultural emissions could be achieved through better crops or a reduction of inputs, such as fertilizer.

Influence of transport distances: The transport distances for both canola oilseed and waste oil and fat have been modelled as fairly high in the base case (400 km and 320 km, respectively). We therefore assume that this is a worst-case scenario and to determine the effect of varying distances, we have halved the distance for feedstock transport in both cases, leaving the transport distance to take biodiesel to the blending place with conventional diesel the same (80 km).

Figure 2.2.6 compares the influence of halved feedstock transport distances for canola-based biodiesel and yellow grease-based fuel. As we have determined greenhouse gas emissions based on input mass, this comparison of a waste product and an energy crop poses some problems: to allow for a comparison, we have kept the emissions figures based on one tonne of canola oilseed input for both cases, suggesting that waste vegetable oil requires the same amount of oilseed to be produced initially. If we would base yellow grease emissions on the feedstock input of oil at the plant, CO_2 emissions per unit would be smaller than those of canola-based biodiesel, which would make this comparison impossible.

As was seen for ethanol in the previous chapter, transport distances do not have an important impact on energy inputs or emission outputs of biodiesel production.

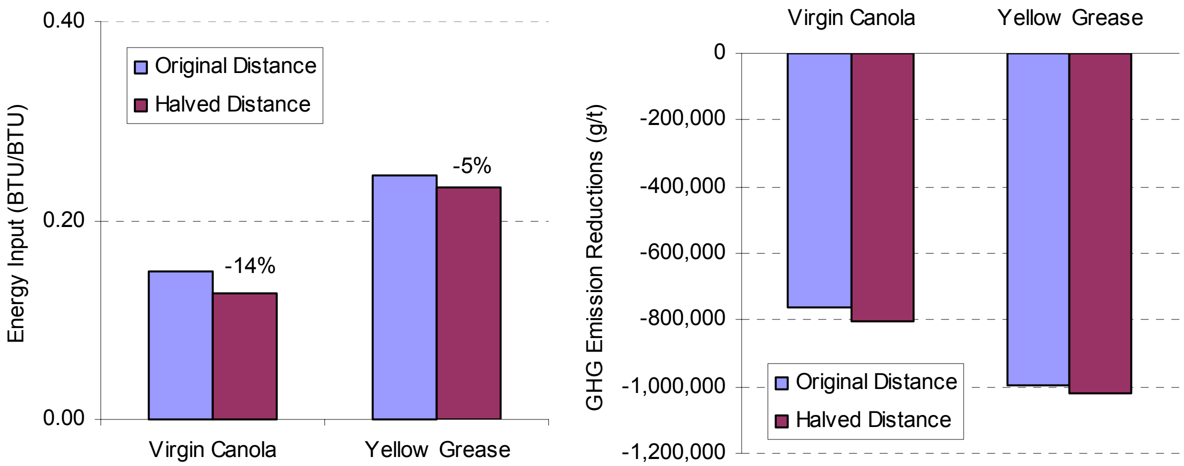


Figure 2.2.6 Comparison of the Influence of Halving Initial Feedstock Transport Distances on Energy Balance and GHG Emission Reductions, for Virgin Canola Oil and Recycled Vegetable Oil as Feedstocks

Influence of electricity background mix: Electricity inputs are very well identified in the Levelton study and indirect emissions could therefore be modelled in detail for all four background mix scenarios. The Alberta background mix relies heavily on coal and is actually even more carbon intensive than Scenario 4, which has been used as the base case. Figure 2.2.7 shows the influence of the background mix on greenhouse gas emissions, leaving all other parameters unchanged. This, however, only takes electricity used for the canola life-cycle into account, but not that used for external processes, such as fertilizer production. As for the previous graph, both canola oilseed and yellow grease/tallow feedstocks are artificially based on the same tonnage input and the fact that only little more than a tonne of waste oil is needed per tonne of biodiesel is ignored to make a comparison possible.

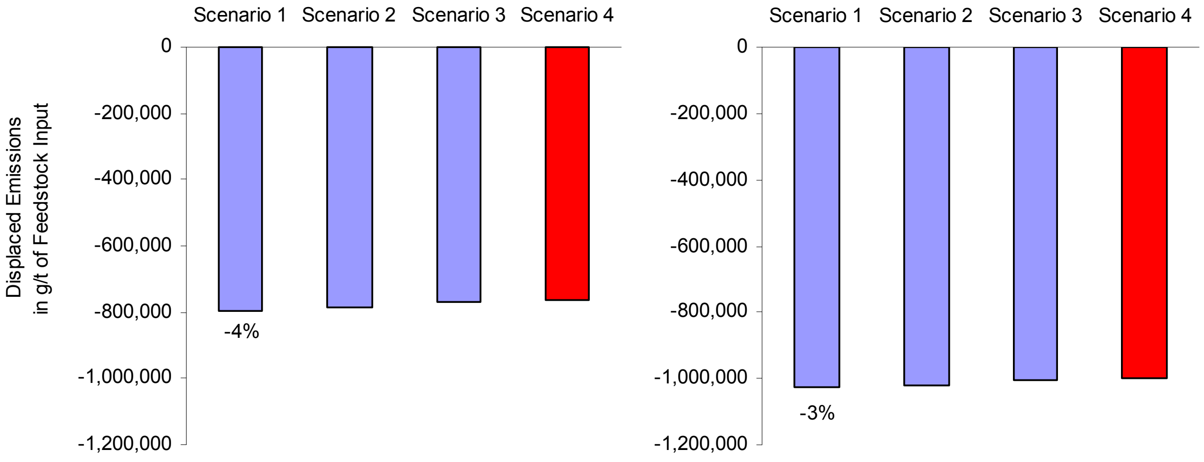


Figure 2.2.7 Influence of Electricity Background Mix on Life-Cycle GHG Emissions for Canola Oilseed as a Feedstock (left) and for Waste Oil and Fat (right)

The entire biodiesel production process consumes 48 kWh of electricity per tonne of oilseed input. For waste oil, this number is increased to 52.4 kWh, as the more energy intensive BIOX process is used. As the electricity consumption for biodiesel production is very moderate, the overall impact of varying background mixes is negligible.

Regional differences: Canola yields throughout Canada are slightly different (see Table 2.2.5), and the Canola Council website mentions that under optimum circumstances, up to 3.9 tonnes per hectare of oilseed can be harvested. The base case modelled above was about 1.3 tonnes per hectare. To determine the influence of yields per hectare, which have a major impact on fertilizer use per litre of biodiesel produced, we have modelled three more cases in Canada, representing Ontario with a high yield of more than 2 tonnes of oilseed per hectare, Saskatchewan with the lowest yield of only 1.24 tonnes per hectare, and the exceptionally high yield of 3.9 tonnes per hectare. We have assumed that fertilizer inputs are the same – this may be a flawed assumption, but this variation will provide an idea of the influence of higher yields, whether based on better soil or weather circumstances, or higher yielding seeds.

Table 2.2.5 Canola Yields in Canadian Provinces (Five-Year Average, 1999 to 2003) [CC 2004]

Province	ON	MB	SK	AB	BC	Exceptionally High
Canola yield in t/ha	2.04	1.58	1.24	1.46	1.40	3.90

The yield influences energy consumption and greenhouse gas emissions from the cultivation of canola oilseed. Although cultivation is a major factor for both parameters, Figure 2.2.8 shows that the yield variation as it occurs in Canada has some impact on both the overall energy balance and emission reductions from biodiesel production: Ontario's increased yields actually increase the emission reductions from canola oilseed as a feedstock to the same level as that of yellow grease and tallow. The maximum yield even reaches the level of animal fat as a feedstock (see Figure 2.2.2 to compare). For the energy balance, increased yields reduce the high energy inputs so much that the overall (output-based) balance even becomes negative, although the difference is not very significant in absolute numbers. This does not mean that energy is actually created, but the displacement of other products through canola meal then means that so much energy is saved from alternative production methods (in this case, soy meal) that there is a net energy gain from the process.

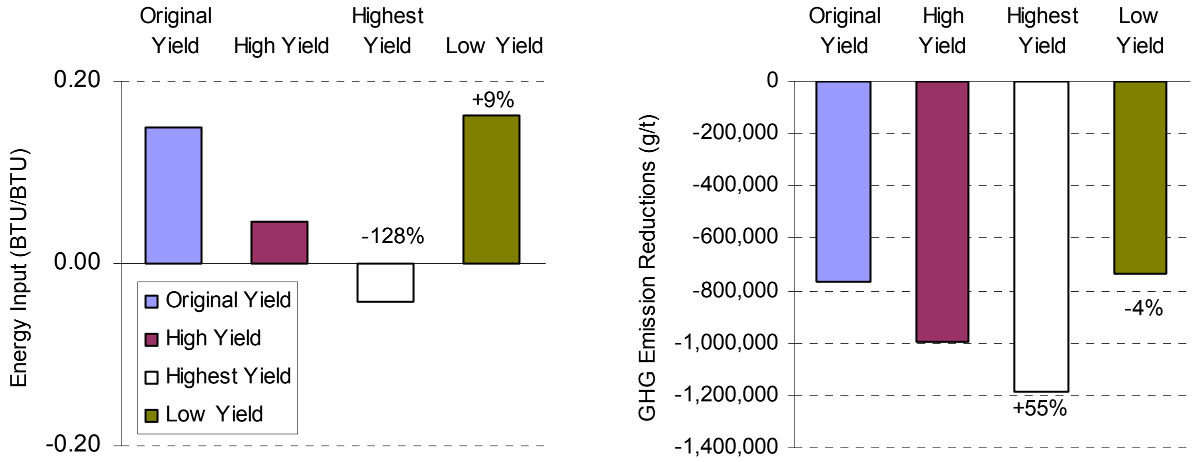


Figure 2.2.8 Influence of Canola Yields on Energy Consumption (left) and Life-Cycle GHG Emissions (right) for Canola Oilseed as a Feedstock

Updated GHGenius Data: Natural Resources Canada provided updated data currently used in the GHGenius model. These data show reduced emissions from the biodiesel lifecycle for both Canola (55% of value used here) and soy beans (56% of value used here) as a biodiesel feedstock. These reduced values are mainly due to increased emission displacements attributed to the animal feed by-products. For canola, these new values would result in about 20% increased emission reductions. While these variations are considerable, they do not change the overall results of this analysis. They show, however, that there are still some uncertainties with respect to by-product credits and their contribution to overall emission reductions.

2.2.8 Summary and Analysis

For all factors that were varied, only small changes in the overall outcome of the analysis were found. Figure 2.2.9 shows that the combined impact of yield variation, changed electricity background mix, and transport distances makes the (output-based) energy balance for canola oilseed as a feedstock negative, i.e. there is an overall energy gain when the highest canola yield of 3.9 tonnes per hectare and a halved transport distance is applied. For yellow grease, no marked difference exists for any of the scenarios, whether for energy or for greenhouse gas emissions. However, the emissions displaced by biodiesel made from canola oilseed surpass the level of emissions displaced by yellow grease as a feedstock in the best case scenario.

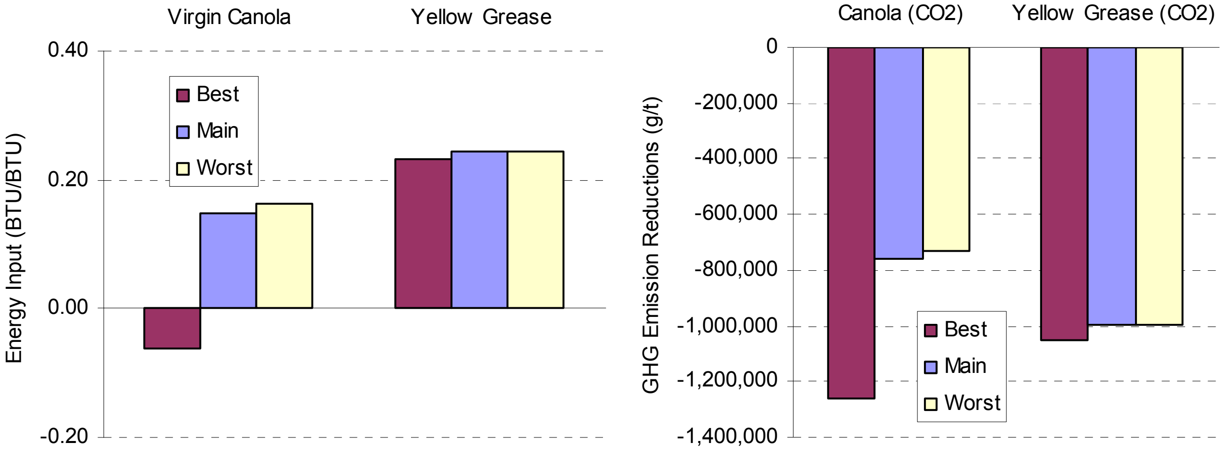


Figure 2.2.9 Combined Influence of Variations of Transport Distance, Yield, and Electricity Background Mix on Energy Consumption and Life-Cycle GHG Emissions for Canola Oilseed and Waste Oil and Fat as Feedstocks

Alberta's resources in terms of waste oil and fat are not sufficient to achieve a 10% target for all diesel used in the province. Sourcing additional feedstocks from outside the province or growing energy crops to make up for the difference will increase the cost of biodiesel, which is about twice as high as conventional diesel when made from virgin canola oil. Biodiesel made from tall oil may be a good alternative to other methods, as production costs are much lower and the resource availability is good.

If the option to use biodiesel as an additive to conventional diesel can indeed be confirmed as increasing fuel efficiency, this option would be a very attractive option in the short run. To add 0.5% of biodiesel to all diesel in Canada (annual consumption: 19 billion litres), less than 100 million litres of biodiesel would be required. This amount could be produced by only two plants of 60 million litres capacity, with an annual input of about 100 million litres of yellow grease or tallow. With annual yellow grease available in Alberta alone amounting to an estimated 18 million litres, this amount should definitely be available throughout Canada, and could thus be cheaply transformed into an additive capable of achieving major emission reductions.

2.3 Hydrogen from Biomass in Ontario

2.3.1 Underlying Studies and Assumptions

This analysis was mainly based on S&T 2003, which examines greenhouse gas emissions from using coal and wood for hydrogen production. The study assumes hydrogen production from willow or poplar, but does not distinguish between the two, assuming annual yields of 4 t/ac-yr for Canada. The wood is assumed to have a moisture content of 30% at the plant gate, and is subsequently dried to 15%. Ontario was selected as the default region because two of the feedstocks are agricultural residues that have been modelled in chapter 2.1.

Emissions are modelled for two scenarios: a case that produces the biomass in a short rotation forest and a case that uses mill residues as the feedstock. The short rotation forestry case assumes that 15% of the wood is grown on conventional forest land, 70% on unimproved agricultural land and 15% on existing agricultural land. The product is compressed hydrogen, which is made in a central location and subsequently transported by pipeline and truck.

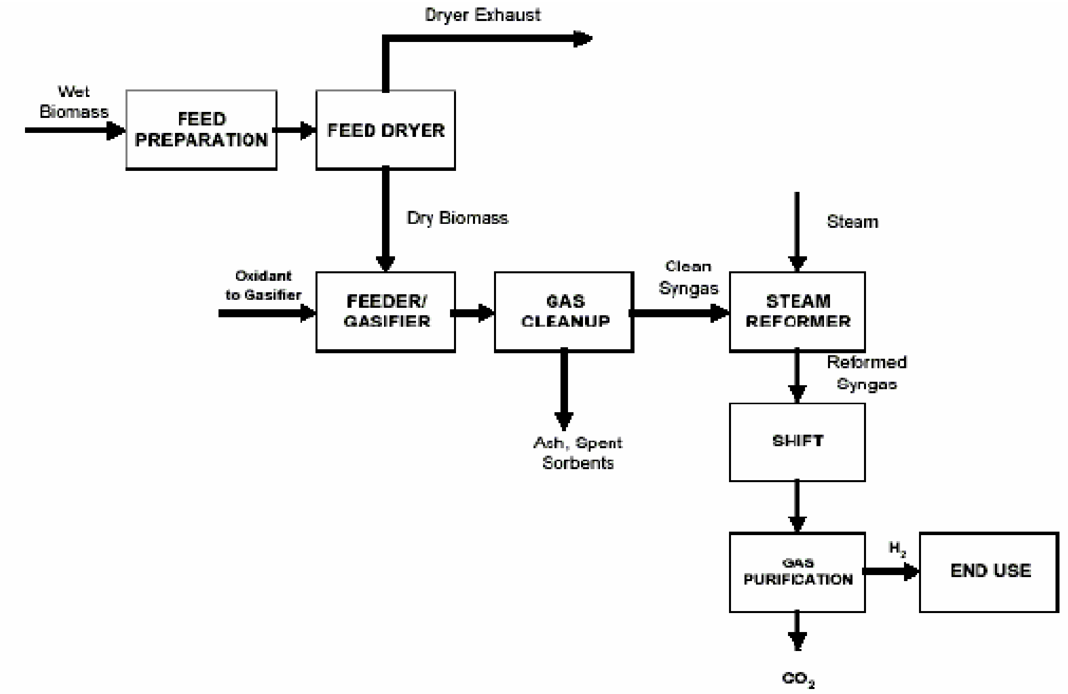


Figure 2.3.1 Biomass Gasification System for Hydrogen Production from Wood [S&T 2003, p.22]

Figure 2.3.1 shows the underlying process that is modeled to determine greenhouse gas effects. Whereas hydrogen could be produced from pyrolysis or using other gasification concepts, the bubbling fluid bed gasifier concept was identified as the most appropriate gasification technology by the U.S. Department of Energy. This concept was proven at the pilot plant stage (11 tonnes per day) for the production of syngas for combustion, but the production of hydrogen from biomass is still at the conceptual stage. The S&T study therefore made assumptions wherever no experimental data were available.

The process modelled is based on an IGT (Institute of Gas Technology) gasifier optimised for hydrogen content in the syngas, with a high temperature dust filter (800 °C), Ceramic Membrane (Internal Shift), and expansion turbine. The IGT gasifier is directly heated, which implies that some char and/or biomass are burned as part of the transformation to syngas and provide some of the necessary heat for gasification. For the production of hydrogen or methanol from biomass, pure oxygen is used instead of air to reduce the volume of nitrogen that must be carried through the downstream reactors, which improves the economics of syngas processing. The expansion turbine burns unconverted gas to produce electricity, covering most of the internal needs of the plant. Overall plant efficiency is 60% (based higher heating value).

Drying: The original study assumed a moisture content of 30% for the wood. This is a too generous assumption as it would require some natural pre-drying (seasoning, or long-term dry storage). Freshly hewn wood has a moisture content of about 50%. The moisture content of waste wood from saw mills could be around 30% if mixed with kiln-dried sawdust. A 30% moisture content was assumed for waste wood (sawmill waste), and a 50% moisture content for unprocessed wood. For drying from 50% to 30%, 2392 BTU of heat energy per kg of dry wood are required. Drying was assumed to be carried out using natural gas, and the corresponding extra emissions were added to the life-cycle data. Life-cycle CO_2 emissions of 3.9 kg/MMBTU were assumed for natural gas [Lewis 1997].

Wood waste: Residues from saw and pulp mills are available at very low costs. Possible feedstocks could include non-stem wood that is currently left behind at the logging site, or burned on site without energy recovery (e.g., in beehive burners). The S&T study assumes that no fertilizer inputs should be attributed to wood waste, and that no carbon sequestration effects (land-use changes) through the cultivation of trees should be counted towards it.

Transport distances: In the base case, the wood feedstocks are transported by rail (240 km), water (160 km), and truck (50 km). The feedstocks for making ethanol are transported by truck over 150 km, as per chapter 2.1. It is assumed that the ethanol plant is in the immediate vicinity of the hydrogen plant, i.e. no additional transport emissions occur from one plant to the other. The hydrogen is transported from the central plant via pipeline (480 km, 500 psi) and truck (160 km) to the filling stations. To determine how much energy is needed for distribution, a figure of 2.2 kWh per kg of hydrogen was assumed to account for compression to 500 psi for pipeline transport.[5] Due to the low energy content of compressed hydrogen (500 psi in a truck capable of transporting 4 tonnes of hydrogen), a fivefold energy consumption per km was assumed for truck transport of hydrogen (160 km) as compared to ethanol. No energy consumption from cultivation and harvesting was attributed to wood waste, and a transport distance of one-third that of wood was assumed for wood waste from the sawmill to the hydrogen plant.

Background power mix: Indirect emissions from grid electricity are described as for “central Canada” in the S&T 2003 study. After checking with the authors, the Ontario background mix was confirmed to be representative for the original study, and these were represented by Scenario 2 emissions in Table 1.1 for this analysis.

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[5] Alternatively, an energy loss amounting to 1.4% of the hydrogen transported through a pipeline could be assumed for every 150 km [Eliasson, und.], which results in a very similar value for pipeline transport.

2.3.2 Life-Cycle GHG Emissions

Table 2.3.1 compares the GHG emission reduction benefits from using four different biomass feedstocks to make hydrogen. These results are “well to wheel” emissions, i.e. they include all emissions during the production process and also those from oxidation in a light duty fuel cell vehicle. The first two feedstocks, wood from a fast-growing forest plantation (poplar or willow) and waste wood from pulp or sawmills, are dried to 15% moisture content, shredded/ground and fed into a gasifier, with subsequent steam reforming to obtain a maximum of hydrogen. The other two feedstocks are corn and switchgrass ethanol made using the Iogen process described in chapter 2.1. The emissions for the first four process steps are the same as in chapter 2.1, and the hydrogen (steam reforming) process was added on as a second processing step. The emissions for the steam reforming step are lower for the wood feedstocks as it is assumed that part of the feedstock is used to produce electricity and oxygen on-site. Only indirect emissions from extra grid electricity (Scenario 2 emissions) are shown. It would be possible to use some ethanol for process heat to reduce process emissions for the two ethanol feedstocks, which has been modelled as part of the sensitivity analysis below.

Hydrogen is supposed to be used as a transport fuel, and would therefore displace other transport fuels. Table 2.3.1 shows two comparisons: a) the case of introducing fuel cell engines that displace internal combustion engines, i.e. the displacement of gasoline, and b) the displacement of hydrogen made from natural gas in a fully-fledged hydrogen economy. Figure 2.3.2 compares the quantitative GHGH emission displacement effects of each hydrogen production option.

Table 2.3.1 CO_2e Emissions from Hydrogen Production, in Grams per Tonne of Feedstock Input

Process Step	Wood	Wood Waste	Ethanol from Corn	Ethanol from Switchgrass
Cultivation & Harvesting	84,741	0	164,017	94,820
Land Use	-237,548	1,284	7,810	-52,454
Feedstock Transport	7,993	7,993	15,360	34,095
Ethanol Production	-	-	342,875	547,644
Drying from 50% to 30%	43,206	-	-	-
Steam Reforming	25,826	25,826	170,309	132,358
Distribution	109,549	109,549	61,652	47,897
Evaporation	40,262	40,262	22,659	17,603
Sub-Total	73,992	184,913	784,683	821,963
Credit for displacing emissions from gasoline	-2,156,694	-2,156,694	-1,213,749	-942,945
or: Credit for displacing hydrogen from natural gas	-1,180,138	-1,180,138	-664,161	-515,977
By-product credit	-	-	-117,155	-76,845
CO2 credit for using feedstock residues for process energy	-	-	-	-513,952
Total (displacing gasoline)	-2,082,702	-1,971,781	-546,222	-711,779
Total (displacing natural gas)	-1,106,146	-995,225	3,367	-284,812

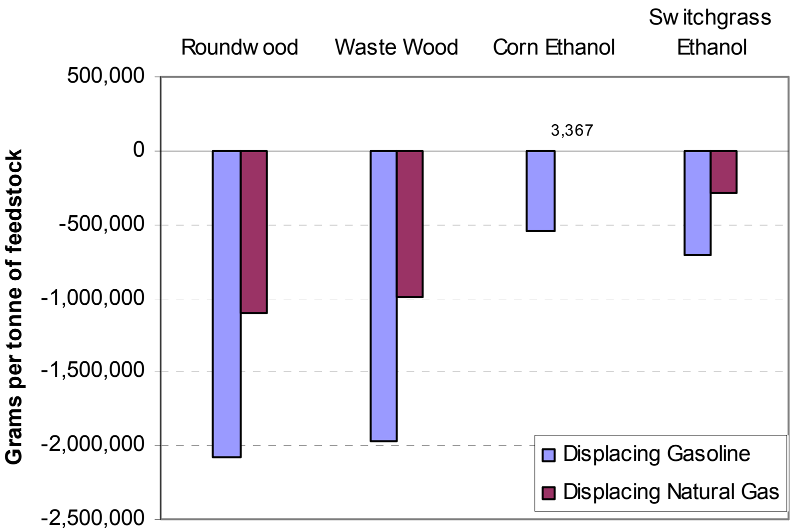


Figure 2.3.2 Absolute GHG Emission Displacement for Four Hydrogen Production Threads, per Tonne of Biomass Input

Several aspects can be seen from the results:

1. From a GHG emissions perspective, it is more beneficial to use biomass gasification and subsequent steam reforming than producing ethanol first and then making hydrogen from ethanol. This is mainly due to the smaller yields of hydrogen per tonne of biomass feedstock when it is made from ethanol as an intermediate product, reducing the amount of other fuels displaced.
2. In general, the emission displacement is strongly reduced (by nearly 50% in the case of wood from poplar/willow plantations) in a hydrogen economy based on hydrogen made from natural gas. However, biomass still has emission reduction benefits in most cases.
3. Hydrogen made from corn ethanol has about the same GHG footprint as hydrogen made from natural gas. There is therefore no preference for either feedstock, and other considerations, such as cost or diversification, should determine which feedstock should be used to what degree.
4. Due to the high efficiency of fuel cells (40%) as compared to internal combustion engines (17% for gasoline), the production of hydrogen from biomass has larger emission displacement benefits than the use of ethanol in internal combustion engines, which can be seen from comparing the results of Table 2.3.1 to those of Table 2.1.2. Despite the extra energy needed to reform ethanol to hydrogen, the emission displacement is still slightly more than what it would be for ethanol.

2.3.3 Energy Balance

The original sources did not provide a complete energy balance for the production of hydrogen. For wood feedstocks, cultivation was assumed to require 2.2 U.S. gallons of diesel fuel per million BTU, and the energy required for making fertilizer was estimated based on the numbers provided for ethanol in chapter 2.1 (one-quarter of fertilizer inputs required for corn). Feedstock transport energy consumption was also extrapolated from the detailed studies on ethanol, based on related greenhouse gas emissions, which are given in both studies. The process energy required for the gasification thread requires 1.13 kWh of external grid electricity, in addition to the electricity generated through the process itself. Round wood is first dried to 30% using natural gas.

The process energy for steam reforming of wood and wood waste is given as the extra electricity imported from the grid. Much of the process energy used is generated within the plant, from unconverted syngas that is used to generate electricity in an expansion turbine, and from coke and tar that is burnt in the process. As no information as to the amount of energy added to the process this way was available from the underlying studies, a 44.9% energy loss with respect to the energy contained in the wood was used, based on the assumptions made concerning gasification in chapter 2.4. To determine this value, an energy requirement of 4000 BTU per kg of water contained in the wood as moisture was assumed, including energy required for grinding. By-product credits are given to the ethanol-based threads for the use of residue as animal food (corn) and for electricity generation (switchgrass), based on the details provided in chapter 2.1. A 40% efficiency was assumed for the fuel cell in a light-duty vehicle.

Table 2.3.2 Energy Balance of Hydrogen Production from Four Different Feedstocks, in BTU per Million BTU Contained in Hydrogen Output

Process Step	Wood	Wood Waste	Ethanol from Corn	Ethanol from Switchgrass
Cultivation & Harvesting	50,385	0	283,758	171,975
Feedstock Transport	6,296	2,099	17,341	51,736
Ethanol Production	-	-	853,998	1,792,837
Drying from 50% to 30%	215,998	-	-	-
Steam Reforming	786,027*	786,027*	403,121	403,121
Distribution	111,210	111,210	111,210	111,210
Sub-Total	1,169,916	899,767	1,669,428	2,530,878
By-product credit	-	-	-223,925	-195,048
Total	1,169,916	899,767	1,445,502	2,335,830

* assumption made based on key data for gasification provided in chapter 2.4

Table 2.3.3 Energy Payback of Feedstocks for Hydrogen Production

Feedstock	Before Credits	After Credits
Wood (Willow/poplar)	0.85	0.85
Waste wood	1.11	1.11
Corn ethanol	0.60	0.73
Switchgrass ethanol	0.40	0.47

The negative energy balance of the ethanol-based processes suggests once more that it is more profitable to produce hydrogen directly from biomass through gasification, rather than using ethanol as an intermediate. The energy balance of hydrogen from waste wood gasification is only slightly positive, and heat required for pre-drying of freshly harvested round wood makes the output-based energy balance negative in that case also. The advantage of ethanol, or methanol, which has not been assessed in this study, is its higher energy content and lower transportation and storage cost as compared to hydrogen. There may therefore be reasons to resort to liquid biofuels and on-board reforming in order to reduce overall costs of using fuel cells in transportation, at least until hydrogen can be stored and transported in a cost-effective way.

Figure 2.3.3 shows the input-based energy balance and illustrates that only about one-fifth of the energy contained in wood actually ends up as electrical energy in the fuel cell car. In the case of hydrogen made from switchgrass, this number is even smaller, although one gets to 13.5% if the energy contained in by-products of the ethanol production process are included.

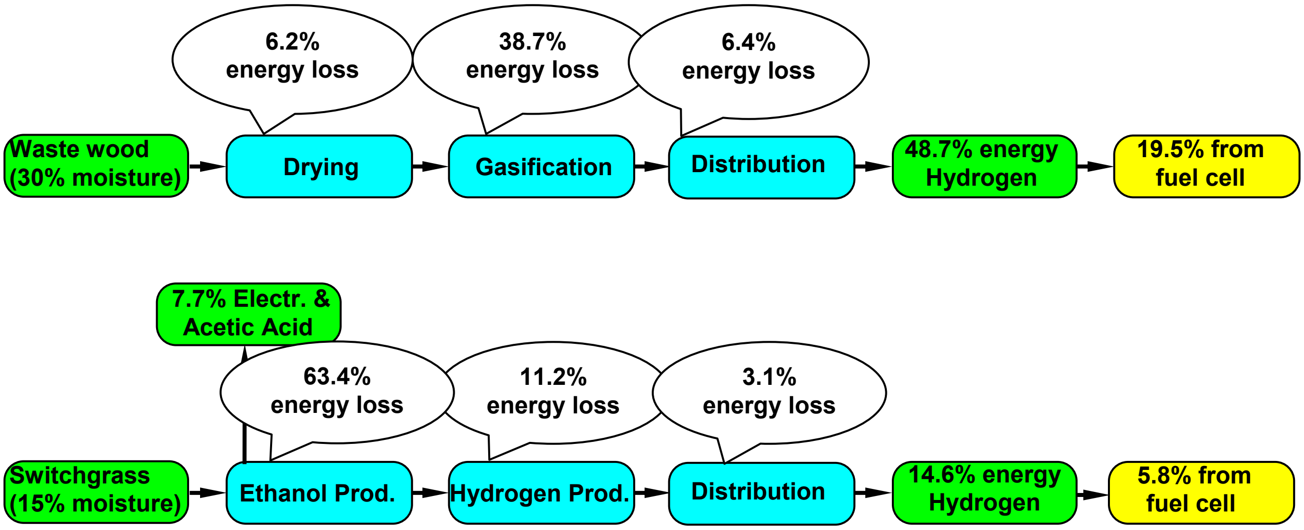


Figure 2.3.3 Input-Based Energy Balances for Hydrogen from Wood (above) and from Switchgrass Ethanol (below)

2.3.4 Economic Aspects

Hamelinck found that a 400 MWth input system can produce hydrogen at 8 – 11 US$/GJ, assuming biomass is available at 2 US$/GJ. This price is only slightly above the current production cost of hydrogen from natural gas. Previous analyses, based on large-scale plants (400 MWth) expected to be commercial on the short term, had assessed hydrogen production costs to 10 – 14 US$/GJ. These cost levels are not competitive with current gasoline and diesel production (about 4-6 US$/GJ). [Hamelinck 2001, p.5]

The hydrogen production cost for various gasifier types is comparable; concepts focussing on optimised fuel production with little or no electricity co-production perform somewhat better. 50% of this cost is capital cost, the bulk of which is in the gasification and oxygen generation system, syngas processing and power generation units. Operation and maintenance costs were modelled as a percentage of the total investment, but may depend on plant complexity as well. According to Hamelinck, long term cost reductions over the next ten to fifteen years can be expected to come from lower biomass costs, technological improvements, and application of large scales (2000 MWth). This could bring hydrogen production costs in the range of gasoline/diesel and even lower: to 6 US$/GJ. The availability of ceramic membrane technologies is crucial to reach this cost level [Hamelinck 2001, p.22]. However, large-scale production facilities require very large volumes of feedstock. So far, the largest biomass power generation plants using sawmill waste in B.C. are in the 30-50 MW range. If harvested trees were used in addition to waste wood, larger scales could be reached. However, but the economic feasibility of large-scale hydrogen production may then be limited by transport distances, especially because feedstock costs account for about 45 % of hydrogen production costs.

2.3.5 Sensitivity Analysis and Extrapolation to Other Regions

Figure 2.3.4 shows the relative share of each processing step in overall energy consumption. For hydrogen from wood gasification, the largest energy consuming step is steam reforming. Small improvements could come from more efficient transport, or if no fertilizer was used for the cultivation of trees. For hydrogen from ethanol, most energy is used in the ethanol plant, and making this process more energy efficient would yield the largest overall savings, and consequently also reduce overall GHG emissions.

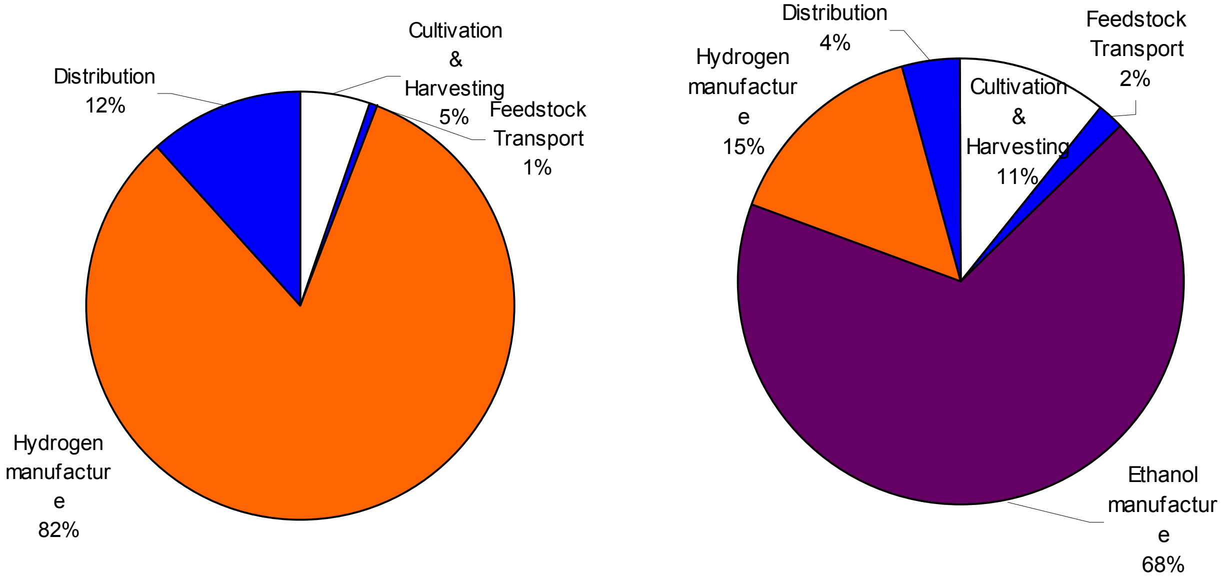


Figure 2.3.4 Energy Consumption for Hydrogen from Wood (left) and from Switchgrass Ethanol (right)

Technology improvements: The technology assumed for making hydrogen from wood is currently still unproven and results are based on modelling and some laboratory testing only. In that sense, future technology improvements have already been incorporated in the default data, and if a plant was built today it may be that the assumed hydrogen yields could not be reached. Emission reduction benefits will be reduced in proportion to hydrogen yields, i.e. a 30% yield reduction will lead to a 30% reduction in displaced emissions. However, as the emission reductions are very high in absolute numbers, the benefits will still be considerable even if somewhat less performing processes were used to make hydrogen from biomass.

In chapter 2.1, future scenarios for 2010 and their impact on GHG emissions from bio-ethanol production were examined. Inserting the numbers for the more efficient process into the dataset for hydrogen production leads to increased GHG emission displacements as shown in Figure 2.3.5 below. This comparison represents the best-case scenario for ethanol production anticipated for the year 2010, which includes higher ethanol yields (375 litres per tonne of biomass instead of 310 litres in the default case), and a fivefold increase of surplus power generation through the use of BIGCC technology (based on Scenario 2 indirect grid emissions). As the graph shows, the improvement is very significant: if hydrogen made from ethanol (switchgrass as the feedstock) is assumed to displace gasoline, 41% more greenhouse gases are displaced than in the default case, and compared to hydrogen made from natural gas, the increase is even higher (72%).

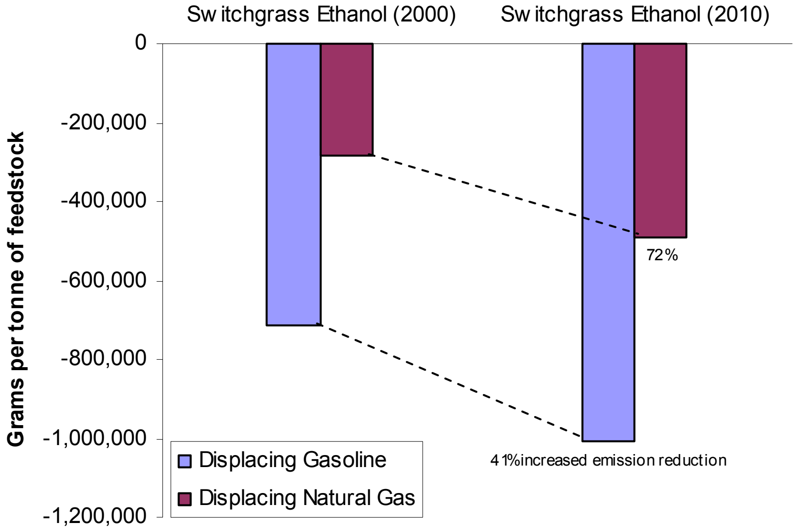


Figure 2.3.5 Impact of Technological Improvements to the Ethanol Manufacturing Process on the Emission Displacement Effect of Hydrogen made from Bio-Ethanol

By 2020, the U.S. National Renewable Energy Laboratory expects the biomass-to-hydrogen conversion process to reach a 10% improved efficiency [NREL 2004]. Yields of energy crops may increase by as much as 25% by 2020, further improving overall energy balances and emission reduction effects.

Regional differences: Canada's strong regional differences with respect to climate and the length of vegetation periods will have an impact on annual yields of fast-growing trees, such as poplar and willow. Table 2.3.4 shows the variation as given in the underlying study for Ontario, Québec and British Columbia:

Table 2.3.4 Variation of Poplar and Willow Short Rotation Forestry Yields in Oven-Dry Tonnes per Hectare and Year [S&T 2003, Table 5-1]

	BC	ON	QC
S&T 2003	10 – 13.2	2.3 – 6.6	3.5 – 11.0
This study	12	2	4 (default)

The data seems to suggest that the milder climate in BC will lead to increased growth, but other factors, such as irrigation, will also influence the yield. The default yield used for calculating the per-tonne emissions was 4 t/ha-yr. To model the influence of yields, Figure 2.3.6 shows the effect of halved and triples yields, as given in the table above. This only applies to wood from short-rotation forestry, as no fertilizer application was attributed to waste wood in Table 2.10. It is assumed that the application of fertilizer per area remains constant, but that it changes (halves or triples) per tonne of wood.

As emissions from fertilizer input are only a small component of overall GHG emissions, the effect of yield is negligible, and only amounts to a maximum of 3% in the case of halved yields, displacing natural gas. This finding is very important for the choice of tree as a feedstock, as from a GHG perspective, faster growing trees do not improve the emissions balance significantly. However, land requirements will increase if the yields are reduced, which can be expected to increase the feedstock price.

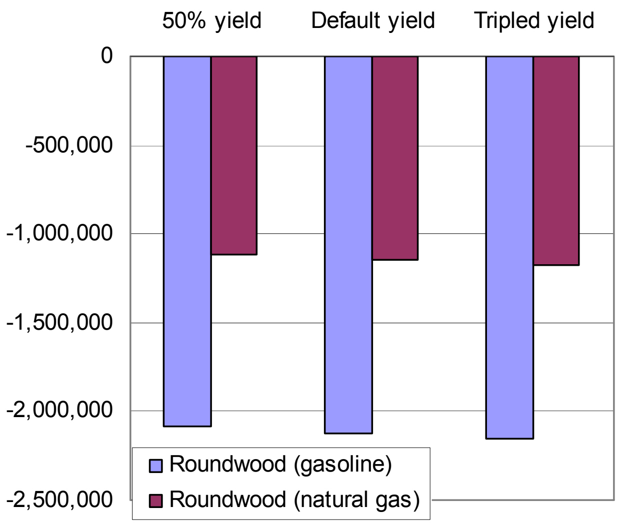


Figure 2.3.6 Influence of Halved and Tripled Yields on the Displacement of CO_2 Emissions through Hydrogen from Short Rotation Forestry Wood

Ethanol for process energy: Another factor that is to be examined is the use of ethanol for process heat for the steam reforming process in the two ethanol-based hydrogen production threads. This would mean that no emissions from using natural gas or electricity would result from the hydrogen production step, as the emissions related to the production of ethanol are already accounted for in the analysis – only the yield of hydrogen would decrease, as would the related fuel displacement effects, as about 20% of ethanol inputs have to be diverted to deliver process energy. Figure 2.3.7 shows the resulting change in CO_2 emissions. This analysis is only shown for corn ethanol.

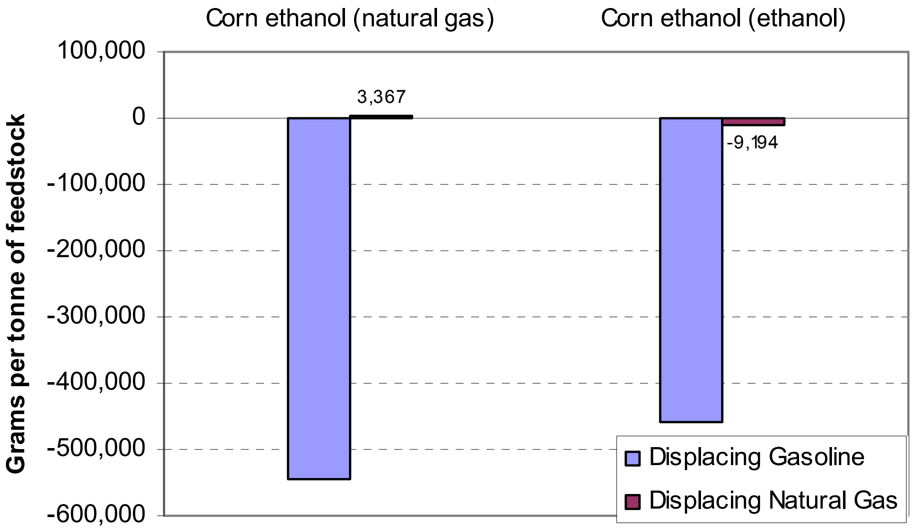


Figure 2.3.7 Impact of the Use of Bio-Ethanol Instead of Natural Gas for Process Energy, Example of Corn Ethanol

While the use of ethanol to produce process heat has a slightly beneficial impact if compared to hydrogen made from natural gas, this impact is negligible in absolute numbers. On the other hand, the displacement effect is reduced by 16% if the corn ethanol-based hydrogen is assumed to displace gasoline in internal combustion engines. This proves that the beneficial impact of using a climate neutral fuel for process energy can be undone by the reduction in hydrogen yields, which in turn reduces the displacement of other fuels. Turning this reasoning around explains why the conversion of bio-ethanol to hydrogen (slightly) outweighs the benefits of using ethanol in an internal combustion engine: due to the high fuel efficiency of fuel cells, the displacement effect of hydrogen is so much higher than that of ethanol that the extra emissions caused by the steam reforming process are outweighed by the additional displacement effect.

Influence of electricity background mix: The default case modelled above was the one for "central Canada", represented by Scenario 2 emissions. Figure 2.3.8 shows the influence of different background mixes on hydrogen emission displacement effects if made from wood that comes from short-rotation forestry, as well as hydrogen made from ethanol with switchgrass as the feedstock. As it is assumed that the ethanol plant and the hydrogen plant are situated close together, the surplus electricity from the ethanol plant was discounted from the electricity needed for the steam reforming process in the hydrogen plant, as if this electricity was directly delivered from the ethanol to the hydrogen plant. For both feedstocks, the electricity needed to compress hydrogen to be transported through a pipeline (assumed to be 2.2 kWh per kg of hydrogen) was also included, as pipeline transport is expected to occur in the same region where the hydrogen is produced. Total net power consumption adds up to 206 kWh per tonne of wood and 224 kWh per tonne of switchgrass. While the way electricity is generated can increase or decrease the overall emission displacement effect of hydrogen by a few percentage points, its impact in terms of absolute numbers is very limited.

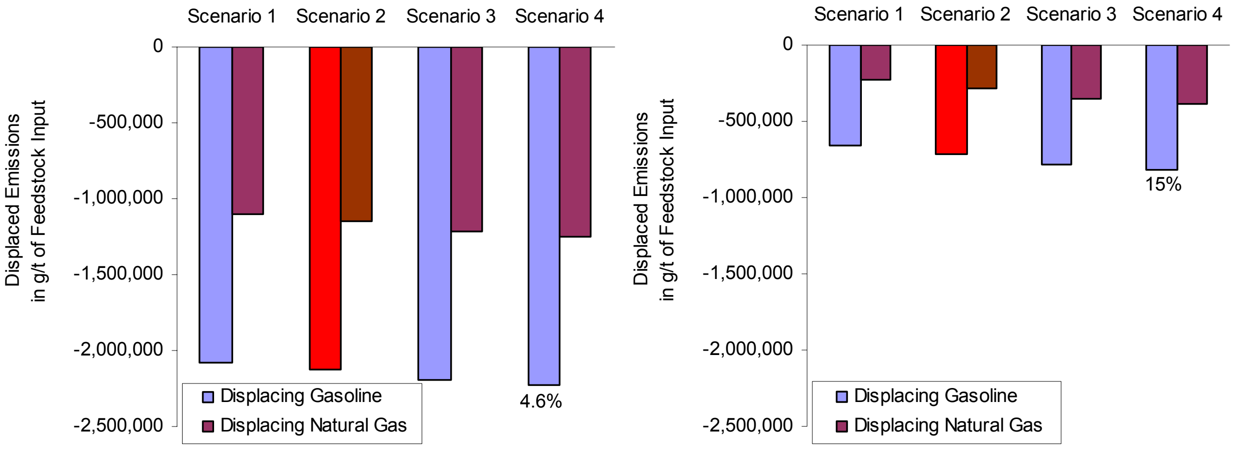


Figure 2.3.8 Influence of the Background Power Mix on Displaced Emissions by Hydrogen Made from Wood (left) and Switchgrass Ethanol (right)

2.3.6 Summary and Analysis

Apart from major future technology improvements expected for the switchgrass-to-ethanol progress, no other factor was shown to have a significant impact on the emission displacement effect of hydrogen. The results are very stable with respect to expected yields from short-rotation forestry, and are also not significantly impacted by the electricity background mix.

What impacts this displacement effect most is the choice of feedstock and whether or not this feedstock is directly transformed into hydrogen through gasification and steam reforming, or whether it is first turned into ethanol, which is easier to transport, and then into hydrogen. Only roughly a quarter of the GHG displaced by hydrogen made through wood gasification are displaced by hydrogen made from bio-ethanol. This ratio can be increased to about half if major improvements to the ethanol production process are achieved, but the difference remains very significant. This emphasises that it is imperative to tackle storage and transportation issues concerning hydrogen in order to maximise GHG benefits.

2.4 Forest Biomass

2.4.1 Comparative Approach

Forest biomass is used primarily for high-value goods such as lumber and paper products. However the harvesting and converting processes involve numerous steps where portions of the resource are removed as waste. This begins in the forest at the point the trees are cut. In Canada, over 2/3 of logging involves full-tree or tree-length methods. In these methods the branches, tops, stumps and sometimes the bark is left in the forest or by the roadside with roadside material often being slash-burned. Further waste residue is generated in processing consisting of bark, sawdust, sander dust, etc. This waste is considered low-value biomass.

Larger operations can collect sufficient quantities of wood waste residuals from manufacturing operations to justify conversion to productive energy due to economies of scale. This is applicable to integrated pulp and paper mills, very large sawmills and communities hosting a number of smaller mills within a confined radius. By contrast, most sources of forest waste are relatively small quantities and distributed. This results in a relatively high cost of transport for this high-bulk, low-value resource, which in turn limits the opportunities for productive use.

Other sources of low-value biomass can be fire-killed trees, insect-infested forests and wildfire hazard undergrowth. It is also generally found that even these higher quantities of biomass are not economically useful due to added costs of large-scale harvesting. Such sources may be productive on a local small scale but not on a large scale.

There are two distinct opportunities for energy recovery from biomass that differ based on the scale of operation. Large scale energy recovery requires locations where sufficient biomass is or can be collected and large steam systems are the industry standard for such power generation. A few other technologies have been proposed for large scale conversion, such as hydrogen production, but these are non-commercial and even experimental in nature and not a realistic option for the near future. Large scale steam systems are a mature technology that is well defined technically, financially and in investment requirements.

The second opportunity is for small scale energy recovery from biomass. Since the majority of harvested trees is not removed from the forest, a great amount of forest wood is considered low value and most saw log operations as well as remanufacturing plants are too small to justify large steam power generation, the majority of unrealized potential biomass energy conversion can be considered small scale. The distributed nature of biomass greatly reduces the opportunity for large scale biopower from this material. This study will attempt to treat these two opportunities separately but will focus on small biopower systems as these have the greatest number of competing technologies, the greatest need for direct comparison and the greatest potential of affecting untapped biomass resource.

The relative values of biomass conversion options are primarily based on size, cost and conversion efficiency. Each of the selected technologies will be analyzed first for its energy conversion efficiency. This will be followed by a comparison of their environmental implications and, in particular, their CO_2 emission profile.

There are two energy end products of interest; heat and power. Heat may be process heat or space heating and is of particular interest for its displacement of fossil fuel energy sources. Power may be transportation or electricity. Since the conversion efficiency of a transport fuel to motive force is similar in value to its conversion to electricity, this report will use electricity generation as its common final power product.

2.4.2 Comparative Data

A number of alternate technologies for conversion of biomass to energy will be reviewed. Some of these are “common knowledge” systems that will be analyzed by energy balance modeling. Other systems are “proprietary knowledge” systems that will be analyzed using published data.

A primary difference between biomass, used as a fuel, and fossil fuels is the moisture content of biomass. Fossil fuels are generally free of significant moisture content and thus there is a small gap between their higher heating value (HHV) and lower heating value (LHV). The lower heating value reflects the unrecoverable energy contained in the evaporative heat load of the water vapour produced by combustion. For moisture-free fuels the water vapour produced is from the combination of hydrogen in the fuel and oxygen in the fuel or combustion air. For high-moisture fuels, the free water in the fuel represents additional unrecoverable energy related to its evaporative heat load. As a result, the HHV and LHV of biomass are very different and put a large practical limit on the overall energy recovery efficiency of all conversion technologies.

All comparisons of conversion technologies of forest biomass in this study will be based on a common feedstock. A typical component analysis of the biomass is selected as shown in table 2.4.1. The most highly variable component is the moisture content. This affects the recoverable energy very significantly. It has been assumed in this study to use a 50% moisture feedstock with higher heating value content of 8800 Btu/BDlb$_{\text{fuel}}$. (20.5 MJ/BDkg$_{\text{fuel}}$). This represents “green” biomass in relatively common abundance. It is recognized that there is a reasonable amount of low-value biomass available at lower moisture contents but freshly harvested material is most likely about 50% moisture. The composition of the biomass feedstock is assumed to be as shown in the table below.

Table 2.4.1 Common Feedstock Analysis

		Weight		kmoles/kg$_{\text{feed}}$	Volume
Feed Analysis	kg/kmole	(dry)	(wet)	0.0705	100%
Carbon C =>	12	50.00%	25.00%	0.0208	29.54%
Hydrogen H_2 =>	2	6.00%	3.00%	0.0150	21.27%
Oxygen O_2 =>	32	42.00%	21.00%	0.0066	9.30%
Nitrogen N_2 =>	28	2.00%	1.00%	0.0004	0.51%
Water H_2O =>	18	0.0%	50.00%	0.0278	39.38%
			14.178	kg/kmole$_{\text{feed}}$	

It is recognized that biomass may be available at differing moisture contents. The energy requirement of pre-treating biomass for the various technologies reviewed is identified in the text. Other moisture contents can be substituted into the comparisons by adjustments made using the energy data given. The selected comparison level of 50% represents a common “green” form of biomass. Lower and higher levels of moisture may be available regionally. Care should be taken when adjusting for other fuel moisture levels that values chosen are realistic and not overly optimistic as has often been the tendencies of promoters.

2.4.3 Conversion Technologies

There are a number of technologies that have been proposed or developed to convert biomass to power and/or heat. These can be segregated into the direct and indirect approaches. The direct conversion approach outputs power and/or heat as a result of its process. The indirect conversion approach outputs a "fuel" that can be converted immediately to power and/or heat or stored for future use. Some of the promoters of indirect conversion systems present the intermediate "fuel" as the end product. However it is clear that such fuels only have value for their further conversion to power production. This review will continue the indirect processes to a final product comparable to the direct approaches.

The indirect conversion processes include:

- (i) Bio-oil
- (ii) Syngas

Both of these intermediate fuels have the capability of being stored for future use. They both are potentially useable in engines: internal combustion or gas turbine. And both can be used to produce electricity through generators connected to engines. There are practical limitations to such uses that are not addressed in this study.

Typically the indirect conversion processes require greater control of both the size and moisture content of their biomass feed. This can add very significant equipment cost and energy inefficiencies to a system. For instance, reducing the moisture content of forest biomass to the 10% level required for bio-oil production is an equivalent process to wood kiln drying; a long, energy consuming process. Even pre-drying to a 25% moisture level for gasification is an inefficient process when applied to chip-size or larger biomass particles. Such considerations need to be considered by prospective users of these technologies.

The direct conversion processes include:

- (i) Large steam Rankine cycle systems
- (ii) Small steam Rankine cycle systems
- (iii) Small steam Rankine cycle CHP systems
- (iv) Organic Rankine cycle (ORC) systems
- (v) Entropic cycle systems
- (vi) Brayton cycle air turbine systems

Generally the direct conversion process involves combustion of the biomass fuel. This is a relatively tolerant process of both size of biomass feed and moisture content. Techniques of enhancing the combustion process are generally common for all of the power conversion processes noted above, thus such techniques are not directly compared in this report.

The industry standard biomass power system is the large steam Rankine cycle system that has been used in large pulp & paper mills, co-generation plants and stand-alone power producers. These are the only systems that have a significant installation base and as such become the comparative standard. All of the other systems are either more recent developments or have been found to be economically uncompetitive.

2.4.3.1 Large Steam Rankine System

The Rankine cycle is the basis of steam systems for power generation by nuclear, coal, oil, solar boiler and biomass systems. Although the fundamental cycle has a limited efficiency, numerous techniques are available to enhance the basic efficiency, such as maximizing the operating pressures and temperatures and by adding economizer, recuperation and reheat loops. The boiler presents a safety issue that is addressed by government regulated qualifications of both systems and operators. There is clearly an economy of scale required to justify the application of steam systems.

Large steam Rankine systems can be used effectively whenever sufficient biomass is or can be collected. This situation can be found in integrated pulp mills and special regions that are centrally located for forest product operations. Within pulp mills the large steam Rankine systems are used for process steam and often co-generation with electricity. Such is generally the highest value application of biomass energy recovery. There are opportunities within many pulp mills to upgrade existing biomass systems to produce electricity or additional electricity and these should be pursued. Generally in these situations the upgrades will involve only electricity production as process steam production already exists, thus the implementation is effectively a power-only option.

Combined heat and power usually refers specifically to energy recovery for both electricity and district (space) heating. Operating a large steam Rankine system requires large facilities including storage and handling areas. Such facilities are distanced from local users and located relatively far from populous areas and city centers. It is generally not practical to assume that a large steam system will be implemented as a CHP facility.

The large steam Rankine cycle system can be used as the comparative standard for all other biomass conversion technologies; including small scale biopower. This report will not attempt to separate the effects of co-generation within pulp mills as it is intended to review new opportunities. New installations and upgrades at pulp mills will generally not increase process steam so will effectively be strictly power producers. The major advantage of new pulp mill installations and upgrades will be to take advantage of existing infrastructure and thus potentially reduce costs. The most direct comparison of systems is to use new, stand-alone power generating from large steam Rankine cycle systems.

The Williams Lake Generating Station is a reasonable example of a stand-alone biomass power generating facility. This system was commissioned in 1993 at Williams Lake, B.C. at a cost of $150 million Cdn. It has a rated capacity of 60 MWe, a capability of 67-69 MWe and achieves an overall efficiency of 29.2% HHV using steam at 1575 psig/ 950°F (10960kPa/510°C) expanded to a 2.5” Hg absolute pressure. 550,000 green tons of wood waste is supplied annually from five sawmills all located within 5 kilometres and includes pulp quality chips as there is no paper mill in the vicinity. This relatively high quality fuel varies in moisture content from 37% in the summer to 50% in the winter; a better quality than used in the balance of this report. This plant is claimed to be “the most efficient stand-alone wood fired power plant in North America” and thus could be viewed as the upper limit of power production efficiency expected from large steam Rankine systems. It should also be noted that this facility operates at or beyond its rated capacity. This implies that there is no capacity available for additional biomass waste generated in the vicinity by other forest industries. Additional biomass waste in the region should be viewed as “small scale” quantity since it cannot be handled by a large scale biopower system. *(http://www.westbioenergy.org/lessons/les12.htm)*

There are a number of practical barriers to large scale biomass systems that has minimized their implementation. The quantity of biomass required is significant and there are limited locations where such quantities exist. The logistics and cost of biomass transport to central facilities are not insignificant. Although the unit cost (~$2500/kWe Cdn) of new large biomass systems is minimized due to the scale, the total investment is high due to the large overall size. This requires large companies or consortiums as investors who often still require subsidies for economic justification. Biomass power is a secondary venture for forest companies and such investment receives limited corporate support. Institutional investors require long-term fuel supply guarantees to which few forest companies will agree. The two most recent major upgrades of large scale biomass systems in B.C. were heavily subsidized by B.C. Hydro ($18 million of $28 million for Weyerhaeuser, Kamloops and $48 million of $81 million for Canfor, Prince George).

2.4.3.2 Bio-Oil

Bio-oil is produced by condensing gases produced by pyrolysis of biomass feed. Generally it is the large, carbon based molecules that will condense. Further it has been found that these molecules will tend to break down to smaller non-condensable molecules if they are maintained at high temperature. Recognizing this, several groups have developed “fast pyrolysis” systems in which the pyrolysis gases are cooled and condensed quickly (<2 seconds), soon after being formed. Fast pyrolysis will maximize the yield of bio-oil and change the constituent molecules as compared to slow pyrolysis.

The chemical mix of bio-oil varies with the feedstock used and the conversion process employed. Some promotion of bio-oil has focused on extracting high-value chemicals before using the remainder for energy. The vision of a “biomass refinery” has been pursued for over a decade. Although this vision may have potential, the scale of such operations appears to be limited. Current high-value chemicals to be extracted do not have the demand to expand significantly. Other proposed chemicals to be extracted are significantly more costly than existing sources they would replace. It is reasonable to require bio-oil be justified as an energy product for the foreseeable future.

(% yield by weight)	**JF Bioenergy**[1]	**ROI**[2]	**Dynamotive**[3]	**Ensyn**[4]
Bio-oil	25%	60%	60% - 75%	60% - 80%
Non-cond. gas	42%	15%	10% - 20%	8% - 17%
Char	33%	25%	15% - 25%	12% - 28%
Fuel Feed				
Moisture content	n/p	<10%	<10%	<10%
Size	n/p	n/p	1 – 2 mm	1 – 2 mm
Bio-oil content				
Energy (Btu/lb / kW)	8000 / 2.34	8000 / 2.34	7100 / 2.08	7500 / 2.20
water	n/p	21%	23.4%	<25%
(% yield by energy)				
Bio-oil	23%	55%	55% - 68%	55% - 73%
Non-cond. gas	14%	5%	3.3% - 6.6%	2.7% - 5.7%
Char	52%	40%	24% - 40%	19% - 44%

Sources:
1. http://www.jfbioenergy.com/ (accessed Dec/2003)
2. Opportunities with BioOils; Phillip C. Badger, Renewable Oil International™ LLC, Florence, Alabama, 2003; http://www.georgiaitp.org/PDF/Bio-Oils.pdf (accessed Dec/2003)
3. http://www.DynaMotive.com/biooil/technology.html (accessed Dec/2003)
4. The Conversion of Wood and Other Biomass to Bio-Oil, Ensyn Group Inc, June 2001

Yields of bio-oil will vary with different technology systems and different fuel feeds. For instance reviewing four alternate systems shows reported results from wood and bark as noted above. Added to the list of yields on a weight basis is an estimate of the energy and water content of the products. Not shown in this list is the large parasitic heat and energy load required to dry and size the fuel in preparation for pyrolysis. A portion of the energy for biomass fuel preparation must be high-value electrical energy rather than strictly heat energy. (n/p indicates "not provided")

Bio-Oil Conversion Calculations: It should be noted that bio-oil production takes outside supply of energy and process materials in addition to feedstock. The Dynamotive and Ensyn processes in particular use fluid bed systems and require nitrogen and sand supplies which are significant financial inputs and implicit energy consumers. Operating power for these systems is also notable at 220 – 450 kWh/BDtonne. This equates to 3.9% - 7.9% of the original energy content of the biomass feed and is in the form of electricity. These processes are not internally self-sufficient.

The energy conversion calculations for bio-oil have been determined using published data. The four technology sources listed above have consistent numbers for fast pyrolysis and expected numbers for the slow pyrolysis example. The energy balance used in this review has been based on a typical composite of the published values noted above and the additional considerations as noted below. It should be noted that review of the yields by weight and by energy implies that the quoted energy contents reflect the higher heating value (HHV) of the resulting bio-oil. With "free" water content in the bio-oil of 21%-25%, it is clear that the lower heating value (LHV) will be significantly less than the HHV and this will reduce the recoverable energy from bio-oil. This high level of free water in the product bio-oil happens despite the very dry biomass fuel used as feedstock.

1) Drying and sizing of biomass is necessary before it can be used in the fast pyrolysis, bio-oil processes. All of the processes require the biomass be dried to less than 10% moisture and sized to less than 2 mm. Drying has a typical energy requirement of 1600 – 2200 Btu/lb$_{H_2O}$ (3.72 – 5.1 MJ/kg$_{H_2O}$). Drying biomass from 50% to 10% equates to 1420 – 1955 Btu/BDlb$_{\text{fuel}}$ (3.3 – 4.54 MJ/BDkg$_{\text{fuel}}$ or 917 – 1262 kWh/BDtonne). This represents 16.1% - 22.2% of the biomass feed fuel energy. Although it may be possible to use energy from the char to dry the biomass feed (as suggested by ROI), most processes assume an outside energy input for this purpose. Sizing of biomass feed requires a high-value form of energy (electricity) that heat alone cannot supply. Reviewing several approaches to sizing results in similar power consumption figures that range from 150 - 200 kWh/BDtonne. This directly reduces the net electrical power produced. It is assumed for this review that sizing of biomass feedstock will consume 170 kWh/BDtonne and drying will consume 1050 kWh/BDtonne. Review of different sizing/drying systems and techniques show similar energy results.

2) The pyrolysis conversion process uses about 8% of the original fuel energy in the form of heat. This is in addition to the power requirements to operate the system. This heat energy can be supplied from by-products of the process. Dynamotive uses the non-condensable gases to supply ¾ of this energy. ROI states that it uses char to produce this energy. However this need would best be met using the bio-oil itself or char rather than the outside fossil fuel used by demonstration systems. This study will assume that a portion of the char is used to supplement the non-condensable gas required to drive the pyrolysis process. Using an estimated LHV for bio-oil, the pyrolysis process will require 3% energy of the char product to supplement the 6% energy of non-condensable gas.

3) Component yield means that bio-oil contains only a portion of the original energy of the biomass feed. Char and volatile gases contain much of the remainder of the original energy. It is assumed in these calculations that the energy content of the products contains all of the original energy of the bone dry biomass feed less the identified losses. This implies that the volatile gases, char and bio-oil are consumed as necessary to drive the process and that no outside energy is added to the pyrolysis process. This assumption is conservative and will result in higher conversion efficiencies than may be realized in practical systems.

4) Engine systems can potentially vary from internal combustion (IC) engines to turbine engines. Practical systems have been proposed for turbines. Due to the low energy content of the fuel an engine must be physically larger and thus reduced in efficiency over fossil-fuelled engines. An engine efficiency of 30% or less can be expected for practical engine applications based on HHV of comparative fuels. The engine efficiency will be lower still due to the much lower LHV of bio-oil. Further losses are found in generators. If an IC engine could be used and connected directly to electrical generators, 80%-90% power efficiency may be realized. If a turbine engine were connected through a gearbox then 75%-85% efficiency may be realized. For this study it is assumed that an engine of 28% is matched to a generator efficiency of 85% to give an overall efficiency of 24%.

2.4.3.3 Syngas

Syngas, also known as producer gas, is generated through gasification and reduction processes. Biomass, heated in an oxygen-deficient atmosphere, releases numerous gaseous compounds. The volatile gases created are largely carbon monoxide, hydrogen and methane. There is typically also a significant quantity of non-volatile gases that include carbon dioxide, water vapour and nitrogen. In addition there are particles of ash, char, tar and alkali compounds.

Syngas must be cooled and filtered before being used in an external IC or gas turbine engine. Cooling is required primarily to remove the water vapour in the gas otherwise the heat content is excessively low and virtually unusable. Cooling also allows the tar and particulates to be filtered out before the syngas is used as a fuel in an IC engine or gas turbine. The temperature reduction of cooling is one of the energy losses of conversion. In practice it is very difficult to filter syngas sufficiently and effectively to allow it to be used in a real IC engine or turbine without excessive maintenance being required.

The heat content of syngas varies greatly with the species and moisture content of the fuel feed as well as the conversion process used. The common process uses air and results in a gas mixture of gross calorific value 4-7 MJ/Nm^3 (dry). Special processes using pure oxygen would result in a gas mixture of gross calorific value 10-18 MJ/Nm^3 (dry). For comparison, natural gas typically has a calorific value of 35 MJ/Nm^3. Higher moisture content in the biomass feedstock causes a lower calorific value of the resulting syngas because more energy is needed to evaporate the moisture and this energy comes from more carbon being converted completely to carbon dioxide.

Syngas processes are generally less tolerant to high moisture content of the biomass feed. Many gasification systems require the biomass feed to have a moisture content to not exceed 35% and systems operate more effectively if the moisture content does not exceed 25%. Such systems require external drying of higher moisture content fuel which is very inefficient and requires large equipment. This report will assume that the process operates on 25% moisture fuel to produce the quality of syngas noted below.

Subsequent utilization of syngas is dependent on its production method, fuel properties and fuel consistency. Cooling and filtering is required to prepare it for use. (Syngas can also be synthesized into methanol.) The low energy content of the gas affects the size of engines required to convert this energy. Generally the physical size of an IC engine operating on producer gas must be significantly larger than an equivalent fossil-fuelled engine. Larger engines are less efficient and more expensive to purchase and operate.

Table 2.4.2 Syngas Composition

	kg/kmole	kmoles	Volume	Dry kmoles	Dry Volume	Dry Weight
Syngas		0.0863	100%	0.0549	100%	kg/kg$_{feed}$
Carbon monoxide CO =>	28	0.0165	19.07%	0.0165	29.94%	0.461
Carbon dioxide CO_2 =>	44	0.0032	3.65%	0.0032	5.73%	0.139
Methane CH_4 =>	16	0.0012	1.43%	0.0012	2.24%	0.020
Water H_2O =>	18	0.0313	36.30%	0.0000	0.00%	0.000
Hydrogen H_2 =>	2	0.0090	10.43%	0.0090	16.38%	0.018
Nitrogen N_2 =>	28	0.0251	29.11%	0.0251	45.70%	0.703
Total =>		22.070	kg/kmole$_{gas}$	24.389	kg/kmole$_{gas}$	1.340

Syngas (dry)			8.18	MJ/kg$_{feed}$		
Carbon monoxide CO =>	82.76	MJ/kmole	2.96	MJ/kg_$_{CO}$	2.76	MJ/m^3
Carbon dioxide CO_2 =>	0.00	MJ/kmole	0.00	MJ/kg	0.00	MJ/m^3
Methane CH_4 =>	19.84	MJ/kmole	1.24	MJ/kg_$_{CH4}$	1.19	MJ/m^3
Water H_2O =>	0.00	MJ/kmole	0.00	MJ/kg	0.00	MJ/m^3
Hydrogen H_2 =>	46.29	MJ/kmole	23.15	MJ/kg_$_{H2}$	1.56	MJ/m^3
Nitrogen N_2 =>	0.00	MJ/kmole	0.00	MJ/kg	0.00	MJ/m^3
	148.90	MJ/kmole	6.11	MJ/kg$_{gas}$	5.50	MJ/m$^3_{gas}$

Gasification Conversion Calculations: The energy conversion calculations for syngas have been determined by assuming a final composition of syngas and back-calculating the energy losses of the process. Based on published information, the syngas is predicted to have the composition shown in Table 2.4.2. This composition is conservatively estimated for syngas produced from high moisture content biomass feed. It is assumed that the fuel must be pre-dried to 25% moisture by heat alone at a rate of 1980 Btu/lb$_{H2O}$ (4.6 MJ/kg$_{H2O}$) which requires 1320 Btu/BDlb$_{fuel}$ (3.8 MJ/BDkg$_{fuel}$) and represents 15% of the original biomass energy.

It is assumed that the process is 100% effective in converting the biomass feed into gas mixture and ash. It is assumed that no char remains, only ash. It is also assumed that the heaviest hydrocarbon produced is methane; that all large molecules are reduced to methane, carbon monoxide, carbon dioxide, hydrogen and water. As noted below, the syngas is cooled and the entrained water vapour is condensed to leave a dry volatile mixture with a heat content of 5.5 MJ/Nm^3. Higher volatile gas could be produced with a dryer fuel.
Syngas can theoretically be used in an IC or turbine engine to provide motive force to drive an electrical generator. Due to the low energy content of the fuel, the engines must be physically larger and thus are reduced in efficiency over fossil-fuelled engines. (A 1.35 MWe

engine/generator set designed for syngas, promoted by Stewart and Stevenson is 40ft x 8ft x 9.5ft x 59000lbs - *www.ssss.com/strategicOps/pdfs/gxseries.pdf*) It is estimated that an IC engine can be made to produce about 75% of its rated power when using syngas at 5.5 MJ/m^3 and its efficiency would be reduced to about 36.7% peak. Further losses are found in generators. An IC engine can be connected directly to electrical generators which can realize 80%-90% conversion efficiency. If a turbine engine were connected through a gearbox then 75%-85% efficiency may be realized. An overall efficiency of 31% has been used in the calculations given in this review and is likely quite conservative. No accounting has been made for additional external energy required to drive the process such as pumps, fans and other parasitic loads which, cumulatively, can be very significant for small systems.

A special technique to plasma gasify biomass has been promoted to produce syngas with a high heat content; 550 Btu/ft^3 (20.5 mJ/m^3 - ~55% of natural gas). According to promotional literature (*DW Energy Research, LLC; Colorado*) each 1.0 kWhr of power used in the process produces syngas with 1.93 kWhr of energy content. However, if one converts that syngas back to electricity, it will produce about 0.6 kWhr of power. This is a net loss of 40% of the input high-value electrical power.

2.4.3.4 Small Steam Rankine Cycle Condensing Systems

Attempts to produce small biopower systems first focused on reducing the scale of large steam systems. Although there have been a few small steam systems implemented, they are almost exclusively combined heat & power (CHP) systems that obtain their primary economics from heat production. There are numerous reasons that the economics of small steam systems cannot compare favourably with large biopower systems. These include:

- economy of scale for basic equipment
- excessive unit cost of operators
- reduced thermal efficiency of turbines
- lower operating pressures/temperatures
- simplified cycles implemented

To keep the basic equipment costs reasonable for small systems the peak pressure/temperature of steam must be limited to about 650psig/750°F (4.6MPa/400°C). Above this temperature special materials must be employed for turbine and boiler components. In small systems this expense would be untenable and thus practical systems have more limited steam conditions than large systems.

Scaling laws for turbines dictate that thermal efficiency reduces with reduced flow rate. Operational speed must be increased to compensate. Turbine size is dictated by its exit volume flow. Since steam becomes voluminous at low pressures, the high exit volume flow prevents sufficient size reduction to prevent efficiency loss. Thermal efficiency of small steam turbines reduces to the low 50% range with a turbine speed increase to 5400 rpm.

The greatest impediment to small steam generating systems is the unit operating cost. Government safety regulations for boiler operation require that qualified and registered steam operators be employed. Such personnel are expensive, of limited availability and more mobile than the systems they serve. The effect of this is a cost structure that cannot be justified except for large systems.

A small steam power generating system has been modeled on the common fuel input baseline of this report noted in table 2.4.4. Figure 2.4.2 shows the system in its basic functional form for a condensing system. An improvement to the overall power conversion efficiency could be realized if a flue gas exchanger were implemented after the economizer to pre-heat combustion air. Similarly the quality of fuel (reduced moisture content in particular) would increase the overall power efficiency. It is assumed in this model that the feed pump and other parasitic losses amount to 4% of the generated power.

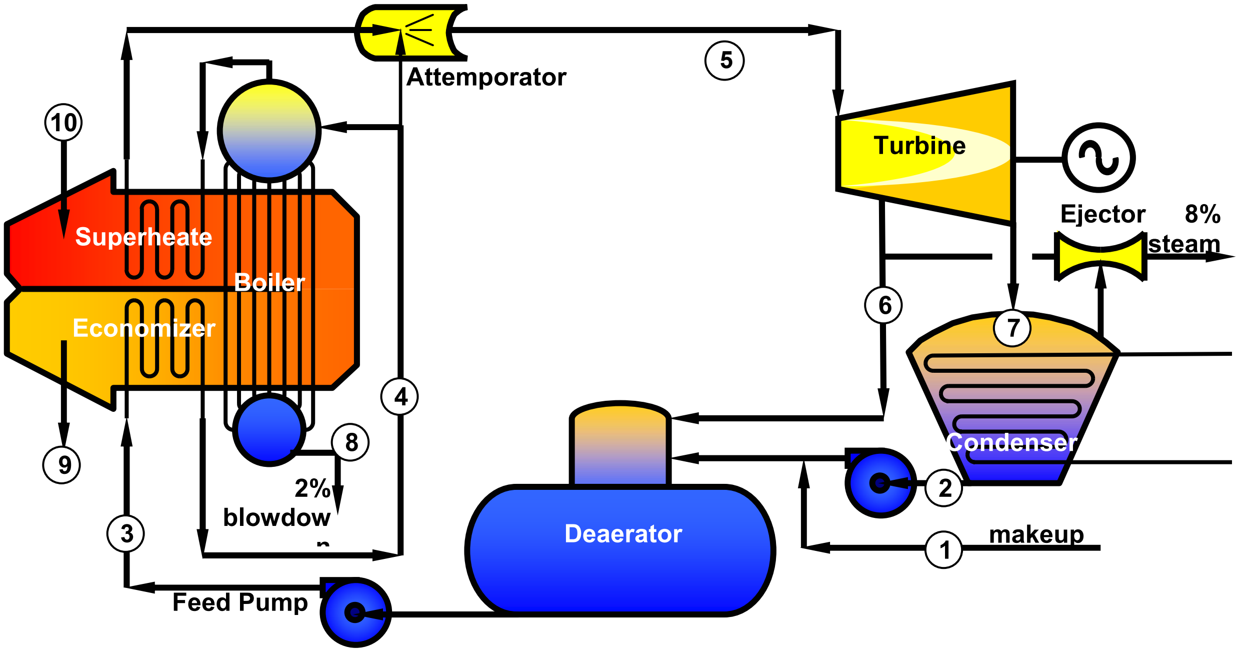


Figure 2.4.2 Small Steam Rankine system

Table 2.4.4 Small Steam Rankine System

state	P (kPa)	T (°C)	h (kJ/kg)
1	343	10	42
2	16	49	204
3	4583	138	578
4	4583	262	1156
5	4583	399	3202
6	343	221	2909
7	117	93	2674
8	4583	259	1128
9	-	315	-
10	-	1000	-

Turbine Thermal Efficiency	51%
Turbine Operating Speed	54 rpm
Generator Efficiency	90%
Boiler Heat Recovery	59.5
Cycle Power Efficiency	16.6
Overall Power Efficiency	9.9%

2.4.3.5 Small Steam Rankine Cycle CHP Systems

The small steam Rankine system has been adapted for combined heat and power application by using a back-pressure turbine rather than a condensing turbine. The steam outlet of the turbine is maintained at a pressure and temperature to be useful for sensible heating processes external to the power cycle. Since less energy is recovered from the steam within the cycle, the power conversion efficiency is reduced. However productive use of the exhaust steam increases the overall efficiency of the system.

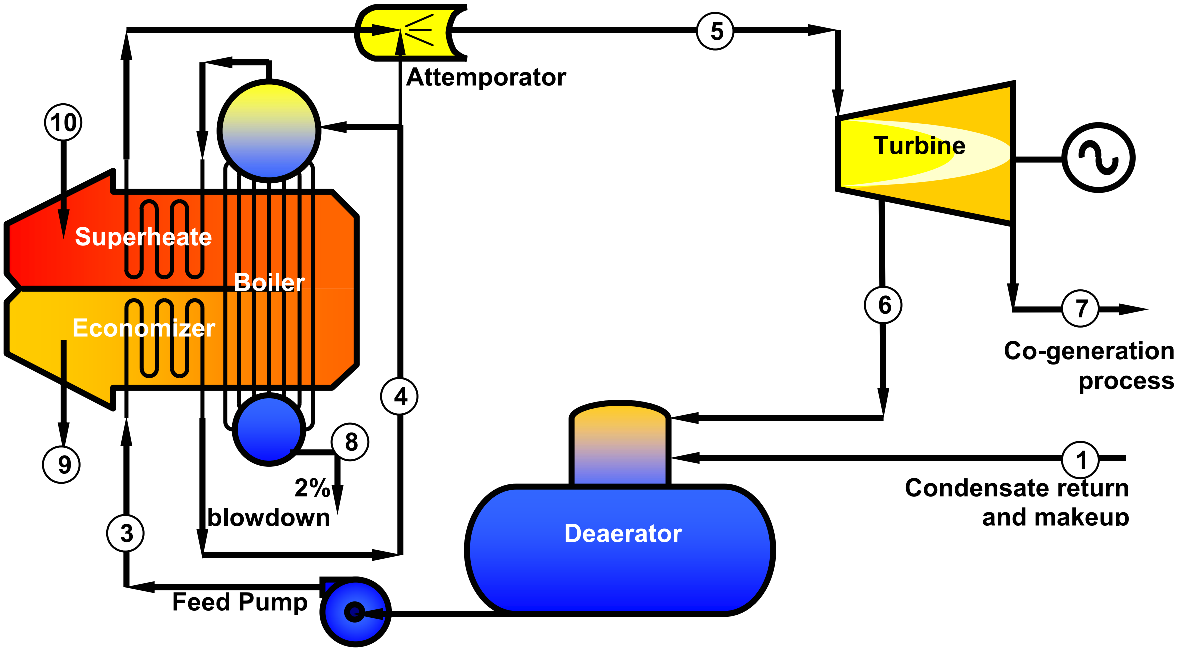


Figure 2.4.3 Small Steam CHP System

Figure 2.4.3 shows the system in its basic functional form for a CHP system. As in the condensing system above, an improvement to the overall power conversion efficiency could be realized if a flue gas exchanger were implemented after the economizer to pre-heat combustion air. Similarly the quality of fuel (reduced moisture content in particular) would increase the overall power efficiency. It is assumed in this model that the feed pump and other parasitic losses amount to 4% of the generated power.

Table 2.4.5 Small Steam Rankine system

state	P (kPa)	T (°C)	h (kJ/kg)
1	343	116	484
3	4583	138	578
4	4583	262	1156
5	4583	399	3202
6	343	249	2966
7	274	223	2919
8	4583	259	1128
9	-	315	-
10	-	1000	-

Turbine Thermal Efficiency	41%
Turbine Operating Speed	5400 rpm
Generator Efficiency	90%
Boiler Heat Recovery	59.5%
Cycle Power Efficiency	9.6%
Overall Power Efficiency	5.7%

2.4.3.6 Organic Rankine Cycle Systems

Organic Rankine cycle (ORC) systems have been recently developed in an attempt to address the specific needs of small system design. The working fluid of these systems is an organic (pentane, butane, etc.) which alters the pressure/temperature regime of the system. A company (Turboden, srl) markets an ORC system using proprietary synthetic oil and is the most published ORC system applied to biomass application. The primary advantage of the ORC approach is to operate at a higher turbine exhaust pressure yet maintain a convenient heat reject temperature. The higher exhaust pressure results in a less voluminous flow of exhaust vapour and, consequently, smaller equipment. In addition, the shape of the saturation dome of the T-S diagram means very little superheat is required and potentially more energy can be recuperated from the turbine exhaust flow.

Working fluids in ORC systems have only a fraction of the available enthalpy of steam and consequently must circulate up to five times the mass flow for the same power generation. This mitigates some of the effects gained by the higher exhaust pressure from the turbine. The turbines must be specially designed employing multiple stages and are still too big in diameter to allow very high speed operation. However the thermal efficiency of ORC turbines can be comparable to large-scale steam systems due to the high molecular weight of the working fluid.

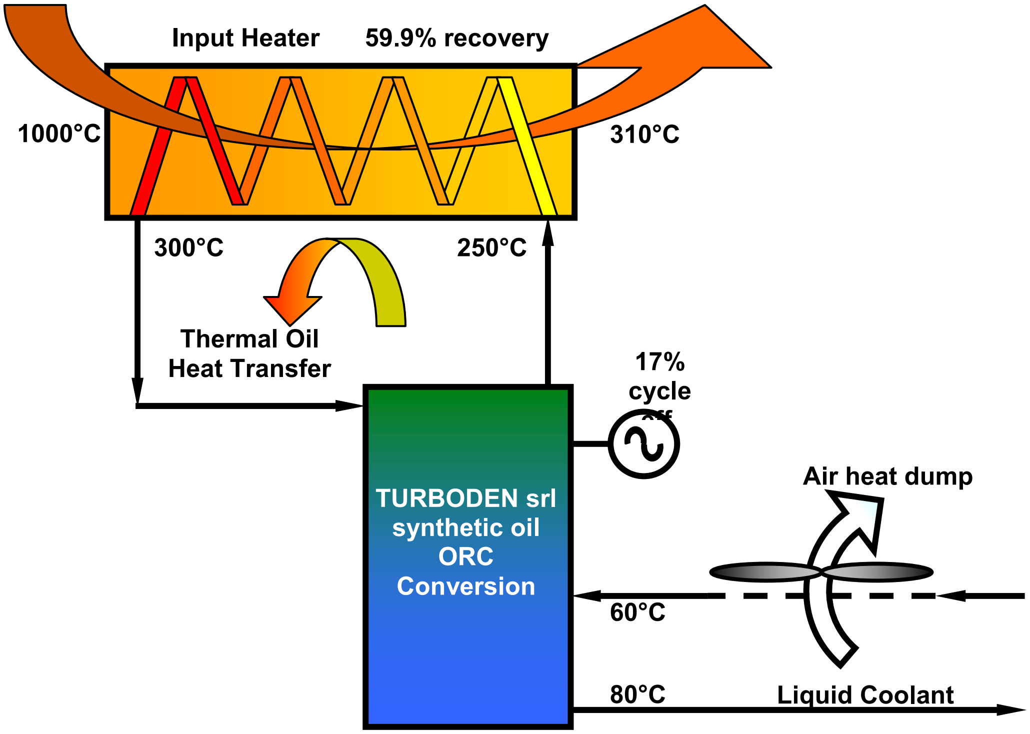


Figure 2.4.4 Turboden, srl ORC System

One aspect of ORC systems is an attempt to bypass requirements of steam operator qualifications. Such systems use a non-vaporizing thermal oil intermediary loop to extract heat from the flue gas and transfer it to the power cycle. The effect of this is to create a boiler that, although has an unlimited energy input, has a limited heat supply temperature in the boiler. The separation of the boiler from the flue gas bypasses regulatory requirements for a qualified steam operator in many jurisdictions. This additional energy loop adds additional heat exchanger, high temperature pump and piping to the system and consequently adds significantly to the system cost. The generic arrangement of an ORC system is shown in figure 2.4.4.

Flue gas temperatures are assumed to enter at 1000°C and exit at 310°C as these are reasonable values based on published data. No accounting has been made for potential heat recuperation from the flue gas leaving the Input Heater. Heat could be used to pre-heat combustion air and enhance the overall efficiency. No accounting has been made for using economizer heat from the flue gas to add to the coolant temperature for CHP application, as is suggested by Turboden, as this is outside the fundamental cycle comparison.

Accounting has been made for parasitic loads associated with the feed pump and other internal system requirements as the data published is quoted as net cycle efficiency. No accounting has been made of parasitic loads associated with the combustor system, flue gas draft requirements, air heat dump or cogeneration process uses. It is assumed in this model that parasitic losses amount to 4% of the generated power.

2.4.3.7 Entropic Power Cycle Systems

A recent, as yet unpublished, entropic power cycle is directed at energy recovery from hot flue gases on a small scale. This technology is similar to both steam cycle and ORC systems. It uses a proprietary non-steam fluid and in a closed loop system. The working fluid however contains about 4 times the enthalpy content of organic fluids which reduces the required circulating mass flow. The fluid is non-flammable and safe to use directly in a flue gas heater. Moreover the entropic power cycle permits biasing to simplify the equipment, reduce size, reduce the equipment count, increase turbine efficiencies and use a high temperature coolant. The entropic cycle results in a system that uses a super-heater not an evaporator in the flue gas and thus does not have the safety concerns of a steam boiler. It does not need a steam qualified or regulated operator. Moreover this application will produce a high temperature coolant (85°-95°C) that returns to the system hot (50°-60°C). These temperatures are directly applicable to district heating or, if the heat is not used productively, dry air cooling by a relatively small heat exchanger. No cooling tower, cooling pond or cooling water is required. Other packaging aspects of this system address minimizing operating and maintenance costs and include no dynamic seals on the turbine or pump, small all-welded compact heat exchangers and automated operation.

Flue gas temperatures are assumed to enter at 1000°C and exit at 215°C as these are reasonable values based on available data. No accounting has been made for potential heat recuperation from the flue gas leaving the Input Heater to the combustion system. Accounting has been made for parasitic loads associated with the feed pump and other internal system requirements. No accounting has been made of parasitic loads associated with the combustor system, flue gas draft requirements, air heat dump or cogeneration process uses. The generic arrangement of an entropic system is shown in figure 2.4.5.

The flue gas outlet temperature is directly related to the efficiency of heat recovery from the combustion process. Lower exit temperatures indicate greater heat removal from the flue gas. However biomass combustion will also produce particulate inclusion. Removal of these emissions is desirable (and often regulated). There are two reasons that flue gas temperatures below 230°C are desirable. First, this is below the ignition temperature of any fuel compounds so fires are less likely at lower temperatures. Second, low temperatures allow more flexibility in material selection for cleaning technologies; bag houses become a permitted option. It is assumed in this model that parasitic losses amount to 4% of the generated power.

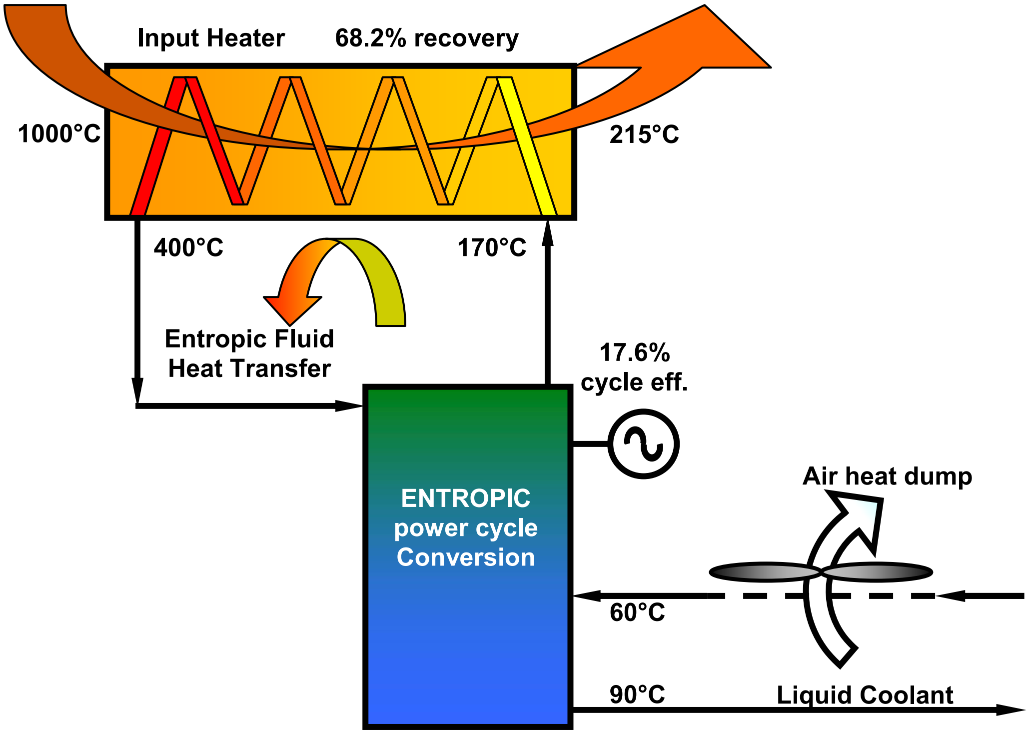


Figure 2.4.5 Entropic Power Cycle System

2.4.3.8 Brayton Cycle Air Turbine Systems

The Brayton cycle is basis of the “jet engine” and has been adapted in concept in an attempt to overcome some of the high-cost aspects of commercial steam systems. This system is an air turbine in which air is compressed, heated by the flue gas then expanded through a turbine. The compressor is driven by the turbine and consumes a large amount of energy. The air is heated by the flue gas in an indirect heat exchanger. The heated, pressurized air is then expanded through a turbine to extract motive energy. Heat remaining in the turbine exhaust air can be recuperated into the incoming air from the compressor going to the heater. Cycle air leaving the recuperator can be used directly as combustion air to increase overall efficiency.

It should be noted that since air holds a limited enthalpy and operating pressures are less than Rankine cycle pressures, the equipment size is larger just to handle the volume flow. Moreover, the compressor requires most of the energy that is being produced by the turbine so the turbine must be much bigger still. Air compressors are designed similar to turbines and are much more expensive than liquid compressors used in Rankine systems. The large turbine size, sophisticated compressor design, large high temperature heater and low cycle efficiencies challenge the cost-effectiveness of the air turbine approach.

Several groups have promoted the air turbine approach for biopower application but the author is not aware of a commercially installed system at this time. This review assumes that the set of inlet flue gas parameters as has been used for the technologies noted previously is excessive for this application. It is also assumed that the system, as shown in figure 2.4.6, is the most realistic for analysis since this is the design that has typically been promoted.

The operating parameters for a Brayton cycle system impose limitations that were not required for other direct conversion technologies. The air used as a working fluid must be taken to a high temperature to maximize the cycle efficiency. However material considerations limit the peak temperature entering the expansion turbine to about 480°C. The heater is used to transfer heat from the flue gas to the working fluid air. However this is a gas-to-gas heat exchanger in which both flow sides have a poor heat transfer coefficient. The metal temperature of the heater tubes must be limited for material considerations similar to the turbine limitation. For this review the tube metal temperature will be limited to 565°C; a very high allowance giving conservative results. (Ceramic heat exchangers may be used but are not yet commercially available.)

It is clear that the operating pressure of the Brayton cycle is a key parameter. However a practical consideration is the expansion ratio through the turbine. A single stage turbine can typically handle an expansion ratio up to 3:1. A greater expansion ratio requires multi-stage and more expensive equipment. More interestingly, it can be readily shown that a low-pressure single-stage turbine with a recuperator will produce a greater cycle efficiency and overall efficiency than a higher pressure two-stage turbine system. This is because the higher pressure system must expend more energy compressing the working fluid which becomes too hot to accept recuperation heat.

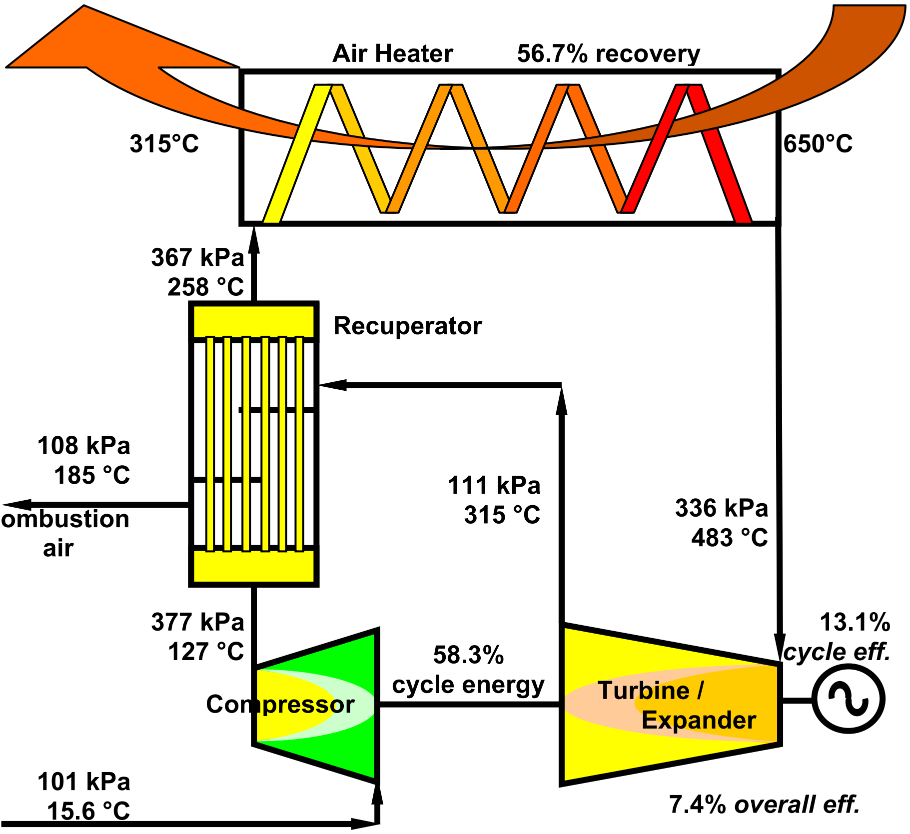


Figure 2.4.6 Brayton Cycle Air Turbine System

No accounting has been made for potential heat recuperation from the flue gas leaving the Air Heater. However, directing the turbine exhaust air to the combustion system can increase the overall efficiency by 34.3%. Very high allowances for both the turbine thermal efficiency (85%) and generator conversion efficiency (95%) have been assumed. No accounting has been made of parasitic loads associated with the combustor system or flue gas draft requirements. For reference it may be noted that operating a two-stage high-pressure (790 kPa) system would negate the use of a recuperator, offer 8.2% cycle efficiency and 6.6% overall efficiency. Thus the single-stage low-pressure recuperated system offers the highest potential efficiency.

2.4.4 Energy of Conversion

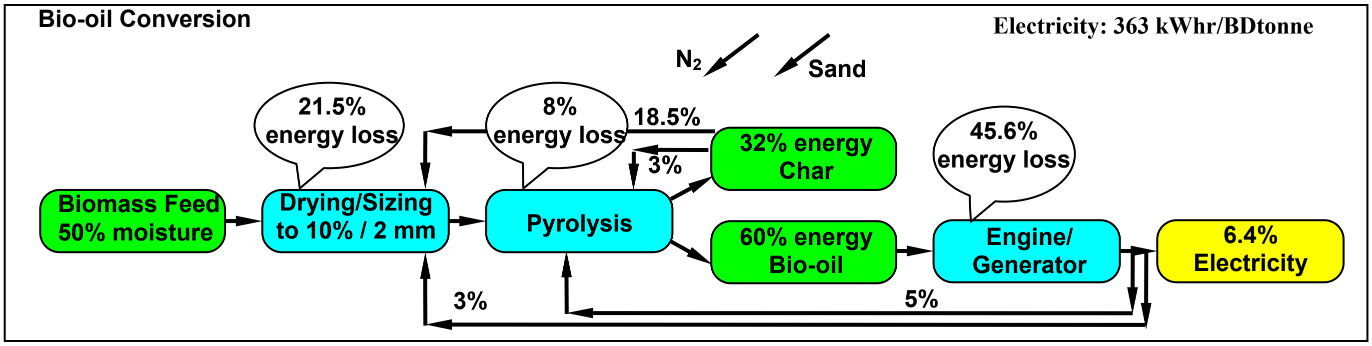
Converting biomass to power involves energy losses at many points during the process. Energy is always lost in conversion processes. The amount of energy captured from an original fuel is an important comparative measure between different conversion technologies. The various technologies discussed above will be compared for energy flow from feedstock source to a common final product. Data for the large steam system is based on a lower average fuel moisture level and the most efficient system known giving this option an enhanced result.

Since various processes have different end products, it is often difficult to determine an impartial comparison. However it is often the case that interested parties promote particular technologies by discussing only a portion of the overall conversion efficiencies. It will be attempted here to make an overall efficiency comparison between numerous technologies by identifying typical efficiencies for every conversion step from biomass fuel to electricity. Where additional products are created, they will be identified. The initial fuel for this comparison, as noted above, is green wood chips at 50% moisture level with heat content 8800 Btu/BD$_{lbfue}$l. (20.5 MJ/BD$_{kgfuel}$)

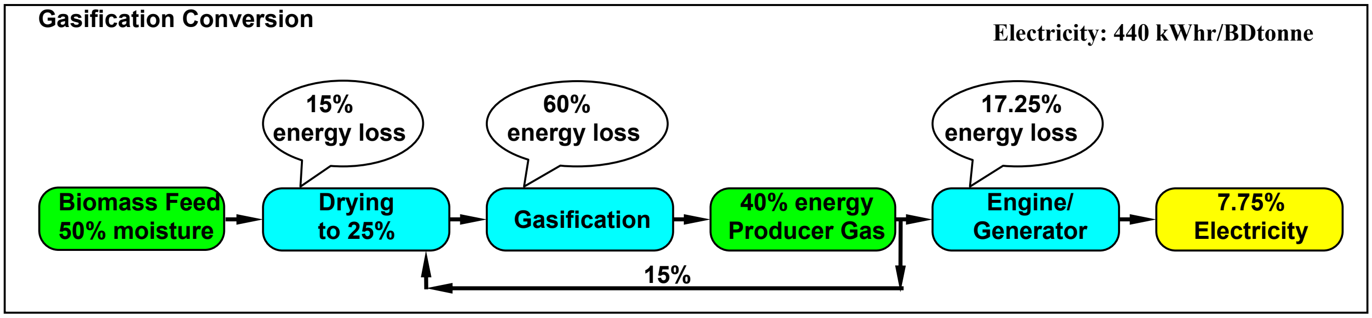
Energy in the diagrams below is in relation to the original energy of the biomass feedstock.

Figure 2.4.7 Input-Based Energy Balances

Bio-oil Conversion

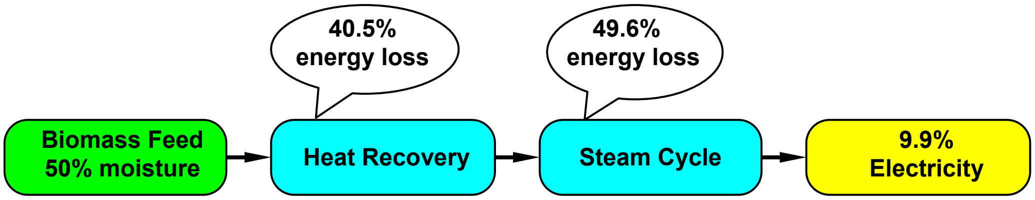


Gasification Conversion



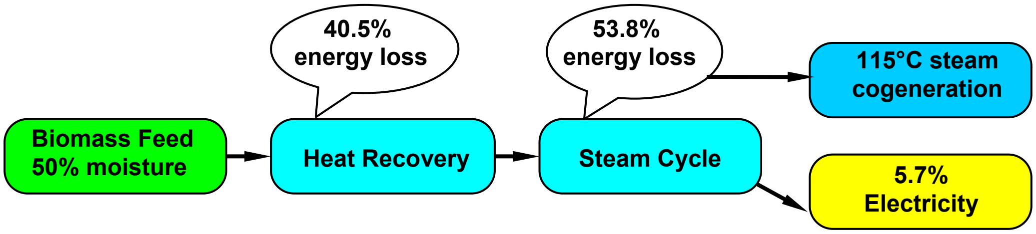
Small Condensing Steam Cycle

Electricity: 563 kWhr/BDtonne



Small Steam CHP Cycle

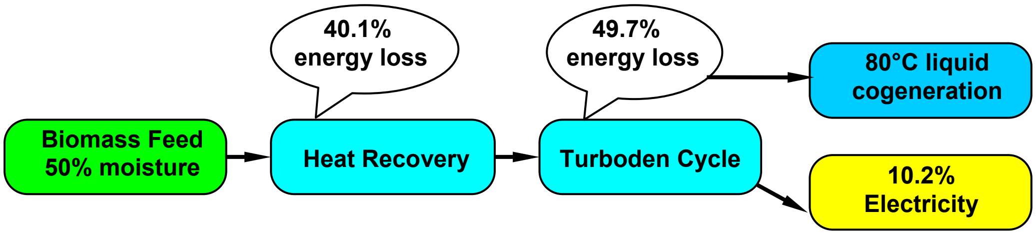
Electricity: 324 kWhr/BDtonne
Heat: 2936 kWhr/BDtonne



*note: steam is available for process uses or space heating very close to the source

Turboden ORC Cycle

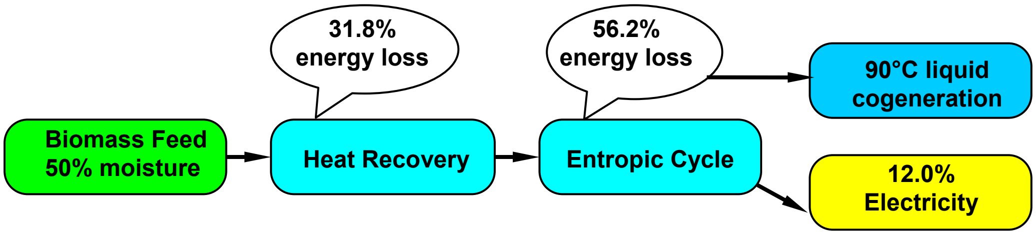
Electricity: 580 kWhr/BDtonne
Heat: 2713 kWhr/BDtonne



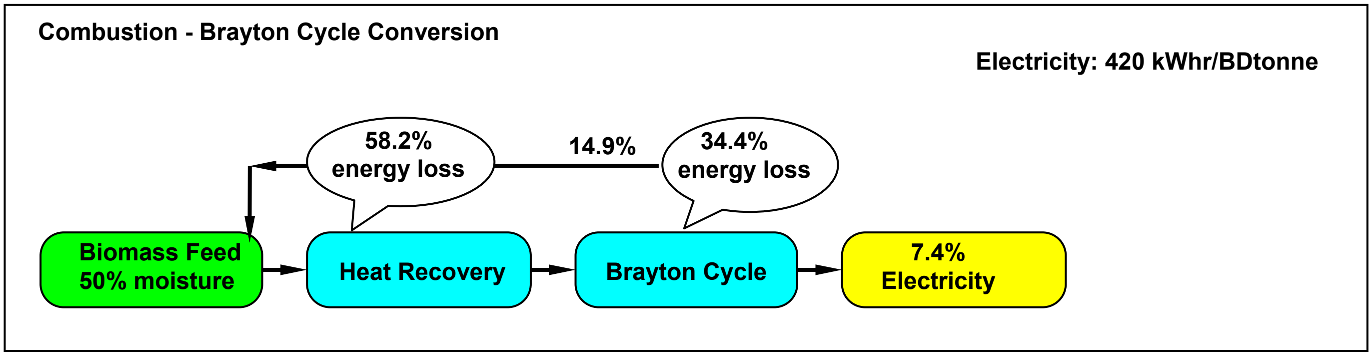
*note: liquid is available for district heating and can be pumped significant distances

Entropic Power Cycle

Electricity: 682 kWhr/BDtonne
Heat: 3066 kWhr/BDtonne



*note: liquid is available for district heating and can be pumped significant distances



The above diagrams indicate the energy flows of various promoted technologies and conversion paths used to convert biomass to electricity. Some of the energy loss values shown can be misleading on first inspection but they have been noted in this manner for consistency. For instance, the energy loss allowances for engine/generator combinations may be similar for both the bio-oil and syngas systems but since they are applied to different amounts of energy feeding the engines, they show as different numerical losses in the diagrams. Similarly higher energy losses of the Entropic cycle compared to the Turboden cycle reflects the greater amount of energy recovered from the biomass feed.

The calculations and assumptions made to develop the technology comparisons have been intentionally conservative. Additional parasitic losses and practical equipment efficiencies may reduce some of the results noted above. In some instances these may be quite significant especially if applied to small scale systems.

A major comparative parameter between technologies is cost. The economic comparison determines the true effectiveness of a system. Reliable cost data is not available to make a realistic cost comparison in the manner employed above for comparing energy losses. However general comparisons of technology complexities, equipment sizes, operator interactions and operator qualifications can give an “order-of-magnitude” cost comparison for capital, operation and maintenance.

Table 2.4.6 is a summary of the conversion technologies described. In this table there are general comparisons made of complexity, capital cost and operating cost as well as added products generated. Moreover an attempt has been made to identify the size range applicable to each technology. Colour coding in this table is intended to give a quick visual indication of relative benefits; green more desirable and red less desirable. The large steam Rankine system is included as a reference although it is recognized that it applies to a different category of biomass (large quantities) than the balance of the technologies compared. Although the large steam system may be preferred for its conversion efficiency, it can only be used where both sufficient biomass is collected and large scale investors can be found. The efficiency indicated for the large system may be higher than a new system may obtain.

TECHNICAL COMPARISON	2.4.3.1 Large Steam Cond. Cycle (Williams Lake Power)	2.4.3.2 Bio-oil Conversion	2.4.3.3 Gasification Conversion	2.4.3.8 Brayton Cycle	2.4.3.4 Small Steam Cond. Cycle	2.4.3.5 Small Steam CHP Cycle	2.4.3.6 Turboden ORC Cycle	2.4.3.7 Entropic Cycle
		(Pyrolysis)	(Syngas)	Combustor or Gasifier Front End				
Technical Complexity								
low 1..2..3..4..5 high	4	5	3	1	4	3	3	2
Equipment size & count								
less 1..2..3..4..5 more	5	4	3	5	5	4	2	1
Fuel Preparation								
less 1..2..3..4..5 more	2	5	4	2	2	2	2	2
Operator Qualification								
low 1..2..3..4..5 high	5	3	3	1	4	4	2	2
Capital Cost ($/kW)								
low 1..2..3..4..5 high	2	5	3	4	5	3	4	2
Optimum System Size	60 MW	> 5 MW	< 2 MW	<1/2 MW	< 5 MW	< 5 MW	< 2 MW	< 2 MW
Power Efficiency -biomass to	29.2%	6.4%	7.75%	7.4%	9.9%	5.7%	10.2%	12.0%
Secondary Products -	-	char	-	-	-	115°C	80°C liquid	90°C liquid
yes 1..2..3..4..5 none	5	4	5	5	5	3	2	1
Overall Cogeneration	29.2%	6.4%	7.75%	7.4%	9.9%	53.9%	54.5%	67.7%

ELECTRICITY: kWhr/BDtonne	1659	363	440	420	563	324	580	682
HEAT: kWhr/BDtonne	-	-	-	-	-	2936	2713	3066

Table 2.4.6 Technology Comparison Chart

The above descriptions offer a direct comparison between various conversion technologies taken from biomass fuel to final product. These comparisons are complete within this range. Each analysis is self-consistent as far as possible, using internal energy for all of its conversion needs. Assumptions made have been identified and conservatively estimated. This conservative approach may overestimate the production of indirect systems such as bio-oil and gasification. Direct systems may have been underestimated if flue gas heat recuperation and other cycle enhancements are added.

2.4.5 Environmental Implications of Conversion Technologies

Forest biomass has some advantages as a fuel. In comparison to coal it has very low sulphur content so it generally produces much less SO_2 emission. Natural gas has even less because sulphur is stripped from the gas during production. NOx is a concern similar to most fuels since much of this emission is due to nitrogen in the combustion air and the temperature of combustion. Many combustion processes of biomass or biomass derived fuels operate at a lower combustion temperature which lessens the NOx production. However there are still concerns to reduce NOx as much as possible. Generally there are no heavy metals in forest biomass such as mercury in coal.

The major emission concern of forest biomass conversion processes is that of particulate. There is a much lower ash content than in coal but there is no ash content in natural gas or processed crude oil. However emissions from biomass combustion can include ash, carbon and unburned particles. The particulate emission from poor biomass combustion can greatly exceed those from coal combustors with cleaning systems.

Bio-oil production: Rapid pyrolysis used to produce bio-oil converts biomass into gases in the absence of added oxygen. However the requirement of collecting and quickly condensing the pyrolysis gas means that a significant transport flow is maintained. Such flows will carry ash to the condensing section of the equipment. As a result, the bio-oil produced will contain some amount of ash. This ash is not easily separated. Along with the water content, this ash works to reduce the usefulness of the product.

Gasification: Gasification is sub-stoichiometric combustion of the biomass to produce a syngas mixture with significant quantities of carbon monoxide, hydrogen and non-condensable hydrocarbons. Typically air is used to supply the oxygen for the process and this air must maintain a transport flow through the fuel. Ash from the biomass will be carried into the volatile gas mixture along with tars and other heavy hydrocarbons.

If the syngas is to be applied to an external engine then it must be cooled to condense the water vapour and produce usable heat content. The cooled gas must be filtered to remove tars and particulate to make it usable in engine operation. Thus the syngas is stripped of particulates during production in the same manner natural gas is stripped of sulphur before use. Subsequent combustion of syngas should be particulate free.

Combustion: Combustion processes vary a great deal and, as such, so do their particulate emission. Wildfires are the worst particulate emitters followed closely by slash pile, beehive and silo burning. Enclosed combustors reduce particulate emission substantially but are still quantity emitters. Large grate boilers produce significant emissions in the form of ash, carbon and unburned particles. New large fluidized bed boilers have reduced overall emissions due to the complete burning of the biomass fuel and burnout of the carbon. However all the ash that doesn't form clinkers as well as silica particles, worn from the sand bed, exits with the flue gas. Flue gas cleaning to remove particulate is required to bring large combustors into regulatory compliance. Moreover, the volume of flue gas limits the practical choices of cleaning technology that can be employed. Electrostatic precipitators are currently the most common and most effective flue gas cleaning technology available for large biomass combustion systems. This technology can generally meet current regulations but it is anticipated that future standards could go beyond its capability.

For smaller combustion systems there are more effective approaches for minimizing particulate emission. High temperature combustors will use a refractory-lined chamber to achieve a very complete burnout of the biomass and prevent the emission of unburned particles or carbon. Sedate fuel feed and grate systems reduce the amount of ash being carried into the flue gas. However these systems still cannot meet regulatory emission requirements without post cleaning of the flue gas.

The smaller sized combustion system has the advantage of greater choice in flue gas cleaning technology. Electrostatic precipitators, scrubbers and baghouses can all be employed since the flow volumes are not excessive. Dry baghouses are the most effective for particulate removal. Baghouses have the specific limitation of flue gas temperature. Excessive temperature requires special bag material and "sparklers" in the flue gas can cause fires. Baghouses can be used when the flow volume is reasonable, the flue gas temperature is below about 230°C and "sparklers" are prevented or with a suitable spark detection/extinguishing system.

2.4.6 CO_2 Emissions from Conversion Technologies

Biomass that is used in a sustainable system is considered CO_2 neutral. This is based on the complete cycle in which CO_2 that is produced during biomass utilization is balanced by the CO_2 absorption by the living plants from which the biomass was taken. Although this concept is useful in the general sense, there are details which depart from CO_2 neutrality.

Within the carbon cycle itself it must be noted that greenhouse gases consist of more than CO_2 with alternate forms of carbon emissions being many times as potent greenhouse gases as CO_2. For instance the next most common emission from biomass is methane (CH_4), with 21 times the GHG potential of CO_2. Any process that emits CH_4 to the atmosphere is more destructive. It can be argued that since natural decomposition of biomass produces some CH_4, it is less environmentally friendly than direct combustion. This is generally not considered a significant effect but it does suggest net benefits to active utilization of biomass.

Where fossil fuels are used during the utilization of biomass, it results in a net production of CO_2. This is the case for harvesting, handling and transporting biomass. However it must be recognized that there is a net increase in CO_2 emissions only where additional fossil fuel is used. For instance the issue of biomass wastes from an existing process of wood use, such as sawmill sawdust, does not entail additional fossil fuel usage for harvesting, handling or transport. Therefore converting such wastes to power may have no associated net CO_2 emission. On the other hand, the removal of waste from logging activities that would otherwise be left in the forest has an associated use of fossil fuels. The CO_2 emissions from this extra fossil fuel use must be accounted.

Finally, where the production of energy from biomass is done to displace an equivalent fossil fuel usage, there is an equivalent net reduction in CO_2 emission. Electricity produced by biomass conversion will displace electricity produced by other means. To the extent that the original electricity production contributes to CO_2 emissions, its displacement equates to an equal net reduction. Similarly where heat produced by biomass conversion is used to displace other sources of heat, then there is a net reduction equivalent to the CO_2 emission of the original source of heat. Clearly the combined heat and power (CHP) conversion systems will show the greatest net reduction in CO_2 emissions where they displace fossil fuel sources.

Harvesting and Transport of Forest Biomass: Forests are the source of raw material for the pulp and paper and wood products industries. These industries produce high-value products that are generally independent of the consideration of energy production or CO_2 emission. However logging practices remove about 54% of the biomass harvested; 46% remains in the forest. This remaining material is left to biodegrade or is slash burned. Furthermore 22% of the saw log that is removed to the mill becomes waste in the form of bark, sawdust, etc. At least 30% of this saw log waste is not used productively.

Whole tree logging is the most common technique currently employed. Stumps and roots are left at site while the whole tree is removed to the roadside for processing. The limbs, branches and some of the bark are separated from the saw log. The saw log is transported to the mill while the balance remains on site. Removal of this waste typically would entail bundling or chipping at the roadside and transporting by truck. Proposals for removal of this waste entail chipping at the roadside and transporting by chip trucks. Recent proposals for removal of this waste suggest bundling, transporting by log trucks then chipping at point of use.

Large on-site chipping systems are estimated to use about 0.068 kg_{fuel} / BDtonne. Large truck transportation of biomass chips will use about 0.0249 kg_{fuel} / km / BDtonne. There is approximately 3 kg_{CO2} released per kg_{fuel} combusted. Transporting this forest biomass waste by truck would equate to 3.2 kg_{CO2}/BDtonne for 40 km and 12.2 kg_{CO2}/BDtonne for 160 km. One BDtonne of biomass has the equivalent energy content of 458 kg_{fuel} of diesel. Therefore for considerations on pure energy equivalence basis, transporting biomass 160 km out of the forest would cost less than 1% of the displaced CO_2 emission. In reality, the CO_2 emission represents a larger portion due to the inequality of conversion efficiency between biomass and fossil fuels and because displaced electricity typically represents less CO_2 emission than fossil fuel.

It should be noted that the emission profile is very positive for biomass fuel transport from forest areas. On the basis of net CO_2 emission, it is clear that there is a great benefit to collecting and transporting biomass for useful conversion. The numbers above show that this will be true for quite extensive distances. However the emission profile does not address the economic issue. Removing biomass has costs associated with forest workers, chipper equipment and operators, transport fuel and maintenance, trucks and drivers as well as coordinating and managing. It is often found that these totalled costs create an excessive $/BDtonne for biomass fuel. It is not unusual for biomass costs to vary from $27/BDtonne and up for roadside waste transported 120 km to $65/BDtonne and up for biomass that is harvested and transported 120 km. These costs are based on commercial operations acting on relatively large scale.

Electricity Displacement: Electricity produced from biomass can be considered to displace electricity from other sources. Where the power generated is connected to the local grid then it can be viewed in different ways. One option is to analyze the amount of CO_2 emission associated with the "average" electricity on the grid. This analysis does a weighted average of emissions to the power generation processes feeding the overall grid. This is the approach taken in this report.

Another option analyzes emissions from the base load generation separately from the additional, or peak, load generation. In this option it is assumed that biomass power would be used to displace the additional load which may have a higher emission profile.

A third option analyzes the effect that introducing biomass generation has based on its specific location. This option assumes that different locations on the power grid have different weighted averages of generation processes. Only some locations can be readily analyzed. In most areas this analysis would be excessively complex.

Heat Displacement: Heat that is produced by biomass can be used to displace other forms of heat. Areas that are "integrated" will use heating oil, natural gas or electricity for heat. Areas that are not integrated will often use heating oil and sometimes direct heating by biomass combustion. The clear trend is away from direct biomass heat as it takes greater effort, is less controllable and requires larger equipment and storage areas. Heating oil is the energy source of choice for non-integrated areas.

However the economics and CO_2 emission displacement of biomass sourced heat are substantial. The traditional approach has used the radiant heat and hot flue gases from biomass combustion to supply space heating. However biomass can be used to supply heat in a more controlled manner by an indirect approach using a liquid or steam intermediary. This indirect approach can also allow district heating systems that are cooperative with combined heat and power systems.

Industrial process heat can be supplied by biomass sources in many locations where there is a biomass source and a heat need. This is a common approach in integrated pulp and paper mills where biomass boilers supply steam for process uses. This is less common in sawmills where often biomass waste is burned for disposal while natural gas is used to heat dry kilns. Some sawmills are modifying their systems to use biomass to produce steam for dry kilns but are constrained by both capital costs and required operator qualifications. A few systems have been installed to directly use biomass generated heat for kiln heating.

Off-Grid Power and Heat: A special situation arises when power generated from biomass is used to displace "off-grid" electricity. In this situation it is usually very clear as to the source of electricity and its associated CO_2 emission. This is particularly interesting for small biomass power generating systems and especially small CHP systems because:

- Most biomass is distributed in relatively small quantities
- Only small power levels can be generated from small quantities of biomass
- Users for small power levels are often near distributed biomass sources
- Power displaced is often generated locally by diesel
- Heat displaced by CHP systems is often produced by heating oil
- Displacing diesel and heating oil creates a net reduction in CO_2 emission

There are only a few technologies that can offer this CHP opportunity but they are either expensive (small steam CHP, ORC) or new (ORC, entropic). However both the potential economic returns and the CO_2 emission profile of CHP systems are very positive.

2.4.7 Sensitivity Analysis and Extrapolation to Other Regions

There are four production steps that can be identified for greenhouse gas (GHG) emission. These steps are cultivation & harvesting, handling & transport of biomass, energy conversion and transport & distribution of the energy product. Although the general purpose of using biomass is to reduce the net GHG emission by displacing fossil fuel energy sources, each of these steps may include outside influences, use of fossil fuel in the process, that add to the GHG emission profile. Cultivation & harvesting, handling & transport and often the conversion process typically use fossil fuel. However, forest biomass is a special consideration with respect to general biomass use for several reasons.

First there is little or no cultivation work associated with forest biomass used for power production. Reforestation is almost exclusively an activity associated with forest cultivation used for high-value (non-energy) wood products. There is effectively no fertilization work associated with reforestation in North America. Furthermore, harvesting is also associated with non-energy uses of forest biomass. In essence, the availability of forest biomass for energy use begins after cultivation & harvesting.

With respect to handling & transport of forest biomass there are three basic scenarios. Waste biomass resulting from high-value wood production processes (e.g. sawmill waste) has essentially no transport associated attributable to its energy value. Only transport of this wood waste from the processing plant to a separate energy plant would add to the fossil fuel use in its conversion. The second scenario would see the handling and transport of forest biomass that currently remains at the roadside or in the forest being removed to a large central power plant. The final scenario would see the roadside forest waste being used close to its point of creation in its relatively small quantities.

The energy conversion processes of forest biomass studied in this report do not produce a net GHG emission. Each of these conversion processes has been defined and analyzed to be “self-contained” such that all of their internal energy needs are supplied by the biomass feed as part of the process. This allows all of the processes to be compared on an equal footing for both energy efficiency and GHG emission.

The transport & distribution of the energy product is also easily compared. Each conversion process has been taken to the point of electricity as the final product. This allows a direct application to the four regional electricity supply scenarios described in section 1.3 to determine the comparative GHG emission displacement.

Central Large Steam Power Plant: The quantity of forest biomass required to operate a large centralized power plant using a steam Rankine cycle is greater than the waste generation by individual high-value wood product plants with the exception of pulp mills. Therefore the forest biomass to feed such a power plant requires handling & transport from a number of such wood product plants or from the forest roadside.

A centralized plant will typically be located to minimize the transport distances of biomass fuel but also where the electricity is near a major consumer. It is assumed for this report that the average transport distance will be 160 km. (It must be noted that although this section of the report is reviewing GHG emissions, economics will be a much greater determinant for such a power plant.)

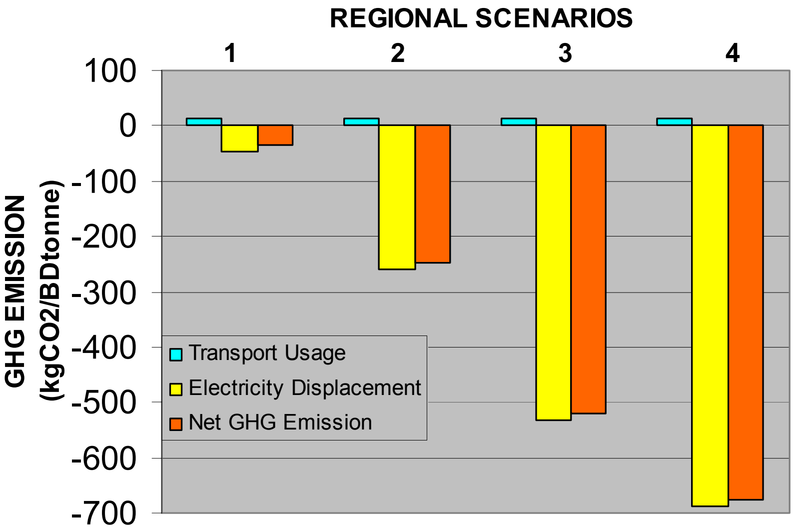


Figure 2.4.8 Large Steam Centralized Power Plant

Distributed Small Power Plant: Small distributed power generating plants are better matched for fuel availability and power consumer use. The majority of unused forest waste is distributed in quantities insufficient to support a large steam power plant. These distributed sources of biomass fuel are located in remote areas where electrical power consumption is also limited. Small distributed power generating plants can use the available biomass to produce sufficient power on a local basis.

There are several power conversion technologies available to use this approach. These have been identified above along with their efficiency of conversion. The small distributed system will sometimes be used to displace diesel generated power in locations that are not connected to the regional power grid. In these special situations the GHG emission profile will be greater than scenario 4.

All of the alternate power conversion technologies reviewed above will be compared for GHG emission as small distributed power systems. It must be noted that although this section of the report is reviewing GHG emissions, economics will be a much greater determinant for such power plants.

Figures 2.4.9a-f graphically display the net GHG emissions on the same scale for comparison. On the basis of GHG only, there is a significant benefit to be realized by using forest biomass for power generation.

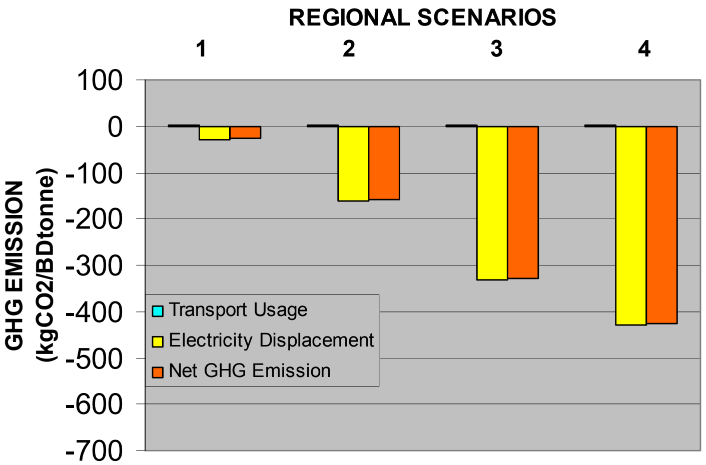


Figure 2.4.9a: Small Steam Rankine System

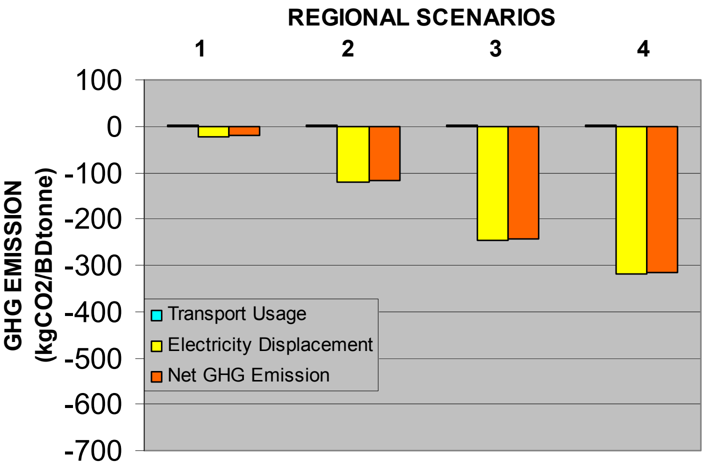


Figure 2.4.9b: Brayton Cycle System

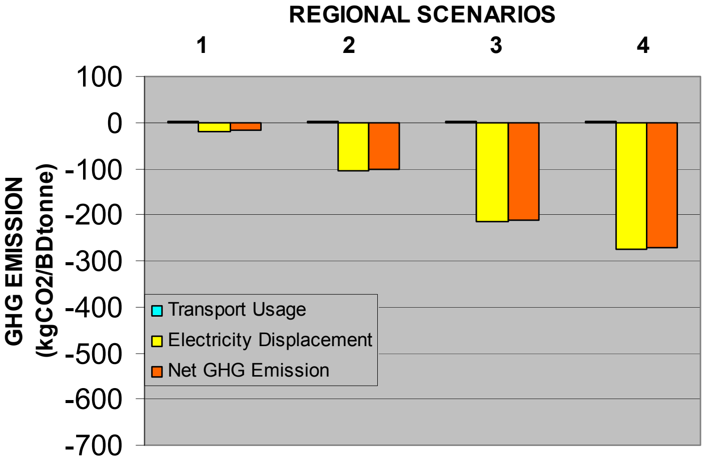


Figure 2.4.9c: Bio-oil System

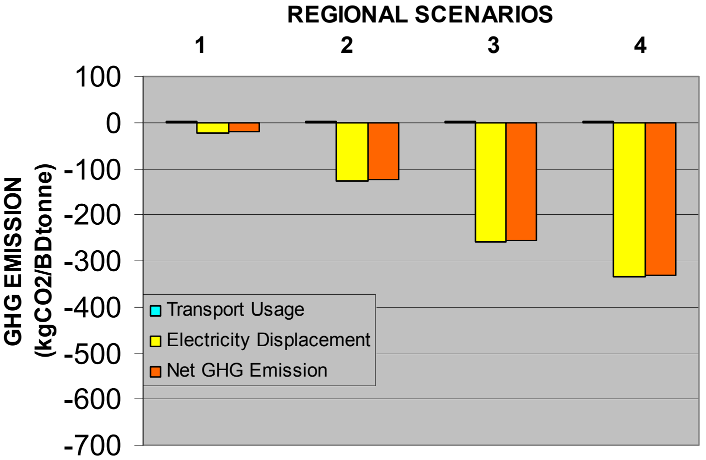


Figure 2.4.9d: Gasification System

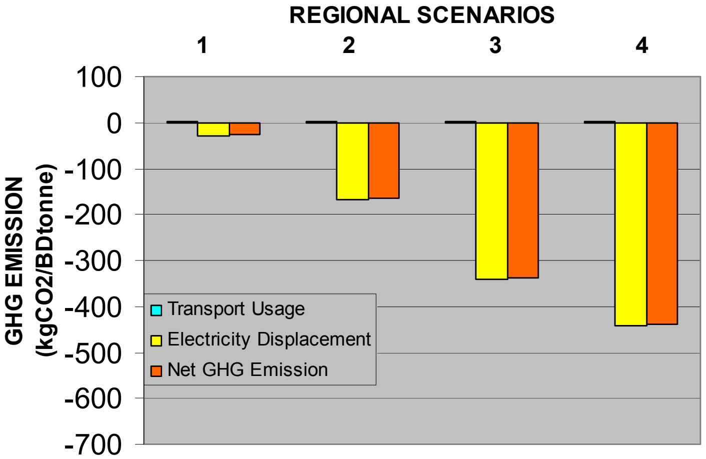


Figure 2.4.9e: Turboden Cycle System

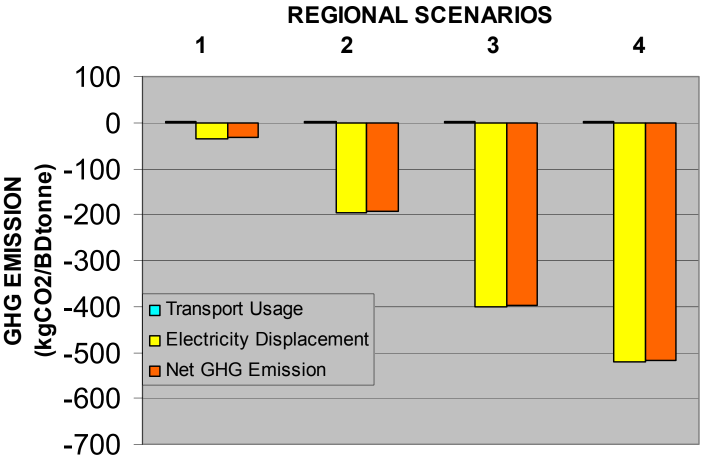


Figure 2.4.9f: Entropic Cycle System

Distributed Small CHP Plant: Combined heat and power (CHP) plants will produce both electricity and heat from the original fuel. Electricity will serve to displace grid power or special diesel generated power. The heat from a CHP system will displace heating oil or natural gas. The GHG emission of heating oil on a thermal basis is about 0.263 kg_{CO2} per $kWhr_{ht.oil}$. The GHG emission of natural gas on a thermal basis is about 0.182 kg_{CO2} per $kWhr_{nat.gas}$. Thus the CHP systems can be reviewed, as shown in figure 2.4.10 below, for their effects on GHG reduction when displacing heating oil or natural gas.

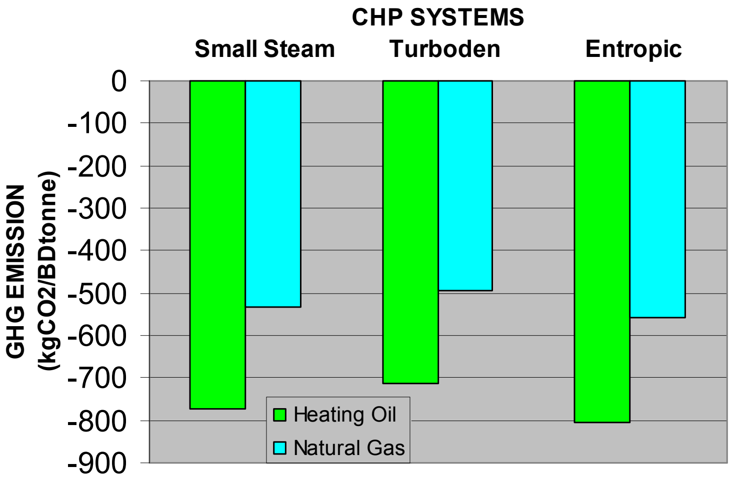


Figure 2.4.10 GHG Reduction from Heat Savings

2.4.8 Summary and Analysis

Forest biomass is a large potential source of alternate energy. There are economic and environmental aspects to its utilization for energy. This report has primarily reviewed the environmental aspects; especially with respect to GHG emissions. It has also made qualitative observations on comparative economic aspects.

There are limited opportunities to use forest biomass on a large scale as there are few situations where large quantities become collected without special transport effort. Pulp mills and a few forest business areas that host multiple companies have sufficient biomass waste to operate large scale steam power generating plants. Other forest operations are not sufficiently sized to support large scale power production. The majority of forest biomass waste does not reach any mill operation. The bulk of the forest biomass available for power generation is distributed in relatively small quantities.

A number of power conversion technologies are defined that can generate small quantities of power using the distributed forest biomass source. For power generation alone, these technologies all show lower conversion efficiency than large steam Rankine systems. However since forest biomass is a green energy source, renewable and lower cost than fossil fuels, lower efficiency is not the primary difficulty. Capital, operating and maintenance cost are much more important.

Three of the small system conversion technologies also provide thermal energy as a product output. In such cases the electricity generated can be used to displace grid power and the heat generated can be used to displace fossil fuels used for space heating. This combined heat and power (CHP) operation will show significant change in both economic and environmental effects.

When reviewed strictly for GHG emission the systems can be compared visually in Figure 2.4.11. In this view it is seen that the greatest benefit comes from small scale CHP systems, followed by the large scale steam Rankine system and finally small scale power systems.

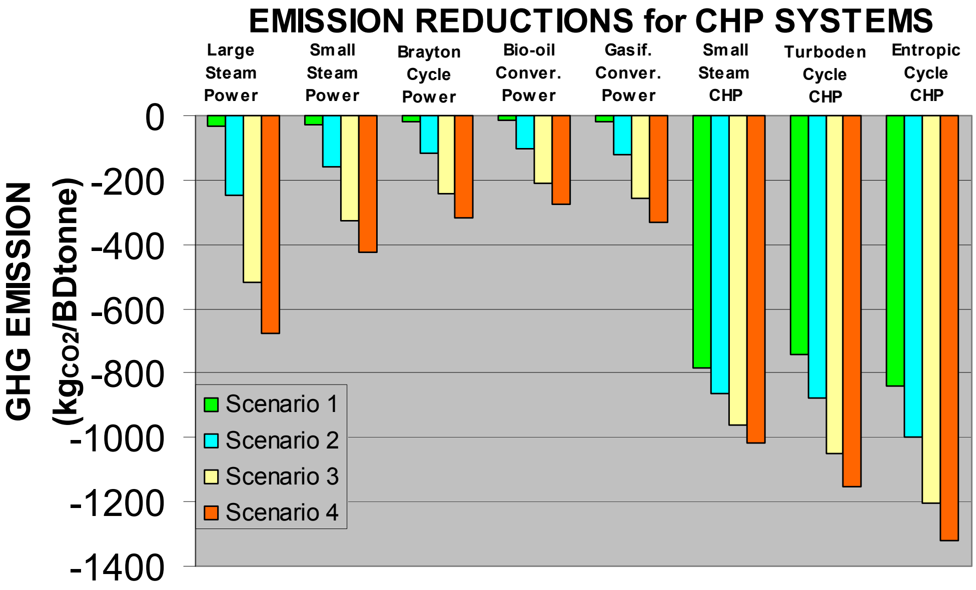


Figure 2.4.11 Comparison of Thermal Biomass Usage Options

2.5 Organic Fraction of Municipal Solid Waste

2.5.1 Underlying Studies and Assumptions

A study carried out for the U.S. Environmental Protection Agency [EPA 1998(1)] examined GHG emissions from several waste management options, including several landfilling options. The following options were adapted for this report:

1. Landfilling without landfill gas capture
2. Landfilling with landfill gas capture and flaring
3. Landfilling with landfill gas capture and electricity generation

The original study examined the GHG effects of several waste fractions. The organic fraction included several kinds of paper, as well as food scraps, leaves, branches, yard trimmings and grass. The paper fraction was left out for one scenario to better adapt the results to those obtained for separately collected biowaste, as such collections will result in a very low paper content.

A Swiss study [ARBI 2001] examined the effects of composting the separately collected organic fraction of municipal solid waste (MSW). The systems selected for this study are

1. Enclosed, automated composting
2. Thermophilic digestion with enclosed composting
3. Incineration

CO_2 emissions from the process were determined through on-site measurements for the composting and digestion systems, and were modelled for the incinerator. All systems are indoors systems, i.e. each treatment step is carried out inside a building. No open composting systems were included as such systems may be unsuitable for many Canadian regions with harsh winter conditions. The biomass feedstocks represent the organic fraction of MSW and other commercial waste, such as waste from restaurants, bakeries or yard trimmings usually delivered to incineration plants. For the composting and digestion plants, biowaste is collected separately from other municipal waste. For the incineration system, data represent the emissions attributable to the organic fraction in MSW only.

Option 1 – Composting only: delivery of biowaste, chipping/grinding, mixing and composting are carried out inside a fully enclosed hall. Most process steps inside the composting compartment are automated in order to reduce the need for personnel to work under the hot and humid conditions caused by the composting process. The biomass is stacked in “channels”, to a height of 2-3m. Walls separate the channels, and automated systems turn the material in order to optimise biological activity. All inside air is evacuated through biofilters. The finished compost is stored inside an open hall before being sold off to customers, and the emissions displaced from the manufacture of fertilizer are subtracted from process emissions. The process is based on the KEWU facility near Bern, Switzerland, which has an annual capacity of 12,000 wet tonnes.

Option 2 – Thermophilic digestion & composting: Biomass is passed through a thermophilic digester, at a temperature of between 55 and 59°C. The digested material is then dewatered, and the water is used to moisturize the incoming fresh biowaste. All air is evacuated through biofilters. Generated biogas is transformed into electricity and heat in a CHP plant. While some heat is required for the process, no external heat user was assumed. The digested material is composted inside an enclosed hall for a few more weeks before being used mainly in agriculture as compost, displacing emissions from artificial fertilizer. This process is based on the KOMPOGAS plant in Otelfingen, Switzerland, with an annual capacity of 10,000 wet tonnes. It generates 124 kWh of surplus electricity per dry tonne of biomass.

Option 3 – Incineration: Incineration is modelled as being carried out in a state-of-the-art incineration plant with selective catalytic reduction to minimize NOx emissions. Greenhouse gas emissions were calculated assuming a 100% burnout for organic carbon from biowaste[6]. Plant data were based on a 100,000 t concept of Swiss company TBF AG (Zürich). The plant produces both electricity and heat for district heating, although the heat is not used to a high degree during the summer months. Note also that the contribution of biomass to electricity and heat generation from an incinerator comes from plastics and paper to a large degree, and the contribution of (wet) biomass is limited due to its high moisture content (60%). 78 kWh of electricity and 232 kWh of heat are produced per dry tonne of biowaste.

Carbon in biomass: The original study counts all carbon contained in biomass as an emission. Due to the methodology described in Chapter 1, CO_2 emissions were taken out of the life-cycle data as biomass is assumed to be closed-loop, with plants sequestering CO_2 out of the air. As no split of GHG emissions was provided in the original study, the share of CO_2 emissions was determined based on the assumptions of how much carbon in biomass would be transformed in the process (100% for incineration; 50% for composing/digestion), and the data given in the report for the split of carbon dioxide and methane emissions from the process. Table 2.5.1 identifies the corrections made to the original data in the Swiss report. The biomass input was given as having a 60% water content; 66% of dry matter is organic (264 t/t of wet biomass feedstock), and 53% of the organic matter is carbon. Based on the molecular weight of CO_2 (44) and a weight-based carbon content of 53% of dry organic matter in biowaste, emissions of 1,283 kg of CO_2 per dry tonne of biomass were assumed in case of complete oxidation.

Table 2.5.1 Corrections to Original Report Data to Eliminate CO_2 Emissions from Biomass Treatment, per Tonne of Biomass Feedstock (assumed carbon content of biomass feedstock: 53%)

Treatment Type	% Carbon Transformed	% CO2	% CH4	Correction
Composting	50	89.7	10.3	-575 kg
Digestion/composting	50	89.7	10.3	-575 kg
Incineration	100	100.0	0.0	-1,283 kg

Methane emissions: The Swiss study modelled the GHG impact of methane emissions for three timelines, instead of using the recommended IPCCC factor of 21 times the GHG potential of CO_2. The 100-year GHG potential of methane was based on a factor of 24.5 over CO_2, and was corrected to a factor of 21, using data in Table 5 of the original report.

Electricity background mix: The Swiss study used the average European power mix of the "Union for the Co-ordination of Transmission of Electricity". This mix is based on 50% thermal, and 50% on low-emission nuclear and renewable power sources, and would lie slightly above Scenario 2 emissions as defined in Table 1.1. These emissions per kWh of electricity generation were counted for both electricity consumption and displacements of emissions from surplus generation. The displaced emissions from the grid were determined based on the surplus

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[6] The real burnout my be less than 100%, but GHG emissions from residual organics were estimated to be less than 0.01 t/t of waste [EPA 1998(1), p.80], which would not affect results in the context of this study.

electricity generation of the plant (210 kWh per dry tonne of biowaste), multiplied by the Scenario 2 emission factor (288 g/kWh). The same percentage increase was applied to both power generation from landfill gas and from the incinerator in order to estimate the displaced emissions for mixed biomass, including paper, instead of separately collected biowaste.

The EPA study assumed that electricity produced by waste incineration would displace an energy mix of 84% coal, 13% natural gas and 3% oil on the margin, and the GHG emission intensity per MWh computes to about 1 tonne of CO_2. These values were also corrected to reflect Scenario 2 emissions.

Transport distances: Separate collection of biomass waste was assumed for the composting and digestion options, requiring two collection trips to collect MSW (one for biowaste and one for remaining waste); no separation of waste fractions was assumed for incineration. However, the higher capacity of the incinerator (100,000 t/yr) requires larger agglomerations, i.e. a population of 250,000, at an average distance of 9 km to the plant. For composting and digestion, the mean transport distance was set to 5.6 km. A population density of 500 inhabitants per km² was assumed, which represents the major urban centres in Canada (Vancouver, Calgary, South Ontario, Ottawa, Montréal).

Emissions due to construction and dismantling: GHG emissions due to both the construction of the plants and their dismantling (including landfilling or incineration of plant components) were included in the emission balance. These could not be subtracted from the data in accordance with the methodology used throughout this study, but were described as insignificant in the Swiss study. They should therefore not impact the results to a large degree.

Carbon sequestration in soils: It could be that some carbon remains sequestered for long periods of time when compost is mixed into the soil. The extent of this effect has been estimated in a study carried out for the U.S. Environmental Protection Agency [EPA 1998(1), p.76], and was quantified as between 0.0001 and 0.05 t/t of raw material, over a 100-year period. As the long-term tendency is for this sequestered carbon to be oxidized to CO_2, a small or no impact on the life-cycle GHG balance is to be expected from carbon sequestration in soil. 10% of the maximum amount was arbitrarily chosen to account for this type of sequestration (12,500 grams per dry tonne of biomass).

Carbon sequestration in landfills: Contrary to soils, carbon sequestration due to incomplete biodegradation of biomass in landfills is significant. It was assessed to be 0.81 tonnes of CO_2 per dry tonne of the organic fraction of MSW (paper, food scraps and yard waste), or an average of 1.22 tonnes for the organic fraction without paper – mainly due to the fact that lignin cannot be decomposed in an anaerobic environment (paper is far more biodegradable and increases the amount of methane generated from biomass). Both values were used to allow for a better comparison between separately collected biowaste, which will not contain a large paper fraction, and landfilling or incineration. Carbon sequestration in landfills also means that only a portion of the carbon is transformed to methane and CO_2. Sequestration rates are based on laboratory data, and should ultimately be confirmed to validate their in situ effects. Note also that "mining" of landfills in the future (e.g., to combust the waste) would eliminate such sequestration benefits.

Methane emissions from landfills: It is assumed that only 90% of the methane generated from biomass in landfills is emitted, whereas 10% are oxidised to CO_2 by bacteria before they reach the surface of the landfill (expert estimates vary between 5% and 40%). For landfill gas capture systems, an efficiency of 75% was assumed (expert estimates vary between 60% and

95%), i.e. 25% of methane is still emitted even when a gas collection system is installed. GHG emissions from the entire organic fraction (including paper) are given as 0.93 tonnes of CO_2e per wet ton. Without the paper fraction, various organic waste fractions create between 0.56 (leaves) and 1.11 tonnes of CO_2e (as methane) per wet tonne. An average of 0.83 tonnes per wet tonne (2.1 tonnes per dry tonne, at 60% moisture) was used for Table 2.5.2. Deviating from the original EPA study, the corresponding CO_2 emissions that would have come from oxidizing the same amount of carbon transformed into methane, are subtracted from the result. The reason is that these emissions would have been transformed into CO_2 if another treatment system had been used, such as an incinerator, and this amount of CO_2 is therefore “avoided” by turning the carbon into methane (calculated based on carbon contained in 1/21 the amount of methane emitted; this reduces the result by about 10%). The respective amount for carbon “lost” to CO_2 was also deducted for the composting and digestion options, i.e. is treated as if it was “sequestered” as methane.

2.5.2 GHG Emissions

Table 2.5.2 shows the greenhouse gas emissions for the three different biowaste treatment options, both for separately collected biowaste (no paper) and for mixed biowaste (with paper, i.e. the organic fraction of MSW – shown in brackets).

Table 2.5.2 GHG Emissions for Biowaste Treatment Options, in g/t of Dry Feedstock (based on Figure 45 in ARBI 2001, corrected for CO_2 emissions as shown in Table 2.5.1, and on Exhibit 7-4 in EPA 1998(1), corrected as described in the text)

Treatment Type	Landfilling/ no gas collection	Landfilling/ Gas Flaring	Landfilling/ Power Generation	Com-posting	Digestion & Com-posting	Incinera-tion
Life-cycle CO_2 emissions in g/t of biomass	1,622,946 (1,818,482)	405,737 (454,621)	405,737 (454,621)	708,750	433,313	187,480
Seques-tered	-1,222,222 (-814,815)	-1,222,222 (-814,815)	-1,222,222 (-814,815)	-12,500	-12,500	0
Electricity generation credit	0	0	-81,648 (-91,485)	0	-89,712	-60,480 (-67,767)
Total	**400,724 (1,003,667)**	**-816.485 (-360,194)**	**-898,133 (-451,679)**	**696,250**	**331,101**	**127,000 (119,713)**
Emission reduction over landfilling without gas collection	0	-1,217,209 (-1,363,861)	-1,298,857 (-1,455,346)	+295,526	-69,623	-273,724 (-883,954)

Note: numbers in brackets represent all organic waste, including paper; numbers without brackets refer to biowaste without paper

The results are surprising, as the landfill gas options with gas collection systems outperform all other options. Incineration causes GHG emissions as a stand-alone process, but also results in an overall emission reduction as compared to open landfilling. The main factor giving landfilling an advantage over other waste treatment options is the high degree of biomass that remains inaccessible to biological activity, and is therefore permanently sequestered inside the landfill. This share varies by material, but laboratory tests showed decomposition rates from 28% for leaves to 84% for food [EPA 1997], which means that in some cases more than half the biomass may remain unaltered inside the landfill. An average of 50% decomposition is confirmed in the literature [UBA 2004].

Composting and digestion, while converting a maximum of biomass into CO_2, consume considerable amounts of energy for waste treatment (shredding), handling, compost aeration and venting of the treatment facilities: the example of the enclosed composting facility requires 250 kWh of electricity per dry tonne of biowaste. This high electricity demand is about neutralised through a 225 kWh energy credit due to the displacement of artificial fertilizer. However, methane emissions from the composting step are the most crucial factor: 27.5 kg of methane is emitted per tonne of dry biomass, which corresponds to 577,500 grams of CO_2 per tonne. These emissions are caused by pockets of anaerobic activity in the compost, leading to the highest overall process emissions for these treatment options. Roughly three times this amount is emitted by open landfills (89.3 kg).

The electricity generation credit should be expected to be higher for the digestion process than for landfill gas, due to the substantial amount of biomass that remains inaccessible to biological activity in the landfill. However, 11% of the energy produced is consumed in the digestion and composting process, and the digestion is not necessarily completed once the biomass leaves the digester. For incineration, internal plant electricity demand is even higher (30%), which leads to a somewhat smaller credit. For landfilling, the extra emission reduction from displacing electricity on the grid if landfill gas is used in an engine to generate electricity does not significantly increase overall emission reductions, showing that oxidizing the methane is the main concern if GHG emissions are to be reduced.

Figure 2.5.1 shows the results graphically, adding the influence of the electricity background mix. Displacing a mix high in coal makes the examined digestion/composting process an option that reduces a modest amount of emissions compared to open landfilling, but in general the impact of the electricity background mix is limited. Incineration has small benefits with respect to non-paper biowaste, but is almost equal to landfilling with gas collection if mixed organic waste (including paper) is the basis of the comparison.

Some aspects have not been included in the above analysis. One is the loss of fertilizer through microbial activity, which increases emissions from both artificial fertilizer and compost. However, this is not expected to significantly alter the results. A more important aspect would be to assess the efficiency of separate biowaste collection: it is unlikely that all biomass in waste can be separately collected from homes, and some biomass will remain in the residual mixed waste, and will either be treated in an incinerator or landfilled, generating additional emissions. Likewise, the separate collection of paper will not capture 100% of paper found in mixed household waste. To completely compare the performance of each treatment option, residues of organic waste remaining in MSW after separate collection would have to be quantified, and a mix of options would then have to be examined, in conjunction with separate biowaste collection and composting or anaerobic treatment. Such an analysis would, however, exceed the scope of this study.

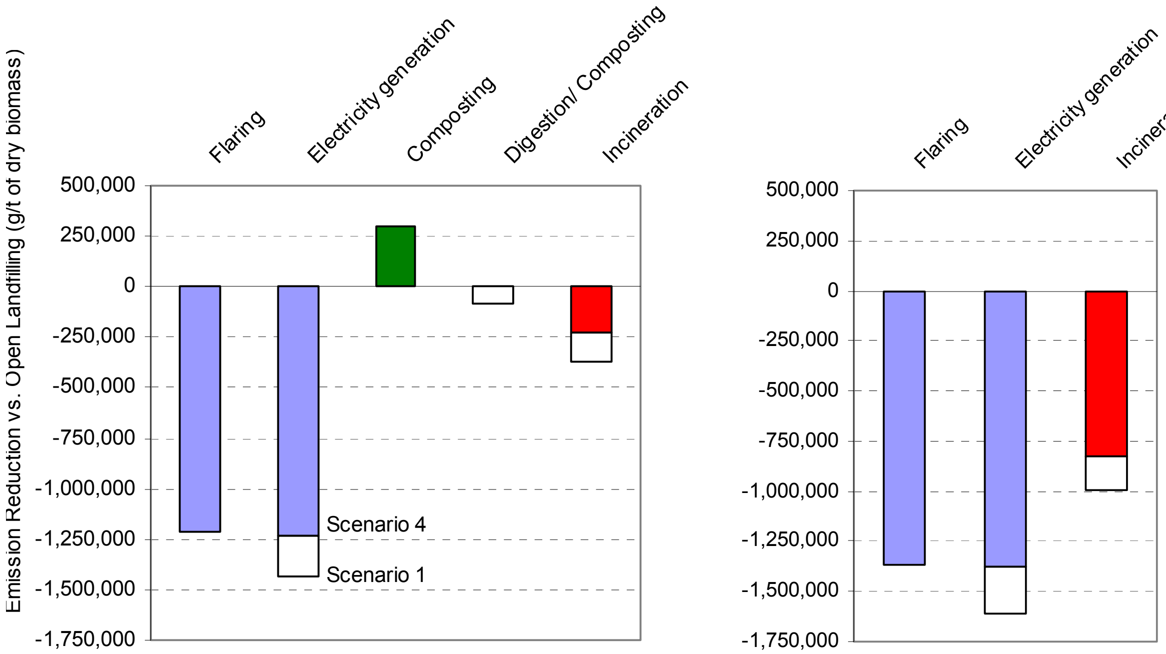


Figure 2.5.1 Comparison of GHG Emission Reductions for Several Biowaste Treatment Options vs. Open Landfilling (left: biowaste without paper, as obtained with separate collections; right: biowaste including paper, as found in MSW)

ICF Consulting completed a study comparing GHG emissions from waste management options for Canada in 2001 [ICF 2001]. This study largely builds upon the findings of the 1998 study ICF completed for the US-EPA [EPA 1998(1)], but modifies the data somewhat to reflect the Canadian electricity background mix and energy intensities for various processes analysed. It is difficult to compare the results of that study to the ones used here, as the methodology was somewhat different:

- transport emissions were excluded;
- for landfills, the Canadian average was used, which is a mix of landfills with and without gas collection systems;
- the study also does not identify leaves, branches and grass as separate biowaste fractions.
- for digestion, treatment of the mixed waste was assumed, instead of separately collected biowaste without paper.

Only a qualitative comparison between the results obtained is therefore possible. Table 2.5.3 provides a simplified comparison of the ICF 2001 study and this study. The ICF 2001 study also includes carbon sequestration inside the landfill. Data for the paper and other organics (food scraps and yard trimmings) fractions have been averaged.

Most of the smaller differences, such as for incineration, could be explained by the fact that transport emissions have been omitted from the ICF 2001 analysis. The large difference for composting is due to the underestimation of methane emissions from composting, which was measured in the Swiss study used for this present analysis. For composting and digestion, another factor is that carbon sequestration effects were estimated higher in ICF 2001 than for this present study. We assumed that virtually all carbon will eventually be turned into CO_2. This means the ICF results would present a short to mid-term scenario with more carbon still present in the soil, whereas our results reflect ultimate reductions after all biomass has been oxidised, if it is used for soil improvement. For landfills, the ICF results are, as expected, in-between our results for landfills with and without gas capturing systems, as they reflect a mix of both.

Table 2.5.3 Comparison of ICF Data from 1998 (USA) and 2001 (Canada), in Tonnes of CO2 per Dry Tonne of Waste

		Incineration	Landfill	Composting	Digestion
Biomass fraction without paper	This study	0.1	0.4 to -0.8	0.7	0.3
	ICF 2001	-0.06	0.1	0.03	-0.24
All biomass	This study	0.1	1.0 to -0.4	-	-
	ICF 2001	-0.2	0.2	-	-0.24

2.5.3 Energy Balance

It was not possible to establish energy balances for each treatment option, as the data in the original reports used were incomplete on this issue. Some general observations can, however, be made:

1. The energy balance of landfilling with gas collection and electricity generation may be slightly positive, as waste transport and handling in the landfill will be counterbalanced by electricity production.
2. The other two landfilling options will have a negative energy balance, as no energy is produced, but energy is required to transport the waste, handle it, and also for the construction and possibly the operation of the gas collection system, if gas pumps are used to evacuate the gas from the landfill body.
3. For composting, it will be negative as the energy displaced from fertilizer production is a bit less than what is needed to handle the compost inside the facility, and transportation costs will further increase overall energy requirements.
4. For digestion with electricity generation and incineration will be positive, as the on-site electricity needs are covered by energy from the digestion process, and surplus electricity is exported to the grid. Here also, compost displaces artificial fertilizer, with associated energy displacements.
5. Incineration is a net exporter of energy and heat and can be expected to have an overall positive energy balance.

On the whole, the processes discussed do not consume as much energy as some of the other biomass treatment options discussed in previous chapters. It can be expected that in comparison, energy requirements will be a fairly small percentage of the energy contained in the waste. The electricity produced is far less than for many other types of biomass, due to the smaller energy content in (non-paper) waste biomass (this was given as 10 GJ per dry tonne of biomass [ARBI 2001, p.69], compared to about 19 GJ for wood).

2.5.4 Discussion of Input Values Used in the Underlying Study

EPA 1998(1) suggests close to zero GHG emissions for composting, but assumes zero methane emissions, which has been shown to be incorrect through the Swiss measurements. However, the energy demand for open composting is also very low in the Swiss study, confirming this aspect. The values for GHG emissions from MSW incineration of biowaste in the Swiss and the EPA studies (for yard trimmings fraction) correspond fairly well. Marginal differences may be caused by the methodology, as the Swiss study included the emissions related to the construction of the plant, and by the high-coal U.S. power generation mix used for the EPA study.

A German worksheet used for emissions estimates from landfills within the European Emissions Registry initiative details methane emissions from landfills with and without gas collection [UBA 2003]. Slightly different assumptions for the different parameters were made, and a comparison is presented in Table 2.5.4. EPA 1998(1) was the source of landfill data used for this study. The data used in the table represent mixed biowaste in order to allow a comparison with the German data. For this study, slightly different data were used in order to allow for a comparison with separately collected biowaste. The data in Table 2.5.4 therefore only correspond to the data given in brackets within Table 2.5.2 above. The key parameters used in the Canadian Greenhouse Gas Inventory were also included, showing they are very similar to those used here.

Table 2.5.4 Comparison of Data Used to Estimate Methane Emissions from Landfills

	UBA 2003	EPA 1998(1)	CGHGI 2002
Biodegradable carbon content in MSW (wet)	18%	14%	
Percentage of carbon biologically converted in landfill	50%	78%	
Percentage of landfill gas not captured by collection system	40%	25%	
Methane content in landfill gas	55%	Lab data for CH4 emissions from several types of biomass	50%
Amount of methane oxidized to CO_2 inside the landfill before it is emitted	10%	10%	
Methane emissions from open landfills	59 kg/t(wet)	44 kg/t(wet) 111 kg(dry)	117 kg/t(dry)
Methane emissions from landfills with capturing system	26 kg/t(wet)	11 kg/t(wet)	

The results for both estimates are within the same range. The estimate for this study is somewhat lower than that of the German study. This difference is even more enhanced for the landfill with capturing system, as the collection efficiency is estimated to be 60% in the German source, compared to 75% used in this study. The 10% methane oxidation was also not applied to the 40% of methane escaping the capturing system in the German source, further enhancing the difference. The German Environmental Protection Agency (Umweltbundesamt) Internet database PROBAS assumes a gas capturing rate of only 37.5% [UBA 2004]. This number is based on the premise that only 30% of gas is captured during the first ten years of operation, as the landfill is uncapped. 50% of methane is assumed to be formed during this phase. Once the landfill is filled (after ten years), a gas collection efficiency of 70% is assumed. The University of Florida works with estimates of 25% (minimum), 50% (average) and 75% (maximum) methane capture for uncapped landfills with gas collection, and 80-90% for landfills with a cap [UCF 2001]. The U.S. Environmental Protection Agency recommends using 75% as the average methane collection efficiency [EPA 1998(2)].

According to a Canadian landfill expert, landfill gas capture efficiencies of 85% can be achieved if, from the very start of operations, the capturing system is designed and maintained as an integral and key part of the landfill operation [CRA 2004]. The 30% assumption made above by the German source therefore seems to represent a worst case scenario. According to the Canadian expert, about 80-90% of methane generated over the entire life of a landfill can be captured and flared or used for electricity generation before this becomes uneconomical in the later phase of the gas generation lifespan of the site. Some methane will escape at the beginning of the life cycle while fresh waste is added, but full methane generation only starts about 1.5 years after the waste has been deposited in the landfill. Assuming that 20% of methane escapes after gas collection is no longer deemed necessary and that 85% of the remaining 80% generated during the active collection phase are captured, this would result in an overall gas collection efficiency of 80 x 0.85 = 68% - slightly lower than the 75% assumed here. However, the 85% efficiency during the active collection phase is close to the practical maximum, unless synthetic cover systems are used to cap the landfill [CRA 2004], and lower efficiencies will be reached if the capturing system is not run and extended to maximise gas recovery.

Table 2.5.5 Comparison of Results for Mixed Waste, Based on Different Estimated Methane Emissions from Landfills

	Open Landfilling	Landfill Gas Capture
This study	1,162,268	-275,462
UBA 2003	1,877,060	371,435

Table 2.5.5 shows that the different assumptions, while leaving overall results in the same order of magnitude, can turn a net emission reduction into a positive GHG emission. The same amount of sequestration (see Table 2.5.2) was assumed in each case, but different methane emissions from waste were used as model inputs. While the UBA 2003 data shows a landfill with gas collection may not be an overall emissions sink, it also attributes much higher emissions to open landfills. This would result in even higher emission reductions from all other biowaste treatment options if compared to an open landfill. It would also make waste incineration the preferred option to minimize emissions as compared to open landfills. In the end, the degree to which methane can be captured from a landfill will be the main factor determining whether landfilling or incineration is the better waste treatment option. Based on the parameters used ion this study, the break-even point of a landfill emitting methane versus the complete oxidisation of biomass in an incinerator (all biomass, including paper) would be a 45% (Scenario 4) to 54% (Scenario 1) efficient gas capturing system.

2.5.5 Other Environmental Considerations

The following aspects should also be considered when deciding which waste management option to choose:

1. Landfills create leachate, which can contaminate groundwater, and also toxic air emissions that can cause health problems in nearby communities;
2. Landfills, as well as composting facilities, can cause odour problems. These can be addressed through the use of biofilters if enclosed facilities are used (closed halls for composting and digestion, or gas collection systems in landfills);
3. In terms of NOx emissions, the digestion process fairs best, whereas enclosed composting has the highest emissions (no data were given for landfills in the studies used);
4. Heavy metal emissions were examined in the Swiss study, and again the digestion process had the lowest emissions, ahead of composting and incineration. Digestion

also trumped other treatment options for "photosmog", carcinogens, eutrophication, ozone depletion and SOx emissions.

5. No data for landfills were found on the above issues, but in general it can be assumed that heavy metal emissions can be avoided as long as there is no leakage, and air emissions can be reduced if gas collection systems are installed.

Considering the qualitative information given above, composting seems to have a lot of negative implications, and if selective collection of biowaste is implemented, the digestion option should be preferred as it has far lower environmental implications. Incineration still is the only option to render waste inert in the long term, whereas landfilling may lead to environmental problems if the integrity of a landfill cannot be guaranteed in the distant future. Separating biowaste from mixed MSW, and converting it to compost, does not displace enough emissions from fertilizer production to eliminate all the environmental life-cycle impacts linked to the production of compost.

2.5.6 Economic Aspects

The waste management costs for each treatment option are given in Table 2.5.6. The Swiss study used a price of C$0.085 for electricity sold to the grid. This was corrected to C$0.055 (current price offered to independent power producers by BC Hydro), to better reflect the lower energy price in Canada. 90% of 48 kg of methane per wet tonne were used to determine electricity generation from landfill gas, resulting in 167 kWh produced. The cost of landfilling is assumed to be $70, including transportation. The actual cost is "hidden", as this gate price is charged to individuals bringing their own waste. However, waste collection is often organised and paid for by municipalities, who in turn charge waste collection fees to residents and businesses. It is assumed here that garbage trucks are charged less than $70 per tonne of waste, and that the municipal collection and disposal costs do not exceed this price. It is also assumed that gas capture will not necessarily increase disposal prices, being mandated by municipal governments and paid for through tipping fees in the long run. Extra costs for generating electricity can often be recovered through the sale of CO_2 offsets (a price of about C$4 per tonne of CO_2 is deemed sufficient).^

Table 2.5.6 Cost of Waste Management Options per Wet Tonne of Biowaste, in C$ (1 Swiss Frank = C$1.09)

Treatment Type	Landfilling/ no gas collection	Landfilling/ Gas Flaring	Landfilling/ Power Generation	Com-posting	Digestion & Com-posting	Incinera-tion
Costs per wet tonne of biomass	70	70	70	252	183	334
Revenues from sale of energy	0	0	-9.2	0	-7.5	-20.5
Total	70	70	60.8	252	175.5	313.5

Clearly, landfilling is the cheapest and also the most common option used in Canada. Incineration and composting are a lot more costly, with digestion somewhere between these extremes. The composting facility has higher capital costs due to the machinery required for handling the biowaste, coming close to the investment cost for an incinerator, on a per-tonne basis. The digestion process requires only about 2/3 of this investment. Incineration is the most expensive option, mainly due to the disposal cost for ash and flue gas cleaning residues, as well as high capital costs.

2.5.7 Sensitivity Analysis

For the composting options, the possibility of reducing methane emissions to 3% of overall carbon emissions from the process is suggested in the Swiss study. This can be achieved through a combination of process optimization, i.e. better aeration and the minimization of anaerobic “pockets” in the material to be composted, and biofilters that oxidize some of the remaining methane emissions to CO_2. The results of such improvements are shown in Figure 2.5.2 for composting and digestion with composting, based on a Scenario 2 electricity mix. These results only apply to separately collected biowaste without paper. Default emissions are 10.3% of total carbon emissions for both treatment options.

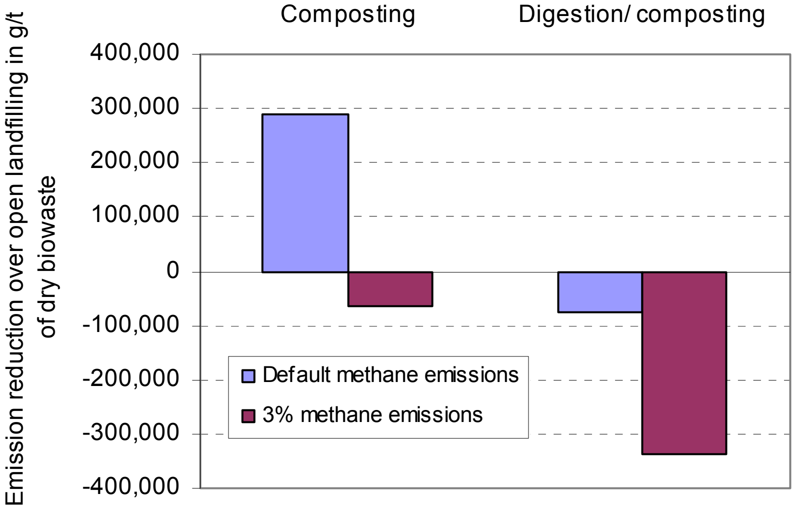


Figure 2.5.2 Effect of Limiting Methane Emissions to 3% of Overall Process Carbon Emissions through Optimization and Biofilters

As methane emissions are the main factor determining GHG impacts of waste treatment options, a reduction of methane emissions from the plant to about 30% of methane emissions measured on-site would make composting a better option than open landfilling, and would make digestion the option preferable over incineration, though not over landfilling with gas collection. The combined digestion/composting process would become overall carbon neutral, or even a small sink for GHG emissions.

2.5.8 Summary and Analysis

Landfilling of biowaste with gas collection and flaring or electricity generation may create the highest emission reduction benefits compared to open landfilling, and could even be an overall carbon sink as some of the biowaste is not accessible to microbial activity inside the landfill. However, this requires a well built gas collection system with an overall collection efficiency of over 50%, over the entire lifecycle of a landfill. Results are different for biowaste without paper on the one hand, and the organic fraction of MSW including paper on the other, as the paper fraction is easily biodegradable and will lead to increased methane emissions from landfills. The extent to which carbon is sequestered inside a landfill can be influenced by landfill management: companies such as Québec's Intersan Inc. manage the moisture content of a landfill in order to achieve maximum methane generation from MSW, which can be expected to reduce the bioaccessible carbon content sequestered in landfills.

Incineration is the next best option, and even wins out over landfilling if the gas collection system is not able to capture most of the methane emissions. The composting and digestion options lead to little or no improvements over open landfilling, in terms of GHG emissions. These emissions could be reduced if the biowaste processing is optimised and methane emissions are reduced through biofilters. The benefits of compost displacing artificial fertilizer do not outweigh the process emissions from producing the compost.

From a cost point of view, landfilling is the cheapest option, followed by combined digestion and composting of biowaste. Incineration is the most expensive option, and requires large annual throughputs.

Reducing the organic content in MSW may be an attractive option in order to reduce methane emissions from landfills. If this option is chosen over incineration, a digestion process should be selected to treat the biowaste. It is also crucial to effectively separate paper waste from the MSW as most methane emissions are created by this easily biodegradable fraction. Reducing methane emissions from the digestion/composting plant will further enhance emission reduction benefits.

In an overall assessment of GHG emissions from waste treatment options, non-organic biomass needs to be included as well. Considering the plastics fraction of MSW would change the results of this analysis, i.e. waste incineration would fare worse in comparison to landfilling, as all non-organic carbon would be turned into CO_2, instead of being stored long-term inside the landfill body.

2.6 Afforestation in Prairie Provinces

2.6.1 Underlying Studies and Assumptions

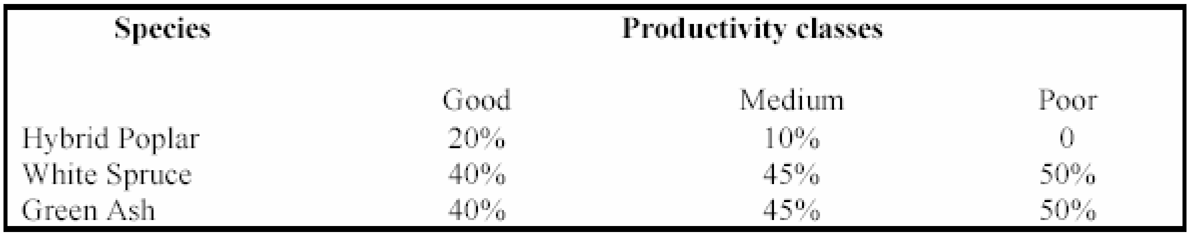
This chapter is based on Nawitka 1999a, a study that examined the potential of afforestation in the context of the Kyoto Protocol for the Sinks Table as part of the National Climate Change Process.

Base case: To assess the carbon storage potential of planted trees in relation to grassland or cropland, the crucial point of comparison is the amount of carbon that would be stored annually as soil organic carbon under grassland and cropland ecosystems in the absence of afforestation. Best management practices and conservation tillage innovations are expected to lead to a 0.73 t CO2/ha/yr of soil organic carbon gain on crop land and improved pasture, which was chosen as the base case to be compared to afforestation projects. However, on cultivated lands that are not under best management practices or on unimproved pasture, soil organic carbon gains were assumed to be 0.0 t C/ha/yr.

Land area: A technical potential of 5,677,000 ha (10% of current agricultural land surface) was identified as suitable for afforestation in the three Prairie Provinces Manitoba, Saskatchewan and Alberta, based on an estimate of how much land may be available from crop land, summer fallow, tame pasture, natural pasture, and "other" agricultural lands, as defined by Statistics Canada. Much of this land is in private hands, and based on the assumption that only 25% of land owners will engage on a large-scale afforestation program, and taking account of other limitations, 258,000 ha of land are deemed available for afforestation.

Tree species: Based on current practice, it was assumed that the species most likely to be planted in Prairie Provinces would be green ash (55% of planting stock in 1991), as well as hybrid poplars, and any of Colorado blue spruce, Scots pine, or white spruce. In the driest zones of south western Saskatchewan and south eastern Alberta, Colorado blue spruce will be more successful than white spruce. The sequestration of carbon dioxide due to tree growth was estimated over 50 years, based on a mix of three tree species, distributed over the available land area as detailed in Table 2.6.1. The growth curves for each species were averaged over 50 years, based on data provided in Table 1 of Appendix 1 of the underlying study.

Table 2.6.1 Distribution of Tree Species to be Planted on Land Areas Part of a Potential Afforestation Program in the Prairie Provinces [Nawitka 1999a, p. 25]



Species	Productivity classes		
	Good	Medium	Poor
Hybrid Poplar	20%	10%	0
White Spruce	40%	45%	50%
Green Ash	40%	45%	50%

Fuel input: Fuel inputs for nursery production of seedlings and cuttings, and fuel required to transport planting stock to afforestation sites were not included in this analysis. Fuel consumption for planting and maintenance of plantings was estimated to be 3.6 litres/ha. The CO$_2$ emissions associated with ultra-low sulphur diesel fuel are 3.05 kg of CO$_2$ per litre [DEFRA 2003, p.37].

Regional variability: For Eastern Canada, figures for “merchantable annual increment”, i.e. for the part of the tree that has commercial value, over 30 years, have a range of between 1.9 and 6.0 m³/ha for tree plantations [AES 1999, Table 8]. Table 2.6.1 details some of these data, which are used in Table 2.6.2 to compare the influence of different annual yields on carbon sequestration after 50 years, assuming that the average yields obtained for the 30-year period will be maintained for another 20 years.

Table 2.6.2 Canadian Data on Average Annual Wood Yields per Hectare and Carbon Sequestered in the Whole Tree [Nawitka 1999b, AES 1999, Table 8]

Plantation	Average annual yield, Bolewood or MAI_{30}	CO_2 sequestered per year, whole tree & root system
Black Spruce & Fir, NB	4.0 m³/yr	6.40 t/yr
Jack Pine, NB	6.0 m³/yr	9.60 t/yr
Black Spruce, NF	1.9 m³/yr	3.04 t/yr
Jack Pine, ON	3.8 m³/yr	6.08 t/yr
Black Spruce, QC	2.2 m³/yr	3.52 t/yr
Prairies (Nawitka 1999a)	2.8 m³/yr	4.52 t/yr
Douglas Fir, BC Coast Area	6.1 m³/yr	9.76 t/yr
Douglas Fir, BC Interior	1.8 m³/yr	2.88 t/yr

As can be seen from the table, yields vary from two-thirds to about twice of the Prairie Provinces data used as the default case. Table 2.6.2 therefore uses a yield of 1.9 m³/yr for Newfoundland and 6 m³/yr for Coastal BC, in addition to the yields used for the Prairies.

Short-rotation forestry: Ranges of annual yields from poplar and willow plantations in Canada are given in Table 2.6.3. The root system of poplar represents about 20% of overall tree biomass, whereas willow roots range from 15 to 30%, depending on soil nutrients. The root system usually grows fast of the first few years of a plantation and then peaks, with no further soil biomass increase on a per-hectare basis. The carbon content of roots is about 40% for both species. Short rotation tree plantations have a number of specific characteristics that contribute to increasing soil organic carbon, including greater biomass inputs through litter fall and mulch applications, increased soil shading, a more lignified organic matter input, and deeper root systems. However, based on several existing studies on soil carbon, it was not possible to establish whether or not short-rotation forestry really increases soil carbon contents over other uses, such as agriculture or grassland. [REAP 2003]

Table 2.6.3 Yield Ranges for Hybrid Poplar and Willow from Short-Rotation Forestry, in Tonnes per Hectare and Year [REAP 2003]

	BC	Prairies	ON/QC	Atlantic
Poplar	9-12 (Southern Mainland)	1-5	2.5-7	2-6
Willow	10-15	7-12	5-10	2-6

2.6.2 Amounts of CO_2 Sequestered through Afforestation

Table 2.6.4 compares the base case with sequestration rates in three provinces with varying yield factors. While the “current use” option reflects the option to not plant a forest and carry on with existing land uses, it does only reflect grassland and cropland under “best management practices". The increase in soil carbon reflected in a sequestration rate of 0.73 tonnes per hectare and year has been observed over a period of ten years, but it is not established that the same sequestration rate will continue over the full length of 50 years modelled here. Actual sequestration rates may therefore be smaller than indicated. Other land available for afforestation, such as unimproved pasture or farmland not under best management practices, is assumed to have a stable soil carbon balance, i.e. there is no increase or decrease in soil carbon over the period modelled. The diesel fuel spent to plant and maintain the forest is marginal in comparison to CO_2 sequestered. The 50-year period was arbitrarily chosen to compare sequestration to other land use options, and while poplar trees will have mostly died after this period, spruce and ash will continue to grow and sequester carbon beyond this period.

Figure 2.6.1 illustrates the results of the previous table, showing the spread of sequestration to be observed across Canada and in different locations, depending on climate, soil quality, and species planted.

Table 2.6.4 Sequestered Amounts of CO_2 in Tonnes per Hectare (annually and over 50 years)

Process Step	Current Use	Prairies	Newfound-land	Coastal BC
Cultivation	-	0.01	0.01	0.01
Land Use	-0.73	-4.5	-3.0	-9.6
TOTAL per year	-0.73	-4.5	-3.0	-9.6
Total over 50 years	-36.5	-225	-150	-480

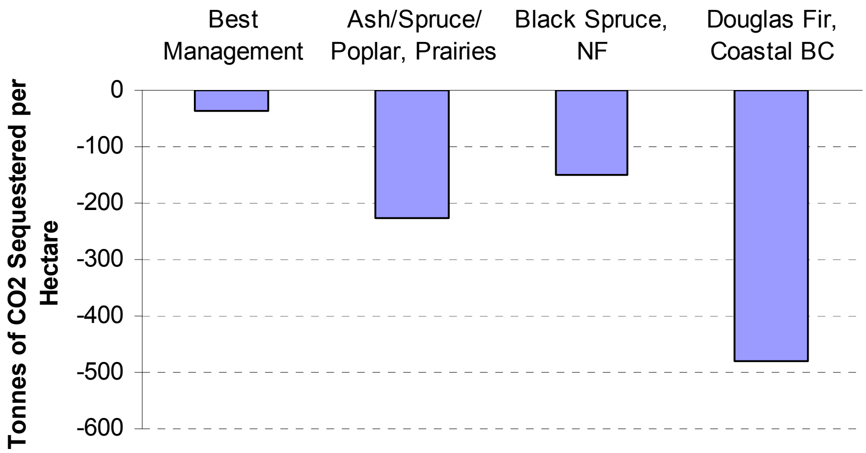
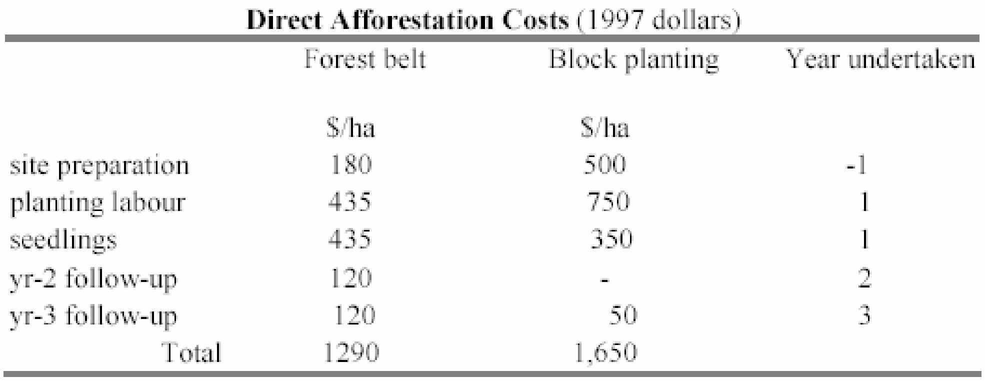


Figure 2.6.1 Carbon Sequestration Over 50 Years, Comparing Current Agricultural Land Use to Afforestation Options

2.6.3 Economic Aspects

Table 2.6.5 shows overall cost estimates for afforestation, which are around $1,500 per hectare. The Sinks Issue Table (see Sinks Table Options Report, 1999) also commissioned studies to estimate the cost of afforestation in Canada. These costs have been estimated to $2.30 per tonne of carbon sequestered for eastern Canada, $2.40 per tonne for British Columbia, and $3 per tonne for the Prairies [UoS 2000, p.64].

Table 2.6.5 Afforestation Costs per Hectare in Canada [Nawitka 1999a, p.27]



Direct Afforestation Costs (1997 dollars)

	Forest belt	Block planting	Year undertaken
	$/ha	$/ha	
site preparation	180	500	-1
planting labour	435	750	1
seedlings	435	350	1
yr-2 follow-up	120	-	2
yr-3 follow-up	120	50	3
Total	1290	1,650	

Chapter 3 Synopsis

3.1 Optimal Land Use

Chapter 2 mainly showed the GHG emission reduction impacts of various biomass usage options in terms of emissions reduced per tonne of biomass input. However, it is also interesting to look at emission reductions per hectare in order to determine which land use option yields the highest GHG benefits. To this goal, section 2.5 summarised the sequestration impact of afforestation. The difficulty in comparing such impacts with other biomass options, such as their transformation to fuel, is the time factor: a litre of biodiesel, for example, displaced a litre of conventional diesel fuel. Emission reductions can then be easily calculated on a life-cycle basis. However, carbon sequestration through afforestation occurs over a long period of time, and is linked to the continued existence of the forest in the future. According to Kyoto Protocol rules, the harvesting of a tree, or its loss to forest fires or through disease, is equal to the emission of the CO_2 that was sequestered in the tree. However, it is usually assumed that a forest reaches an equilibrium of carbon content after a certain time, which is balanced through the death of trees on the one side and the growth of new tress over a large area. While research continues on the exact values to be used for carbon stocks in forests, a period of 50 years was selected here to compare sequestration effects to other land-use options. Other periods of time may result in slightly different results, but these will not differ by an order of magnitude from the results obtained here.

Land-use options to be examined for a full comparison would have to include:

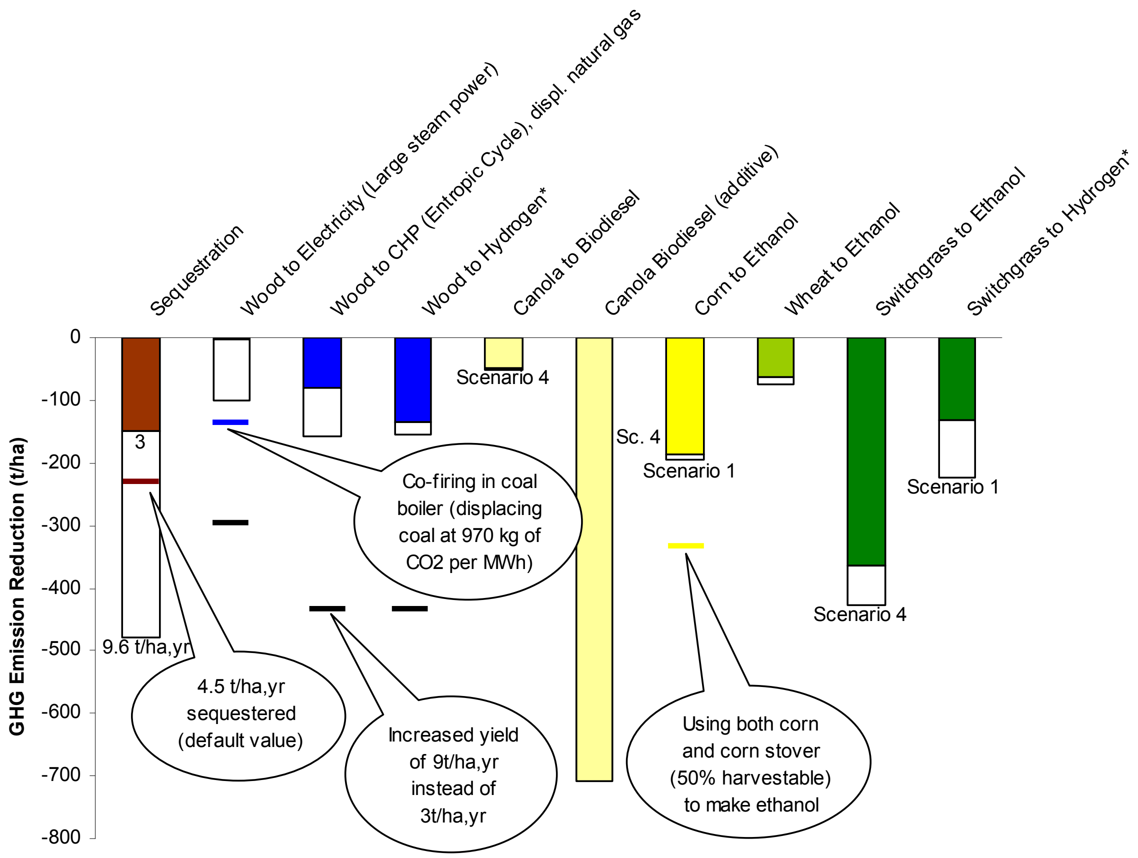
1. Afforestation without harvesting
2. Afforestation/reforestation and harvesting of wood to produce:
    - Electricity
    - Heat
    - Hydrogen
    - Ethanol or Methanol
3. Agricultural uses:
    - Growing of switchgrass or other species to make ethanol
    - Growing of switchgrass or other species to produce heat or electricity
    - Growing of corn, beets or grains to make ethanol
    - Growing of canola or soy to make biodiesel
    - Growing of other plants to make chemical products, such as bio-based plastics.

Some of these options were examined above, and an overall comparison of the effects of each option per hectare and over a period of 50 years is presented in Figure 3.1.1. The graph shows the spread of displacement results (white area) depending on the background power mix, with either Scenario 1 or Scenario 4 from Table 1.1 as the maximum value, depending on whether the process has a net production or consumption of electricity. No other impacts, such as future technology improvements, have been included in this graph so not to make it too complicated.

Short-rotation forestry: To make a comparison of different options to use short rotation forestry wood possible in this chapter, emissions and sequestration effects from short-rotation forestry as used in Chapter 2.3 (Hydrogen) above were applied to a large steam power and a small scale CHP plant (Entropic Cycle). The values used are given in Table 3.1.1. The underlying study (S&T 2003) notes that the annual sequestration effects for short-rotation forestry are averaged over 15 years, without further specifying any details. It is assumed for this study that soil carbon and carbon in underground biomass will not increase further after 15 year, i.e. the sequestration effects in soil have been averaged over 50 years for this comparison.

Table 3.1.1 Values Used to Determine CO_2 Emissions and Sequestration from Short-Rotation Forestry (grams of CO_2 per tonne of wood)

	Wood to Electricity (Large steam power)	Wood to CHP (Entropic Cycle), displacing heat from natural gas	Wood to Hydrogen, displacing natural gas-based hydrogen
Cultivation & Harvesting	84,741	84,741	84,741
Land-Use	-71,275	-71,275	-71,275
Feedstock Transport	12,200	3,200	7,993
Processing	0	0	218,843
Displacement, Scenario 1	-46,956	-558,047	-1,131,451
Displacement, Scenario 4	-687,183	-1,077,014	-1,277,718
TOTAL, Scenario 1	-21,290	-541,382	-891,150
TOTAL, Scenario 4	-661,517	-1,060,348	-1,037,417



* displacing natural gas as a hydrogen feedstock
NOTE: For the left three threads and switchgrass to ethanol, Scenario 4 represents the highest displacement, for the other threads Scenario 1 is the highest displacement

Figure 3.1.1 GHG Emission Reductions per Hectare for Different Biomass Use Options, as a Function of Electricity Background Mix, over 50 years

Comparing afforestation without harvesting to commercial use based on short-rotation forestry: From each hectare used for short-rotation forestry, 3 tonnes of wood could be harvested each year from hybrid poplar plantations in Prairie Provinces. This compares to a maximum per-hectare biomass stock of about 260 m³ (bole wood) for spruce after 50 years, under the best conditions (equivalent to about 225 tonnes of bone-dry biomass, including roots and branches). So the overall harvest from short-rotation forestry (3 tonnes a year x 50 years = 150 tonnes) is smaller than the total biomass in the afforested area, based on the mix of tree species assumed for afforestation in Prairie Provinces. Yields can be increased using willow (7 to 12 tonnes per hectare), and 9 tonnes per hectare was therefore used to indicate the range of displacement benefits per hectare from short-rotation forestry (see also Table 2.6.3 above). Biomass processing entails energy losses, and soil carbon sequestration effects are assumed to be lower for short rotation forestry than for afforestation, providing an advantage to the latter with respect to GHG emissions, despite the lower sequestration rates.

Hydrogen from wood: Emission reduction benefits of hydrogen made from wood surpasses those of other options, and is very stable with respect to the background power mix. Only very high growth rates (5 m³ of bole wood/ha-yr and more) will deliver GHG benefits in the same order of magnitude from sequestration. This result is likely to be the same if other high-yielding feedstocks, such as switchgrass, are used.

Influence of yields: Switchgrass and short rotation forestry wood perform rather well in comparison to other forms of biomass, which is mainly due to the very high yields that were assumed (11.5 t/ha for switchgrass and 9 t/ha for short-rotation forestry, high-range option) as compared to other plants (corn: 7.8 t/ha; wheat: 2.7 t/ha; canola: 1.3 t/ha). The afforestation/sequestration option assumes a modest growth rates in the Prairie Provinces as the default value, but shows the variability of growth rates throughout Canada (the carbon sequestration rates used are shown in Table 2.6.4). Depending on these growth or sequestration rates, emission reductions from afforestation, large steam power, CHP and wood to hydrogen will change proportionately, with (small-scale) CHP and hydrogen having about the same benefits as afforestation. The low yields for canola oilseed also explain why the biodiesel option fares so low in comparison to other threads (soy would have very similar results, because the oil yield per hectare is nearly the same as for canola). Ethanol from wheat has far lower GHG emission reductions per hectare than higher yielding species, such as corn or switchgrass. The results clearly show that using wheat for ethanol or canola for biodiesel does not deliver significantly lower emission reductions than other land-use options.

Using lignocellulosic biomass: Overall biomass yields from corn, wheat and canola could be increased if the remaining biomass, such as corn stover, was also harvested and used to make lignocellulosic ethanol. However, the increased yields will still not reach the much higher yields expected for switchgrass, as for example wheat straw only represents about 50% of the plant's harvestable biomass [SHU 2003]; canola and corn stover represent about the same amount as the main crop, but only 50% is considered harvestable [BIOCAP 2003]. This means emission reductions could increase somewhat, but as a large part of the biomass is used to produce process energy in the Iogen process, and some biomass has to remain in the field for agriculture to remain sustainable, this possible increase remains limited. For corn and corn stover, nearly the same emission reductions as for switchgrass could be achieved, but switchgrass seems the better alternative as less valuable agricultural land can be used, and fertiliser inputs are much smaller. Using the increased values for by-product credits used in the updated GHGenius model (see section 2.), an increase in emission reductions from corn ethanol of about 37% would result. Combined with the use of corn stover, corn ethanol would then clearly match the emission reduction benefits of switchgrass ethanol. However, these increased values depend on the accounting rules for by-product credits, which may change over time and introduce significant variability into the analysis.

Thermal options: As the conversion of biomass to electricity has a low efficiency, only moderate GHG emission displacement effects can be achieved per hectare. In the case of a background mix that is dominated by large hydropower or other low-emission power sources, hardly any emission reductions can be achieved. On the other hand, biomass co-firing in coal-powered plants would directly displace coal as a feedstock and delivers quite considerable emission reductions. This is only shown for a low wood yield of 3 tonnes per hectare and year in Figure 3.1.1, but with higher yields, co-firing can reach the same level of emission reductions as ethanol production from switchgrass. In most cases, the production of combined heat and power (assumed to displace natural gas) is more beneficial than other options and can even be superior to planting trees with a low sequestration rate. CHP with high yielding crops, such as fast-growing trees or switchgrass, can reach the emission reductions from switchgrass ethanol, and could even surpass them if heating oil is displaced (not shown).

Canola-based biodiesel: Clearly, emission reduction benefits from canola oilseed are smaller than all other options, which is also confirmed in the literature for rape seed oil [EU 2000, p.66]. This changes if biodiesel is used as an additive to increase fuel efficiency, but then depends on how much fuel efficiency is really increased, which still has to be established in large-scale trials. If fuel savings would fall to only 2.5%, then even canola-based biodiesel additive could not compete with the benefits from other land-use options. It is also not necessary to grow canola oilseed for biodiesel as an additive because waste oil and animal fat is available in sufficient quantities to achieve a 0.5% share in diesel fuel for all of Canada.

Switchgrass: Making ethanol from switchgrass has the second largest emission reduction benefits, and would be the most favoured option as long as hydrogen is not becoming a mainstream transportation fuel. Further processing of ethanol to hydrogen, however, uses up many of the emission reduction benefits. Making hydrogen from switchgrass directly through gasification has not been examined in this study.

Comparative study: Sugar beets as a raw material were not examined here, but may bear significant potential: a European review study identified a three times higher GHG emission reduction potential per hectare for beets than for grain [Concawe 2002]. The same source examined both GHG emissions displaced by (rapeseed) biodiesel and (wheat and beet-based) ethanol. Results for biodiesel are about twice as high than those obtained for this study (2 t/ha displaced, i.e. about 100 tonnes over 50 years), which is mainly due to the fact that land use emissions were not included, and also to the fairly high credits attributed to the animal feed in the Levelton study used in this present report. For wheat ethanol, a CO_2 displacement of only 1.3 t/ha (65 tonnes over 50 years) is used, and about three times as much for sugar beets (3.8 t/ha). The wheat data coincide well with the results shown above, and the higher sugar beet yield suggests that ethanol from beets and corn will have very similar GHG emission reduction effects.

Other aspects: Many crops can be continuously planted year after year, but generally this can lead to diseases, decreased yields and weed problems and alternating crops is therefore recommended. On the other hand, both switchgrass and trees can be planted and harvested on the same area over the entire 50 years used above as the reference period. This may mean that actually, a larger area is required to obtain the same yields over a long period of time, although for example corn, wheat and soy can be alternated on the same field, thus achieving a similar average result for all three crops when the entire planted surface is combined. Several crops will require irrigation in dry areas, and virtually all high-value crops require good or very good soil qualities to grow, whereas switchgrass and trees could be planted on marginal farmland, thus not affecting food or cash crop production on the best land. Finally, the nitrogen requirement indicates fertiliser application and therefore eutrophication due to fertilizer losses to ground or surface water. To qualify the yield comparison further, switchgrass only achieves its full yields after three years, and poplar can only be harvest after a stand age of about 15 years. The fact that these crops do not have to be rotated also means that the ground is not fallow and erosion is minimised, i.e. they can be planted on slopes without risking soil losses. Table 3.1.2 shows that switchgrass and hybrid poplar fare best in most categories, and therefore seem to be preferable energy crops. Poplar or willow short-rotation forestry may require irrigation in dry areas. The use of waste water from food processing, or sewage has been suggested as a possible source of irrigation water for willow or poplar.

Table 3.1.2 Comparison of Requirements for Various Energy Crops*

Crop	Yield	Crop cycle	Water requirement	Required soil quality	N-fertiliser application
Switchgrass	High	Continuous	Moderate	Low	Moderate
Poplar	High	Continuous	High	Low	Low
Wheat	Low	Rotation	Low	High	Moderate
Corn	Moderate	Rotation	Moderate	High	High
Canola	Low	Rotation	Moderate	High	High
Soy	Low	Rotation	Low	High	Low

* compiled by the authors based on Ontario yield statistics and expert opinions

3.2 Optimising GHG Emission Reductions from Wood and Wood waste

Several threads were examined for both wood and wood waste, and the results are compared in this chapter. Wood can be used in manifold ways, including:

1. Combustion of wood to produce:
   - Electricity
   - Heat
   - Combined heat and power
2. Gasification of wood to produce
   - hydrogen
   - syngas to produce other chemicals like methanol, alcohols, gas or diesel
3. Enzymatic hydrolysis to produce ethanol
4. Pyrolysis to produce bio-oil (and possibly specialty chemicals)

A comparison of the GHG displacement effects of several of these threads is shown in Figure 3.2.1. These results were obtained by comparing each process on a per-tonne basis, i.e. all life-cycle GHG emissions from the process, as well as the resulting emission displacements from the use of electricity or hydrogen, feed into the end result. The chart must be read as “one tonne of bone-dry wood displaces x grams of CO_2 if used for thread y”. Ranges are given for each thread to reflect different background power mixes: the lower value represents Scenario 1 emissions, and the upper value represents Scenario 4 from Table 1.1.

As might be expected, much larger benefits can be gained from using wood in a combined heat and power (CHP) plant than if only electricity is used, as the overall energy efficiency is significantly increased for CHP (displacing heating oil for the heat component). If measured against average emissions from the regional electricity background mix (i.e., the combination of generation technologies and their combined emissions per MWh produced), the production of electricity in low-emission background mix regions does hardly reduce emissions. In regions that heavily rely on coal for their power generation, up to 0.5 tonnes of CO_2 per tonne of wood can be displaced.

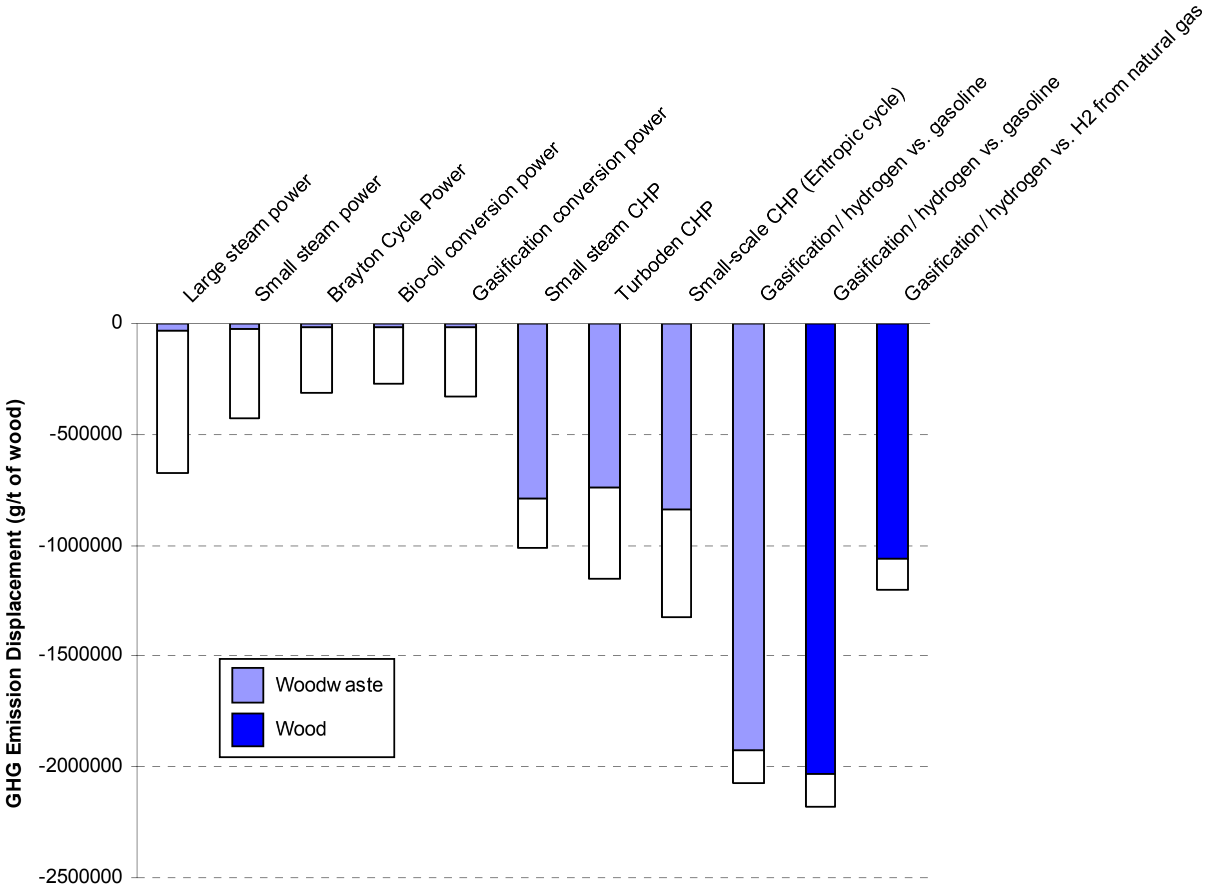


Figure 3.2.1 Comparison of GHG Emission Displacements from Different Wood and Wood waste Threads

For CHP, the minimum emission reductions are superior to any power-only option, and increase further if the background mix is emission-intensive. The largest emission reductions are achieved if hydrogen is produced from wood gasification, and if this hydrogen displaces gasoline. The emission displacements of wood and wood waste are nearly identical (wood displaces slightly more GHG because of sequestration of CO_2 in tree roots). However, as hydrogen requires both a different feedstock and also a different technology, the comparison to using natural gas for hydrogen production was included as well. Based on this comparison, hydrogen from wood has very similar effects to the decentralised use of wood in CHP plants.

3.3 Switchgrass and Other Lignocellulosic Feedstocks

Lignocellulosic feedstock can, much like wood, be used in several feedstock-to-product threads. Some of these threads identified in the Stage 1 study are:

1. Combustion of lignocellulosics to produce:
    - Electricity
    - Heat
    - Combined heat and power
2. Gasification to produce
    - hydrogen
    - syngas to produce other chemicals like methanol, alcohols, gas or diesel
3. Enzymatic hydrolysis to produce ethanol
4. Separation of fibres and lignin to produce construction materials and chemicals

In this study, only the ethanol and ethanol-to-hydrogen (not gasification) threads were examined. A comparison between various lignocellulosic feedstocks for each of the two threads was made in previous chapters. Figure 3.3.1 compares the use of switchgrass for use as a transportation fuel in three cases: the use of ethanol mixed in with gasoline, and the further processing of ethanol made from lignocellulosics to make hydrogen used in a fuel-cell powered car and displacing either gasoline used in an internal combustion engine or displacing hydrogen made from natural gas instead of bioethanol. Note that the ethanol process exports surplus electricity to the grid, which causes the highest emission displacement to occur under a Scenario 4 background mix. Further processing bio-ethanol to hydrogen requires extra electricity, which optimises emission benefits under Scenario 1.

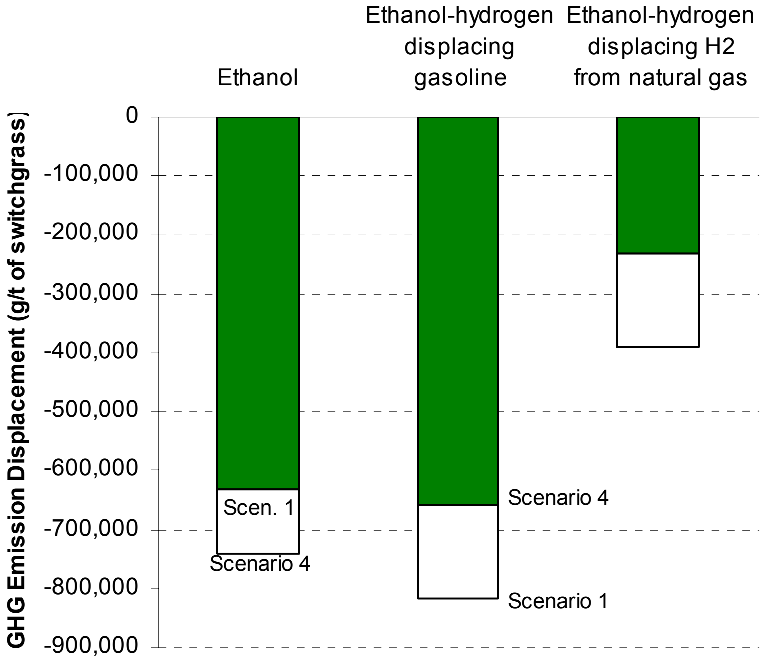


Figure 3.3.1 Comparison of GHG Emission Displacements from Different Switchgrass Threads

While it may be surprising to realise the increased benefits from further processing bio-ethanol to hydrogen, it must e clear that this is only the case when the use of ethanol in an internal combustion engine (ICE) is compared to the use of hydrogen in a fuel cell, with about twice the efficiency of an ICE. This doubling in efficiency means that more gasoline is displaced by hydrogen than by ethanol, and although more energy is consumed when reforming ethanol to hydrogen, this is more than counterbalanced by the high fuel cell efficiency. If compared to hydrogen from natural gas, it becomes obvious that the two-step processing of switchgrass first to ethanol and then to hydrogen is less beneficial than its direct use in an ICE.

Further analysis would be required to assess the possibility of gasifying switchgrass to make hydrogen, and also to use switchgrass in other applications, such as power or combined heat and power generation, and space heating, for example. As an indication, switchgrass may have similar emission reduction benefits in those applications as short-rotation crops due to the similar yields of switchgrass compared to the default case for wood (9 t/ha-yr).

3.4 Comparing GHG Benefits on a Per-Tonne Basis

Figure 3.4.1 compares the main threads analysed in this study on a per-tonne of biomass input basis. For three of the threads, maximum options were added to show the bandwidth of some options can still vary if some input parameters are changed considerably.

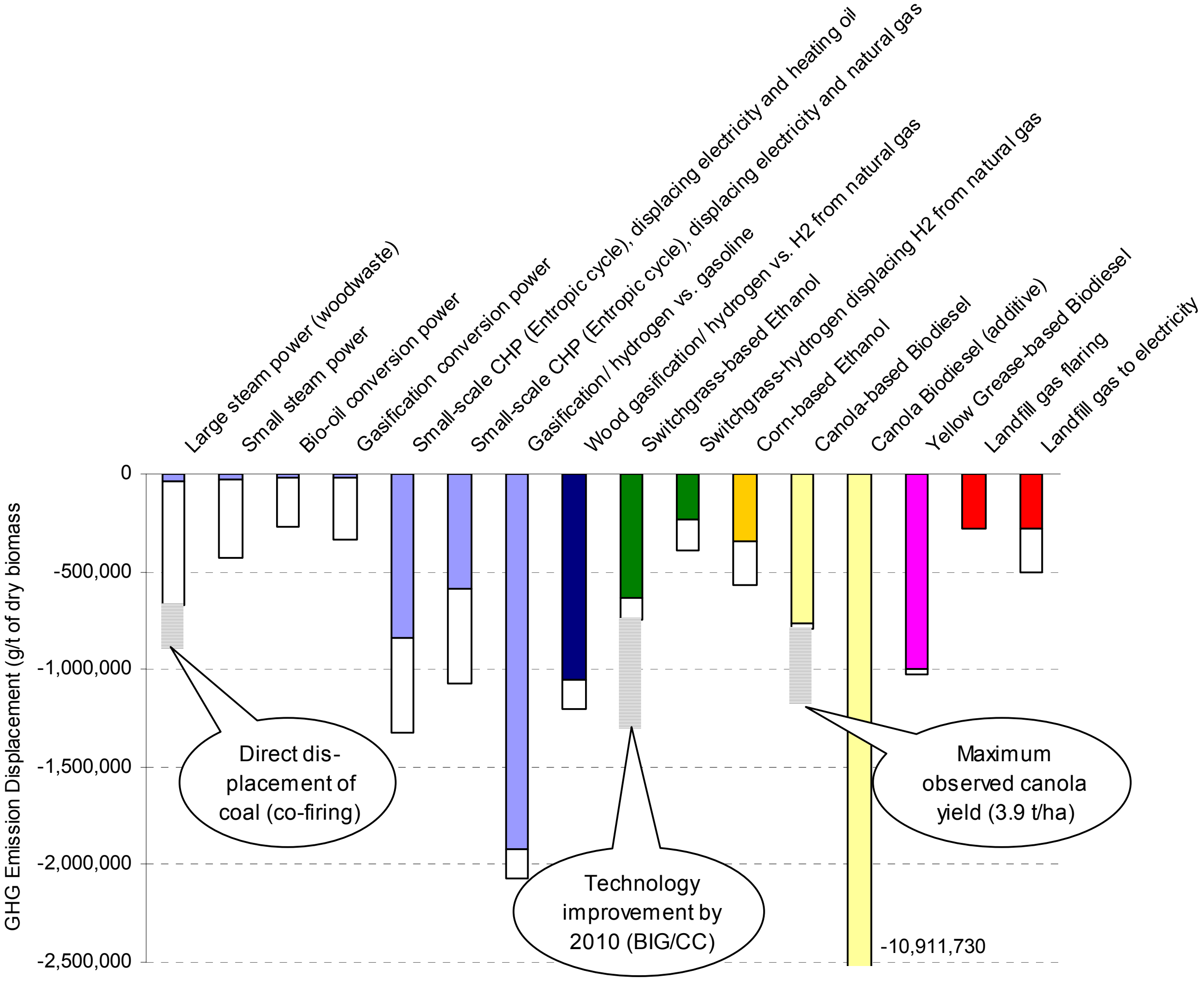


Figure 3.4.1 Comparison of GHG Emission Displacements Per Tonne, for Various Feedstocks (note that only identical feedstocks with the same colour can be compared in this graph)

While one needs to be cautious not to compare different feedstocks on a per-tonne basis (only threads of the same colour can safely be compared), some lessons can be learnt from the graph: first, all biomass options do reduce GHG emissions, compared to fossil fuels – however, “a tonne of biomass is not a tonne of biomass”, as the type of feedstock and related processes are important. Second, those options displacing a liquid fossil fuel for either transport (gasoline or diesel) or heating (heating oil) have larger emission reduction benefits than those displacing electricity only. Third, using biomass for electricity production when displacing coal in a coal-based power station (co-firing) may reach the same level of emission reductions as a CHP plant displacing natural gas for heat, whereas a CHP plant that displaces heating oil will almost always fare better. Fourth, there is no clear winner between using wood for CHP and for hydrogen (through gasification). Other considerations, such as the need to preserve natural gas for other purposes than steam reforming for hydrogen, or price issues, will decide which of the options is better for biomass. Fifth, transportation fuels do not have the same emission displacement benefits just because they are based on cultivated biomass resources. Yields and life-cycle energy requirements have significant effects on the performance of a biofuel. The better performance of biodiesel versus ethanol in this graph does not mean that biodiesel should be preferred. Rather, Figure 3.1.1 above shows that if given the choice to use an area of land to maximise emission reduction benefits, growing canola to make biodiesel may not be the first choice. However, if used as an additive, biodiesel may exceed the emission reduction benefits of any other option more than fivefold. Only two (mixed) biowaste treatment options were included, as all others will create, not reduce, GHG emissions.

3.5 Summary and Conclusions on GHG Benefits

The following conclusions can be drawn from the previous sections:

1. The amount of CO_2 sequestered in biomass is the main factor for displacement effects. It is therefore very important to determine which type of energy carrier biomass will displace. Fossil fuels, such as gasoline, have high carbon contents, which are displaced fully by the use of a biofuel, which has no carbon emissions attached to it. The emissions caused by processing the feedstock to make the biofuel are often in the same order of magnitude as those required for fossil fuel production, and as the later are also displaced by the use of biofuels, process-related emissions are more or less cancelled out.
2. If electricity is displaced by biofuels, benefits will heavily depend on which energy source is displaced. If it is a low-emitting source, such as large hydro, then almost no benefits ensue. If coal is an important part of the background power mix, significant emission reductions can be achieved. However, combined heat and power will almost always prevail over producing electricity only from biomass in terms of emission reductions.
3. Technology improvements and process efficiencies can lead to significant increases in emission reductions. However, they are not a decisive factor in classifying a given type of biomass as of high or low benefit. Some extra emissions caused by transportation or drying will not shift the overall picture enough to lead to different conclusions.
4. For energy crops, biomass yields are very important. Low-yield species, such as canola, will tend to having lesser emission reduction benefits than high-yielding species, such as switchgrass or some fast-growing trees.
5. Two-stage processes, such as making ethanol from biomass and then making hydrogen from ethanol, cause large losses of emission reduction benefits and also have unfavourable energy balances.

Another important aspect of determining the benefits of using biomass are fossil energy inputs. These are partly reflected in the energy balance, and will affect aspects such as energy security and fossil fuel pricing. The next section will examine this context in more detail.

Based only on GHG emission displacement effects, the following ranking of biomass uses could be established:

1. **Hydrogen:** If compared to the internal combustion engine, making hydrogen from biomass seems to be the most attractive option, which can be explained to a large extent by the fact that fuel cells are about twice as efficient as gasoline engines. However, a move towards a hydrogen economy is not related to biomass use, and once vehicles with fuel cell technology are available, biomass will compete with other hydrogen feedstocks, and the current understanding is that this will mainly be natural gas. If compared to hydrogen from natural gas, hydrogen from biomass is still a high-end option, and is only beaten by CHP when heating oil and a carbon intensive electricity background mix are displaced.
2. **Heat or CHP:** Displacing both electricity and heating oil or gas, this option is the second best if GHG emission reductions are to be maximised. It bears great potential, considering that small-scale applications are possible, combined with district heating. This result suggests that, although not examined in this study, the **use of biomass for space heating** – directly replacing natural gas or heating oil – might be even more beneficial in terms of emission displacements. Further analysis to confirm this assumption, considering transportation, drying and other aspects, such as ash content, would be required.
3. **Ethanol:** Directly displacing gasoline in cars, ethanol appears to be the next best option from a GHG perspective. This option is also very stable with respect to the background electricity mix, thus will deliver considerable emission reductions in any environment. Ethanol can be made from lignocellulosic feedstocks, and work on turning wood into ethanol is progressing. Corn-based ethanol has lesser benefits than lignocellulosic ethanol, mainly because the latter uses emission neutral biomass residue to power the ethanol production process.
4. **Electricity:** The least interesting option is to produce electricity only from biomass. Especially in areas where the background power mix is based on renewable energy, benefits can be marginal. Even if it is assumed that biomass power displaces natural gas in those areas, this option cannot compete with any of the above in terms of emission reductions. Increased efficiencies due to gasification, or the use of bio-oil, do not change the picture significantly.

The above ranking holds true if the question is, “What should I do with available biomass?” – but does not mean that policy decisions should be taken based on it. If a process exists that creates a residues, such as waste wood, then hydrogen or CHP would be the preferred options. However, if economic development decisions are to be made, such as restructuring the agricultural economy in order to move towards a biobased economy, then emission reduction benefits should be evaluated based on a per-hectare approach. Figure 3.1.1 reveals the priorities, and suggests the best uses of agricultural land, wherever possible:

1. **Afforestation and reforestation:** this option should be considered first, unless short-term emission reductions are sought. Over a 50-year period, trees can sequester more carbon dioxide out of the air than can be displaced through transportation fuels or electricity from biomass.

2. **Ethanol from switchgrass:** by far the best option, making ethanol from switchgrass exceeds the emission reduction benefits from other land-use options by close to 100%. It is also more beneficial than making ethanol from corn, although the emissions displacements from corn ethanol could theoretically be increased by using biomass for that process also. The use of biomass for process energy occurs in several threads and can disguise the sometimes significant energy demand of biomass-based threads.
3. **Hydrogen and CHP:** There is no clear winner between these two threads – of course, hydrogen would win out if it is seen as displacing gasoline, but if the more realistic comparison is made between hydrogen from biomass and from natural gas, both options may deliver similar benefits. There may be an interest in the future to reduce natural gas use for hydrogen production to save shrinking gas reserves for other purposes, such as space heating, but on the other hand hydrogen production from biomass may require very large central plants, which may not be feasible unless there is a high concentration of available biomass near the plant.
4. **Biodiesel:** Due to the fairly small yield per hectare for canola or soy, biodiesel tends to be a bad choice for the maximisation of GHG emission reduction benefits. As switchgrass has three to nine times the yield of canola per hectare, ethanol emerges as the superior option in this case. Ethanol can also be mixed with diesel in order to reduce emissions from transport, although some issues are to be resolved for this use (see Levelton 2002a). On the contrary, a very different picture emerges if it can be confirmed that biodiesel increases fuel efficiency if used as a **fuel additive**.
5. **Electricity:** The production of electricity only may exceed biodiesel benefits where it displaces an emission intensive background mix. If natural gas is displaced (which causes roughly half the GHG emissions of coal-based generation), the benefits of both threads are almost equal.

Again, certain other threads, such as using pelletized switchgrass for space heating, or making hydrogen from switchgrass through gasification, should be examined to be more inclusive of alternative threads related to land-use.

Chapter 4 Other Considerations

4.1 Ranking Feedstock-to-Product Threads According to Fossil Fuel Displacement

In an age where some fossil energy resources, such as gas and oil, are approaching peak production, while demand continues to increase and international developments could jeopardize the continued supply of energy resources to developed nations, the paradigm of energy security has gained a lot of momentum.

Biomass, as a domestic resource, can help alleviate the increasing demand of imported energy carriers, while reducing GHG emissions. Biofuels can displace natural gas and heating oil for heat, coal and natural gas for electricity production, and oil-based transportation fuels. However, as some fossil fuel inputs are required to make biomass fuels, these need to be subtracted from the amounts displaced at the user level, whereas any fossil fuel inputs displaced from the displaced fossil fuel production have to be added to the displaced amount:

Fossil fuels displaced = Displacement in the application (engine, fuel cell, turbine, etc.) – Fossil fuels used to produce and transport the biomass fuel + Equivalent amount of fossil fuel inputs for fossil fuel production

Determining the amount of crude oil displaced by biobased transportation fuels is a non-trivial assignment. Crude oil is refined to produce a number of oil-based products, with 47% of the distillate being processed into gasoline and 23% to diesel fuel. Based on the U.S. Energy Information Administration's data, 44 gallons of oil-based products are made from 1 barrel of crude oil (42 gallons). For simplicity's sake, this relation is used here to determine displacement effects of both ethanol (displacing gasoline) and biodiesel (displacing conventional diesel), but corrected for the relative energy content of each fuel, i.e. an amount of ethanol with the same energy content as 44 gallons of gasoline would displace one barrel of crude oil. Natural gas is converted to barrels of oil at a rate of 6 barrels per 1,000 m^3.

To determine fossil fuel use during the life-cycle of biofuel production, the energy inputs per tonne of biomass were converted to barrels of oil, using an energy content of 5.8 million BTU per barrel of crude oil. For electricity, natural gas was assumed as the power source to be used or displaced, assuming a consumption of 230 m^3 of natural gas per MWh in a combined cycle natural gas plant. The life-cycle energy inputs for biomass-based fuels were taken from the data used in the preceding chapters. Only energy inputs covered by fossil fuels or electricity were counted; no energy inputs were included where part of the biomass feedstock was used to power the process. The avoided energy required for the production of the fossil fuels displaced was calculated based on the energy requirements for conventional diesel. This is given as 0.24 BTU per BTU in diesel fuel in Levelton 2002a. Note that this includes the complete life-cycle of diesel, including crude oil production, transport, and processing, part of which will occur outside the importing country (Canada does not import oil).

Table 4.1.1 shows the numbers for the different threads, which are once more displayed graphically in Figure 4.1.1, taking into account both natural gas and oil.

Table 4.1.1 Avoided Use of Fossil Fuels for Selected Biomass Threads, in barrels of crude oil, per dry tonne of biomass input

Thread	Displacement at User Level	Life-cycle Fossil Fuel Inputs	Avoided Fossil Fuels for Crude Oil Recovery and Processing	Resulting Displacement
Corn to ethanol	1.70	1.26 Energy credit: -0.52	0.41	1.37
Switchgrass to ethanol	1.32	0.20 Energy credit: -0.38	0.32	1.81
Canola to biodiesel	2.08	1.09 Energy credit: -0.72	0.50	2.21
Yellow grease to biodiesel	2.08*	0.65 Energy credit: -0.04	0.50	1.97
Wood waste to hydrogen	Gasoline: 3.54[1] Natural gas[2]: 1.81 (301 m³)	0.24	Gasoline: 0.85 Natural gas: 0.43	Gas.: 4.15 Nat. gas: 2.01
Wood waste to electricity (large steam)	Natural gas: 1.25 (208 m³)	0.02	0.30	1.53
Wood waste to electricity (small-scale CHP/Entropic Cycle)	Electricity: Natural gas: 0.94 (157 m³) Heat: Heating oil: 1.71 Natural gas: 1.77 (295 m³)	0.005	Heating oil: 0.64 Natural gas: 0.65	H. oil: 3.28 Nat. gas: 3.36
Landfill gas to electricity	(electricity) 0.23	0.05[3]	0.06	0.24
Waste Digestion/ composting	(electricity) 0.17	0.01 Fertilizer credit: -0.31	0.04	0.52
MSW Incineration	(electricity, heat) 0.34	0.01	0.11	0.41

* artificially related to the same biomass input as canola in order to make numbers comparable
[1] assuming 1.89 MJ of hydrogen is needed for 1 km of travel [NRCan 2003]
[2] 83% efficiency of natural gas reforming process, based on lower heating value
[3] assuming 40 km transport distance and same diesel consumption as for forest biomass

It is important to note that some of the biomass fuels require very large amounts of energy to be produced. Switchgrass-based ethanol requires more energy than is contained in the ethanol produced, and 40 to 50% of energy contained in wood will be required to produce hydrogen through gasification. However, as this energy is produced with part of the biomass feedstock it is not included with the fossil energy inputs above.

Figure 4.1.1 shows that the displaced amounts of fuel are very similar for most biomass feedstocks. The electricity options displace between 50 and 100% more oil than the other options, based on the assumption that natural gas the alternative fuel for electricity production, which is not necessarily the case. However, this assumption is often valid and can even be made in areas where large hydropower or nuclear are predominant, as natural gas-fired power plants are frequently the most likely alternative for newly added generation, unless more renewable power can be developed.

The comparison of biobased hydrogen displacing gasoline in an internal combustion engine and displacing hydrogen made from natural gas is included again, but as discussed earlier the latter option is the more realistic one. Leaving this data point out, CHP becomes the most attractive option, followed by biodiesel and then biomass gasification to produce hydrogen. Given the large benefits of CHP compared to other options, the use of biofuels for heat generation may fare even better, but could not be included in the current analysis.

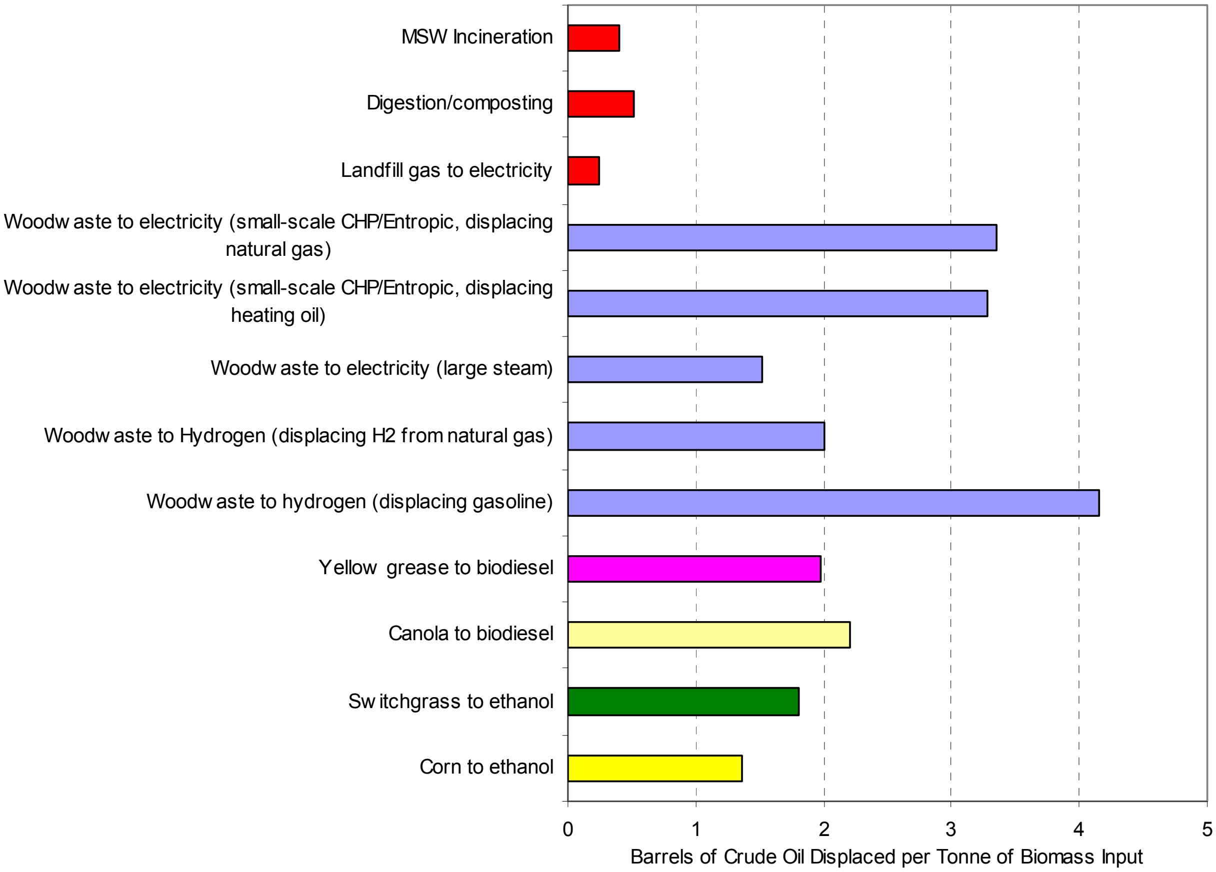


Figure 4.1.1 Graphic Representation of Displaced Fossil Fuels for Selected Technologies

For biowaste management options, MSW incineration is a favourable technology, as it produces both electricity and heat – if this heat can be used for district heating (the heat benefits were reduced by one-third to account for the seasonal use of district heating). However, digestion with composting fares even better than incineration due to the extra credit from displacing energy to make artificial fertilizer. Because of the high water content of biomass, the substantial energy required for the process and because mainly electricity is displaced, the overall fossil fuel savings from biowaste treatment options are very modest, compared to other sorts of biomass.

4.2 Ranking Feedstock-to-Product Threads Based on Technical and Economic Feasibility

4.2.1 Technical Aspects

Several of the technologies discussed in this report are not yet proven, or not yet economically viable. While academically interesting, and relevant for future planning and long-term strategies over the next decade and beyond, GHG emission reduction benefits cannot be the only criterion for deciding which technologies should be supported in the biomass field. Table 4.2.1 provides an overview of technologies and their technological status.

Table 4.2.1 Technical Status of Biomass Conversion Technologies

	R&D	Pilot stage	Pre-commercial	Commercial	Small-scale possible	Comments
Ethanol from corn and grain			x		N	Competitive with subsidy
Ethanol from lignocellulosic feedstocks			x		N	Competitive with subsidy
Biodiesel from canola and soy			x		N	Competitive with subsidy
Biodiesel from animal fat and waste oil				x	N	Competitive at high oil prices
Hydrogen from wood and woodwaste	x				N	Modelled; requires very large scale
Large steam Rankine Cycle				x	N	
Small steam Rankine Cycle				x	Y	
Brayton Cycle		x			Y	
Bio-Oil Conversion			x		N	Plant size >5MW
Gasification		x			Y	
Small steam CHP				x	Y	
Turboden Cycle			x		Y	
Entropic Cycle		x			Y	
Landfill gas capture				x	N	expensive for small landfills
Composting				x	Y	
Digestion/Composting				x	Y	
MSW Incineration				x	N	100,000 t/a or larger

The question of whether a small-scale application will be possible is a decisive factor in determining the feasibility of a system. Large-scale systems require very large concentrations of biomass in one area. This can be the case with sawmills or pulp mills, for example, where large amounts of wood waste are generated. Only very few locations will allow for the operation of a large-scale plant. For example, Williams Lake in BC has the largest single-unit biomass power plant in North America. It feeds on the residues of five sawmills located within five kilometres of the plant, supplying fuel at very little cost. The 60 MW unit consumes about 46 dry tons of wood per hour, whereas the conceptual biomass-to-hydrogen plant of Chapter 2.3 is laid out for the consumption of nearly twice as much, at a throughput of 80 tons per hour [WBE 2004]. Although the operating and fuel costs of the station are very low (the cost per kWh is estimated to be only C$0.02-0.03), and allow for some expansion of this concept, such concentrations of waste biomass are not frequently encountered. In Canada, many of these locations are already being exploited, using biomass for power and steam generation in the pulp & paper industry. The smaller a system can be built, the shorter the transport distances become, and the greater the number of suitable sites for biomass.

Likewise, for agricultural and other types of biomass that have to be collected over large distances, a large-scale system may prevent the process from having a chance of becoming commercial as transportation costs are becoming too large a factor.

The processes based on agricultural feedstocks are all commercial or pre-commercial. Many biodiesel plants are working today across the world, and with prices for crude oil rising, especially a plant using waste vegetable oil and animal fats would be able to compete with conventional diesel, certainly in case there are additional incentives, such as tax exemptions. Ethanol is also being produced commercially in both the U.S. and Canada, and the first plant using lignocellulosic feedstocks has started operating in Ontario in 2004.

For hydrogen production with a gasifier, no full-size plant has ever been built. The life-cycle data used in this report was based on laboratory and small-scale testing and modelling of the system. Some gasification systems have been tested, but the complete process to make hydrogen is still only at the conceptual stage. This rules out its use over the coming years, but shows that biomass may become a significant source of hydrogen in the near future.

From the wood-based processes, many are already at the commercial stage and whether or not a process can be profitably run will rather depend on local circumstances, such as the national tax structure or the local cost and availability of biomass, than on making the system itself more viable. However, gasification and bio-oil production are still experimental.

Some small-scale systems, such as the Turboden and Entropic Cycles, bear a lot of potential for biomass-based systems as they combine both small scales and high efficiencies through the production of both electricity and heat. Turboden has been demonstrated at various locations in Europe but requires a significant decrease in cost for it to be commercially viable. Entropic promises to be cost effective but requires demonstration of the system.

Based on technical availability, the following ranking of biomass usage technologies can be derived:

1. Large or small scale steam or CHP systems using woody biomass are viable options for making power and possibly also heat today. For agricultural residues, both biodiesel and ethanol technologies are established. This includes ethanol from lignocellulosic residues, although research on using wood as a feedstock for ethanol production is currently still on-going. Some of the biofuel technologies still require subsidies, but with rising oil prices the margin between biofuels and fossil fuels is narrowing.
2. Bio-oil and emerging improved CHP systems are coming to technological maturity quickly. However, the use of bio-oil is directly linked to the possibility of extracting valuable chemicals before its use as a fuel, which has so far not been accomplished.
3. Making hydrogen from biomass may become a viable alternative in the future, but currently there are no functioning applications available.

Concerning waste treatment, all technologies are commercially available, although at very different costs. The main difference is their scale: whereas composting and digestion facilities are suitable for small amounts of biomass (around 10,000 t/yr), landfill gas capture is generally only implemented on large landfills due to their higher relative cost on small ones. MSW incineration requires very large annual throughputs to keep prices acceptable. The required amounts of waste can reach 400,000 tonnes per year, although only about 50% of this will be organic waste.

4.2.2 Economic Aspects

The technical and economic feasibility of biomass conversion systems is intrinsically linked. The components determining whether or not a process is economic are the feedstock cost, capital and operating costs, and the sales value of products and by-products.

Table 4.2.2 shows throughputs and required cultivated areas for two feedstocks, using switchgrass as an agricultural biomass resource and trees as an alternative. It is assumed that either feedstock is used in a Rankine Steam Cycle plant to produce electricity. Note that switchgrass is usually only harvested either in the spring or in the fall, which would require considerable dry storage capacities. Results are presented for a very small plant, a medium-sized plant, a large-scale plant like the Williams Lake plant in British Columbia, and a very large plant (200 MW) and can be transposed to any other biomass processing plant of the same throughput.

Table 4.2.2 Comparison of Switchgrass and Wood from Short-Rotation Forestry as Feedstocks for a Steam Plant, with Respect to Throughput and Minimum Area Required

	Switchgrass		Short Rotation Forestry Wood	
Harvest	11.5 t/ha-year		9 t/ha-year	
Energy content	16.7 million BTU/BDtonne		19.4 million BTU/BDtonne	
1 MW – 0.56 MWh/t	18,076 t/yr	1,572 ha	15,560 t/yr	1,729 ha
10 MW – 0.75 MWh/t	135,684 t/yr	11,799 ha	116,800 t/yr	12,987 ha
60 MW – 0.90 MWh/t	676,164 t/yr	58,797 ha	582,059 t/yr	64,673 ha
200 MW – 1.0 MWh/t	2,035,257 t/yr	176,979 ha	1,752,000 t/yr	194,667 ha

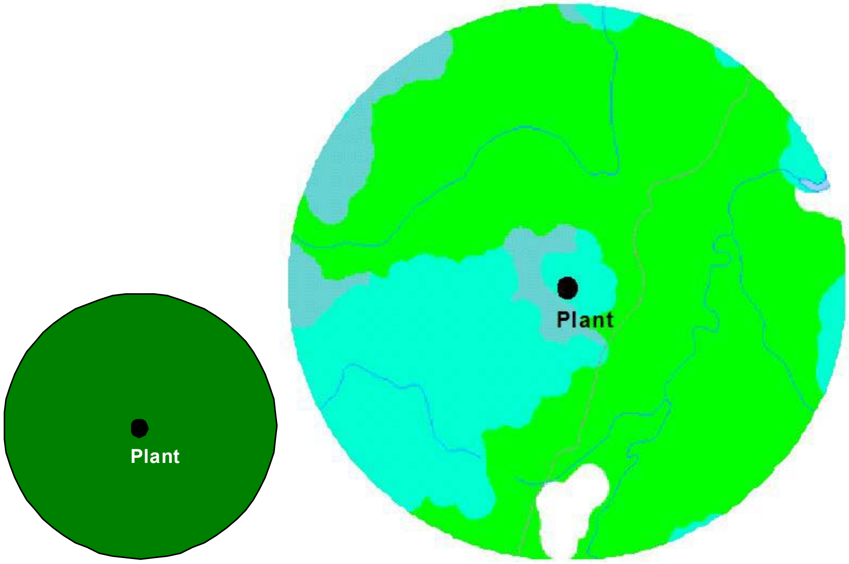


Figure 4.2.1

Left circle: biomass is concentrated around the plant

Right circle: fourfold area increase due to patchy availability of harvestable biomass

The smallest unit, with a capacity of 1 MW, would require 17.3 km² of forested area to harvest 15,560 tonnes of wood per year. Concentrated around the plant, this would be a circle with a radius of 2.3 km, or a mean transport distance of about 1.7 km. However, a much more widely spread availability of biomass, and more indirect transportation routes, are a far more likely scenario. Figure 4.2.1 illustrates this, suggesting a fourfold increase in land area required to collect the biomass. In the case of wood, it would still have to be assumed that this area is fully dedicated to serving the plant, and that no other uses of the wood available here are allowed if the harvest is to be sustainable over a long time. With this still generous assumption, a forest area of 6,916 ha (4 x 1,729 ha) would be required for a 1 MW plant, and the mean transport distance is now assumed to be 80% of the radius, i.e. 3.8 km. For a 10 MW plant, this would increase to 10.3 km, and for a 60 MW plant the estimated mean transport distance would exceed 23 km. For switchgrass as a feedstock, the use of unimproved farmland is suggested in Levelton 1999. In Ontario, this represents about 25% of total available farmland in the province. So if the plant was located in an agricultural area, the above assumption of a fourfold increase in land area required to provide for the amounts needed to feed the plant seems to work out the same way as for wood as a feedstock.

A report examining switchgrass use for energy purposes in Kansas determined the transportation cost of switchgrass as US$5.56 per tonne, assuming an average transport distance of 12 miles from the field to the plant and a load of 20 tonnes per trailer [King 1999, p.64]. Converting this to Canadian dollars (rate: C$0.72 per US$), this would correspond to a cost of $0.43 per km-tonne. Another U.S. report from 1999 provides transportation cost data for various states as between US$0.25 to $0.28 per km-tonne [USDA 2003]. The higher price (converted to C$0.39/t,km) is assumed for transporting wood in Table 4.2.2 as the data is already several years old, and also in light of recent tendencies towards higher fuel prices in North America. In addition to these transportation costs, chipping would be required for wooden feedstocks (possibly at the site where it is collected), while pelletization - at least for some of the feedstock - would be required to enable storage of switchgrass over longer periods of time. Chipping will consume about 0.068 kg of fuel per dry tonne of wood (see Chapter 2.4.6; at $0.95 per litre this is about 7.3 cents per tonne, excluding capital and operating costs), while the cost of pelletization was estimated to be C$25 to 40 per tonne [REAP 2000].

Table 4.2.2 Comparison of Switchgrass and Wood as Feedstocks for a Steam Plant, with Respect to Transport Cost (based on Table 4.2.1; 25% of land area assumed available for biomass feedstock cultivation and harvesting; fourfold land area required)

	Switchgrass		Short-Rotation Forestry Wood	
Plant Size	Mean Distance	Transport Cost	Mean Distance	Transport Cost
1 MW	3.6 km	$1.45/t	3.8 km	$1.46/t
10 MW	9.8 km	$3.92/t	10.3 km	$4.02/t
60 MW	21.9 km	$8.76/t	23.2 km	$9.05/t
200 MW	38.0 km	$16.34/t	39.8 km	$15.52/t

Biomass feedstock costs were estimated to be between U.S.$1.7 and $3.0 per GJ in the study underlying Chapter 2.3 (hydrogen). This corresponds to a cost of C$48 to $85 per tonne. The lower price would allow production of hydrogen at a price of US$7.2 per GJ, which compares to hydrogen from natural gas at an estimated price of US$5-9/GJ. [Hamelinck 2001]. On the other hand, a CHP plant requires wood for a price of about $15 to $30 per tonne [NBC 2003], which indicates that the 60 MW plant may become an upper limit for biomass-fired plants. This cost range is also confirmed for using fuel wood for ethanol production [NRCan 1994]. According to the same source, short rotation plantations yield one tonne of wood for a price between US$11 and $63[7], and switchgrass can be harvested at prices between US$19 and 36 per tonne. These prices illustrate the difficulty of using energy crops for electricity or biofuel production. As transport distances increase with increasing plant size, it may only be economically viable to use biomass feedstocks that have a zero extra cost, i.e. if they are waste products, rather than specially grown feedstocks. Note that the above cases assume fairly high biomass densities because of the use of energy crops, whereas roadside slash or other forestry waste may be more dispersed.

Transportation of biomass feedstocks over longer distances by rail or ship may be economically viable, but extra handling cost for loading and unloading has to be taken into account. As truck transport cannot exceed a limit of about 50 km without making the feedstock too expensive for most applications, this severely limits the use of biomass in areas where no cheap long-distance transportation option exists, and confines activity to areas close to waterways and railway lines. Other sources confirm this range, citing 70 km as the upper bound for transporting biomass cost-effectively [Concawe 2002, p.13].

The above financial analysis is not exhaustive, but provides some general indications and priorities for different biomass use options:

- Small-scale systems of between 1 and 10 MW may be preferable over large, central plants that require substantial biomass inputs, as truck transport distances over 50 km will make the biomass fuel unaffordable, unless it comes at a zero cost.
- The use of energy crops, as opposed to no-cost biomass residues, requires that these are grown at very low prices in order to allow for biobased electricity or fuels to be competitive.
- Especially for the scenario used for biodiesel in Chapter 2.2, the long assumed transport distances of up to 400 km to the plant for canola oilseed may not be realistic, unless most of the distance can be bridged using transportation by train or ship.

For waste treatment, the separate collection of different waste fractions often causes considerable extra costs. However, where landfills or other treatment options are distant, it may be worthwhile examining the options to build smaller, more local, treatment facilities, such as biowaste digestion with composting. From a purely economic point of view, this is the second best option after landfilling, and possibly the best option if landfills are very far removed, or where (even more expensive) incineration is the only other option.

Another aspect to be considered is to which extent by-products of certain processes can be used if the feedstock is increasingly used for energy purposes. For example, making ethanol from corn produces animal feed as a by-product. Ingeldew 2002 (quoted in Coxworth 2003) determined that half the U.S. annual corn yield would be required to make enough ethanol for a 10% ethanol standard throughout the United States. This would lead to a significant expansion of fodder production from ethanol plants, and a likely collapse of the market value of the animal food. The residue could then be used for energy, rather than as animal feed, but as ethanol is already more expensive to make than gasoline, this would make the fuel even less commercially attractive. The limit for the use of grains for ethanol production is estimated to lie at about 15% of the volume of grain/feed markets [Coxworth 2003, p.18].

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[7] Prices between $60 and $134 per tonne are suggested for willow in REAP 2003

Chapter 5 Results and Recommendations

The initial question this report was meant to answer was, if I have a tonne of biomass, how would I want to use it in order to maximise GHG emission reductions? However, it is important to know whether the biomass is the residue of another process, or an energy crop. If it is an energy crop, the question should be reworded, saying “If I have a hectare of land, how would I want to use it in order to maximise GHG emission reductions?” The following general findings are therefore based on two separate rankings of feedstock-to-product threads, one based on emission reductions per hectare of land, and one for the feedstocks that can be used for different threads.

Finding No. 1: Displacing fuels is better than displacing electricity.
The main parameter that determines how much CO_2 biomass is displaced by the carbon that is released in the conventional process chain. For example, electricity is often made with low-carbon fuels, such as natural gas, or even with renewable resources that have next to no GHG emissions impacts. Even when coal-fired generation is displaced, the benefits can scarcely compete with other options. Directly displacing fossil fuels in non-power applications, such as heating oil or natural gas for heating, or transportation fuels, is the better alternative since a maximum of carbon is displaced from combusting the fossil fuel in an engine or burner, as well as the emissions linked to its production.

Finding No. 2: CHP beats all other options in terms of reduced crude oil consumption.
Modelled as displacing either natural gas or heating oil for heating, plus electricity from the grid, CHP was found to displace the largest amount of barrel-of-crude-oil equivalents of all biomass use options examined. This suggests that if energy security concerns are an important focus besides GHG emission reduction benefits, CHP should be a preferred option.

Finding No. 3: Biomass distribution suggests small-scale systems.
One disadvantage of biomass is that it is often dispersed and that local concentrations may not be sufficient to allow for large-scale plants with the resulting economies of scale. The same applies to the long-term availability of a biomass supply, as a large-scale plant will require long-term contracts for biomass fuel, which may not be easily obtained. In addition, biomass in areas where large amounts are available at a close distance may already be used, such as at the Williams Lake power plant in BC. A maximum truck transport distance of 50 to 70 km seems a reasonable limitation for the collection of biomass, and a plant size of 1-10 MW seems a good match for such short transport distances.

Finding No. 4: For energy crops, yields are the determining factor.
When compared on a per-hectare basis, the highest yielding crops will deliver the highest emission reductions. Technology becomes a side issue, and a clear prioritization can be established that prefers switchgrass, with high yields of around 11.5 t/ha, over other options, such as grains or oilseeds, with much lower yields. This puts oil-based fuels, such as biodiesel, at a disadvantage as compared to ethanol, which can be made using most of the biomass of lignocellulosic plants. However, wheat-based ethanol also has very low emission reduction benefits, similar to canola-based biodiesel.

Finding No. 5: Using biodiesel as an additive could be an alternative that has been overlooked so far.
If it can be confirmed that biodiesel improves fuel efficiency when added to conventional diesel in small quantities, the GHG emission reductions from using biodiesel are multiplied and exceed all other options by an order of magnitude. Mixing 0.5% biodiesel into conventional diesel could be achieved using waste animal fat and used cooking oils, without growing additional canola oilseed for this purpose.

Finding No. 6: Hydrogen from biomass could become an option - maybe.
If society moves towards a hydrogen-based economy, biomass may become one of the sources to produce hydrogen. However, the requirement to use small-scale plants due to the local availability of biomass resources will reduce the efficiency of the process and may reduce hydrogen yields in comparison to the example modelled in Chapter 2.3. It is not clear how these developments will affect the price of hydrogen from biomass in the future. So far, this technology is not commercially available or viable.

Finding No. 7: Landfill gas capture may make landfilling the most preferable biowaste treatment option.
Large amounts of biomass remain sequestered inside the body of a landfill, inaccessible for biological transformation. This makes landfilling with gas collection the most attractive option for biowaste treatment.

Finding No. 8: The background power mix is not the main factor determining which biomass use should be preferred.
Regional differences in terms of the background power mix to be displaced were modelled, and showed that especially the emission reduction benefits from electricity-only options are approaching zero when a low-emission grid electricity mix is displaced. However, the ranking of most other biomass use options was found to be very robust towards the background power mix. The findings of this report are therefore nearly universal. Regional difference may, however, occur – less due to the type of existing power generation, but possibly due to differing yields for different types of biomass energy crops.

A ranking of biomass use options to optimise emission reduction benefits can now be established, either based on land use or on per-tonne inputs.

Ranking of Biomass Use Options Based on Land Use

1. Switchgrass to ethanol (future: wood, or possibly switchgrass, to hydrogen)
2. Wood to CHP (future: wood to hydrogen)
3. Afforestation (unless very high sustained growth rates can be achieved)
4. Corn to ethanol
5. Wood to electricity (unless very low-emission source is displaced on the grid)
6. Wheat to ethanol
7. Canola to biodiesel

Given one hectare of land, the best option to reduce GHG emissions may simply be afforestation or reforestation. Certainly a cheap option to sequester CO_2 from the air, trees can perform better than many other options over a 50-year period. This also avoids the issues related to the high cost to grow and transport energy crops. However, unless the sequestration rates of the tree plantation above average, high yielding plants, such as switchgrass and short-rotation forestry crops, are the most attractive options in terms of GHG emission reductions. Both can be used to make hydrogen (only wood was assessed in this study) and ethanol (only switchgrass was assessed in this study; ethanol from softwood is still an experimental process). CHP is next, as it partly displaces natural gas or heating oil. Corn ethanol may compete with CHP if the electricity used to produce the ethanol has low emissions. Producing electricity alone from wood does also not deliver high emission reductions, unless it displaces lots of coal-based generation on the grid (for example, if used for co-firing in coal-based power plants). Biodiesel emerges as a very ineffective option if made from virgin canola oil, as does ethanol from wheat, due to very low yields per hectare.

Ranking of Biomass Use Options Based on Emission Reductions per Tonne of Input

a) Wood and Wood waste

1. CHP (or hydrogen in the future)
2. Large steam power
3. Small steam power
4. Gasification and Brayton Cycle
5. Bio-oil

Among the options examined, CHP fared best and displaced most emissions per tonne of input. Wood-based hydrogen (displacing natural gas) displaces about the same amount of emissions, but the technology is not currently available, and questions remain about its economic viability if produced in small-scale plants. Large steam power comes in next, but only at about half the amount of reductions. It outperforms smaller systems due to its better efficiency, but may only be applicable in few cases due to the limited availability of large amounts of biomass close to a given plant location. After that, small steam power, the Brayton Cycle and gasification produce relatively small emission reduction benefits, especially if displacing low-emission energy sources on the grid. Last, bio-oil has the smallest emission reduction benefits when converted to electricity. The oil is also very rich in water, which limits options to use it.

b) Switchgrass and Other Lignocellulosics

1. Ethanol
2. Hydrogen from ethanol

Switchgrass represents a range of other feedstocks, such as hay, straw and corn stover, with very similar life-cycle GHG analysis results. Only two options were examined for switchgrass, and a comparison with pelletized switchgrass for space heating would add to this study. Although hydrogen is used in fuel cells with twice the efficiency of internal combustion engines, the displacement of emissions from hydrogen made from natural gas is far smaller than that from ethanol displacing gasoline. On the other hand, gasification of switchgrass to make hydrogen may be a better option, but has not been examined in this report.

c) Waste Vegetable Oil and Animal Fat

1. Biodiesel as an additive (0.5%)
2. Biodiesel (10% to 100%)

For waste vegetable oil and animal fat, making biodiesel is one option to reduce GHG emission reductions, but this resource is limited, and making extra biodiesel would require using much more expensive virgin canola or soybean oil. The potential to use biodiesel as a diesel fuel additive in small quantities causing an overall increase in fuel efficiency deserves further consideration as it bears the potential of substantially increased emission reduction benefits.

d) Biowaste

Separately collected biowaste (default)	Separately collected biowaste (low methane option)	Mixed biowaste, incl. paper
1. Landfilling with gas collection and electricity generation	1. Landfilling with gas collection and electricity generation	1. Landfilling with gas collection and electricity generation
2. Landfilling with gas collection and flaring	2. Landfilling with gas collection and flaring	2. Landfilling with gas collection and flaring
3. Incineration	3. Digestion with composting	3. Incineration
4. Digestion with composting	4. Incineration	4. Digestion with composting
5. Open landfilling	5. Composting	5. Composting
6. Composting	6. Open landfilling	6. Open landfilling

If most of the methane emissions are captured then landfilling with gas collection (gas flared or used to generate electricity) is the best waste management option for biowaste, out of landfilling, composting, digestion with composting, and incineration. Although some of the other treatment options also generate surplus electricity, or produce compost which displaces artificial fertilizer, the sequestration effect in landfills is far larger than these emission reductions. Only if a large portion of the landfill gas is not captured by the collection system, incineration becomes the best option to reduce GHG emissions.

The ranking has been established for a biowaste composition as obtained through separate collection, which will exclude paper waste. Mixed biowaste, on the other hand, represents the organic fraction of MSW, which will include substantial amounts of paper. The easily biodegradable paper causes extra methane emissions in the landfill, which makes open landfilling the least desirable treatment option. On the other hand, composting takes this space if paper is left out, as it enhances biological activity, and thus also methane emissions from pockets of anaerobic activity in the compost. If, however, methane emissions from composting or digestion with composting can be reduced to 30% of default emissions, through process optimization and biofilters, then digestion with composting moves up ahead of incineration as a waste management option. Incineration may prevail in case the landfill gas capturing system is ineffective, and a large amount of methane is emitted unoxidized. In many case, cost and size considerations may play out against using incineration. In those cases, digestion with composting systems would be the second cheapest option, allowing for small-scale applications of around 10,000 wet tonnes per year, and landfilling remains the least costly measure. If no landfill is available close to where the waste is collected, transportation costs may shift the cost balance towards the small-scale digestion systems.

Other environmental impacts: Positive or negative environmental impacts of using biomass instead of fossil fuels other than GHG emissions were not assessed in detail for this analysis. Whereas this may seem to limit the validity of results obtained, the literature indicates that there are no significant differences between fossil and biofuels when several environmental impact categories are compared. For example, Figure 5.1 is taken from a European [EU 2000] study and illustrates that only eutrophication is markedly higher for willow used for heat generation (compared to light oil as a heat source). Depending on how much fertiliser is used or allocated to the biomass feedstock, this parameter will increase or decrease. Results are given for an amount of 100 TJ - equivalent to the average heat requirement of 4,000 inhabitants of Europe in one year. The amount of extra eutrophication caused by substituting willow for light oil is equal to the amount which about 250 European citizens would on average cause in one year.

Acidification and summer smog impacts are very similar for both biofuels and fossil fuels, whereas GHG emission reductions and fossil fuel displacement are high for all types of biomass. Nitrous oxide emissions are included here and refer to emissions due to fertiliser use. These are seen as ozone forming, but the science is not well enough established to describe the exact role of nitrous oxide in ozone formation. Likewise, “human toxicity” is not a well established evaluation criterion. The toxicological impact of a substance is measured in relation to how many m³ of the environmental medium (air, water or soil) will bring the emission to a level with no toxic effect, using the HRC (human reference concentration), i.e. the highest concentration of the substance in the inhaled air expected to give no effect on humans on life-long inhalation under standard conditions. These two last criteria were not included in the final analysis by the original authors because of data uncertainty.

While the combined environmental impacts of biomass feedstocks as compared to fossil fuels are not always clearly superior, these assessments suggest that optimising GHG emission benefits will not create any other undue environmental impacts that would question the benefit of biomass use.

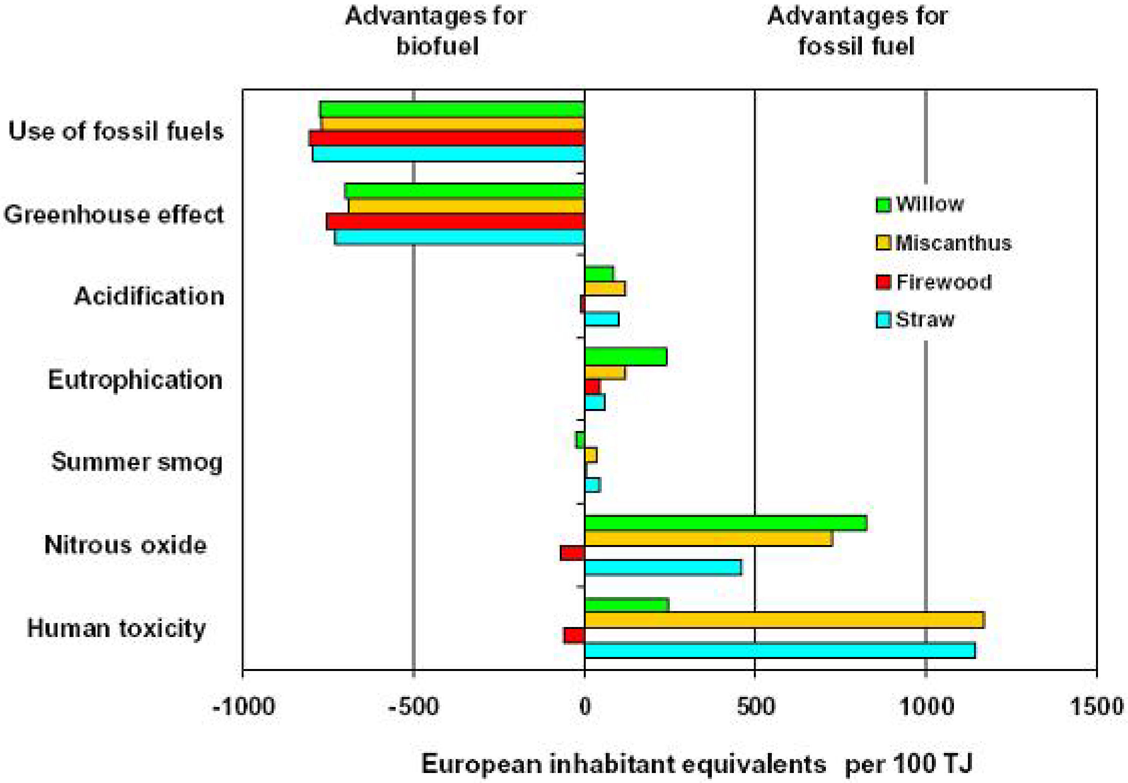

Figure 5.1 **Environmental Impacts of Heat Production from Four Biomass Feedstocks as Compared to Fossil Fuels** [EU 2000, p. 64]

Outlook

This study has analysed a large number of biomass feedstock-to-product threads. For the first time, GHG emissions were quantified based on one tonne of input, instead of based on the energy contained in products. This has enabled the comparison of different threads with the same feedstock, assessing GHG emission reductions achieved with respect to resources invested.

Some questions remain unanswered and could be further developed if additional funding for this study could be found:

- Comparison between manure management options: digestion vs. direct application of manure
- Heat-only options: wood pellets, compressed switchgrass pellets, vegetable oil etc. and their GHG benefits, especially in a context where small amounts are transported by truck to homes for decentralised combustion
- Black liquor: both Sweden and the USA are actively working on this resource, with the idea of greatly increasing the amount of energy over what is now achieved in conventional pulp mills. The Canadian resource base is large (around 24 million tonne of dry matter).
- Chemical products: what is the GHG impact of making plastics, such as polylactic acid, from crops instead of from crude oil-based resources? For example, if plastics derived from canola-based lipids are used in cars to reduce weight and therewith increase fuel efficiency, effects may be larger than those of biodiesel from canola.
- How does ethanol from wood produced with gasification – which is generally seen as being more energy-efficient than fermentation and distillation - compare to other wood use options?
- What are the benefits of using switchgrass instead of wood to produce hydrogen through gasification?
- How does methanol compare to other biofuel options?
- How does the emerging “biorefinery” concept perform with respect to energy and GHG balances? For example, the production of polymers to make plastics from biomass and the use of residual biomass for energy production could yield benefits that cannot be deducted from the materials reviewed for this study.

In addition, questions relating to GHG offset costing are becoming more and more relevant: determining the price of a tonne of CO_2e emission reduction from different biomass use options would be a useful tool for government policy, and could at the same time identify opportunities for the private sector to be considered for investment.

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