

**THE ADDITION OF COAL AND BIOMASS TO
HYDROGEN PATHWAYS TO GHGENIUS**

Prepared For:

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EXECUTIVE SUMMARY

The GHGenius model has been developed for Natural Resources Canada over the past four years. It is based on the 1998 version of Dr. Mark Delucchi's Lifecycle Emissions Model (LEM). GHGenius is capable of analyzing the emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels.

The model is capable of analyzing the emissions from conventional and alternative fuelled internal combustion engines for light duty vehicles, for class 8 heavy-duty trucks, for urban buses and for a combination of buses and trucks, and for light duty battery powered electric vehicles. There are currently 79 vehicle and fuel combinations possible with the model.

The hydrogen pathways currently in the model include light duty internal combustion vehicles:

- Hydrogen from electrolysis or reforming natural gas (compressed or liquefied),
- Hythane (a mixture of natural gas and hydrogen),

For light duty fuel cell vehicles the hydrogen pathways that the model is capable of analyzing include:

- Hydrogen from electrolysis (compressed or liquefied),
- Hydrogen from reforming natural gas, methanol, any ethanol, liquid petroleum gases, gasoline, or FT Distillate,
- Hydrogen from nuclear thermo cracking of water,

For heavy duty internal combustion vehicles the fuels that can be analyzed include:

- Hydrogen from electrolysis (compressed or liquefied),
- Hydrogen from reforming natural gas,
- Hythane, (a mixture of natural gas and hydrogen from reforming natural gas).

For heavy duty fuel cell applications the fuels that are included in the model are:

- Hydrogen from electrolysis (compressed or liquefied),
- Hydrogen from reforming natural gas, methanol, any ethanol, liquid petroleum gases, gasoline, FTD,
- Hydrogen from nuclear thermo cracking of water.

The goal of this work was to add two new hydrogen pathways, coal to hydrogen and biomass to hydrogen. The new pathways are fully integrated into GHGenius, for each fuel cycle the fuel will be used for both light duty and heavy duty applications fuel cell applications so the full cycle results for sheets AC, AD, Cost LDV, Cost HDV, Summary LDV, and Summary HDV will include both light duty and heavy duty results. Sheets K and I have also been modified to include the new fuel cycles. All of the existing functionality of the model has been retained.

Both of these new pathways are likely to involve large individual plants. The hydrogen will be transported from these plants to the locations where it will be dispensed. Previous versions of GHGenius handled the transportation of hydrogen (either compressed or liquid) as if it were a liquid fuel with only 20% more energy being used. This has been changed in this new version of GHGenius. There are different and specific energy consumed factors for compressed and liquid hydrogen. The user now has much greater flexibility to model the way that hydrogen is distributed. Combinations of transportation

modes such as pipeline and truck can now be specified. On site production can also be modelled.

GHGenius contains a number of pathways for the production of hydrogen. These include electrolysis, steam methane reforming, reforming of liquid fuels such as methanol, ethanol, LPG, gasoline and FT distillates. The concept of the conversion of coal to hydrogen is similar to these other pathways. The coal is first gasified to produce hydrogen, carbon monoxide and carbon dioxide, the carbon monoxide is shifted to produce more hydrogen and carbon dioxide and then there is a purification step to concentrate the hydrogen.

The full lifecycle GHG emissions for hydrogen produced from coal in Central Canada are shown in the following table. The hydrogen is used in a light duty fuel cell vehicle. For comparison the emissions from gasoline used in internal combustion engine vehicles and hydrogen produced from SMR are shown. If the hydrogen were used in a heavy-duty fuel cell vehicle the GHG emissions would be about the same as the diesel engine vehicle. The difference is a result of the higher efficiency of the diesel engine versus the gasoline engine. Carbon sequestration, which may be technically feasible with this technology is not included here.

Table ES-1 Full Lifecycle GHG Emission Results, Coal to Hydrogen LDVs, 2003

	Gasoline	Hydrogen	Hydrogen
Fuel specification	113ppm S	CH ₂	CH ₂
Feedstock	Crude oil	NG100	Coal
	Grams/mile	Grams/mile	Grams/mile
Vehicle operation	339.8	0.0	0.0
Fuel dispensing	0.5	8.9	8.9
Fuel storage and distribution	6.3	24.1	24.1
Fuel production	63.2	189.1	391.6
Feedstock transport	0.9	8.2	9.6
Feedstock and fertilizer production	49.7	13.8	3.6
CH ₄ and CO ₂ leaks and flares	14.2	15.6	9.0
Emissions displaced by co-products	0.0	0.0	-14.3
Sub total (fuelcycle)	474.6	259.7	432.5
% Changes (fuelcycle)	2.9	-43.7	-6.3
Vehicle assembly and transport	8.1	8.9	8.9
Materials in vehicles (incl. storage) and lube oil production/use	74.0	80.7	80.7
Grand total	556.8	349.3	522.1
% Changes to RFG (grand total)	-0.0	-37.3	-6.2

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.

The full lifecycle GHG emissions for hydrogen produced from biomass (short rotation forestry) in Central Canada are shown in the following table. The hydrogen is used in a fuel

cell vehicle. For comparison the emissions from gasoline used in internal combustion engine vehicles and hydrogen produced from SMR are shown. Net GHG emissions from the fuel cycle are almost completely eliminated under this scenario.

Table ES-2 Full Lifecycle GHG Emission Results, Biomass to Hydrogen LDVs, 2003

	Gasoline	Hydrogen	Hydrogen
Fuel specification	113ppm S	CH ₂	CH ₂
Feedstock	Crude oil	NG100	Short Rotation Forests
	Grams/mile	Grams/mile	Grams/mile
Vehicle operation	339.8	0.0	0.03
Fuel dispensing	0.5	8.9	8.9
Fuel storage and distribution	6.3	24.1	24.1
Fuel production	63.2	189.1	5.7
Feedstock transport	0.9	8.2	1.8
Feedstock and fertilizer production	49.7	13.8	-33.6
CH ₄ and CO ₂ leaks and flares	14.2	15.6	0.0
Emissions displaced by co-products	0.0	0.0	0.0
Sub total (fuelcycle)	474.6	259.7	6.8
% Changes (fuelcycle)	2.9	-43.7	-98.5
Vehicle assembly and transport	8.1	9.0	8.9
Materials in vehicles (incl. storage) and lube oil production/use	74.0	80.7	80.7
Grand total	556.8	349.3	96.4
% Changes to RFG (grand total)	-0.0	-37.3	-82.7

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1. INTRODUCTION

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GHGenius is capable of estimating life cycle emissions of the primary greenhouse gases and the criteria pollutants from combustion sources. The specific gases that are included in the model include:

- Carbon dioxide (CO₂),
- Methane (CH₄),
- Nitrous oxide (N₂O),
- Chlorofluorocarbons (CFC-12),
- Hydro fluorocarbons (HFC-134a),
- The CO₂-equivalent of all of the pollutants above.
- Carbon monoxide (CO),
- Nitrogen oxides (NO_x),
- Non-methane organic compounds (NMOCs), weighted by their ozone forming potential,
- Sulfur dioxide (SO₂),
- Total particulate matter.

The model is capable of analyzing the emissions from conventional and alternative fuelled internal combustion engines for light duty vehicles, for class 8 heavy-duty trucks, for urban buses and for a combination of buses and trucks, and for light duty battery powered electric vehicles. There are currently 79 vehicle and fuel combinations possible with the model.

The hydrogen pathways currently in the model include light duty internal combustion vehicles:

- Hydrogen from electrolysis or reforming natural gas,
- Hydrogen from electrolysis or reforming natural gas (compressed or liquefied).

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- Hydrogen from nuclear thermo cracking of water.

GHGenius can predict emissions for past, present and future years through to 2050 using historical data or correlations for changes in energy and process parameters with time that are stored in the model. The fuel cycle segments considered in the model are as follows:

- **Vehicle Operation**
Emissions associated with the use of the fuel in the vehicle. Includes all greenhouse gases.
- **Fuel Dispensing at the Retail Level**
Emissions associated with the transfer of the fuel at a service station from storage into the vehicles. Includes electricity for pumping, fugitive emissions and spills.
- **Fuel Storage and Distribution at all Stages**
Emissions associated with storage and handling of fuel products at terminals, bulk plants and service stations. Includes storage emissions, electricity for pumping, space heating and lighting.
- **Fuel Production (as in production from raw materials)**
Direct and indirect emissions associated with conversion of the feedstock into a saleable fuel product. Includes process emissions, combustion emissions for process heat/steam, electricity generation, fugitive emissions and emissions from the life cycle of chemicals used for fuel production cycles.
- **Feedstock Transport**
Direct and indirect emissions from transport of feedstock, including 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.
- **Feedstock Production and Recovery**
Direct and indirect emissions from recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, upstream processing prior to transmission, and mining.
- **Fertilizer Manufacture**
Direct and indirect life cycle emissions from fertilizers, and pesticides used for feedstock production, including raw material recovery, transport and manufacturing of chemicals. This is not included if there is no fertilizer associated with the fuel pathway.
- **Land use changes and cultivation associated with biomass derived fuels**
Emissions associated with the change in the land use in cultivation of crops, including N₂O from application of fertilizer, changes in soil carbon and biomass, methane emissions from soil and energy used for land cultivation.
- **Carbon in Fuel from Air**
Carbon dioxide emissions credit arising from use of a renewable carbon source that obtains carbon from the air.
- **Leaks and flaring of greenhouse gases associated with production of oil and gas**
Fugitive hydrocarbon emissions and flaring emissions associated with oil and gas production.
- **Emissions displaced by co-products of alternative fuels**
Emissions displaced by co-products of various pathways. System expansion is used to determine displacement ratios for co-products from biomass pathways.
- **Vehicle assembly and transport**

Emissions associated with the manufacture and transport of the vehicle to the point of sale, amortized over the life of the vehicle.

- Materials used in the vehicles

Emissions from the manufacture of the materials used to manufacture the vehicle, amortized over the life of the vehicle. Includes lube oil production and losses from air conditioning systems.

GHGenius uses mostly US units of measurements. The results in this report are presented in the units that they are produced in by the model. Model inputs specified in the report are given in the units that the model requires. Where possible some input data is also presented in metric units.

The goal of this work is to add two new hydrogen pathways, coal to hydrogen and biomass to hydrogen. The new pathways are fully integrated into GHGenius, for each fuel cycle the fuel will be used for both light duty and heavy duty applications fuel cell applications so the full cycle results for sheets AC, AD, Cost LDV, Cost HDV, Summary LDV, and Summary HDV will include both light duty and heavy duty results. Sheets K and I will also be modified to include the new fuel cycles. All of the existing functionality of the model will be retained.

Both of these new pathways are likely to involve large individual plants. The hydrogen will be transported from these plants to the locations where it will be dispensed. Previous versions of GHGenius handled the transportation of hydrogen (either compressed or liquid) as if it were a liquid fuel with only 20% more energy being used. This has been changed in this new version of GHGenius. There are different and specific energy consumed factors for compressed and liquid hydrogen. The user now has much greater flexibility to model the way that hydrogen is distributed. Combinations of transportation modes such as pipeline and truck can now be specified. On site production can also be modelled.

The version of GHGenius that has been developed along with this report is version 2.3.

2. HYDROGEN DISTRIBUTION AND TRANSPORTATION

The low density of hydrogen makes the transportation of hydrogen a challenge. Today hydrogen is moved by pipeline in a few locations around the world. It is also liquefied to increase the density to make the truck transportation more realistic and feasible for longer distances. There is also work underway to increase the pressure that hydrogen can be stored and transported at to improve the feasibility of that supply option. The volumetric density of hydrogen in various forms is summarized and compared to gasoline in the following table.

Table 2-1 Hydrogen Density

	Compressed Hydrogen, 5,000 psi	Compressed Hydrogen, 10,000 psi	Liquid Hydrogen	Gasoline
Weight of 1 M ³	23 kg	40 kg	71 kg	730 kg
Energy of 1 M ³ , million BTU	3.09	5.37	9.53	32.12
Energy of 1 M ³ , GJ	2.92	5.07	9.00	30.35

2.1 PIPELINES

Hydrogen can be moved by pipeline where there are sufficient volumes to do so economically. The previous version of GHGenius was able to move hydrogen by pipeline and the energy required was a function of the distance involved. This version of GHGenius has the added flexibility of allowing hydrogen to move by pipeline and by other modes either in parallel or in series. The user can now choose the pipeline distance and the fraction moved by pipeline on the Input Sheet. Other modes of transportation can also be chosen simultaneously. The situation where hydrogen is pipelined from the production facility to a terminal and then distributed from the terminal to a service station can now be modelled. This data is now chosen by the user on the Input Sheet in rows 79 to 89 and columns Q and R.

2.2 LIQUID HYDROGEN

GHGenius has always been able to model the liquefaction and truck transport of liquid hydrogen. In previous versions of GHGenius, it had been assumed that the energy required for the transportation of liquid hydrogen was 20% higher than that for light petroleum products. This factor of 20% extra energy was applied to all modes of transportation and was derived from LEM. This factor was an assumption assigned by Delucchi. There is some data available on the transportation of liquid hydrogen that allows this factor to be estimated with higher precision.

Linde (1997) state that they have liquid hydrogen transportation containers available with volumetric capacities of 15,000, 41,000 and 53,000 litres. The largest container has a capacity similar to that of gasoline transportation trucks in Canada and the middle size is similar to gasoline trucks in the US. The weight of hydrogen transported, the payload, in each of these containers is only 1,000, 2,900 and 3,750 kg respectively. The payload of gasoline transported in a similar size of truck is an order of magnitude higher. The fuel that is consumed in delivering the fuel payload to the customer moves the weight of the truck both ways and the payload one way. If the weight of the truck and trailer is 40,000 kg then the liquid hydrogen payload contributes to only about 4.5% of the total fuel consumed

$(3,750/2*40,000 + 3,750)$ whereas the gasoline payload contributes to about 30% of the fuel consumed ($37,500/37,500+2*40000$). The energy consumption for hydrogen is therefore 666% of that of gasoline on a BTU/Tonne-mile basis.

Amos (1998) details the costs of storing and transporting hydrogen. In his transportation cost assumptions, he assumed that 4,082 kg of liquid hydrogen could be delivered by a truck and that the truck averaged 6 miles per gallon (39.4 l/100 km) for the round trip. This is equivalent to 9,280 BTU/Ton-mile based on the one-way distance that GHGenius uses. This is 475% of the value that is used for the transport of light petroleum products or 375% extra energy.

The value for the extra energy that has been used for version 2.3 of GHGenius is 400% based on these two examples. The energy required for transportation slowly decreases over time but at the same rate as it does for other fuels. The total energy required is therefore five times that for light petroleum products. It is assumed that not all liquid hydrogen trucks will be as large as Amos has assumed and that his estimate represents a best case scenario rather than an average scenario. This same value will be used for rail and shipment movements of liquid hydrogen. This probably overestimates the energy required for these modes but very little liquid hydrogen is moved by rail or barge today and these are not likely to significant transportation modes in the near future.

There is full flexibility in the model for mixed mode transport. The default values for liquid hydrogen are that 5% of the hydrogen is transported by rail 400 miles and then 100% of the hydrogen is transported by truck a further 100 miles. With this scenario 5% of the transportation energy is consumed in the rail stage and 95% in the truck transport. If onsite generation is to be modelled then the transportation distances should be set to zero on the Input Sheet rather than using the flag that was in the previous version of GHGenius.

2.3 COMPRESSED HYDROGEN

Compressed hydrogen faces similar but even larger challenges than liquid hydrogen due to its even lower density. Linde have steel tanker trucks for compressed hydrogen that are capable of a theoretical capacity of 300 kg and composite fibre wrapped flasks that can theoretically move 500 kg. Linde note that the effective capacity is less due to the pressure equalization of the customer tanks.

Amos assumed that 181 kg (400 pounds) could be transported by truck. Eliasson et al (2002) note that compressed hydrogen trucks in Europe can transport about 320 kg of hydrogen at 3000 psi (20 MPa) and that about 80% of that can be delivered to the customer. With technical developments they estimate that it should be possible to deliver 400 kg to a customer.

The energy requirements for truck transportation calculated by Amos are 22.6 times higher than that for liquid hydrogen or 210,400 BTU/Ton-mile. This is 108 times higher than the energy required for light petroleum products. Eliasson calculate that the energy requirement for compressed hydrogen is 48 times that of light petroleum products. The two values are actually quite close when the different quantities of hydrogen that each move are considered.

It is assumed that if hydrogen as a vehicle fuel is adopted and compressed hydrogen is moved by truck that there will be developments of the tanks so that 400 kg can be transported at a time. The value for extra energy that has been used for the model is therefore set at 50 times that of petroleum products. This value is extremely sensitive to the weight of hydrogen that can be transported.

There is full flexibility in the model for mixed mode transport. The default values for compressed hydrogen are that 100% of the hydrogen is transported by pipeline 300 miles (480 km) and then 100% of the hydrogen is transported by truck a further 100 miles (160 km). With this scenario 30% of the transportation energy is consumed in the pipeline stage and 70% in the truck transport. Onsite generation is now modelled by setting the transportation distances to zero on the Input Sheet.

3. COAL PRODUCTION

The data that is in GHGenius for emissions from coal production are based on data from the 1992 US Census. The model is structured such that emissions from coal production in other countries is calculated relative to US emissions. The relative emission factor for Canada has been set to 1.0 in previous versions of the model. Part of this work is to review data on the emissions from coal production in Canada and to update the model.

Canada has coal reserves of over eight billion tonnes. Canada produces about 70 million tonnes per year of coal, 40% of that is metallurgical coal, which is mostly exported. The other 60% of coal production is thermal coal which is mostly consumed domestically and it is augmented by about 24 million tonnes of coal imports.

There are twenty coalmines in Canada and their locations are summarized in the following table (Coal Association of Canada).

Table 3-1 Canadian Coal Mines

Province	Surface	Underground	Total
British Columbia	7	1	8
Alberta	8	--	8
Saskatchewan	3	--	3
New Brunswick	1	--	1
Total	19	1	20

The energy content of Canadian coal varies with the deposit. The typical energy contents are shown in the following table (NRCan, 1997). In GHGenius the coal used for fuel production has an energy content of 10,061 BTU/lb (23.5 GJ/tonne). While the current average for domestic use is lower than this it is likely that less lignite would be used for fuel production compared to electricity production so no change has been made to this value for Canada.

Figure 3-1 Energy Content Canadian Coal

Coal Type	Energy Content	Energy Content
Anthracite	27.70 GJ/tonne	11,870 BTU/lb.
Bituminous	27.70 GJ/tonne	11,870 BTU/lb.
Sub-bituminous	18.80 GJ/tonne	8,057 BTU/lb.
Lignite	14.40 GJ/tonne	6,170 BTU/lb.
Average Domestic use	22.20 GJ/tonne	9,515 BTU/lb.

There are three primary sources of emissions during the coal production process, the mining of the coal itself, methane emissions from the coal during the mining and transportation steps and the movement of the coal from the mine to the hydrogen production plant. These are discussed in the following sections.

3.1 ENERGY FOR MINING

Two of Canada's coal mining companies have filed reports with The Voluntary Challenge and Registry Inc., Fording Coal Limited (1999) report and Luscar Ltd (2002 Action Plan). Luscar accounts for about 50% of Canadian coal production and Fording for almost 30%. Both companies report their GHG emissions in terms of CO₂ equivalents per tonne of coal and Fording also provided their energy consumption per tonne of coal.

The energy for mining in the US is estimated based on 1992 Census data and is 140,600 BTU/Ton of coal for 1992 and there are small increases of about 0.15% per year programmed into the model. The energy estimates from the Fording VCR report are 495,000 BTU/Ton. This is 3.5 times the US average value. The Fording energy consumption values do not equate with their reported emission factors unfortunately. If this quantity of energy was used GHGenius would calculate higher GHG emissions than Fording report. One possible explanation is that some of the electricity used by Fording may be in BC where it would be produced from hydro.

The US energy consumption in the model produces GHG emissions of 14,640 gms CO₂ eq/Ton of coal when the model is set for Canada. In the following table, this is compared to the published GHG emission rates for Luscar, Fording, and a weighted average estimate for Canada. The weighted estimate is based on the coal production of Luscar and Fording and extrapolating that to the whole Canadian industry. The value of 1.71 has been used in GHGenius for the relative energy consumption between Canadian coalmines and US mines. This is probably a function of the different ratio of open pit mines to underground mines between Canada and the US.

Table 3-2 GHG Estimates for Canadian Coal Mining

	Gms CO ₂ eq/Ton	Relative to US
GHGenius for US energy consumption and Canadian electricity mix	14,620	1.0
Luscar VCR data	18,800	1.28
Fording VCR data	35,545	2.43
Weighted Average for Canada	25,075	1.71

3.2 METHANE EMISSIONS

There are emissions of methane associated with the production and transportation of coal. In GHGenius there are separate emission factors for underground and above ground mines and then factors which account for the rate of capture and utilization of the methane. The US data in GHGenius is based on information developed by the US Energy Information Administration. The model uses the same emission factors for all regions of the world.

The issue of methane emissions from coal mining and handling is discussed in the “Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual” (1996). An excerpt from that report is presented below.

The process of coal formation, commonly called coalification, inherently generates methane and other by-products. The formation of coal is a complex physio-chemical process occurring over millions of years. The degree of coalification (defined by the rank of the coal) determines the quantity of methane generated and, once generated, the amount of methane stored in the coal is controlled by the pressure and temperature of the coal seam and by other, less well-defined characteristics of the coal. The methane will remain stored in the coal until the pressure on the coal is reduced, which can occur through the erosion of overlying strata or the process of coal mining.

The amount of CH₄ generated during coal mining is primarily a function of coal rank and depth, gas content, and mining methods, as well as other factors such as moisture. Coal rank represents the differences in the stages of coal formation and depends on the pressure and temperature history of the coal seam; high coal ranks,

such as bituminous coal, contain more CH₄ than low coal ranks, such as lignite. Depth is important because it affects the pressure and temperature of the coal seam, which in turn determines how much CH₄ is generated during coal formation. If two coal seams have the same rank, the deeper seam will hold larger amounts of CH₄ because the pressure is greater at lower depths, all other things being equal. As a result, the methane emission factors for surface-mined coal are assumed to be lower than for underground mining.

In most underground mines, methane is removed by ventilating large quantities of air through the mine and exhausting this air (typically containing a concentration of 1 per cent methane or less) into the atmosphere. In some mines, however, more advanced methane recovery systems may be used to supplement the ventilation systems and ensure mine safety. These recovery systems typically produce a higher concentration product, ranging from 35 to 95 per cent methane. In some countries, some of this recovered methane is used as an energy source, while other countries vent it to the atmosphere. Recent technological innovations are increasing the amount of medium- or high-quality methane that can be recovered during coal mining and the options available to use it. Thus, methane emissions could be reduced from this source in the future.

In surface mines, exposed coal faces and surfaces, as well as areas of coal rubble created by blasting operations, are believed to be the major sources of methane. As in underground mines, however, emissions may come from the overburden (in limited cases where these strata contain gas), which is broken up during the mining process, and underlying strata, which may be fractured and destressed due to removal of the overburden. Because surface-mined coals are generally lower rank and less deeply buried, they do not tend to contain as much methane as underground-mined coals. Thus, emissions per tonne of coal mined are generally much lower for surface mines. Research is underway in the United States and elsewhere to increase the understanding of CH₄ emissions from surface mines (Kirchgessner et al., 1993; USGS, 1993).

A portion of the CH₄ emitted from coal mining comes from post-mining activities such as coal processing, transportation, and use. Coal processing involves the breaking, crushing, and thermal drying of coal, making it acceptable for sale. Methane is released mainly because the increased surface area allows more CH₄ to desorb from the coal. Transportation of the coal contributes to CH₄ emissions, because CH₄ desorbs directly from the coal to the atmosphere while in transit (e.g., in railroad cars).

Some methane is also released from coal waste piles and abandoned mines. Coal waste piles are comprised of rock and small amounts of coal that are produced during mining along with marketable coal. There are currently no emission measurements for this source. Emissions are believed to be low, however, because much of the methane would likely be emitted in the mine and the waste rock would have a low gas content compared to the coal being mined. Emissions from abandoned mines may come from unsealed shafts and from vents installed to prevent the build-up of methane in mines. There is very little information on the number of abandoned mines, and no data are currently available on emissions from these mines. Most available evidence indicates that methane flow rates decay rapidly once deep mine coal production ceases (Williams and Mitchell, 1992; Creedy, 1991).

Neither of the two Canadian companies report coal methane emissions in their VCR reports. These emissions are estimated by Environment Canada (Environment Canada, 2002) as

part of the national emission inventory. Environment Canada estimate net emissions of methane, that is after any of the gas is collected and utilized or flared. The Environment Canada value is built from the mine up and is based on estimates of the methane content of the coal from different regions of Canada. The average methane emission rate determined from the Environment Canada data is 580 grams per tonne (527 grams/Ton) of coal. In the emission inventory there is evidence that the emission rate from underground mines in BC is 15.75 times higher than the rate from the average surface mine. This is consistent with the data in the model from the EIA. In Canada there is one operating underground mine and 19 surface mines, assuming that the one mine also contributes 5% of the production then it is possible to solve for the average emission rate for underground mines and surface mines. The results and comparison to the original data in the model are shown in the following table.

Table 3-3 Methane Emission Rates

Mine Type	Original Model Value	Revised Values
	SCF/ton coal	SCF/ton coal
Underground mines	510	270
Surface mines	40	17

The values for Canada are lower than those originally in the model. The surface values should be lower since the Canadian value is after any mitigation effort whereas the US value is before an allowance is made for collection and utilization or flaring. There is little opportunity for mitigation at surface mines so the lower value can only be explained by a lower methane content of the Canadian coal.

The IPCC has some default values for making global estimates of methane emissions where more detailed country or mine specific data is not available. For underground mines, the range for the emission factors is 320 to 800 SCF/Ton and for surface mines, the range for the emission factors is 9.5 to 64 SCF/Ton. The values calculated from the Environment Canada emissions are low or at the low end of the range compared to these global estimates.

While GHG emissions from Canadian coalmines are higher than US mines for the actual mining process, the emissions of fugitive methane are lower than they are for US mines as a result of Canada's higher proportion of surface mines and the lower rank of the coal.

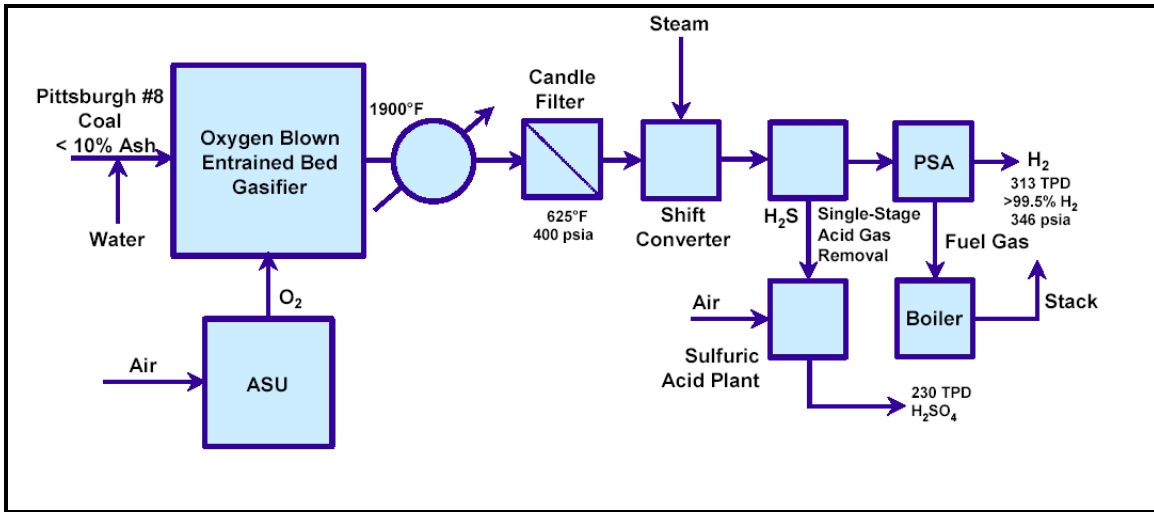
3.3 TRANSPORTATION EMISSIONS

For the production of most alternative fuels, the production facility is usually located close to the source of feedstock. In the case of hydrogen this may not be the ideal situation given the difficulties of transporting large amounts of hydrogen long distances. The base case in the model has been set so that the coal is transported by rail from western Canada to various locations in the country. The average distance is assumed to 1700 miles. There is no additional transportation by truck. This data can be changed on the Input Sheet in Column E, rows 65 to 75.

4. COAL TO HYDROGEN

GHGenius contains a number of pathways for the production of hydrogen. These include electrolysis, steam methane reforming, reforming of liquid fuels such as methanol, ethanol, LPG, gasoline and FT distillates. The concept of the conversion of coal to hydrogen is similar to these other pathways. The coal is first gasified to produce hydrogen, carbon monoxide and carbon dioxide, the carbon monoxide is shifted to produce more hydrogen and carbon dioxide and then there is a purification step to concentrate the hydrogen. The typical flow process is shown in the following figure (US DOE, 2002).

Figure 4-1 Coal to Hydrogen Block Flow Diagram



4.1 PRODUCTION TECHNOLOGY

There are several different production concepts that are being sold or developed. There are different manufacturers of the gasifiers themselves including Texaco, E-Gas and Shell. There are also different concepts being developed for the gas clean-up stages, including some that are very energy efficient.

Two hydrogen production concepts were found in the literature that use existing commercial technology and have fully developed mass balances. The first system uses a Texaco quench gasifier, conventional cold cleaning, water gas shift, and pressure swing adsorption with no carbon dioxide sequestration. This system was reviewed for the US DOE as the baseline for the study of advanced membrane technologies (Mitretek, 2002). The second system was described by Parsons for the US DOE (US DOE, 2002), it uses an E-Gas gasifier and conventional gas clean-up trains. The characteristics of each system are summarized in the following table.

Table 4-1 Coal to Hydrogen Systems

	Texaco Gasifier	E-Gas Gasifier
Coal Consumed	3000 T/D	2500 T/D
Coal Quality	12,450 BTU/lb.	12,450 BTU/lb.
Hydrogen Produced	131 MMSCFD	112 MMSCFD
Excess Power Produced	20.4 MW	38 MW
Coal Consumed per million BTU Hydrogen	135.5 lb.	132 lb.
Excess Electricity produced per million BTU Hydrogen	11 kWh	24 kWh
Cold Gas Efficiency	59.3%	59.9%
Overall Efficiency	63.0 %	64.4%

The Texaco gasifier has more installations around the world so that is the system that is modeled here. One adjustment that must be made is to adjust the coal quality to that in the model. The coal in the model has an energy content of 10,061 BTU/lb so the coal feed rate has been increased from 135.5 pounds to 167.7 pounds per million BTU of hydrogen to maintain the same energy efficiency as in the above table.

There was already a coal to methanol process in GHGenius. The emission factors on Sheet N for the coal to hydrogen process have been set the same as the methanol process. These were originally derived from EPA AP-42 and other sources. The emission factors are summarized and compared to those of a SMR unit in the following table. Many of the emissions are much higher with the coal system. These estimates may be based on old plant data when coal gasification systems were used to produce "town Gas" or "manufactured gas" prior to the widespread adoption of natural gas. New plants would have to meet existing emission control requirements and may have lower emissions of the criteria air contaminants closer to the emissions of the natural gas systems.

Table 4-2 Other Emissions Factors, Coal to Hydrogen Systems

Device or process	Hydrogen Production Plants	
	NG	Coal
Fuel or feedstock	Grams/million BTU consumed	Grams/million BTU consumed
Aldehydes (as HCHO) exhaust	n.e.	n.e.
Fuel evaporation or leakage	10.0	4.5
NMOC exhaust	0.2	88.2
Evaporation +NMOC exhaust	10.2	92.8
Carbon in evap. + NMOC exh.	7.4	54.6
Ozone-weighted total NMOC	1.4	58.1
CH ₄ (exhaust)	0.4	9.3
CO	8.0	7.6
N ₂ O	0.3	1.4
NO _x (NO ₂)	20.0	29.4
SO _x (SO ₂)	0.1	29.4
PM	3.0	5.9
PM10	0.1	4.4
PM2.5	n.e.	n.e.

Coal to hydrogen systems will be large facilities that will be located remotely from the location where the fuel is dispensed. The location will be close to the point of end use since it is more efficient to transport the coal than the hydrogen. The distribution of hydrogen will be as a liquid with the distances and transportation modes set on the input sheet (rows 79 to 89, columns Q and R) or through pipelines as a compressed gas. The model results presented here are for hydrogen distributed by pipeline a distance of 300 miles (480 km) by pipeline and 100 miles (160 km) by truck as compressed gas.

4.2 UPSTREAM EMISSIONS

The greenhouse gas emissions for the upstream portion of the coal to hydrogen lifecycle are presented in the following table. The results are for Western and Central Canada for the year 2003 and assumed a decentralized production facility. The source of the coal is different in the two scenarios, in the Central Canada case two thirds of the coal is imported from the US and one third is from Western Canada (the current distribution pattern) and for the western Canada scenario the coal is 99% from the west. The same coal and hydrogen distribution patterns have been used for each of the two scenarios. The results are compared to hydrogen production from SMR.

Coal from Canada requires more energy to produce but has lower methane emissions than US coal. This accounts for most of the differences in emissions for the two scenarios. The emissions from the hydrogen production stage are higher than from a SMR system because of the lower system efficiency and the different carbon to hydrogen content of the feedstocks. It has been assumed that the electricity produced by the system displaces electricity produced from a gas fired combined cycle system.

Table 4-3 Upstream GHG Emissions from Coal to Hydrogen-2003

Fuel	CH ₂	CH ₂	CH ₂
Feedstock	NG	Coal	Coal
		Central Canada	Western Canada
	Grams/million BTU	Grams/million BTU	Grams/million BTU
Fuel dispensing	3,637	3,637	3,597
Fuel distribution and storage	9,896	9,896	9,889
Fuel production	77,653	160,764	160,764
Feedstock transmission	3,384	3,961	3,956
Feedstock recovery	5,647	1,479	2,032
Land-use changes, cultivation	0	0	0
Fertilizer manufacture	0	0	0
Gas leaks and flares	5,423	3,695	958
CO ₂ , H ₂ S removed from NG	967	0	0
Emissions displaced	0	-5,876	-5,875
Total	106,606	177,555	175,321

4.3 LIFECYCLE EMISSIONS

The full lifecycle GHG emissions for hydrogen produced from coal in Central Canada are shown in the following table. The hydrogen is used in a fuel cell vehicle. For comparison the emissions from gasoline used in internal combustion engine vehicles and hydrogen produced from SMR are shown.

Table 4-4 Full Lifecycle GHG Emission Results, Coal to Hydrogen LDVs 2003

	Gasoline	Hydrogen	Hydrogen
Fuel specification	113ppm S	CH ₂	CH ₂
Feedstock	Crude oil	NG100	Coal
	Grams/mile	Grams/mile	Grams/mile
Vehicle operation	339.8	0.0	0.0
Fuel dispensing	0.5	8.9	8.9
Fuel storage and distribution	6.3	24.1	24.1
Fuel production	63.2	189.1	391.6
Feedstock transport	0.9	8.2	9.6
Feedstock and fertilizer production	49.7	13.8	3.6
CH ₄ and CO ₂ leaks and flares	14.2	15.6	9.0
Emissions displaced by co-products	0.0	0.0	-14.3
Sub total (fuelcycle)	474.6	259.7	432.5
% Changes (fuelcycle)	2.9	-43.7	-6.3
Vehicle assembly and transport	8.1	8.9	8.9
Materials in vehicles (incl. storage) and lube oil production/use	74.0	80.7	80.7
Grand total	556.8	349.3	522.1
% Changes to RFG (grand total)	-0.0	-37.3	-6.2

While it has not been added to the model, if the hydrogen produced from coal was used in an internal combustion engine instead of a fuel cell, the GHG emissions would be significantly higher than the current gasoline vehicle produces.

The results for heavy-duty buses are shown in the following table. In this case, the GHG emissions do not change compared to the diesel engine buses. The case of hydrogen from a SMR unit is also shown. There are three reasons for this, the first is that the fuel cell vehicles are now being compared to a diesel engine rather than a gasoline engine, secondly the buses only operate on the city cycle where the fuel cells are more efficient than they are on the highway cycle and finally the emissions associated with the vehicle production are different between the light and heavy duty vehicles.

Table 4-5 Full Lifecycle GHG Emission Results, Coal to Hydrogen HDVs 2003

	Diesel	Hydrogen	Hydrogen
Fuel specification	500 ppm S	CH ₂	CH ₂
Feedstock	Crude oil	NG100	Coal
	Grams/mile	Grams/mile	Grams/mile
Vehicle operation	2,134.7	0.2	0.2
Fuel dispensing	3.0	55.0	55.0
Fuel storage and distribution	33.6	149.8	149.8
Fuel production	160.3	1,175.3	2,433.2
Feedstock transport	5.2	51.2	60.0
Feedstock and fertilizer production	295.3	85.5	22.4
CH ₄ and CO ₂ leaks and flares	92.8	96.7	55.9
Emissions displaced by co-products	0.0	0.0	-88.9
Sub total (fuelcycle)	2,724.9	1,613.7	2,687.5
% Changes (fuelcycle)	--	-40.8	-1.4
Vehicle assembly and transport	14.6	19.1	19.1
Materials in vehicles (incl. storage) and lube oil production/use	61.8	90.8	90.8
Grand total	2,801.2	1,723.6	2,797.4
% Changes (grand total)	--	-38.5	-0.1

5. BIOMASS PRODUCTION

The biomass that will be used to produce hydrogen is assumed to be wood. Other biomass feedstocks such as grass or agricultural residues can also be gasified to produce hydrogen. Wood has been chosen for the model because of the increased interest in using managed forests for carbon sequestration. These forests must eventually be harvested and the wood could be used for energy production. The wood can be specifically grown for energy production or it could be a waste product from the forest industry. GHGenius has been developed for the use of short rotation forestry and the possibility of using a waste product has been specifically added as part of this project.

The assumptions that are used for short rotation forestry have also been reviewed as part of this project. The values that had been in the model previously were developed for conditions in the United States and these may not be fully applicable to Canada.

5.1 SHORT ROTATION FORESTRY

Short rotation forestry involves the growing of species such as hybrid poplars and willow. In the United States, poplars have been studied extensively and in Canada, both willow and poplar have been considered as candidates for short rotation forestry plantations. The location and the intended end use of the material have an impact on the determination of the best specie. The poplars have been and continue to be used in some commercial applications for pulpwood in Canada. The willows are harvested more frequently and are less suited to pulpwood applications but would be perfectly applicable for energy crops.

It is difficult to determine a single set of data that should be used as the inputs for a short rotation forest as the input requirements and yields can change depending on the general location, soil conditions and moisture conditions among other factors. The data that is used in the model needs to be internally consistent as well, that is, the yield modelled should be consistent with the inputs used. The system that is modelled should also be sustainable.

5.1.1 Yield

The yield of wood in a short rotation forest does have an impact on the amount of carbon that is stored in the plant before it is harvested. It does not directly influence the fertilizer and energy requirements in the model as this data is input on a per ton of biomass produced basis. There are significant differences in the yield of short rotation forests in Canada and the United States. Information on yield was summarized by REAP for the Forest Sector and Sinks Tables of the National Climate Change Process (1999). This is shown in the following table and all of the data is from commercial plots.

Table 5-1 Short Rotation Forestry Yield Data

Author	Location	Plot Age	Annual Growth Increment
		Years	Odt/ha/yr
Poplar			
Hendry, 1990	Ontario	14	2-3
OMNR, 1983	Ontario	7	2.2-4.6
Zsuffa, 1973	Ontario	12-14	2.4-6.6
Vallee, 1975	Quebec	10	3.5-6.9
Perinner, 1999	Quebec	15	5.0-6.6
Van Oosten, 1999	British Columbia	10-12	10-13.2
Riemenschneider, 1999	Wisconsin	9-11	5.4-6.5
DeBell, 1993	Washington	5	8.2-18.8
Willow			
Labrecque, 1998	Quebec	3	6.2-11.0
Girouard, 1998	Quebec	5	7.5-8.9
Fillhart, 1999	New York	2	5.5-10.0

One of the primary factors determining the yield of poplar and willow is the moisture. Irrigated plots measured by DeBell in Washington State showed much higher growth rates than non-irrigated plots. It is reasonable to expect different yields across Canada but GHGenius has the ability to model only three regions in Canada, west, central and east. In each of these regions, there will be significant variances in the expected yields depending on the location but the differences between regions is probably less.

The US DOE developed a software program called Biocost (Walsh, 1996) that estimates the cost of producing bioenergy crops such as switchgrass and poplar. A Canadian version of this software was also developed by REAP (Girouard, 1999) in conjunction with the US DOE. The Canadian version models switchgrass and willow crops in Canada. The default yield for the poplar in the United States is 5 tons/ac/year (11.23 tonnes/ha/year). The default value for willow in Canada is 9 tonnes/ha/year (4 tons/ac/year).

The data that was in the model was 4.45 tons/ac/yr in the year 1995 and a 1.36% annual improvement factor. The same yield was used for all regions in Canada and the US and 10% less for Mexico. Based on this information, the default values in the model have been changed. The new values are shown in the following table. The annual improvement factor has been changed significantly since there is not a trend apparent in the data and there does not appear to be a significant research effort underway to increase the yields. The Mexico value is an estimate based on lower moisture availability.

Table 5-2 New Default Information on Wood Yields

	United States	Canada	Mexico
Yield	5.0 tons/ac/year	4.0 tons/acre/year	3.5 tons/acre/year
Growth rate	0.1%	0.1%	0.1%
Base year	1996	1996	1996

5.1.2 Fertilizer Requirements

The fertilizer requirements in GHGenius are input as pounds of fertilizer per ton of wood produced. The requirements are the same for all of the regions in the model in spite of the fact that there can be different yields. The values in the model are shown in the following table. They are relatively low and were based on a data review workshop that was held at Oakridge National Laboratory in 1997 by the developers of the Biocost software.

Table 5-3 Fertilizer Requirements for Wood in GHGenius

	N (lbs)	P ₂ O ₅ (lbs)	K ₂ O (lbs)	Lime (lbs)
Hybrid poplar (per ton of wood)	2.0	1.6	1.1	41.3

REAP (1999) referred to Biocost for the fertilizer requirements in their assessment of the implication of Short Rotation Forestry. In the following table the recommendations from the US and Canadian versions of Biocost are compared. Biocost provides estimates on a pounds per acre basis and these have been converted to pounds per ton using the default yields in the models. The US has a seven-year cycle for poplar (Lake States) and Canada has a four-year cycle for willow.

Table 5-4 Fertilizer Requirements for Wood in Biocost

	Biocost US		Biocost Canada	
	Lb/acre/cycle	Lb/ton	Lb/acre/cycle	Lb/ton
Nitrogen	270	7.71	178	11.1
Phosphorus	20	0.57	42	2.61
Potassium	35	1.0	131	8.2
Lime	0.0	0.0	0.0	0.0

In the US version of Biocost there are slightly different fertilizer requirements for the seven different regions of the model but there are clearly some differences between the two versions of Biocost and the original data in GHGenius. This is somewhat surprising given the common people and datasets involved in all three models. The difference in the nitrogen requirement between GHGenius and Biocost appears to be a result of a misunderstanding of how often the fertilizer is required over the seven-year cycle. The Biocost papers call this a biennial requirement in some places but in other locations suggest that this is the total cycle requirement. The software output clearly shows that this is a biennial requirement starting in the second year. The differences between the two versions of Biocost are derived from a different approach to the data (Girouard, 2003). The Canadian version is more conservative and represents an average case whereas the US version represents more of a best case results and may not be sustainable over the long term.

This version of GHGenius has been changed so that different fertilizer application rates for all of the fertilizers can be used for Canada, the US and Mexico. The values that are used for Canada and the US are the default values derived from the two versions of Biocost shown above. The values used for Mexico are between those of Canada and the US. The user can change these values on the Input Sheet in rows 95 to 137 and columns B to J.

In both versions of Biocost there are similar treatments of herbicides applied. A broad spectrum herbicide such as Round-up is applied first and followed by plowing. This is followed by two applications of a product for weed control. There are differences in the yield and the harvest cycle that has an impact on the herbicide application rate per ton of product

produced. In the following table the herbicide requirements from the two Biocost models and GHGenius are compared.

Table 5-5 Comparison of Herbicide Requirements

	Herbicides/acre/cycle	Herbicides Pounds per Ton Wood
Biocost US	3.0	0.086
Biocost Canada	2.4	0.15
GHGenius	-	0.10

The value in GHGenius is between the two versions of Biocost. No changes have been made to the default values.

5.1.3 Cultivation, Harvesting and Transportation Energy

There are a number of mechanical cultivations required during the cultivation and harvesting process. The sites are prepared with a ploughing and two diskings in the first year and the some mechanical cultivation in subsequent years to control weeds. Harvesting poplar involves felling, skidding and chipping the wood on site. The wood is then transported to the site where it is converted to energy. Harvesting willow is done using a custom harvester and chipping the trees as they are harvested. In spite of the differences in the methodology the energy requirements for the two systems are quite similar. The results from the two versions of Biocost are compared with the default values in GHGenius in the following table. No changes have been made to the default values in GHGenius.

Table 5-6 Comparison of Energy Requirements

	Fuel/acre/cycle	Fuel, USG per Ton Wood
Biocost US	76.27 USG	2.18
Biocost Canada	33.72 USG	2.10
GHGenius	-	2.20

The energy required for moving the wood from the plantation to the conversion site is calculated based on the modes of transport and distances chosen by the user on the Input Sheet. The default values are summarized in the following table.

Table 5-7 Transportation Assumptions

Mode	Average miles shipped	Tons-shipped/ton-produced
By Rail	150	0.00
Domestic water	100	0.00
International water	0	0.00
Pipeline, tram, conveyor	0	0.00
Truck	50	1.00

5.1.4 Emissions Due to Land Use

GHGenius calculates changes in above ground biomass and soil carbon changes based on the difference between the wood crop and what might have otherwise been grown on this

land. The changes in carbon content of this system is amortized over the length of the plantation (15 years default value) and then a discount factor (default is 2%) is applied that adjusts the results for the estimated permanency of the change. No change has been made to this methodology or default values in GHGenius. The values can be changed by the user on Sheet W in cells B159 and Sheet B in cell B35.

5.2 WASTE WOOD

There are a number of areas of Canada and the United States that have significant quantities of waste wood available for conversion to energy. This wood is generally the residue from the sawmill or pulp mill. It could be forest residues that are left behind in the forests or burned at the logging site prior to reforestation.

The utilization of this material as a feedstock for an energy conversion process would not involve any incremental fertilizer or herbicide usage but would also not benefit from any change in above or below ground carbon that may result from the growth of a dedicated energy crop. In order to make it easier to model this scenario several changes to the model have been made.

5.2.1 Methodology

An input cell (B111) has been added to the Input Sheet under the Sheet V section. If the user wishes to model wood residues a zero must be entered in this cell, otherwise the default value is a one. This will remove any emissions associated with changes in biomass carbon or soil carbon.

There could be the case where the user is modelling forest residue and wishes to add some fertilizer to replace the nutrients that have been removed with the forest residue. In this case the fertilizer requirements should be adjusted on the Input Sheet (rows 98, 130, 133 and 134). If it is mill residue that is being modelled then the user should set the fertilizer requirements to zero.

The energy and power inputs should be set appropriately for waste wood (row 107 on the Input Sheet). They could be zero for mill residues or there may be energy required for chipping forest residues if that is the source of wood waste being modelled.

5.2.2 Transportation

The transportation requirements for waste wood could be zero if the product is being consumed at the same site that it is being generated at. There could also be transportation requirements if many mills are shipping their waste to a central site or if forest residues are being moved to the energy conversion site. The appropriate values need to be set on the Input Sheet in column H, rows 65 to 75.

6. BIOMASS TO HYDROGEN

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.

In a recent report prepared for the US DOE by E²S (2002) biomass gasification technologies were benchmarked for the production of fuels, chemicals and hydrogen. They concluded that for hydrogen production it would be desirable to have a gas that had a high hydrogen to carbon monoxide ratio, low hydrocarbon levels, low nitrogen content, high water content and have a temperature of 100-200°C at the exit. This report compared the operating characteristics of a large number of gasifiers and concluded that bubbling fluid bed gasifiers for the production of fuels, chemicals and hydrogen applications currently have an advantage over other types of gasifiers. Their conclusions and reasons are presented below.

By far, directly heated bubbling fluidized bed biomass gasification has been the most widely demonstrated of the technologies considered. It has been operated over a wide range of conditions, such as temperature, pressure and throughput, using a variety of biomass feedstocks. For fuels, chemicals and hydrogen applications, it is beneficial to operate at high temperatures as is done for coal gasification. At temperatures greater than 1200-1300°C, little or no methane, higher hydrocarbons or tar is formed, and H₂ and CO production is maximized without requiring a further conversion step. The Tampella BFB gasifier has been operated with biomass at temperatures (950°C max) approaching but still well short of this range. Several BFB gasifiers have been operated at the high pressures that would be used in fuels and chemical synthesis (>20 bar). It is advantageous in these applications to operate the gasifier at a pressure higher than that of the synthesis reactor to avoid the requirement for costly gas compression between these two steps. However, this expense is somewhat balanced by the need for more complicated solid feedstock handling equipment upstream of the gasifier. Particle size reduction may be necessary with most BFB gasifiers, and the biomass would likely need to be dried to increase operating temperatures.

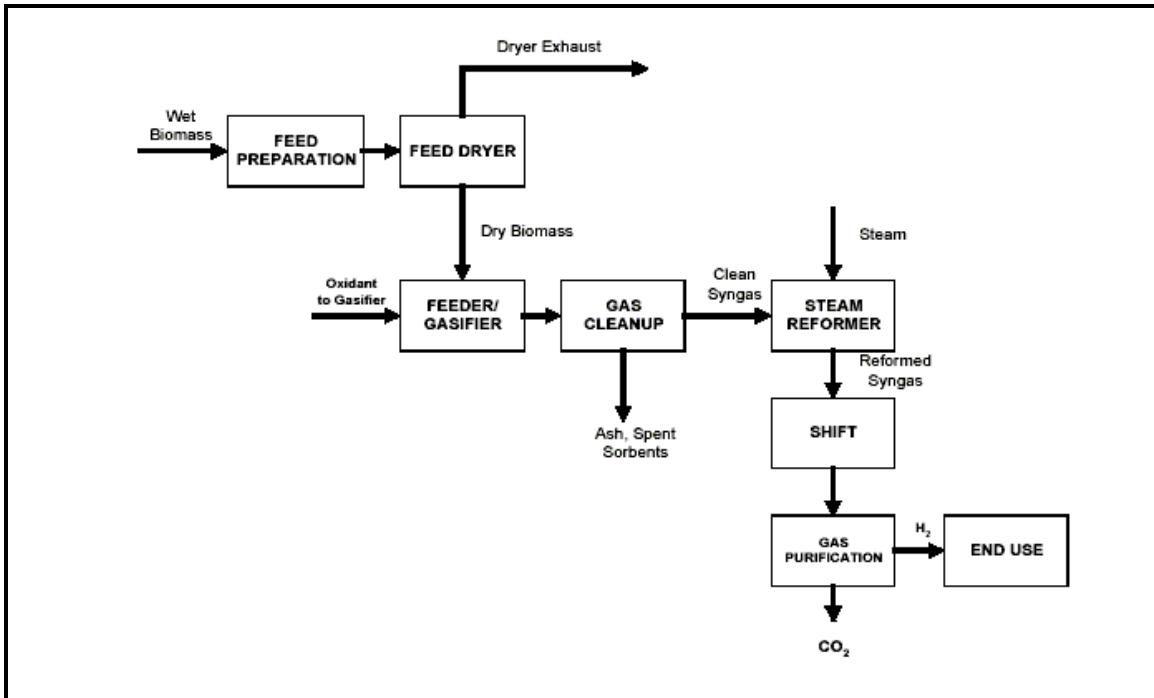
BFB gasifiers have been operated with co-feeds of air, oxygen and steam. Nitrogen dilution of the syngas is especially detrimental for synthesis application and an oxygen plant is normally required. Varying the relative amounts of oxygen and steam can be used as a means to adjust the H₂/CO ratio of the syngas to match synthesis requirements. For hydrogen production, it is desirable to maximize the production of H₂ over CO in the gasifier by promoting the water-gas-shift reaction. If an all fuels or chemicals product slate is desired, steam reforming or partial oxidation of the methane and higher hydrocarbons present in the syngas is required. The H₂/CO ratio requirement for methanol synthesis makes the requirement of an external shift reactor or separation step a strong likelihood; however, for FT synthesis an iron catalyst can be employed to adjust this ratio within the FT reactor. If it results in higher H₂/CO ratios, the high CO₂ production from BFB gasifiers is not undesirable. Other than tar cracking, which would be necessitated if higher operating temperatures cannot be achieved, gas cleanup will be minimal for synthesis applications. BFB gasifiers are possibly the lowest capital cost option among the advanced biomass gasification technologies. Sufficient information exists to conduct

conceptual design studies on these systems. It, therefore, appears that for fuels, chemicals and hydrogen applications, existing BFB gasifiers currently have an advantage.

6.1 PRODUCTION TECHNOLOGY

An example of a bubbling fluid bed gasifier is the one developed by the Gas Technology Institute and its predecessor the Institute of Gas Technology. The block for diagram for the biomass to hydrogen technology is shown in the following figure. This gasification technology has been demonstrated at the 11 tonne per day level producing synthesis gas for combustion. The technology has not been demonstrated for the production of hydrogen.

Figure 6-1 Biomass to Hydrogen



In spite of the lack of an actual demonstration of the technology, there have been a number of techno-economic studies performed on the production of hydrogen from biomass (Spath et al, 2000, Lau et al, 2002, Hamelinck et al, 2001). There are many different configurations that could be devised for biomass to hydrogen systems. Most, but not all produce hydrogen and some electricity and the ratio of the two products can vary with different configurations. For the base modelling case, the work of Hamelinck will be used as their published work has the most complete mass and energy balance of all of the studies. Of the five variations of the biomass to hydrogen process that they studied, three used an IGT gasifier and one configuration was designed for maximum hydrogen production. The inputs and outputs required for this process are summarized in the following table. The electrical requirements are the net requirements after the electricity produced by the process and the total process demands are considered. The wood required as the input must have a moisture content of less than 30% in this case. The thermal efficiency for this case is about 60% which is comparable to that reported in several of the other studies.

Table 6-1 Mass and Energy Inputs for Hydrogen from Biomass

	Plant	Model Inputs
Hydrogen Produced	259 MW _{th}	1 million BTU
Biomass Input	430 MW _{th}	198.9 lbs.
Electricity Required	1 MW	1.13 kWh

None of the reports identified with mass and energy balance data for the biomass to hydrogen process have any information on the overall emissions from the gasification systems. Two reports on biomass gasification used for power generation were found with information on emissions. The results from these two reports (Mann and Spath, 1997, and US DOE EREN) are compared with AP-42 results for wood combustion in the following table. The values chosen for the model are also shown, these have been chosen based on the other values in the table as well as considering the values in the model for wood fired boilers.

Table 6-2 Emission Factors Biomass Gasification

	Mann Grams/million BTU	EREN Grams/million BTU	AP-42 Grams/million BTU	GHGenius Grams/million BTU
Aldehydes (as HCHO) exhaust			2.4	0.5
Fuel evaporation or leakage				0.0
NMOC exhaust	150	10.0	6	10.0
CH ₄ (exhaust)	0.08		9.5	2.0
CO	0.25	21.8	270	50
N ₂ O			6	4
NO _x (NO ₂)	140	68.2	100-225	75
SO _x (SO ₂)	74	85.6	11	Calc.
PM	1.1			
PM10			18-227	25
PM2.5			16-195	25

These new factors for GHGenius have been used for the wood to methanol process. Previously this fuel pathway used the same emission factors as the wood to ethanol pathway but those two processes are quite different and these factors should better represent the wood to methanol process. These factors are an estimate and are not based on any test data and should test data become available they could be updated.

6.2 UPSTREAM EMISSIONS

The upstream emission for the biomass to hydrogen pathway are presented 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 plants produce compressed hydrogen and use the model defaults of a 300mile pipeline and a 100 mile truck movement from the production site to the dispensing site.

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 emissions are shown in the following table and compared to the steam methane reforming

case. The net emissions are close to zero because of the changes in soil and biomass carbon contents resulting from the forestry practices.

Table 6-3 Upstream GHG Emissions from Biomass to Hydrogen, 2003

Fuel	CH ₂	CH ₂
Feedstock	NG	Short Rotation Forestry
	Grams/million BTU	Grams/million BTU
Fuel dispensing	3,637	3,637
Fuel distribution and storage	9,896	9,896
Fuel production	77,653	2,333
Feedstock transmission	3,384	722
Feedstock recovery	5,647	4,361
Land-use changes, cultivation	0	-21,462
Fertilizer manufacture	0	3,294
Gas leaks and flares	5,423	0
CO ₂ , H ₂ S removed from NG	967	0
Emissions displaced	0	0
Total	106,606	2,780

In the following table, the results are shown for the case where wood residues are used instead of purpose grown trees. The fertilizer requirements have been set to zero but it is assumed that the wood will still have to be trucked from several sites to the central hydrogen production site. In this case, the emissions are higher because there is no carbon fixing attributable to the biomass production. The emissions are still very low compared to the SMR pathway.

Table 6-4 Upstream GHG Emissions from Waste Biomass to Hydrogen, 2003

Fuel	CH ₂	CH ₂
Feedstock	NG	Wood Residues
	Grams/million BTU	Grams/million BTU
Fuel dispensing	3,637	3,637
Fuel distribution and storage	9,896	9,896
Fuel production	77,653	2,333
Feedstock transmission	3,384	722
Feedstock recovery	5,647	0
Land-use changes, cultivation	0	116
Fertilizer manufacture	0	0
Gas leaks and flares	5,423	0
CO ₂ , H ₂ S removed from NG	967	0
Emissions displaced	0	0
Total	106,606	16,704

6.3 LIFECYCLE EMISSIONS

The full lifecycle GHG emissions for hydrogen produced from biomass in Central Canada are shown in the following table. The hydrogen is used in a fuel cell vehicle. For comparison the

emissions from gasoline used in internal combustion engine vehicles and hydrogen produced from SMR are shown.

Table 6-5 Full Lifecycle GHG Emission Results, Biomass to Hydrogen LDVs, 2003

	Gasoline	Hydrogen	Hydrogen
Fuel specification	113ppm S	CH ₂	CH ₂
Feedstock	Crude oil	NG100	Short Rotation Forests
	Grams/mile	Grams/mile	Grams/mile
Vehicle operation	339.8	0.0	0.03
Fuel dispensing	0.5	8.9	8.9
Fuel storage and distribution	6.3	24.1	24.1
Fuel production	63.2	189.1	5.7
Feedstock transport	0.9	8.2	1.8
Feedstock and fertilizer production	49.7	13.8	-33.6
CH ₄ and CO ₂ leaks and flares	14.2	15.6	0.0
Emissions displaced by co-products	0.0	0.0	0.0
Sub total (fuelcycle)	474.6	259.7	6.8
% Changes (fuelcycle)	2.9	-43.7	-98.5
Vehicle assembly and transport	8.1	9.0	8.9
Materials in vehicles (incl. storage) and lube oil production/use	74.0	80.7	80.7
Grand total	556.8	349.3	96.4
% Changes to RFG (grand total)	-0.0	-37.3	-82.7

The results for heavy-duty buses are shown in the following table. The case of hydrogen from a SMR unit is also shown.

Table 6-6 Full Lifecycle GHG Emission Results, Biomass to Hydrogen HDVs, 2003

	Diesel	Hydrogen	Hydrogen
Fuel specification	500 ppm S	CH ₂	CH ₂
Feedstock	Crude oil	NG100	Short Rotation Forests
	Grams/mile	Grams/mile	Grams/mile
Vehicle operation	2,134.7	0.2	0.2
Fuel dispensing	3.0	55.0	55.0
Fuel storage and distribution	33.6	149.8	149.8
Fuel production	160.3	1,175.3	35.3
Feedstock transport	5.2	51.2	10.9
Feedstock and fertilizer production	295.3	85.5	-209.0
CH ₄ and CO ₂ leaks and flares	92.8	96.7	0.0
Emissions displaced by co-products	0.0	0.0	0.0
Sub total (fuelcycle)	2,724.9	1,613.7	42.3
% Changes (fuelcycle)	--	-40.8	-98.4
Vehicle assembly and transport	14.6	19.1	19.1
Materials in vehicles (incl. storage) and lube oil production/use	61.8	90.8	90.8
Grand total	2,801.2	1,723.6	152.2
% Changes (grand total)	--	-38.5	-94.6

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