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 ve 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 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

The GHGenius model has been developed for Natural Resources Canada over the past four years. It is based on the 1998 ve

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

(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

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 CO_2 equivalents per tonne of coal and Fording also provided their energy consumption per tonne of coal.

> *such as bituminous coal, contain more CH_4 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 CH_4 is generated during coal formation. If two coal seams have the same rank, the deeper seam will hold larger amounts of CH_4 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 CH_4 emissions from surface mines (Kirchgessner et al., 1993; USGS, 1993).*
>
> *A portion of the CH_4 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 CH_4 to desorb from the coal. Transportation of the coal contributes to CH_4 emissions, because CH_4 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

4. C

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	
Fuel or feedstock	NG	Coal
	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_20	0.3	1.4
NOx (NO_2)	20.0	29.4
SOx (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

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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 rotation forests and yields can requirem
location, soil conditions and moisture conditions among other facto
in the model needs to be internally consistent as well, that is, the y
consistent with plan and coused. The system that is modelled should

5.1.1 Yield

The yield of wood in a short rotation forest does have an impact
that is stored in the plant beforan t is harvested. It does not directly i
energy requirements in the model as plis data isn and on a per
basis. There are significant differences in the yield of short rotation f
United States. Information on yield was summarized by REAP on
Sinks Tables of the National Climate Change Process (1999). This
table and all of the data is from commercial plots.

5.1.2 Fertilizer Requirements

The fertilizer requirements in GHGenius are input as pounds of fertilizer per ton of wood

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.

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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	EREN	AP-42	GHGenius
	Grams/million BTU	Grams/million BTU	Grams/million BTU	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_20			6	4
NOx (NO_2)	140	68.2	100-225	75
SOx (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

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**

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