University of Alberta

Hydrogen Production from Biomass

by

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Abstract

Hydrogen can be produced from biomass; this hydrogen is called biohydrogen. Biohydrogen produced in Western Canada can partially contribute to meeting the demand for hydrogen needed for bitumen upgrading. Gasification and pyrolysis are two promising pathways for producing biohydrogen in a large-scale plant. Syngas, produced from the gasification of biomass, and bio-oil, produced from fast pyrolysis of biomass, can be steam reformed to produce biohydrogen. The cost of biohydrogen delivered by pipeline to a distance of 500 km is \$2.20 per kg of H_2, assuming that a plant utilizes 2000 dry tonnes of whole-tree biomass per day processing it in a Battelle Columbus Laboratory (BCL) gasifier. For forest residue- and straw-based biohydrogen plants the values are similar: \$2.19 and \$2.31 per kg of H_2, respectively. Maximum economy of scale benefits are realized for biohydrogen production plants capable of processing 2000 and 3000 dry tonnes per day using BCL and GTI (Gas Technology Institute) gasification technology, respectively. The cost of biohydrogen from fast pyrolysis (\$2.47 per kg of H_2 from a 2000 dry tonne per day plant), using forest residue as the feedstock, is higher than the cost of biohydrogen produced by gasification. Carbon credits of about \$120-\$140 per tonne of CO_2 are required to make biohydrogen competitive with natural-gas-based hydrogen.

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Acronyms and Abbreviations

API	American Petroleum Institute
Aspen	Advanced Simulator for Process Engineering
atm	Atmospheric pressure
bbl/d	Barrel per day
BCL	Battelle Columbus Laboratory
CAPP	Canadian Association of Petroleum Producers
CFB	Circulating fluidized bed
d	diameter
D	Distance
ERCB	Energy Resources Conservation Board (ERCB)
FERIC	Forest Engineering Research Institute of Canada
gal	Gallon
GHG	Greenhouse gas
GJ	Gigajoule
GTI	Gas Technology Institute
ha	Hectare
HHV	Higher heating value
hr	Hour
HRSG	Hear recovery steam generation
HTS	High temperature shift
km	Kilometer
kW	Kilowatt

kWh	Kilowatt-hour
LHV	Lower heating value
LTS	Low temperature shift
MG	Moderate growth
mm	Millimeter
MPa	Megapascal
m/s	Meter per second
MW	Megawatt
NG	Natural gas
NREL	National Renewable Energy Laboratory
odt	Oven dry tonne (0% moisture content)
PMH	Productive machine hour
PP	Pipeline planning
PSA	Pressure swing adsorption
ROW	Right-of-way
scf/bbl	Standard cubic feet per barrel (15.55°C and 1 atm)
SMH	Schedule machine hour
SMR	Steam methane reforming
TCI	Total capital investment
TIC	Total installed cost
TPI	Total project investment
WCSB	Western Canada Sedimentary Basin
wt%	Weight %

Chapter 1. Introduction

1.1. Background

Fossil fuel is the primary source of energy for generating electricity, running vehicles, and producing primary & secondary goods. The utilization of fossil fuels is associated with release of greenhouse gases (GHGs). An indiscriminate increase in GHGs may result in increases in atmospheric temperature which could raise sea level, and produce air pollution, flood, and drought (Bates et al., 2008). Use of renewable energy sources such as wind, biomass, solar, and geothermal energy mitigates GHG production as, compared to fossil fuels, these generate far fewer GHGs over their life cycle. Renewable energy sources, although quite abundant on the planet, are not, however, as economical as fossil fuels. In 2006, 13.4% of the world's energy was generated from renewable energy sources, more than 75% of which was contributed by biomass (REN21, 2008). Biomass is the only renewable energy source which can be directly converted to liquid fuels such as ethanol, methanol, biodiesel, and bio-oil. Biomass can also be used to produce gaseous fuels (e.g. syngas and hydrogen) and solid fuels (e.g. charcoal and pellets). Biomass is considered nearly carbon neutral as the amount of CO_2 released during its conversion is the same as that taken up by a plant during its growth assuming no external energy source during processing. Biomass-based energy technologies are at various stages of development.

Canada has a large fossil fuel resource base, and Western Canada has the largest hydrocarbon base in Canada. Canada has the second largest proven oil reserves in the world, preceded by Saudi Arabia and followed by Iran; however, the majority of these Canadian reserves are bitumen rather than conventional crude oil; therefore it requires intensive energy for the process of extraction and production (EIA, 2007). Most of the bitumen found in Alberta is in the form of oil sands. The bitumen reserves in the Western Canada Sedimentary Basin are shown in Table 1-1.

Table 1-1: Oil sands' status in the Western Canada Sedimentary Basin (WCSB)

Factors	**Value [a] (Billion barrels)**
Volume in-place	
Mineable [b]	101
In-situ [b]	1,610
Total volume in-place	**1,712**
Reserve [c]	
Mineable	35.2
In-situ	143.4
Total reserve	**178.7**
Remaining established reserve	
Mineable	31.2
In-situ	141.5
Total reserve	**172.7**

[a] Data source: (Dunbar, 2008; EUB, 2007; NEB, 2007).

[b] Mineable bitumen is less than 75 m from surface and is extracted by shovel and truck; in-situ bitumen is deposited deeper than 75 m from the surface and requires steam or solvent injection (Dunbar, 2008).

[c] 10% of bitumen is recoverable according to as estimate by ERCB (Dunbar, 2008).

Bitumen has high viscosity. It contains large amounts of impurities but, due to a shortage of hydrogen in the carbon/hydrogen bond (NEB, 2004), it has a low hydrogen content. Thus it needs to be upgraded before it can be used for the production of liquid fuels by the hydro-conversion process (Dunbar, 2008). During the bitumen upgrading process, large hydrocarbon chains are broken down into smaller hydrocarbons by adding hydrogen, and impurities such as sulfur and nitrogen are separated by forming hydrogen sulphide and ammonia, respectively (Dunbar, 2008; NEB, 2004). Most of the hydrogen used for bitumen upgrading is currently produced from steam methane reforming of natural gas; however, new technologies such as gasification of bitumen, coke, and asphaltenes will be utilized in the new oil sands projects to produce syngas which will, it turn, be used for hydrogen fuel and steam production (Dunbar, 2007a). All these sources of hydrogen are fossil-fuel-based.

The amount of hydrogen required for the bitumen upgrading process depends on the upgrading technology, the sulfur content in the bitumen, and the density of the upgraded bitumen (Dunbar, 2008). Normally, 1000 scf of hydrogen is required for upgrading a barrel of bitumen (i.e. about 2.41 kg of H_2/barrel of bitumen); however, hydrogen consumption could be as high as 1600-1800 scf per barrel (~4 kg of H_2 per barrel) for the production of synthetic crude oil (SCO) with a high API gravity (Dunbar, 2007b). Current and projected capacities for upgrading bitumen in Alberta are shown in Figure 1-1.

It is evident from Figure 1-1 that the hydrogen needed for bitumen upgrading will increase as, over time, the bitumen upgrading capacity increases. The projected demand for hydrogen fuel for upgrading bitumen is illustrated in Figure 1-2. The projected upgrading capacity and hydrogen demand were predicted in 2007. With the current economic downturn it is likely that the projections will not be the same and the growth might be at a slower rate. The current production of hydrogen comes mostly from fossil-fuel-based sources and is associated with significant GHG emissions. Alternative sources of fuel can be used for the production of hydrogen, thus reducing demand for fossil fuel and significantly reducing GHG emissions.

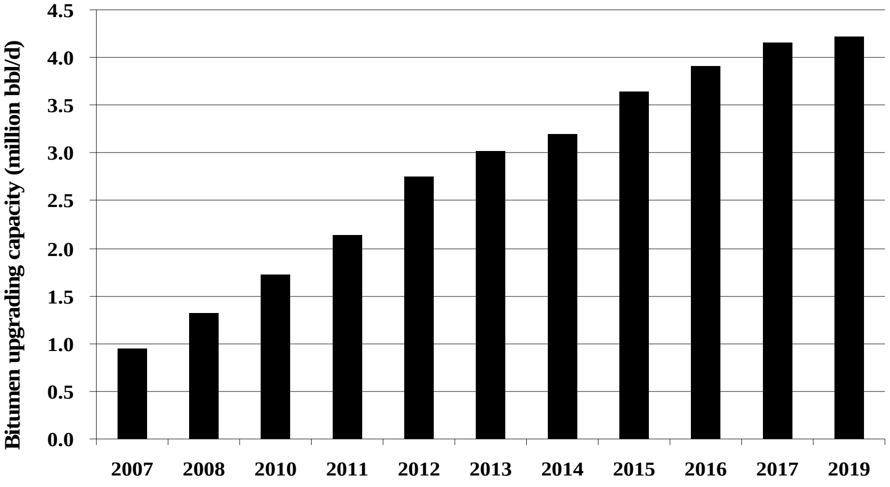

Figure 1-1: Projected bitumen upgrading capacity [derived from Dunbar (2007b)]

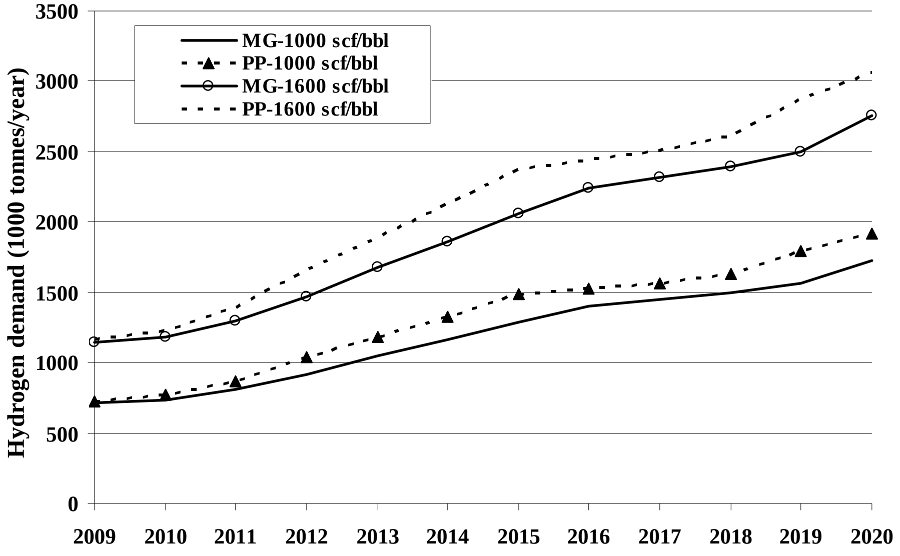

Figure 1-2: Predicted demand for hydrogen fuel for bitumen upgrading

For this study, biomass has been selected as an alternative source of hydrogen for the bitumen upgrading process; hydrogen produced from biomass (biohydrogen) will partially fill the demand generated by bitumen upgraders in Western Canada. There is a scarcity of data on the cost of producing the biohydrogen needed for bitumen upgrading. This research is an effort to fill the gap.

1.2. The objective of this study

The overall research objective is to conduct a detailed techno-economic assessment of hydrogen production from biomass feedstocks in Western Canada. This consists of estimating the optimum size for a biohydrogen production plant and the value of carbon credits which would make biohydrogen competitive with natural-gas-based hydrogen.

Following are the specific objectives of this research.

- Identify and analyze the availability of lignocellulosic biomass feedstocks for hydrogen fuel production in Western Canada.
- Identify and select a biohydrogen production process.
- Estimate the optimum size for a biohydrogen production plant. This is the size of the plant at which the cost of producing biohydrogen is minimal.
- Estimate the cost of biohydrogen production in Western Canada (\$/kg of H_2).
- Estimate the delivered-cost of biohydrogen to bitumen upgraders in the Province of Alberta by selecting the optimum method of transporting biohydrogen (\$/kg of H_2).
- Estimate the carbon credits required for making biohydrogen competitive with natural-gas-based hydrogen (\$/tonne of CO_2).

Three biomass resources — whole-tree, forest residue, and agricultural residue — are considered for producing hydrogen to be used for bitumen upgrading. Whole-tree biomass includes wood chips from different trees such as spruce, poplar, and aspen; forest residue includes tree tops, limbs, needles, and branches left in the forest after conventional pulp and lumber logging operations. The agricultural residue considered in this study is straw, which is recovered sustainably from wheat and barley crops in Alberta. Each of these biomass resources is evaluated based on their properties, harvesting methods, method of transportation, biohydrogen yield, and sensitivities to biohydrogen production costs. The subsequent chapters describe all of these factors in detail.

1.3. The scope and limitations of this study

The biomass conversion processes — gasification and pyrolysis — considered for hydrogen fuel production, are thermochemical conversion processes. These are explained in Chapter 2 and 4, respectively.

Biomass feedstock delivery methods and costs are evaluated for Western Canada, especially for Alberta, but could be calculated for other places with some modification in different cost parameters. Various costs from the literature have been adjusted for Alberta, according to the location and size.

Note that this study has been conducted to estimate the cost of producing hydrogen from biomass-based feedstocks using currently available technologies; no effort has been made to improve production technology or the efficiency of producing hydrogen from biomass. There are several methods of biohydrogen production, but only thermo-chemical processes, i.e. gasification and pyrolysis, have been considered. This is because these processes can be used in large-scale production plants.

1.4. The organization of this thesis

This thesis contains five chapters in addition to a table of contents, a list of tables, a list of figures, a list of abbreviations, and six appendices. This thesis is a consolidation of papers, each chapter of which is intended to be read independently. As a result, some concepts and data are repeated.

Chapter 1 includes the background of this study, definition of the problem, and limitations of the study.

Chapter 2 gives a techno-economic assessment of producing biohydrogen from whole-tree biomass using gasification, as well as optimizing the size of the production plant. This chapter investigates the various modes of biohydrogen transportation from production plant to bitumen upgrader. This chapter also estimates the GHG abatement cost required in order for biohydrogen from whole-tree biomass to be competitive with natural-gas-based hydrogen.

Chapter 3 estimates the cost of producing biohydrogen by gasifying forest residue and straw, and then compares this cost with the cost of whole-tree-based biohydrogen. This chapter also estimates the necessary GHG abatement credits for biohydrogen from two biomass feedstocks and the optimum size of the biohydrogen plant.

Chapter 4 describes the process whereby biohydrogen is produced by reforming bio-oil obtained through fast pyrolysis of biomass feedstock. This chapter also estimates the cost of biohydrogen and necessary carbon credit for this pathway.

Chapter 5 discusses the conclusions and recommends future work which would build upon this study.

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Chapter 2. Biohydrogen Production from Whole-Forest [*]

2.1. Introduction

Increase in the atmospheric concentration of greenhouse gases (GHGs) has emerged as one of the most important environmental issues in recent years. The contribution to global warming made by GHG emissions can be effectively mitigated by reducing emissions at the source. One option is switching to low-emission fuels. If produced and used sustainably, biomass can act as a reservoir of carbon or as a direct substitute for fossil fuels with no or little net contribution to atmospheric buildup of GHGs. Because of various social and environmental benefits, the large potential for biomass in Western Canada is considered a key renewable energy resource for the future. Its favorable characteristics have increased interest in biomass-based fuel.

A bioeconomy would consist of various pathways of biomass utilization (e.g. power, liquid fuels, and chemicals). Different products obtained from biomass can be substituted for fossil-fuel-based products in various energy sectors. For example, bioethanol can replace gasoline in the transportation sector, biopower can replace coal-based power in the electricity sector, and biohydrogen can replace natural-gas-based hydrogen in the industrial sector as well as fossil fuels in the transportation sector. All these pathways can help in mitigating GHG emissions. Many of these

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[*] *A version of this chapter has been published. Sarkar S., and A. Kumar. 2009. Transactions of the ASABE 52(2): 519-530.*

biomass energy technologies are now in different stages of development, demonstration, and commercialization.

Western Canada is one of the largest hydrocarbon bases in North America. In 2007, Canada produced about 438 million barrels of synthetic crude oil and bitumen (CAPP, 2008). Western Canada has a large resource of oil sands (an extremely dense form of petroleum) that is currently being used for bitumen production, which in turn is used for the production of synthetic crude oil. Additionally, Canadian oil production was 2.7 million barrels per day in 2007, of which more than 85% was produced in Western Canada (CAPP, 2008). Bitumen needs upgrading with hydrogen before it can be used for the production of crude oil. Current oil sands demand for hydrogen is about 2,000 tonnes per day; it is expected that by 2020 this will increase to 14,400 tonnes per day (Deligiannis et al., 2004; Tarun, 2006). Today, almost all of the hydrogen for bitumen upgrading is produced from natural gas. Alternative sources of hydrogen could be competitive with conventional sources, and there is a need to investigate these. In Alberta, this hydrogen can be partially replaced by biomass-based hydrogen (biohydrogen).

This study presents a techno-economic assessment of Western Canada's biohydrogen production using whole-tree biomass. The key objectives of this study are: to estimate the cost of biohydrogen production and delivery from whole-tree biomass in Western Canada (\$/kg of H_2) using the thermo-chemical conversion process (gasification) to a bitumen upgrader; to estimate the optimum size, i.e. the size of the biohydrogen production plant at which the cost of biohydrogen production is at a minimum; and to estimate the cost of natural gas at which the cost of biohydrogen is competitive with natural-gas-based hydrogen. This study also estimates the carbon credit (\$/tonne of CO_2 equivalent) required for biohydrogen to be competitive with current natural-gas-based hydrogen in Western Canada. Note that all cost figures in this study are adjusted to the year 2008 and given in U.S. dollars (US\$), unless specified otherwise.

2.2. Current technologies for biohydrogen production

Biohydrogen can be produced using thermo-chemical, electrohydrogenesis, and biological processes from a range of forest and agricultural biomass feedstocks. These processes can be subdivided into several categories. Figure 2-1 gives an overview of the processes that can be used for biohydrogen production from biomass (Cheng and Logan, 2007; Chum and Overend, 2001; Hallenbeck and Benemann, 2002; Hamelinck and Faaij, 2002; Lau et al., 2003; Ni et al., 2006; Simbeck and Chang, 2002; Spath and Dayton, 2003). Among these different processes, gasification (a thermo-chemical process) is more advanced in development and commercialization. This process is used as the basis for the biohydrogen production in this study.

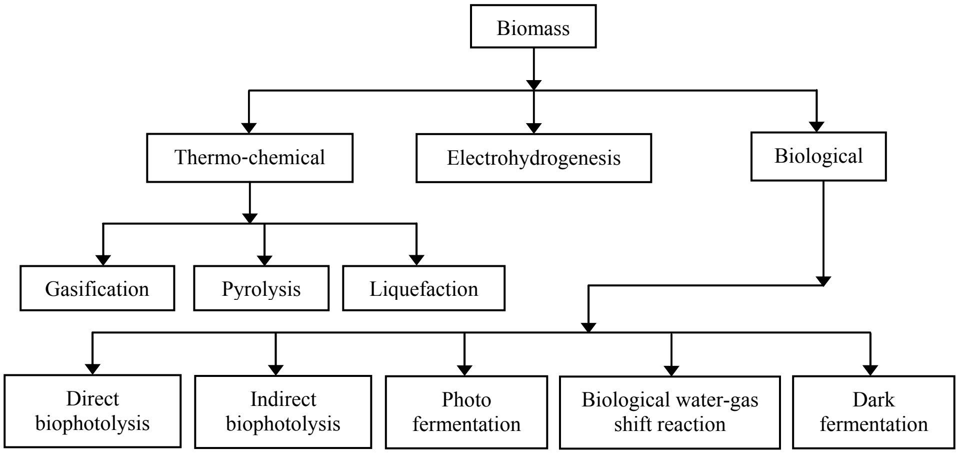

Figure 2-1: Biohydrogen production processes

2.3. Thermo-chemical conversion process

In thermo-chemical conversion, biomass is chemically converted to a blend of numerous gases using heat. As shown in Figure 2-1, three different thermo-chemical conversion processes can be used for energy production from biomass; however, all of these processes are not efficient in terms of biohydrogen yield and conversion efficiency for biohydrogen production (McKendry, 2002b; Ni et al., 2006). Basically, gasification and pyrolysis are the two thermo-chemical processes with the best potential for biohydrogen production on a commercial scale (Abedi et al., 2002; Babu, 2005; Bridgwater et al., 2002; NETL, 2007; Ni et al., 2006; Williams et al., 1995).

2.4. Gasification of biomass

Gasification is the process of heating biomass to a high temperature using steam in the presence of a limited supply of air or oxygen; this is done in a gasifier (where biomass is gasified) to produce impure syngas (Demirbaş, 2002; Larson et al., 2005; Mahishi et al., 2008; McKendry, 2002c). Biomass feedstock harvested and processed in the forest has a large chip size (>50 mm) and high moisture content (~50%), which make it difficult to gasify without reducing size and drying. The gasification of whole-forest biomass requires a moisture content of approximately 10% to 20% and a feedstock size of about 50 to 80 mm in order to obtain a high heat transfer rate between the heat transfer medium and the biomass feedstock (McKendry, 2002c). Upon being transported to the biohydrogen plant, biomass is put through a hammer mill to reduce chip size. This ground feedstock is dried (to a moisture content of up to 12%) in a rotary drum biomass dryer, which is a commonly used piece of equipment for biomass-based feedstock drying (Lau et al., 2003). The energy required for drying is obtained by burning char produced during the gasification process. In this study, feedstock handling and drying contribute 21% of plant's total capital cost.

Gasification of whole-forest biomass is conducted at 870°C in a circulating fluidized bed gasifier where steam acts as a fluidization medium, and synthetic olivine (calcined magnesium silicate) transfers heat (mostly by conduction) into the gasifier (Bridgwater, 1999; Spath et al., 2005). Gasifier exit gases consist mainly of H_2, CO, CO_2, and H_2O (about 85% on a mole basis), and the remaining gases are CH_4, H_2S,

NH_3, and long hydrocarbon chain compounds (Hamelinck and Faaij, 2002; Larson et al., 2005; Lau et al., 2003; Spath et al., 2005). This information is based on the National Renewable Energy Laboratory's published report on hydrogen production by gasification of biomass (Spath et al., 2005).

Syngas, produced from biomass gasification, contains particulates, tar, and impurities. Tar cracking (this is the process of breaking down of long chain hydrocarbons to short chain hydrocarbons), which takes place at around 800°C in the presence of a catalyst, decreases tar concentration and increases the concentration of syngas in the product gases (Larson et al., 2005; Spath et al., 2005). Large particulates are removed by cyclones, and small particulates are removed by ceramic candle filters. The remaining ammonia and tars are cleaned by a water scrubber, which also reduces the syngas temperature (Hamelinck and Faaij, 2002; Larson et al., 2005; Spath et al., 2005). Several technologies for gas cleaning are used in oil refining, syngas production, steam methane reforming, and ammonia and urea plants. This study used the LO-CAT gas cleaning process (Gas Technology Products, 2008) followed by a ZnO bed for removal of sulfur from syngas (Spath et al., 2005). In this study, the capital cost of equipment for gas clean up and compression constituted 17% of the total capital cost.

The yield of hydrogen from biomass gasification can be increased by dual water-gas shift reactors at around 350°C for high-temperature shift reactors and 260°C for low temperature shift reactors (Hamelinck and Faaij, 2002; McKendry, 2002c). The water-gas shift reaction increases hydrogen to 55% in the syngas, which finally passes through the pressure swing adsorption (PSA) unit, where all the gases except hydrogen are adsorbed. Finally, the hydrogen gas is compressed to about 7 MPa for pipeline transportation to the bitumen upgrading plant. Figure 2-2 shows the various steps of hydrogen production from whole-forest biomass using a gasification process derived from several studies (Hamelinck and Faaij, 2002; IEA, 2006; Lau et al., 2003; Ni et al., 2006; Simbeck and Chang, 2002; Spath et al., 2005; Spath et al., 2003).

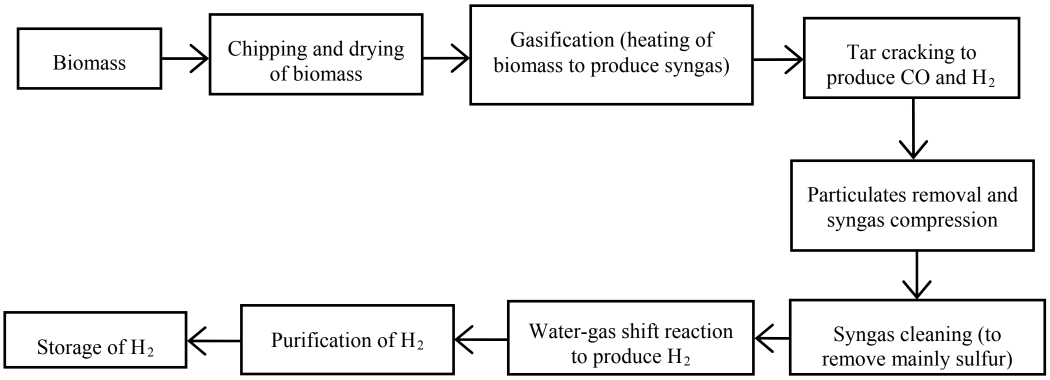

Figure 2-2: Hydrogen production from whole forest biomass by gasification

2.5. Status of the technology

A range of gasifiers can be used for producing hydrogen from biomass. These gasifiers include: fixed bed updraft and downdraft, bubbling fluidized bed, circulating fluidized bed, and entrained flow gasifiers (Ciferno and Marano, 2002; Henrich and Weirich, 2004; Schingnitz and Mehlhose, 2005; Veringa, 2005; Williams et al., 1995). Details on the characteristics of these gasifiers can be found in the literature (Bridgwater, 2003; Bridgwater, 2007; Ciferno and Marano, 2002; McKendry, 2002c; Schingnitz and Mehlhose, 2005; Veringa, 2005). Although there are a few research-scale biomass gasification projects that generate electricity, presently there is no large-scale commercial biomass gasification plant that produces hydrogen (Babu, 2005; IEA, 2006). One example of a demonstration scale biomass gasification plant is BIOSYN, Inc., where methanol is produced by a biomass gasification process (Babu, 2005). Another example of an advanced biomass gasification process is the Carbo-V process, a three-stage gasification process for syngas production, developed by CHOREN in Freiberg, Germany (CHOREN, 2007).

Biohydrogen yield depends on the thermo-chemical process and feedstock used for its production. Various other studies have reported yields of biohydrogen using a range of processes (e.g. electrohydrogenesis, synthetic enzymatic pathway, autothermal reforming, and flash volatilization) (Cheng and Logan, 2007; Cortright et al., 2002; Deluga et al., 2004; Salge et al., 2006; Zhang et al., 2007). Table 2-1 shows the bio-hydrogen yields from gasification of different biomass feedstocks.

A range of factors contribute to the overall cost of producing biohydrogen from biomass. The main factors are: type of thermo-chemical conversion process, feedstock for production, capital cost of the plant, biohydrogen yield, delivered feedstock cost, and operation and maintenance costs. These costs vary with the location of the plant. This study is a techno-economic assessment of biohydrogen production in Western Canada. All the input data are specific to this location and, wherever required, data are adjusted for this location.

Table 2-1: Biohydrogen yield

Technology	Feedstock	H_2 production rate [a] (kg/bone dry tonne biomass)
Gasification	Bagasse	78.1
	Switchgrass	84.1
	Nutshell mix	88.3
	Poplar wood chip	83.4
	Rice straw	72.2

[a] Derived from: DOE (2003), Larson et al. (2005), Lau et al. (2003), Parker (2007), and Spath et al. (2005).

2.6. Biohydrogen production in Western Canada

Large areas of Western Canada are covered with boreal forest. The forest in the province of Alberta consists of softwoods and hardwoods. This study is based on using a good biomass yield site that has a combination of spruce and aspen stands (Alberta Energy, 1985; Kumar et al., 2003). The scope of this techno-economic assessment includes felling (cutting) trees, skidding (moving) trees to the roadside, chipping by the roadside, and transporting wood chips to a centralized biohydrogen production plant. The biohydrogen produced is transported to the existing bitumen upgrader by pipeline. Various parameters are considered in estimating the total cost of biohydrogen delivered to the bitumen upgrader. Specific techno-economic cost models based on discounted cash flow analysis are developed for estimating the total cost of delivered biohydrogen. Details on these parameters are given in subsequent sections.

2.7. Input data and assumptions

2.7.1. Biomass delivery cost

The Canadian Forest Service (CFS) and the Forest Engineering Research Institute of Canada (FERIC) have conducted extensive studies on biomass recovery from forests in Western Canada. The biomass delivery costs include costs for felling, skidding, chipping, and transportation. These costs are estimated in consultation with researchers and experts using an review of the extensive literature (ALPAC, 2006; Dumouchel, 2006; Hall et al., 2001; Hankin et al., 1995; Hudson, 1995; Hudson and Mitchell, 1992; Kumar et al., 2003; LeDoux and Huyler, 2001; Lieffers, 2006; McKendry, 2002a; Mellgren, 1990; Perlack et al., 1996; Puttock, 1995; Silversides and Moodie, 1985; Zundel, 1986; Zundel and Lebel, 1992; Zundel et al., 1996). Details on each of the cost components in biomass delivery are given below in Table 2-2.

Tree biomass is cut by a feller buncher, which is equipment commonly used in Western Canada. The forwarder or grapple skidder is used to skid the tree to the road side, where it is chipped by a Morbark 50/48A whole-tree chipper (Kumar et al., 2003; MacDonald, 1999; MacDonald, 2006; Morbark, 2004).

The biomass is transported to the production plant by B-train chip vans after the chipping operation. The delivery costs also include road construction and silviculture costs. The plant is assumed to be in a remote location, so there would be costs for the construction of primary and secondary roads. These costs are included in this analysis. Silviculture costs include the cost of preparing the land after harvesting wood. In addition to these costs, the study also includes a royalty payment of \$4.8/dry tonne to the province of Alberta, which is an average value for the royalty charged by the province (Kumar et al., 2003). The biomass delivery cost assumptions are shown in Table 2-2. Finally, summary of cost calculation of whole-tree felling, skidding, and chipping process is explained in Appendix C.

Table 2-2: Characteristics and costs of biomass procurement and delivery

Items	Values/formulae	Comments/sources
Biomass yield (dry tonnes/ha)	84	Assumed yield based on hardwood and spruce yield in Alberta (Kumar et al., 2003). This yield reflects the average amount of biomass that can be obtained from 80 to 120 years old trees.
Biomass harvesting cost: • Felling (\$/dry tonne) • Skidding (\$/dry tonne)	 3.75 3.11	Calculated based on biomass harvesting cost (ALPAC, 2006; Dumouchel, 2006; Folkmann, 2006; MacDonald, 1999; MacDonald, 2006).
Biomass chipping cost (\$/dry tonne)	3.84	Calculated for Morbark 50/48A whole-tree chipper (ALPAC, 2006; MacDonald, 2006; Morbark, 2004).
Chip loading, unloading, and transportation cost (\$/m^3)	$0.9056 \times (2.30+0.0257\ D)$	*D* is the round-trip transportation distance between in-bush chipping and a centralized biohydrogen production plant (Kumar et al., 2003).
Cost of road construction (\$/ha)	$[0.9056 + (453/VT)] \times$ average gross yield (m^3/ha)	*VT* is the mean merchantable volume, where *T* is the number of merchantable stems per hectare, and *V* is the volume per merchantable stem. *VT* is assumed to be 185.4 m^3/ha for Canadian boreal forest (Kumar et al., 2003).
Cost of silviculture (\$/ha)	181	This cost is attributed to prepare the land for next cycle of forest growth (Kumar et al., 2003).
Ash disposal cost: • Ash hauling cost (\$/dry tonne/km) • Ash disposal cost (\$/dry tonne/ha)	 0.18 25.22	Ash produced from gasification is transported and spread within a radius of 50 km (Zundel et al., 1996).
Tortuosity factor	1.27	Increases feedstock transportation distance for geographical condition such as swamps, hills, and lakes in the biomass site (Overend, 1982).

2.7.2. Biomass fuel properties

The techno-economic model developed for calculating the cost of producing hydrogen from biomass makes several assumptions on fuel properties. The moisture content, density, and ash content are different for hardwood and softwood. In this study, we have assumed an average value for each of the properties. Table 2-3 shows the feedstock properties assumed in this study.

Table 2-3: Fuel properties

Characteristics	Whole-forest biomass	Comments/sources
Moisture content (%, wet basis)	50	Feedstock moisture content during transportation (Kumar et al., 2003; Spath et al., 2005).
Fuel density during transportation (kg/m^3)	570	Calculated for 50% moisture content (SImetric, 2007; Simpson, 1993).
Heating value (MJ/dry kg, HHV)	20	Calorific value of whole-tree biomass (Gullett et al., 2003; Kumar et al., 2003).
Percentage of H_2 (%)	6.4	Taken from ultimate analysis of dry Western pine (Gullett et al., 2003).
Percentage of ash (%)	1	Ash content (Kumar et al., 2003).

Finally, different equations which are used to calculate various operating parameters of biohydrogen production plant are explained in Appendix A.

2.7.3. Capital cost and scale factor

Biomass gasification is the basis of biohydrogen production technology. The base-case size of a biohydrogen plant is assumed to be 2000 dry tonnes per day, which is equal to the size studied by the National Renewable Energy Laboratory (NREL) and other researchers (Simbeck and Chang, 2002; Spath et al., 2005).

The capital cost of the production plant was obtained primarily from an extensive literature review and from consultation with experts (Curtis et al., 2003; Hamelinck and Faaij, 2002; Hamelinck et al., 2005; Kreutz et al., 2005; Larson et al., 2005; Lau et al., 2003; Mann, 1995; NAE et al., 2004; Padró and Putsche, 1999; Parker, 2007; Spath et al., 2005; Tijmensen, 2000). The capital cost of individual equipment for the 2000 dry tonnes per day plant is derived from these studies using their respective scale factors. The range for the scale factor is 0.33 to 1 for different equipment. The capital cost of the plant includes the purchase price of each piece of equipment, engineering fees, installation costs, plant construction, and contingency budgeting.

Using the capital costs and scale factors of various equipment for a 2000 dry tonnes per day plant, an overall scale factor for the capital cost of the plant is calculated as 0.76. In this study, the maximum unit size of the gasifier is considered to be 1000 dry tonnes per day. Thus, a 2000 dry tonnes per day plant has two 1000 dry tonnes per day gasifiers. Accordingly, capital costs are estimated for various plant sizes using scale factors (for instance, $\text{cost } E_1 = \text{cost } E_2 \times (\text{size } E_1/\text{size } E_2)^{\text{scale factor}}$, where cost E represents the total cost of the equipment). The biohydrogen production plant's construction period is assumed to be three years. Other details on plant characteristics are given in Table 2-4.

Table 2-4: Biohydrogen production plant characteristics

Items	Values	Comments/sources
Base-case biohydrogen plant size (dry tonnes/day)	2000	Based on the literature (Spath et al., 2005).
Capital for biohydrogen production plant using 2000 dry tonnes of biomass per day (million dollars)	178	Derived from (Spath et al., 2005). The capital cost for feedstock handling and drying is about 21% of total plant capital cost.
Plant life (years)	20	Assumed.
Biohydrogen yield (kg H_2 per dry tonne biomass)	83.40	H_2 yield from wood chip biomass (Spath et al., 2005).
Plant operating factor: • Year 1 • Year 2 • Year 3 onwards	 0.70 0.80 0.85	These years refer to the first three years of operation of plant (Kumar et al., 2003; Spath et al., 2005). This is similar to other solids handling plants.
Operating staffing including maintenance staff: • 2000 dry tonnes per day • For every change of 1000 dry tonnes per day in capacity of the plant	 50 5	Calculated from Aden et al. (2002) and Spath et al. (2005). It is assumed that if there is an increase or decrease of 1000 dry tonnes per day in the capacity of plant, the number of operating staff changes by 5.
Administrative staff	4	Assumed to be almost same for all the sizes of plants.
Average labor cost including benefits ($/h): • Operating staff • Administration staff	 40 64	Salaries have been adjusted for the province of Alberta (Aden et al., 2002; PAQ Services, 2007; Ringer et al., 2006).
Spread of costs during construction (%): • Year 1 • Year 2 • Year 3	 8 60 32	Plant goes into production at the end of year 3 (Ringer et al., 2006; Spath et al., 2005).

2.7.4. Operating cost

In a biohydrogen plant, the variable operating costs include the cost of natural gas, electricity, catalysts, raw materials, and waste disposal when the biomass gasification process is taken into account (Spath et al., 2005). It is assumed that the variable operating cost changes linearly with plant size. Accordingly, costs are adjusted for different plant sizes.

Other costs include employees' remuneration and maintenance costs. Employees' remuneration is estimated at an hourly rate, as given in Table 2-4. Finally, the number of administrative staff is assumed to be the same for different plant sizes. Table 2-5 shows the general input data for this study.

Synthetic olivine and MgO are used in the gasifier as catalysts to transfer heat to the biomass and continue the fluidization process, respectively, while Fe_2O_3, Cr_2O_3, CuO, and ZnO are used as shift reactor catalysts (Spath et al., 2005). The gasifier bed material and catalysts' costs contribute 38% of the total plant variable operating cost.

Table 2-5: General input data

Items	Values	Comments/sources
Scale factor	0.76	Overall plant scale factor is derived from individual scale factors of different equipment as given in the NREL's report (Spath et al., 2005).
Maximum unit size of gasifier (dry tonnes/day)	1000	Maximum gasifier size for indirectly heated gasification process taken from personal communication and literatures (Aden, 2007; Spath et al., 2005; Tijmensen, 2000).
Cost of an additional equal sized biohydrogen production plant unit (gasifier) relative to the first	0.95	Any additional unit will reduce 5% capital cost of the first unit (Kumar et al., 2003).
Factor to reflect capital cost impact for remote location	1.10	The remote location of the plant will lead to increase capital cost (Kumar et al., 2003).
Annual maintenance cost (% of capital cost)	2	Maintenance cost is assumed as a percentage of capital cost based on biomass based industries (Hamelinck and Faaij, 2002; Larson et al., 2005; Parker, 2007; Spath et al., 2005).
Labor surcharge for remote location	1.20	Cost of transporting and keeping labor (Kumar et al., 2003).
Aggregate pre-tax return on investment (blend of debt plus equity) – discount rate	10	
Reclamation cost (% of the capital cost)	20	This is the cost incurred in decommissioning and clearing of land (Kumar et al., 2003).

2.7.5. Biohydrogen transportation cost

Once biohydrogen is produced in a remote location, it needs to be transported from the central production plant to the bitumen upgrader. The transportation method could be classified according to the phase of H_2 fuel as well as the medium used for carrying H_2 (Amos, 1998). Three modes of hydrogen fuel transport are most frequently found in commercial operations in North America (Deligiannis et al., 2004; DOE, 2006a; Yang and Ogden, 2007): compressed gas in a tube trailer transported by truck, liquid hydrogen in a cryogenic tank transported by truck, and compressed gas transmitted through a pipeline. The total transportation cost for these three modes varies with changing transportation rates (i.e. amount transported amount per day) as well as transportation distance. Selection of a transportation method relies on several factors, such as transportation rate (tonnes/day), transportation distance (km), type of hydrogen fuel supply (continuous or intermittent), phase of H_2 (gas or liquid), and infrastructure availability (Amos, 1998). Typically, for a low transportation rate (<600 kg/day) tube trailers could be used, for a medium transportation rate (600 kg/day < flow rate <2.4 tonnes/day) cryogenic tanks could be used, and for a high hydrogen fuel demand (>2.4 tonnes/day) pipeline transportation could be used (Amos, 1998; Deligiannis et al., 2004; DOE, 2006b; Parker, 2005; Simbeck and Chang, 2002; Yang and Ogden, 2007).

Figure 2-3 illustrates the location of a biohydrogen production plant (point *O*), biomass harvesting area (circle with radius R), and bitumen upgrading plant (point *A*). Distance R is the maximum distance that whole-forest biomass is transported to the biohydrogen production plant located at the center of the circular area, and $\overline{R}$ is the average biomass transportation distance. Finally, hydrogen is transported a distance *X* from the biohydrogen production plant to the bitumen upgrading plant (point *A*). In this study, the average transportation distance of biomass (wood chips) is 18 km (i.e. the value of $\overline{R}$), and the average transportation distance of biohydrogen (i.e. the value of *X*) is 500 km. Biomass transportation distance also includes the impact of the tortuosity factor, as indicated in Table 2-2.

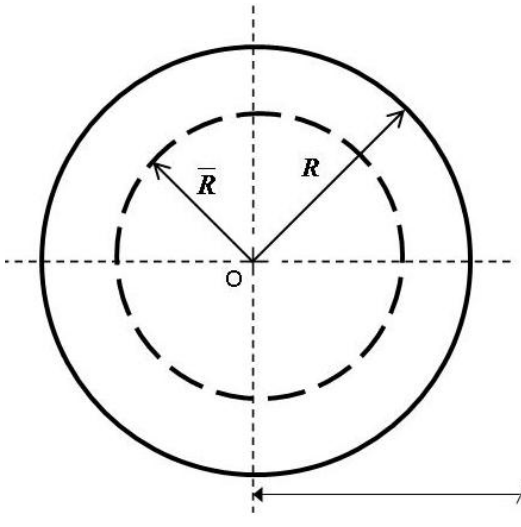

Figure 2-3: Schematic diagram of biohydrogen plant and hydrogen transportation distance

Figure 2-4 shows the cost of hydrogen transportation by the three modes (discussed above) for a plant producing 167 tonnes of hydrogen per day. This capacity corresponds to a plant utilizing 2000 dry tonnes of biomass per day. This study is based on this size of plant. During three transportation modes, hydrogen will be lost during compression and transmission. In this study, the losses for pipeline, cryogenic tank trailer, and tube trailer transportation methods are: 1%, 1.58%, and 0.5% of total transportation capacity, respectively (Parker, 2007; Yang and Ogden, 2007). Cost of transporting hydrogen is estimated based on the amount of hydrogen transported to the bitumen upgrading plant. In the case of Western Canada, the biohydrogen produced would be transported to a bitumen upgrader, where it would be used to upgrade bitumen that is then further refined for crude oil production. Currently, there are four upgraders in Western Canada; two of these are located in Fort McMurray (500 km north of Edmonton), Alberta, one is located in Edmonton, Alberta, and one is in Lloydminster, Saskatchewan (CAPP, 2007; Deligiannis et al., 2004). Biohydrogen production from whole-tree biomass in the boreal forest will be at a plant located at a maximum of 500 km from the upgrader. This assumption is made based on the location of the biomass resource and the location of the upgraders in Alberta.

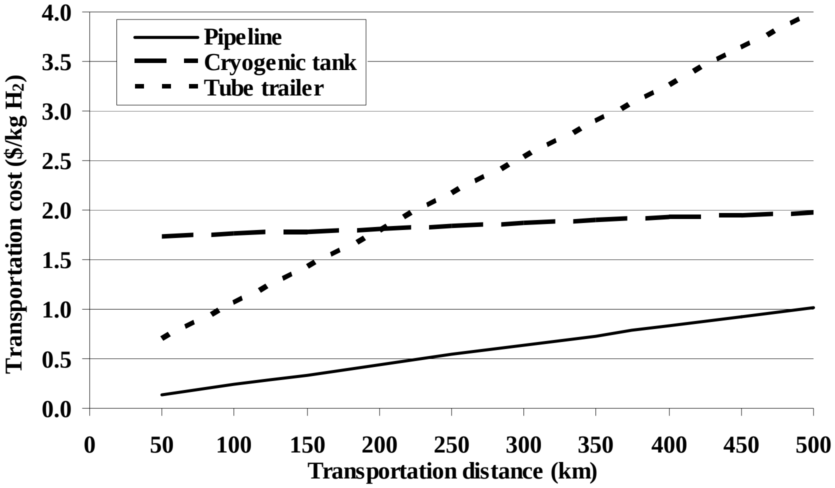

Figure 2-4: Variation in biohydrogen transportation cost for three transportation modes

From Figure 2-4, it is clear that for biohydrogen transportation at a capacity of 167 tonnes per day and for a distance of 500 km, pipeline is the most economical option.

Hence, in this study, we have considered pipeline transport as the mode of biohydrogen transportation. This mode can be changed if the transportation distance and capacity change. Based on earlier studies on hydrogen transportation, the pipeline cost is lowest for a large capacity and a long distance (Amos, 1998; Parker, 2007; Simbeck and Chang, 2002). Pipeline transportation of hydrogen for a long distance and large capacity costs the least (\$/kg of H_2) due to economy of scale in the capital cost of pipelines (Figure 2-4). The capital cost of pipelines per unit of throughput decreases as the capacity increases. For tube and cryogenic tank trailers, there is no decrease in transportation cost (\$/kg of H_2) as transportation capacity increase. Finally, the details on the pipeline size and design estimation parameters for this study are given in the Appendix B in Table B-1 and Table B-2.

2.8. Results and discussion

2.8.1. Biohydrogen production costs

Table 2-6 shows the breakdown of biohydrogen production costs using whole-tree biomass from the boreal forest in Western Canada. These costs are the output of a detailed discounted cash flow analysis based techno-economic assessment model developed in this study using the input parameters explained above. The cost of biohydrogen produced by a plant utilizing 2000 dry tonnes of biomass per day is \$1.18/kg of H_2 or \$9.83/GJ of H_2 (i.e. \$1 per kg of H_2 = \$8.32/GJ of H_2). This is based on the lower heating value of H_2 of 120.1 MJ/kg. This cost is an estimation for the third year of operation at an 85% operating factor.

Table 2-6: H_2 production cost components for base case in 2008 US$ for third year of operation from a plant using 2000 dry tonnes of biomass per day

Cost components	**Value ($/kg of H_2)**
Capital	0.38
Operating	0.31
Maintenance	0.06
Harvesting	0.13
Transportation	0.12
Road and infrastructure	0.10
Silviculture	0.02
Royalty fee	0.06
Ash disposal	0.001
Total cost	1.18

Capital and operating costs contribute about 32% and 26% of the total cost of production, respectively. In addition, biomass harvesting and transportation costs are the main components of the total feedstock delivery cost. The total cost of delivering biomass to the biohydrogen plant is $0.43/kg of H_2, which is about 36% of the total production cost. The total cost of delivered biomass is $36/dry tonne, as calculated using the formulae in Table 2-2. Note that the cost of delivered biomass includes a biomass production cost of $15.50/dry tonne.

2.8.2. Optimum size for a biohydrogen plant

Figure 2-5 shows the cost of biohydrogen at various plant sizes. In this study, the largest gasifier unit processes 1000 dry tonnes of biomass per day. This size is based on a detailed literature review (Aden, 2007; Simbeck and Chang, 2002; Spath et al., 2005). Figure 2-5 illustrates a few points that are unique to biomass processing facilities. The cost of biohydrogen production decreases as the size of the plant increases. The cost of production decreases about 30% in a size range of 500 to 3000 dry tonnes/day. For a plant size greater than 3000 dry tonnes/day, the curve is flat. There are two competing factors: first, capital cost per unit of biohydrogen production; and, second, the transportation cost of biomass feedstock. The capital cost of biohydrogen production plants per unit of capacity decreases as the size of the plant increases; this is due to the benefits from economy of scale. The cost of transporting biomass to the plant increases with the increase in the size of the plant because the biomass is collected from a larger area, resulting in longer biomass transportation distances. As a result of these two competing factors, there is a plant size at which the total cost of production is lowest. This is the economic optimum size of the plant, which, in this case, is higher than 5000 dry tonnes/day.

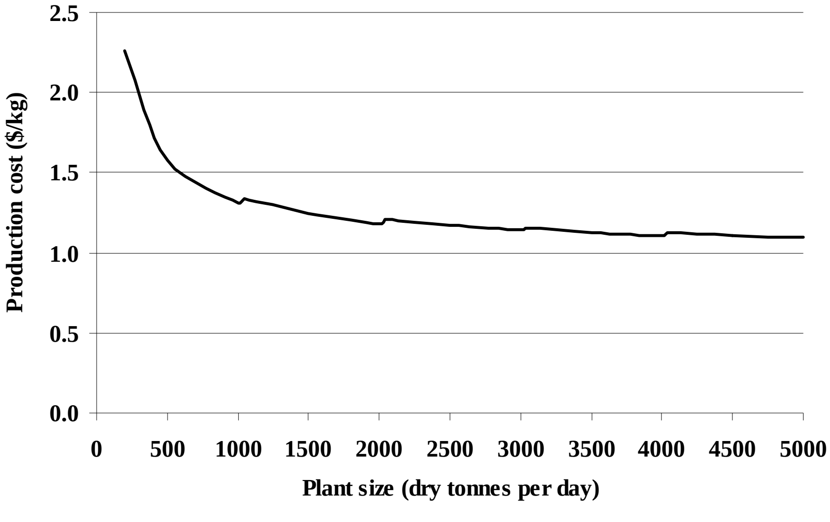

Figure 2-5: Variation of H_2 production cost with plant size for whole-tree biomass

In the size range of a 500 to 3000 dry tonnes per day plant, the capital cost savings due to economy of scale are much higher than the transportation cost increase. Above 3000 dry tonnes per day, the capital cost benefit due to economy of scale is close to the increase in the transportation cost, resulting in a flat curve.

Since the maximum size of gasifier considered in this study is 1000 dry tonnes/day, multiple units are required for larger plants, resulting in a saw-tooth-shaped curve. For example, a plant having a capacity of 1001 dry tonnes/day would require two units, each with a capacity of 500.5 dry tonnes/day. This results is a sharp rise in biohydrogen production cost from a plant having a capacity of 1001 dry tonnes/day because the capital cost per unit of output is higher for a plant having two units with a capacity of 500.5 dry tonnes/day compared to a plant having one unit with a capacity of 1000 dry tonnes/day.

2.8.3. Cost of delivered biohydrogen

As discussed earlier, biohydrogen plants are assumed to be located 500 km away from bitumen upgrading plants. As a result, the total cost of biohydrogen delivered to the upgrader consists of biohydrogen production and biohydrogen transportation costs. The total cost of delivered biohydrogen from a 2000 dry tonnes/day plant is \$2.20/kg of biohydrogen (consisting of a production cost of \$1.18/kg of biohydrogen and a pipeline transportation cost of \$1.02/kg of biohydrogen) for 167 tonnes of biohydrogen transported 500 km by pipeline per day. By increasing the capacity of the plant by 1000 dry tonnes/day (i.e. an increase of capacity from 2000 to 3000 dry tonnes/day), the total cost of delivered biohydrogen decreases by 14% due to the benefits of economy of scale.

2.8.4. Hydrogen production from natural gas

Natural gas, which consists of 25% hydrogen on mass basis, is the preferred feedstock for hydrogen production due to its commercially available conversion process, readily available feedstock, and low feedstock price. In the steam methane reforming process, typically used for commercial hydrogen fuel production, natural gas is heated in the presence of steam to a high temperature and pressure, using a steam-to-carbon ratio of 3-5 and a nickel catalyst (Damen et al., 2006; Longanbach and Rutkowski, 2002). Steam methane reforming is an endothermic process in which the heat of reaction is supplied by the combustion of natural gas (Longanbach and Rutkowski, 2002). Unlike biomass gasification, the steam methane reforming process produces syngas comprised of H_2, CO, CO_2, H_2O, and CH_4, and does not generate any long hydrocarbons or tar. That makes it a simple and inexpensive process compared to the biomass gasification process. Afterward, syngas passes through a water-gas shift reaction, which increases the hydrogen gas concentration. Bulk CO_2 and sulfur compounds are removed through an acid gas removal unit before the syngas is purified in a pressure swing adsorption (PSA) unit. The water-gas shift reaction is accelerated by using an iron-based catalyst, while activated carbon, zeolite, and silica gel act as adsorbing agents in the PSA unit (Longanbach and Rutkowski, 2002; Sircar and Golden, 2000). This is the method of producing hydrogen from natural gas used in this study; the relevant costs and characteristics of the process are illustrated in the Appendix B.

2.9. Carbon credits required for biohydrogen

Most of the hydrogen in Western Canada is produced from natural gas. Natural gas is delivered to bitumen upgraders, and hydrogen is produced on-site. For this study, a techno-economic assessment model was developed to estimate the cost of producing hydrogen from natural gas. The data for this model were derived from an extensive literature review (Deligiannis et al., 2004; Ghafoori and Flynn, 2007; Padró and Putsche, 1999). The model-based cost of delivered hydrogen produced from natural gas at an upgrader is about \$0.96/kg of H_2 for natural gas at a price of \$5/GJ and a hydrogen production plant processing of 427 tonnes/day. This cost is similar to the values reported elsewhere for on-site hydrogen fuel production from natural gas (Ghafoori and Flynn, 2007; Longanbach and Rutkowski, 2002). The cost of producing hydrogen from natural gas depends mainly on the facility size, natural gas price, and location of the plant. The cost of biohydrogen delivered to an upgrader from a plant utilizing 2000 dry tonnes of whole-tree biomass per day is \$2.20/kg of H_2. At this price, it is not currently economical.

One of the key benefits of producing hydrogen from biomass is its carbon neutrality; therefore, carbon credits can make biohydrogen competitive with natural-gas-based hydrogen. Nonetheless, the price of natural gas would be low for a long-term contract, and if purchased directly from the producer. Estimating the value of carbon credits requires the calculation of life-cycle emissions of greenhouse gases (GHGs) in the production and transportation of both types of hydrogen: that produced from natural gas, and that produced from biomass. Considering the emission characteristics, natural-gas-based hydrogen has a higher emission factor than does biomass-based hydrogen. The life-cycle GHG emissions from the production of 1 kg of hydrogen from natural gas are about 11.88 kg of CO_2 equivalent (Spath and Mann, 2001). This includes GHG emissions during natural gas production, transportation, conversion to hydrogen, and plant construction and decommissioning. The life-cycle GHG emissions for biohydrogen are 3.12 kg of CO_2 equivalent per kg of H_2 (Koroneos et al., 2004; Spath and Mann, 2001). This includes emissions during biomass production, transportation, and plant construction and decommissioning. For drying of biomass, the flue gas produced during the char combustion is used, hence there is no additional GHG contribution from drying. The GHG emission during the conversion of biomass to hydrogen is considered to be zero (assuming negligible GHG emissions from external energy sources); the amount of GHG released during conversion is the same as the amount taken up by the tree during its growth (carbon neutral).

The GHG emissions during transportation of biohydrogen 500 km to a bitumen upgrader is 0.50 kg of CO_2 equivalent per kg of H_2. This value was estimated using emissions factors derived from the literature (CASA, 2003; Environment Canada, 2006; GPSA, 1972; Meier and Kulcinski, 2000). The total GHG life-cycle emissions of biohydrogen delivered to a bitumen upgrader is 3.62 kg of CO_2 equivalent per kg of H_2. The total cost of hydrogen delivered to a bitumen upgrader is \$0.96/kg of H_2 for natural-gas-based hydrogen (at a natural gas price of \$5/GJ) and \$2.20/kg of H_2 for biohydrogen. Using these values, carbon credits were calculated. Figure 2-6 shows the carbon credit values required for biohydrogen to be competitive with natural-gas-based hydrogen as a function of natural gas price. It also correlates the production cost of natural-gas-based hydrogen with the price of natural gas. At a price of \$5/GJ of natural gas, a carbon credit of \$140/tonne of CO_2 equivalent is required for biohydrogen to be competitive.

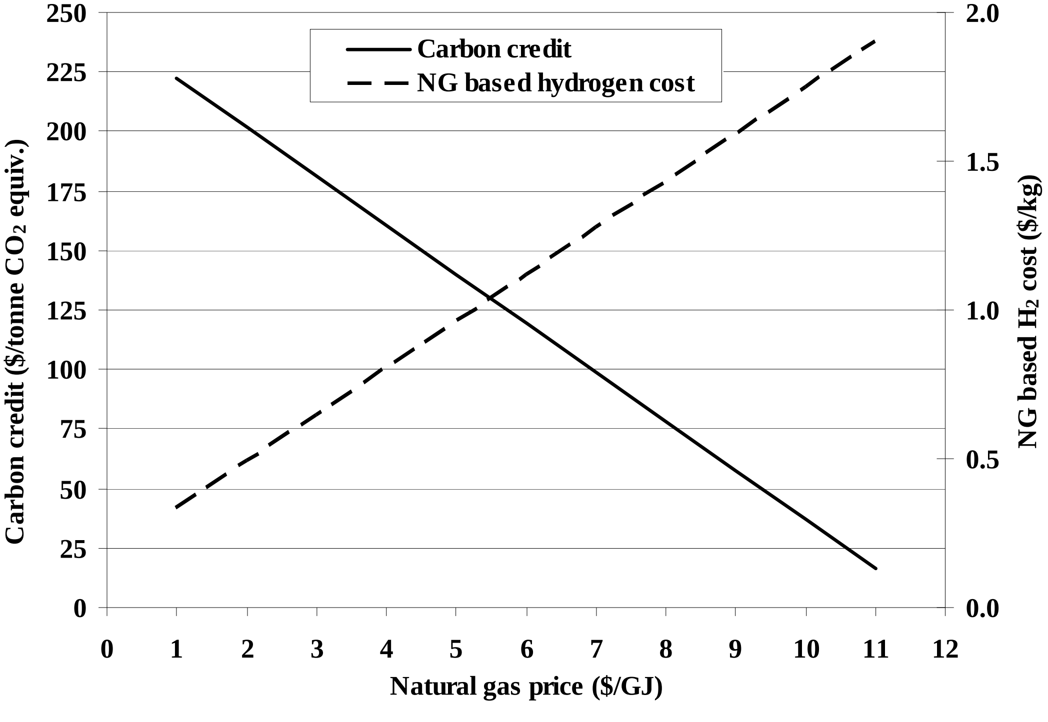

Figure 2-6: Carbon abatement cost for biomass-based hydrogen replacing natural-gas-based hydrogen

2.10. Sensitivities

The major sensitivities of H_2 production from whole forest biomass are shown in Table 2-7. Among the different parameters of the sensitivity analysis, the hydrogen yield from biomass has the most significant influence on the hydrogen production cost (8.5% to 12%). Capital cost and operating costs have a similar impact on production cost (about 3% to 4%), and other factors listed in Table 2-7 have little impact on the production cost for the same percentage of change. As a result, the cost of biohydrogen production could be decreased by increasing the hydrogen yield from biomass through improved production processes.

Table 2-7: Key sensitivities for H_2 production from whole-tree biomass

Factors	H_2 price ($/kg)	Price impact (%)
Base case H_2 production cost	1.18	
Capital cost of H_2 plant:		
• 10% higher	1.23	+ 4.2
• 10% lower	1.14	- 3.4
Operating cost of H_2 plant:		
• 10% higher	1.22	+ 3.4
• 10% lower	1.15	- 2.5
Feedstock transportation cost:		
• 10% higher	1.20	+ 1.7
• 10% lower	1.17	- 0.8
H_2 yield from whole tree biomass:		
• 10% higher	1.08	- 8.5
• 10% lower	1.32	+ 12.0
Biomass yield:		
• 10% higher	1.17	- 0.8
• 10% lower	1.20	+ 1.7
Biomass harvesting cost:		
• 10% higher	1.20	+ 1.7
• 10% lower	1.17	- 0.8
Ash disposal at zero cost	1.17	- 0.8
Pretax return on capital cost is 12% rather than 10%	1.24	+ 5.6

2.11. Conclusions

Using gasification technology, hydrogen can be produced from forest biomass (whole-tree biomass) in Western Canada at a cost of \$1.18/kg (or \$9.83/GJ of H_2). The cost of feedstock delivery and the capital cost are the two major components of the total production cost, contributing about 36% and 32%, respectively. The economic optimum size (the size at which the cost of production is at a minimum) for a hydrogen production plant based on whole-tree biomass is greater than 5000 dry tonnes per day; however, in practice, smaller plants could be built to reduce the risk and minimize capital penalty. Most of the economies of scale are exploited by 2000 dry tonnes per day.

The cost of biohydrogen transportation has a significant impact on the total delivered fuel cost. For 500 km of pipeline transportation, the total cost of delivered biohydrogen is \$2.20/kg (or \$18.32/GJ of H_2), of which about 50% is for the pipeline transportation of the hydrogen. The cost of delivered biohydrogen could be lowered by optimizing the size of the biohydrogen production plant and its location between the biomass resource and the bitumen upgrader.

In Western Canada today, biohydrogen from whole-tree biomass is not competitive with current natural-gas-based hydrogen. Carbon credits could improve the competitiveness of biohydrogen. At a natural gas price of \$5/GJ, a carbon credit of \$140/tonne of CO_2 equivalent could make biomass-based hydrogen competitive. There is a huge demand for hydrogen in Western Canada, especially for upgrading bitumen since bitumen production is increasing rapidly. In future, biohydrogen could play a significant role in the oil sands industry.

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Chapter 3. Biohydrogen Production from Forest and Agricultural Residues [†]

3.1. Introduction

In Western Canada, large amounts of forest and agricultural residues are left in the forest/field, which could be harvested for energy production. These residues are left to rot and release GHGs to the atmosphere. Utilization of forest and agricultural residues for biohydrogen production could reduce emission of GHGs and dependence on fossil fuels. Biohydrogen from biomass resources could be used in bitumen upgrading for synthetic crude oil (SCO) production. On average, there are about 3.29 million dry tonnes/year of forest residue and 3.19 million dry tonnes/year of agricultural residue available in Alberta which could be used for biohydrogen production (Sokhansanj et al., 2006; Statistics Canada, 2008; Wood and Layzell, 2003).

Most of the whole-forest in the Province of Alberta is allocated to pulp and timber production companies. As a result of this, whole-forest biomass is not available at present for biohydrogen production, although a large amount of forest residue could be sustainably removed for biohydrogen production. At present, the only residue collected in Alberta is the forest residue on the roadside, which is burnt to prevent forest fires (Kumar et al., 2003). Similarly, there is some use of the agricultural

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[†] *A version of this chapter has been submitted for publication. Sarkar S., and A. Kumar. 2009. Energy.*

residue but most of it is left to rot in the field, although it could be removed from the field for biohydrogen production.

In the previous Chapter 2, the cost of producing biohydrogen from whole-forest was estimated along with the cost of transporting it to an upgrader. The carbon credits required to make it competitive with natural-gas-based hydrogen were also estimated. This chapter deals with using forest and agricultural residues for producing biohydrogen for bitumen upgrading. Two types of gasification technology are considered for biohydrogen production. As well, this chapter compares biohydrogen production from agricultural and forest residues with the whole-forest case.

This part of the research focused on the collection and harvesting of forest residue and straw by conventional harvesting methods, and their transportation by truck to a biohydrogen production plant using the existing road networks. Once biohydrogen is produced in a plant, it is transported to an upgrader. When all the data were collected and the assumptions were made, a techno-economic model was developed to calculate the cost of producing biohydrogen from forest residue and straw. Note that all the costs presented in this study are in 2008 US dollars, unless specified otherwise. Other additional assumptions are described in this chapter as required.

3.2. Gasification technologies

The general methodology for gasifying forest residue and straw is similar to the whole-tree gasification process which was explained in the previous chapter. The gasification of biomass can be carried out in an atmospheric pressure gasifier (Spath et al., 2005) or a pressurized gasifier (Larson et al., 2005). The former gasifier is the Battelle Columbus Laboratory (BCL) gasifier which was developed by the National Renewable Energy Laboratory (NREL) (Figure 3-1 shows the schematic of a BCL gasifier). The latter gasifier is the Gas Technology Institute (GTI) gasifier which was named for its developer (Figure 3-2 shows the schematic of a GTI gasifier). The key difference between these two gasifiers is in their operating pressures. BCL gasification is at atmospheric pressure and involves feedstock drying with flue gases from char combustion, a wet gas cleaning process, a water-gas shift reaction, and a purification process. GTI gasification operates at high pressure and involves a high temperature syngas cleaning process, a shift reaction, and a purification process (Hamelinck and Faaij, 2002). In fact, pure oxygen is obtained from an oxygen production plant for the process in the GTI gasifier. This adds to the capital cost of the GTI process. Further details on this are given in subsequent sections.

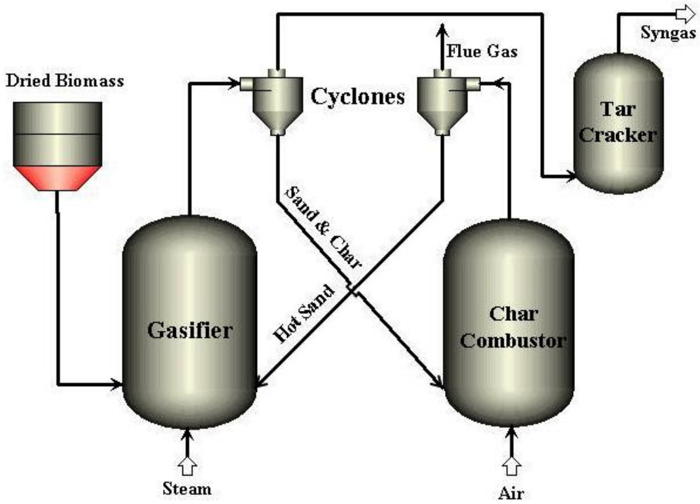

Figure 3-1: Schematic diagram of a BCL gasifier for biohydrogen production [derived from Spath et al. (2005)]

Figure 3-1 and Figure 3-2 depict the gasification of biomass in a BCL and a GTI gasifier, respectively. Syngas clean up, compression, water-gas shift reaction, and pressure swing adsorption (PSA) are the remaining steps in the BCL gasification process; hot gas clean up, water-gas shift reaction, and PSA are the remaining steps in the GTI gasification process (Larson et al., 2005; Spath et al., 2005).

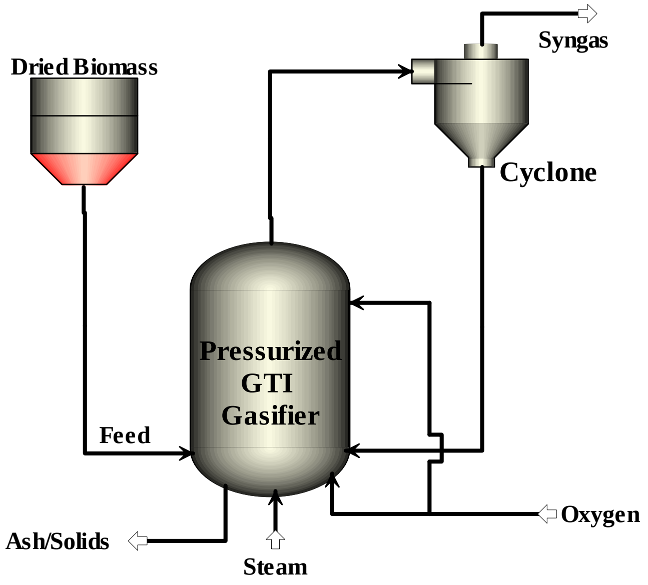

Figure 3-2: Schematic diagram of a GTI gasifier for biohydrogen production [derived from Larson et al. (2005)]

The basic operating principle of fluidized bed reactors (i.e. the GTI gasifier) is the same for gasification, combustion, or pyrolysis of biomass or coal. A number of studies have considered fluidized bed gasifiers for the biomass gasification process (Bose et al., 2006; Bridgwater, 1999; Bridgwater, 2003; Ciferno and Marano, 2002; McKendry, 2002; Ringer et al., 2006). Biomass is fed into a bubbling fluidized bed (BFB) reactor, while oxidant and steam flow at the bottom of the reactor to create the fluidized medium, and product gases leave at the top of the reactor (Larson et al., 2005). Ash is separated by solid-particle-removal units such as the cyclone, baghouse filter, and/or electrostatic precipitator. The circulating fluidized bed (CFB) gasifier (i.e. the BCL gasifier) has similar operating characteristics, except that heat is transferred to the reactor by hot sand which leaves through the top of the reactor along with product gases and char (McKendry, 2002).

The yield of biohydrogen from gasification and further water-gas shift reforming of forest and agricultural residues in BCL and GTI gasifiers is assumed to be the same: 83.40 kg of hydrogen per dry tonne of biomass (Larson et al., 2005; Spath et al., 2005). Yields from both residues are assumed to be the same because moisture content after drying is 12% for both these feedstocks. Like yield, the gasification, gas clean up, and separation processes are identical for the two feedstocks.

The gasification conversion process of biomass feedstock is same for BCL and GTI gasification process, except the operating temperature, pressure, and heat transfer method. The following equation shows the products of the gasification process (Ni et al., 2006):

Biomass + heat + steam $\rightarrow H_2 + CO + CO_2 + CH_4$ + hydrocarbons + char

3.3. Biomass fuel properties

The “as received” moisture content of forest residue and straw was 45% and 16%, respectively (Kumar et al., 2003). Upon being received, the feedstock is processed in the biohydrogen production plant by grinding and drying. There are basic differences between forest residue and agricultural residue which are critical for biohydrogen production; these are the "as received" moisture content, ash content (3% ash in the former and 4% ash in the latter feedstock), and feedstock size (Kumar et al., 2003). Minor differences in moisture content could lead to change in yield, but various studies on biohydrogen yield from these feedstocks show similar yields as listed in Table 3-1.

Table 3-1: Yield of biohydrogen from GTI gasification process

Feedstock	Moisture after drying	Yield of H_2 (kg/ dry tonne)	Comments/sources
Bagasse	20%	78.10	Hot gas cleaning followed by steam methane reforming (SMR), water-gas shift, and PSA (Lau et al., 2003).
Switchgrass	12%	84.10	Hot gas cleaning followed by SMR, shift, and PSA (Lau et al., 2003).
Switchgrass	20%	83.48	Maximum hydrogen production case without carbon capture (Larson et al., 2005).
Nutshell mix	12.5%	88.30	Hot gas cleaning followed by SMR, shift, and PSA (Lau et al., 2003).
Rice straw	15%	72.18	Hot gas cleaning followed by dual shift and PSA (Parker, 2007).
Wood	15%	55.65	Hot gas cleaning with dual shift reactor and PSA (Hamelinck and Faaij, 2002).
Wood	15%	82.20	Hot gas cleaning with ceramic membrane and internal shift (Hamelinck and Faaij, 2002).
Wood	Unknown	73.20	Hot gas cleaning followed by SMR, dual shift, and PSA (Spath et al., 2003).

The yield of forest residue was calculated based on the yield of whole-tree in the Province of Alberta. The Forest Engineering Research Institute of Canada (FERIC) has estimated harvesting, processing, and transportation costs for mountain-pine-beetle infested trees in British Columbia, where the yield from forest residue is estimated at 14-55% of the yield from whole-tree (MacDonald, 2006). In an another study, the yield from forest residue in Western Canada was calculated as yielding 20% of the yield of whole-tree (Kumar et al., 2003). Additionally, the yield of whole-tree from a medium-yield site in Western Canada is 84 dry tonnes per hectare (Kumar, 2004); therefore, for 100-year rotation of forest growth, the yield of forest residue is 0.247 dry tonnes per hectare (as shown in Table 3-2) according to Kumar et al. (2003). This yield is based on the assumption that all forest residues on the roadside are recovered.

Most studies have calculated the yield of straw from crop production and net harvest area using straw-to-grain ratios (Campbell et al., 2002; Sokhansanj and Fenton, 2006; Sokhansanj et al., 2006; Wood and Layzell, 2003). Kumar et al. (2003) estimated the yield of straw from wheat and barley crops in Alberta to determine on the basis of gross harvest area required to support a power-producing biomass facility. Yield of straw was reported as being 0.416 dry tonnes per gross hectare where straw moisture content was assumed to be 16% (Kumar et al., 2003). Twenty percent of the straw was left on the field for soil nutrient content, making the yield of sustainably recoverable straw 0.333 dry tonnes per hectare (as shown in Table 3-2).

3.4. Harvesting and transporting forest residue and straw

Pulp, paper, and lumber industries harvest only tree stem, leaving behind tree tops, branches, and needles which could be used as feedstock for biohydrogen production. In this study, it is assumed that forest residue is collected and processed in the forest following conventional whole-tree harvesting. The collection of forest residue includes piling and forwarding for chipping; this is followed by chip transportation by truck. Since whole-tree harvesting companies build roads for the harvesting and transportation of tree stem, forest residue can be transported using these existing roads, and hence, there is no cost for road construction in this case.

Alberta has great potential for using wheat and barley straw for producing biohydrogen. The straw-harvesting area for biohydrogen production is assumed to be square in shape, with the plant location at the intersection of the diagonals. This assumption is based on the general shape of agricultural fields in the Province of Alberta. In this study, it is assumed that the straw is harvested by the field owner and baled; the bales are then transported on a flat-bed trailer to a biohydrogen production plant where the straw is chopped up. Figure 3-3 shows the distances that whole-tree, forest residues, and straw are transported, in correlation to production plants of various sizes.

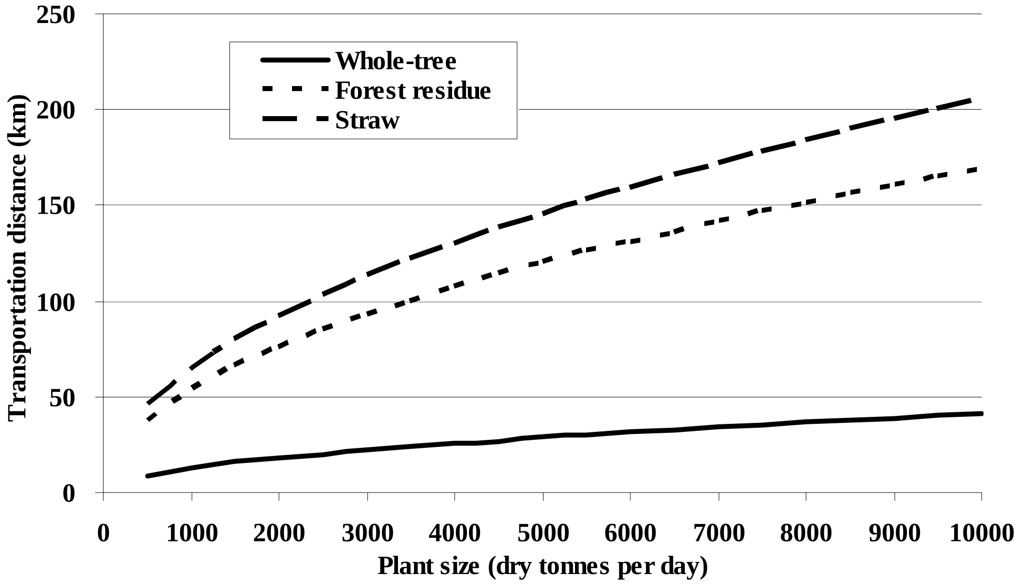

Figure 3-3: Variation in transportation distance and plant size for three types of feedstock

3.5. Estimating the cost of biohydrogen production

In the base case, the size of the biohydrogen plant is assumed to be 2000 dry tonnes of biomass per day, as discussed in the previous chapter. The cost of biohydrogen production includes the cost of all upstream and downstream processes. The key components of the cost of biohydrogen production involving forest residue and straw includes: cost of feedstock delivery (i.e. harvesting cost, transportation cost, and premium payment to the producer), the capital cost of the plant, the cost of plant operation and maintenance, the cost of ash disposal, and the cost of site reclamation. The following sections explain the different cost parameters for forest and agricultural residues.

3.5.1. The cost of delivering biomass residue

Forest residue, which is collected after the whole-tree harvesting process, is piled up in the forest by a forwarder and processed by a chipper. In preparation for whole-tree harvesting, pulp and lumber companies construct roads in the forest. Since these roads can be used to transport forest residue, there is no road construction cost to be incurred in order to utilize forest residue. Its low yield compared to whole-tree means that large time is required for piling and chipping. Transportation to the biohydrogen production plant is achieved by B-train chip vans. Kumar et al. (2003) conducted an extensive analysis of biomass processing for electricity production. Data on forest residue's yield, harvesting cost, and transportation cost are derived from this study. The total delivery cost of forest residue is \$33.50 per dry tonne for a feedstock transportation distance of 76 km. 52% and 34% of this cost come from feedstock transportation and harvesting, respectively. The cost of delivering forest residue to a biohydrogen production plant is shown in Table 3-2.

Agricultural residue, i.e. straw from wheat and barley crops, is harvested by the crop owner taking into consideration the amount of straw which should remain in order to prevent soil and water erosion, and maintain soil fertility. Sustainably recoverable agricultural residue (bales of straw) is collected from the roadside and transported to a biohydrogen production plant. The cost of straw delivery includes the cost of harvesting, loading, transportation by truck trailer, and unloading. Straw loading and unloading cost is \$5.70 per dry tonne, and transportation costs \$0.16 per dry tonne per km (Kumar et al., 2003). At the biohydrogen production plant, the straw is processed by a straw shredder which is driven by electric motor, so the cost of the electricity consumed by it is added to the variable operating cost. Finally, the farmers are paid the cost of purchasing fertilizer to replace the nutrients in the straw taken from their field; the cost of nutrient replacement is calculated on the basis of the nutrient content of the sustainably recovered residue (Kumar et al., 2003). The delivered cost of straw is $48 per dry tonne; this includes 38% for a feedstock transportation distance of 92 km, and 30% for nutrient replacement. The cost of delivered straw to a biohydrogen production plant is shown in Table 3-2.

3.5.2. Capital cost

Table 3-3 shows a base case, outlining the capital and other costs of biohydrogen plants, including scale factors for BCL and GTI gasifier. In the base case, the capital cost of processing forest residue by GTI gasifier consists primarily of the capital cost of power production (19% of the total capital cost) and the capital cost of the air separation process (17% of the total capital cost). GTI gasification requires a large amount of oxygen which is used in the gasification reactor; producing this oxygen results in a high capital cost compared to that of the BCL gasification process.

Table 3-2: Characteristics and costs for the procurement and delivery of forest residue and straw

Items	Values	Comments/sources
Feedstock yield (dry tonnes per hectare):		Yield of forest residue is calculated from the yield of whole-tree on a 100-year rotation of forest growth. Straw yield is based on figures from Kumar et al. (2003) for sustainable straw removal.
• Forest residue	0.247	
• Straw	0.333	
Harvesting cost:		Harvesting cost is derived from Kumar et al. (2003).
• Forest residue ($ per dry tonne)	11.25	
• Straw ($ per dry tonne)	10.58	
Straw loading and unloading cost ($ per green tonne)	4.80	Straw loading and unloading costs are for straw bale loading and unloading by fork-lift to and from the truck.
Straw transportation cost ($ per green tonne per km)	0.13	Transportation of bales is on a flat-bed trailer with a transport capacity of about 19 tonnes per load (Jenkins et al., 2000).
Nutrient replacement cost ($ per dry tonne)	14.75	Nutrient replacement cost is estimated for sustainable straw recovery from the field (Kumar et al., 2003). Note that nutrient replacement cost is not included for forest-based biomass feedstocks.
Royalty fee ($ per dry tonne)	4.80	For forest residue, a payment is made to the owner of the feedstock (Kumar et al., 2003). The same amount is considered as the payment to the farmer for straw.

In this chapter, both BCL and GTI gasification are considered for producing biohydrogen from forest residue and straw. Due to the remote location of forest residue-based production plants, a penalty factor of 10% is added to the capital cost. In contrast, straw-based gasification plants are not in remote areas; so, no extra amount is added to the capital cost. Using these data, the cost of biohydrogen is calculated for both the BCL and GTI processing of forest residue and straw.

Table 3-3: Characteristics of biohydrogen production plants for forest residue and straw

Items	Values	Comments/sources
Base case biohydrogen plant size (dry tonnes per day):		Based on the literature (Larson et al., 2005; Spath et al., 2005).
• BCL gasification	2000	
• GTI gasification	1000	
Base case capital cost (million $):		For BCL gasification, the cost is derived from Spath et al. (2005); capital cost for GTI gasification is extracted from Larson et al. (2005). Capital costs have been adjusted for forest residue and straw-based on the size of the drying plant required due to variation in moisture content of the feedstock.
• Forest residue (BCL gasification)	178	
• Forest residue (GTI gasification)	186	
• Straw (BCL gasification)	154	
• Straw (GTI gasification)	155	
Scale factors:		Overall plant scale factor is derived from literature for both these plants (Larson et al., 2005; Spath et al., 2005).
• BCL gasification	0.76	
• GTI gasification	0.68	
Biohydrogen yield (kg of H_2 per dry tonne biomass):		Yields are assumed to be the same for both gasification processes for feedstocks with 12% moisture content after drying process.
• Forest residue	83.40	
• Straw	83.40	

3.5.3. Operating cost

Operating costs for the GTI process include electricity, non-fuel operating (4% of the capital cost), and employees' remuneration (Larson et al., 2005). The yearly operating cost for a plant processing 2000 dry tonnes of forest residue per day is 7.40% of the capital cost for a GTI-based plant and 9.80% for a BCL-based plant.

The operating cost of BCL gasification in this case is based on the values estimated in Chapter 2 for a whole-tree based plant. Similar values for straw-based plants are 7.50% and 10.30%, respectively. Note that the operating cost does not include the feedstock delivery cost which is 6% and 10% of capital cost for a GTI gasification plant, based on forest residue and straw, respectively. For BCL gasification plants, the feedstock delivery cost is 9.60% and 16.40% of plant capital cost for forest residue and straw, respectively. The feedstock delivery cost increases as the plant size increases for both BCL and GTI gasification processes. The capital and operating costs for forest residue- and agricultural residue-based gasification plants using BCL and GTI gasifiers are shown in Table D-1 and Table D-2 of Appendix D, respectively; they have also been compared to the capital and operating costs for whole-tree-based gasification plants. Additionally, Appendix D shows techno-economic models for base case biohydrogen production processes using BCL and GTI gasification on forest and agricultural residues.

3.6. Results and discussion

3.6.1. The cost of biohydrogen production

Table 3-4 shows different cost components for biohydrogen production by BCL gasifier when using forest residue and when using straw as feedstock. For a 2000 dry tonnes per day plant using forest residue, the cost is \$1.17 per kg of H_2 (\$9.75 per GJ of H_2), where capital, operating, and feedstock transportation costs are the largest cost components at 33%, 26%, and 19%, respectively. For a plant of the same type and capacity using straw, the cost is \$1.29 per kg of H_2 (\$10.75 per GJ of H_2).

Different cost components of biohydrogen production using agricultural residue are shown in Table 3-4 and Table 3-5 for the BCL and GTI gasification processes, respectively. The cost of producing biohydrogen from forest residue is lower, basically due to the nutrient replacement cost for agricultural residue. Cost versus capacity of plant for forest residue and straw are shown in Figure 3-4 and Figure 3-5 for the BCL and GTI processes.

Table 3-4: Cost components of BCL gasification of forest residue and straw in a 2000 dry tonnes per day plant

Feedstock	**Forest residue**		**Straw**	
Cost components	\$ per kg of H_2	%	\$ per kg of H_2	%
Capital	0.38	33	0.33	26
Operating	0.31	26	0.30	23
Maintenance	0.06	5	0.06	4
Harvesting	0.13	11	0.12	10
Transportation	0.22	19	0.24	19
Nutrient replacement	0	0	0.16	13
Royalty/Premium	0.06	5	0.06	4
Ash disposal	0.01	1	0.02	1
Total cost	1.17	100	1.29	100

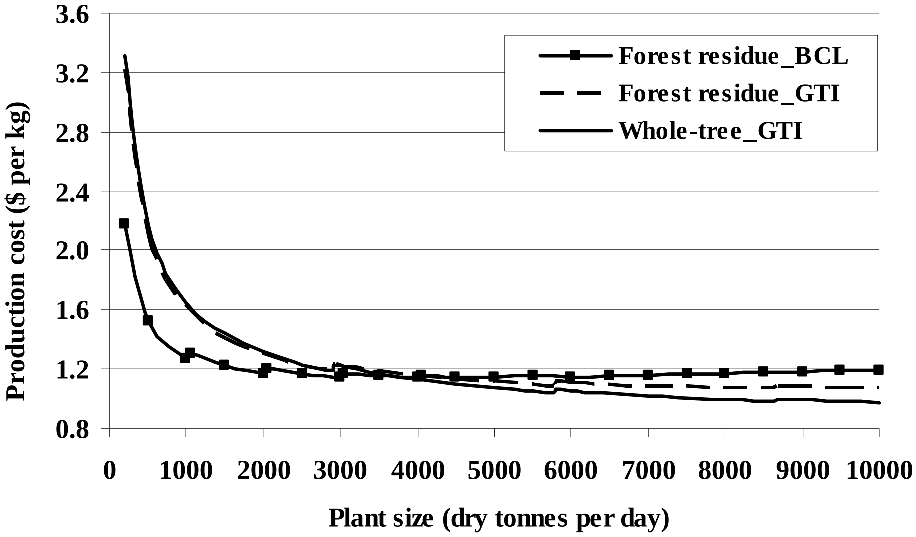

Figure 3-4: Comparison of biohydrogen production costs for BCL and GTI gasification of forest biomass

For a plant size of 4000 dry tonnes per day, the cost of biohydrogen production for forest residue undergoing BCL gasification is lower than the production cost for GTI gasification. Above a capacity of 4000 dry tonnes per day, the GTI process is economical. The key reason is the benefit from economy of scale for the capital cost of the oxygen production plant for the GTI process. As well, there is a large difference between the cost for the GTI and BCL processes for forest residue in plants with a capacity less than 2000 dry tonnes per day. This difference is due to the high capital cost of the oxygen production plant for the GTI process. This is clear from Figure 3-4 and Figure 3-5.

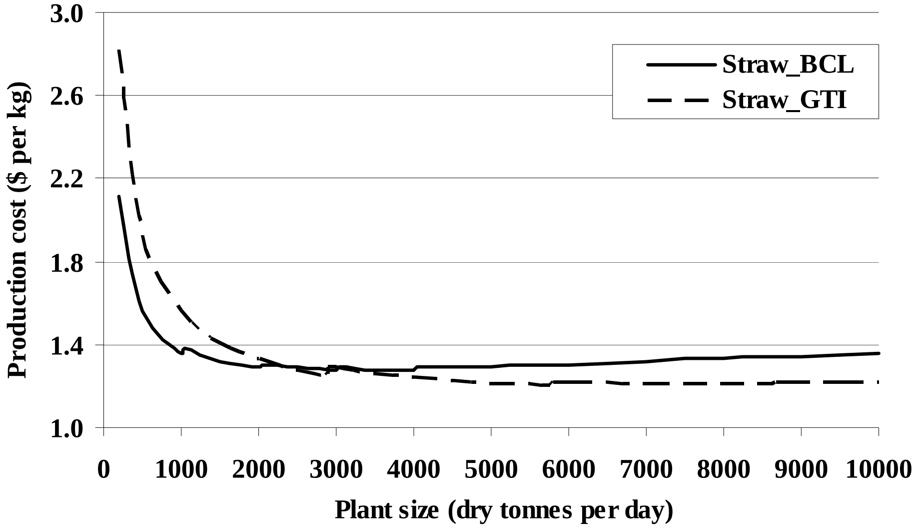

Figure 3-5: Comparison of biohydrogen production costs for BCL and GTI gasification of straw

For agricultural residue (i.e. straw), the cost of biohydrogen production using BCL process is lower than the cost of using the GTI process, for plants with a capacity below 2500 dry tonnes per day. Above this size, the cost of biohydrogen production from the GTI process is lower. Again, the reason is that there is a reduction in the capital cost per unit of output of the oxygen production plant, due to economy of scale benefits.

As illustrated by the above results, when the gasification process is chosen, selection of feedstock and plant size should take into account the impact of size on production cost. Table 3-5 lists the biohydrogen production costs for GTI gasification of forest residue and straw in a 2000 dry tonnes per day plant.

Table 3-5: Cost components of biohydrogen production for GTI gasification of forest residue and straw in a 2000 dry tonnes per day plant

Feedstock	**Forest residues**		**Straw**	
Cost components	\$ per kg of H_2	%	\$ per kg of H_2	%
Capital	0.61	48	0.52	39
Operating	0.16	12	0.12	9
Maintenance	0.11	8	0.10	7
Harvesting	0.13	10	0.12	9
Transportation	0.22	17	0.24	18
Nutrient replacement	0	0	0.16	12
Royalty/Premium	0.06	4	0.06	5
Ash disposal	0.01	1	0.01	1
Total cost	1.30	100	1.33	100

The capital cost of biohydrogen production using gasification of forest residue in BCL and GTI gasifiers in a 2000 dry tonnes per day plant is 33% and 48% of the total production cost, respectively. Keeping plant size the same, the feedstock transportation cost is 19% and 17% of the biohydrogen production cost for forest residue using BCL and GTI gasification, respectively. Hence, GTI gasification is a more highly capital intensive process (as shown in Table 3-3) than is BCL gasification. As a result of this, scale factor is important. GTI gasification process actually costs less for large plants. The case is similar for plants processing straw.

Similarly, the cost of producing biohydrogen using GTI gasification is higher for whole-tree, although with a plant size of less than 4000 dry tonnes per day BCL gasification costs less. As with forest residue, at a plant size greater than 4000 dry tonnes per day, GTI gasification costs less. The cost of producing biohydrogen is

\$1.32 per kg of H_2 (\$11 per GJ of H_2) using GTI gasification on whole-tree feedstock at plant size of 2000 dry tonnes per day.

3.6.2. The optimum size for a biohydrogen plant

Per unit of output, there is a trade-off between capital cost and biomass transportation cost when building a field/forest sourced biohydrogen facility. As the size of the biohydrogen plant increases, the capital cost per unit of output decreases due to the benefit of economy of scale. On the other hand, the total cost of biomass transportation increases due to the increase in the distance the biomass must be transported. This trade-off results in a size of biohydrogen plant at which the total cost of production is at a minimum. This size is referred to as the optimum size of the biohydrogen plant. In this work, the optimum size of the biohydrogen plant is estimated for both forest and agricultural residues.

For forest residue and BCL gasification, the optimum biohydrogen plant size is 3000 dry tonnes per day with a production cost of \$1.15 per kg of H_2 (\$9.58 per GJ of H_2). Note that the lowest cost of producing biohydrogen is \$1.07 per kg (\$8.92 per GJ of H_2); this cost is possible for forest residue processed in a plant with size a capacity of 8500 dry tonnes per day by a GTI gasifier. Theoretically, the optimum size in the case of forest residue is 8500 dry tonnes per day (with an average feedstock transportation distance of 156 km).

The optimum plant size for straw is 5760 and 3000 dry tonnes per day for BCL and GTI gasification, respectively (as shown in Figure 3-5). As well, straw has the potential for producing biohydrogen at a lower price than whole-tree and forest residue feedstocks, as long as the plant size is less than 500 and 1500 dry tonnes per day for BCL and GTI gasification, respectively.

3.6.3. The cost of delivered biohydrogen

For a 500 km long pipeline (which is the optimum transportation method for long distance and large capacity), the cost of transportation is \$1.02 per kg of hydrogen at a pipeline capacity of 167 tonnes of hydrogen per day, from a gasification plant of 2000 dry tonnes per day (explained earlier in Chapter 2). From a plant processing 2000 dry tonnes of forest residue that uses the BCL gasification process, the cost of delivered biohydrogen is \$2.19 per kg (\$18.24 per GJ of H_2). For a straw-based plant, the delivered cost is \$2.31 and \$2.35 per kg of H_2 at 2000 dry tonnes per day using BCL and GTI gasifiers, respectively. The cost of delivered whole-tree-based biohydrogen from a 2000 dry tonnes per day GTI gasifier plant is \$2.34 per kg; this is higher than forest residue-based hydrogen at the same plant size.

3.6.4. Carbon credits required for biohydrogen

The cost of biomass-based hydrogen is higher than that of natural-gas-based hydrogen. Carbon credits are, therefore, required to make biohydrogen competitive. The carbon credit assessment methodology for biohydrogen is explained in Chapter 2, and the same emissions factor for hydrogen from natural gas is used in this chapter to calculate the carbon credits for the production of forest residue- and straw-based biohydrogen. Basically, mitigation cost is calculated using the following equation.

Carbon abatement cost (\$/tonne of CO_2) = [Cost of H_2 from biomass (\$/kg) - Cost of H_2 from NG (\$/kg)] / [Life cycle emission for producing H_2 from NG (tonnes of CO_2/kg of H_2) - Life cycle emission for producing H_2 from biomass (tonnes of CO_2/kg of H_2)]

Life cycle emissions for forest residue- and straw-based biohydrogen production plants are shown in Table 3-6. Forest residue and straw are transported to the plant by diesel-fuel-driven truck. The emissions from biohydrogen production include not only the emission from the production itself, but those from biomass transportation (average 76 km for forest residue and 92 km for straw), from plant construction and decommission, and from 500 km of pipeline transport. Estimated emissions for forest residue- and straw-based biohydrogen production from a 2000 dry tonnes per day plant are 1.11 and 0.60 kg of CO_2 equivalent per kg of H_2, respectively. Assuming that the biohydrogen will be transported 500 km from the production plant to the bitumen upgrading plant, the emission for the pipeline transport alone is about 0.50 kg of CO_2 equivalent per kg of H_2. The basis on which the transportation distance was set at 500 km is explained in Chapter 2.

Table 3-6: Life cycle emissions (kg CO_2 equivalent per kg H_2) from biohydrogen production

Factors	Forest residue	Straw
Production	0.518 [a]	0.214 [b]
Feedstock transportation	0.362 [c]	0.156 [c]
Construction and decommissioning	0.23 [d]	0.23 [d]
Energy conversion	0	0
Biohydrogen transportation	0.50 [e]	0.50 [e]
Total emissions	1.61	1.10

[a] An emissions factor is calculated for the forwarding and chipping of forest residue. For the production and combustion of diesel fuel, they are 0.12 and 2.758 kg of CO_2 equivalent per liter, respectively (Environmental Canada, 2006; Furuholt, 1995; MacDonald, 2006).

[b] Emissions are estimated for rice straw harvesting that includes swathing, raking, bailing, and roadsiding (Hong, 2007). For wheat and barley straw, the emissions during production are assumed to be the same as rice straw.

[c] For a biohydrogen production plant with a capacity of 2000 dry tonnes per day, the feedstock transportation distances are 76 and 92 km for forest residue and straw, respectively.

[d] Plant construction and decommissioning emissions are derived from a study on a biomass-based power generation facility (Kumar et al., 2003).

[e] Transportation distance by pipeline is 500 km (CASA, 2003; Environmental Canada, 2006; GPSA, 1972; Meier and Kulcinski, 2000).

Based on the above data, the estimated life cycle GHG emissions for forest residue- and straw-based production of biohydrogen are 1.61 and 1.10 kg of CO_2 equivalent per kg of H_2, respectively. The delivery-cost for biohydrogen from a BCL plant with a capacity of 2000 dry tonnes per day is \$2.19 and \$2.31 per kg of H_2 for forest residue and straw, respectively (from BCL gasification process). In contrast, the cost of producing hydrogen through the SMR of natural gas is about \$0.96 per kg of biohydrogen. This was calculated for a plant size of 427 tonnes hydrogen per day, and at a natural gas price of \$5 per GJ, as described in Chapter 2 (Ghafoori and Flynn, 2007; Longanbach et al., 2002).

Using these values, carbon credits are calculated for producing biomass-based hydrogen fuel in Western Canada. Figure 3-6 shows the carbon credit values that are required for biohydrogen to be competitive with natural-gas-based hydrogen; these are a function of the price of natural gas. At a price of \$5 per GJ of natural gas, a carbon credit of \$119 and \$124 per tonne of CO_2 equivalent are required for biohydrogen from BCL-gasified of forest residue and straw, respectively. The values for GTI-gasified forest and agricultural residues are \$131 and \$128 per tonne of CO_2 equivalent, respectively.

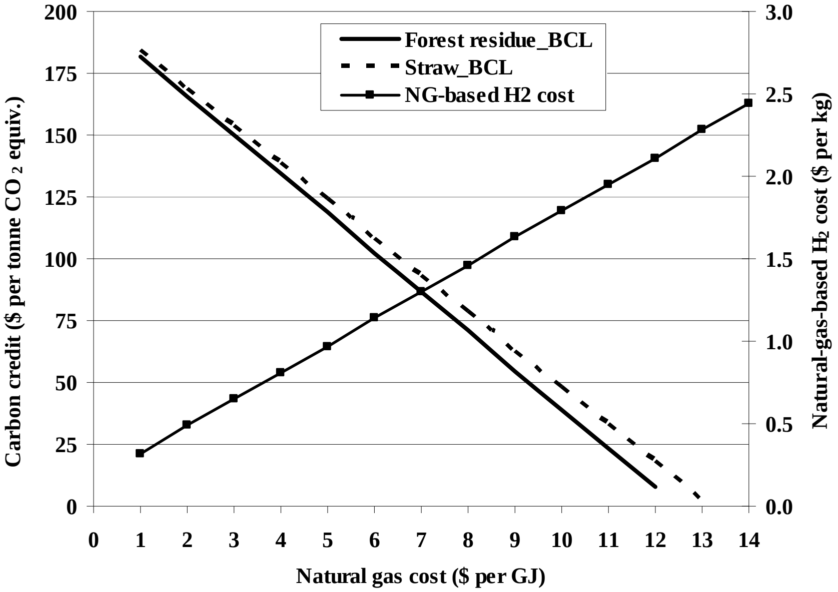

Figure 3-6: Carbon abatement costs for hydrogen based on forest residue and straw rather than natural gas

3.6.5. Sensitivities

For a 2000 dry tonnes per day plant, forest residue-based biohydrogen costs \$1.17 and \$1.30 per kg of H_2 using BCL and GTI gasification, respectively. Table 3-7 shows an analysis on different parameters of forest residue for BCL and GTI gasification. The cost of biohydrogen from forest residue depends largely on the capital cost and hydrogen yield for both of these gasification processes. Other factors have a slight impact on production cost.

From a 2000 dry tonnes per day plant, straw-based biohydrogen costs \$1.29 and \$1.33 per kg of H_2 using BCL and GTI gasification, respectively. Table 3-7 shows sensitivity analyses of various input parameters. These show trends similar to those for biohydrogen production from forest residue.

Table 3-7: Key sensitivities for H_2 production from forest residue and straw

Feedstock	**Forest residues**				**Straw**			
Gasification type	BCL		GTI		BCL		GTI	
Factors	Price ($/kg)	Impact (%)	Price ($/kg)	Impact (%)	Price ($/kg)	Impact (%)	Price ($/kg)	Impact (%)
Capital cost of H_2 plant:								
• 10% higher	1.22	+ 4.3	1.39	+ 6.9	1.32	+ 2.3	1.39	+ 4.5
• 10% lower	1.13	- 3.4	1.21	- 6.9	1.25	- 3.1	1.23	- 7.5
Operating cost of H_2 plant:								
• 10% higher	1.21	+ 3.4	1.33	+ 2.3	1.31	+ 1.6	1.34	+ 0.8
• 10% lower	1.14	- 2.6	1.27	- 2.3	1.26	- 2.3	1.28	- 3.8
Transportation cost of feedstock:								
• 10% higher	1.20	+ 2.6	1.32	+ 1.5	1.31	+ 1.6	1.33	0
• 10% lower	1.15	- 1.7	1.28	- 1.5	1.26	- 2.3	1.29	- 3.0
H_2 yield from biomass:								
• 10% higher	1.07	- 8.5	1.18	- 9.2	1.17	- 9.3	1.19	- 10.5
• 10% lower	1.31	+ 12	1.44	+ 10.8	1.43	+ 10.9	1.46	+ 9.8
Biomass yield:								
• 10% higher	1.17	0	1.29	- 0.8	1.28	- 0.8	1.32	- 0.8
• 10% lower	1.18	+ 0.9	1.31	+ 0.8	1.29	0	1.34	+ 0.8
Harvesting cost of biomass:								
• 10% higher	1.19	+ 1.7	1.31	+ 0.8	1.30	+ 0.8	1.34	+ 0.8
• 10% lower	1.16	- 0.9	1.29	- 0.8	1.27	- 1.6	1.29	- 3.0
Staffing cost:								
• 10% higher	1.18	+ 0.9	1.31	+ 0.8	1.29	0	1.34	+ 0.8
• 10% lower	1.16	- 0.9	1.29	- 0.8	1.28	- 0.8	1.32	- 0.8
Ash disposal at zero cost	1.15	- 1.7	1.29	- 0.8	1.26	- 2.3	1.31	- 1.5
Pretax return on capital cost is 12% rather than 10%	1.24	+ 6.0	1.40	+ 7.7	1.34	+ 3.9	1.41	+ 6.0

3.6.6. Location of biohydrogen production plant

As mentioned earlier, forest residue is harvested after pulp and lumber industries' whole-tree harvesting process; their yield depends on the yield of whole-tree biomass. As a result, possible locations for forest residue-based biohydrogen production plants would be similar to the locations for whole-tree-based biohydrogen production plants. Possible locations in Alberta for large scale plants could be: Fort McMurray, Whitecourt, and High Level. A map showing the possible locations (as shown by 3 stars) of forest residues (or whole-tree) based biohydrogen production plants is shown in Figure 3-7. Based on the proposed locations, biohydrogen needs to be transported to bitumen upgrading plants by pipeline in order to minimize the cost of transportation.

Western Canada's straw production is highest in Saskatchewan, and second highest is in Alberta. Although Saskatchewan produces large amount of straw, the yield of straw per hectare is highest in Alberta (Sokhansanj et al., 2006). Large amount of bitumen is upgraded in Alberta, so that makes Alberta the preferred location for straw-based biohydrogen production plants depending on plant size.

Most straw is produced on the Canadian prairie, and, as Figure 3-7 shows, the soil on the prairie can be generally divided into five categories (Smith and Hoppe, 2000). Basically, crop production varies among these soil categories, with the black soil zone having the highest crop production capacity, followed by the dark brown and brown zones (Campbell et al., 2002; Smith and Hoppe, 2000). The location preferred proposed for the bitumen upgrading facilities is Edmonton, Alberta which is known as upgrader alley with an upgrading capacity of 1,946,000 barrels per day predicted for 2020 (Griffiths and Dyer, 2008).

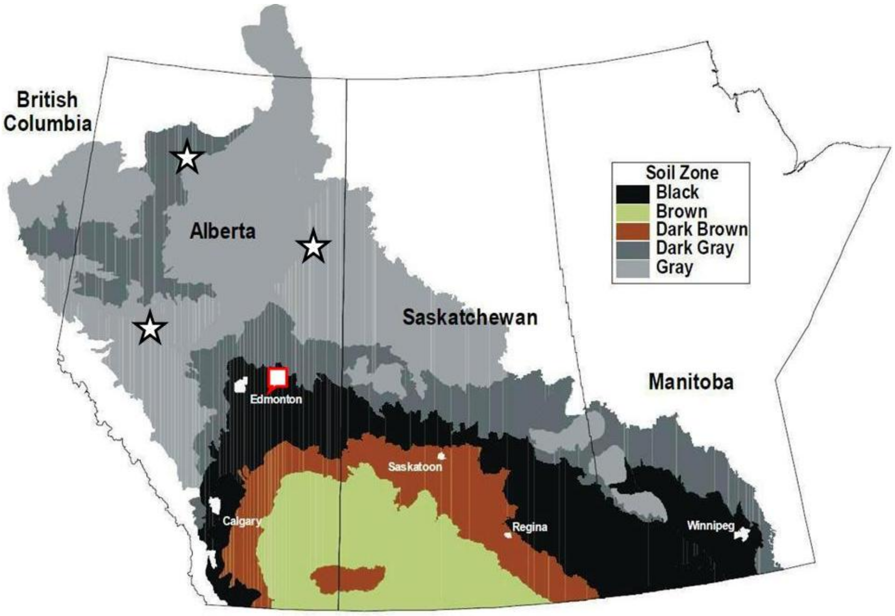

Figure 3-7: Soil zones of Western Canada [reproduced with the permission of the Minister of Public Works and Government Services, 2009 (Smith and Hoppe, 2000)]

Based on these considerations, the locations for preliminary biohydrogen production plants in Alberta are as shown in Figure 3-7. A square drawn in Figure 3-7 shows the possible location that would minimize transportation distance and cost for straw-based biohydrogen production plants in Western Canada. Biohydrogen production plants should be located close to Edmonton, Alberta to minimize the biohydrogen transportation distance.

3.7. Conclusions

Hydrogen can be produced at \$1.15 per kg of H_2 (\$9.58 per GJ of H_2) through BCL gasification by a plant able to process 3000 dry tonnes of forest residue per day. This is the optimum size for the plant, i.e. the size at which the cost of producing biohydrogen from residue is lowest. GTI gasifiers have a scale factor which results in a rapid reduction of capital cost per unit of output as capacity increases. BCL gasifiers do not provide such economy of scale.

The optimum size for a biohydrogen production plant is 3000 dry tonnes per day for straw processed by a BCL gasifier; the cost of production is \$1.28 per kg of H_2 (\$10.66 per GJ of H_2). In contrast, 5760 dry tonnes per day is the optimum plant size for GTI gasification of straw at a production cost of \$1.20 per kg of H_2 (\$10 per GJ of H_2). In both cases, the cost of feedstock delivery is the foremost cost contributor; at optimum capacity, it accounts for 49% and 58% of the total cost for the BCL and GTI processes, respectively.

The impact on cost of feedstock transportation distance is high for both forest residue and straw; therefore, the cost of producing of biohydrogen from forest and agricultural residues increases for large-scale BCL plants. Additionally, more than 40% of the cost of biohydrogen production is contributed by the capital cost. This is true for both forest residue and straw feedstock destined for GTI gasification.

In order to be competitive with hydrogen from natural gas, carbon credits of \$119 and \$124 per tonne of CO_2 are required for forest residue- and straw-based BCL gasification plants with delivered biohydrogen costs of \$2.19 per kg of H_2 and \$2.31 per kg of H_2, respectively. Due to the high capital cost of the GTI gasification process, the carbon credit required for biohydrogen from GTI gasification is 11% and 3% higher than for BCL gasification of forest residue and straw, respectively.

Among three biomass feedstocks and two gasification processes dealt within this thesis, the lowest cost of delivered biohydrogen are for: forest residue processed by a BCL gasifier when plant capacity is lower than 2000 dry tonnes per day; whole-tree processed by a BCL gasifier when plant capacity is 2000-4000 dry tonnes per day; and whole-tree processed by a GTI gasifier when plant capacity is higher than 4000 dry tonnes per day. The cost of producing biohydrogen using whole-tree gasification decreases as plant size increases, even at plant capacities higher than 4000 dry tonnes per day; therefore, there is no technical optimum plant size. To mitigate GHG emissions, biohydrogen could be an attractive source of energy for the bitumen-upgrading process in the oil sands industry. The economic realities of the situation do, however, require substantial carbon credits, in order to off-set the higher cost of producing hydrogen from biomass.

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Chapter 4. Biohydrogen Production from Bio-oil

4.1. Introduction

Mitigating GHGs is one of the key challenges in the 21st century, and renewable energy could be one of the key contributors to meeting this challenge. Mitigation of GHG emissions requires long-term planning as well as social awareness. Renewable sources of energy can contribute significantly to the effort of mitigating GHGs. Among the different renewable energy technologies, the biomass-based energy technologies have high potential and are at various stages of development, demonstration, and commercialization.

The production of synthetic crude oil (SCO) from crude bitumen, a product of the oil sands in Alberta, requires hydrogen. This hydrogen comes almost exclusively from natural gas, and it is predicted that as SCO production increases, more hydrogen will be required for bitumen upgrading, and that will further increase the demand for natural gas (Dunbar, 2007a). Due to high volatility in the price of natural gas and to the emissions associated with its extraction and consumption, alternative sources of energy such as biomass are being seriously considered for producing hydrogen for the Alberta oil sands.

Western Canada has high potential for biomass resources which could be used for energy production. The amount of lignocellulosic biomass available in Alberta is about 3.29 million dry tonnes of forest residue and 3.19 million dry tonnes of agricultural residue every year (Sokhansanj et al., 2006; Statistics Canada, 2008; Wood and Layzell, 2003). Approximately 11.84 million dry tonnes of whole-tree are harvested in Alberta every year (Wood and Layzell, 2003). Clearly, biomass could be an attractive alternative fuel for steam and hydrogen generation, one capable of reducing overall GHG emissions.

Biomass has two key characteristics. First, biomass feedstocks are highly dispersed i.e. the amount of biomass which can be obtained per unit of area is low (dry tonnes of biomass/ha). As a result, the distance biomass must be transported to bioenergy facilities is great compared to the distance fossil fuels must be transported to a facility with the same capacity. Second, biomass has a low energy density (GJ/m^3) compared to fossil fuel. These two characteristics of biomass make its delivery-cost high.

Conversion of biomass to a dark viscous liquid called bio-oil can help by increasing energy density; if transported in liquid form, biomass can be transported at a reduced cost. Bio-oil has properties similar to grade 2 fuel oil. It can be produced by fast pyrolysis of biomass along with char and non-condensable gas (Bridgwater, 2004). Details on bio-oil production from biomass are given in subsequent sections.

The overall scope of this work includes production of bio-oil in the field/forest and transportation of bio-oil by truck to a bitumen upgrading plant where it can be used for production of biohydrogen and steam. This chapter provides a techno-economic assessment of producing biohydrogen by reforming bio-oil which is produced from the fast pyrolysis of biomass.

4.2. Scope and assumptions

The fast pyrolysis of biomass is carried out in the field or forest. This helps by shortening transportation distance, thereby lowering transportation cost. The bio-oil produced in the field/forest has a higher energy density than does raw biomass feedstock. Bio-oil is transported to bitumen upgrading plants over longer distances. Whole-tree, forest residue, and agricultural residue (i.e. a blend of straw from wheat and barley crops) are considered suitable feedstocks for bio-oil production. The bio-oil produced from these feedstocks is used to produce biohydrogen. Alcohol (e.g. methanol) is added to bio-oil to keep its chemical properties stable (Lu et al., 2008). Methanol is transported to the bio-oil production plant by the same truck that will transport bio-oil to the bitumen upgrading plant. The bio-oil and methanol mixture goes through an autothermal steam reforming process and becomes biohydrogen. The pipeline transport of bio-oil is not considered in this study as there is very limited research on it.

The cost of producing biohydrogen from biomass via bio-oil production has been estimated for various plant sizes. Data on the costs and characteristics of upstream and downstream processes have been collected through review of the literature, and discussion with experts and manufacturers. Data on bio-oil production have been taken from simulation models developed by using Aspen Plus, and from data on operating plants (Mullaney et al., 2002; Ringer et al., 2006). The process of bio-oil reforming is modeled using an Aspen Plus simulation tool representing a large-scale biohydrogen plant for which bio-oil is the feedstock. This modeling is done in order to study equipment size, plant operating parameters, and biohydrogen yield. Variable operating costs are estimated from the data generated from the simulation, and the fixed operating cost is estimated by analyzing earlier studies on producing hydrogen from natural gas (Curtis et al., 2003; Longanbach et al., 2002). Finally, the cost of delivered biohydrogen is estimated for this pathway.

4.3. Biomass pyrolysis for biohydrogen production

The process of producing biohydrogen by the fast pyrolysis of biomass can be separated into three phases: bio-oil production from biomass (i.e. forest and agricultural biomass), transportation of bio-oil by truck, and bio-oil reforming to produce biohydrogen. The following sections explain the production of biohydrogen from bio-oil using the fast pyrolysis of biomass.

4.3.1. Production of bio-oil from biomass

Biomass feedstock is collected from the field using existing harvesting technologies and then is transported to a bio-oil production plant by truck. Forest biomass is transported in the form of chips by B-train chip vans, and agricultural residue is transported in the form of bales. The key operating parameters for bio-oil production by fast pyrolysis include small feedstock size (2-3 mm), low feedstock moisture content (<10%), high heat transfer rate to the feedstock, short pyrolysis vapor residence time (around 2 seconds) in the reactor, and rapid cooling of the pyrolysis vapor (Bridgwater, 2003; Bridgwater, 2007; Ringer et al., 2006). Ground feedstock is dried using flue gases generated from a bio-oil quenching process, while non-condensable pyrolysis vapor is used to increase the feedstock's temperature to enhance the decomposition of the biomass and its fluidization so it can act as the medium in a bubbling fluidized bed reactor (Ringer et al., 2006). With a very short vapor resistance time, pyrolysis vapor leaves the reactor at around 500°C, and is cooled in the heat recovery steam generation (HRSG) process, forming bio-oil. This bio-oil is stored in anti-corrosive tanks that are made of steel, plastic, or fiberglass because bio-oil is a caustic oil (Easterly, 2002; Tampier et al., 2004). Note that methanol is added to the bio-oil in the bio-oil production plant, and this bio-oil/methanol blend is transported to a bitumen upgrading plant where it is used as a feedstock for producing hydrogen fuel.

The yield of bio-oil from fast pyrolysis is assumed to be 77.4 wt% for whole-tree, 70.3 wt% for forest residue, and 58.7 wt% for straw (Dynamotive Energy Systems, 2007; Ringer et al., 2006). The yield of bio-oil from forest residue is calculated on the basis of a biomass mixture of pine and spruce tree; yields were taken from experimental studies conducted by DynaMotive, a bio-oil production company.

Char, which is also produced from biomass by fast pyrolysis, has a heating value similar to coal. This char can be burnt to generate heat for the pyrolysis process and for producing steam (Ringer et al., 2006). In the long run, fast pyrolysis results in reduced fossil fuel consumption for bio-oil production.

Pyrolysis vapor can be quenched by spraying cold bio-oil (Mullaney et al., 2002); however, in this study, the quenching process was carried out through steam generation and air preheating processes (Ringer et al., 2006). Methanol is required as a solvent in the bio-oil reforming process; as well it reduces viscosity and density and impedes phase separation which occurs as bio-oil ages (Oasmaa et al., 2004). For these reasons, methanol is added to bio-oil. The bio-oil/methanol mixture is stored in the bio-oil production plant.

4.3.2. Production of biohydrogen from bio-oil

4.3.2.1. Feedstock preparation for bio-oil reforming

The properties of bio-oil vary significantly with changes of temperature and the passing of time. The most important property thus altered is viscosity. Adding methanol (10 wt%) reduces viscosity and density and stabilizes bio-oil for long-term storage without phase separation by stabilizing water-insoluble fraction of bio-oil (Oasmaa et al., 2004). This has been discussed in detail in earlier studies (Boucher et al., 2000; Domine et al., 2008; Oasmaa et al., 2004; Oasmaa and Peacocke, 2001). Sulfur content is also important for the reforming of any feedstock. Biomass as well as bio-oil has a low sulfur content (i.e. <0.05 wt% in bio-oil) that relies on the type of biomass feedstock used for bio-oil production (Oasmaa and Peacocke, 2001; Ringer et al., 2006; Wang et al., 1997); hence, desulfurization of the feedstock is not required. The bio-oil consists of various organic compounds, and different chemicals of bio-oil is explained in detail by Oasmaa and Peacocke (2001). The simulated composition is listed in Table F-1 of Appendix F.

4.3.2.2. Bio-oil reforming

The bio-oil/methanol mixture is transported to the bitumen upgrading plant by truck, and then heated using flue gases from the combustion of fossil fuel. The bio-oil reforming process which produces hydrogen fuel is carried out in a fluidized bed reactor where steam acts as the fluidizing medium.

Steam reforming of bio-oil is carried out in the presence of a noble metal catalyst, rhodium (Rh), which resists coke formation during reforming reactions (Domine et al., 2008; Vagia and Lemonidou, 2008b). Bio-oil is a complex liquid fuel consisting of a large number of long-chain chemical compounds (shown in Appendix F in Table F-1); the reforming process generates carbon on catalyst surface requiring a catalyst regeneration process (Davidian et al., 2008b). Noble metal catalysts, such as Pt and Ru, better control carbon formation on the catalyst surface and reactor wall, making these chemicals suitable for large-scale production of biohydrogen through biomass pyrolysis (Domine et al., 2008). There have been other studies reporting experimental work on using noble metal catalysts for bio-oil reforming (Basagiannis and Verykios, 2007; Iojoiu et al., 2007; Rioche et al., 2005). Some work has been done on bio-oil reforming in the presence of a Ni-based catalyst, and research is still being done on improving the performance of the Ni catalyst during the bio-oil reforming process (Bimbela et al., 2007; Davidian et al., 2008a; Magrini-Bair et al., 2002; Wang et al., 1997). Finally, there is autothermal steam reforming of bio-oil; this produces mainly CO_2, CO, H_2, H_2O, and CH_4 which are cooled and compressed after removing solid particles (i.e. char, ash) from the product gas (Czernik et al., 2007; Evans et al., 2008).

4.3.2.3. Reformed gas clean up and compression

Upon being separated from char during fast pyrolysis, bio-oil contains about 0.2 wt% solid content (i.e. char) which, in passing through the reforming process, results in coke formation on the surface of the catalyst (Bridgwater, 2004). Some catalyst is removed with the reformed gases and from them catalyst must be separated before the compression process. This is done by cyclone and baghouse filter. Gases produced by the reforming process are at a low pressure and high temperature; they require a rise in pressure for the water-gas shift reaction, if the rate at which hydrogen is produced is to be increased. Three stages of cooling (by HRSG) reduce the temperature of syngas (to 50ºC) in preparation for the compression process. A reciprocating compressor with 5 stages integrated with intercoolers increases the pressure of the gas (about 2.27 MPa). Compression of the gas further increases temperature, which is reduced by an air-cooled intercooler that causes water condensation. The water formed during the cooling process is removed before the next stage of compression through the use of knockout vessels. In short, 5-stage reciprocating compression is used in conjunction with 5 intercoolers and 5 knockout vessels to increase gas pressure. The power required to run the compressor shaft is supplied by an electric motor.

4.3.2.4. Water-gas shift reaction

The water-gas shift reaction, an exothermic reaction, increases the concentration of hydrogen gas in the product gas through the conversion of CO into CO_2 by steam. Heat is generated during the reaction, and higher temperatures decrease the rate of hydrogen production (Chen et al., 2008). For that reason, catalysts are used in the beds of the shift reactors during the conversion process to produce more hydrogen. Generally, two shift reactors — a high temperature shift (HTS) reactor and a low temperature shift (LTS) reactor — are used for producing hydrogen; iron oxide and chromium oxide are two catalysts commonly used in the former reactor, and copper oxide and zinc oxide are two catalysts commonly used in the latter reactor (Chen et al., 2008). The CO conversion rate on both HTS and LTS reactors relies on several factors, being influenced mainly by residence time, catalyst bed size, temperature, and CO/steam ratio (Chen et al., 2008). One of the most important design parameters for the water-gas shift reaction is the steam requirement for the process. If the reformed gas has enough steam to accelerate the water-gas shift reaction in the presence of a catalyst, no further steam is required for the process. Additionally, the steam requirement is governed by the CO/steam ratio in the reactors. The gas leaving the reactor is cooled for the biohydrogen purification process.

4.3.2.5. Biohydrogen purification

During the process of cooling syngas after the water-gas shift reaction, some of the steam in the reformed gas is condensed and then removed to prevent catalyst poisoning in the pressure swing adsorption (PSA) unit. The PSA unit is a gas separation unit where gas at a high pressure and low temperature is separated from a blend of gases using adsorption solvents. The PSA unit has several columns where successive pressurization and depressurization in the columns separate the hydrogen from other gases (Sircar and Golden, 2000). The recovery rate of biohydrogen from a PSA unit is assumed to be 80 wt%.

4.3.2.6. Steam production

Steam is one of the most important parameters of the bio-oil reforming process, and its flow rate has a large impact on the production of biohydrogen. Steam is required to create the fluidizing medium, to transfer heat into the reforming reactor, and for the water-gas shift reaction, it assists in the conversion of CO and production of hydrogen. In this study, the steam required for the reforming process and the water-gas shift reaction is produced from the HRSG process. The electricity required for the equipment is purchased from the grid, although there might be a possibility of using electricity generated through a cogeneration process at the bitumen upgrading plant. Bio-oil reforming is an endothermic process which produces reformed gases at a high temperature; heat is recovered from the reformed gases for steam production. The steam required for the reforming process is produced from external sources such as the combustion of natural gas.

The process flow diagrams of biohydrogen production from bio-oil, developed using the Aspen Plus simulation model, are depicted graphically in Figure F-1 to Figure F-5 of Appendix F. The operating conditions are also provided in Table F-2.

4.4. Estimation of biohydrogen production cost

The cost of producing biohydrogen from bio-oil which, in turn, is produced from the fast pyrolysis of biomass has three key cost components: the cost of producing bio-oil from biomass, the cost of transporting, and the cost of reforming bio-oil for biohydrogen production. Details on the cost parameters for biohydrogen production are given in subsequent sections.

4.4.1. The cost of producing bio-oil

4.4.1.1. Capital cost

The capital cost of the biomass pyrolysis process for bio-oil production includes: the cost of biomass preparation and handling, the cost of converting biomass to bio-oil, the cost of storing bio-oil and recycling non-condensable gas, and the cost of producing steam and electricity (Ringer et al., 2006). "As received" biomass from the forest has a high moisture content and large feedstock size after the chipping process which requires drying and grinding. In this study, a plant capacity of 500 dry tonnes per day is assumed in the base case which has been derived from earlier studies (Curtis et al., 2003; Ringer et al., 2006). The cost of the feedstock drying and handling equipment contributes about 27% of the total equipment cost for the base case plant size (Ringer et al., 2006). The second largest cost contributor (19% of the total equipment cost) is the pyrolysis unit which includes a bubbling fluidized bed reactor and a char combustor. Scale factors for the biomass fast pyrolysis process are derived from different studies which use similar types of process equipment

(Hamelinck and Faaij, 2002; Ringer et al., 2006; Spath et al., 2005). The estimated overall scale factor for a bio-oil production plant is 0.67.

Basically, a demonstration scale biomass fast pyrolysis plant has a capacity in the range of 60-240 dry tonnes of biomass per day (Cole Hill Associates, 2004). The maximum capacity of the bubbling fluidized bed (BFB) reactor is assumed to be 1000 dry tonnes per day based on the maximum size of a circulating fluidized bed (CFB) gasifier reported in an earlier study (Spath et al., 2005). Multiple reactors are used for plants processing more than 1000 dry tonnes per day. Details on the components of capital cost of a base case bio-oil production plant are summarized in Table 4-1.

Table 4-1: Capital cost of a base case bio-oil production plant size (500 dry tonnes per day)

Factors	**Base case cost ($1,000)**	**Scale factor [k]**
Feedstock drying and handling [a]	6,160	0.7
Pyrolysis unit [b]	4,335	0.6
Quenching unit [c]	2,145	0.6
Heat recovery unit [d]	1,261	0.7
Bio-oil recovery and storage unit [e]	885	0.6
Recycle pyrolysis vapor unit [f]	1,526	0.7
Steam and power generation unit [g]	3,495	0.7
Cooling tower unit and other utilities [h]	3,462	0.7
Equipment contingency (% of equipment cost)	35	
Total equipment cost	31,415	
Warehouse (% of total equipment cost)	1.5	
Site development [i]	1,024	
Total installed cost (TIC)	32,910	
Indirect cost (% of TIC) [j]	48	
Total capital investment (TCI)	48,707	
Startup cost (% of TCI)	10	
Total project investment	**53,578**	

[a] Maximum size of the feedstock drying and handling system is 2640 wet tonnes per day (Hamelinck and Faaij, 2002), and a number of feedstock handling systems are used when plant size exceeds the maximum size. Cost of the feedstock pretreatment is taken from Ringer et al. (2006).

[b] The pyrolysis reactor is a bubbling fluidized bed; its estimated cost is based on the cost of the fluidized bed boiler (Ringer et al., 2006).

[c] Pyrolysis vapor is cooled and condensed by water and air, and steam is produced from the HRSG process (Ringer et al., 2006).

[d] Char is burnt to generate heat that will be used to produce steam and preheat ground biomass (Ringer et al., 2006).

[e] Consists of pump, cooler, mixer, and storage tank (Ringer et al., 2006).

[f] Non-condensable pyrolysis vapor is recycled back to the pyrolysis reactor to transfer heat and fluidize feedstock (Ringer et al., 2006).

[g] Cost represents the purchase price of an economizer, a boiler, and a steam turbine capable of generating 4.9 MWe of electricity (Ringer et al., 2006). This is in keeping with other studies (Hamelinck and Faaij, 2002).

[h] Major units are the cooling tower, boiler feedwater pumps, and compressors (Ringer et al., 2006).

[i] Cost represents 9% of the major equipment cost for a biomass pyrolysis plant (Ringer et al., 2006).

[j] Indirect costs are for engineering, construction, project contingency, and the contractor fee; these costs are about 44% to 51% of TIC, based on figures from different biomass based studies (NAE et al., 2004; Ringer et al., 2006; Spath et al., 2005).

[k] Scale factors are estimated from earlier studies which use similar processes (Hamelinck and Faaij, 2002; Larson et al., 2005; Ringer et al., 2006; Spath et al., 2005).

Note that cases have been developed for biohydrogen production from bio-oil for three different feedstocks: whole-tree, forest residue, and straw. The capital cost of the bio-oil production plants for three feedstocks differs due to differences in the drying requirements of the feedstock, hence, capital costs are modified accordingly. A ten percent capital cost penalty is attributed to plant processing whole-tree and forest residue due to their remote location.

4.4.1.2. Operating cost

The operating cost of a bio-oil production plant includes the cost of electricity for the feedstock grinder, compressor motor, pumps, and other plant equipment. Note that no air/oxygen is supplied to the pyrolysis reactor to impede combustion of the feedstock. The heat required for the drying process is provided from the combustion of char. Even at a char combustion efficiency of 34 wt%, there is excess char (about 0.1% of the biomass dry basis capacity) in the biomass fast pyrolysis process (Mullaney et al., 2002). In this study, the yield of char is assumed to be 15.3 wt% of dry whole-tree, all of which is burnt for heat and steam production (Ringer et al., 2006); therefore, there will be some excess electricity produced during bio-oil production which can be transmitted to the grid. A fixed value is assumed for electricity and chemical consumption for waste water treatment. A plant's yearly operating cost, excluding the cost of feedstock, is about 1.2% of its capital cost.

Fixed operating cost, one component of the total bio-oil production cost, is assumed to be comparable with the fixed cost of a biomass gasification plant, as explained in Chapter 2 and 3. All the variable operating costs of a bio-oil production plant are listed in Table 4-2. The maintenance cost of a biomass fast pyrolysis plant is assumed to be 2% of the plant investment cost based on different studies on biomass processing (Kumar, 2009; Spath et al., 2005).

Table 4-2: Operating cost for a bio-oil production plant

Factors	Value	Comments/sources
Feedstock delivery cost ($/dry tonne): • Whole-tree • Forest residue • Straw	 36 33.5 48	For forest biomass the feedstock delivery cost includes the cost of biomass harvesting, and transportation, road construction, silviculture, and royalty fee. Forest residue costs do not include silviculture and road construction. For straw, the cost includes harvesting, collection, baling, transportation, nutrient replacement, and premium paid to the farmer in addition to the nutrient replacement cost. Details on these costs are given in Chapter 2 and 3.
Gross electricity production from HRSG (kWh/dry tonne)	235	Electricity is produced from a heat recovery steam generation process (Ringer et al., 2006).
Non-condensable recycle gas compression (kWh/dry tonne)	125	Non-condensable gases are recycled back to the pyrolysis reactor (Ringer et al., 2006).
Feedstock grinding process (kWh/dry tonne)	67	Overall energy consumption for feedstock grinding (about 3 mm) process (Ringer et al., 2006).
Purchase price of methanol ($/liter)	0.13	Spot price of methanol (The Innovation Group, 2000).
Water treatment plant ($/dry tonne)	6.66	Assumed waste-water treatment and plant chemical cost (Ringer et al., 2006).
Electricity selling price ($/kWh)	0.07	The excess electricity, which is produced from the HRSG process, is sold to the grid.
Average labor cost including benefits ($/hr): • Operating staff • Administration staff	 40 64	Salaries have been adjusted for the Province of Alberta and are explained in Chapter 2 and 3 (Aden et al., 2002; PAQ Services Inc., 2007; Ringer et al., 2006).

4.4.1.3. Bio-oil production cost

Whole-tree, forest residue, and straw are taken into account for bio-oil production. Different cost components of bio-oil production for a plant capacity of 500 dry tonnes per day (base case) are listed in Table 4-3. In the base case (500 dry tonnes per day), whole-tree has the lowest production cost ($0.15 per kg of bio-oil), where 37% and 30% of the total production cost is contributed by capital cost and feedstock-delivery cost, respectively. As plant size increases, the contribution of the feedstock-delivery cost increases for all of the feedstocks because of increasing biomass transportation distance.

Table 4-3: Base case production cost of bio-oil from biomass fast pyrolysis (500 dry tonnes per day)

Cost components	Whole-tree (% of total cost)	Forest residue (% of total cost)	Straw (% of total cost)
Capital	37	36	32
Operating	4	5	5
Maintenance	6	6	5
Administrative	23	25	20
Harvesting	9	11	9
Transportation	8	12	12
Road and infrastructure	7	0	0
Silviculture	2	0	0
Nutrient replacement	0	0	12
Royalty cost/premium	4	4	4
Ash disposal	0	1	1
Total production cost ($/kg of bio-oil)	0.15	0.17	0.19

Figure 4-1 gives a summary of the variation in bio-oil production cost at different capacities for plants processing whole-tree, forest residue, and straw. The whole-tree-based plant has the lowest bio-oil production cost; however, the cost of bio-oil from whole-tree and forest residue is quite similar for plants capable of handling 200-1000 dry tonnes per day.

The cost of producing bio-oil decreases rapidly for whole-tree feedstock until the plant capacity reaches 1500 dry tonnes per day ($0.11 per kg of bio-oil). Additionally, the cost of producing bio-oil drops rapidly for forest residue and straw until a plant capacity is reached of about 1000 dry tonnes per day ($0.12 per kg of bio-oil) and 2000 dry tonnes per day ($0.15 per kg of bio-oil), respectively. Beyond these plant capacities, costs are almost constant for whole-tree and forest residue, whereas, for straw, bio-oil production cost increases above 4000 dry tonnes per day due to large straw transportation distance compared to whole-tree and forest residue. As a result, there is no technical optimum plant size for bio-oil production based on whole-tree below a capacity of 10000 dry tonnes per day as shown in Figure 4-1, but it is possible to build at a size after which the cost of production is almost flat.

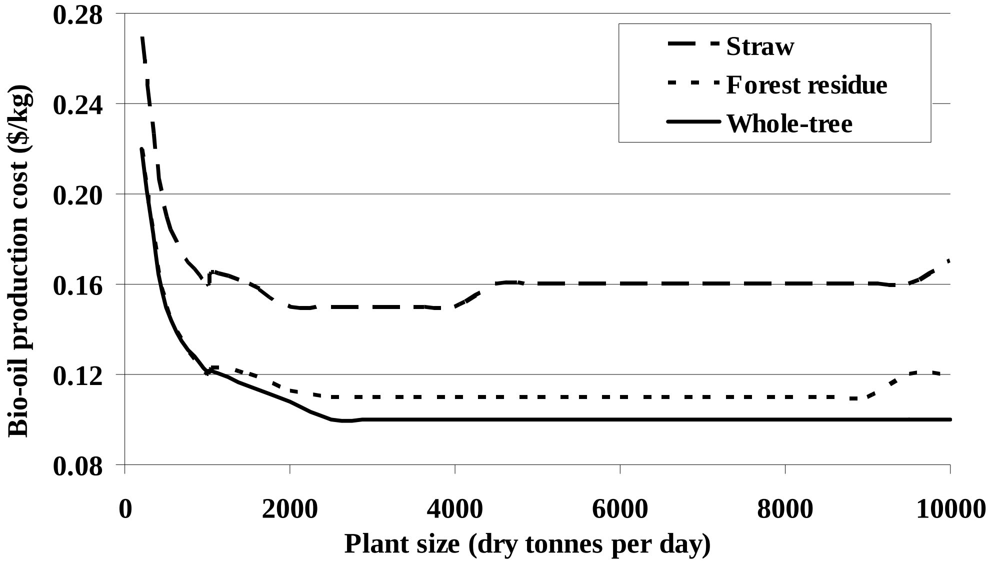

Figure 4-1: Variation of bio-oil production cost with plant size for whole-tree, forest residue, and straw

Based on these results, in this study it is assumed that bio-oil is produced in a plant processing 2000 dry tonnes of biomass per day. Bio-oil produced by this plant is transported to a biohydrogen production plant. The size of the biohydrogen production plant will differ, depending on which feedstock (i.e. whole-tree, forest residue, or straw) is the source of the bio-oil to be processed. This is because the bio-oil yields are different.

4.4.2. The cost of transporting bio-oil

Once bio-oil is produced, it is stored in a large tank (made of plastic, stainless steel, or fiberglass) (Easterly, 2002), and methanol is added to keep the bio-oil properties stable. The bio-oil/methanol mixture is transported to a biohydrogen production plant by truck, and that same truck will transport methanol to the bio-oil production plant on the return trip. The transportation of bio-oil is carried out by eight-axle super B-train trucks with a transportation capacity of about 60 m^3 (about 72 tonnes of bio-oil). This truck has a distance-fixed cost and distance-variable cost of \$1.193 per m^3 and \$0.048*D* per m^3 of bio-oil, respectively (Transport Canada, 2005). Here, *D* is the transportation distance between the bio-oil production plant and the biohydrogen production plant. In this study, this is assumed to be 500 km. The transportation of bio-oil by B-train costs \$0.041 per kg of bio-oil for each 500 km trip.

4.4.3. The cost of reforming bio-oil

4.4.3.1. Capital cost

Fast pyrolysis of whole-tree yields 77.4 wt% bio-oil. Based on this yield, 1548 tonnes of bio-oil is produced from fast pyrolysis of 2000 dry tonnes of whole-tree. Thus a plant processing 2000 dry tonnes of whole-tree per day will supply a bio-oil reforming plant that has a capacity of 1548 tonnes bio-oil per day. The bio-oil reforming plant produces biohydrogen. The capital cost of the biohydrogen production plant (or bio-oil reforming plant) is \$101 million with a scale factor of 0.60 for a plant capacity of 1548 tonnes of bio-oil per day (illustrated in Figure 4-2), so the scale factor of the bio-oil production plant is higher than the scale factor of the bio-oil reforming plant.

The total amount of bio-oil/methanol blend transported per day is 1720 tonnes; this requires 24 truck trips per day (including the transportation of 10 wt% of methanol).

The cost of equipment (Hamelinck and Faaij, 2002; Larson et al., 2005; Spath et al., 2005) and operating parameters (Cicconardi et al., 2006; Hao et al., 2008; Vagia and Lemonidou, 2008a) are estimated from different studies (which use similar processes or equipment) and the Aspen Plus model, respectively. The capital cost of a bio-oil steam reforming plant for producing biohydrogen includes the cost of each unit of feedstock (bio-oil and methanol) storage, feedstock reforming, product gas clean up, product gas compression, water-gas shift reaction, hydrogen purification (i.e. PSA), and steam production. The Aspen Plus simulation tool is used to calculate equipment size and other operating parameters (e.g. stream flow rate, hydrogen yield from bio-oil). For example, the capacity of the heat transfer equipment (i.e. boiler, superheater, and heater) is calculated from the heat duty, whereas the capacity of the pump and compressor is calculated from the power requirement for the driving motor. Once all the cost components and parameters are collected, a techno-economic model of bio-oil production from biomass and of biohydrogen production from bio-oil can be developed. These techno-economic models are given in Table E-1 and Table E-2 of Appendix E for whole-tree biomass.

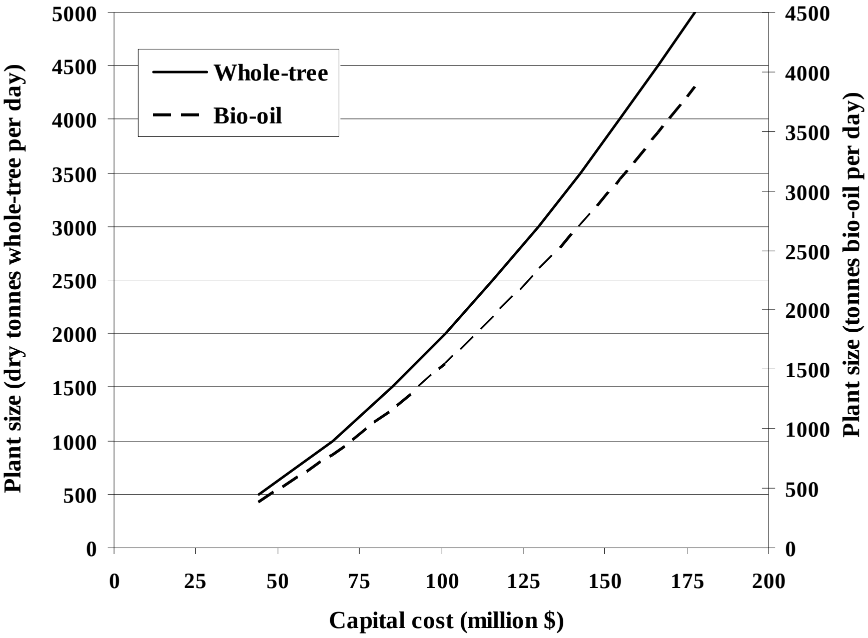

Figure 4-2: Capital cost of a bio-oil reforming plant for biohydrogen production

4.4.3.2. Operating cost

The variable operating cost of a bio-oil reforming process includes the cost of electricity, natural gas, reforming catalyst, boiler chemicals, waste-water treatment, and reactor catalysts. Natural gas is burnt to produce process steam. The cost of the electricity the plant consumes is calculated from the electricity purchased from the grid. Generally, a large bitumen upgrading plant has a cogeneration process for steam and electricity production using natural gas as its feedstock. It is assumed that the cogeneration process will produce enough electricity to meet the electricity demand of the bitumen upgrading and bio-oil reforming processes. The variable operating costs for bio-oil reforming are shown in Table 4-4.

Table 4-4: Variable operating cost for base case bio-oil reforming

Factors	Value	Comments/sources
Power requirement (MW_e)	39.71	Gas compression and air separation units consume the most power.
Price of electricity ($/kWh)	0.07	A stable value is assumed for electricity price in Alberta.
Natural gas consumption (million GJ)	6.06	Natural gas is used to produce steam for the reforming reaction and water-gas shift reaction.
Cost of natural gas ($/GJ)	5	A stable value is assumed for natural gas price in Alberta.
Amount of reforming catalyst (kg)	1,672	The amount of catalyst is calculated from a stand-alone hydrogen production plant with a capacity of 1500 kg per day (Evans and Steward, 2007).
Life of catalyst (in years)	5	Catalyst is lost as solids are removed from the syngas (Evans and Steward, 2007).
Cost of reforming catalyst ($/kg)	13,539	Rhodium (Rh) is the catalyst which is used in the bio-oil reforming process (Evans and Steward, 2007).
Water consumption (m^3/kg of H_2)	0.02	The steam to carbon ratio is assumed to be 3.
Cost of water treatment ($/$m^3$)	0.79	Cost of waste water treatment (Spath et al., 2005).

4.5. Results and discussion

4.5.1. Delivered biohydrogen cost

The cost of biohydrogen from a 2000 dry tonnes per day whole-tree-based bio-oil plant (one that produces 1548 tonnes of bio-oil per day) is $2.48 per kg ($20.66 per GJ), where the yield of bio-oil from the whole-tree biomass is assumed to be 77.4 wt%. For a plant with a capacity of 2000 dry tonnes of whole-tree per day, the cost of bio-oil production is $0.11 per kg, and bio-oil production cost contributes 33% of the total cost of biohydrogen production. The overall yield of biohydrogen from the fast pyrolysis process is 9.45 wt% of the dry whole-tree biomass in the bio-oil production plant, or 12.2 wt% of the bio-oil in a biohydrogen production plant. Note that the properties of bio-oil from the three biomass feedstocks are assumed to be the same; therefore, the yield of biohydrogen from steam reforming will be similar. Table 4-5 lists the cost associated with producing biohydrogen from the fast pyrolysis of biomass and the steam reforming of bio-oil.

Table 4-5: Base case delivered H_2 production cost from fast pyrolysis of whole-tree with bio-oil reforming

Cost factors	Value (\$/kg of H_2)	% of total cost
Capital	0.19	8
Operating	0.90	36
Maintenance	0.02	1
Administrative	0.06	3
Bio-oil production	0.82	33
Methanol	0.14	5
Bio-oil transportation	0.35	14
Total cost	2.48	100

The largest contributor to the cost of producing biohydrogen is the total operating cost. Consumption of natural gas constitutes about 54% of the variable operating cost; other variable operating costs are the cost of electricity (35%), cost of the reforming catalyst (9%), and cost of water treatment (1%).

Figure 4-3 shows the costs entailed in producing biohydrogen from the fast pyrolysis of biomass and the steam reforming of bio-oil for various plant sizes. The cost of producing biohydrogen decreases rapidly up to a plant capacity of about 2000 dry tonnes per day. Since there is no economy of scale for truck transportation of bio-oil and operating cost of biohydrogen production from bio-oil, there is no technical optimum size for biohydrogen production using pyrolysis of biomass below a plant capacity of 10000 dry tonnes per day. The cost of producing biohydrogen from whole-tree and forest residue is almost same for plants processing 200-2000 dry tonnes per day. The cost of producing straw-based biohydrogen is high compared to whole-tree-based and forest-residue-based biohydrogen. This is due to the high cost of producing bio-oil.

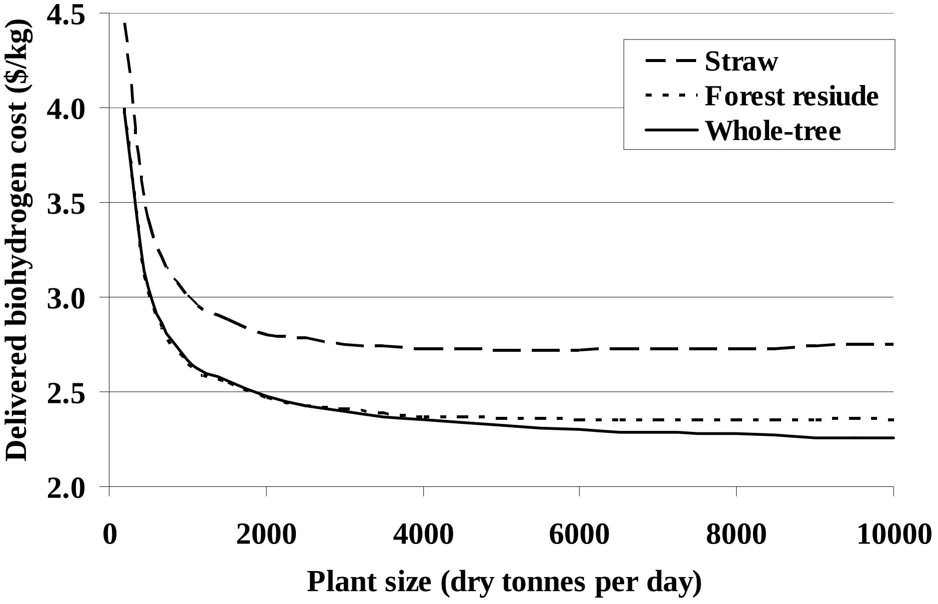

Figure 4-3: Cost of delivered biohydrogen from bio-oil produced by fast pyrolysis of biomass

Forest residue biomass has the lowest biohydrogen production cost, followed by whole-tree. Even though the yield of bio-oil from whole-tree and forest residue is different, the cost of producing bio-oil is quite same for these feedstocks for plants processing 200-2000 dry tonnes of biomass per day. All the cost components of a forest residue-based bio-oil reforming plant are lower than those of a whole-tree-based bio-oil reforming plant. As a result, biohydrogen from forest residue costs the least. At a bio-oil production cost of \$0.11 per kg and \$0.15 per kg from 2000 dry tonnes of biomass per day, the cost of producing biohydrogen is \$2.47 per kg of H_2 and \$2.80 per kg of H_2 from forest residue and agricultural residue, respectively. Hence, forest residue has the greatest potential for economical biohydrogen production through fast pyrolysis when there is a biomass feedstock constraint.

4.5.2. Carbon credits required for biohydrogen

Chapter 2 and 3 explain life cycle emissions and carbon abatement for biohydrogen production involving gasification of whole-tree, forest residue, and agricultural residue feedstocks. Biohydrogen production using pyrolysis of biomass involves bio-oil production and steam reforming. Similar emissions are used for calculating carbon abatement costs. The total amount of biomass needed for biohydrogen production is different from that needed for the gasification process, therefore, emissions are calculated based on the total amount of biomass required to produce 1 kg of biohydrogen. During the storage and transportation of bio-oil, 10 wt% of methanol is added to the bio-oil, so the emissions from producing methanol are disregarded; this is because they are negligible compared with the total emissions from the process of producing bio-oil. On the other hand, emissions during the transportation of methanol are included in the emissions for bio-oil transportation.

Table 4-6 gives the life cycle emissions for producing biohydrogen from the pyrolysis of biomass.

Table 4-6: Life cycle emissions (kg CO_2 equivalent per kg of H_2) from biohydrogen using fast pyrolysis of biomass

Factors	Whole-tree	Forest residue	Straw
Biomass production [a]	0.339	0.504	0.356
Biomass transportation [b]	0.076	0.352	0.259
Construction and decommissioning of bio-oil plant [c]	0.192	0.211	0.361
Bio-oil transportation [d]	0.502	0.502	0.502
Energy conversion	0	0	0
Construction and decommissioning of bio-oil reforming plant [e]	0.066	0.06	0.05
Total emissions	1.17	1.63	1.53

[a] With bio-oil yields of 77.4 wt%, 70.3 wt%, and 58.7 wt% from whole-tree, forest residue, and straw, and with a biohydrogen yield of 11 wt% from the bio-oil/methanol mixture, the amount of feedstock required for one kg of H_2 production is 10.6 kg of dry whole-tree, 11.7 kg of dry forest residue, and 19.9 kg of dry straw, respectively. Emissions for whole-tree biomass include emissions during felling, skidding, chipping, and transportation of chips to the bio-oil production plant. Emissions for forest and agricultural residues are explained earlier, in Chapter 3.

[b] Biomass is transported by truck to a bio-oil production plant capable of processing 2000 dry tonnes per day; the average transportation distance is 18 km, 76 km, and 92 km for whole-tree, forest residue, and straw, respectively.

[c] Emission from plant construction and decommissioning are calculated based on the amount of biomass required to produce 1 kg of biohydrogen which, for bio-oil production, is 18.1 gm CO_2/kg of dry biomass (Kumar et al., 2003).

[d] The bio-oil/methanol mixture is transported 500 km by truck; truck capacity is 60 m^3.

[e] Estimating emissions from the construction and decommissioning of the bio-oil reforming plant relies on a comparison of hydrogen production and the process of natural gas reforming (Spath and Mann, 2001).

Using the data in Table 4-6, the cost of carbon mitigation is estimated for biohydrogen production from bio-oil, which is produced from whole-tree, forest residue, and straw. For the three lignocellulose biomass feedstocks, the cost of biohydrogen from forest residue is the lowest, followed by whole-tree and straw. Figure 4-4 depicts the comparison of the cost of carbon mitigation for producing biohydrogen from three feedstocks. Finally, at natural gas price of $5 per GJ, the mitigation costs are $140, $146, and $177 per tonne of CO_2 equivalent for producing biohydrogen from fast pyrolysis of whole-tree, forest residue, and straw, respectively.

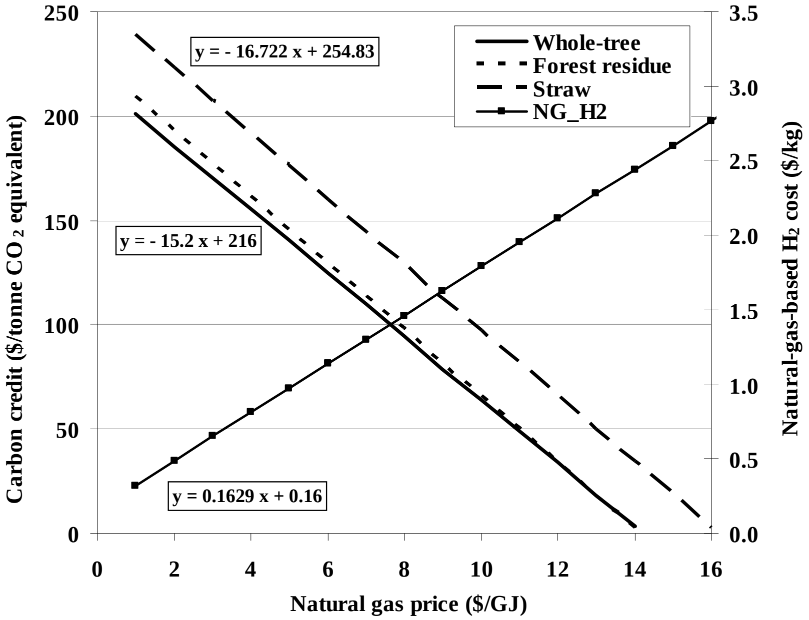

Figure 4-4: Carbon abatement cost for biohydrogen where bio-oil replaces natural-gas-based hydrogen

4.5.3. Sensitivities

Sensitivity analyses of bio-oil production from whole-tree, forest residue, and agricultural residue show similar characteristics. The impact of different cost components is approximately the same for the three biomass feedstocks. The yield of bio-oil has the greatest impact on the cost of bio-oil production, followed by the capital cost for a forest residue-based bio-oil plant. The size of a bio-oil reforming plant is estimated based on the rate at which its bio-oil production plant processes biomass. Various sensitivity analyses show that biohydrogen yield has the greatest impact on biohydrogen cost, although other parameters do have a slight impact on that cost. Table 4-7 provides a sensitivity analysis of biohydrogen production from the fast pyrolysis of forest residue. Because forest residue provides the cheapest biohydrogen, the various in costs are shown for this case.

Table 4-7: Key sensitivities of producing H_2 from the fast pyrolysis of biomass

Factors	Price ($/kg)	Price impact (%)
Base case, cost of producing bio-oil from forest residue	0.15	
Capital cost of bio-oil plant:		
• 10% higher	0.16	+ 6.7
• 10% lower	0.14	- 6.7
Operating cost of bio-oil plant:		
• 10% higher	0.15	0
• 10% lower	0.14	- 6.7
Yield of bio-oil:		
• 10% higher	0.14	- 6.7
• 10% lower	0.17	+ 13.3
Base case, cost of producing biohydrogen from the fast pyrolysis of forest residue	2.47	
Capital cost of biohydrogen plant:		
• 10% higher	2.49	+ 0.9
• 10% lower	2.45	- 0.7
Operating cost of biohydrogen plant:		
• 10% higher	2.56	+ 3.7
• 10% lower	2.38	- 3.6
Price of bio-oil:		
• 10% higher	2.55	+ 3.3
• 10% lower	2.38	- 3.6
Yield of biohydrogen:		
• 10% higher	2.24	- 9.3
• 10% lower	2.74	+ 11
Cost of bio-oil transportation:		
• 10% higher	2.50	+ 1.3
• 10% lower	2.43	- 1.6
Cost of natural gas:		
• 10% higher	2.51	+ 1.7
• 10% lower	2.43	- 1.6
Cost of electricity:		
• 10% higher	2.50	+ 1.3
• 10% lower	2.44	- 1.2
Pretax return on capital cost is 12% rather than 10%	2.50	+ 1.3

4.6. Conclusions

Biohydrogen can be produced from the fast pyrolysis of forest residue at a cost of \$2.47 per kg of H_2 (\$20.57 per GJ of H_2); this includes the cost of bio-oil production (\$0.85 per kg), bio-oil transportation (\$0.34 per kg), and bio-oil reforming (\$1.28/kg). The bio-oil production and operating costs are 35% and 34% of the total delivered biohydrogen cost, respectively. Methanol (10 wt% of total feedstock for biohydrogen production) is added to bio-oil to maintain the viscosity, density, and composition of the bio-oil during transportation and the reforming process. Overall, there is no technical optimum size for bio-oil production plants processing whole-tree, forest residue, or straw; however, maximum economy of scale for fast pyrolysis of whole-tree is observed at 2000 dry tonnes per day. Cost at this size is \$0.11 per kg of bio-oil for forest-based biomass feedstock. For plants larger than this, there is very little decrease in the cost of bio-oil as the plant size increases. For a 500 km of truck transportation of bio-oil and methanol, the cost of transportation contributes 14% of the total delivered biohydrogen cost. A 2000 dry tonnes per day forest residue-based fast pyrolysis plant produces 1406 tonnes of bio-oil per day. That will produce 172 tonnes of hydrogen per day at a cost of \$2.47 per kg of H_2. Because the cost of biohydrogen is higher than the cost of natural-gas-based hydrogen, carbon credit (\$146 per tonne of CO_2 equivalent at a natural gas price of \$5/GJ) is required if biohydrogen is to be competitive with natural-gas-based hydrogen.

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Chapter 5. Conclusions and Recommendation for Future Work

5.1. Conclusions

Whole-tree, forest residue, and agricultural residue are analyzed for biohydrogen production in Alberta. Two different pathways of biohydrogen production are considered: biohydrogen production through the reforming of syngas produced by the gasification of biomass, and biohydrogen production through the reforming of bio-oil produced from the fast pyrolysis of biomass. These processes are considered for large-scale biohydrogen production suitable for use in the bitumen upgrading process in Alberta. Various techno-economic models are developed to estimate optimum size and the cost of biohydrogen production. Three different feedstocks which are abundant in Alberta are considered for producing biohydrogen. In order to reduce the cost of transporting the biomass feedstock, biohydrogen production plants processing whole-tree and forest residue are located in remote areas. As a result, biohydrogen must be transported to the bitumen upgrading plant. Biohydrogen, produced by reforming syngas, is transported by pipeline, cryogenic tank, and tube trailer.

5.1.1. Biohydrogen production by reforming syngas produced through the gasification of biomass

Biomass is gasified in two types of gasifier, one developed by Battelle Columbus Laboratory (BCL) and one developed by the Gas Technology Institute (GTI). The former, uses a low pressure gasification process with a lower capital cost that results in a lower cost of biohydrogen production. In this study, biohydrogen is produced in a large-scale plant in order to get benefit from the economy of scale.

The results from this study show that, for syngas reforming, plant size can be separated into two ranges according to production cost and type of gasification process. These size ranges are: 200-2000 and 2000-10000 dry tonnes per day. The cost of producing biohydrogen decreases sharply for plant with a capacity in the range of 200-2000 dry tonnes per day. There is very little decrease in production cost as plant capacity increases for plants processing more than 2000 dry tonnes per day.

Based on the results of this study, sizes can be recommended for plants producing biohydrogen from three biomass feedstocks. For whole-tree feedstock, BCL gasification should be considered for plants with a capacity in the range of 200-4000 dry tonnes per day, and GTI gasification should be considered for plants with a capacity in the range of 4000-10000 dry tonnes per day. Similar, plant capacities should be considered for forest residue-based biohydrogen production plants. When straw is the feedstock, BCL gasification should be used in plants with a capacity of 200-2200 dry tonnes per day, while GTI should be selected for larger plants. Note that the minimum size for a biohydrogen production plant is considered to be 200 dry tonnes per day.

The results obtained in this study can be used to recommend feedstock and plant capacity for BCL gasification. At less than 500 dry tonnes per day, the cost of producing biohydrogen is almost the same for the three biomass feedstocks. The cost of producing biohydrogen from forest residue is lowest when the plant processes 500-2000 dry tonnes per day (\$1.52-\$1.17 per kg of H_2). The cost of producing biohydrogen is nearly the same for whole-tree and forest residue when plants process 2000-3000 dry tonnes per day (\$1.18-\$1.14 per kg of H_2); whereas, for plants processing more than 3000 dry tonnes per day, whole-tree-based biohydrogen has the lowest production cost.

Straw-based GTI gasification plants have the lowest production cost when the plant processes less than 1500 dry tonnes per day. The cost is almost the same for whole-tree and forest residue (for GTI gasifiers) at 1500-3000 dry tonnes per day (\$1.44-\$1.22 per kg of H_2). Whole-tree has the lowest production cost (for GTI gasifiers) at more than 3000 dry tonnes per day.

This study found the optimum capacity of a biohydrogen production plant to be greater than 5000 dry tonnes per day for three biomass feedstocks using two types of gasification. The cost of biohydrogen from whole-tree gasification continues to decrease as plant capacity increases, even for plants able to process more than 5000 dry tonnes per day. The optimum size for biohydrogen production plants processing forest and agricultural residues in BCL gasifiers is 3000 dry tonnes per day; the cost of biohydrogen for these biomass feedstocks at this optimum size are \$1.15 per kg and \$1.29 per kg, respectively. The optimum capacity of biohydrogen plants for GTI gasification is 8500 dry tonnes per day for forest residue (cost at this size is \$1.07 per kg of H_2), and 5760 dry tonnes per day for agricultural residue (cost at this size is \$1.20 per kg of H_2).

The cost of transportation is lowest when a pipeline is used instead of cryogenic tanks or tube trailers for large amounts of biohydrogen traveling a great distance. At a pipeline transportation capacity of 167 tonnes of hydrogen per day, the pipeline has the lowest transportation cost, up to a distance of 1,140 km; beyond this distance, transporting liquid hydrogen in cryogenic tanks costs less. Note, however, that pipeline transportation is not optimum for less than 75 tonnes of hydrogen per day for 500 km.

The delivered biohydrogen cost from a 2000 dry tonnes per day plant processing whole-tree using a BCL gasifier is \$2.20 per kg of H_2 (i.e. \$18.32 per GJ kg of H_2). Delivered cost is \$2.19 per kg of H_2 (i.e. \$18.24 per GJ of H_2) for forest residue and \$2.31 per kg of H_2 (i.e. \$19.24 per GJ of H_2) for straw. On the other hand, the production of biohydrogen costs \$2.34 per kg of H_2 (i.e. \$19.49 per GJ of H_2), \$2.32 per kg of H_2 (i.e. \$19.33 per GJ of H_2), and \$2.35 per kg of H_2 (i.e. \$19.58 per GJ of H_2) for the GTI gasification of whole-tree, forest residue, and agricultural residue, respectively when processed at a plant with a capacity of 2000 dry tonnes per day plant. In conclusion, the largest biohydrogen production plant capacity is 2000 dry tonnes per day for BCL gasification and 3000 dry tonnes per day for GTI gasification.

There is no appreciable capital cost penalty since biohydrogen production plants do not obtain significant economy of scale benefits regarding capital cost.

5.1.2. Biohydrogen production by reforming bio-oil produced through the fast pyrolysis of biomass

Biohydrogen can also be produced by reforming bio-oil produced through the fast pyrolysis of biomass. Producing biohydrogen this way eliminates the long-distance transportation of biohydrogen to a bitumen upgrading plant, because bio-oil is transported by truck to the bitumen upgrading plant where it is steam reformed to produce biohydrogen. Among the selected biomass feedstocks, forest residue has the lowest bio-oil production cost. Bio-oil can be produced at $0.11 per kg from whole-tree at a plant size of 2000 dry tonnes per day, so that feedstock-delivery cost (43%) and capital cost (36%) are the largest contributors to the total production cost.

The feedstock-delivery cost for biohydrogen production — which includes the production cost of bio-oil, the purchase cost of methanol, and the transportation cost of bio-oil/methanol mixture — contributes more than 50% of the cost of producing biohydrogen from bio-oil. For a 2000 dry tonnes per day forest residue-based plant, the cost is \$2.47 per kg of H_2 (\$20.56 per GJ of H_2) which includes \$0.85 per kg of H_2 for bio-oil production and \$0.35 per kg of H_2 for transportation of the bio-oil/methanol blend.

5.1.3. Comparison of biohydrogen production pathways

The cost of producing biohydrogen through pyrolysis of biomass is higher than through gasification of biomass. Feedstock delivery and biohydrogen transportation are the major economic factors for biohydrogen production, how much they cost depends on where the biohydrogen production plant is located. Delivering the feedstock costs \$1.70-\$2.95 per GJ (based on HHV of dry biomass) for different feedstocks at a plant size of 2000 dry tonnes per day. The cost of delivery increases as plant capacity and transportation distance increase. The distance between a biohydrogen production plant and a bitumen upgrading plant is assumed to be 500 km in Alberta.

5.1.4. Carbon credits required for biohydrogen to be competitive with natural-gas-based hydrogen

Delivered biohydrogen cost more than does natural-gas-based hydrogen; so much more that currently it is not economical to produce hydrogen from biomass. The life cycle emissions from producing biohydrogen are very low (they vary with the feedstock transportation distance), but the low price of natural gas and, hence, of natural-gas-based hydrogen makes biohydrogen uncompetitive unless it receives a substantial carbon credits. At 2000 dry tonnes per day, a carbon credit of \$120-\$140 per tonne of CO_2 equivalent is required in order for different biomass feedstocks and gasification processes to be competitive when natural gas costs \$5 per GJ. At a natural gas price of $12 per GJ no carbon credit would be needed to make biohydrogen competitive.

5.2. Recommendations for future research

This study is basically a techno-economic assessment of biohydrogen production from available biomass resources in Western Canada. The cost of large-scale biohydrogen production is estimated for whole-tree, forest residue, and agricultural residue processed by the gasification and pyrolysis. Some opportunities for future research on biohydrogen production are given below.

- Production cost of biohydrogen is estimated for a centralized plant which operates with only one type of biomass feedstock throughout the plant life. It might be interesting to investigate the techno-economics of biohydrogen production from multiple biomass feedstocks (i.e. blend of straw and forest residues). This will help in further increasing the scale of the biohydrogen production plant.

- The yield of biohydrogen from the BCL gasification of whole-tree has been derived from the NREL pilot plant but, as yet, the yield of biohydrogen from forest and agricultural residues has not been determined from experimental studies on BCL and GTI gasifiers. This would merit research, as would experimental studies using other biomass feedstocks such as corn stover.

- Some CO_2 produced during the biohydrogen production process is not captured and stored. Future studies could focus on carbon capture to reduce GHG emissions and cost of the GHG abatement.

- At present, the location for biohydrogen plants is determined by biomass resource availability, the distance between biohydrogen production plants and bitumen upgrading plants is assumed to be 500 km, and the yield of biomass is as estimation based on average yield in Alberta. Future work could be conducted on particular feedstocks and the precise location of biohydrogen production plants using Geographic Information Systems (GIS). Data on biomass yield and availability, as well as on feedstock, and biohydrogen transportation distances could be determined more precisely along with the cost of production and carbon credits.

- The fast pyrolysis of biomass is a mature technology for bio-oil production, whereas bio-oil reforming for large-scale continuous production of hydrogen fuel has not been successfully done on a demonstration scale; this leads to a significant research opportunity involving bio-oil reforming. Experimental studies should be performed on different catalysts and feedstocks. Different studies have been proposed using parallel reactors for a catalyst regeneration process; this could be validated through experimental studies.

- Western Canada's, especially British Columbia's, forest is infested with mountain pine beetles which have destroyed large areas of forest. These dead trees, which can not be used by the pulp or lumber industries, could be used for biohydrogen production. Hence, experimental work on the gasification of these beetle-infested trees could be performed in order to determine their hydrogen yield and economic feasibility.

Appendix A.

Equations Used to Calculate Different Parameters of Biohydrogen Production and Transportation Model

- **Biomass density at given moisture content**

Biomass density increases with increasing moisture content which is calculated from the following equation (Simpson, 1993).

Biomass density (green kg/m^3) = Density of water (kg/m^3) × Biomass specific gravity × (1 + % Moisture content)

- **Harvesting area**

Harvesting area (ha) = Total biomass required (green tonnes)/Average biomass yield (green tonnes per hectare)

- **Harvesting cost**

Harvesting cost (\$/year) = Biomass required (green tonnes per year) × Harvesting cost (\$ per green tonne)

- **Calorific value at given moisture content**

Calorific value at given moisture content (Matthews, 2001):

$$C'_{wood} = FC^{*}{}_{wood} - 0.206FH_2 - 0.023(W_{wood} + 0.1FA)$$

Where,

C'_{wood} is the net calorific value of wood at moisture content W_{wood} in wet basis (MJ/kg)

C^{*}_{wood} is the gross calorific value of oven dry wood (MJ/kg)

H_2 is average percentage of hydrogen content of oven dry wood (%)

A is average percentage of ash content of oven dry wood (%)

W_{wood} is the moisture content of wood in wet basis (note that, for 50% moisture content, W_{wood}=50)

F is the oven dry mass of wet wood where, F = (100- W_{wood})/100 (oven-dry kg/ wet kg)

- **Transportation distance of agricultural residue**

Transportation distance of straw is calculated according to the assumption of square straw harvesting area, and biohydrogen production plant would be at the intersection of the diagonals of the square. Generally, one can assume rectangular crop harvesting area; however, it is easier to assume square harvesting area to calculate average transportation distance. Actually straw harvesting area would be the same for each of the year during the 20 years plant life, unless there is drought or downpour which might reduce crop yield and ultimately straw yield.

Since the average radius of an inscribed circle of the square is 67% of the radius of the inscribed circle (i.e. half of the one side of the square), and average radius of a circumcircle of the square is 94% of the radius of the inscribed circle (shown in

Figure A-1); an equivalent circular area of the square is calculated which has an average radius of 75.22% of the radius of inscribed circle. Therefore, average straw transportation distance is assumed 75% of the half of one arm of the square. In Figure A-1, straw harvesting area is presented by the square *EFGH*, point *O* is the location of the biohydrogen production plant, point *A* is the location of the bitumen upgrading plant, and *X* is the hydrogen fuel transportation distance from the biohydrogen production plant to the bitumen upgrading plant. Additionally, $\overline{R}$ is the average straw transportation distance, and R is the half of one side of the square.

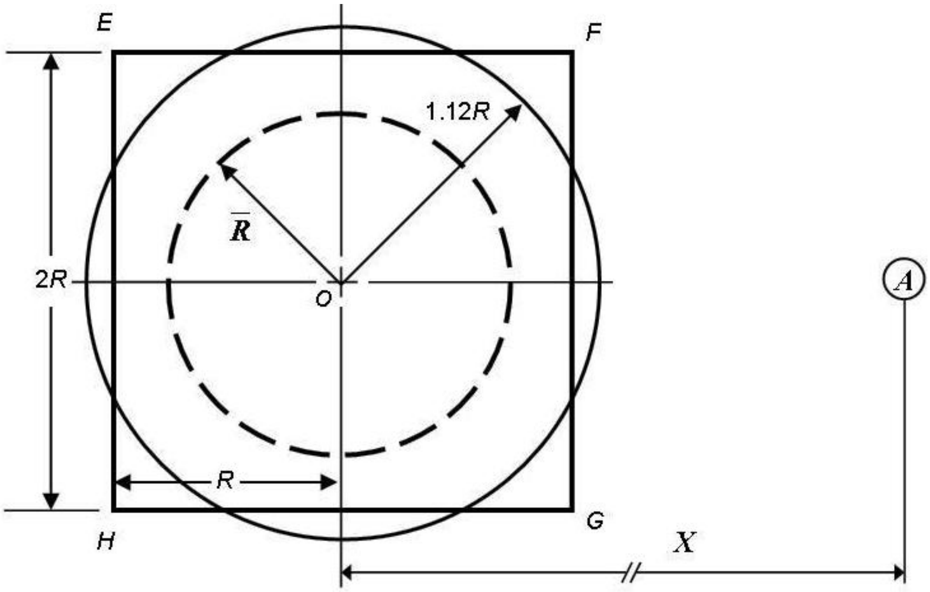

Figure A-1: Schematic diagram for straw-based biohydrogen production plant and hydrogen transportation distance

- **Transportation cost of forest biomass**

Whole-tree and forest residue loading, unloading, and transportation costs ($ per year) were calculated using the following equation developed by Kumar et al. (2003).

Chip loading, unloading, and transportation cost ($ per year) = Infrastructure cost ($ per m^3) × (2.3 + 0.0257D) ×Feedstock requirement (green tonnes per year)/Chip bulk density (green tonnes/m^3)

Here, D is the round trip transportation distance between roadside chipping and biohydrogen production plant.

- **Cost of road construction**

Primary and secondary road construction cost is calculated by harvesting area and gross biomass yield per unit area (Kumar et al., 2003).

Road construction cost ($/year) = [(Road construction cost ($/ha)/Average merchantable volume (m^3/ha)) + Infrastructure cost ($/$m^3$)] × Average gross yield (m^3/ha) × Harvesting area (ha/year)

- **Nutrient replacement cost**

Nutrient replacement cost is not assigned for whole-tree- and forest residue-based biohydrogen production plant. On the other hand, nutrient content of straw is replaced by applying fertilizer on the field to maintain soil health after harvesting straw. Cost of fertilizer purchase is given to the straw owner, and cost does not include transporting fertilizer to the fields and spreading cost of fertilizer on the field. Moreover, 20% of total straw is left in the field to maintain soil health during wind and water erosion (Wood and Layzell, 2003). Finally, nutrient replacement cost is calculated by the actual nutrient contents on collected straw by the following equation (Kumar et al., 2003).

Nutrient replacement cost (\$/year) = $\sum$[Nutrient content in straw (%) × Straw amount (tonnes/year) × Price of fertilizers (\$/tonne)]

- **Hydrogen gas pipeline frictional factor**

- Darcy-Weisbach equation (Kreith, 1997):

$$f = 0.094k^{0.225} + 0.53k + 88k^{0.44}\,\mathrm{Re}^{-1.62k^{0.134}}$$

Where, $k =$ Relative roughness (0.00004 < *e/d < 0.04*)

$\mathrm{Re} =$ Reynolds number (>10,000)

$e =$ Pipe roughness (m)

$d =$ Pipe diameter (m)

- Colebrook-White equation (Schroeder, 2001):

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{\frac{e}{d}}{3.7} + \frac{2.51}{\mathrm{Re}\sqrt{f}}\right)$$

Where, $\mathrm{Re} =$ Reynolds number

$e =$ Pipe roughness (m)

$d =$ Pipe diameter (m)

- **Hydrogen gas pipeline frictional head loss**

Frictional head loss, $H_f = \dfrac{fLV^2}{2gd}$

Where, $f =$ Frictional factor

$L =$ Pipe length (m)

$V =$ Velocity of the fluid (m/s)

$g =$ Gravitational acceleration, 9.807 (m/s^2)

$d =$ Pipe diameter (m)

- **Compressibility factor for hydrogen**

Gas compressibility factor offsets non-ideal behaviors of gas during compression process and could be calculated using iteration method (DOE, 2006).

Compressibility factor calculation equation:

$$Z^3 - Z^2 + [A - B(B+1)]Z - AB = 0$$

Where,

$A = \dfrac{Pa}{R^2T^{2.5}}$, dimensionless parameter

$B = \dfrac{Pb}{RT}$, dimensionless parameter

$a = 0.42748\dfrac{R^2T_c^{2.5}}{P_c}$, for hydrogen gas

$b = 0.08664\dfrac{RT_c}{P_c}$, for hydrogen gas

$R =$ Gas constant, 8.3144 J/K-mol

$T_c =$ Hydrogen gas critical temperature, 33.15 K

$P_c =$ Hydrogen gas critical pressure, 1.315 MPa

$P =$ Hydrogen gas pressure

$T =$ Hydrogen gas temperature (K)

Here, among three roots of compressibility factors, largest value of compressibility factor is taken into account.

- **Compressor power requirement**

Theoretical compressor power requirement could be calculated from the following equation (DOE, 2006).

$$P_{th} = \left(\frac{\dot{m}}{2.0158} \right) ZRT_i \left(\frac{1}{\eta_{isen}} \right) \left(\frac{\gamma}{\gamma - 1} \right) \left[\left(\frac{p_o}{p_i} \right)^{\frac{\gamma-1}{\gamma N_{st}}} - 1 \right]$$

Where, $P_{th} =$ Theoretical compressor power requirement (kW)

$\dot{m} =$ Mass flow rate of gas (kg/s)

$T_i =$ Gas inlet temperature (K)

$Z =$ Compressibility factor

$\eta_{isen} =$ Compressor isentropic efficiency (%)

$\gamma =$ Gas heat capacity ratio, (1.4 for hydrogen gas)

$p_o =$ Gas pressure at compressor outlet (MPa)

$p_i =$ Gas pressure compressor inlet (MPa)

$N_{st} =$ Number of compression stages

- **Diameter of hydrogen gas pipeline**

For turbulent gas flow rate, Panhandle B equation is used to calculate pipe diameter (GPSA, 2004) and selection of equation relies on the laminar or turbulent flow of gas.

Panhandle B equation:

$$Q = 0.339\left(\frac{T_b}{P_b}\right)^{1.02} \eta \left[\frac{P_i^2 - P_o^{\ 2}}{\gamma^{0.961} L T_{avg} Z_{avg}}\right]^{0.51} d^{2.53}$$

Where, $Q =$ Flow rate of gas at base temperature and pressure (m^3/day)

$T_b =$ Base absolute temperature, (288.9 K)

$P_b =$ Base absolute pressure, (101.56 kPa)

$\eta =$ Pipeline efficiency (%)

$P_i =$ Gas inlet temperature in pipeline, (kPa)

$P_o =$ Gas outlet temperature in pipeline, (kPa)

$\gamma =$ Relative density of gas

$L =$ Length of gas pipeline (m)

$T_{avg} =$ Gas average temperature (K)

$Z_{avg} =$ Gas average compressibility factor

$d =$ Pipe diameter (m)

- **Optimum pressure drop and compression ratio for gas transmission in pipeline**

Practically, pressure drop is limited to 15-25 kPa/km during gas transmission, and maximum compression ratio should be less than 6; however, at high pressure and temperature, this value is designated between 1.2-2 (Mohitpour et al., 2007).

- **Truck scheduling for gas transportation in tube trailer and cryogenic tank**

The following steps were used during scheduling truck for gas transmission process (Amos, 1998).

1. Number of trips per day= Gas transportation capacity (tonnes/day)/Each truck capacity (tonne)
2. Number of trips per year= Number of trips per day × 365
3. Total travel distance (km/day) = 2 × Number of trips per day × Transportation distance (km)
4. Total travel distance (km/year) = Total travel distance per day × 365
5. Time of each round trip (hr) = 2 × Transportation distance (km)/Truck speed (km/hr)
6. Total driving time per year (hr/year) = Trips per year × Time of each round trip
7. Total load and unload time (hr/year) = Trips per year × Pick-up and drop-off time (hr)
8. Total delivery time per year (hr/year) = Total driving time per year (hr/year) +Total load and unload time (hr/year)
9. Number of trucks required = Total delivery time per year (hr)/Truck availability per year (hr)

Appendix B.

Pipeline Biohydrogen Transportation

The designed nominal diameter of pipeline is 0.254 m (10 in). Pressure of hydrogen is approximately 2.4 MPa at the end of purification process in a biomass-based hydrogen fuel production plant. In this study, hydrogen gas is compressed to about 7 MPa with a two-stage reciprocating compressor for pipeline transmission (Spath et al., 2005). Table B-1 lists pipeline characteristics and costs. Table B-2 presents the capital and production cost of hydrogen from natural gas.

Table B-1: Parameters for pipeline transport of hydrogen

Items	Values/ formulae	Comments/sources
Pipeline nominal diameter (m)	0.254	Diameter is calculated using Panhandle B equation, and nominal diameter is selected from an engineering data handbook (GPSA, 1972; Schroeder, 2001).
Hydrogen gas velocity in the pipe (m/s)	7.1	H_2 gas velocity inside the pipeline.
Average frictional pressure loss (kPa/km)	4	Hydrogen gas pressure loss during pipeline gas transmission for the specific hydrogen gas velocity and pipeline diameter (Mohitpour et al., 2007).
Pipeline inlet pressure (MPa)	7	Allowable maximum pipeline operating pressure (DOE, 2006a; GPSA, 1972).
Pipeline outlet pressure (MPa)	4.8	H_2 gas pressure at the end of pipeline.
Pipeline length (km)	500	Assumed for the Province of Alberta considering biomass recourse location and upgrader location (Ghafoori and Flynn, 2007).
Compressor power (MW)	3.44	Reciprocating compressor with each stage compression ratio 1.7 to compress 2.4 MPa to about 7 MPa for pipeline transmission (Mohitpour et al., 2007; Spath et al., 2005).
Pipeline capital cost ($/km)	$1869D^2$	Pipeline material cost which depends on pipeline diameter (D is the pipeline diameter in inch) (Yang and Ogden, 2007).
Pipeline installation and ROW cost ($/km)	600,000	Pipeline average installation and right-of-way (ROW) cost for urban area (Yang and Ogden, 2007).
Pipeline fixed operating cost (% of pipeline capital cost)	5	(Yang and Ogden, 2007).
Compressor base size (kW)	10	(Yang and Ogden, 2007).
Compressor base size capital cost ($)	15,000	Compression package cost which includes compressor, intercooler, and knockout vessel (Spath et al., 2005; Yang and Ogden, 2007).
Compressor scale factor	0.9	(Yang and Ogden, 2007).
Compressor operating and maintenance cost (% of compressor capital cost)	5	(Yang and Ogden, 2007).

Table B-1: (continued)

Items	Values/ formulae	Comments/sources
Electricity price ($/kWh)	0.07	Assumed electricity price for the Province of Alberta.
H_2 loss (% of total transmission)	1	Hydrogen loss during compression and pipeline transmission (DOE, 2006a).

Table B-2: Parameters for natural-gas-based hydrogen production plant

Items	Values of natural gas based hydrogen production plant	Comments/sources
Plant size	100,000 N-m^3/hr	This is the volume of natural gas at normal pressure and temperature.
Hydrogen production rate	427 tonnes/day	
Natural gas consumption rate	0.172 GJ/kg of H_2	Natural gas consumption rate is 3.27 time of hydrogen on mass basis (Ghafoori and Flynn, 2007; Spath and Mann, 2001).
Natural gas price	$5/GJ	Natural gas would be purchased for long term contract basis.
Capital cost	$134 million	(Ghafoori and Flynn, 2007; Longanbach and Rutkowski, 2002; Spath et al., 2005)
Hydrogen production cost	$0.96/kg	Levelized production cost of hydrogen.

Appendix C.

Summary of Whole-Tree Felling, Skidding, and Chipping Cost Calculation

Harvesting costs of whole-tree which include felling, skidding, and chipping are explained in Table C-1, Table C-2, and Table C-3, respectively. Costs are estimated from literature and consultation with tree harvesting companies in Western Canada and also followed the methodology of FERIC's harvesting cost calculation (ALPAC, 2006; Han and Renzie, 2001; Kumar, 2004; MacDonald, 2006). All the cost figures presented here are in US dollar in the year of 2011. Hence, data were inflated according to the corresponding inflation rate and adapted for the Province of Alberta. Note that productive machine hour (PMH) of equipment is assumed 85% of schedule machine hour (SMH). Cost of felling, skidding, and chipping of whole-tree are \$3.75/dry tonne, \$3.11/dry tonne, and \$3.84/dry tonne in the year of 2008, respectively.

Table C-1: Cost calculation of whole-tree felling process

Equipment name	**Feller buncher**
Equipment model number and rated power	John Deere 853J, 205 kW, 6 cylinders, 1500 rpm
Ownership costs	
Total purchase price (P), $	567,310
Expected life (Y), year	3
Expected life (H), hour	12000
Scheduled hours/year (h)=(H/Y), hour	4000
Salvage value as % of P (s)	20
Interest rate (Int)	10
Insurance (Ins)	2
Salvage value (S)=(P×s)	113,462
Depreciation (D)=((P-S)/Y), $	151,283
Average investment (AVI)=((P-S)/2)	340,386
Loss in resale value ((P-S)/H), $/h	37.82
Interest rate ((Int×AVI)/h), $/h	8.51
Insurance ((Ins×AVI)/h), $/h	1.7
Total hourly ownership cost (OW), $/SMH	**48.03**
Operating costs	
Fuel consumption (F), liter/h	47
Fuel (fc), $/liter	0.9
Lube & oil as % of fuel (fp)	7
Track & undercarriage replacement (Tc), $	33,950
Track & undercarriage life (Th), h	5,500
Annual repair & maintenance (Rp = 10%×P), $	85,097
Shift length (SL), h	10
Wages (W), $/h	20
Wage benefit loading (WBL), %	5
Fuel (F×fc), $/h	42.30
Lube & oil ((fp)×(F×fc)), $/h	2.96
Track & undercarriage (Tc/Th), $/h	6.17
Repair & maintenance (Rp/h), $/h	15.47
Wages & benefits (W×(1+WBL))	27
Prorated overtime (((1.5×W-W)×(SL-8)×(1+WBL))/SL), $/h	2.7
Total hourly operating costs (OP), $/SMH	**96.61**
Total hourly costs (OW+OP), $/SMH	***144.64***
Total hourly costs (OW+OP), $/PMH	***170.16***
Machine productivity (m^3/PMH)	75
Felling cost ($/$m^3$)	2.27
Density of whole-tree (tonnes/m^3)	0.57
Felling cost ($/odt)	**3.98**

Table C-2: Cost calculation of whole-tree skidding process

Equipment name	**Grapple skidder**
Equipment model number and rated power	John Deere 748H, 141 kW, 2200 rpm
Ownership costs	
Total purchase price (P), $	329,797
Expected life (Y), year	3
Expected life (H), hour	12000
Scheduled hours/year (h)=(H/Y), hour	4000
Salvage value as % of P (s)	40
Interest rate (Int) %	10
Insurance (Ins) %	2
Salvage value (S)=(P×s)	131,919
Depreciation (D)=((P-S)/Y), $	65,959
Average investment (AVI)=((P-S)/2)	230,858
Loss in resale value ((P-S)/H), $/h	16.49
Interest rate ((Int×AVI)/h), $/h	5.77
Insurance ((Ins×AVI)/h), $/h	1.15
Total hourly ownership cost (OW), $/SMH	**23.42**
Operating costs	
Fuel consumption (F), liter/h	40
Fuel (f_c), $/liter	0.9
Lube & oil as % of fuel (f_p)	7
Annual tire consumption (t) no.	4
Tire & chain replacement (T_c), $	4300
Tire & chain life (T_L) h	4000
Annual repair & maintenance (R_p=10%×P), $	32,980
Shift length (SL), h	10
Wages (W) $/h	20
Wage benefit loading (WBL), %	35
Fuel (F×f_c), $/h	36
Lube & oil (f_p×F×f_c), $/h	2.52
Tire ((t×T_c)/T_h), $/h	4.3
Repair & maintenance (R_p/T_h), $/h	8.24
Wages & benefits (W×(1+WBL))	27
Prorated overtime (((1.5×W-W)×(SL-8)×(1+WBL))/SL), $/h	2.7
Total hourly operating costs (OP), $/SMH	**80.77**
Total hourly costs (OW+OP), $/SMH	***104.18***
Total hourly costs (OW+OP), $/PMH	***122.57***
Machine productivity (m^3/PMH)	65
Skidding cost ($/$m^3$)	1.886
Density of whole-tree (tonnes/m^3)	0.57
Skidding cost ($/odt)	**3.31**

Table C-3: Cost calculation of whole-tree chipping process

Equipment name	**Whole-tree chipper**
Equipment model number and rated power	Morbark 50/48A, 522-653 kW
Ownership costs	
Total purchase price (P), $	481,840
Expected life (Y), year	3.3
Expected life (H), hour	16500
Scheduled hours/year (h)=(H/Y), hour	5000
Salvage value as % of P (s)	20
Interest rate (Int), %	10
Insurance (Ins), %	2
Salvage value (S)=(P×s)	96,368
Depreciation (D)=((P-S)/Y), $	116,810
Average investment (AVI)=((P-S)/2)	289,104
Loss in resale value ((P-S)/H), $/h	23.4
Interest rate ((Int×AVI)/h), $/h	5.8
Insurance ((Ins×AVI)/h), $/h	1.2
Total hourly ownership cost (OW), $/SMH	30.3
Operating costs	
Fuel consumption (F), liter/h	100
Fuel (f_c), $/liter	0.9
Lube & oil as % of fuel, (f_p)	15
Annual repair & maintenance (R_p=10%×P), $	48,184
Shift length (SL), h	10
Wages (W), $/h	20
Wage benefit loading (WBL), %	35
Fuel (F×f_c), $/h	90
Lube & oil (f_p×F×f_c), $/h	13.5
Repair & maintenance (R_p/T_h), $/h	10
Wages & benefits (W×(1+WBL))	27
Prorated overtime (((1.5×W-W)×(SL-8)×(1+WBL))/SL), $/h	2.7
Total hourly operating costs (OP), $/SMH	**142.84**
Total hourly costs (OW+OP), $/SMH	***173***
Total hourly costs (OW+OP), $/PMH	***204***
Machine productivity (m^3/PMH)	100
Chipping cost ($/$m^3$)	2.04
Moisture content (%)	50
Chipping cost ($/odt)	**4.07**

Appendix D.

Discounted Cash Flow Analysis for Different Biomass Feedstocks and Biohydrogen Production Processes at Base Case Plant Size

The distribution of capital cost in various processes of biohydrogen production from BCL and GTI gasifier is shown in Table D-1 and Table D-2, respectively. Costs in Table D-1 and Table D-2 are in the US$ in the year of 2008. Discounted cash flow analysis for base case (2000 dry tonnes per day) gasification of whole-tree, forest residue, and agricultural residue in BCL gasifier is shown in Table D-3, Table D-4, and Table D-5, respectively. Similarly, cash flow analyses for base case (1000 dry tonnes per day) GTI gasification process of whole-tree, forest residue, and agricultural residue are shown in Table D-6, Table D-7, and Table D-8, respectively. If the construction of biohydrogen production plant had started in the year of 2008, it would have produced hydrogen for a plant life of 20 years starting in the year of 2011. Therefore, costs are shown accordingly in different years of plant construction and biohydrogen production. Biohydrogen production process will start in the year of 2011 and will end in the year of 2030.

Table D-1: Capital and operating cost of BCL gasification-based biohydrogen production plant

Feedstock	**Whole-tree**		**Forest residue**		**Straw**	
Plant size (dry tonnes/day)	2000		2000		2000	
Capital costs ($1000)						
Feed handling and drying	24,939	14%	24,939	14%	17,760	12%
Gasification, tar reforming/regeneration, & quench	27,519	15%	27,519	15%	25,018	16%
Syngas compression & sulfur removal	20,313	11%	20,313	11%	18,467	12%
Shift and PSA	21,373	12%	21,373	12%	19,430	13%
Steam system and power generation	18,773	11%	18,773	11%	17,066	11%
Cooling water and other utilities	4,619	3%	4,619	3%	4,199	3%
Total installed cost (TIC)	117,538		117,538		101,941	
Indirect (49% of TIC)	57,594	32%	57,594	32%	49,951	32%
Land procurement	2,855	2%	2,855	2%	2,476	2%
Total project investment (TPI)	**177,987**	**100%**	**177,987**	**100%**	**154,368**	**100%**
Operating costs ($1000)						
Feedstock	18,463	51%	17,093	49%	25,365	60%
Natural gas	3,298	9%	3,298	9%	3,298	8%
Catalyst	471	1%	471	1%	471	1%
Olivine	4,475	12%	4,475	13%	4,475	11%
Other raw material	589	2%	589	2%	589	1%
Waste disposal	673	2%	673	2%	673	2%
Electricity	3,519	10%	3,519	10%	3,148	7%
Fixed operating	5,006	14%	5,006	14%	4,172	10%
Total operating costs	**36,494**	**100%**	**35,124**	**100%**	**42,190**	**100%**

Table D-2: Capital and operating cost of GTI gasification-based biohydrogen production plant

Feedstock	**Whole-tree**		**Forest residue**		**Straw**	
Plant size (dry tonnes/day)	1000		1000		1000	
Capital costs ($1000)						
Feedstock preparation and gasification	111,494	20%	64,837	18%	101,138	20%
Gas clean up	98,632	18%	58,932	16%	97,751	19%
Water gas shift	46,256	8%	32,652	9%	38,195	8%
CO_2 removal	61,576	11%	43,933	12%	60,753	12%
Hydrogen purification	35,536	6%	24,340	7%	30,750	6%
Air separation	69,387	13%	53,200	15%	56,402	11%
Power production	117,802	21%	77,679	21%	106,621	21%
Land procurement	10,814	2%	7,111	2%	9,832	2%
Total project investment (TPI)	**551,498**	**100%**	**362,685**	**100%**	**501,442**	**100%**
Operating costs ($1000)						
Feedstock delivery	48,368	79%	26,167	71%	79,489	91%
Non-fuel operating	22,060	36%	14,507	39%	20,058	23%
Electricity benefit	-15,910	-26%	-9,345	-25%	-18,047	-21%
Fixed operating	6,954	11%	5,579	15%	6,004	7%
Total operating costs	**61,471**	**100%**	**36,908**	**100%**	**87,504**	**100%**

Table D-3: Summary of discounted cash flow of whole-tree gasification in BCL gasifier for biohydrogen production at base case (2000 dry tonnes per day)

Cost items ($1000)/year	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
Capital	14,239	106,792	56,956	0	0	0	0	0
Operating	0	0	0	9,682	11,287	11,992	12,232	12,477
Maintenance	0	0	0	3,560	3,631	3,704	3,778	3,853
Administrative	0	0	0	5,316	5,423	5,531	5,642	5,755
Harvesting	0	0	0	5,806	6,768	7,191	7,335	7,482
Transportation	0	0	0	5,584	6,509	7,055	7,196	7,340
Road & infrastructure	0	0	0	4,456	5,194	5,519	5,629	5,742
Silviculture	0	0	0	1,170	1,364	1,449	1,478	1,508
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	2,592	3,021	3,210	3,274	3,340
Ash disposal	0	0	0	186	215	229	233	238
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	14,239	106,792	56,956	38,352	43,413	45,880	46,798	47,734
Present value (PV) of total cost at 10%	17,229	117,471	56,956	34,866	35,879	34,470	31,963	29,639
Amount of hydrogen sold (tonnes)	0	0	0	42,610	48,697	51,740	51,740	51,740
Price required for 10% return ($/kg)	0	0	0	1.26	1.28	1.31	1.33	1.36
Revenue required for 10% return	0	0	0	53,574	62,452	67,683	69,036	70,417
PV of revenue at 10% return	0	0	0	48,704	51,613	50,851	47,153	43,723

Table D-3: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	12,726	12,981	13,241	13,505	13,776	14,051	14,332	14,619
Maintenance	3,930	4,009	4,089	4,171	4,254	4,339	4,426	4,515
Administrative	5,870	5,987	6,107	6,229	6,354	6,481	6,610	6,743
Harvesting	7,632	7,784	7,940	8,099	8,261	8,426	8,594	8,766
Transportation	7,486	7,636	7,789	7,945	8,103	8,266	8,431	8,599
Road & infrastructure	5,856	5,974	6,093	6,215	6,339	6,466	6,595	6,727
Silviculture	1,538	1,569	1,600	1,632	1,665	1,698	1,732	1,767
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	3,407	3,475	3,544	3,615	3,687	3,761	3,836	3,913
Ash disposal	243	248	253	258	263	268	274	279
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	48,688	49,662	50,655	51,668	52,702	53,756	54,831	55,927
Present value (PV) of total cost at 10%	27,483	25,484	23,631	21,912	20,319	18,841	17,471	16,200
Amount of hydrogen sold (tonnes)	51,740	51,740	51,740	51,740	51,740	51,740	51,740	51,740
Price required for 10% return ($/kg)	1.39	1.42	1.44	1.47	1.50	1.53	1.56	1.59
Revenue required for 10% return	71,825	73,262	74,727	76,222	77,746	79,301	80,887	82,505
PV of revenue at 10% return	40,543	37,595	34,861	32,325	29,974	27,794	25,773	23,899

Table D-3: (continued)

Cost items ($1000)/year	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Capital	0	0	0	0	0	0	0
Operating	14,911	15,209	15,513	15,824	16,140	16,463	16,792
Maintenance	4,605	4,697	4,791	4,887	4,984	5,084	5,186
Administrative	6,877	7,015	7,155	7,298	7,444	7,593	7,745
Harvesting	8,942	9,120	9,303	9,489	9,679	9,872	10,070
Transportation	8,771	8,947	9,126	9,308	9,495	9,684	9,878
Road & infrastructure	6,862	6,999	7,139	7,282	7,427	7,576	7,727
Silviculture	1,802	1,838	1,875	1,912	1,950	1,989	2,029
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	3,991	4,071	4,153	4,236	4,320	4,407	4,495
Ash disposal	285	290	296	302	308	314	320
Site recovery and reclamation	0	0	0	0	0	0	35,597
Salvage value	0	0	0	0	0	0	0
Total cost	57,046	58,187	59,351	60,538	61,748	62,983	99,840
Present value (PV) of total cost at 10%	15,022	13,929	12,916	11,977	11,106	10,298	14,841
Amount of hydrogen sold (tonnes)	51,740	51,740	51,740	51,740	51,740	51,740	51,740
Price required for 10% return ($/kg)	1.63	1.66	1.69	1.73	1.76	1.80	1.83
Revenue required for 10% return	84,155	85,838	87,555	89,306	91,092	92,914	94,772
PV of revenue at 10% return	22,161	20,549	19,054	17,669	16,384	15,192	14,087

Table D-4: Summary of discounted cash flow of forest residue gasification in BCL gasifier for biohydrogen production at base case (2000 dry tonnes per day)

Cost items ($1000)/year	-2	-1	0	1	2	3	4	5
Capital	14,239	106,792	56,956	0	0	0	0	0
Operating	0	0	0	9,682	11,287	11,992	12,232	12,477
Maintenance	0	0	0	3,560	3,631	3,704	3,778	3,853
Administrative	0	0	0	5,316	5,423	5,531	5,642	5,755
Harvesting	0	0	0	6,104	7,115	7,560	7,711	7,865
Transportation	0	0	0	9,457	11,485	12,685	12,939	13,198
Road & infrastructure	0	0	0	0	0	0	0	0
Silviculture	0	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	2,592	3,021	3,210	3,274	3,340
Ash disposal	0	0	0	677	690	704	718	732
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	0	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	14,239	106,792	56,956	37,388	42,653	45,387	46,294	47,220
Amount of hydrogen sold (tonnes)	17,229	117,471	56,956	33,989	35,250	34,100	31,620	29,320
Price required for 10% return ($/kg)	0	0	0	42,610	48,697	51,740	51,740	51,740
Revenue required for 10% return	0	0	0	1.25	1.27	1.30	1.32	1.35
PV of revenue at 10% return	0	0	0	53,117	61,919	67,105	68,447	69,816
Capital	0	0	0	48,288	51,173	50,417	46,750	43,350

Table D-4: (continued)

Cost items ($1000)/year	6	7	8	9	10	11	12	13
Capital	0	0	0	0	0	0	0	0
Operating	12,726	12,981	13,241	13,505	13,776	14,051	14,332	14,619
Maintenance	3,930	4,009	4,089	4,171	4,254	4,339	4,426	4,515
Administrative	5,870	5,987	6,107	6,229	6,354	6,481	6,610	6,743
Harvesting	8,023	8,183	8,347	8,514	8,684	8,858	9,035	9,215
Transportation	13,462	13,731	14,006	14,286	14,571	14,863	15,160	15,463
Road & infrastructure	0	0	0	0	0	0	0	0
Silviculture	0	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	3,407	3,475	3,544	3,615	3,687	3,761	3,836	3,913
Ash disposal	747	762	777	793	809	825	841	858
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	0	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	48,165	49,128	50,110	51,113	52,135	53,178	54,241	55,326
Amount of hydrogen sold (tonnes)	27,188	25,210	23,377	21,677	20,100	18,638	17,283	16,026
Price required for 10% return ($/kg)	51,740	51,740	51,740	51,740	51,740	51,740	51,740	51,740
Revenue required for 10% return	1.38	1.40	1.43	1.46	1.49	1.52	1.55	1.58
PV of revenue at 10% return	71,212	72,636	74,089	75,571	77,082	78,624	80,196	81,800
Capital	40,197	37,274	34,563	32,049	29,718	27,557	25,553	23,695

Table D-4: (continued)

Cost items ($1000)/year	14	15	16	17	18	19	20
Capital	0	0	0	0	0	0	0
Operating	14,911	15,209	15,513	15,824	16,140	16,463	16,792
Maintenance	4,605	4,697	4,791	4,887	4,984	5,084	5,186
Administrative	6,877	7,015	7,155	7,298	7,444	7,593	7,745
Harvesting	9,400	9,588	9,779	9,975	10,175	10,378	10,586
Transportation	15,773	16,088	16,410	16,738	17,073	17,414	17,763
Road & infrastructure	0	0	0	0	0	0	0
Silviculture	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	3,991	4,071	4,153	4,236	4,320	4,407	4,495
Ash disposal	875	893	911	929	947	966	986
Site recovery and reclamation	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	35,597
Total cost	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	56,432	57,561	58,712	59,887	61,084	62,306	99,149
Amount of hydrogen sold (tonnes)	14,860	13,780	12,778	11,848	10,987	10,188	14,738
Price required for 10% return ($/kg)	51,740	51,740	51,740	51,740	51,740	51,740	51,740
Revenue required for 10% return	1.61	1.64	1.68	1.71	1.75	1.78	1.82
PV of revenue at 10% return	83,436	85,105	86,807	88,543	90,314	92,120	93,963
Capital	21,971	20,373	18,892	17,518	16,244	15,062	13,967

Table D-5: Summary of discounted cash flow of straw gasification in BCL gasifier for biohydrogen production at base case (2000 dry tonnes per day)

Cost items ($1000)/year	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
Capital	12,349	92,621	49,398	0	0	0	0	0
Operating	0	0	0	9,406	10,965	11,650	11,883	12,121
Maintenance	0	0	0	3,087	3,149	3,212	3,276	3,342
Administrative	0	0	0	4,430	4,519	4,609	4,702	4,796
Harvesting	0	0	0	5,741	6,692	7,110	7,253	7,398
Transportation	0	0	0	10,167	12,422	13,756	14,031	14,312
Road & infrastructure	0	0	0	0	0	0	0	0
Silviculture	0	0	0	754	879	934	953	972
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	7,536	8,613	9,151	9,334	9,520
Ash disposal	0	0	0	2,592	3,021	3,210	3,274	3,340
Site recovery and reclamation	0	0	0	902	920	939	957	977
Salvage value	0	0	0	0	0	0	0	0
Total cost	0	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	12,349	92,621	49,398	44,616	51,180	54,572	55,664	56,777
Amount of hydrogen sold (tonnes)	14,943	101,883	49,398	40,560	42,298	41,001	38,019	35,254
Price required for 10% return ($/kg)	0	0	0	42,610	48,696	51,740	51,740	51,740
Revenue required for 10% return	0	0	0	1.36	1.39	1.42	1.45	1.48
PV of revenue at 10% return	0	0	0	58,129	67,762	73,437	74,906	76,404
Capital	0	0	0	52,845	56,002	55,174	51,162	47,441

Table D-5: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	12,363	12,611	12,863	13,120	13,383	13,650	13,923	14,202
Maintenance	3,409	3,477	3,546	3,617	3,690	3,763	3,839	3,916
Administrative	4,892	4,989	5,089	5,191	5,295	5,401	5,509	5,619
Harvesting	7,546	7,697	7,850	8,007	8,168	8,331	8,498	8,668
Transportation	14,598	14,890	15,188	15,492	15,802	16,118	16,440	16,769
Road & infrastructure	0	0	0	0	0	0	0	0
Silviculture	991	1,011	1,031	1,052	1,073	1,095	1,116	1,139
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	9,711	9,905	10,103	10,305	10,511	10,722	10,936	11,155
Ash disposal	3,407	3,475	3,544	3,615	3,687	3,761	3,836	3,913
Site recovery and reclamation	996	1,016	1,036	1,057	1,078	1,100	1,122	1,144
Salvage value	0	0	0	0	0	0	0	0
Total cost	0	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	57,913	59,071	60,252	61,457	62,686	63,940	65,219	66,523
Amount of hydrogen sold (tonnes)	32,690	30,313	28,108	26,064	24,168	22,411	20,781	19,269
Price required for 10% return ($/kg)	51,740	51,740	51,740	51,740	51,740	51,740	51,740	51,740
Revenue required for 10% return	1.51	1.54	1.57	1.60	1.63	1.66	1.70	1.73
PV of revenue at 10% return	77,932	79,491	81,081	82,702	84,356	86,043	87,764	89,520
Capital	43,991	40,791	37,825	35,074	32,523	30,158	27,964	25,931

Table D-5: (continued)

Cost items ($1000)/year	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Capital	0	0	0	0	0	0	0
Operating	14,486	14,775	15,071	15,372	15,680	15,993	16,313
Maintenance	3,994	4,074	4,155	4,238	4,323	4,410	4,498
Administrative	5,731	5,846	5,963	6,082	6,204	6,328	6,454
Harvesting	8,841	9,018	9,198	9,382	9,570	9,761	9,956
Transportation	17,104	17,446	17,795	18,151	18,514	18,885	19,262
Road & infrastructure	0	0	0	0	0	0	0
Silviculture	1,162	1,185	1,208	1,233	1,257	1,282	1,308
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	11,378	11,605	11,838	12,074	12,316	12,562	12,813
Ash disposal	3,991	4,071	4,153	4,236	4,320	4,407	4,495
Site recovery and reclamation	1,167	1,190	1,214	1,238	1,263	1,289	1,314
Salvage value	0	0	0	0	0	0	30,874
Total cost	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	67,854	69,211	70,595	72,007	73,447	74,916	107,288
Amount of hydrogen sold (tonnes)	17,868	16,569	15,364	14,246	13,210	12,249	15,948
Price required for 10% return ($/kg)	51,740	51,740	51,740	51,740	51,740	51,740	51,740
Revenue required for 10% return	1.76	1.80	1.84	1.87	1.91	1.95	1.99
PV of revenue at 10% return	91,310	93,136	94,999	96,899	98,837	100,814	102,830
Capital	24,045	22,296	20,675	19,171	17,777	16,484	15,285

Table D-6: Summary of discounted cash flow of whole-tree gasification in GTI gasifier for biohydrogen production at base case (1000 dry tonnes per day)

Cost items ($1000)/year	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
Capital	14,934	112,005	59,736	0	0	0	0	0
Operating	0	0	0	7,467	7,616	7,769	7,924	8,082
Maintenance	0	0	0	3,733	3,808	3,884	3,962	4,041
Administrative	0	0	0	4,689	4,783	4,879	4,976	5,076
Electricity benefit	0	0	0	-3,379	-3,939	-4,186	-4,269	-4,355
Harvesting	0	0	0	2,902	3,383	3,595	3,667	3,740
Transportation	0	0	0	2,555	2,979	3,228	3,293	3,358
Road & infrastructure	0	0	0	2,228	2,597	2,759	2,814	2,871
Silviculture	0	0	0	585	682	725	739	754
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	1,296	1,511	1,605	1,637	1,670
Ash disposal	0	0	0	113	115	117	120	122
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	14,934	112,005	59,736	22,190	23,535	24,375	24,863	25,360
Present value (PV) of total cost at 10%	18,070	123,205	59,736	20,172	19,450	18,314	16,982	15,747
Amount of hydrogen sold (tonnes)	0	0	0	21,323	24,369	25,892	25,892	25,892
Price required for 10% return ($/kg)	0	0	0	1.76	1.79	1.83	1.86	1.90
Revenue required for 10% return	0	0	0	37,448	43,654	47,310	48,256	49,221
PV of revenue at 10% return	0	0	0	34,044	36,077	35,544	32,959	30,562

Table D-6: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	8,244	8,409	8,577	8,749	8,924	9,102	9,284	9,470
Maintenance	4,122	4,205	4,289	4,374	4,462	4,551	4,642	4,735
Administrative	5,177	5,281	5,387	5,494	5,604	5,716	5,831	5,947
Electricity benefit	-4,442	-4,531	-4,621	-4,714	-4,808	-4,904	-5,002	-5,102
Harvesting	3,815	3,891	3,969	4,048	4,129	4,212	4,296	4,382
Transportation	3,426	3,494	3,564	3,635	3,708	3,782	3,858	3,935
Road & infrastructure	2,928	2,987	3,047	3,107	3,170	3,233	3,298	3,364
Silviculture	769	784	800	816	832	849	866	883
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	1,703	1,737	1,772	1,808	1,844	1,881	1,918	1,957
Ash disposal	125	127	130	132	135	137	140	143
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	25,867	26,385	26,912	27,451	28,000	28,560	29,131	29,713
Present value (PV) of total cost at 10%	14,601	13,540	12,555	11,642	10,795	10,010	9,282	8,607
Amount of hydrogen sold (tonnes)	25,892	25,892	25,892	25,892	25,892	25,892	25,892	25,892
Price required for 10% return ($/kg)	1.94	1.98	2.02	2.06	2.10	2.14	2.18	2.23
Revenue required for 10% return	50,205	51,209	52,234	53,278	54,344	55,431	56,539	57,670
PV of revenue at 10% return	28,340	26,279	24,367	22,595	20,952	19,428	18,015	16,705

Table D-6: (continued)

Cost items ($1000)/year	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Capital	0	0	0	0	0	0	0
Operating	9,659	9,853	10,050	10,251	10,456	10,665	10,878
Maintenance	4,830	4,926	5,025	5,125	5,228	5,332	5,439
Administrative	6,066	6,188	6,311	6,437	6,566	6,698	6,832
Electricity benefit	-5,204	-5,308	-5,415	-5,523	-5,633	-5,746	-5,861
Harvesting	4,470	4,559	4,650	4,743	4,838	4,935	5,034
Transportation	4,014	4,094	4,176	4,259	4,344	4,431	4,520
Road & infrastructure	3,431	3,499	3,569	3,641	3,714	3,788	3,864
Silviculture	901	919	937	956	975	995	1,015
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	1,996	2,036	2,076	2,118	2,160	2,203	2,247
Ash disposal	146	149	152	155	158	161	164
Site recovery and reclamation	0	0	0	0	0	0	37335
Salvage value	0	0	0	0	0	0	0
Total cost	30,308	30,914	31,532	32,163	32,806	33,462	71,466
Present value (PV) of total cost at 10%	7,981	7,401	6,862	6,363	5,900	5,471	10,623
Amount of hydrogen sold (tonnes)	25,892	25,892	25,892	25,892	25,892	25,892	25,892
Price required for 10% return ($/kg)	2.27	2.32	2.36	2.41	2.46	2.51	2.56
Revenue required for 10% return	58,824	60,000	61,200	62,424	63,672	64,946	66,245
PV of revenue at 10% return	15,490	14,364	13,319	12,350	11,452	10,619	9,847

Table D-7: Summary of discounted cash flow of forest residue gasification in GTI gasifier for biohydrogen production at base case (1000 dry tonnes per day)

Cost items ($1000)/year	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
Capital	14,884	111,629	59,535	0	0	0	0	0
Operating	0	0	0	7,442	7,591	7,743	7,897	8,055
Maintenance	0	0	0	3,721	3,795	3,871	3,949	4,028
Administrative	0	0	0	4,689	4,783	4,879	4,976	5,076
Electricity benefit	0	0	0	-3,446	-4,017	-4,268	-4,353	-4,440
Harvesting	0	0	0	3,052	3,558	3,780	3,856	3,933
Transportation	0	0	0	3,890	4,697	5,175	5,279	5,384
Road & infrastructure	0	0	0	0	0	0	0	0
Silviculture	0	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	1,296	1,511	1,605	1,637	1,670
Ash disposal	0	0	0	338	345	352	359	366
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	14,884	111,629	59,535	20,982	22,263	23,137	23,599	24,071
Present value (PV) of total cost at 10%	18,009	122,791	59,535	19,075	18,399	17,383	16,119	14,946
Amount of hydrogen sold (tonnes)	0	0	0	21,323	24,369	25,892	25,892	25,892
Price required for 10% return ($/kg)	0	0	0	1.71	1.74	1.78	1.81	1.85
Revenue required for 10% return	0	0	0	36,381	42,409	45,961	46,880	47,818
PV of revenue at 10% return	0	0	0	33,073	35,049	34,531	32,020	29,691

Table D-7: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	8,216	8,381	8,548	8,719	8,894	9,072	9,253	9,438
Maintenance	4,108	4,190	4,274	4,360	4,447	4,536	4,627	4,719
Administrative	5,177	5,281	5,387	5,494	5,604	5,716	5,831	5,947
Electricity benefit	-4,529	-4,620	-4,712	-4,806	-4,903	-5,001	-5,101	-5,203
Harvesting	4,011	4,092	4,173	4,257	4,342	4,429	4,517	4,608
Transportation	5,492	5,602	5,714	5,828	5,944	6,063	6,185	6,308
Road & infrastructure	0	0	0	0	0	0	0	0
Silviculture	0	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	1,703	1,737	1,772	1,808	1,844	1,881	1,918	1,957
Ash disposal	374	381	389	396	404	412	421	429
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	24,553	25,044	25,545	26,056	26,577	27,108	27,650	28,204
Present value (PV) of total cost at 10%	13,859	12,851	11,917	11,050	10,247	9,501	8,810	8,170
Amount of hydrogen sold (tonnes)	25,892	25,892	25,892	25,892	25,892	25,892	25,892	25,892
Price required for 10% return ($/kg)	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16
Revenue required for 10% return	48,774	49,750	50,745	51,760	52,795	53,851	54,928	56,026
PV of revenue at 10% return	27,532	25,529	23,673	21,951	20,355	18,874	17,502	16,229

Table D-7: (continued)

Cost items ($1000)/year	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Capital	0	0	0	0	0	0	0
Operating	9,627	9,819	10,016	10,216	10,420	10,629	10,841
Maintenance	4,813	4,910	5,008	5,108	5,210	5,314	5,421
Administrative	6,066	6,188	6,311	6,437	6,566	6,698	6,832
Electricity benefit	-5,307	-5,413	-5,521	-5,631	-5,744	-5,859	-5,976
Harvesting	4,700	4,794	4,890	4,988	5,087	5,189	5,293
Transportation	6,435	6,563	6,694	6,828	6,965	7,104	7,246
Road & infrastructure	0	0	0	0	0	0	0
Silviculture	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	1,996	2,036	2,076	2,118	2,160	2,203	2,247
Ash disposal	438	446	455	464	474	483	493
Site recovery and reclamation	0	0	0	0	0	0	37210
Salvage value	0	0	0	0	0	0	0
Total cost	28,768	29,343	29,930	30,528	31,139	31,762	69,606
Present value (PV) of total cost at 10%	7,575	7,024	6,514	6,040	5,601	5,193	10,347
Amount of hydrogen sold (tonnes)	25,892	25,892	25,892	25,892	25,892	25,892	25,892
Price required for 10% return ($/kg)	2.21	2.25	2.30	2.34	2.39	2.44	2.49
Revenue required for 10% return	57,147	58,290	59,456	60,645	61,858	63,095	64,357
PV of revenue at 10% return	15,049	13,954	12,939	11,998	11,126	10,316	9,566

Table D-8: Summary of discounted cash flow of straw gasification in GTI gasifier for biohydrogen production at base case (1000 dry tonnes per day)

Cost items ($1000)/year	-2	-1	0	1	2	3	4	5
Capital	12,392	92,940	49,568	0	0	0	0	0
Operating	0	0	0	6,196	6,320	6,446	6,575	6,707
Maintenance	0	0	0	3,098	3,160	3,223	3,288	3,353
Administrative	0	0	0	3,908	3,986	4,066	4,147	4,230
Electricity benefit	0	0	0	-3,485	-4,062	-4,316	-4,402	-4,490
Harvesting	0	0	0	2,870	3,346	3,555	3,626	3,699
Transportation	0	0	0	4,046	4,918	5,434	5,543	5,654
Road & infrastructure	0	0	0	377	440	467	476	486
Silviculture	0	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	3,768	4,306	4,575	4,667	4,760
Ash disposal	0	0	0	1,296	1,511	1,605	1,637	1,670
Site recovery and reclamation	0	0	0	451	460	469	479	488
Salvage value	0	0	0	0	0	0	0	0
Total cost	0	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	12,392	92,940	49,568	22,526	24,385	25,526	26,036	26,557
Amount of hydrogen sold (tonnes)	14,994	102,234	49,568	20,478	20,153	19,178	17,783	16,490
Price required for 10% return ($/kg)	0	0	0	21,323	24,369	25,892	25,892	25,892
Revenue required for 10% return	0	0	0	1.65	1.69	1.72	1.75	1.79
PV of revenue at 10% return	0	0	0	35,260	41,103	44,545	45,436	46,345
Capital	0	0	0	32,054	33,969	33,467	31,033	28,776

Table D-8: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	6,841	6,978	7,117	7,260	7,405	7,553	7,704	7,858
Maintenance	3,420	3,489	3,559	3,630	3,702	3,776	3,852	3,929
Administrative	4,315	4,401	4,489	4,579	4,670	4,764	4,859	4,956
Electricity benefit	-4,580	-4,672	-4,765	-4,861	-4,958	-5,057	-5,158	-5,261
Harvesting	3,773	3,848	3,925	4,004	4,084	4,165	4,249	4,334
Transportation	5,767	5,882	6,000	6,120	6,242	6,367	6,495	6,625
Road & infrastructure	496	506	516	526	537	547	558	569
Silviculture	0	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	4,855	4,953	5,052	5,153	5,256	5,361	5,468	5,577
Ash disposal	1,703	1,737	1,772	1,808	1,844	1,881	1,918	1,957
Site recovery and reclamation	498	508	518	529	539	550	561	572
Salvage value	0	0	0	0	0	0	0	0
Total cost	0	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	27,088	27,630	28,182	28,746	29,321	29,907	30,505	31,116
Amount of hydrogen sold (tonnes)	15,290	14,178	13,147	12,191	11,304	10,482	9,720	9,013
Price required for 10% return ($/kg)	25,892	25,892	25,892	25,892	25,892	25,892	25,892	25,892
Revenue required for 10% return	1.83	1.86	1.90	1.94	1.98	2.02	2.06	2.10
PV of revenue at 10% return	47,271	48,217	49,181	50,165	51,168	52,192	53,235	54,300
Capital	26,684	24,743	22,943	21,275	19,728	18,293	16,962	15,729

Table D-8: (continued)

Cost items ($1000)/year	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Capital	0	0	0	0	0	0	0
Operating	8,015	8,175	8,339	8,506	8,676	8,849	9,026
Maintenance	4,008	4,088	4,169	4,253	4,338	4,425	4,513
Administrative	5,055	5,156	5,259	5,365	5,472	5,581	5,693
Electricity benefit	-5,367	-5,474	-5,583	-5,695	-5,809	-5,925	-6,044
Harvesting	4,420	4,509	4,599	4,691	4,785	4,881	4,978
Transportation	6,757	6,892	7,030	7,171	7,314	7,460	7,610
Road & infrastructure	581	592	604	616	629	641	654
Silviculture	0	0	0	0	0	0	0
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	5,689	5,803	5,919	6,037	6,158	6,281	6,407
Ash disposal	1,996	2,036	2,076	2,118	2,160	2,203	2,247
Site recovery and reclamation	584	595	607	619	632	644	657
Salvage value	0	0	0	0	0	0	30980
Total cost	0	0	0	0	0	0	0
Present value (PV) of total cost at 10%	31,738	32,373	33,020	33,680	34,354	35,041	66,722
Amount of hydrogen sold (tonnes)	8,358	7,750	7,186	6,663	6,179	5,730	9,918
Price required for 10% return ($/kg)	25,892	25,892	25,892	25,892	25,892	25,892	25,892
Revenue required for 10% return	2.14	2.18	2.23	2.27	2.32	2.36	2.41
PV of revenue at 10% return	55,386	56,494	57,624	58,776	59,952	61,151	62,374
Capital	14,585	13,524	12,541	11,629	10,783	9,999	9,271

Appendix E.

Discounted Cash Flow Analysis for Biohydrogen Production from Pyrolysis of Whole-Tree

Bio-oil is produced from fast pyrolysis of whole-tree, forest residue, and agricultural residue. Production cost of bio-oil is lowest for whole-tree compared to forest and agricultural residues. Bio-oil costs \$0.11 per kg (in 2008 US dollar) at a plant size of 2000 dry tonnes per day for forest biomass. Discounted cash flow analysis of bio-oil production from fast pyrolysis of whole-tree is shown in Table E-1. If the construction of the plant had started in the year of 2008, production of biohydrogen would have started in the year of 2011, and dollar values are represented in their successive year. Finally, discounted cash flow analysis of bio-oil steam reforming process is shown in Table E-2.

Table E-1: Summary of discounted cash flow of fast pyrolysis of whole-tree for bio-oil production at 2000 dry tonnes per day

Cost items ($1000)/year	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
Capital	13,309	99,816	53,235	0	0	0	0	0
Operating	0	0	0	2,601	3,032	3,222	3,286	3,352
Maintenance	0	0	0	3,327	3,394	3,462	3,531	3,601
Administrative	0	0	0	5,316	5,423	5,531	5,642	5,755
Harvesting	0	0	0	5,806	6,768	7,191	7,335	7,482
Transportation	0	0	0	5,584	6,509	7,055	7,196	7,340
Road & infrastructure	0	0	0	4,456	5,194	5,519	5,629	5,742
Silviculture	0	0	0	1,170	1,364	1,449	1,478	1,508
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	0	0	0	2,592	3,021	3,210	3,274	3,340
Site recovery and reclamation	0	0	0	0	0	0	0	0
Ash disposal	0	0	0	186	189	193	197	201
Salvage value	0	0	0	0	0	0	0	0
Total cost	13,309	99,816	53,235	31,038	34,895	36,832	37,568	38,320
Present value (PV) of total cost at 10%	16,104	109,798	53,235	28,217	28,839	27,672	25,660	23,793
Amount of bio-oil sold (tonnes)	0	0	0	395,514	452,016	480,267	480,267	480,267
Price required for 10% return ($/kg)	0	0	0	0.11	0.12	0.12	0.12	0.12
Revenue required for 10% return	0	0	0	45,276	52,779	57,199	58,343	59,510
PV of revenue at 10% return	0	0	0	41,160	43,619	42,975	39,849	36,951

Table E-1: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	3,419	3,487	3,557	3,628	3,701	3,775	3,850	3,927
Maintenance	3,673	3,747	3,822	3,898	3,976	4,056	4,137	4,220
Administrative	5,870	5,987	6,107	6,229	6,354	6,481	6,610	6,743
Harvesting	7,632	7,784	7,940	8,099	8,261	8,426	8,594	8,766
Transportation	7,486	7,636	7,789	7,945	8,103	8,266	8,431	8,599
Road & infrastructure	5,856	5,974	6,093	6,215	6,339	6,466	6,595	6,727
Silviculture	1,538	1,569	1,600	1,632	1,665	1,698	1,732	1,767
Nutrient replacement	0	0	0	0	0	0	0	0
Royalty/premium	3,407	3,475	3,544	3,615	3,687	3,761	3,836	3,913
Site recovery and reclamation	0	0	0	0	0	0	0	0
Ash disposal	205	209	213	218	222	226	231	236
Salvage value	0	0	0	0	0	0	0	0
Total cost	39,086	39,868	40,665	41,478	42,308	43,154	44,017	44,897
Present value (PV) of total cost at 10%	22,063	20,458	18,971	17,591	16,312	15,125	14,025	13,005
Amount of bio-oil sold (tonnes)	480,267	480,267	480,267	480,267	480,267	480,267	480,267	480,267
Price required for 10% return ($/kg)	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.15
Revenue required for 10% return	60,700	61,914	63,152	64,416	65,704	67,018	68,358	69,725
PV of revenue at 10% return	34,264	31,772	29,461	27,318	25,332	23,489	21,781	20,197

Table E-1: (continued)

Cost items ($1000)/year	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Capital	0	0	0	0	0	0	0
Operating	4,006	4,086	4,167	4,251	4,336	4,423	4,511
Maintenance	4,304	4,390	4,478	4,568	4,659	4,752	4,847
Administrative	6,877	7,015	7,155	7,298	7,444	7,593	7,745
Harvesting	8,942	9,120	9,303	9,489	9,679	9,872	10,070
Transportation	8,771	8,947	9,126	9,308	9,495	9,684	9,878
Road & infrastructure	6,862	6,999	7,139	7,282	7,427	7,576	7,727
Silviculture	1,802	1,838	1,875	1,912	1,950	1,989	2,029
Nutrient replacement	0	0	0	0	0	0	0
Royalty/premium	3,991	4,071	4,153	4,236	4,320	4,407	4,495
Site recovery and reclamation	0	0	0	0	0	0	33,272
Ash disposal	240	245	250	255	260	265	271
Salvage value	0	0	0	0	0	0	0
Total cost	45,795	46,711	47,646	48,598	49,570	50,562	84,845
Present value (PV) of total cost at 10%	12,059	11,182	10,369	9,615	8,916	8,267	12,612
Amount of bio-oil sold (tonnes)	480,267	480,267	480,267	480,267	480,267	480,267	480,267
Price required for 10% return ($/kg)	0.15	0.15	0.15	0.16	0.16	0.16	0.17
Revenue required for 10% return	71,120	72,542	73,993	75,473	76,983	78,522	80,093
PV of revenue at 10% return	18,728	17,366	16,103	14,932	13,846	12,839	11,905

Table E-2: Summary of discounted cash flow of bio-oil reforming for biohydrogen production at 2000 dry tonnes whole-tree per day

Cost items ($1000)/year	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**
Capital	8,133	60,999	32,533	0	0	0	0	0
Operating	0	0	0	45,683	53,253	57,713	58,867	60,045
Maintenance	0	0	0	1,423	1,452	1,481	1,510	1,541
Administrative	0	0	0	4,040	4,121	4,204	4,288	4,373
Methanol purchase	0	0	0	7,232	8,430	8,957	9,136	9,319
Bio-oil production	0	0	0	42,665	49,735	52,843	53,900	54,978
Bio-oil/methanol transportation	0	0	0	18,015	21,001	22,313	22,759	23,215
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	8,133	60,999	32,533	119,058	137,992	147,511	150,461	153,470
Present value (PV) of total cost at 10%	9,841	67,098	32,533	108,235	114,043	110,827	102,767	95,293
Amount of biohydrogen sold (tonnes)	0	0	0	48,286	55,184	58,633	58,633	58,633
Price required for 10% return ($/kg)	0	0	0	2.63	2.68	2.73	2.79	2.84
Revenue required for 10% return	0	0	0	126,799	147,812	160,191	163,395	166,662
PV of revenue at 10% return	0	0	0	115,272	122,158	120,354	111,601	103,484

Table E-2: (continued)

Cost items ($1000)/year	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Capital	0	0	0	0	0	0	0	0
Operating	61,246	62,471	63,720	64,994	66,294	67,620	68,972	70,352
Maintenance	1,571	1,603	1,635	1,668	1,701	1,735	1,770	1,805
Administrative	4,461	4,550	4,641	4,734	4,829	4,925	5,024	5,124
Methanol purchase	9,505	9,695	9,889	10,087	10,289	10,494	10,704	10,918
Bio-oil production	56,078	57,199	58,343	59,510	60,700	61,914	63,152	64,416
Bio-oil/methanol transportation	23,679	24,153	24,636	25,128	25,631	26,144	26,666	27,200
Site recovery and reclamation	0	0	0	0	0	0	0	0
Salvage value	0	0	0	0	0	0	0	0
Total cost	156,540	159,670	162,864	166,121	169,444	172,832	176,289	179,815
Present value (PV) of total cost at 10%	88,363	81,936	75,977	70,452	65,328	60,577	56,171	52,086
Amount of biohydrogen sold (tonnes)	58,633	58,633	58,633	58,633	58,633	58,633	58,633	58,633
Price required for 10% return ($/kg)	2.90	2.96	3.02	3.08	3.14	3.20	3.27	3.33
Revenue required for 10% return	169,996	173,396	176,864	180,401	184,009	187,689	191,443	195,272
PV of revenue at 10% return	95,958	88,979	82,508	76,508	70,943	65,784	61,000	56,563

Table E-2: (continued)

Cost items ($1000)/year	14	15	16	17	18	19	20
Capital	0	0	0	0	0	0	0
Operating	71,759	73,194	74,658	76,151	77,674	79,228	80,812
Maintenance	1,841	1,878	1,916	1,954	1,993	2,033	2,073
Administrative	5,227	5,331	5,438	5,547	5,658	5,771	5,886
Methanol purchase	11,137	11,359	11,587	11,818	12,055	12,296	12,542
Bio-oil production	65,704	67,018	68,358	69,725	71,120	72,542	73,993
Bio-oil/methanol transportation	27,744	28,299	28,865	29,442	30,031	30,631	31,244
Site recovery and reclamation	0	0	0	0	0	0	20,333
Salvage value	0	0	0	0	0	0	0
Total cost	183,411	187,079	190,821	194,637	198,530	202,501	226,884
Present value (PV) of total cost at 10%	48,298	44,785	41,528	38,508	35,707	33,110	33,725
Amount of biohydrogen sold (tonnes)	58,633	58,633	58,633	58,633	58,633	58,633	58,633
Price required for 10% return ($/kg)	3.40	3.46	3.53	3.60	3.68	3.75	3.83
Revenue required for 10% return	199,177	203,161	207,224	211,368	215,596	219,908	224,306
PV of revenue at 10% return	52,450	48,635	45,098	41,818	38,777	35,957	33,342

Appendix F.

Modeling of Steam Reforming of Bio-oil in Aspen Plus

The composition of bio-oil for reforming process in Aspen Plus simulation tool is shown in Table F-1. The process flow diagrams of producing biohydrogen from bio-oil reforming are developed by using Aspen Plus tool and include feedstock preparation and steam reforming, gas cooling, gas compression, water-gas shift and purification, and finally, natural gas combustion. These are shown in Figure F-1 to Figure F-5. Mass flow rate and operating characteristics of bio-oil reforming process are also shown in Table F-2.

Table F-1: Simulated composition of bio-oil

Compound type	Selected compound	Simulated composition [a] (wt%)
Carboxylic acid	Acetic acid ($C_2H_4O_2$)	7.56
Carboxylic acid	Propionic acid ($C_3H_6O_2$)	9.33
Carboxylic acid	Formic acid (CH_2O_2)	4.35
Carboxylic acid	3,5-Dimethoxy-4-hydroxy benzoic acid ($C_{10}H_{12}O_2$)	20.86
Phenol	Guaiacol ($C_7H_8O_2$)	0.78
Phenol	Phenol (C_6H_6O)	0.59
Aromatic hydrocarbon	Toluene (C_7H_8)	2.90
Aromatic hydrocarbon	Benzene (C_6H_6)	0.98
Hydrocarbon	Propylene (C_3H_6)	0.19
Esters	Methyl acetate ($C_8H_{10}O_3$)	4.85
Aromatic aldehyde	Furfural ($C_5H_4O_2$)	24.20
Water	Water (H_2O)	23.40

[a] Chemical composition of bio-oil is taken from the bio-oil produced from wood (Ringer et al., 2006).

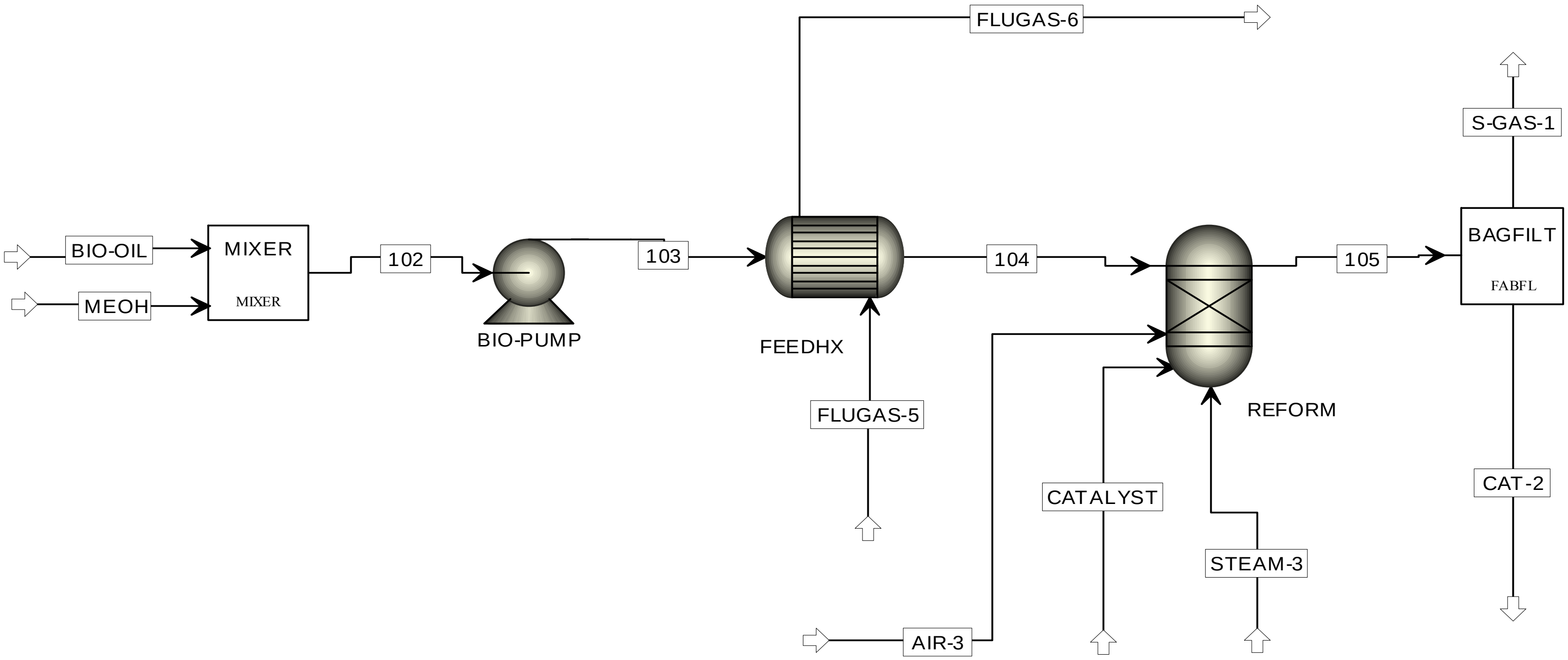

Figure F-1: Bio-oil/methanol atomization and steam reforming process

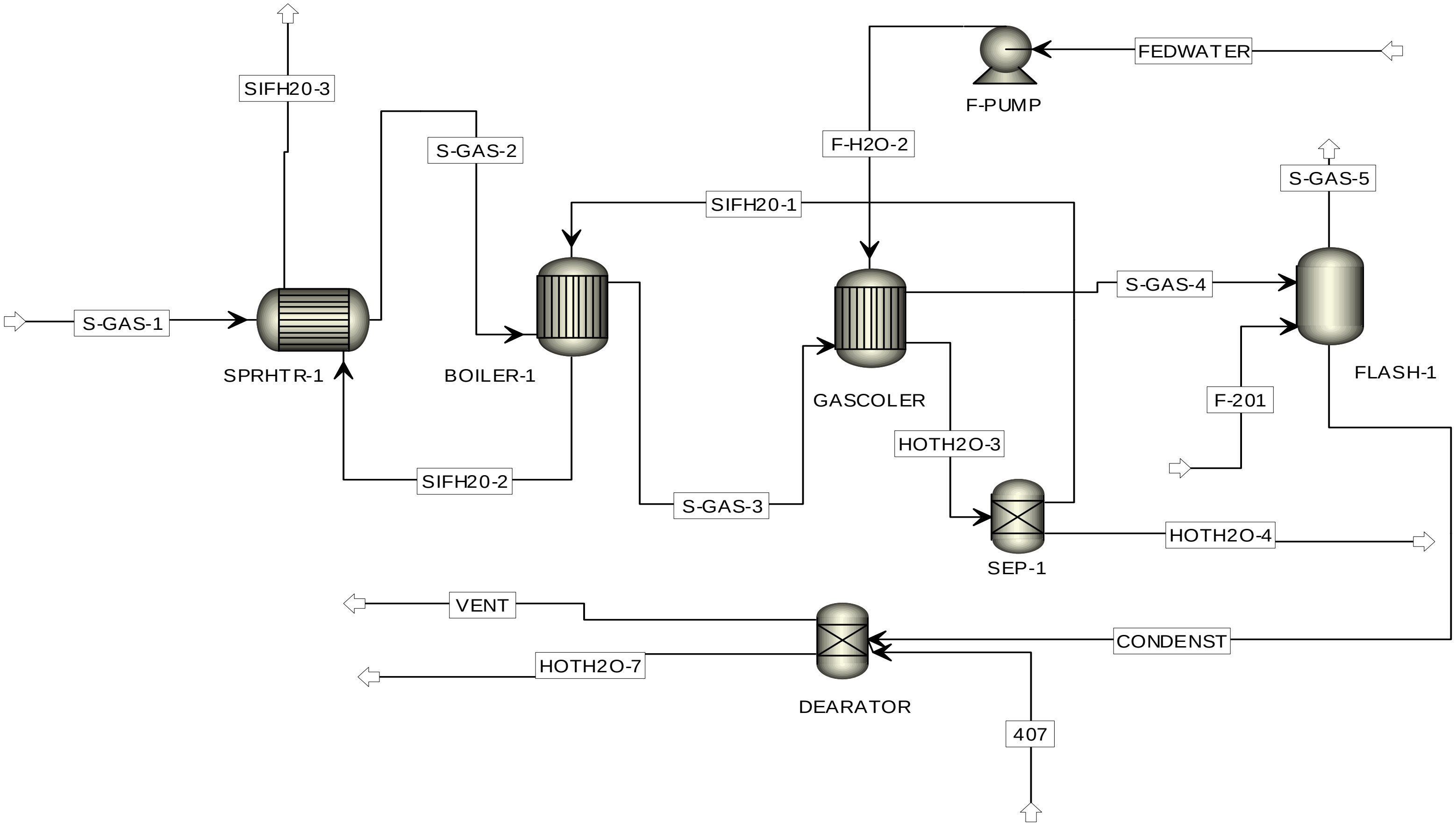

Figure F-2: Reformed gas cooling process

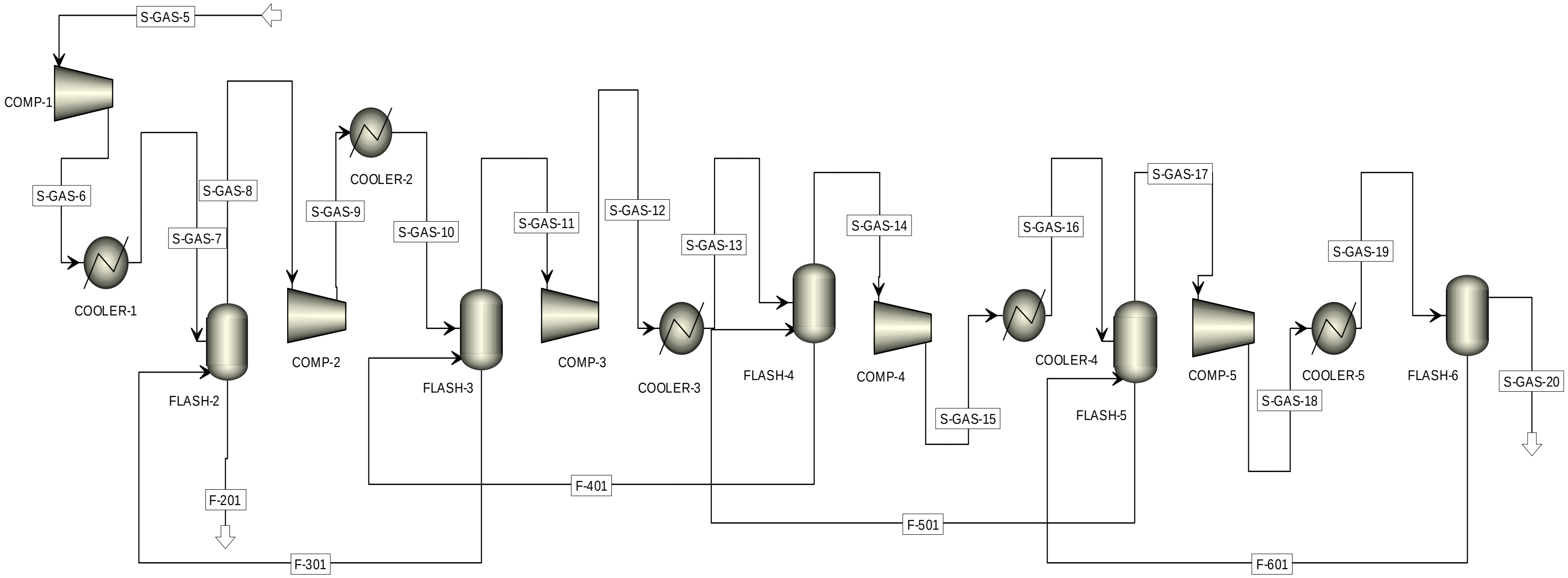

Figure F-3: Gas compression process

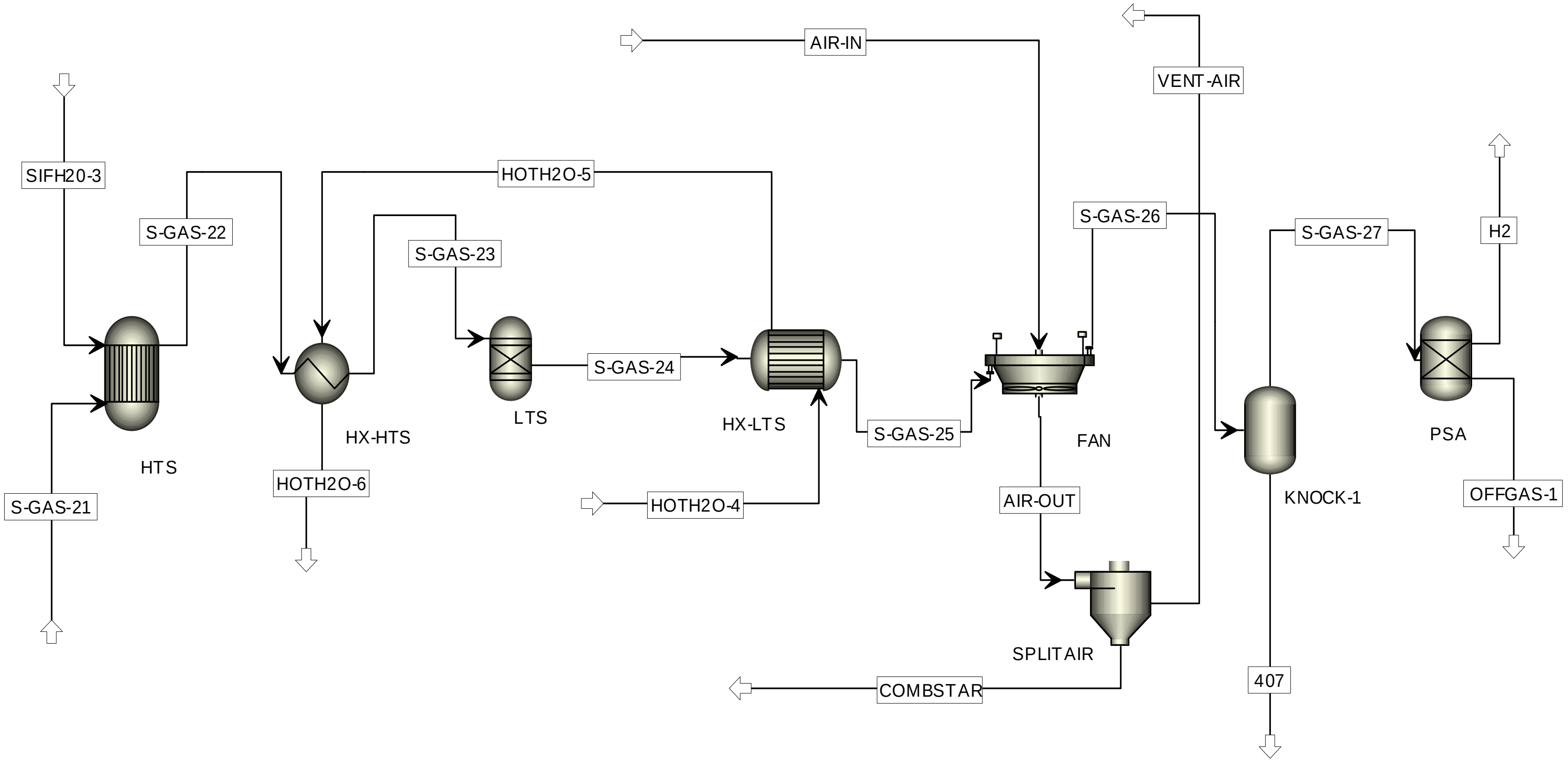

Figure F-4: Shift reaction and purification process

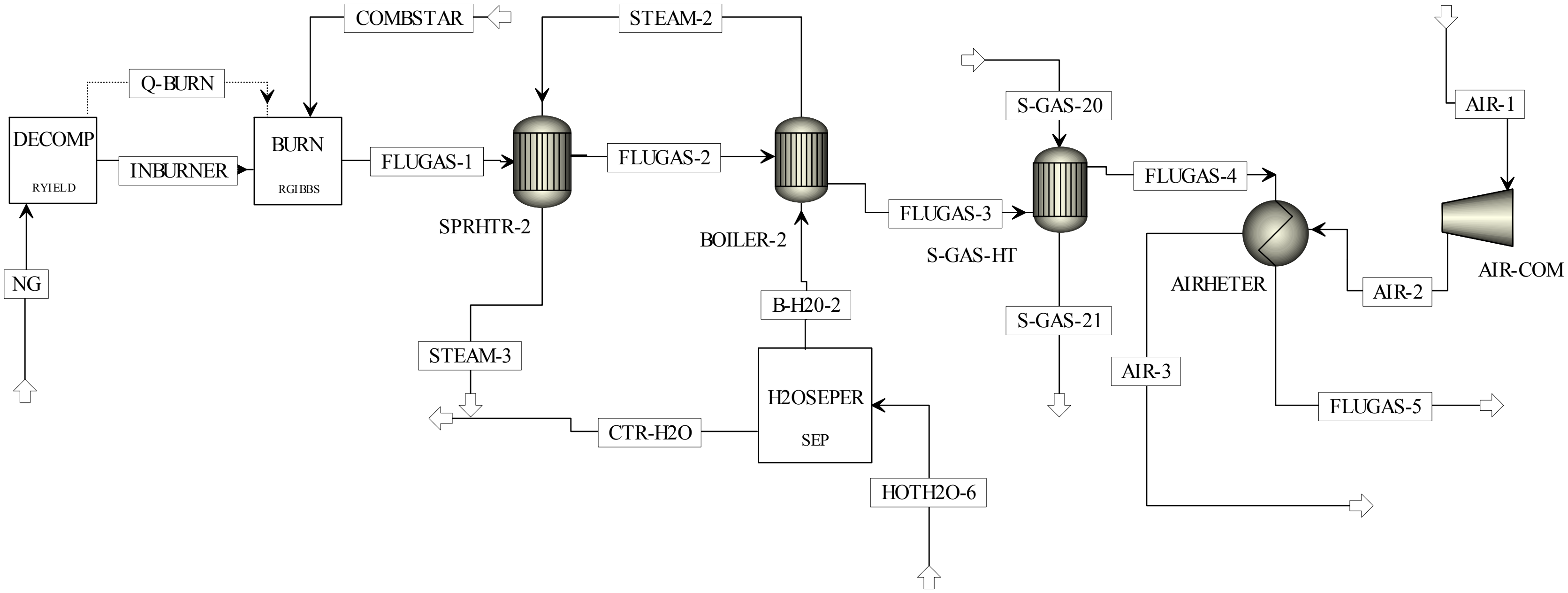

Figure F-5: Natural gas combustion process for steam production

Table F-2: Mass flow rate and operating characteristics of bio-oil reforming from Aspen Plus model

Components	**Unit**	**102**	**103**	**104**	**105**	**407**	**AIR-1**	**AIR-2**	**AIR-3**
H_2	kg/hr	0	0	0	7,372	6	0	0	0
O_2	kg/hr	0	0	0	0	0	22,580	22,580	22,580
H_2O	kg/hr	15,093	15,093	15,093	82,037	54,242	0	0	0
N_2	kg/hr	0	0	0	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0	0
CO	kg/hr	0	0	0	36,344	15	0	0	0
CO_2	kg/hr	0	0	0	65,256	9,632	0	0	0
CH_2O_2	kg/hr	2773.5	2773.5	2773.5	0	0	0	0	0
CH_4	kg/hr	0	0	0	10.54	0.2	0	0	0
CH_4O	kg/hr	7,166	7,166	7,166	0	0	0	0	0
$C_2H_4O_2$	kg/hr	4,902	4,902	4,902	0	0	0	0	0
C_3H_6	kg/hr	129	129	129	0	0	0	0	0
$C_3H_6O_2$	kg/hr	5,999	5,999	5,999	0	0	0	0	0
$C_5H_4O_2$	kg/hr	15,609	15,609	15,609	0	0	0	0	0
C_6H_6	kg/hr	645	645	645	0	0	0	0	0
C_6H_6O	kg/hr	387	387	387	0	0	0	0	0
C_7H_8	kg/hr	1,871	1,871	1,871	0	0	0	0	0
$C_7H_8O_2$	kg/hr	516	516	516	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	3,161	3,161	3,161	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	13,416	13,416	13,416	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0	0
Mole Flow	kmol/hr	1,594	1,594	1,594	10,991	3,233	706	706	706
Mass Flow	kg/hr	71,666	71,666	71,666	191,019	63,895	22,580	22,580	22,580
Temperature	K	293	293	570	1,123	318	293	372	932
Pressure	atm	1.0	2.0	1.5	1.7	20.0	1.0	2.0	1.5
Vapor Fraction		0	0	1	1	0	1	1	1

Table F-2: (continued)

Components	Unit	AIR-IN	AIR-OUT	B-H20-2	BIO-OIL	CAT-2	CATALYST	COLTWER2
H_2	kg/hr	0	0	0	0	0	0	0
O_2	kg/hr	279,500	279,500	0	0	0	0	0
H_2O	kg/hr	0	0	96,773	15,093	0	0	2,162,525
N_2	kg/hr	920,500	920,500	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0
CO	kg/hr	0	0	0	0	0	0	0
CO_2	kg/hr	0	0	0	0	0	0	0
CH_2O_2	kg/hr	0	0	0	2773.5	0	0	0
CH_4	kg/hr	0	0	0	0	0	0	0
CH_4O	kg/hr	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	4,902	0	0	0
C_3H_6	kg/hr	0	0	0	129	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	5,999	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	15,609	0	0	0
C_6H_6	kg/hr	0	0	0	645	0	0	0
C_6H_6O	kg/hr	0	0	0	387	0	0	0
C_7H_8	kg/hr	0	0	0	1,871	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	516	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	3,161	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	13,416	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	41,594	41,594	5,372	1,371	0	0	120,038
Mass Flow	kg/hr	1,200,000	1,200,000	96,773	64,500	0	0	2,162,525
Temperature	K	293	313	351	293			349
Pressure	atm	2.0	1.5	3.0	1.0	1.7	1.0	3.0
Vapor Fraction		1	1	0	0			0

Table F-2: (continued)

Components	Unit	COMBSTAR	CONDENST	COOLTWR	CTR-H2O	F-201	F-301	F-401	F-501
H_2	kg/hr	0	0.57	0	0	0.05	0	0	0
O_2	kg/hr	51,981	0	0	0	0	0	0	0
H_2O	kg/hr	0	81,057	2,162,525	2,027,227	7,927	9,155	7,720	3,188
N_2	kg/hr	171,195	0	0	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0	0
CO	kg/hr	0	36	0	0	3	6	11	9
CO_2	kg/hr	0	663	0	0	54	102	180	153
CH_2O_2	kg/hr	0	0	0	0	0	0	0	0
CH_4	kg/hr	0	0.02	0	0	0	0	0.01	0.01
CH_4O	kg/hr	0	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0	0
Mole Flow	kmol/hr	7,736	4,516	120,038	112,528	441	511	433	181
Mass Flow	kg/hr	223,176	81,756	2,162,525	2,027,227	7,985	9,263	7,912	3,351
Temperature	K	313	323	349	351	322	333	333	333
Pressure	atm	1.5	1.7	20.0	20.5	1.4	2.8	5.6	11.2
Vapor Fraction		1	0	0	0	0	0	0	0

Table F-2: (continued)

Components	Unit	F-601	F-H2O-2	FEDWATER	FLUGAS-1	FLUGAS-2	FLUGAS-3	FLUGAS-4
H_2	kg/hr	0	0	0	0	0	0	0
O_2	kg/hr	0	0	0	1,591	1,591	1,591	1,591
H_2O	kg/hr	1,044	2,200,000	2,200,000	29,044	29,044	29,044	29,044
N_2	kg/hr	0	0	0	171,195	171,195	171,195	171,195
C	kg/hr	0	0	0	0	0	0	0
CO	kg/hr	6	0	0	2,415	2,415	2,415	2,415
CO_2	kg/hr	103	0	0	31,931	31,931	31,931	31,931
CH_2O_2	kg/hr	0	0	0	0	0	0	0
CH_4	kg/hr	0	0	0	0	0	0	0
CH_4O	kg/hr	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	61	122,119	122,119	8,585	8,585	8,585	8,585
Mass Flow	kg/hr	1,154	2,200,000	2,200,000	236,176	236,176	236,176	236,176
Temperature	K	333	294	293	2,263	1,874	1,179	984
Pressure	atm	22.4	22.0	1.0	1.0	1.0	1.0	1.0
Vapor Fraction		0	0	0	1	1	1	1

Table F-2: (continued)

Components	Unit	FLUGAS-5	FLUGAS-6	H2	HOTH2O-3	HOTH2O-4	HOTH2O-5	HOTH2O-6
H_2	kg/hr	0	0	7,874	0	0	0	0
O_2	kg/hr	1,591	1,591	0	0	0	0	0
H_2O	kg/hr	29,044	29,044	0	2,200,000	2,124,000	2,124,000	2,124,000
N_2	kg/hr	171,195	171,195	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0
CO	kg/hr	2,415	2,415	0	0	0	0	0
CO_2	kg/hr	31,931	31,931	0	0	0	0	0
CH_2O_2	kg/hr	0	0	0	0	0	0	0
CH_4	kg/hr	0	0	0	0	0	0	0
CH_4O	kg/hr	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	8,585	8,585	3,906	122,119	117,900	117,900	117,900
Mass Flow	kg/hr	236,176	236,176	7,874	2,200,000	2,124,000	2,124,000	2,124,000
Temperature	K	942	608	318	325	325	346	351
Pressure	atm	1.0	0.5	20.0	21.5	21.5	21.0	20.5
Vapor Fraction		1	1	1	0	0	0	0

Table F-2: (continued)

Components	Unit	HOTH2O-7	INBURNER	MEOH	NG	OFFGAS-1	S-GAS-1	S-GAS-10
H_2	kg/hr	0	3,250	0	0	1,969	7,372	7,371
O_2	kg/hr	0	0	0	0	0	0	0
H_2O	kg/hr	135,298	0	0	0	595	82,037	10,135
N_2	kg/hr	0	0	0	0	0	0	0
C	kg/hr	0	9,750	0	0	0	0	0
CO	kg/hr	0	0	0	0	1,863	36,344	36,314
CO_2	kg/hr	0	0	0	0	109,057	65,256	64,695
CH_2O_2	kg/hr	0	0	0	0	0	0	0
CH_4	kg/hr	0	0	0	13000	10.32	10.54	10.52
CH_4O	kg/hr	0	0	7,166	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	7,510	2,424	224	810	3,555	10,991	6,986
Mass Flow	kg/hr	135,298	13,000	7,166	13,000	113,494	191,019	118,526
Temperature	K	321	298	293	293	318	1,123	333
Pressure	atm	1.7	1.0	1.0	3.0	1.0	1.7	2.8
Vapor Fraction		0	1	0	1	1	1	1

Table F-2: (continued)

Components	**Unit**	**S-GAS-11**	**S-GAS-12**	**S-GAS-13**	**S-GAS-14**	**S-GAS-15**	**S-GAS-16**	**S-GAS-17**
H_2	kg/hr	7,371	7,371	7,371	7,371	7,371	7,371	7,371
O_2	kg/hr	0	0	0	0	0	0	0
H_2O	kg/hr	8,701	8,701	8,701	4,169	4,169	4,169	2,024
N_2	kg/hr	0	0	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0
CO	kg/hr	36,319	36,319	36,319	36,317	36,317	36,317	36,314
CO_2	kg/hr	64,773	64,773	64,773	64,746	64,746	64,746	64,696
CH_2O_2	kg/hr	0	0	0	0	0	0	0
CH_4	kg/hr	10.52	10.52	10.52	10.52	10.52	10.52	10.52
CH_4O	kg/hr	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	6,909	6,909	6,909	6,656	6,656	6,656	6,536
Mass Flow	kg/hr	117,174	117,174	117,174	112,614	112,614	112,614	110,416
Temperature	K	333	411	333	333	411	333	333
Pressure	atm	2.8	5.6	5.6	5.6	11.2	11.2	11.2
Vapor Fraction		1	1	1	1	1	1	1

Table F-2: (continued)

Components	Unit	S-GAS-18	S-GAS-19	S-GAS-2	S-GAS-20	S-GAS-21	S-GAS-22	S-GAS-23
H_2	kg/hr	7,371	7,371	7,372	7,371	7,371	9,536	9,536
O_2	kg/hr	0	0	0	0	0	0	0
H_2O	kg/hr	2,024	2,024	82,037	980	980	57,635	57,635
N_2	kg/hr	0	0	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0
CO	kg/hr	36,314	36,314	36,344	36,308	36,308	6,229	6,229
CO_2	kg/hr	64,696	64,696	65,256	64,593	64,593	111,852	111,852
CH_2O_2	kg/hr	0	0	0	0	0	0	0
CH_4	kg/hr	10.52	10.52	10.54	10.51	10.51	10.51	10.51
CH_4O	kg/hr	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	6,536	6,536	10,991	6,475	6,475	10,694	10,694
Mass Flow	kg/hr	110,416	110,416	191,019	109,263	109,263	185,263	185,263
Temperature	K	411	333	1,076	333	623	643	523
Pressure	atm	22.4	22.4	1.7	22.4	21.9	21.0	20.5
Vapor Fraction		1	1	1	1	1	1	1

Table F-2: (continued)

Components	Unit	S-GAS-24	S-GAS-25	S-GAS-26	S-GAS-27	S-GAS-3	S-GAS-4	S-GAS-5	S-GAS-6
H_2	kg/hr	9,849	9,849	9,849	9,843	7,372	7,372	7,371	7,371
O_2	kg/hr	0	0	0	0	0	0	0	0
H_2O	kg/hr	54,837	54,837	54,837	595	82,037	82,037	8,908	8,908
N_2	kg/hr	0	0	0	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0	0
CO	kg/hr	1,878	1,878	1,878	1,863	36,344	36,344	36,311	36,311
CO_2	kg/hr	118,688	118,688	118,688	109,057	65,256	65,256	64,647	64,647
CH_2O_2	kg/hr	0	0	0	0	0	0	0	0
CH_4	kg/hr	10.51	10.51	10.51	10.32	10.54	10.54	10.52	10.52
CH_4O	kg/hr	0	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0	0
Mole Flow	kmol/hr	10,694	10,694	10,694	7,461	10,991	10,991	6,917	6,917
Mass Flow	kg/hr	185,263	185,263	185,263	121,368	191,019	191,019	117,248	117,248
Temperature	K	543	356	318	318	570	323	323	399
Pressure	atm	20.5	20.0	19.5	20.0	1.7	1.7	1.7	3.4
Vapor Fraction		1	1	1	1	1	1	1	1

Table F-2: (continued)

Components	**Unit**	**S-GAS-7**	**S-GAS-8**	**S-GAS-9**	**SIFH20-1**	**SIFH20-2**	**SIFH20-3**	**STEAM-2**
H_2	kg/hr	7,371	7,371	7,371	0	0	0	0
O_2	kg/hr	0	0	0	0	0	0	0
H_2O	kg/hr	8,908	10,135	10,135	76,000	76,000	76,000	96,773
N_2	kg/hr	0	0	0	0	0	0	0
C	kg/hr	0	0	0	0	0	0	0
CO	kg/hr	36,311	36,314	36,314	0	0	0	0
CO_2	kg/hr	64,647	64,695	64,695	0	0	0	0
CH_2O_2	kg/hr	0	0	0	0	0	0	0
CH_4	kg/hr	10.52	10.52	10.52	0	0	0	0
CH_4O	kg/hr	0	0	0	0	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_3H_6	kg/hr	0	0	0	0	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0	0	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0	0	0	0	0
C_6H_6	kg/hr	0	0	0	0	0	0	0
C_6H_6O	kg/hr	0	0	0	0	0	0	0
C_7H_8	kg/hr	0	0	0	0	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0	0	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0	0	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0	0	0	0	0
Rh	kg/hr	0	0	0	0	0	0	0
Mole Flow	kmol/hr	6,917	6,986	6,986	4,219	4,219	4,219	5,372
Mass Flow	kg/hr	117,248	118,526	118,526	76,000	76,000	76,000	96,773
Temperature	K	333	322	397	325	489	623	401
Pressure	atm	1.4	1.4	2.8	21.5	21.0	20.5	2.5
Vapor Fraction		1	1	1	0	1	1	1

Table F-2: (continued)

Components	Unit	STEAM-3	VENT	VENT-AIR
H_2	kg/hr	0	7	0
O_2	kg/hr	0	0	227,519
H_2O	kg/hr	96,773	0	0
N_2	kg/hr	0	0	749,305
C	kg/hr	0	0	0
CO	kg/hr	0	52	0
CO_2	kg/hr	0	10,294	0
CH_2O_2	kg/hr	0	0	0
CH_4	kg/hr	0	0.22	0
CH_4O	kg/hr	0	0	0
$C_2H_4O_2$	kg/hr	0	0	0
C_3H_6	kg/hr	0	0	0
$C_3H_6O_2$	kg/hr	0	0	0
$C_5H_4O_2$	kg/hr	0	0	0
C_6H_6	kg/hr	0	0	0
C_6H_6O	kg/hr	0	0	0
C_7H_8	kg/hr	0	0	0
$C_7H_8O_2$	kg/hr	0	0	0
$C_8H_{10}O_3$	kg/hr	0	0	0
$C_{10}H_{12}O_2$	kg/hr	0	0	0
Rh	kg/hr	0	0	0
Mole Flow	kmol/hr	5,372	239	33,858
Mass Flow	kg/hr	96,773	10,352	976,824
Temperature	K	1,073	321	313
Pressure	atm	2.0	1.7	1.5
Vapor Fraction		1	1	1

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