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Biohydrogen production from forest and agricultural residues for upgrading of bitumen from oil sands

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ABSTRACT

In this study, forest residues (limbs, tops, and branches) and straw (from wheat and barley) are considered for producing biohydrogen in Western Canada for upgrading of bitumen from oil sands. Two types of gasifiers, namely, the Battelle Columbus Laboratory (BCL) gasifier and the Gas Technology Institute (GTI) gasifier are considered for biohydrogen production. Production costs of biohydrogen from forest and agricultural residues from a BCL gasification plant with a capacity of 2000 dry tonnes/day are \$1.17 and \$1.29/kg of H_2, respectively. For large-scale biohydrogen plant, GTI gasification is the optimum technology. The delivered-biohydrogen costs are \$2.19 and \$2.31/kg of H_2 at a plant capacity of 2000 dry tonnes/day from forest and agricultural residues, respectively. Optimum capacity for biohydrogen plant is 3000 dry tonnes/day for both residues in a BCL gasifier. In a GTI gasifier, although the theoretical optimum sizes are higher than 3000 dry tonnes/day for both feedstocks, the cost of production of biohydrogen is flat above a plant size of 3000 dry tonnes/day. Hence, a plant at the size of 3000 dry tonnes/day could be built to minimize risk. Carbon credits of \$119 and \$124/tonne of CO_2 equivalent are required for biohydrogen from forest and agricultural residues, respectively.

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. Forest residues are the limbs and tops of the trees which are left on the roadside after logging operation by pulp and lumber companies. These residues are left to rot and release GHGs to the atmosphere. Agricultural residues include straw from wheat and barley crops. 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 in Western Canada. On average, there are about 3.29 million dry tonnes/year of forest residues and 3.19 million dry tonnes/year of agricultural residues available in Alberta which could be used for biohydrogen production [1–3].

Most of the whole-forest biomass (i.e. use of whole-tree as feedstock) 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 residues 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 [4]. Similarly, there is some use of the agricultural residues but most of it is left to rot in the field, although it could be removed from the field for biohydrogen production.

Generally, natural gas and coal are used for producing hydrogen that is consumed in chemical and oil sands industries in Canada. In 2005, Western Canada had a production capacity of about 3 million tonnes of hydrogen and 31% of this was used for upgrading 527 thousand barrel of bitumen/day. The capacity of upgrading bitumen is expected to be about 2045 thousand barrel of bitumen/day in 2020 [5,6]. So, it is quite apparent that the demand for hydrogen fuel for bitumen upgrading will increase.

Consumption of hydrogen fuel during bitumen upgrading varies with primary upgrading technology (i.e. coking or hydro-conversion) and quality of synthetic crude oil (SCO) [7]; typical value is 1000 standard cubic feet (scf) of hydrogen/barrel of bitumen (i.e. about 2.41 kg of H_2/barrel of bitumen) upgraded [8]. Additionally, about 2.86 kg of natural gas is consumed as fuel and feed, emitting 11.88 kg of CO_2 equivalent for producing 1 kg of H_2 by steam methane reforming (SMR) process [9]; however, this rate may vary with plant size and efficiency. Utilization of biomass for producing hydrogen will reduce the intensity of CO_2 emission from oil sands industries.

Demonstrations at various scale have been carried out for gasification of biomass for producing electricity and heat by co-

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firing with fossil fuels [10,11]; although, none of these plants have produced hydrogen from gasification of biomass. A number of studies have dealt with techno-economic assessment of hydrogen fuel production from gasification of biomass especially from wood [12–19]. Besides, most of these studies have considered a fixed-value for delivered-biomass cost (approximately \$30–\$60/dry tonne), and estimated production cost of H_2 is in the range of \$1–\$2/kg of H_2 for plants processing 360–5000 dry tonnes biomass/day. Although some studies have estimated production cost of \$2–\$5/kg of H_2 [17,20].

In an earlier study by the authors [21], the cost of producing biohydrogen from whole-forest was estimated along with the cost of transporting it to an upgrader in Western Canada. The carbon credits required to make it competitive with natural gas-based hydrogen were also estimated. This paper deals with using forest and agricultural residues for producing biohydrogen for bitumen upgrading. Two types of gasification technology are considered for biohydrogen production. This paper also compares biohydrogen production from agricultural and forest residues with the whole-forest case.

This part of the work focused on the collecting and harvesting of forest residues and straw by conventional harvesting methods, and their transportation by truck to a biohydrogen production plant using the existing road networks. Once the biohydrogen is produced in a plant, it is transported to an upgrader. After collecting all the data and making some assumptions, techno-economic models were developed to calculate the cost of producing biohydrogen from forest residues 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 paper as required.

2. Gasification technologies

The general methodology for gasifying forest residues and straw is similar to the whole-tree gasification process which is given in detail in an earlier study by the authors [21]. The gasification of biomass can be carried out in an atmospheric pressure gasifier [12] or a pressurized gasifier [18]. The former gasifier is the Battelle Columbus Laboratory (BCL) gasifier which was developed by the National Renewable Energy Laboratory (NREL) (Fig. 1 shows the schematic of a BCL gasifier). The latter gasifier is the Gas Technology Institute (GTI) gasifier which was named for its developer (Fig. 2 shows the schematic of a GTI gasifier). The key difference between these two gasifiers is in their operating pressure. BCL gasification is an atmospheric pressure (~0.16 MPa) and involves feedstock drying with flue gases from char combustion, a wet gas cleaning process, a water-gas shift reaction, and a purification process [12]. GTI gasification operates at high pressure (~3.45 MPa) and involves a high temperature syngas (~982 °C) cleaning process, a shift reaction, and a purification process [14,22–24]. 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. The oxygen flow rate for GTI gasification process is 0.3 kg/kg of dry biomass, while 0.4 kg and 0.3 kg steam are supplied for each kg of dry biomass feed rate in BCL and GTI gasifiers, respectively [12,22,24]. Further details on this are given in subsequent sections.

Figs. 1 and 2 depict the gasification of biomass in a BCL and in 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 [12,18,25]. The temperature and pressure of the syngas vary with the types of gasification process (i.e. BCL or GTI processes), and detail of the syngas clean up to remove particulates and sulfur, tar reforming, compression, and cooling are explained in different studies [18,25–31].

The basic operating principle of fluidized bed reactors 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 [23,31–37]. 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 [18]. 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 [34]. A large number of studies have been published on biomass gasification process that produces syngas, and the syngas is used either in: electricity production by burning syngas in turbines/boilers; or liquid fuel production processes by liquefying in a synthesis reactor [24,30,31,38–41].

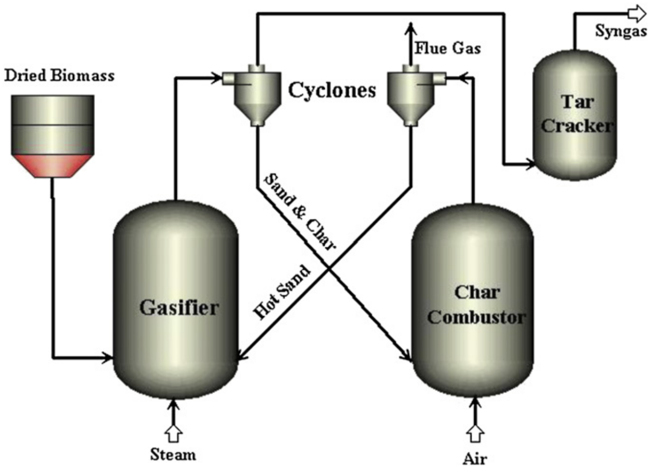

Fig. 1. Schematic diagram of a BCL gasifier for biohydrogen production (derived from Spath et al. [12]).

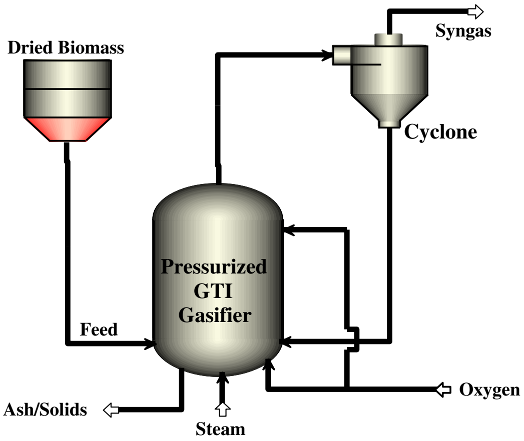

Fig. 2. Schematic diagram of a GTI gasifier for biohydrogen production (derived from Larson et al. [18]).

Table 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 [16].
Switchgrass	12%	84.10	Hot gas cleaning followed by SMR, shift, and PSA [16].
Switchgrass	20%	83.48	Maximum hydrogen production case without carbon capture [18].
Nutshell mix	12.5%	88.30	Hot gas cleaning followed by SMR, shift, and PSA [16].
Rice straw	15%	72.18	Hot gas cleaning followed by dual shift and PSA [15].
Wood	15%	55.65	Hot gas cleaning with dual shift reactor and PSA [14].
Wood	15%	82.20	Hot gas cleaning with ceramic membrane and internal shift [14].
Wood	Unknown	73.20	Hot gas cleaning followed by SMR, dual shift, and PSA [20].

Table 1 shows the yield of biohydrogen from different biomass feedstocks in GTI gasifier. Minor differences in moisture content could lead to change in yield, but various studies on biohydrogen yield from these feedstocks show yields in the range of about 70–90% for different biomass feedstocks as listed in Table 1. 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 H_2/dry tonne of biomass [12,18]. Yields from both residues are assumed to be the same because moisture content after drying is 12% for both of these feedstocks. Like yield, the gasification, gas clean up, and separation processes are identical for these two feedstocks. Detail of these processes for biohydrogen production is explained in Sarkar and Kumar [21].

3. Biomass fuel properties

The “as received” moisture content of forest residues and straw was 45% and 16%, respectively [4]. Upon being received, the feedstock is processed in the biohydrogen production plant by grinding and drying. There are basic differences between forest residues and agricultural residues which are crucial 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 [4]. Table 2 shows the properties of forest residues and straw which are considered for hydrogen fuel production in BCL and GTI gasification process, while properties of whole-forest is explained by the authors in the earlier paper [21].

The yield of forest residues 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 residues is estimated at 14–55% of the yield from whole-tree [46]. In an another study, the yield from forest residues in Western Canada was calculated as yielding 20% of the yield of whole-tree [4]. Additionally, the yield of whole-tree from a medium-yield site in Western Canada is 84 dry tonnes/ha [47]; therefore, for 100-year rotation of forest growth, the yield of forest residues is 0.247 dry tonnes/ha (as shown in Table 3) according to Kumar et al. [4]. This yield is considered in this study. There is provision of storage in the production plant for the time when roads are impassable.

Table 2
Properties of forest residues and straw.

Characteristics	Forest residues	Straw	Comments/sources
Moisture content (%, wet basis)	45	16	Feedstock moisture content during transportation by truck [4].
Fuel density during transportation (kg/m^3)	551	174	Forest residue is transported by truck after chipping process, while straw is transported in large bale by truck to the biohydrogen production plant [42,43].
Heating value (MJ/dry kg, HHV)	19.7	16.28	[15,44].
Percentage of H_2 (%)	6.4	6.2	[44,45].
Percentage of ash (%)	3	4	[4].

Most studies have calculated the yield of straw from crop production and net harvest area using straw-to-grain ratios [2,4,48,49]. Kumar et al. [4] have estimated the yield of straw from wheat and barley crops in Alberta 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/gross hectare where straw moisture content was assumed to be 16% [4]. 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/ha (as shown in Table 3). Straw is stored in the field most of the year, and there is also provision of storage in the production plant for the time when roads are impassable.

4. Harvesting and transporting forest residues 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 residues 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 transporting tree stems, forest residues can be transported using these existing roads, and hence, there is no cost for road construction in this case.

Alberta has a 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. In this study, it is assumed that the straw is harvested in the field and baled; the bales are then transported on a flat-bed trailer to a biohydrogen production plant where the straw is chopped. Biomass feedstock is harvested and transported to the centralized biohydrogen plant, and feedstock transportation cost is estimated from the average transportation distance of biomass feedstock. For the comparison of hydrogen production from the three biomass feedstocks, moisture content is reduced to 12% before feeding in the BCL and GTI gasifiers. Fig. 3 shows the distances that whole-tree, forest residues, and straw are transported, in correlation to the production plants of various sizes. Note that the assumptions and methodology for estimating feedstock transportation distance is explained in previous paper by the authors [21].

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/day, as discussed in the earlier study

Table 3
Characteristics and costs for the procurement and delivery of forest residues and straw.

Items	Values	Comments/sources
Feedstock yield (dry tonnes/hectare):		
Forest residues	0.247	Yield of forest residues 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. [4] for sustainable straw removal.
Straw	0.333	
Surface area of the field (km^2):		
Forest residues	25,121	Average transportation distance of forest residues is 76 km and straw is 92 km for plant size of 2000 dry tonnes/day in the 3rd year of operation.
Straw	18,645	
Harvesting cost:		
Forest residues ($/dry tonne)	11.25	Harvesting cost is derived from Kumar et al. [4].
Straw ($/dry tonne)	10.58	
Straw loading and unloading cost ($/green tonne)	4.80	Straw loading and unloading costs are for straw bale loading and unloading by fork-lift to and from the truck.
Straw transportation cost ($/green tonne/km)	0.13	Transportation of bales is on a flat-bed trailer with a transport capacity of about 19 tonnes/load [43].
Nutrient replacement cost ($/dry tonne)	14.75	Nutrient replacement cost is estimated for sustainable straw recovery from the field [4].
Royalty/Premium fee ($/dry tonne)	4.80	For forest residues, a payment is made to the owner of the feedstock [4]. The same amount is considered as the payment to the farmer for straw.
Plant operating factor (%):		
Year 1	70	Because of no existing large-scale biohydrogen plant, conservative approach is taken in plant operating factor [4,12].
Year 2	80	
Year 3 onwards	85	

by the authors [21]. 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 residues and straw include: 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. Once all the economic and technical parameters are determined, a data intensive discounted cash flow techno-economic model using spreadsheet program was developed to estimate the cost and optimum plant size. The following sections explain the different cost parameters for forest and agricultural residues.

5.1. The cost of delivering biomass residues

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 residues, there is no road construction cost to be incurred in order to utilize forest residues. Transportation to the biohydrogen production plant is achieved by B-train chip vans. Kumar et al. [4] have conducted an extensive analysis of biomass processing for electricity production utilizing direct combustion process. Data on forest residues' yield, harvesting cost, and transportation cost are derived from this study. The total delivery cost of forest residues is $33.50/dry tonne for a feedstock transportation distance of 76 km. 52% and 34% of this cost come from feedstock transportation and harvesting cost, respectively. The cost of delivering forest residues to a biohydrogen production plant is shown in Table 3. The delivery cost of forest residues includes feedstock harvesting and transportation. Harvesting cost ($/dry tonne) of biomass feedstock remains constant with increasing the plant size, but the transportation cost increases with increasing the plant size. The transportation cost follows the trend shown in Fig. 3.

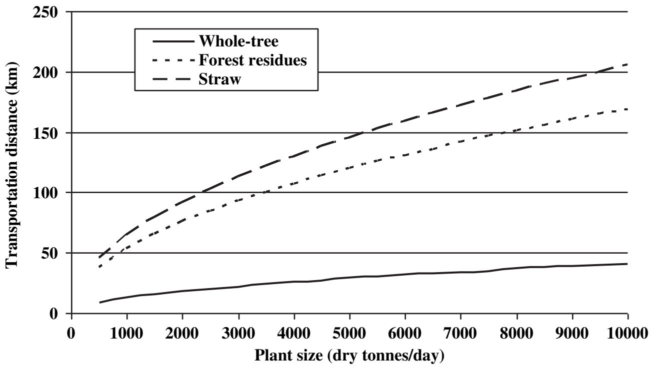

Fig. 3. Variation in transportation distance and plant size for three types of feedstocks.

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, transporting by truck trailer, and unloading. Straw loading and unloading cost is $5.70/dry tonne, and transportation cost is $0.16/dry tonne/km [4]. In 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 for 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 residues [4]. The delivered-cost of straw is $48/dry tonne; this includes 38% cost for a feedstock transportation distance of 92 km and 30% cost for nutrient replacement. The cost of delivered straw to a biohydrogen production plant is shown in Table 3. The delivery cost of straw includes feedstock harvesting and transportation. Harvesting cost ($/dry tonne) of biomass feedstock remains constant with increasing the plant size, but the transportation cost increases with increasing the plant size. The transportation cost follows the trend shown in Fig. 3.

5.2. Capital cost

Table 4 shows a base case, outlining the capital and other costs of biohydrogen plants, including scale factors for BCL and GTI

Table 4
Characteristics of biohydrogen production plants based on forest residues and straw.

Items	Values	Comments/sources
Base case biohydrogen plant size (dry tonnes/day):		
BCL gasification	2000	Based on the literature [12,18].
GTI gasification	1000	
Base case capital cost (million $):		
Forest residues (BCL)	178	For BCL gasification, the cost is derived from Spath et al. [12]; capital cost for GTI gasification is extracted from Larson et al. [18]. Capital costs have been adjusted for forest residues and straw-based on the size of the drying plant required due to variation in moisture content of the feedstock. For instance, before drying process straw and forest residues have 16% and 45% moisture content, respectively. Therefore, higher moisture content in forest residues will have higher mass flow rate in the dryer that will increase dryer capital cost. Hence, capital cost is adjusted by the scale factor for different dryer size.
Forest residues (GTI)	186	
Straw (BCL)	154	
Straw (GTI)	155	
Scale factors:		
BCL gasification	0.76	Overall plant scale factor is derived from literature for both of these plants [12,18].
GTI gasification	0.68	
Biohydrogen yield (kg of H_2/dry tonne biomass):		
Forest residues	83.40	Yields are assumed to be the same for both gasification processes for feedstocks with 12% moisture content after drying process.
Straw	83.40	

gasifier. In the base case, the capital cost of processing forest residues 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.

In this paper, both BCL and GTI gasification are considered for producing biohydrogen from forest residues and straw. Due to the remote location of forest residues-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 cost is added to the capital cost. Using these data, the cost of biohydrogen is calculated for both of the BCL and GTI gasifiers processing of forest residues and straw.

5.3. *Operating cost*

Operating costs for the GTI gasification process include electricity, non-fuel operating (4% of the capital cost), and employees' remuneration [18]. The purchased price of electricity is assumed to be $70/MWh for Alberta. Employee's remuneration of the biohydrogen plant is estimated for both administrative ($64/h) and operating ($40/h) employees, and the number of employees for biohydrogen plant is estimated from the literature review of biohydrogen and bioethanol production plants [12,21,36,50]. Ten percent increment in fixed operating cost is assumed due to remote location of the forest-based biohydrogen production plant [4]. The yearly operating cost for a plant processing 2000 dry tonnes of forest residues/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 earlier study by the authors [21] for a whole-tree-based plant. Similar values of operating cost for straw-based plants are 7.50% and 10.30% of the capital cost for a plant size of 2000 dry tonnes/day in GTI and BCL gasification processes, respectively. Note that the operating cost does not include the feedstock delivery cost which is 6% and 10% of the capital cost for a GTI gasification plant (1000 dry tonnes/day), based on forest residues and straw, respectively. For BCL gasification plants, the feedstock delivery cost is 9.60% and 16.40% of the plant capital cost for forest residues and straw, respectively. The feedstock delivery cost increases as the plant size increases for both BCL and GTI gasification processes due to increasing feedstock transportation distance with larger plant size.

6. Results and discussion

6.1. *The cost of biohydrogen production*

Table 5 shows different cost components for biohydrogen production by BCL gasifier when using forest residues and when using straw as feedstock. For a 2000 dry tonnes/day plant using forest residues, the cost is $1.17/kg of H_2 ($9.75/GJ of H_2). For a plant of the same type and capacity using straw, the cost is $1.29/kg of H_2 ($10.75/GJ of H_2). Similarly, different cost components of biohydrogen production for these two feedstocks using GTI gasifier are shown in Table 6. The cost of producing biohydrogen from forest residues using GTI gasifier is lower than agriculture residues-based biohydrogen due to the nutrient replacement cost for agricultural residues case.

The capital cost of biohydrogen production using gasification of forest residues in BCL and GTI gasifiers in a 2000 dry tonnes/day plant is 33% and 48% of the total production cost, respectively. Keeping the plant size same, the feedstock transportation cost is 19% and 17% of the biohydrogen production cost for forest residues using BCL and GTI gasification, respectively. Hence, GTI gasification is a more highly capital intensive process (as shown in Table 4) than is BCL gasification. As a result of this, scale factor is important. GTI gasification process actually costs less for larger plants. The case is similar for plants processing straw.

Variation in cost of production of biohydrogen with the capacity of plant for forest residues is shown in Fig. 4 for the BCL and GTI processes. For a plant size of 4000 dry tonnes/day or lower, the cost of biohydrogen production from forest residues undergoing BCL gasification is lower than the production cost for GTI gasification.

Table 5
Cost components of BCL gasification of forest residues and straw in a 2000 dry tonnes/day plant.

Feedstock	Forest residues		Straw	
Cost components	$/kg H_2	%	$/kg 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

Table 6
Cost components of biohydrogen production for GTI gasification of forest residues and straw in a 2000 dry tonnes/day plant.

Feedstock	Forest residues		Straw	
Cost components	\$/kg H_2	%	\$/kg 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

Above a capacity of 4000 dry tonnes/day, the GTI process is economical compared to BCL process. The key reason is the benefit from economy of scale in the capital cost of the oxygen production plant for the GTI process. As well, there is a huge difference between the cost for the GTI and BCL processes for forest residues in plants for a capacity less than 2000 dry tonnes/day. This difference is due to the high capital cost of the oxygen production plant for the GTI process.

For agricultural residues (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/day (see Fig. 5). Above this size, the cost of biohydrogen production from the GTI process is lower. Again, this is due to a reduction in the capital cost per unit of output of the oxygen production plant because of 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.

Similarly, the cost of producing biohydrogen using GTI gasification is lower for whole-tree when plant size is larger than 4000 dry tonnes/day, although with a plant size of less than 4000 dry tonnes/day, BCL gasification costs less. The cost of producing biohydrogen is \$1.32/kg of H_2 (\$11/GJ of H_2) using GTI gasification on whole-tree feedstock at plant size of 2000 dry tonnes/day.

6.2. The optimum size for a biohydrogen plant

There is a trade-off between capital cost per unit output 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.

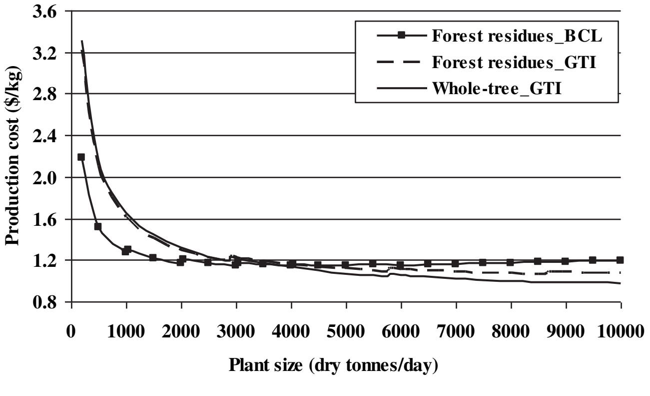

Fig. 4. Comparison of biohydrogen production costs for BCL and GTI gasification of forest biomass.

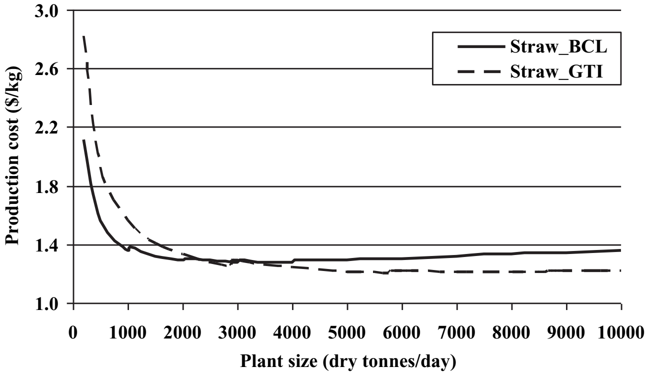

Fig. 5. Comparison of biohydrogen production costs for BCL and GTI gasification of straw.

For forest residues and BCL gasification, the optimum biohydrogen plant size is 3000 dry tonnes/day with a production cost of \$1.15/kg of H_2 (\$9.58/GJ of H_2). Note that the lowest cost of producing biohydrogen is \$1.07/kg (\$8.92/GJ of H_2); this cost is possible for forest residues processed in a plant with a capacity of 8500 dry tonnes/day by a GTI gasifier. Even though, the theoretical optimum size in the case of forest residues is 8500 dry tonnes/day (with an average feedstock transportation distance of 156 km), the cost of production of biohydrogen is flat above a plant size of 3000 dry tonnes/day. Hence, a plant at the size of 3000 dry tonnes/day could be build to minimize risk.

The optimum plant sizes for straw are 3000 and 5670 dry tonnes/day for BCL and GTI gasification, respectively (as shown in Fig. 5). In a GTI gasifier, although the theoretical optimum size is 5760 dry tonnes/day for agricultural residues, the cost of production of biohydrogen is flat above a plant size of 3000 dry tonnes/day. Hence, again a plant at the size of 3000 dry tonnes/day could be built to minimize risk. As well, straw has the potential for producing biohydrogen at a lower price than whole-tree and forest residues feedstocks, as long as the plant size is less than 500 and 1500 dry tonnes/day for BCL and GTI gasification, respectively.

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/kg of H_2 at a pipeline capacity of 167 tonnes of H_2/day, from a gasification plant of 2000 dry tonnes/day (details on the pipeline transport is given in an earlier study by the authors [21]). From a plant processing 2000 dry tonnes of forest residues per day that uses the BCL gasification process, the cost of delivered biohydrogen is \$2.19/kg (\$18.24/GJ of H_2). For a straw-based plant, the delivered-cost is \$2.31 and \$2.35/kg of H_2 at 2000 dry tonnes/day using BCL and GTI gasifiers, respectively. The cost of delivered whole-tree-based biohydrogen from a 2000 dry tonnes/day GTI gasification plant is \$2.34/kg; this is higher than forest residues-based hydrogen at the same plant size.

6.4. The 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 used here is detailed in Sarkar and Kumar [21], and also the same emission factor for hydrogen production from natural gas is used in this paper to calculate the carbon credits for the production of forest residues- and straw-based biohydrogen. This study uses the emission from natural gas-based hydrogen only to estimate the carbon credit because almost all the hydrogen in Western Canada is produced from natural gas for bitumen upgrading and chemical process industries. If emission factor for solid fuel-based (i.e. coal) hydrogen is used to estimate the carbon credit, the carbon mitigation will be more compared to natural gas-based hydrogen case.

The estimated life cycle emissions for forest residues- and straw-based biohydrogen production plants are shown in Table 7. Forest residues and straw are transported to the biohydrogen production 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 residues and 92 km for straw), from plant construction and decommission, and from 500 km of pipeline transport. Estimated emissions for forest residues- and straw-based biohydrogen production from a 2000 dry tonnes/day plant are 1.11 and 0.60 kg of CO_2 equivalent/kg of H_2, respectively. Assuming that the biohydrogen will be transported 500 km from the production plant to the bitumen upgrading plant (based on the location of biomass feedstocks and upgraders in Alberta), the emission for the pipeline transport alone is about 0.50 kg of CO_2 equivalent/kg of H_2, which is calculated by the authors in an earlier study [21]. Emission from hydrogen fuel transportation by pipeline includes emission from manufacturing pipeline material, emission from pipeline installation, and emission from compressor electricity consumption.

Based on the above data, the estimated life cycle GHG emissions for forest residues- and straw-based production of biohydrogen are 1.61 and 1.10 kg of CO_2 equivalent/kg of H_2, respectively. The delivery-cost for biohydrogen from a BCL plant with a capacity of 2000 dry tonnes/day is \$2.19 and \$2.31/kg of H_2 for forest residues and straw, respectively. In contrast, the cost of producing hydrogen through the steam methane reforming (SMR) of natural gas is about \$0.96/kg of H_2. This was calculated for a plant size of 427 tonnes of H_2/day and at a natural gas price of \$5/GJ, as described in previous studies [21,41,58,59]. As a result, gasification of forest residues for producing hydrogen fuel could reduce 24.77 kg of CO_2 equivalent during upgrading of 1 barrel of bitumen, based on the emission factor of 11.88 kg CO_2 equivalent/kg of H_2 from natural gas [9] and hydrogen fuel consumption of 2.41 kg/barrel of bitumen upgrading [8]. Hence, significant amount of greenhouse gas could be mitigated by switching from the production of hydrogen from natural gas to the production of hydrogen from biomass.

Using these values, carbon credits are calculated for producing biomass-based hydrogen fuel in Western Canada. Fig. 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/GJ of natural gas, a carbon credit of \$119 and \$124/tonne of CO_2 equivalent are required for biohydrogen from BCL-gasified forest residues and straw, respectively. The values for GTI-gasified forest and agricultural residues are \$131 and \$128/tonne of CO_2 equivalent, respectively.

6.5. Sensitivities

The base case plant sizes for BCL and GTI gasification processes are 2000 dry tonnes/day and 1000 dry tonnes/day, respectively. To compare the impacts of different economic and technical parameters on the overall cost of production of biohydrogen using BCL and GTI gasifiers for the selected biomass feedstocks, a sensitivity analysis is performed for a plant size of 2000 dry tonnes/day for both BCL and GTI gasification processes. Table 8 shows an analysis on different parameters of forest residues and straw for BCL and GTI gasification. The percentage change in the cost of biohydrogen production is shown with respect to the base case for various scenarios.

For a 2000 dry tonnes/day plant, forest residues-based biohydrogen costs \$1.17 and \$1.30/kg of H_2 using BCL and GTI gasification, respectively. The cost of biohydrogen from forest residues 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/day plant, straw-based biohydrogen costs \$1.29 and \$1.33/kg of H_2 using BCL and GTI gasification, respectively. Table 8 shows sensitivity analyses of various input parameters. These show trends similar to those for biohydrogen production from forest residues.

In order to evaluate the impact of ambient temperature on the preheating of the intake air, a specific case for BCL gasifier was evaluated. To heat the air for gasification during winter by 48 °C

Table 7
Life cycle emissions (kg of CO_2 equivalent/kg H_2) from biohydrogen production.

Items	Forest residues	Straw
Production	0.518[a]	0.214[b]
Feedstock transportation	0.362[c]	0.156[c]
Construction and decommissioning	0.230[d]	0.230[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 residues. For the production and combustion of diesel fuel, they are 0.12 and 2.758 kg of CO_2 equivalent/liter, respectively [46,51,52].

[b] Emissions are estimated for rice straw harvesting that includes swathing, raking, bailing, and roadsiding [53]. For wheat and barley straw, the emissions during production are assumed to be the same.

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

[d] Plant construction and decommissioning emissions are derived from a study on a biomass-based power generation facility [4].

[e] Transportation distance by pipeline is 500 km [52,54–57].

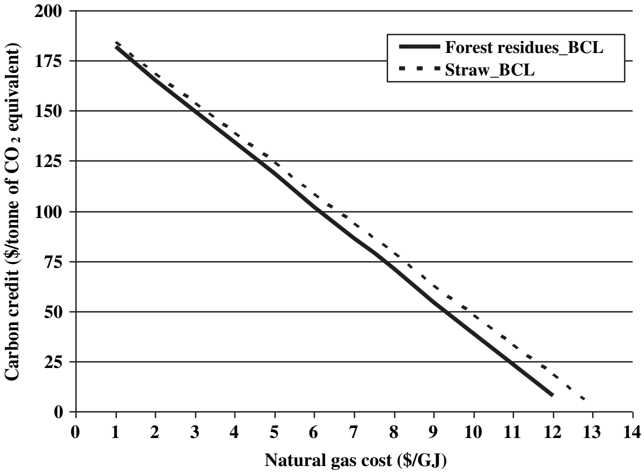

Fig. 6. Carbon abatement costs for hydrogen based on forest residues and straw.

Table 8
Key sensitivities for H_2 production from forest residues 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 (%)
Base case	1.17	–	1.30	–	1.29	–	1.33	–
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
Cost of preheating air by natural gas over one year	1.25	+6.8	–	–	1.37	+6.2	–	–

and by 12 °C in summer (based on local conditions), additional cost of $0.08/kg of hydrogen is required. This is based on a natural gas price of $5/GJ.

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, locations for forest residues-based biohydrogen production plants will be similar to the locations for whole-tree-based biohydrogen production plants. Possible locations in Alberta are: 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 Fig. 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.

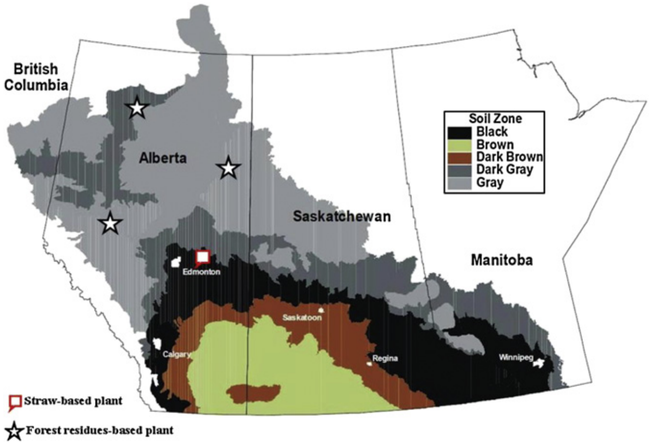

Fig. 7. Soil zones of Western Canada (reproduced with the permission of the Minister of Public Works and Government Services, 2009 [60]).

Western Canada's straw production is highest in Saskatchewan and the second highest is in Alberta. Although Saskatchewan produces large amount of straw, the yield of straw per hectare is highest in Alberta [3]. Large amount of bitumen is upgraded in Alberta, which makes Alberta the preferred location for straw-based biohydrogen production plants depending on plant size.

Most of the straw is produced on the Canadian prairie, and, as Fig. 7 shows, the soil on the prairie can be generally divided into five categories [60]. 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 [49,60]. The preferred location proposed for the bitumen upgrading facility is Edmonton, Alberta which is known as upgrader alley with an upgrading capacity of 1946 thousand barrels/day which is predicted for 2020 [61].

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

7. Conclusion

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

The optimum size for a biohydrogen production plant is 3000 dry tonnes/day for straw processed by a BCL gasifier; the cost of production is \$1.28/kg of H_2 (\$10.66/GJ of H_2). In contrast, 5760 dry tonnes/day is the optimum plant size for GTI gasification of straw at a production cost of \$1.20/kg of H_2 (\$10/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. Although the theoretical optimum size is 5760 dry tonnes/day for agricultural residues, the cost of production of biohydrogen is flat above a plant size of 3000 dry tonnes/day. Hence, a plant at the size of 3000 dry tonnes/day could be built to minimize risk.

In order to be competitive with hydrogen from natural gas, carbon credits of \$119 and \$124/tonne of CO_2 are required for forest residues- and straw-based BCL gasification plants with delivered-biohydrogen costs of \$2.19/kg of H_2 and \$2.31/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 that of BCL gasification of forest residues and straw, respectively.

Among these two biomass feedstocks and two gasification processes described in this paper and its comparison with whole-tree-based hydrogen [21], the lowest cost of delivered biohydrogen are for: forest residues processed by a BCL gasifier when plant capacity is lower than 2000 dry tonnes/day; whole-tree processed by a BCL gasifier when plant capacity is 2000–4000 dry tonnes/day; and whole-tree processed by a GTI gasifier when plant capacity is higher than 4000 dry tonnes/day. 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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