Life Cycle and Techno-economic Assessment of Transportation Biofuels from Hydrothermal Liquefaction of Forest Residues in British Columbia

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Abstract

Biofuels from hydrothermal liquefaction (HTL) of abundantly available forest residues in British Columbia (BC) can potentially make great contributions to reduce the greenhouse gas (GHG) emissions from the transportation sector. Life cycle and technoeconomic assessment are conducted to evaluate the environmental and economic performance of a hypothetic 100 million liters per year (MLPY) HTL biofuel system in the Coast Region of BC based on three different supply chain designs.

The life cycle GHG emission of HTL biofuels ranges from 17.0-20.5 g CO₂-eq/MJ, corresponding to 78%-82% reduction compared with petroleum fuels. A further reduction of 6.8 g CO₂-eq/MJ can be achieved when by-product biochar is applied for soil amendment. The conversion stage dominates the total GHG emissions, making up more than 50%. The process emitting most GHGs over the life cycle of HTL biofuels is HTL buffer production. Transportation emissions can be lowered by 83% if forest residues are converted to bio-oil before transportation. Process performance parameters (e.g., HTL energy requirement and biofuel yield) and the location specific parameter (e.g., electricity mix) have significant influence on the GHG emissions of HTL biofuels.

The economic analysis shows that the minimum selling price (MSP) of HTL biofuels ranges from \$0.82-\$0.90 per liter of gasoline equivalent, which is about 63%-80% higher than that of petroleum fuels. Converting forest residues to bio-oil and wood pellets before transportation can significantly lower the variable operating cost but not the MSP of HTL biofuels, due to the considerable increase in capital investment. Biooil and biofuel yield can significantly influence the MSP of HTL biofuels. Therefore, technology advancement is needed to bring down the production cost of HTL biofuels, otherwise, a high carbon tax can be applied to make HTL biofuels competitive with petroleum fuels.

Lay Summary

To date, there has been nearly no large-scale commercial plants reported for drop-in biofuels production using sustainable feedstock like forest residues, which are abundantly available but under-utilized in British Columbia (BC). Many of the current studies on biofuels focus on addressing the technical bottlenecks and there has been very limited comprehensive evaluation of the environmental and economic performance of the conversion technologies, let alone a study based on BC's specific context.

In this thesis, we have identified a promising but under-studied thermochemical conversion technology called hydrothermal liquefaction (HTL) and quantified the environmental and economic impacts of deploying a HTL biofuel system in BC based on different supply chain designs. Since there has been no similar study before, the results of this study can help provide a preliminary insight for other researchers and local companies or investors as well as a reference for government policy makers.

Preface

The research work presented in this thesis was completed under the supervision of Dr. Xiaotao Bi. The author, Yuhao Nie conducted literature review, identified the research problems, developed the research goals, and collected the data to build the life cycle and economic models and analyzed the results. The publications below were first drafted by Yuhao Nie and then refined with the help of Dr. Xiaotao Bi.

A version of Chapter 3 has been published:

Yuhao Nie and Xiaotao Bi. Life-cycle assessment of transportation biofuels from hydrothermal liquefaction of forest residues in British Columbia. *Biotechnology for Biofuels*, 11:23, 2018.

Part of the results from Chapter 3 has also been presented:

Yuhao Nie and Xiaotao Bi. Life cycle assessment of bio-jet fuel production from hydrothermal liquefaction of forest residues in British Columbia (oral & poster presentation), *Advanced Biofuels Symposium*, Vancouver, Canada, July 2016.

A version of Chapter 4 has been published:

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List of Acronyms

AB	Alberta
AD	Anaerobic Digestion
ASTM	American Society for Testing and Materials
BC	British Columbia
Bo-DBR	Bio-oil from Distributed Biorefineries to Central Oil Refinery
CAD	Canadian Dollar
DCFROR	Discounted Cash Flow Rate of Return
FCI	Fixed Capital Investment
FDP	Feedstock Delivery Point
FOC	Fixed Operating Cost
Fr-CIR	Forest Residues to Central Integrated Refinery
GHG	Greenhouse Gas
GHSV	Gas Hourly Space Velocity
HHV	Higher Heating Value
HTL	Hydrothermal Liquefaction
IC	Indirect Cost
IPCC	Intergovernmental Panel on Climate Change

IRR	Internal Rate of Return
LCA	Life Cycle Assessment
LGE	Liter Gasoline Equivalent
LHSV	Liquid Hourly Space Velocity
LTT	Liquid Tanker Truck
MACRS	Modified Accelerated Cost Recovery System
MLPY	Million Liters Per Year
MSP	Minimum Selling Price
NG	Natural Gas
NMSP	Net Minimum Selling Price
NPP	Net Petroleum Price
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OC	Operating Cost
PHWW	Post HTL Waste Water
PNNL	Pacific Northwest National Laboratory
SC	Start-up Cost
ST	Semi-trailer
TCI	Total Capital Investment
TEA	Techno-economic Assessment
TIC	Total Installed Cost
TSA	Timber Supply Area

- TPEC Total Purchased Equipment Cost
- VOC Variable Operating Cost
- WC Working Capital
- Wp-CIR Wood Pellet from Distributed Pellet Plants to Central Integrated Refinery
- WTT Well-to-Tank
- WTW Well-to-Wheel
- WTWa Well-to-Wake

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To my beloved parents

Chapter 1

Introduction

1.1 Background

British Columbia (BC) government released its Bioenergy Strategy in 2008 and recognized bioenergy as a critical approach to help BC achieve its greenhouse gas (GHG) emission reduction goals and economic objectives [3]. By 2013, a bioenergy sector has been established in BC, including 726 MW electricity capacity from pulp and paper mills, 2400 kW biogas system, 30 community bio-heat installations and 2-million-tonne capacity of wood pellets [4]. Besides, insights have been shed on developing a liquid biofuel industry in BC to help the transportation sector get rid of high reliance on fossil fuels and mitigate GHG emissions [5].

In BC, transportation consumes nearly 85% of total refined petroleum fuels [6] and generated about 25 million tonnes of carbon dioxide equivalent (CO₂-eq) in 2014, which corresponds to approximately 38% of total GHG emissions and leads all other economic sectors [7]. To address the concerns of global warming, BC government released its Climate Action Plan in 2008 and set up step-wise GHG emission reduction targets. The interim and ultimate targets aim at achieving 33% and 80% GHG reduction below 2007 level by 2020 and 2050, respectively [8]. Besides the improvements in technology and operation efficiencies of transportation, displacing fossil fuels with biofuels is expected to make important contributions in reducing the GHG emissions. In 2050 Renewable City Strategy, Vancouver proposed to replace all transportation fossil fuels with renewable hydro-electricity and biofuels, demanding the development of low-carbon and renewable transportation fuels [9]. Biofuels that are functionally equivalent to petroleum fuels and are fully compatible with existing petroleum infrastructure are called "drop-in" biofuels [10]. This type of biofuels is attractive and promising becasue it avoids the huge capital investment associated with retrofitting existing petroleum infrastructure or building new infrastructure. Several pathways to produce drop-in biofuels include: oleochemical pathway, such as the hydroprocessing of lipid feedstocks extracted from oil seeds or animal fat; thermochemical pathway, such as the thermochemical conversion of lignocellulosic biomass to intermdiates (syn-gas or bio-oil) with subsequent catalytic upgrading to hydrocarbons; and biochemical pathway, such as the biological conversion of biomass (e.g., sugar, starch, or lignocellulosic biomass) to longer chain alcohols as intermediates followed by catalytic upgrading to hydrocarbons [10].

To date, only oleochemical pathway is technically mature, and it has been the main supplier of biofuels that have been approved for commercial application in sectors like aviation and have a defined ASTM (American Society for Testing and Materials) specification [10–12]. It is anticipated that in the near term, the vast majority of drop-in biofuels will still be produced via oleochemical pathway. However, significant expansion of this pathway is constrained by: (1) the high cost of lipid feedstocks; (2) sustainability issues such as occupation of arable lands for producing the feedstocks and food security; (3) competing with other value-added markets like food and cosmetics industries. Compared with thermochemical pathway, biochemical pathway typically provides lower yield of more oxygenated intermediate products, such as carboxylic acids, alcohols and polyols, which often possess a higher value in the rapidly growing bio-chemicals markets than they do as upgrading to biofuels [10]. Therefore, it is likely that thermochemical pathway would account for a large amount of growth in drop-in biofuels production in the mid-to-long term, and probably it will share the markets with biochemical pathway after the bio-based chemicals markets are saturated [10]. The current challenges for thermochemical pathway lie in the technical side. It requires further technology advancement and process optimization to improve the conversion efficiency, address the technology risks for scale-up and bring down the high capital investment.

Forest residues from logging operations, which contain branches, barks, tree tops, etc., are generally of no merchantable value and are burned as part of the forestry management strategy in BC [13]. According to Industrial Forestry Service Ltd., the volume of woody biomass potentially available for bioenergy production and surplus to the demand of existing forestry industry in BC in 2016 is estimated to be around 21 million m³, of which 15.7% is forest logging residues [14]. Forest residues also make up $5\%\sim10\%$ of the feedstock of BC wood pellet industry, which produces about 2 million tonnes of pellets annually, representing 61% of the total capacity of Canada [4]. However, 94% of the produced pellets ends up being exported due to a lack of markets in BC, among which 84% is exported to Europe for district heating and power generation [15, 16]. This is because in BC, residential heating is mostly done by electricity and natural gas (NG), and more than 90% power is generated from hydro [17]. According to Pa et al. [1], the long distance transportation of pellets could also result in a high carbon footprint (295 kg CO₂-eq/tonne of pellets). Thus, the shift of abundant forest residues in BC for liquid biofuel production can be a promising strategy to meet its 2050 renewable transportation target.

In view of the overall promise for large-scale commercialization in the mid-to-long term and the abundantly available forest residues as feedstock in BC, only thermochemical pathway will be focused on in later context of this thesis.

1.2 Thermochemical Conversion Pathways

Thermochemical conversion of forest residues to intermediate products, such as bio-oil and syngas, with subsequent catalytic upgrading to finished products can be used for drop-in transportation biofuels production in BC. These thermochemical conversion pathways include gasification followed by Fisher-Tropsch synthesis, pyrolysis followed by hydroprocessing and hydrothermal liquefaction (HTL) followed by hydrotreating [18]. The high-level processes of biomass-to-biofuels thermochemical conversion are shown in Figure 1.1.

Table 1.1 shows the comparisons of three different thermochemical conversion pathways, including gasification, pyrolysis and HTL, based on a few technical criteria, i.e., feedstock quality requirement, reaction conditions, intermediate products quality, and currently reported technology scale. The conversion pathways are ranked based on each criterion using characters MF (most favorable), N (neutral) and LF (least favorable) to indicate their relative favorability.



Figure 1.1: Schematic diagram of biomass-to-biofuels thermochemical conversion processes

Feedstock quality requirement Pyrolysis and HTL generally require fine particle size, i.e., less than or equal to 3 mm [20, 22], while gasification is not that strict, with particle less than 2.0 to 2.5 inch (equivalent to 50.8~63.5 mm) being preferred [19]. Both pyrolysis and gasification require control of the moisture content of feedstock to ensure healthy process operation and product quality, so pre-drying is usually needed. In contrast, HTL doesn't have any requirement for the moisture content of feedstock since it is essentially a process that decomposes biomass in an aqueous condition, thus avoiding the energy-intensive pre-drying process.

Reaction conditions Pyrolysis can be achieved in a simple atmospheric pressure with moderate temperature $(400 \sim 500 \,^{\circ}\text{C})$ [20]. Gasification and HTL need more severe conditions. HTL happens under moderate temperature $(280 \sim 370 \,^{\circ}\text{C})$ and high pressure $(10 \sim 25 \,\text{MPa})$ in order to keep water in a subcritical or critical condition where water can have special properties [23]. Gasification also requires high temperature and pressure, typically $600 \sim 1000 \,^{\circ}\text{C}$ [19, 24] and $20 \sim 70$ bar (equivalent to $2 \sim 7 \,^{\circ}\text{MPa}$) [22].

Intermediate product quality Gasification produces syn-gas which contains mainly carbon monoxide (CO) and hydrogen (H₂). Before sent to Fisher-Tropsch synthesis, it first needs removal of tar and other impurities to prevent the contamination of downstream equipment, followed by reforming to a desired H₂/CO ratio via watergas shift reaction. Pyrolysis and HTL both generate a crude-oil-like product called bio-oil. Although pyrolysis-based bio-oil has nearly two times of yield compared with HTL-based bio-oil, it is generally of low quality, i.e., high oxygen content $(35\sim40 \text{ wt\%})$ [27] and low heating value $(16\sim18 \text{ MJ/kg})$, higher heating value (HHV) basis) [29]. Besides, it requires an additional step of hydrotreating to stabilize before it can be upgraded [26]. In contrast, HTL can produce high quality and stable bio-oil with lower oxygen content $(5\sim15 \text{ wt\%})$ [28] and higher heating value $(30\sim37 \text{ MJ/kg})$, HHV basis) [23] which has the potential to be directly co-processed with crude oil in a refinery [26, 30, 38].

The commercialization of gasification of biomass is challenged Technology scale by huge initial capital investment associated with the facility requirement under high temperature and pressure as well as the technologies for syn-gas cleaning [24]. Hence, only plant with a large scale can make economic sense. No commercial scale biomass gasification plant has been reported, although there are some pilot- and demonstrationscale plants. Total S.A. and five other companies launched the BioTfueL project which has started building a demonstration platform that is scheduled to come on stream in 2017 [34]. Pyrolysis is the most mature technology among these three pathways. It has already reached the commercial scale as reported by companies like Ensyn-UOP and BTG BioLiquids. Ensyn-UOP's RTP[®] technology, essentially fast pyrolysis, with 3 million gallons per year bio-oil production, has been proven to be practically and commercially feasible [36]. The main hurdle for commercialization of HTL is also the high capital investment for developing the reaction system [23]. Two well-known corporations who play the leading role in HTL technology development are Licella and Steeper Energy. In 2016, Licella reported that their HTL facility has successfully demonstrated the conversion of wood and agriculture wastes at large pilot scale [33], and recently, it has announced to collaborate with a Canadian wood product company Canfor to form a joint venture to integrate its HTL technology with Canfor's pulp mills in Prince George, BC, to convert woody biomass to biofuels [39]. The commercial-scale plant is scheduled to be constructed in 2019 with a capacity of 125,000 tonnes of slurry per year [33]. Steeper Energy Company has also had several sites under development for an industrial scale demonstration plant in Europe and North America to test the performance of various feedstock for HTL bio-oil production and optimize its processes to address the technical and economic issues for scale-up [40].

1.3 Environmental and Economic Assessment

Besides resolving the technology bottlenecks, the environmental and economic impacts of a certain technology are important aspects to be considered before commercialization. This section will introduce a commonly utilized technique for environmental and economic assessment, each followed by a literature review of the state-of-art studies on evaluating the environmental and economic performance of the three thermochemical conversion technologies previously described.

1.3.1 Life Cycle Assessment (LCA)

Life cycle assessment (LCA) is a technique used to quantitatively assess the environmental impacts of a product or a service from cradle to grave, i.e., from raw material extraction, manufacture to distribution, end use and disposal or recycling. The systematic and quantitative features have provided LCA an advantage of offering a complete profile of the environmental impacts of the analyzed products or services and facilitating the identification of the "hot spots". Thus, LCA has become a popular tool in recent years in product design and various decision making processes ([41], [42], [43], [44]). The ISO 14040 [45] has recommended a standard procedure for conducting an LCA, including the following four phases: (1) goal and scope definition; (2) life cycle inventory analysis; (3) impact assessment; and (4) interpretation, which is illustrated by Figure 1.2. A general LCA methodology will be introduced below, and the specific LCA model of this study will be described in Section 3.1 of Chapter 3.

Goal and scope definition An LCA starts with the goal and scope definition. The goal is essentially the reason why you want to carry out such an LCA. It should be clearly stated at the beginning and be consistent with the intended application and audience [45]. The definition of the scope includes the following specific activities:

1. Definition of the system boundary This is to delimitate the processes to be included and excluded in the analysis of the system. It is subjective and depends on how detailedly you want to study the system as well as the data availability. Any assumptions you made should be specified at this stage. For example, if you conduct an LCA of a certain product, you might need to think about whether or not to include the construction of the factory in your boundary.



Figure 1.2: LCA framework

- 2. Identification of the functional unit Functional unit defines what exactly is being studied and indicates the service delivered by the product [46]. The final environmental impact results should be presented based on the functional unit you selected. Furthermore, functional unit enables the comparison of alternative products from different systems. For example, if you want to compare the environmental impacts of coal and natural gas for power generation, you can set functional unit to be 1 MWh of electricity generated.
- 3. Selecting the allocation methods Allocation is used to assign the environmental burdens between the main product and the co- or by-products, which is usually dealt with in one of the three ways: system expansion, substitution and partition. ISO 14041 [47] suggests that partition should be avoided whenever possible through expansion of the system or division of the multifunction process into sub-processes. Where partition cannot be avoided, it should be done between the system's different products based on the physical relationships such as mass and energy content. If the physical relationship cannot be established or used as the basis for partition,

economic value of the products can be used.

Life cycle inventory analysis In this phase, a flowchart of the system is usually constructed first. The goal of building the life cycle inventory is to complete the mass and energy flows of each process of the system by collecting and compiling the data from various sources. Generally, there are two types of data sources, i.e., primary data and secondary data. Primary data, i.e., the industrial operation or monitoring data, are preferred if they are provided or they can be obtained from survey or interview, because this type of data is more specific and accurate. Otherwise, secondary data can be used, including recognized LCA database such as Ecoinvent [48] and USLCI [49], peer-reviewed literature, and technical reports from government or authorized scientific organizations like PNNL (Pacific Northwest National Laboratory) and NREL (National Renewable Energy Laboratory), etc. LCA software such as SimaPro, GREET and GHGenius, with built-in process models, can be used to model the processes such as material manufacture, fuel production and product transportation. Once the data have been collected, mass and energy balances need to be done to calculate the material and energy inputs and outputs of each process. Inputs consider resources, materials, energy from nature or technosphere, while outputs cover products, wastes and emissions, etc. The emissions of a process can usually be estimated by multiplying the consumption of materials or secondary energy by its corresponding emission factors, which can be obtained from the LCA databases mentioned above or open literature.

Impact assessment With the life cycle inventory compiled, the environmental impacts can be quantified. There are different impact categories, such as global warming, ozone layer depletion, aquatic eutrophication, acid rain formation and Nonrenewable energy consumption. One or a few impact categories can be choosen depending on the goal of the LCA. Each impact category has a benchmark compound and the environmental impacts can be quantified and presented in the unit of, say, grams of benchmark compound equivalent. For example, the benchmark compound of global warming impact is carbon dioxide (CO_2) , while the benchmark compound of acid rain formation is sulfur dioxide (SO_2) . The emission data from the life cycle inventory can be characterized to the benchmark compound equivalent by the potential factors of each impact category. The potential factors indicate the relative capability of a certain compound contributing to the environmental impact compared with the benchmark compound. Taking global warming impact as an example, the potential factors for methane (CH₄) and nitrous oxide (N₂O) are 25 and 298, respectively, related to CO₂ on a 100-year basis [50]. Normalization (using, for example, the domestic or regional emission as the benchmark to normalize the corresponding characterized environmental impact) and weighting (subjectively assigning weighting factor to each impact category) might be done then, if needed, to obtain a single integrated result.

Interpretation Interpretation phase is to identify the hot spots and evaluate the information from the results of life cycle impact assessment and inventory analysis phases. Besides, the limitations and uncertainties of the study will be reviewed, sensitivity of key parameters will be checked, and recommendations for improving the environmental performance of the products or services will be communicated.

The life cycle of transportation fuels is also referred to as well-to-wheel (WTW) or well-to-wake (WTWa), and the whole upstream related to biofuel production and distribution is usually called well-to-tank (WTT). Numerous LCA studies has been performed to quantify the GHG emissions of transportation biofuels from thermochemical conversion of lignocellulosic biomass based on a systematic review of the state-of-art literature. The criteria of selecting the literature for review are as follow: (1) only studies assessing thermochemical conversion technologies, i.e., pyrolysis, gasification and HTL were included; (2) only studies focused on the lignocellulosic biomass were included, because this type of feedstock is abundantly available in BC with an established supply chain. Other types of feedstock like oil seed or algae are either unsustainable over long term nor short of stable supply; (3) only LCA studies on the following liquid transportation fuels were included: jet, gasoline and diesel, while ethanol was not considered.

Wong [51] studied the life cycle GHG emissions of gasification-based bio-jet fuel from forest residues and corn stover, and the results showed that they could reduce GHG emissions by 86% and 94%, respectively, relative to conventional petroleum jet baseline 85 g CO₂-eq/MJ. Han et al. [52] conducted an LCA to compare the WTWa GHG emissions of fast pyrolysis-based bio-jet and gasification-based jet fuel using corn stover as feedstock, and found that the net GHG emissions per MJ of pyrolysis-based bio-jet is 22.1 g CO₂-eq if bio-product biochar is applied for soil amendment or 29.4 g CO₂-eq if biochar is applied for electricity generation, while the GHG emissions associated with a MJ of gasification-based bio-jet is 10.1 g CO₂-eq. Tews et al. [26] quantified and compared the GHG emissions of HTL-based gasoline and diesel with pyrolysis-based gasoline and diesel using woody biomass feedstock made up of 50 wt% logging residues and 50 wt% forest thinnings, and they founded that in a WTW basis, per MJ of HTL biofuels can produce 27 g CO₂-eq, by contrast, per MJ of pyrolysis biofuels can produce 34 g CO_2 -eq. The detail information of the reviewed studies can be found in Table 1.2.

1.3.2 Techno-economic Assessment (TEA)

Techno-economic assessment (TEA) is one of the most commonly utilized methods to evaluate the economic feasibility of a project [18], and the key outcomes of a TEA include the estimates of capital and operating costs. With the capital required and the cost of production estimated, the profitability of the project can then be assessed. Below is a general introduction of TEA methodology, and the detailed TEA methods will be described in Section 4.1 of Chapter 4.

The basic framework for estimation of a project cost is shown in Figure 1.3, consisting of essentially two parts, the total capital investment (TCI) and the operating cost (OC). TCI can be estimated based on factor method, starting with the total purchased equipment cost (TPEC) on which the estimation of other elements in TCI can be based. Thus, it is important to ensure that the estimation of TPEC is accurate and can properly reflect the project scope. The most reliable data source is the equipment manufacturer's quotation, if the specific equipment is known. Otherwise, data from peer-reviewed literature or software simulation, such as Aspen $Plus^{\textcircled{R}}$, can be used. It also depends on the accuracy of the estimation. A detailed estimation (i.e., usually with an uncertainty $\pm 5\%$ [53]) may require the specific information of the equipment for a better estimation of the purchased equipment cost, while for a preliminary estimation (i.e., usually with an uncertainty $\pm 20\%$ [53]), the cost of the equipment with similar capacity or flow rate from literature or simulation would be suffice. OC includes the variable parts and the fixed parts. The variable operating cost (VOC) depends on the material, utility input and waste output in the daily operation, which can be derived from the mass and energy balances of the system. The fixed operation cost (FOC) is mainly related to the labor and capital of the project. After the capital and operating costs of the project been estimated, discounted cash flow rate of return (DCFROR) analysis can be used to evaluate the economic feasibility of the project. The product's

Technical criteria	Gasification	Pyrolysis	HTL
Feedstock quality requirement	N	LF	MF
Moisture content	$10{\sim}20 \text{ wt\%} [19]$	$<\!10 \text{ wt\%} [20]$	No requirement
Particle size	$<2.0\sim2.5$ inch [19]	<3 mm [20]	<3 mm [21]
Reaction conditions	Ν	MF	LF
Pressure	$20{\sim}70$ bar or atmo- spheric [22]	Atmospheric [20]	$10{\sim}25$ MPa [23]
Temperature	High: 600~1000 °C [24]	Moderate: $400 \sim 500 ^{\circ}{\rm C}$ [20]	Moderate: $280 \sim 370 ^{\circ}\text{C}$ [23]
Intermediate product quality	Ν	LF	MF
Type	Syngas	Bio-oil	Bio-oil
Yield	$1.54{\sim}2.41 \text{ m}^3/\text{kg}$ biomass [25]	$50{\sim}70 \text{ wt\%} [20]$	$30{\sim}35 \text{ wt\%} [26]$
Oxygen content	N/A	$35{\sim}40 \text{ wt\%} [27]$	$5{\sim}15 \text{ wt\%} [28]$
Higher heating value	N/A	$16{\sim}18~{\rm MJ/kg}~[29]$	$30{\sim}37~{\rm MJ/kg}~[23]$
Upgrading pretreatment	Cleanup and reform- ing [24]	Hydrotreating to stabilize [26]	Potentially co- processed with crude oil [30]
Technology scale	LF	MF	Ν
Pilot	Bioliq project by Karlsruhe Institute of Technology (500 kg/h biomass) [31]	N/A	Steeper Energy (half barrel bio- oil/day) [32]; Licella (10,000 tonnes of slurry/year) [33]
Demonstration	Total BioTfuel project (Capacity N/A, scheduled to come on stream in 2017) [34]	BTG Bioliquids Empyro project (aiming at 20 million liters bio- oil/year) [35]	N/A
Commercial	N/A	Ensyn-UOP (3 mil- lion gallons bio-oil /year) [36]; BTG Bioliquids Malaysia plant (1.2 tonnes bio-oil/hr) [37]	N/A (Licella plans to construct a commercial-scale plant in 2019 with a capacity of 125,000 tonnes of slurry per year) [33]

 Table 1.1: Technical comparisons of thermochemical conversion pathways

Conversion pathway	Reference	Year	Region	System boundary	Facility capacity	Functional unit (FU)	Software	Feed- stock	Focused products	Life cycle GHG emission (g CO ₂ - eq/FU)
Gasification	[54]	2007	Europe	WTW	$200 \ \mathrm{MW}$	MJ of fuel	E^3 database	\mathbf{FR}	Diesel	4.8
	[51]	2008	US	WTWa	N/A	MJ of fuel	GREET	FR; CS	Jet fuel	FR: 11.6; CS: 5.4
	[55]	2009	Europe	WTW	N/A	km	Excel	\mathbf{FR}	Diesel	90
	[56]	2010	US	WTWa	300 BPD	MJ of fuel	GREET	FR; SG	Jet fuel	FR: 12.2; CS: 17.7
	[57]	2010	Europe	WTT	N/A	MJ of fuel	GREET	SG	Diesel	21.6
	[52]	2013	US	WTWa	3000 DTPD	MJ of fuel	GREET	\mathbf{CS}	Jet fuel	10.1
Pyrolysis	[58]	2011	US	WTW	200 TPD	Hectare of land	GREET	\mathbf{CS}	Gasoline	-2.99E+06
	[59]	2011	US	WTW	2000 DTPD	MJ of fuel	GREET	\mathbf{FR}	Gasoline	42.90
	[60]	2012	US	WTW	2000 DTPD	MJ of fuel	SimaPro and GREET	\mathbf{FR}	G&D	G: 39; D: 39
	[61]	2012	N/A	WTW	500 DTPD	MJ of fuel	SimaPro	SRP	G&D	-50.54
	[52]	2013	US	WTWa	2000 DTPD	MJ of fuel	GREET	\mathbf{CS}	Jet fuel	$29.4^{\rm a}/22.1^{\rm b}$
	[62]	2013	US	WTW	2000 DTPD	MJ of fuel	GREET	FR; CS	Gasoline	FR: $38^{\rm c}$; CS: $(10^{\rm a}/-16^{\rm b})^{\rm d}$
	[26]	2014	US	WTW	2000 DTPD	MJ of fuel	SimaPro and GREET	LR&FT	G&D	G: 33.8; D: 34.0
	[63]	2014	N/A	WTT	2000 DTPD	MJ of fuel	GREET	\mathbf{CS}	G&D	$28.82^{\rm e}; 25.15^{\rm f};$ - $18.13^{\rm g}$
	[64]	2017	US	WTWa	N/A	MJ of fuel	GREET	\mathbf{FR}	Jet fuel	$22^{\rm h}; 37^{\rm i}$
HTL	[26]	2014	US	WTW	2000 DTPD	MJ of fuel	SimaPro and GREET	LR&FT	G&D	G: 27.2; D: 27.3
	[64]	2017	US	WTWa	N/A	MJ of fuel	GREET	\mathbf{FR}	Jet fuel	$18^{\rm h}; 20^{\rm i}$

Table 1.2: Review of LCA studies on thermochemical conversion of lignocellulosic biomass to transportation biofuels

^a Byproduct bio-char is used for power generation; ^b Byproduct bio-char is used for soil amendment; ^c H₂ is from fuel gas reforming; ^d H₂ is from pyrolysis oil reforming; ^e Hydrogen comes from external NG reforming, and biofuel yield is 43.5%; ^f Hydrogen comes from steam reforming of 35% bio-oil, and biofuel yield is 33.1%; ^g Hydrogen comes from steam reforming of 100% bio-oil, and biofuel yield is 16.1%; ^h In-situ hydrogen production via steam reforming of process off-gases; ⁱ Ex-situ hydrogen production via steam reforming of natural gas; WTWa=Well-to-wake; WTW=Well-to-wheel; WTT=Well-to-Tank; BPD=Barrel per day; TPD=Tonne per day; DTPD=Dry tonne per day; FR=Forest residue; CS=Corn stover; SG=Switchgrass; SRP=Short Rotation Polar; LR&FT=Logging residues and forest thinnings; G: gasoline; D: diesel

minimum selling price is calculated, the essence of which is to manipulate the product's selling price to find the breakeven point where the project net present value (NPV) equals zero. The minimum selling price of the designated product can be used to compare with other alternative products in order to see if it is economically competitive.



Figure 1.3: Project cost estimation framework

Several TEA studies have been reported on evaluating the economic performance of thermochemical conversion pathways, and the details are shown in Table 1.3. Swanson et al. [65] compared the capital investment and operating cost of corn stover to biofuels gasification plant with different technologies. The biofuel product value is found to be \$1.06/L to \$1.32/L, and it further concluded that the technology with a higher fuel yield could lower the product value, although the capital investment will be higher. Wright et al. [66] examined the product value of naphtha and diesel range fuels from fast pyrolysis of corn stover and subsequent upgrading. The assessment studied two scenarios, hydrogen from bio-oil on-site reforming versus purchased hydrogen. The results showed that in a nth plant design, the product value of purchased hydrogen scenario is \$0.56/L, lower than that of on-site hydrogen production scenario \$0.82/L. In the analysis for a pioneer plant, the cost considerably increases to \$0.9/L and \$1.73/L, respectively. Zhu et al. [67] implemented TEA to assess the economic feasibility of a commercial scale HTL biofuel plant by comparing state-of-technology case with goal case, and indicated that the potential process improvement can reduce the minimum fuel selling price to \$0.74/L from the current technology status of \$1.29/L.

1.4 Research Problems

According to the comprehensive review of the thermochemical conversion pathways, we can observe that HTL is overall a very promising technology in terms of its technical, environmental and economic performance compared with pyrolysis and gasification. However, most current researches on HTL biofuels are trying to solve the technical obstacles, e.g., the design of HTL reactor for scale up [21], the integration of HTL with other systems [68], process parameters optimization [69] and the co-upgrading potential of HTL bio-oil with crude oil [30, 70], etc. There has been little investigation of HTL in terms of its GHG emission and economic performance in comparison to gasification and pyrolysis.

What's more, the results of the reviewed LCA and TEA varied from study to study, due to the variation in geographic locations, settings of system, feedstock, analytical methods, modelling parameters, and the treatment of by- or co-products. A review study focused on the pyrolysis technologies by Roy and Dias in 2017 [71] has reported similar observations on the variability of LCA and TEA results based on feedstock, technology, etc. Therefore, the specific context of BC needs to be considered in evaluating the deployment of HTL biofuel system in BC, but to our best knowledge, there

Conversion pathway	Region	Facility capacity	Feedstock	Focused products	Capital investment (million \$)	$\frac{\mathrm{IRR}}{(\%)}$	MFSP (\$/L)	Reference
Gasification	US	2000 DTPD	CS	G&D	498;606	10	1.06;1.32	[65]
	Canada	2000 DTPD	\mathbf{FR}	G&D	298;552	10	0.78; 1.22	[72]
	Germany	N/A	LB	G&D	344 ^a	7	1.6^{a}	[73]
Pyrolysis	US	2000 DTPD	\mathbf{CS}	N&D	$(200;287)^{\mathrm{b}};$ $(585;911)^{\mathrm{c}}$	10	$(0.56;0.82)^{\rm b};$ $(0.9;1.73)^{\rm c}$	[66]
	US	2000 DTPD	CS	G&D	429	10	$0.68^{\rm d}$	[74]
	US	2000 DTPD	LR& FT	G&D	358	10	$0.82^{\rm d}$	[26]
HTL	US	2000 DTPD	LR& FT	G&D	244	10	$0.51^{\rm d}$	[26]
	US	2000 DTPD	WB	G&D	$(275;301)^{\rm e}$	10	$(0.74;1.29)^{\rm e}$	[67]
	Finland	1500 DTPD	\mathbf{FR}	G&D	828 ^g	10	0.96^{f}	[75]

Table 1.3: Review of TEA studies on thermochemical conversion of lignocellulosic biomass to transportation biofuels

^a Converted from Euro to USD using $1 \in =1.3$ \$; ^b Nth plant design, capital investment 200 million \$ and MFSP \$0.56/L are for hydrogen purchased externally, while capital investment 287 million \$ and MFSP \$0.82/L are for hydrogen produced from bio-oil reforming; ^c Pioneer plant design, capital investment 585 million \$ and MFSP \$0.90/L for hydrogen purchase externally, and capital investment 911 million \$ and MFSP \$1.73 /L for hydrogen produced from bio-oil reforming; ^d Converted from per gallon basis to per liter basis using 1 gallon=3.78 L; ^e Capital investment 275 million \$ and MFSP \$0.74/L are for goal scenario, while capital investment 301 million \$ and MFSP \$1.29/L are for state-of-technology scenario; ^f Converted from €1.03/kg to \$0.96/L by assuming $1 \in =1.3$ \$ and the gasoline density to be 0.72 kg/L; ^g Converted from 1.7 million \in /MW_{LHV} to 2.21 million \$/ MW_{LHV} by assuming $1 \in =1.3$ \$ and the total feed consumption is 375.1 MW_{LHV}; IRR=Internal rate of return; MFSP=Minimum fuel selling price; DTPD=Dry tonne per day; CS=Corn stover; FR=Forest residues; LB=Lignocellulosic biomass; LR&FT=Logging residues and forest thinnings mix; WB=Woody biomass; G&D=Gasoline and diesel; N&D=Naphtha and diesel

has been no such integrated assessment being reported.

1.5 Objectives and Implications

In view of the great interest in deploying facility to convert abundant but underutilized forest residues to biofuels in BC, as well as the gaps mentioned above, specific LCA and TEA are timely needed to evaluate the environmental impact and economic feasibility of the HTL technology in order to have a comprehensive understanding of its performance. In short, three basic questions need to be answered by this thesis:

- 1. What is the GHG emission reduction potential associated with producing and using HTL biofuels in BC?
- 2. What is the economic cost for producing HTL biofuels in BC and is it competitive compared with petroleum fuels under the current carbon tax scheme in BC?
- 3. What are the potential strategies or policies that can be implemented if the decision makers want to promote HTL biofuel production in BC?

Specifically, the following points are to be addressed by the LCA: (1) quantification of the life cycle GHG emissions of HTL biofuels system based on different scenarios; (2) identification of the "hot spots" of the processes that intensively emit GHGs; (3) analysis of the large proportional change of GHG emissions under different scenarios; (4) comparison of the GHG emissions of HTL biofuels produced in BC with general values reported in the literatures; (5) sensitivity analysis on the key parameters impacting the GHG emissions of HTL biofuels; and (6) making recommendations for improving the GHG emission performance of HTL biofuels.

The following points are to be addressed by the TEA: (1) estimation of the capital and operating costs of producing HTL biofuels in BC based on different scenarios and calculation of the minimum selling price (MSP); (2) comparison of the MSP of HTL biofuels produced in BC with general values reported in the open literature; (3) identification of the impact of carbon tax and technology advancement on the economic performance of HTL biofuels; and (4) sensitivity analysis on the key parameters that influence the MSP of HTL biofuels. To our best knowledge, there has been no similar integrated assessment of HTL biofuels from forest residues reported based on the BC context. Therefore, the results from this study could help provide a preliminary insight for other researchers and local companies or investors as well as a reference for government policy makers.

1.6 Structure of Thesis

The thesis is organized as follow:

Chpater 2 presents the case study we developed with three different scenarios, followed by a thorough description of the processes associated with each stage of the proposed HTL biofuel system, which lays the basis of Chapter 3 and Chapter 4.

Chapter 3 and Chapter 4 are the two main contributions of this thesis, presenting the environmental and economic assessment case study of the proposed HTL biofuel system, respectively. In Chapter 3, an LCA is performed to quantify the GHG emissions of HTL biofuels based on three different supply chain designs. In Chapter 4, a TEA is conducted to estimate the capital and operating costs of HTL biofuels based on three supply chain designs, and DCFROR analysis is used to calculate the minimum fuel selling prices of HTL biofuel products. Each chapter starts with a description of the modelling methods, followed by results and discussions presented in detail. Conclusions for each specific study are given at the end of the corresponding chapter.

Chapter 5 draws the conclusions based on the overall environmental and economic performance of HTL biofuels, states the limitations of this study and recommends some future work to improve the current study.

The Appendices summarize all supplementary data and information relevant to this work. Appendix A tabulates the detailed mass and energy balances data based on the process modelling, which lay the basis for the life cycle and economic assessment. Appendix B and Appendix C present the process emission factors used to build the life cycle inventory and emission inventory of each life cycle stage, respectively. Appendix D shows the detailed stage-wise cost results from economic analysis and Appendix E attaches the spreadsheet for carrying out the DCFROR analysis.

Chapter 2

Description of Case Study and Processes

2.1 Case Study and Scenarios

A total liquid biofuel production rate of 100 million liters per year (MLPY) is assumed as the basis for this study, as proposed in an UBC-Boeing joint project on evaluating the viability of bio-jet fuel production in Western Canada, based on the availability and distribution of forest residues in BC [13]. The Coast Region of BC (see Figure 2.1) is chosen as the study area for deploying the 100 MLPY hypothetic HTL biofuel system due to the abundantly available forest residues as feedstock, existing oil refining infrastructure for bio-oil upgrading and local markets for biofuel products consumption in this area. BC government partitions the Coast Region into several timber supply areas (TSAs) and a sales office is established for timber marketing in each TSA. The locations of these timber sales offices, namely, Chilliwack, Squamish, Powell River and Port Alberni, where biomass feedstock is assumed to be supplied to the conversion facilities, are referred to as the feedstock delivery points (FDPs) in this study. There is an existing Chevron oil refinery in Burnaby with a throughput of 8700 m^3/d [76], and we assume that this oil refinery is utilized to upgrade the bio-oil produced in HTL biorefinery. Four different biofuel products: gasoline, jet fuel, diesel and heavy oil are produced and distributed to local markets for end use, specifically, gasoline and diesel for light- and heavy-duty vehicles, respectively, at City of Vancouver, jet fuel for airplanes at Vancouver International Airport, and heavy oil for marine vessels at Port of Vancouver. The geographic locations of all the places mentioned above are
schematically shown in Figure 2.1.



Figure 2.1: Schematic diagram of geographic information of HTL biofuel system (Powell River, Squamish and Chilliwack lie in the South Coast Region; Port Alberni lies in the West Coast Region)

The forest residues availability for each TSA is estimated using the method proposed by MacDonald et al. in a BC government report [77]. The essence is to multiply the annual logs harvest volume in that TSA by a biomass ratio, which is defined as the volume of forest residues recovered from unit volume of merchantable logs harvested in the logging operation. The annual logs harvest volume is retrieved from Harvest Billing System of BC based on 5-year average data of August 2011 to July 2016 [78]. In this study, we assume that the biomass ratio is 15% based on the situation that most of the timbers in the BC Coast Region are second growth Hemlock and the harvesting mode is ground-based and cable [77]. In ground-based harvesting systems, a machine travelling over the ground is used to carry the fell trees or logs from the stump to the landing. While in cable systems, the fell trees or logs are carried by a stationary machine with an overhead cable attached [79]. The density (dry basis) and moisture content (wet basis) of forest residues used in this study are 420 kg/m³ and 49 wt%, respectively. Due to the lack of specific feedstock analysis data, i.e., proximate analysis and ultimate analyses, for forest residues in the Coast Region of BC, the feedstock analysis data from Tews et al. [26] were used in our models. The 5-year average annual volume of harvest logs and estimated available forest residues is shown in Table 2.1.

	Harvest logs	Biomass ratio	Forest residues availability		
	m^3/yr	- Diomass ratio -	m^3/yr	dry tonne/yr	wet tonne/yr
Chilliwack	$1.21E{+}06$	0.15	1.82E + 05	7.64E + 04	1.50E + 05
Squamish	$4.98E{+}05$	0.15	7.47E + 04	3.14E + 04	6.14E + 04
Power River	$1.93E{+}06$	0.15	$2.89E{+}05$	$1.21E{+}05$	$2.38E{+}05$
Port Alberni	5.24E + 06	0.15	7.85E + 05	$3.30E{+}05$	6.46E + 05
Total	8.87E+06	0.15	1.33E + 06	5.59E + 05	1.09E + 06

Table 2.1: Annual forest residues availability in BC Coast Region

The case study is developed based on three different scenarios in order to investigate how supply chain designs could influence the system's environmental and economic performance. The main differences between these three scenarios lie in the configuration of biorefinery (integrated with oil refinery or distributed at FDPs) and the type of feedstock (bulky forest residues or forest residues derived bio-oil or wood pellets) supplied to conversion facility. For scenario 1 (denoted as Fr-CIR scenario), the collected bulky forest residues from each FDP are directly transported to the central integrated refinery for conversion (Figure 2.2(a)). For scenario 2 (denoted as Bo-DBR scenario), forest residues are first converted to bio-oil at distributed biorefineries and then transported to a central oil refinery for upgrading (Figure 2.2(b)). For scenario 3 (denoted as Wp-CIR scenario), forest residues are first densified to wood pellets at distributed pellet plants located at FDPs and then transported to the central integrated refinery for conversion (Figure 2.2(c)).

2.2 Description of Processes

Although the processes vary with each scenario, the basic structure of the proposed HTL biofuel system includes the following stages: biomass collection, transportation, pre-processing, biomass-to-biofuels conversion, and biofuel products distribution and end use. It should be noted that for LCA, all these six stages are considered, while for TEA, the biofuel distribution and end use stages are not included. The detailed processes associated with each stage are described in the following subsections.



Figure 2.2: Supply chain designs of HTL biofuel system for each scenario (the dash line arrows stand for the flow of feedstock or intermediate products and the solid line arrows stand for the flow of final biofuel products)

2.2.1 Biomass Collection

Collection of biomass feedstock is modeled in two steps. The piled forest residues on forest stands of each TSA are first gathered, chipped to smaller size and loaded to dump trucks, and then shuttled to the corresponding FDP. Due to the lack of specific location and productivity of each forest stand in corresponding TSA, we simply assume that the forest residues after logging operation are uniformly distributed around the FDP and 12.5 km is used as the average distance for shuttling forest residues to FDP. The equipment energy input for biomass collection modelling are presented in Table 2.2.

Table 2.2: Equipment energy input for biomass collection modeling

Equipment	Fuel type	Process	Energy input	Reference
Loader	Diesel	Load forest residues to chipper	0.82 L/dry tonne	[80]
Chipper	Diesel	Chip forest residues	3.01 L/dry tonne	[80]

In order to meet the 100 MLPY biofuels production target, for Fr-CIR and Bo-DBR scenarios, a total of \sim 300,000 dry tonnes of forest residues are needed. While for Wp-CIR scenario, due to the consumption of forest residues as drying fuel in pellet plants, additional \sim 36,000 dry tonnes are required. The detailed methods of calculating the annual forest residues requirement are described in the following context. The parameters used in the calculations of the annual forest residues requirement as well as their notations are summarized in Table 2.3. It should be noted that we assume that there is no mass loss in the feedstock collection and transportation stages as well as the biofuel products separation process.

Forest residues requirement for Fr-CIR, Bo-DBR, Wp-CIR scenarios (R_i , dry tonne/yr, $i = {Fr-CIR, Bo-DBR, Wp-CIR}$) can be calcualted by Equation 2.1 and Equation 2.2.

When i=Fr-CIR, Bo-DBR:

$$R_{i} = \frac{P_{v} \times \rho_{bm}}{\alpha_{botd} \times \alpha_{frtb}}$$
(2.1)

Parameter	Notation	Value	Reference
Annual productivity of total biofuels (million liters per year)	P_{v}	100	
Mass conversion rate			
Forest residues to bio-oil (kg/kg dry forest residues)	$lpha_{ m frtb}$	0.367	[26]
Forest residues to wood pellet (kg/kg dry forest residues)	$lpha_{ m frtw}$	0.89	[81]
Wood pellet to bio-oil (kg/kg dry wood pellet)	$\alpha_{ m wptb}$	0.367	[26]
Bio-oil to deoxygenated oil (wt%)	$lpha_{ m botd}$	75	[26]
Moisture content (wet basis, wt%)			
Wood pellet	$\mathrm{MC}_{\mathrm{wp}}$	5.6	[81]
Biofuel products distribution (wt%)			
Gasoline	$eta_{ ext{g}}$	21	[70]
Jet fuel	$\beta_{ m jf}$	25	[70]
Diesel	$eta_{ m d}$	35	[70]
Heavy oil	$\beta_{ m ho}$	19	[70]
Biofuel density (kg/m^3)			
Gasoline	$ ho_{ m g}$	739	[2]
Jet fuel	$ ho_{ m jf}$	808	[2]
Diesel	$ ho_{ m d}$	843	[2]
Heavy oil	$ ho_{ m ho}$	944	[2]

 Table 2.3: Parameters for calculating forest residues requirement

When i=Wp-CIR:

$$R_{i} = \frac{P_{v} \times \rho_{bm}}{(\alpha_{botd} \times \alpha_{wptb} \times \alpha_{frtw})(1 - MC_{wp})}$$
(2.2)

Where $\rho_{\rm bm}$ is the density of biofuel mix in kg/m³, and $\rho_{\rm bm}$ can be calculated by Equation 2.3 below:

$$\rho_{\rm bm} = \frac{\sum_{j} \beta_{j}}{\sum_{j} \frac{\beta_{j}}{\rho_{j}}}, \ j = \{g, jf, d, ho\}$$
(2.3)

2.2.2 Transportation

The transportation of biomass feedstock from FDPs to conversion facility varies with scenarios. For Fr-CIR scenario, forest residues arriving at FDPs are reloaded to semitrailers (STs) and then directly transported to the central integrated refinery for conversion. However, for Bo-DBR and Wp-CIR scenarios, the arriving forest residues are first converted to bio-oil and wood pellets in the distributed HTL and pellet plants at FDPs, respectively, and then the intermediates are loaded to STs or liquid tanker trucks (LTTs) and transported to the refinery for further conversion. It should be noted that transportation from Powell River and Port Alberni to Chevron oil refinery will undergo marine routes, STs or LTTs are thus assumed to be carried by ferries run by British Columbia Ferry Services Inc. To account for the emission associated with carrying STs or LTTs and the feedstock, the total emissions of ferry transportation were allocated by the mass of people, STs or LTTs and other vehicles, which are estimated by the information provided on the website of British Columbia Ferry Services Inc. [82]. The transportation distance from Chilliwack, Squamish, Powell River and Port Alberni to Chevron oil refinery are 102 km, 74 km, 179 km (including 37 km marine transportation), and 170 km (including 57 km marine transportation), respectively. The energy input factors for feedstock transportation modelling are presented in Table 2.4.

Equipment	Fuel type	Process	Energy input	Reference
Dump truck	Diesel	Shuttle chipped forest residues to FDP	$6279 \ \mathrm{kJ/Tkm}$	[2]
Loader	Diesel	Load feedstock at FDPs to STs or LTTs	$1.02~\mathrm{L/dry}$ to nne	[80]
ST	Diesel	Transport forest residues or wood pellets to refinery	1988 kJ/Tkm	[2]
LTT	Diesel	Transport bio-oil to refinery	1988 kJ/Tkm	[2]
Ferry	Marine diesel	Carry loaded STs or LTT on the sea	$95 \mathrm{~L/km}$	[83]

Table 2.4: Energy input for feedstock transportation modeling

To minimize the transportation emissions, the total annual feedstock requirement is apportioned among four FDPs according to their feedstock availability and proximity to Chevron oil refinery, that is, the closer the FDP to the refinery, the higher priority it will be assigned for forest residues utilization. The data for the annual forest residues transported from each FDP to the conversion facility are shown in Table 2.5 below.

FDP	Fr-CIR	Bo-DBR	Wp-CIR
Chilliwack	7.64E + 04	7.64E + 04	7.64E + 04
Squamish	3.14E + 04	$3.14E{+}04$	$3.14E{+}04$
Power River	$1.21E{+}05$	$1.21E{+}05$	$1.21E{+}05$
Port Alberni	7.12E + 04	7.12E + 04	1.07E + 05
Total	3.00E + 05	3.00E + 05	3.36E + 05

Table 2.5: Annual forest residues supply at each FDP for different scenarios (dry tonne/yr)

2.2.3 Pre-processing

In biorefinery, the incoming forest residues or wood pellets will first go through the pre-processing step, where the biomass feedstock is unloaded, cleaned and sent to a grinder for further size reduction. Then the ground feedstock is mixed with hot water recycled from HTL reaction, producing biomass-water slurry with 8 wt% solid content [26]. The energy input factors for the equipment used in feedstock pre-processing stage are presented in Table 2.6. To make the life cycle stages consistent between different scenarios, the pellet plant operation process in Wp-CIR scenario is incorporated into the pre-processing stage.

Table 2.6: Energy input of feedstock pre-processing in biorefinery

Equipment	Fuel type	Process	Energy input	Reference
Front-end loader	Diesel	Unload biomass feedstock	$0.42 \mathrm{~L/dry}$ tonne	[26]
Grinder	Electricity	Grind biomass feedstock	$71.2~\mathrm{kWh}/\mathrm{dry}$ tonne	[26]
Auxilliary	Electricity	Chip cleaning, dust collection	$5~{\rm kWh/dry}$ tonne	[26]

2.2.4 Conversion

Conversion stage covers two parts, i.e., thermochemical conversion of biomass feedstock in biorefinery to produce bio-oil and bio-oil upgrading in the oil refinery. The process design of biorefinery thermochemical conversion and oil refinery upgrading are based on the study by Tews et al. [26]. Biorefinery conversion includes the following processes: HTL and anaerobic digestion (AD), while oil refinery upgrading includes bio-oil hydrotreating and hydrogen production. An AD unit is integrated with HTL system in order to treat and recover energy from the HTL wastewater, and a hydrogen production process is designed to meet the hydrogen demand for bio-oil hydrotreating. Figure 2.3 shows the process flows of the pre-processing and conversion stages for integrated and distributed systems. The parameters used to model the processes of biorefinery and oil refinery are given in Table 2.7 and Table 2.8, respectively, and the mass and energy balances are detailed in Appendix A.



Figure 2.3: Process flow diagram of pre-processing and conversion stages for integrated and distributed system (Fr-CIR and Wp-CIR scenarios belong to integrated system, while Bo-DBR scenario belongs to distributed system)

The HTL process in this study is modelled based on the experimental and simulation data from PNNL report by Tews et al. [26]. The water-biomass slurry generated in the pre-processing process is pressurized and sent to the HTL reactor. The HTL process produces bio-oil, non-condensable gases, biochar as well as water containing high concentration of dissolved organics, called post HTL waste water (PHWW). Sodium carbonate (Na_2CO_3) is used as the buffer agent to prevent the pH of the slurry from dropping below 4, thus inhibiting the formation of high molecular weight compounds and solid wastes [67]. HTL bio-oil has low oxygen content and is thermally stable [26]. Therefore, we assume that it is directly co-processed with crude oil in the Chevron oil refinery without pre-hydrotreating step. Non-condensable gases, referred to as off-gases in this study, contains the non-condensable volatile compounds, mostly CO₂, a moderate part of light hydrocarbons (C1 \sim C4) and a small portion of H₂ (see in Table 2.7). The energy in off-gases is assumed to be recovered and reused in conversion processes. For Fr-CIR and Wp-CIR scenarios, off-gases are sent to hydrogen plant as fuel for hydrogen production, and the remaining is used as fuel for heating anaerobic digester. For Bo-DBR scenario, these gases cannot be sent to hydrogen plant, so they are consumed as heating fuel for HTL or AD. The solid phase product biochar is assumed to be collected and applied for soil amendment in local farms for HTL biofuel LCA, while it is assumed to be sold at the biorefinery gate for HTL biofuel TEA. Panisko et al. [84] reported that chemical oxygen demand (COD) of PHWW ranged from 41,000 to 77,000 mg/L, compared with 200 to 1200 mg/L of raw municipal waste water. Hence, a dedicated treatment facility must be employed at the processing facility. In this study, we assume that an AD unit is designed for the treatment and energy recovery of PHWW, while the majority of PHWW is recycled for slurry formation in the biomass feedstock pre-processing.

In the anaerobic digester, the PHWW is converted into biogas and solid and liquid digestates. Biogas is sent to the HTL unit as heating fuel. The solid and liquid digestates are sent to landfill and waste water plant, respectively, for further treatment. Due to the lack of reported data for PHWW as substrate for AD, a large-scale AD operating at mesophilic temperature (35 °C) and using liquid swine manure as feed-stock was used as an approximation to quantify the heat and electricity requirements [85, 86]. A typical large-scale AD can digest 20,000~60,000 tonnes of raw materials per year [86]. The PHWW input into the AD unit in this study is ~409,000 tonnes per year (see Appendix A), which is about ten times larger. While the world's largest AD plant reported in 2013 being constructed digests 270,000 tonnes organic wastes per year [87], no energy input data of this plant is available. The energy input of a typical large-scale AD is thus the best available data to be used in our study.

Parameters	Value	Reference
Annual operating hours, hr	8000	
Hydrothermal liquefaction		
Material and energy input		
Buffer (Na ₂ CO ₃) content, wt% of slurry	1	[67]
Electricity, MW	$4.03^{\rm a}/4.10^{\rm b}$	Scaled from [26]
Heat, MW	$50.42^{\rm a}/50.24^{\rm b}$	Scaled from [21]
Product yields, kg/kg dry feedstock ^{c}		[26]
Bio-oil	0.367	
Off-gases	0.173	
Water (with dissolved organics)	0.404	
Biochar	0.056	
Off-gases composition, wt $\%$		[26]
CO_2	90.2	
H_2	0.9	
CH_4	3.0	
C_2H_6	2.5	
C_3H_8	1.9	
C_4H_{10}	1.5	
Anaerobic digestion		
Product yields, kg/kg waste water		[26]
Biogas	0.23	
Solid digestate	0.01	
Liquid digestate	0.76	
Material and energy input		Average of $[85, 86]$
Electricity, MJ/GJ biogas produced	102.32	
Heat, MJ/GJ biogas produced	140.89	

Table 2.7: Major inputs and parameters for modeling HTL biorefinery processes

^a Applicable to Fr-CIR and Bo-DBR scenarios. For Bo-DBR, this is the total electricity/heat input of the HTL units of four distributed biorefinerie; ^b Applicable to Wp-CIR scenario; ^c Wood pellets were assumed to have the same conversion rate as forest residues

The hydrotreating process is a catalytic reaction process where the oxygenated com-

pounds in bio-oil are exposed to hydrogen under elevated pressure and high temperature [88]. The catalyst utilized in hydrotreating process is assumed to be conventional NiMo/Al₂O₃ catalyst which is commonly used in crude oil hydroprocessing. The effluent from hydrotreating reactors is cooled and separated into deoxygenated oil, waste water and off-gases streams. The off-gases from hydrotreating containing mainly light hydrocarbons (see in Table 2.8) are sent to hydrogen plant as feedstock for steam reforming. The deoxygenated oil is then distilled into gasoline, jet, diesel and heavy fuel oil as finished products.

Hydrogen for bio-oil upgrading is produced by NG steam reforming in a hydrogen plant of the oil refinery. The hydrogen demand is determined by the bio-oil production from HTL. As reported in the study of Zhu et al. [67], per gram of dry bio-oil to be treated, 0.033 gram of H₂ is needed. The hydrogen production process is modeled based on a NREL report by Spath et al. [89] with scaling to the specific hydrogen demand. Certain modifications are made on the NREL model to accommodate the entire HTL biofuel production system. Specifically, the reformer is fueled mainly by the combustible off-gases from hydrogen production, while the remaining 4.4 wt% [89] is assumed to be supplied by off-gases from hydrotreating as well as HTL depending on the specific scenarios, instead of using purchased NG. The electricity requirement of the hydrogen plant is modified to be met by BC grid. The catalyst utilized in hydrogen production process is assumed to be NiMo/Al₂O₃.

Parameters	Value	Reference
Annual operating hours, hr	8000	
Hydrotreating		
LHSV, h^{-1}	0.22	[26]
Material and energy input		
H_2 , g H_2 /g dry bio-oil	0.033	[67]
Electricity, MW	1.12	Scaled from [26]
Catalyst		
Load, kg catalyst/tonne bio-oil	0.41	Calculated based on LHSV
Life, yrs	1	

Table 2.8: Major inputs and parameters for modeling oil refinery proces

Parameters	Value	Reference
Product distribution, wt%		[26]
Deoxygenated oil	75	
Off-gases	7	
Water	18	
Off-gases composition, wt $\%$		[26]
H_2	7.8	
CH_4	18.2	
C_2H_6	15.1	
C_3H_8	13.2	
C_4H_{10}	4.9	
C_5H_{12}	1.5	
C_6H_{14}	39.3	
Deoxy genated oil distillation streams, $\mathrm{wt}\%$		[70]
Gasoline	21	
Jet	25	
Diesel	35	
Heavy oil	19	
Hydrogen plant		
GHSV, h^{-1}	4000	[90]
Material and energy input		
NG (feedstock), $kg/m^3 H_2$ produced	0.24	Scaled from [89]
Steam (feedstock), $kg/m^3 H_2$ produced	0.76	Scaled from [89]
NG (fuel), $kg/m^3 H_2$ produced	0.03	Scaled from [89]
Catalyst		
Load, kg catalyst/tonne H_2 produced	0.12	Calculated based on GHSV
Life, yrs	3	
Electricity, MW	0.15	Scaled from [89]

 Table 2.8: Major inputs and parameters for modeling oil refinery proces (continued)

2.2.5 Distribution and End Use

Four different liquid biofuel products: gasoline, jet fuel, diesel and heavy oil, are produced in Chevron oil refinery and distributed to the local markets. The gasoline and diesel are assumed to be delivered by LTT to a hypothetic refueling station for lightand heavy-duty vehicles, respectively, at City of Vancouver, which is 10 km away from Chevron refinery. The jet fuel is delivered via an existing 40 km oil pipeline from Chevron oil refinery to Vancouver International Airport, for airplanes. The heavy oil is delivered by LTT to Port of Vancouver, 11.3 km away from Chevron refinery, for marine vessels.

Chapter 3

HTL biofuel LCA

3.1 LCA Model

3.1.1 Goal and Scope Definition

A process-based attributional LCA is conducted to quantify the GHG emissions of HTL biofuels from forest residues in BC. The analysis follows the international standard ISO 14040 [45] and the functional unit is set to be 1 MJ of HTL biofuels mix produced. The system boundary of each scenario are shown in Figure 3.1.

All emissions from each process and its associated upstream supply chain are accounted for in this study. However, the emissions associated with construction of infrastructure and manufacture of equipment as well as waste treatment are not included within the scope. Additionally, forest residues as feedstock for biofuels production are considered to carry no environmental burdens linked with the harvested timber in light of low value of these forest residues, which otherwise will be burned to reduce the risk of wild fire in BC. We also assume that no soil carbon change due to controlled sustainable removal of forest residues from forest stands to produce biofuels in BC, with 25% of forest residues being left in forest stands to provide nutrients and for the health of the forests [13]. It is assumed that the carbon released from the utilization of the off-gases from the conversion stage does not contribute to global warming impact since it essentially origins from the carbon intake during trees growth.



Figure 3.1: The system boundary of different HTL biofuel scenarios (AD: anaerobic digestion; NG: natural gas; PHWW: post HTL waste water)

3.1.2 Life Cycle Inventory Analysis

Data quality and specificity are generally considered as critical issues for LCA studies. Spatial variation and local environmental uniqueness are one of the concerns that require special attention [91]. Therefore, to enhance the consistency and accuracy of the life cycle inventory data, whenever possible, BC specific data are utilized, e.g., the feedstock availability, the locations of biofuels supply chain nodes, the transportation and electricity mix. Otherwise, Canadian average, or if not available, U.S. average, data are used with modification on the electricity mix to reflect BC specificity. GH-Genius v4.03 [2], a Canadian-based LCA program, is primarily employed for modeling processes such as transportation, energy and fuels production and consumption, by setting BC as the analyzed region and 2016 as the base year. For the processes lacking built-in models in GHGenius v4.03, e.g., materials production and delivery including HTL buffer agent, hydrotreating and hydrogen production catalyst, and nitrogen fertilizer, the GREET 2015 (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) [92] or SimaPro v8.2 coupled with Ecoinvent v3.2 database [48] is used to model the process emissions with modification on the electricity mix. When the data could not be found in the software database described above, they are collected from peer-reviewed journal articles or reports issued by government and widely recognized scientific organizations (e.g., PNNL, NREL).

The emissions from each process are obtained based on the emission factors method. Concretely, materials and energy consumptions are first calculated for each process through mass and energy balances and then multiplied by the corresponding emission factors. The detailed mass and energy balances of pre-processing and conversion stages can be found in Appendix A. The processes emission factors used in modeling are summarized in Appendix B.

3.1.3 Impact Assessment

This LCA study only focuses on the global warming impact, quantified by the metrics of GHG emissions. The collected raw data from the various sources described above are first compiled in Microsoft Excel to build the life cycle inventory of HTL biofuels, and then IPCC (Intergovernmental Panel on Climate Change) 2007 global warming potential factors are used to convert CO_2 (1), CH_4 (25) and N_2O (298) into CO_2 -eq for a time horizon of 100 years.

3.1.4 Handling of By-product

The method of handling process by-products can significantly influence the life cycle results of biofuel [52, 62, 93]. The by-product biochar produced in HTL plant is assumed to be shipped out to a hypothetic farm 50 km away from biorefinery and applied for soil amendment. HTL biochar contains carbon originating from forest residues and is modeled as sequestered carbon in this analysis. Although the stability of carbon in biochar depends on many factors such as feedstock, processing and environmental conditions, we assume that 80% of the carbon in biochar could be stably sequestrated when it is applied for soil amendment as suggested by Roberts et al. [94]. Wang et al. [95] meta-analyzes 24 studies of biochar decomposition in soil and find that about 97%of biochar could contribute to long-term carbon sequestration in soil, hence the 80%assumption we make in this analysis is conservative. Besides the sequestered carbon credit, N in biochar is assumed to displace the same amount of nitrogen fertilizer as suggested by Han et al. [62]. The emissions associated with the nitrogen fertilizer production are avoided, thus creating another credit. The average data, rather than the marginal data, is used to calculate the credit for replacing nitrogen fertilizer. The C and N content in biochar are assumed to be 51 wt% and 0.5 wt%, respectively [66].

3.2 Results and Discussion

3.2.1 Life Cycle GHG Emissions

Figure 3.2 shows the life cycle stage-wise GHG emissions of three different HTL biofuels production scenarios. The life cycle GHG emissions for Fr-CIR, Bo-DBR and Wp-CIR scenarios are 20.5, 17.0 and 19.5 g CO_2 -eq/MJ, respectively, corresponding to 78%, 82% and 79% reduction relative to 2005 gasoline baseline 93 g CO_2 -eq/MJ [96]. When considering the credit from biochar applied for soil amendment, the life cycle GHG emissions of HTL biofuels can be further reduced by 6.8 g CO_2 -eq/MJ, corresponding to 85%, 89% and 86% reduction of the life cycle GHG emissions compared to petroleum fuels for Fr-CIR, Bo-DBR and Wp-CIR scenarios, respectively.

The detailed GHG emission profile of individual processes is given in Table 3.1. For all three scenarios, the most dominant contributor to GHG emissions is biofuel conversion,



Figure 3.2: Stage-wise GHG emissions of HTL biofuels from three different scenarios

which makes up more than 50%, followed by feedstock delivery, including collection and transportation of biomass feedstock, accounting for 19% to 39% of total emissions depending on specific scenario. The process having the highest global warming impact over the whole life cycle of HTL biofuels is the HTL buffer agent Na₂CO₃ production. In this study, due to the lack of industrial data of Na_2CO_3 consumption in the HTL process, we use the bench test data reported by Zhu et al. [67] and Panisko et al. [84] from PNNL, i.e., Na_2CO_3 is consumed at 1wt% of the total feed slurry. This value could be higher than the demonstration- or industrial-scale data because of the assumed no-recycling of Na₂CO₃. Although it is assumed that PHWW is recycled for the slurry formation, we do not consider the remaining Na_2CO_3 in the recycled waste water, because no data are currently available about the buffer consumption rate in the HTL reaction. The contribution of biomass collection is similar among the three scenarios $(13\% \sim 16\%)$, while the transportation varied significantly. In Fr-CIR scenario, feedstock transportation accounts for about 25% of the GHG emissions of HTL biofuels. The long-distance transportation and the low energy density of bulky forest residues lead to the high transportation emissions. In contrast, for Bo-DBR and Wp-CIR scenarios, the bulky forest residues are first densified into high energy density intermediates, bio-oil and wood pellet, which are transported to refinery for further conversion. Compared with Fr-CIR scenario, Bo-DBR and Wp-CIR scenarios can lower the transportation emissions by 83% and 44%, respectively. However, the configuration change also causes increase of GHG emissions in other stages. For Wp-CIR scenario,

due to the use of biomass feedstock as heating fuel in pellet plant operation, more forest residues need to be collected from forest stands, thus increasing the emissions of collection stage. Besides, pellet plant operation is linked with upstream (heating fuel production and electricity generation) and downstream (fuel combustion) emissions [1], which contribute to the increased emissions in pre-processing stage compared with the other two scenarios. For Bo-DBR scenario, the off-gases produced in the distributed HTL plants could not be used in the refinery as in integrated systems, i.e., Fr-CIR and Wp-CIR, so NG is needed as a feedstock for hydrogen production, thus increasing hydrogen production emissions. Overall, Bo-DBR and Wp-CIR scenarios can achieve 16.9% and 4.7% reduction of total GHG emissions compared with Fr-CIR scenario. In Fr-CIR and Wp-CIR scenarios, AD operation is an important contributor to the life cycle GHG emissions of HTL biofuels, accounting for around 14%. NG is used as heating fuel for maintaining the AD operating temperature since off-gases produced by HTL are sent to refinery for hydrogen production. However, in Bo-DBR scenario, the impact of AD operation can be considerably reduced due to the use of remaining off-gases from HTL as heating fuel for AD.

3.2.2 Comparison with Peer-reviewed Literature

To check whether the GHG emissions of HTL biofuels from this study are consistent with those from peer-reviewed literature, we have conducted a comparison using the results from part of the reviewed studies presented in Table 1.2. The studies are chosen for comparison only when the following criteria are met: (1) the system boundary is well-to-wheel or well-to-wake; (2) the functional unit is MJ of biofuel. Figure 3.3 presents the analyzed life cycle GHG emissions of this study and those of literatures. The bar in Figure 3.3 stands for the median value of the GHG emissions of all studies of a specific conversion pathway, instead of the mean value, because we find that the mean can be easily influenced by the extreme values of certain studies, and the error bar represents the standard deviation. It should be noted that the GHG emission results of this study used to compare are the net emission results including the biochar credit, since the results from majority of the selected literatures consider the by- or co-products credit.

According to the results shown in Figure 3.3, gasification generally has the best GHG

HTL biofuel life cycle stage	Fr-CIR (%)	Bo-DBR (%)	Wp-CIR (%)
Feedstock collection	13.12	15.79	15.47
Loader and chipper operation	7.53	12.28	12.22
Forest residues shuttling to FDPs	5.59	3.51	3.25
Feedstock transportation	25.47	5.29	14.90
Pre-processing	2.88	3.47	8.07
Grinder and dust collector operation	2.25	2.71	2.36
Loader operation	0.63	0.76	0.66
Pellet plant operation	N/A	N/A	5.04
Conversion	53.36	69.23	56.11
HTL buffer	34.44	41.46	36.15
Electricity	4.17	5.02	4.44
AD gas combustion in HTL burner	1.10	1.32	1.15
AD operation	13.53	5.02	14.24
Hydrogen production	0.07	16.34	0.07
Hydrotreating catalyst	0.06	0.07	0.06
Fuel distribution	0.17	0.20	0.17
End use	5.00	6.02	5.28

Table 3.1: Contribution of each process to the GHG emissions of HTL biofuels

emission performance (11.60 \pm 4.14 g CO₂-eq/MJ), followed by HTL (12.67 \pm 1.46 g CO₂-eq/MJ from this study and 23.58 \pm 4.18 g CO₂-eq/MJ from literatures) and lastly pyrolysis (33.77 \pm 16.24 g CO₂-eq/MJ). Our results seem to be consistent with the general trend, although it is about 46% lower than the median value of HTL biofuels results from the literature. This could be explained by the much lower emission intensity of the BC electricity mix compared with the US electricity mix, which is used in the two HTL LCA studies we reviewed [26, 64]. Another major reason could be the credit assigned for by-products. In this study, we assume that by-product biochar applied for soil amendment could create credits both from carbon sequestration in the soil as well as the avoidance of nitrogen fertilizer production. In contrast, the other two studies do not consider the credit from biochar produced by HTL.



Figure 3.3: Comparison of HTL biofuels life cycle GHG emissions with literatures

3.2.3 Sensitivity Analysis

To investigate key factors influencing the GHG emissions of HTL biofuels, a sensitivity analysis is conducted by adjusting the nominal values of uncertain parameters to $\pm 10\%$. For analyzing the impact of electricity mix, BC electricity mix is entirely displaced with Alberta (AB) electricity mix while keeping all other modelling parameters unchanged. The parameters as well as their values used for sensitivity analysis are categorized and listed in Table 3.2. It should be noted that the life cycle GHG emissions are the net values with the biochar credit considered.

As shown in Figure 3.4, although each scenario presented different results, in general, the most sensitive parameters are associated with process performance. The change of HTL energy requirement and biofuel yield by 10% can lead to more than 10% variation of the GHG emissions for all scenarios. However, it should be noted that for Bo-DBR scenario, the 10% decrease of HTL energy requirement does not have appreciable impact on the GHG emissions. This is because at the nominal HTL energy requirement level, the HTL and AD units can be self-energized by biogas from AD as well as off-gases from HTL in Bo-DBR scenario. Therefore, further lowering the HTL energy requirement will not make a difference.

The 10% change in biomass content in slurry and carbon sequestrated in biochar shows a moderate impact (range of $\pm 5\%$ to $\pm 10\%$). With a fixed biomass input, the biomass

Category	Parameters	Nominal	-10%	+10%
Feedstock property	Moisture content of forest residues: wt%	48.91	44.02	53.80
Feedstock supply	Feedstock collection distance: km	12.5	11.25	13.75
Process performance	Biomass content in slurry for HTL: wt $\%$	8.0	7.2	8.8
	Bio-oil yield: kg/kg dry wood	0.367	0.330	0.404
	HTL energy requirement: MW	50.4	45.38	55.46
	Biofuel yield: kg/kg bio-oil	0.75	0.68	0.83
By-product credit	Carbon sequestrated in biochar: wt $\%$	80	72	88
Location specificity	Electricity mix: $\%$			
	BC ^a : Hydro:90.4; Biomass: 4.9; NG: 2.9;	Fuel oil: 1.5	5; Wind:	0.3
	AB ^b : Coal:72.4; NG: 19.6; Wind: 3.6; Hy	dro: 3.5; Fu	uel oil: 0	.9

 Table 3.2: List of parameters used for sensitivity analysis

^a From [17], average of 2010–2012, detailed emission factors are shown in Appendix B; ^b From [17], average of 2010–2012, detailed emission factors are shown in Appendix B

content in slurry can influence the total weight of slurry, which further determines the electricity consumption of pumping as well as the input of HTL buffer Na₂CO₃. As the results in Table 3.1 suggest, the consumption of Na₂CO₃ is a crucial contributor to the GHG emissions of HTL biofuels. Biochar, in this study, is assumed to be applied for soil amendment and creates GHG credits from carbon sequestration as well as the avoidance of nitrogen fertilizer production. Although there is uncertainty regarding the biochar carbon stability in the soil, reported studies [95, 97] generally show a stable property of the biochar carbon. However, specific models need to be developed in the future to verify the carbon sequestration potential of HTL biochar.

The 10% change in other parameters such as bio-oil yield, moisture content of forest residues and feedstock collection distance has modest (within $\pm 5\%$) impact on the GHG emissions. Although moisture content of forest residues is considerably sensitive to Fr-CIR scenario, it makes little impact for Bo-DBR and Wp-CIR scenarios. Bio-oil yield does not influence the GHG emissions of HTL biofuels as much as biofuel yield, because the bio-oil yield has larger impact on the biochar credit, which can offset the impact of other life cycle stages, than biofuel yield. The biochar credit is directly related to biochar yield, which can be influenced by bio-oil yield from two layers. First, the change of bio-oil yield can impact the feedstock requirement, which leads to parallel

change of the yield of all HTL products, i.e., bio-oil, off-gases, biochar and PHWW. The second layer is that the bio-oil yield can influence HTL products profile. For example, the decrease of bio-oil yield will increase the fraction of biochar in HTL products. In contrast, the change of biofuel yield only has the first layer effect.



Figure 3.4: Sensitivity analysis of net life cycle GHG emissions of HTL biofuels

The significant impact of electricity mix on the HTL biofuels GHG emissions can be observed in Figure 3.5. With more than 90% renewable composition, BC's electricity mix is more favorable than that of AB. A change from BC electricity mix to AB electricity mix can lead to a 168%, 225%, 182% increase in the GHG emissions for Fr-CIR, Bo-DBR, Wp-CIR scenarios, respectively. Therefore, locating the potential HTL system in a place with clean electricity mix like BC, can considerably lower the GHG emissions of HTL biofuels.



Figure 3.5: Impact of electricity mix on net life cycle GHG emissions of HTL biofuels for different scenarios

3.2.4 Improving the GHG Performance of HTL Biofuels

Based on the life cycle "hot spots" and the key parameters impacting the GHG emissions of HTL biofuels identified, the following recommendations can be made to help improve the GHG emission performance of HTL biofuels produced in BC as well as to provide insights for companies or investors who want to deploy such a facility:

(1) Increase the recycling rate of HTL buffer Na₂CO₃ with the understanding of energy and materials consumption of the recycling process. Na₂CO₃ use has been identified to contribute mostly to the life cycle GHG emissions of the proposed HTL plant in BC. According to our analysis, if the recycling rate of the buffer increases by 25%, the GHG emissions can be reduced by 13%~17%. This is a promising way to further increase the environmental performance of HTL biofuels, while the energy and materials input associated with the recycling need to be first clearly understood.

- (2) Lower the transportation emissions by densifying biomass feedstock before transportation to conversion facilities. For long distance transportation of feedstock with high moisture content, we recommend to first convert these raw materials into high energy density intermediates such as bio-oil or wood pellet. If such infrastructure is available within a reasonable distance, it will be ideal to utilize such existing facility. Otherwise, the economics of constructing the new infrastructure, or alternatively, purchasing the mobile conversion devices, needed to be first investigated.
- (3) Increase the process performance of the HTL biofuel system. Specifically, main efforts need to be put on increasing the energy efficiency of HTL and maximizing the biofuel yield. This relies on the optimization of system design, e.g., integrated with AD, to reduce the fossil energy input. Other improvement can be made in increasing the biomass content in the slurry. With the advancements of pump technology, transmission of large scale biomass-water slurry would be feasible.
- (4) Make full use of the process by-products, i.e., off-gases, biochar and PHWW, to create GHG savings. Off-gases can be used as either heating fuel for different operation units or feedstock for hydrogen production to avoid the input of external NG. Biochar applied for soil amendment can create credits from both carbon sequestration and the avoidance of nitrogen production, while specific models need to be developed to verify the carbon sequestration potential of biochar to reduce the uncertainty. HTL can be integrated with an AD unit in order to recover energy from the PHWW, hence increase the energy efficiency of HTL.
- (5) Locate the HTL biofuel system in a place with favorable electricity mix. This can make a big difference, as shown in the comparison of the impact of electricity mix of BC and AB on the GHG emission of HTL biofuels (Figure 3.5).

3.3 Conclusion

This chapter quantifies the life cycle GHG emissions of a hypothetic 100 MLPY HTL biofuel production system in BC based on three different scenarios. The results suggest that compared with conventional petroleum fuels, up to 89% GHG emission reduction can be achieved by HTL biofuels with the biochar credit considered. The conversion stage dominates the total emissions, contributing more than 50%. The process emitting most GHGs over the life cycle of HTL biofuels is HTL buffer production, resulted from the large amount of buffer consumed to maintain the pH of biomass slurry in the HTL process. Recycling of the HTL buffer thus needs to be further investigated to reduce the impact. Converting forest residues to bio-oil and wood pellet before transportation can significantly lower the transportation emissions and contribute to the considerable reduction of the life cycle GHG emissions of HTL biofuels. A sensitivity analysis indicates the importance of process performance parameters, such as HTL energy requirement and biofuel yield, as well as the location specific parameter such as the electricity mix. Therefore, main efforts can be put on increasing the energy efficiency of HTL and maximizing the biofuel yield to further improve the GHG emission performance of HTL biofuels.

Chapter 4 HTL biofuel TEA

4.1 Economic Analysis

The following subsections describe the methods for estimating the feedstock delivered cost, capital investment and operating cost of the three HTL biofuel production scenarios, as well as the method for calculating the minimum selling price (MSP) of the biofuel products. The economic analysis is carried out based on each stage as described in the Chapter 2 and the detailed stage-wise results can be found in Appendix D. It should be noted that the costs associated with biofuel distribution and end use are not included in the economic analysis.

4.1.1 Feedstock Delivered Cost

The feedstock delivered cost covers the raw material cost, machinery cost and transportation cost to the gate of refinery. To estimate the feedstock delivered cost, the method proposed by Akhtari [98] is used. It should be noted that the conversion cost of forest residues to bio-oil or wood pellet in Bo-DBR and Wp-CIR scenarios is not included in feedstock delivered cost, instead it is included in the capital and operating costs of the plants to avoid double counting, which will be thoroughly described in later subsections.

Raw Material Cost

Raw material cost is the cost for purchasing the forest residues left on logging sites. Usually these forest residues are regarded as a waste of logging operation and would be left onsite and burned as a part of forestry management in BC [9], hence they can be purchased at a low price, in this study we used \$3/dry tonne forest residues [10]. The amount of forest residues purchase is shown in Table 2.5. The raw material cost is the product of the purchase price and the amount.

Machinery Cost

We assume that piled forest residues on the forest stands are first chipped for size reduction and loaded to dump truck, and then transported to the nearby FDP, where the chipped residues from different forest stands are unloaded and reloaded to the semi-trailers for transportation to conversion facility. Therefore, the machinery cost includes the capital and operating costs for loaders and chippers used in forest residues collection. The capital costs contain the purchase cost, insurance and tax cost of loaders and chippers, and the operating costs include fuel and lubricant cost, labor and maintenance cost and annual depreciation. The assumptions for machinery cost estimation are listed in Table 4.1.

The capital cost is converted to an annuity by multiplying a capital recovery factor (CRF), where i is the interest rate and n is the life time of the machine:

$$CRF = \frac{i(i+1)^n}{(i+1)^n - 1}$$
(4.1)

The insurance and tax cost (C_i) is estimated as a fraction of machine purchase price:

$$C_i = P \times f_i \tag{4.2}$$

Where P is the machine purchase price, f_i is the insurance and tax cost fraction of machine price. Annual depreciation (D) is calculated as:

$$D = (1 - f_s) \times \frac{P}{n}$$
(4.3)

Where $f_{\rm s}$ is the salvage fraction of machine price. Fuel and lubricant cost $({\rm C}_{\rm fl})$ is

Parameter	Notation	Loader at forest stands/at FDPs	Chipper
Purchase price (\$/machine)	Р	240000	200000
Machine life (years)	n	10	10
Interest rate (%)	i	6.5	6.5
Insurance and tax rate (% of purchase price) $% \left(\left(1-\frac{1}{2}\right) \right) =0$	$\mathbf{f}_{\mathbf{i}}$	2.5	2.5
Scheduled machine hours (SMH) per year	SMH	1200/3000	1200
Utilization rate (%)	u	65	75
Productive machine hours (PMH) per year	PMH	780/1950	900
Fuel (diesel) consumption (L/PMH)	F	7.96/14.24	29.22
Fuel cost $($ L)	$\mathbf{F}_{\mathbf{c}}$	1.2	1.2
Lubricant cost (% of fuel cost)	\mathbf{f}_{l}	36.8	36.8
Number of operators	Ν	1	0
Labor rate of operator $(\$/hr)$	W	25	25
Fringe benefit of operator (% of wage)	f_b	30	30
Salvage value (%)	f_s	30	20
Repair and maintenance (% of depreciation)	f_r	90	100
Productivity of machine (GMT/PMH)	MP	19/34	19

Table 4.1: Assumptions for machinery cost estimation

Note: data from [98] with modification; SMH = Working hours per day \times working days per year; PMH = SMH \times u; GMT = green metric ton

calculated as:

$$C_{\rm fl} = F \times F_{\rm c} \times (1 + f_{\rm l}) \times \rm PMH$$
(4.4)

Where F is the fuel consumption in L/PMH, F_c is the fuel cost in L/PMH.

$$C_l = N \times w \times (1 + f_b) \times SMH$$
(4.5)

Where N is the number of operator required, w is the labor rate of operator in $hr, and f_b$ is the benefit fraction of labor cost. The machine repair cost (C_r) was calculated using the following equation, Where f_r is the maintenance and repair cost fraction.

$$C_{\rm r} = D \times f_{\rm r} \tag{4.6}$$

When the annual machinery cost (C_{tot}) has been calculated, the cost per unit of forest residues collected can be obtained using the following equation:

per unit
$$cost = \frac{C_{tot}}{Annual biomass production}$$
 (4.7)

and the annual biomass production can be calculated as:

Annual biomass production =
$$PMH \times MP$$
 (4.8)

Based on the above calculations, the annualized machinery cost per machine and the number of machines required at each FDP are in Table 4.2 and Table 4.3, respectively.

Dependenten	Loader	Chinner
Farameter	at forest stands/at FDPs	— Cmpper
Capital cost	$3.94E{+}04$	3.28E + 04
Equipment purchase cost	3.34E + 04	2.78E + 04
Insurance and tax cost	$6.00E{+}03$	5.00E + 03
Operating cost	8.11E+04 / 1.75E+05	7.52E + 04
Annual depreciation	$1.68E{+}04$	1.60E + 04
Fuel and lubricant cost	$1.02E{+}04 \ / \ 4.56E{+}04$	4.32E + 04
Labor cost	$3.90E{+}04 / 9.75E{+}04$	$0.00E{+}00$
Repair and maintenance cost	$1.51E{+}04$	1.60E + 04
Total cost	$1.20E{+}05 / 2.14E{+}05$	1.08E + 05
Annual biomass production (GMT/yr)	1.48E+04 / 6.63E+04	1.71E + 04
Per unit cost (GMT)	8.13 / 3.23	6.32

Table 4.2: Annual machinery cost summary (\$/yr/machine)

Transportation Cost

Transportation cost covers the cost of shuttling forest residues from forest stands to FDPs using dump truck and transporting forest residues or bio-oil or wood pellet from

Parameter	Loader at forest stands/at FDPs	Chipper
Chilliwack	10 / 2	9
Squamish	4 / 1	4
Powell River	16 / 4	14
Port Alberni	9 / 2	8
Total	40 / 9	34

Table 4.3: The number of machines required at each FDP

FDPs to Chevron oil refinery, including trucks rental cost and labor cost, which is calculated using Equation 4.9 as below:

$$C_t = H \times (t_t + t_w) \tag{4.9}$$

Where C_t is the transportation cost, H is the transportation hourly rate including truck rental cost and labor cost, t_t is the transportation time, t_w is the waiting time for loading and unloading, etc. The assumptions for estimating transportation cost are listed in Table 4.4.

 Table 4.4:
 Assumptions for transportation cost estimation

Parameter	Dump truck	ST or LTT	Ferry
Average speed (km/h)	40	60	$16^{\mathrm{b}};25^{\mathrm{c}}$
Waiting time for loading and unloading, etc. (hr)	2	2	4.3
Payload of truck (tonne)	11.8	23.25	$30 \ (m^3)$
Hourly rate ^a (hr)	55^{d}	$85^{\rm e}$	$6.5^{\mathrm{f}}(\mathrm{foot})$

^a Include vehicle rental cost and labor cost; ^b In the marine route from Powell River to Chevron oil refinery; ^c In the marine route from Port Alberni to Chevron oil refinery; ^d From [99]; ^e From [100]; ^f Reservation cost of ST or LTT on ferry is based on the length of the truck [101], which was assumed to be 23 m; ST: semi-trailer; LTT: liquid tanker truck

4.1.2 Capital Investment

The capital investment is estimated using the factor method summarized in Table 4.5. The method begins with the total purchased equipment cost (TPEC) of major process equipment or operation unit based on literatures [26, 102] and scales to the specific capacity using the following cost-capacity relationship:

$$C_{new} = C_{base} \times \left(\frac{S_{new}}{S_{base}}\right)^x$$
 (4.10)

where C_{base} is the base cost of equipment of base capacity S_{base} , C_{new} is the new cost of equipment of new capacity S_{new} and x is the scaling factor, which is assumed to be 0.7 in this study [103]. Other capital investment elements are estimated based on TPEC. The reference costs of the specific process equipment or operation unit for biorefinery and wood pellet plant can be found in Table D.2 and Table D.7, respectively, in Appendix D. The capacity, feed rate and productivity of the studied biorefinery and wood pellet plants are shown in Table D.3 of Appendix D.

It should be noted that in this study we assume that bio-oil is upgraded in an existing Chevron oil refinery, hence, we do not consider the capital investment associated with building the upgrading infrastructure in view of the transition of fossil fuels to renewable biofuels in the future. Specifically, the capital investment of Chevron refinery is not considered in neither integrated refinery scenarios, i.e., Fr-CIR and Wp-CIR, nor distributed biorefineries scenario, i.e., Bo-DBR.

4.1.3 Operating Cost

The major assumptions for estimating the operating cost are summarized in Table 4.6. The operating cost includes variable part and fixed part. The variable operating cost consists of the costs associated with purchasing feedstock, catalyst and chemicals, utilities and the treatment of wastes. The cost of feedstock is essentially the feedstock delivered cost from forest stands to plant, the estimation of which has been described in Subsection 4.1.1. The fixed cost covers the costs of labor, maintenance and supplies, property tax and insurance, and plant overhead. Besides, the credit from selling the by-product biochar is also considered. Three types of labor are involved, i.e., operating labor, maintenance labor and supervisory labor. The operating and maintenance labor

Parameter	Methods	Reference
Capital investment	Biorefinery/Wood pellet plant	
Depreciable cost (DepC)	TIC+IC	_
Total installed cost (TIC)	$2.47^{\rm a}/{\rm X^{b}*TPEC}$	
TPEC	100%	
Indirect cost (IC)	$1.2/1.23^{*}$ TPEC	
Engineering	32%/33%	[53]
Construction	34%/39%	[53]
Contractor fees	18%/17%	[53]
Contingency	36%/34%	[53]
Non-depreciable cost (NDepC)	3.99%/4.35% of DepC	
Land cost	1.5% of DepC	[53]
Site development	2.49%/2.85% of DepC	[53]
Fixed capital investment (FCI)	DepC+NDepC	
Start-up cost (SC)	9% of FCI	[104]
Working capital (WC)	20% of FCI	[103]
Total capital investment (TCI)	FCI+SC+WC	

Table 4.5: Methods for estimating the capital investment of the HTL biofuel system

^a from [105]. The installation factor 2.47 was used for all operating units in HTL biorefinery. This factor covers the costs including equipment installation, instrumentation and controls, piping, electrical systems, building and yard improvement; ^b from [103]. X is the individual factor varied with specific equipment modules and the details are presented in Appendix D.

requirement is estimated by the following equation from US EPA [106].

$$L_{new} = L_{base} \times \left(\frac{V_{new}}{V_{base}}\right)^{y}$$
(4.11)

Where L_{base} is the base labor requirement of base plant of capacity V_{base} , L_{new} is the new labor requirement of new plant of capacity V_{new} and y is the scaling factor, which is assumed to be 0.25 in this study. The base plant capacity and labor requirement for biorefinery and wood pellet plant are referenced from study by Tews et al. [26] and Hoque et al. [102], respectively. The supervisory labor cost is assumed to be 20% of the operating labor cost [103]. The maintenance cost, including materials and operating supplies, and the property tax and insurance, are estimated as 2.55% and 3% of FCI, respectively [53]. The plant overhead is assumed to be 72% of the total labor cost [53].

Parameter	Methods	Reference
Variable operating cost (VOC)		
Feedstock delivered cost	see Subsection 4.1.1	
Catalyst and chemicals		
Na_2CO_3 price, \$/tonne	275	[107]
$Ni/Mo/Al_2O_3$ price, kg	34	[108]
Waste disposal		
Waste disposal cost, \$/tonne	0.73	[26]
Utilities		
Electricity price, \$/kWh	0.057	[109]
Diesel, L	0.97	[110]
Natural gas, \$/GJ	2.84	[111]
Propane, L	0.54	[112]
Wood wastes, \$/dry tonne	3 ^a	[113]
Fixed operating cost (FOC)		
Labor cost		
Operating labor rate, \$/hr	24	[114]
Maintenance labor rate, \$/hr	28	[114]
Supervisory labor rate, \$/hr	20% of operating labor cost	[103]
Maintenance and supplies	2.55% of FCI ¹	[53]
Property tax and insurance	3% of FCI	[103]
Plant overhead	72% of total labor cost	[53]
Total operating cost	VOC+FOC	
By-product (biochar) price, \$/tonne	385^{b}	[115]

Table 4.6: Methods for estimating the operating cost of the studied HTL biofuel system

^a The wood wastes used in the pellet plant operation was assumed to be part of the forest residues input; ^b Took the average of high-end price 500/ton (equivalent to 550/tonne) and low-end price 200/ton (equivalent to 220/tonne)

¹It can be derived that the maintenance cost of biorefinery equals 0.097*TPEC based on information provided in Table 4.5. It should be mentioned that we used a different method for estimating the maintenance cost for equipment used in feedstock collection. By combining Equation 4.3 and 4.6, it can be derived that the maintenance cost of the feedstock collection machine equals 0.063*TPEC based on the information provided in Table 4.1. We keep using these two different methods for sep-

4.1.4 Minimum Selling Price

The MSP of HTL biofuels is calculated using discounted cash flow rate of return (DCFROR) analysis, which manipulates the fuel selling price to find the breakeven point where the project net present value (NPV) equals zero. The calculation is performed by iteration in Excel using self-developed Excel VBA code and the detailed spreadsheet can be found in Appendix E. Table 4.7 presents the major assumptions used in DCFROR analysis.

Parameter	Assumptions
Internal rate of return (IRR)	10%
Plant life time	20 years
Plant annual operating time	8000 hours/yr
Plant financing by equity/debt	40%/60% of total capital investment
Interest rate for debt financing	6.5% annually
Term for debt financing	10 years
Salvage value	0
Depreciation schedule	7-year MACRS ^a schedule
Income tax rate	26%
Construction period (spending schedule)	3 years (year 1: 30%, year 2: 50%, year 3: 20%)
Start-up time	3 months
Revenue and costs during start-up	Revenue = 50% of normal
	Variable operating $\cos t = 75\%$ of normal
	Fixed operating $\cos t = 100\%$ of normal

Table 4.7: Major assumptions for DCFROR analysis

 $^{\rm a}$ MACRS = Modified Accelerated Cost Recovery System

It should be noted that the MSP of HTL biofuels is calculated as the price of biofuel mix, including gasoline, jet, diesel and heavy oil in a unit of \$/L. In addition, for a consistent comparison with the price of petroleum gasoline, the liter gasoline-equivalent (LGE) price at \$/LGE for the biofuel product mix is calculated using Equation 4.12

arate parts of this study as the maintenance cost does not contribute much and also the cost for maintaining the equipment used in biorefinery and feedstock collection could be different.

to account for the difference in heating value.

$$MSP(\$/LGE) = \frac{MSP \text{ of final product } \times \text{Gasoline HHV}}{\text{Final product HHV}}$$
(4.12)

The HHV of biofuel product mix is calculated to be 37.9 MJ/L based on the product distribution and the HHVs of individual component (34.7, 37.4, 38.6 and 41.35 MJ/L for bio-based gasoline, jet, diesel and heavy oil, respectively), while the HHV of petroleum gasoline is assumed to be 34.7 MJ/L.

4.2 Results and Discussion

4.2.1 Cost Estimation

Table 4.8 summarizes the major costs of the 100 MLPY HTL biofuel system for the investigated scenarios. The TCI is dominated by the installed equipment cost, which accounts for about 50% for all scenarios. Fr-CIR scenario has the lowest capital investment as expected, and the other two scenarios have a higher capital investment as a result of the economy of scale, i.e., several small distributed plants need more capital investment than a large centralized plant of the same total capacity, and additional infrastructure construction, i.e., wood pellet plants. The detailed installed equipment cost of three studied scenarios is shown in Figure 4.1(a). The results indicate that the HTL reactor system requires the most capital expense, making up about 70% of the TIC on average for three scenarios. Therefore, the cost reduction of the HTL reactor system is significant for lowering the TCI.

Figure 4.1(b) demonstrates the detailed operating cost. Bo-DBR scenario has the lowest operating cost, followed by Fr-CIR scenario and lastly Wp-CIR scenario. The fixed operating costs of Bo-DBR and Wp-CIR scenarios are both higher than the Fr-CIR scenario, because most of the elements in fixed operating cost, such as plant overhead and the property tax and insurance are estimated based on the FCI (see Table 4.5). In contrast, the variable operating cost of these two scenarios are 32% and 8% lower. The main reason is the reduction in feedstock cost. As the pie chart of Figure 4.1(b) shows,
the feedstock cost of Fr-CIR scenario is dominated by the transportation cost, which makes up about 73%, indicating that the long-distance transportation of low energy density bulky forest residues is not a cost-effective option. Bo-DBR and Wp-CIR scenarios try to address this issue by converting the bulky forest residues into high energy density intermediates, i.e., bio-oil and wood pellet. This strategy shows a reduction of the feedstock cost by 48% and 20% for Bo-DBR and Wp-CIR scenarios, respectively. Bo-DBR scenario successfully reduces the total operating cost by lowering the feedstock cost, however, Wp-CIR scenario fails to do so as the increase of fixed operating cost and other variable operating costs outweigh the decrease of feedstock cost.

For comparing the overall economic feasibility, MSPs of different studied scenarios are calculated based on an assumed minimum acceptable IRR of 10% and the results are shown in Table 8. Fr-CIR scenario achieves the lowest MSP at \$0.89/L, followed by Bo-DBR scenario at \$0.97/L and Wp-CIR scenario at \$0.98/L. When compared with the 2016 gasoline wholesale price in Vancouver at \$0.50/L [116], the MSPs of HTL biofuels (\$/LGE) are 63% to 80% higher, which means under current circumstance, the HTL biofuels are not economically competitive with petroleum fuels. To promote the HTL biofuels, government incentives would be needed, or technology should be advanced to bring down the production cost of HTL biofuels.

4.2.2 Comparison with Peer-reviewed Literature

In order to check whether the MSP of HTL biofuels from this study agree with those from peer-reviewed literature, we compare our results with the literature data presented in Table 1.3. For a specific conversion pathway, the median value of the results from all studies is used instead of the mean, because the mean can be easily influenced as the results varied from study to study. Figure 4.2 compares the MSP results of different biofuel thermochemical conversion pathways. The literature results show that pyrolysis has the best economic performance ($0.82\pm0.38/L$), followed by HTL ($0.85\pm0.29/L$) and lastly gasification ($1.22\pm0.27/L$). The result from our study ($0.97\pm0.04/L$) is about 12% higher than the median value of literature results for HTL biofuels. This is due to the variance in the system configuration, factors and parameters used for process modeling, estimating the capital investment and operating cost as well as calculating the MSP. Since this study aims at a preliminary assessment of the economic feasibility



Figure 4.1: Detailed installed equipment cost and operating cost of studied HTL biofuel scenarios (the pie chart in part (b) represents the distribution of the feedstock cost)

of HTL biofuels in BC, the factors used in the cost estimation tend to be conservative.

	Fr-CIR	Bo-DBR	Wp-CIR
Capital investment, million \$			
Total installed cost (TIC)	120.4	178.8	138.0
Indirect cost (TIC)	58.5	86.9	68.1
Non-depreciable cost	7.1	10.6	8.3
Fixed capital investment (FCI)	186.0	276.2	214.4
Start-up cost (SC)	16.7	24.9	19.3
Working capital (WC)	37.2	55.2	42.9
Total capital investment (TCI)	240	356.3	276.6
Annual operating cost, million $/year$			
Variable operating cost	50.7	34.7	46.6
Fixed operating cost	16.0	26.4	24.6
Total annual operating cost	66.7	61.2	71.2
Annual sales, million \$/year			
Main products – biofuels	89.2	97.4	98.1
By-product – biochar	6.5	6.5	6.5
Total annual sales	95.7	103.8	104.6
Minimum selling price (MSP), L	0.89	0.97	0.98
Minimum selling price (MSP), $/LGE$	0.82	0.89	0.90

Table 4.8: Estimated costs for the HTL biofuel system

4.2.3 Impact of Carbon Tax and Technology Advancement

To mitigate the global warming impact, BC government has implemented a carbon tax since 2008 [117], which is levied based on the life cycle GHG emissions of a fuel. The initial carbon tax is 10 Canadian dollar (CAD) per tonne of CO_2 -eq, and it increased to 30 CAD/tonne CO_2 -eq in 2012. In 2016, BC government implemented a Climate Leadership Plan to further enhance GHG emission mitigation and help BC move towards 2050 emissions reduction target of 80% below 2007 level [5]. The Climate Leadership Team had called for a 10 CAD increase in carbon tax beginning in 2018 [118].



Figure 4.2: MSP of HTL biofuels from this study and literatures

Figure 4.3 shows the trend of BC carbon tax with a 10 CAD increase per year starting from 2018, the net petroleum price (NPP) and the net minimum selling price (NMSP) of HTL biofuels under the impact of increasing carbon tax. The initial MSPs of HTL biofuels are based on the MSPs of HTL biofuels from three studied scenarios, i.e., 0.82/LGE, 0.89/LGE and 0.90/LGE for Fr-CIR scenario, Bo-DBR scenario and Wp-CIR scenario, respectively. The initial petroleum price is assumed to be 0.50/L[116]. The life cycle GHG emission of petroleum fuel is based on 2005 gasoline baseline 93 g CO₂-eq/MJ (equivalent to 3226 g CO₂-eq/L) [96], while the life cycle GHG emissions of HTL biofuels are 20.5 g CO₂-eq/MJ (equivalent to 778 g CO₂-eq/L), 17.0 g CO₂-eq/MJ (equivalent to 646 g CO₂-eq/L) and 19.5 g CO₂-eq/MJ (equivalent to 739 g CO₂-eq/L) for Fr-CIR scenario, Bo-DBR scenario, respectively, based on the results from Chapter 3.

With the impact of carbon tax, the price gap between HTL biofuels and petroleum fuel shrinks year by year. The breakeven points are achieved when the carbon tax reaches $130/\text{tonne CO}_2$ -eq in 2030 for Fr-CIR scenario, $154/\text{tonne CO}_2$ -eq in 2033 for Bo-DBR scenario and $162/\text{tonne CO}_2$ -eq in 2034 for Wp-CIR scenario, corresponding to the NMSP of HTL biofuels at 0.92/LGE, 0.99/LGE and 1.02/LGE, respectively. The analysis would be conservative without the impact of technology advancement be-

ing accounted for, but even if a 1% cost reduction per year is assumed to be achieved by the advancement of HTL technology, the breakeven points are achieved in 2026, 2028 and 2029 with the NMSP of HTL biofuels at \$0.81/LGE, \$0.86/LGE and \$0.88/LGE for Fr-CIR, Bo-DBR and Wp-CIR scenario, respectively. Hence, under current technology status, carbon tax should be counted as a key incentive, while from a long-term point of view, the technology should be advanced to bring down the production cost of HTL biofuels.



Figure 4.3: Impact of carbon tax on petroleum fuel and HTL biofuels price (carbon tax was converted from Canadian dollars to US dollars using exchange rate of 1 CAD = \$0.81; NPP: net petroleum price; NMSP: net minimum selling price)

4.2.4 Sensitivity Analysis

Large-scale commercial HTL plants have not been reported. The uncertainty exists in the process design and cost estimation of the proposed HTL biofuel system due to the reliance on literature data. To investigate key factors influencing the MSP of HTL biofuels, a sensitivity analysis is conducted by adjusting the nominal values of uncertain parameters by $\pm 10\%$. As shown in Figure 4.4, although each scenario presents different results, in general, the most influencing parameters are associated with conversion processes, i.e., bio-oil and biofuel yield. The yield of intermediate and final products can significantly influence the input and output of other materials, as well as the energy consumption associated with the entire supply chain of HTL biofuels. It further implies that the technology advancement to improve the conversion and energy efficiency of HTL will make key contributions in reducing the costs of HTL biofuels. The property of raw material, i.e., the moisture content of forest residues, also matters, but shows different effect on each scenario. Fr-CIR scenario is the most sensitive, because the moisture content of forest residues can largely determine the cost of feedstock transportation, which has a significant contribution to the total operating cost of Fr-CIR scenario as discussed in the previously (Figure 4.1(b)). In contrast, the moisture content has less impact on the other two scenarios since the raw bulky forest residues are first converted to high energy density intermediate products before transportation. The cost estimation factors, such as debt interest rate and IRR, have a moderate impact on the MSP of HTL biofuels. Besides, the price of raw material, HTL buffer and by-product show little influence, i.e., the change rates of MSP are within $\pm 1.2\%$ based on a $\pm 10\%$ change of the nominal values.

4.3 Conclusion

This chapter estimates the capital investment and operating cost of a hypothetic 100 MLPY HTL biofuel production system in BC based on three different supply chain designs. The MSP of HTL biofuels is estimated to be \$0.82/LGE-\$0.90/LGE, which is about 63%-80% higher than that of petroleum fuel. Converting forest residues to bio-oil and wood pellet before being transported to the conversion facility can significantly reduce the variable operating cost, but the MSPs of HTL biofuels are found to be 9%-10% higher, respectively, due to a considerable increase in capital investment. A sensitivity analysis indicates the importance of technology advancement, such as the increased yield of bio-oil and biofuel, to the economic performance of HTL biofuels. With the increasing carbon tax and technology advancement, HTL biofuels will become competitive with petroleum fuels.



Figure 4.4: Sensitivity analysis of the MSP of HTL biofuels for different scenarios

Chapter 5 Conclusion and Future Work

The transportation sector of British Columbia (BC) is the leading contributor of refined petroleum fuels consumption and greenhouse gas (GHG) emissions. Therefore, it has become a hard nut for BC in moving toward its ambitious target of 80% GHG emission reduction by the middle of this century. Drop-in biofuels have been attracting the government's attention in mitigating the intensive emissions and high reliance on fossil fuels of the transportation sector. To date, there has been nearly no large-scale commercial plants reported for drop-in biofuels production using sustainable feedstock like forest residues, which are abundantly available but under-utilized in BC. Although numerous scientific studies and demonstration projects have been conducted to try to solve the technical bottlenecks, there has been very limited comprehensive and systematic evaluation on the environmental and economic performance of the conversion technologies, let alone a study based on BC's situation. According to a state-of-the-art review of the literature, we have identified a promising but under-studied thermochemical conversion technology called hydrothermal liquefaction (HTL) and quantified the environmental and economic impacts of deploying a HTL biofeul system in BC to fill the gap. The results of this study can help provide a preliminary insights for other researchers and local companies or investors as well as a reference for a government policy makers.

A life cycle assessment (LCA) and a techno-economic assessment (TEA) are conducted to quantify the GHG emission and the minimum selling price (MSP) of biofuels produced from a hypothetic 100 million liters per year (MLPY) HTL biofuel system in BC based on three different supply chain designs. The results suggest that comparing with conventional petroleum fuel, up to 89% GHG emission reduction can be achieved by HTL biofuel with the by-product biochar credit considered, but at a MSP of \$0.82-\$0.90/LGE (liter gasoline-equivalent), which is about 63%-80% higher than that of petroleum fuels. The conversion stage dominates the total GHG emissions, making up more than 50%. Converting forest residues to bio-oil and wood pellet before transportation to the upgrading facility contributes to a considerable reduction of the life cycle GHG emissions and the variable operating cost, but not the MSP because of a significant increase in capital investment. Sensitivity analysis indicates the importance of process performance parameters, such as the energy requirement of HTL and the yield of biofuel, to both the life cycle GHG emissions and the MSP. Thus, technology should be advanced to further reduce the GHG emissions and bring down the production cost of HTL biofuels. Otherwise, to make HTL biofuels economically competitive with petroleum fuels, a high carbon tax is needed.

The following limitations in this study that need to be addressed in the future work:

- 1. This study relies largely on secondary data from literature for the process modelling and environmental and economic assessment since there are currently no industrial data available. The key parameters influencing the environmental or economic performance of HTL biofuels, such as the energy requirement of HTL, the product yield and the recycling of HTL buffer agent remain uncertain. For HTL buffer production for use in HTL, it is the process which emits most GHGs over the life cycle. The material and energy input associated with the recycling of HTL buffer agent need to be determined. Besides, this study aims at a preliminary economic assessment of the HTL system, so the parameters used for economic modelling is relatively conservative. Thus, the data quality ought to be improved in the future to account for the industrial practice as well as the specific conditions in BC.
- 2. A more realistic model about the supply of forest residues needs to be built in the future. In this study, we used an assumed average distance for forest residues collection due to the lack of the specific location of forest stands, and also the availability of feedstock was based on an estimated five-year average data. The uncertainty usually involved in the real-world practice as the supply and the price of forest residues may vary with seasons or other disturbances. The operation of forest residues supply system needs to be optimized with such uncertainty considered,

and the trade-offs between the environmental and economic objectives need to be accounted for in order to build a more realistic model.

- 3. In the HTL system, some optimistic assumptions made in the process modelling need to be checked as the technology matures in the future. For example, the offgases from HTL and hydrotreating are used as feedstock for hydrogen production, the post HTL waste water (PHWW) can be used to produce biogas from AD, and the bio-oil produced from HTL can be co-upgraded with crude oil. There have been no industrial practice of these assumptions so far, therefore, these assumptions need to be validated in the future.
- 4. The following two scenarios are worthwhile to be examined in the future to see whether it can improve the economic performance of HTL biofuels. First, using mobile units for HTL of forest residues rather than building the distributed HTL infrastructure. The operation of these mobile units need to be optimized first based on the supply of forest residues in BC so it can maximumly reduce the capital and operating costs. Second, putting the proposed HTL biofuel system in a place of BC with existing wood pellet industry to avoid building the new pellet plants, such as Prince George, so that the capital investment of the Wp-CIR scenario can be brought down.

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Appendices

A Mass and Energy Balances

Appendix A contains the following content:

1. Stream flow diagrams of biomass to biofuel conversion processes

2. Detail mass and energy balance data of each operation unit

A.1 Stream Flow Diagrams

The stream flow diagrams of biomass to biofuel conversion processes for the three studied scenarios are presented in Figure A.1, A.2 and A.3 below.



Figure A.1: The stream flow diagram of Fr-CIR scenario



Figure A.2: The stream flow diagram of Bo-DBR scenario



Figure A.3: The stream flow diagram of Wp-CIR scenario

A.2 Tabulated Mass and Energy Balances Data

The detail mass and energy balance data of each operation unit are tabulated as below.

	Mass balance (kg/s)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
Forest residues ^a /Wood pellet ^b	20.41	20.41	11.01
Recycled water	109.93	109.93	118.88
Total	130.34	130.34	129.89
Output			
Biomass slurry	130.34	130.34	129.89
Total	130.34	130.34	129.89

 Table A.1: Mass balance of pre-processing for each scenario

^a for Fr-CIR and Bo-DBR scenarios; ^b for Wp-CIR scenario;

	Energy balance (MW)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
Forest residues ^a /Wood pellet ^b	191.98	191.98	192.08
Power	2.86	2.86	2.85
Recycled water	36.88	36.88	39.88
Total	231.72	231.72	234.81
Output			
Biomass slurry	231.72	231.72	234.81
Total	231.72	231.72	234.81

 Table A.2: Energy balance of pre-processing for each scenario

^a for Fr-CIR and Bo-DBR scenarios; ^b for Wp-CIR scenario

	Mass balance (kg/s)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
Biomass slurry	130.34	130.34	129.89
Biogas from AD	3.33	3.33	3.32
Combustion air	17.07	17.07	17.02
Total	150.75	150.75	150.23
Recycled			
Off-gases	0.2	0.2	0.2
Output			
Bio-oil	3.83	3.83	3.83
Recycled water	109.93	109.93	118.88
PHWW	14.20	14.20	4.80
Biochar	0.58	0.58	0.58
Off-gas	1.80	1.60	1.59
Flue gas	20.41	20.61	20.854
Total	150.75	150.75	150.23

 Table A.3: Mass balance of HTL for each scenario

	Ener	gy balance	(MW)
Input	Fr-CIR	Bo-DBR	Wp-CIR
Biomass slurry	231.72	231.72	234.81
Biogas from AD	49.20	49.20	49.20
Power	4.03	4.03	4.10
Total	284.96	284.96	287.94
Recycled			
Off-gases	1.21	1.21	1.21
Output			
Bio-oil	148.52	148.52	148.52
Recycled water	36.88	36.88	39.88
PHWW	61.15	61.15	62.84
Biochar	11.68	11.68	11.64
Off-gas	9.50	9.50	9.47
Heat loss	17.23	17.23	15.58
Total	284.96	284.96	287.94

 Table A.4: Energy balance of HTL for each scenario

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	Mass balance (kg/s)			
Input	Fr-CIR	Bo-DBR	Wp-CIR	
PHWW	14.20	14.20	4.80	
NG	0.08	0.00	0.08	
Combustion air	1.37	0.00	1.38	
Total	15.65	14.20	6.26	
Output				
Biogas	3.33	3.33	3.32	
Solid digestate	0.18	0.17	0.18	
Liquid digestate	10.78	10.79	1.30	
Flue gas	1.45	0.00	1.46	
Total	15.65	14.20	6.26	

 Table A.5: Mass balance of AD for each scenario

	Energy balance (MW)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
Off-gas from HTL	3.48	9.50	3.45
PHWW	61.15	61.15	62.84
NG	4.22	0.00	4.32
Power	5.03	5.03	5.02
Total	70.40	75.69	67.86
Output			
Biogas	49.20	49.20	49.03
Heat loss	12.03	17.31	17.72
Liquid digestate	9.17	9.17	1.11
Total	70.40	75.69	67.86

 Table A.6:
 Energy balance of AD for each scenario

 Table A.7: Mass balance of hydrotreating for each scenario

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	Mass balance (kg/s)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
Bio-oil	3.83	3.83	3.83
Hydrogen	0.13	0.13	0.13
Total	3.96	3.96	3.96
Output			
Biofuels	2.62	2.62	2.62
Waste water	1.06	1.06	1.06
Off-gas	0.28	0.28	0.28
Total	3.96	3.96	3.96

	Energy balance (MW)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
Bio-oil	148.52	148.52	148.52
Hydrogen	18.49	18.49	18.49
Power	1.12	1.12	1.12
Total	167.01	167.01	167.01
Output			
Biofuels	120.22	120.22	120.22
Waste water	30.69	30.69	30.88
Off-gas	16.11	16.11	16.11
Total	167.01	167.01	167.01

 Table A.8: Energy balance of hydrotreating for each scenario

	Mass balance (kg/s)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
NG(feed)	0.00	0.12	0.00
Off-gas (feed)	0.92	0.24	0.92
Off-gas (fuel)	0.37	0.04	0.37
Combustion air	3.01	3.03	3.01
Steam required	1.26	1.26	1.26
Total	5.56	4.69	5.56
Recycled			
Off-gases	0.91	0.91	0.91
Output			
Steam produced	1.81	1.81	1.81
Flue gas	3.15	2.27	3.15
Hydrogen	0.13	0.13	0.13
Blowdown	0.48	0.48	0.48
Total	5.56	4.69	5.56

 Table A.9: Mass balance of hydrogen production for each scenario

	Energy balance (MW)		
Input	Fr-CIR	Bo-DBR	Wp-CIR
NG(feed)	0.00	6.02	0.00
Off-gas (feed)	19.94	13.92	19.94
Off-gas (fuel)	2.19	2.19	2.19
Power	0.15	0.15	0.15
Steam required	3.53	3.53	3.53
Total	25.81	25.81	25.81
Recycled			
Off-gases	5.81	5.81	5.81
Output			
Steam produced	5.06	5.06	5.06
Hydrogen	18.49	18.49	18.49
Heat loss	2.26	2.26	2.26
Total	25.81	25.81	25.81

Table A.10: Energy balance of hydrogen production for each scenario

B Process Emission Factors

Appendix B summarizes all processes emission factors used in building the life cycle inventory of HTL biofuels. The emissions factors cover all life cycle stages, including biomass collection and transportation, pre-processing, conversion, biofuels distribution and end use. Besides, a section is added to describe the emission factors associated with by-product biochar application. Emission factors are classified into two types: upstream and downstream. The upstream emission factors account for emissions associated with the upstream supply chain of materials and energy, i.e., production and delivery, while the downstream emission factors are related to the emissions from the materials and energy utilization.

B.1 Biomass Collection and Transportation

The emissions from biomass collection and transportation stages are mainly contributed by the operation of diesel-powered and marine diesel-powered equipment. The upstream is associated with diesel production and delivery, and the downstream is related to diesel combustion in the equipment engine. The upstream and downstream emission factors are presented in Table B.1, Table B.2 and Table B.3.

Pollutant	Diesel ^a	Marine diesel ^b
	kg/MJ diesel	kg/MJ marine diesel
$\rm CO_2$	2.05E-02	2.05E-02
NMOCs	4.10E-06	4.10E-06
CH_4	1.31E-04	1.31E-04
СО	1.36E-05	1.36E-05
N_2O	6.00E-07	6.00E-07
NO_2	5.17E-05	5.17E-05
SO_{x}	4.46E-05	4.46E-05
PM	3.06E-06	3.06E-06

 Table B.1: Diesel and marine diesel production and delivery emission factors

^a from [2], "Upstream Results HHV — Hwy diesel, crude oil" model; ^b from [2], "Upstream Results HHV — Marine/Rail diesel, crude oil" model

Pollutant	Chipper and loader on forest stands ^a	Dump truck ^b	Loader at FDPs ^c		
	kg/dry tonne biomass	kg/Tkm	kg/MJ diesel		
CO_2	1.17E + 01	4.35E-01	6.82E-02		
NMOCs	7.10E-03	4.50E-05	2.15E-05		
CH_4	1.15E-02	2.70E-05	1.10E-06		
СО	1.02E-01	7.50E-05	9.60E-05		
N_2O	0.00E + 00	1.90E-05	2.86E-05		
NO_2	2.13E-01	1.64E-04	1.41E-04		
$\mathrm{SO}_{\mathbf{x}}$	1.18E-02	1.50E-05	6.54 E-07		
PM	1.12E-03	8.00E-06	0.00E + 00		

Table B.2: Biomass collection equipment operation emission factors

^a from [80]; ^b from [2], "Freight Emissions — Medium Duty Truck" model; ^c from [2], "Equip Emis Factors — Wheeled loader, diesel powered" model

Pollutant	Semi-trailer ^a kg/Tkm	Liquid tanker truck ^a kg/Tkm	Ferry ^b kg/tonne diesel
CO_2	1.38E-01	1.38E-01	3.49E+03
NMOCs	1.43E-05	1.43E-05	2.64E + 00
CH_4	8.45E-06	8.45E-06	1.87E-01
СО	2.38E-05	2.38E-05	8.14E + 00
N_2O	5.94E-06	5.94E-06	1.28E + 00
NO_2	5.19E-05	5.19E-05	6.67E + 01
$\mathrm{SO}_{\mathbf{x}}$	4.62E-06	4.62E-06	2.20E + 01
PM	2.54 E-06	2.54E-06	1.32E + 00

 Table B.3:
 Transportation emission factors

^a from [2], "Freight Emissions — Heavy Duty Truck" model; ^b from [83], the total emission factors of ferry are the sum of underway, maneuvering and dockside emission factors

B.2 Pre-processing

The emissions from biomass pre-processing stage are contributed by the operation of equipment in biorefinery, including diesel-powered front-end loader, electricity-powered grinder and auxiliary equipment, as well as the operation of wood pellet plant in Wp-CIR scenario. The upstream is associated with diesel and electricity production and delivery, and the downstream is related to diesel combustion in equipment engines. It should be noted that the emission factors of wood pellet plant operation are presented in a life cycle basis, which cover both the upstream and downstream emissions. Besides, the emission factors of electricity generation in Alberta is summarized blow, which is used in the sensitivity analysis. The upstream emission factors of diesel are the same as those presented in Subsection B.1 (see Table B.1) and the downstream emission factors of loader operation at feedstock delivery points (see Table B.2). The emission factors of wood pellet plant operation are presented in Table B.4 to Table B.8.

Pollutant	kg/tonne of wood pellet
CO_2	8.33E+00
NMOCs	1.32E-02
CH_4	6.05E-02
СО	2.95E-01
N_2O	6.40E-03
NO_2	1.58E-01
SO_{x}	1.89E-02
РМ	2.07E-01

Table B.4: Wood pellet plant operation Emission factors [1]

	Natural gas (Boiler)	Natural gas (Turbine)	Fuel oil	Biomass	Hydro	Wind
Contribution to BC electricity ^a (%)	1.43	1.43	1.52	4.91	90.44	0.28
Fuel to electricity efficiency b $(\%)$	42.34	42.34	44.66	20.00	100.00	100.00
Electricity distribution efficiency c $(\%)$	92.00	92.00	92.00	92.00	92.00	92.00

Table B.5: British Columbia (BC) electricity mix profile and electricity generation and distribution efficiency

^a from [17], the average value of 2010-2012, and assume electricity generated by natural gas (boiler) and natural gas (turbine) share 50% of total natural gas generation, respectively; ^b [17]; ^c from [2], "Elec Emissions"

Table B.6: Alberta electricity mix profile and electricity generation and distribution efficiency

	Natural gas (Boiler)	Natural gas (Turbine)	Fuel oil	Coal	Hydro	Wind
Contribution to BC electricity ^a (%)	9.78	9.78	0.93	72.40	3.53	3.58
Fuel to electricity efficiency b $(\%)$	33.17	33.17	26.10	29.65	100.00	100.00
Electricity distribution efficiency c $(\%)$	92.00	92.00	92.00	92.00	92.00	92.00

^a from [17], the average value of 2010-2012, and assume electricity generated by natural gas (boiler) and natural gas (turbine) share 50% of total natural gas generation, respectively; ^b [17]; ^c from [2], "Elec Emissions"

	Natural gas(Boiler)		Natural gas(Turbine)		Fuel oil			Biomass				
	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total
Pollutant	kg/MJ electric					ty distrib	ty distributed					
$\rm CO_2$	1.59E-2	1.33E-1	1.49E-1	1.59E-2	1.21E-1	1.37E-1	3.42E-2	1.91E-1	2.26E-1	-	-	-
NMOCs	6.40E-6	3.90E-6	1.03E-5	6.40E-6	6.30E-7	7.03E-6	8.35E-6	2.94E-6	1.13E-5	-	1.93E-5	1.93E-5
CH_4	1.71E-4	2.57E-6	1.73E-4	1.71E-4	8.93E-6	1.80E-4	2.95E-4	2.17E-6	2.97E-4	-	3.47E-5	3.47E-5
СО	1.34E-5	9.40E-5	1.07E-4	1.34E-5	8.51E-5	9.85E-5	2.01E-5	3.87E-5	5.88E-5	-	9.92E-4	9.92E-4
N_2O	3.66E-7	9.32E-8	4.59E-7	3.66E-7	3.11E-6	3.48E-6	6.48E-7	3.55E-8	6.83E-7	-	1.54E-5	1.54E-5
NO_2	9.80E-5	1.72E-4	2.70E-4	9.80E-5	1.82E-4	2.80E-4	9.97E-5	1.91E-4	2.91E-4	-	3.64E-4	3.64E-4
SO_x	1.26E-5	1.40E-6	1.40E-5	1.26E-5	1.28E-6	1.38E-5	6.76E-5	2.07E-4	2.75E-4	-	3.46E-4	3.46E-4
PM	6.63E-7	8.51E-6	9.17E-6	6.63E-7	6.85E-6	7.52E-6	3.38E-6	3.48E-5	3.81E-5	-	1.32E-4	1.32E-4
		Hydro Wind										
						BC mix						
Pollutant	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total						
CO_2	3.26E-3	4.53E-3	7.79E-3	-	-	3.32E-3	1.46E-2]				
NMOCs	-	-	-	-	-	-	1.37E-6					
CH_4	-	2.72E-4	2.72E-4	-	-	-	2.57E-4					
СО	-	-	-	-	-	-	5.25E-5					
N_2O	-	-	-	-	-	-	8.21E-7					
NO_2	-	-	-	-	-	-	3.01E-5					
SO_x	-	-	-	-	-	-	2.15E-5					
РМ	-	-	-	-	-	-	7.31E-6					

 Table B.7: British Columbia (BC) electricity generation emission factors [2]
	Natural gas(Boiler)		Natural gas(Turbine)		Fuel oil		Coal					
	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total
Pollutant					kg/	MJ electric	ty distribu	uted				
$\rm CO_2$	2.03E-2	1.33E-1	1.53E-1	2.03E-2	1.21E-1	1.41E-1	5.86E-2	1.91E-1	2.50E-1	1.55E-2	2.82E-1	2.97E-1
NMOCs	8.17E-6	3.90E-6	1.21E-5	8.17E-6	6.30E-7	8.80E-6	1.43E-5	2.94E-6	1.72E-5	1.09E-6	2.69E-6	3.78E-6
CH_4	2.18E-4	2.57E-6	2.21E-4	2.18E-4	8.93E-6	2.27E-4	5.05E-4	2.17E-6	5.07 E-4	1.02E-4	2.76E-6	1.05E-4
СО	1.71E-5	9.40E-5	1.11E-4	1.71E-5	8.51E-5	1.02E-4	3.44E-5	3.87E-5	7.31E-5	8.01E-6	3.45 E-5	4.25E-5
N_2O	4.67E-7	9.32E-8	5.60 E- 7	4.67E-7	3.11E-6	3.58E-6	1.11E-6	3.55E-8	1.14E-6	5.56E-7	1.18E-7	6.74E-7
NO_2	1.25E-4	1.72E-4	2.97E-4	1.25E-4	1.82E-4	3.07E-4	1.71E-4	1.91E-4	3.62 E-4	4.82E-6	8.21E-4	8.26E-4
SO_x	1.60E-5	1.40E-6	1.74E-5	1.60E-5	1.28E-6	1.73E-5	1.16E-4	2.07E-4	3.23E-4	2.41E-6	4.21E-4	4.23E-4
РМ	8.47E-7	8.51E-6	9.35E-6	8.47E-7	6.85E-6	7.70E-6	5.78E-6	3.48E-5	4.05E-5	1.30E-6	5.83E-5	5.96E-5
		Hydro			Wind							
							BC mix					
Pollutant	Up- stream	Down- stream	Total	Up- stream	Down- stream	Total						
$\rm CO_2$	3.26E-3	4.53E-3	7.79E-3	-	-	3.32E-3	2.47E-1					
NMOCs	-	-	-	-	-	-	4.94E-6					
CH_4	-	2.72E-4	2.72E-4	-	-	-	1.34E-4					
СО	-	-	-	-	-	-	5.23E-5					
N_2O	-	-	-	-	-	-	9.04E-7					
NO_2	-	-	-	-	-	-	6.60E-4					
SO_x	-	-	-	-	-	-	3.13E-4					
РМ	-	-	-	-	-	-	4.52E-5					

 Table B.8: Alberta electricity generation emission factors [2]

B.3 Conversion

The emissions from conversion stage are contributed by the following processes:

Upstream processes The production and delivery of materials, including HTL buffer agent Na₂CO₃, natural gas (NG) as heating fuel for anaerobic digestion (AD), hydrotreating catalyst NiMo/Al₂O₃, hydrogen production catalyst NiMo/Al₂O₃. Additionally, for Bo-DBR scenario, NG is required as feedstock for hydrogen production. Upstream emission factors are summarized in Table B.9. The production and delivery of energy, i.e., electricity. See Table B.7 for BC electricity mix emission factors.

Pollutant	AD heating ^a (HTL) kg/kg Na ₂ CO ₃	HTL heating ^b (AD) kg/MJ NG	Hydrogen production ^c (Hydrotreating) kg/kg NiMo/Al ₂ O ₃	Hydrogen production ^d (Hydrogen production) kg/kg NiMo/Al ₂ O ₃
$\rm CO_2$	6.94E-01	6.55E-03	9.37E-01	3.35E + 00
NMOCs	9.63E-05	3.27E-06	6.53E-05	3.90E-04
CH_4	7.59E-04	1.49E-04	7.85E-04	7.81E-03
CO	5.40E-04	6.57E-06	3.28E-04	1.42E-03
N_2O	1.17E-06	2.15 E- 07	5.82E-06	5.29E-05
NO_2	4.23E-04	3.92 E- 05	3.65 E-04	2.37E-03
SO_{x}	4.50E-04	5.37E-06	1.69E-04	3.42E-03
PM	1.72E-04	4.36E-07	6.72E-05	3.30E-04

Table B.9: Materials production and delivery emission factors of conversion stage

^a from [92], "Soda ash production for use in US" model, with US electricity mix changed to BC electricity mix; ^b from [2], "Upstream Results HHV — CNG, NG" model, also applied for NG as feedstock in Bo-DBR scenario; ^c from [92], "Mo/Ni spent catalyst-biobased" model, with US electricity mix changed to BC electricity mix; ^d from [92], "Mo/Ni spent catalyst-petrochemical" model, with US electricity mix changed to BC electricity mix

Downstream processes The combustion of NG for heating AD, the combustion of biogas for heating HTL, hydrogen production via steam reforming using NG as feedstock (Bo-DBR scenario), hydrogen production via steam reforming using off-gases from HTL and hydrotreating as feedstock (Fr-CIR and Wp-CIR scenarios). Downstream emission factors are summarized in Table B.10.

Pollutant	AD heating ^a (NG as fuel) kg/MJ NG	HTL heating ^b (biogas as fuel) kg/MJ biogas	Hydrogen production ^c (NG as feedstock) kg/MJ NG	Hydrogen production ^d (off-gases as feedstock) kg/MJ off-gases
$\rm CO_2$	5.02E-02	0.00E + 00	5.02E-02	0.00E + 00
NMOCs	3.69E-06	3.69E-06	9.72E-06	9.72E-06
CH_4	9.74 E- 07	9.74 E-07	3.79E-07	3.79E-07
CO	3.56E-05	3.56E-05	7.58E-06	7.58E-06
N_2O	4.91E-07	4.91E-07	2.37E-07	2.37E-07
NO_2	6.19E-05	6.19E-05	1.90E-05	1.90E-05
$\rm SO_x$	2.67E-07	2.67E-07	9.48E-08	9.48E-08
\mathbf{PM}	3.22E-06	3.22E-06	2.84E-06	2.84E-06

 Table B.10:
 Downstream emission factors of conversion stage

^a from [2], "Equip Emis Factors — Industrial boiler — NG" model; ^b from [2], "Equip Emis Factors — Industrial boiler — NG" model; CO₂ emission is modified to be 0 since the carbon in biogas is biogenic; ^c from [2], "Equip Emis Factors — Hydrogen Production Plants — NG" model; ^d from [2], "Equip Emis Factors — Hydrogen Production Plants — NG" model; CO₂ emission is modified to be 0 since the carbon in off-gases is biogenic

B.4 Biofuels Distribution and End Use

The emissions from biofuel distribution stage are contributed by the operation of diesel-powered liquid tanker truck (distribution of gasoline, diesel and heavy oil) and electricity-powered pipeline (distribution of jet fuel). The upstream is associated with diesel and electricity production and delivery, and the downstream is related to diesel combustion in the truck engine. The upstream and downstream emission factors of diesel are the same as those presented in Subsection B.1 (see Table B.1 and Table B.3, respectively). The pipeline transportation consumes electricity from BC grid and the energy consumption for transporting 1 tonne of biofuel via pipeline for 1 km is 404 Btu [119], which is equivalent to 0.292 MJ/Tkm. The BC electricity mix emission factors are presented in Table B.7. The emissions from biofuels end use stage are associated with biofuels combustion in the vehicle and airplane engines, which are summarized in Table B.11 as follow:

Pollutant	Gasoline ^a kg/MJ	Jet fuel ^b kg/MJ	Diesel ^c kg/MJ	Heavy oil ^d kg/MJ
$\rm CO_2$	2.87E-04	0.00E + 00	7.31E-04	0.00E + 00
NMOCs	4.07 E-05	1.08E-06	5.78E-06	2.94 E- 05
CH_4	3.28E-06	1.68E-06	3.79E-06	7.15E-07
СО	1.64E-03	7.00E-06	7.71E-06	1.91E-04
N_2O	1.32E-06	1.90E-06	2.96E-06	1.99E-06
NO_2	3.56E-05	2.50E-04	2.45 E-05	1.79E-03
SO_{x}	1.20E-06	0.00E + 00	2.07E-06	6.76E-07
PM	2.32E-06	2.50E-06	9.60E-07	3.58E-05

Table B.11: Biofuels combustion in vehicle and jet engines emission factors

^a from [2], "LDV Summ — Biomass Fuels, Gasoline, Wood Res" model. The emission factors are presented in unit of g/km originally, and they are converted to kg/MJ base by assuming that the energy intensity of light duty vehicle (LDV) is 2.21 MJ/(person*km) and average 3 persons are transported; ^b from [2], "Freight Emissions — Airplanes, BTL, Wood Res" model. The emission factors are presented in unit of g/Tkm originally, and they are converted to kg/MJ base by assuming that the energy intensity of airplane is 15 MJ/Tkm; ^c from [2], "HDV Summ — Biomass Fuels, FT Diesel, Wood Res" model. The emission factors are presented in unit of g/km originally, and they are converted to kg/MJ base by assuming that the fuel efficiency of heavy duty vehicle (HDV) is 40 L/100km and higher heating value of diesel is 38.65 MJ/L; ^d from [2], "Freight Emissions — Marine Liquids and Bulk Freight, Fuel oil (0.002% S), Crude oil" model. The emission factors are presented in unit of g/Tkm originally, and they are converted to kg/MJ base by assuming that the energy intensity of marine vessel is 60 KJ/Tkm. Besides, the CO₂ emission in the original model is modified to be 0 as the carbon in biofuels are biogenic

B.5 Biochar Application

Biochar produced from HTL of forest residues as a by-product is assumed to be shipped out to a hypothetic farm for soil amendment. The emissions associated with the biochar application are transportation emissions, which use the same upstream and downstream emission factors as those described in Subsection B.1 (see Table B.1 and Table B.3). Meanwhile, the application of biochar can create greenhouse gas emissions reduction credit. According to the assumption made by Roberts et al. [94], 80% of the carbon in biochar can be viewed as stable sequestered carbon. Besides, N in biochar was assumed to displace the same amount of nitrogen fertilizer, so the upstream emissions of nitrogen fertilizer can be avoided. Table B.12 tabulates the emission factors associated with the production and delivery of nitrogen fertilizer.

Pollutant	kg/tonne of wood pellet
CO_2	4.47E+00
NMOCs	1.55 E- 03
CH_4	7.80E-03
СО	7.39E-03
N_2O	2.01E-02
NO_2	1.94E-02
$\mathrm{SO}_{\mathbf{x}}$	1.89E-02
PM	3.90E-03

Table B.12: Nitrogen fertilizer production and delivery emission factors

from [48], "Nitrogen fertilizer, as N {GLO}—market for—Alloc Def, S" model

C Detail Stage-wise Emission Results

Appendix C tabulates the detail emission results associated with each life cycle stage of three studied scenarios.

C.1 Biomass Collection

Biomass Collection					
Pollutant	Fr-CIR	Bo-DBR	Wp-CIR		
CO_2	9.62E + 06	9.62E + 06	1.08E + 07		
NMOCs	3.14E + 03	3.14E + 03	3.51E + 03		
CH_4	$1.71E{+}04$	$1.71E{+}04$	1.92E + 04		
CO	3.37E + 04	3.37E + 04	3.78E + 04		
N_2O	5.40E + 02	5.40E + 02	6.04E + 02		
NO_2	7.21E + 04	7.21E + 04	8.08E + 04		
$\rm SO_x$	8.23E + 03	8.23E + 03	9.21E + 03		
PM	7.08E + 02	7.08E + 02	7.93E + 02		
CO ₂ -eq	1.02E + 07	1.02E+07	1.14E+07		

Table C.1: Emission inventory of biomass collection for each scenario (kg/yr)

C.2 Transportation

Feedstock Transportation						
Pollutant	Fr-CIR	Bo-DBR	Wp-CIR			
CO_2	1.84E + 07	$3.19E{+}06$	1.02E + 07			
NMOCs	5.44E + 03	$8.39E{+}02$	$3.13E{+}03$			
CH_4	2.72E + 04	4.84E + 03	$1.50E{+}04$			
CO	1.56E + 04	2.36E + 03	8.99E+03			
N_2O	2.28E + 03	3.43E + 02	$1.32E{+}03$			
NO_2	1.06E + 05	$1.53E{+}04$	6.17E+04			
SO_{x}	3.95E + 04	5.87E + 03	2.29E + 04			
PM	2.60E + 03	3.95E + 02	1.50E + 03			
CO ₂ -eq	1.98E + 07	3.42E + 06	1.10E + 07			

Table C.2: Emission inventory of feedstock transportation for each scenario (kg/yr)

C.3 Pre-processing

Pre-processing					
Pollutant	Fr-CIR	Bo-DBR	Wp-CIR		
CO_2	1.63E + 06	1.63E + 06	4.27E + 06		
NMOCs	2.38E + 02	2.38E + 02	4.42E + 03		
CH_4	$2.19E{+}04$	2.19E + 04	4.10E+04		
СО	4.86E+03	4.86E+03	9.84E + 04		
N_2O	2.10E + 02	2.10E + 02	2.24E + 03		
NO_2	3.42E + 03	3.42E + 03	5.35E + 04		
SO_{x}	$1.99E{+}03$	$1.99E{+}03$	7.98E + 03		
\mathbf{PM}	6.17E + 02	6.17E + 02	6.62E + 04		
CO ₂ -eq	2.24E + 06	2.24E + 06	5.96E+06		

Table C.3: Emission inventory of pre-processing for each scenario (kg/yr)

C.4 Conversion

Conversion					
Pollutant	Fr-CIR	Bo-DBR	Wp-CIR		
$\rm CO_2$	3.73E + 07	4.03E+07	3.73E + 07		
NMOCs	3.08E + 04	3.33E + 04	3.08E + 04		
CH_4	1.29E + 05	1.37E + 05	$1.29E{+}05$		
СО	2.37E + 05	2.55E + 05	2.36E + 05		
N_2O	3.16E + 03	3.42E + 03	$3.15E{+}03$		
NO_2	3.82E + 05	4.15E + 05	3.80E + 05		
SO_{x}	2.55E + 04	2.59E + 04	2.54E + 04		
PM	2.82E + 04	2.99E + 04	2.81E + 04		
CO ₂ -eq	4.15E+07	4.47E+07	4.14E+07		

Table C.4: Emission inventory of conversion for each scenario $\rm (kg/yr)$

C.5 Distribution

Pollutant	Distribution
CO ₂	1.18E+05
NMOCs	1.10E + 03
CH_4	2.35E + 02
СО	$4.53E{+}01$
N_2O	4.77E + 00
NO_2	1.06E + 02
$\rm SO_x$	$6.49E{+}01$
PM	7.28E + 00
CO ₂ -eq	1.25E+05

Table C.5: Emission inventory of distribution (kg/yr)

C.6 End Use

Pollutant	End Use
CO ₂	1.20E+06
NMOCs	6.23E + 04
CH_4	9.80E + 03
СО	1.48E + 06
N_2O	8.20E + 03
NO_2	1.54E + 06
SO_{x}	$4.19E{+}03$
PM	3.04E + 04
CO ₂ -eq	3.89E + 06

Table C.6: Emission inventory of end use(kg/yr)

D Detail Stage-wise Cost Results

The results summarized in the tables below are the detailed cost associated with each stage of HTL biofuels production, including forest residues collection, feedstock transportation and biomass to biofuels conversion. The costs of first two stages are covered in the feedstock delivered cost, while the costs of biomass to biofuels conversion consist of the capital investment and operating cost of biorefinery, oil refinery and wood pellet plant. It should be noted that the capital investment of oil refinery is not considered in this study since we assume that bio-oil is co-upgraded with crude oil in an existing oil refinery.

D.1 Feedstock Delivered Cost

	Feedstock					
Scenario	delivered cost	Chilliwack	Squamish	Powell River	Port Alberni	Total
Fr-CIR	Raw material	2.29E + 05	9.41E+04	3.64E + 05	2.14E + 05	9.01E+05
	Machinery	$2.75E{+}06$	$1.13E{+}06$	$4.37E{+}06$	$2.57E{+}06$	$1.08E{+}07$
	Transportation	4.78E + 06	$1.75E{+}06$	$1.58E{+}07$	$8.73E{+}06$	$3.10E{+}07$
Bo-DBR	Raw material	$2.29E{+}05$	$9.41E{+}04$	3.64E + 05	2.14E + 05	9.01E + 05
	Machinery	$2.75E{+}06$	$1.13E{+}06$	$4.37E{+}06$	$2.57E{+}06$	$1.08E{+}07$
	Transportation	$2.25E{+}06$	$8.93E{+}05$	4.72E + 06	$2.70E{+}06$	$1.06E{+}07$
Wp-CIR	Raw material	$2.29E{+}05$	$9.41E{+}04$	3.64E + 05	$3.21E{+}05$	$1.01E{+}06$
	Machinery	$2.75E{+}06$	$1.13E{+}06$	$4.37E{+}06$	3.86E + 06	$1.21E{+}07$
	Transportation	$3.25E{+}06$	$1.23E{+}06$	$9.10E{+}06$	7.66E + 06	$2.12E{+}07$

Table D.1: Summary of feedstock delivery cost breakdown for different scenarios (\$/yr)

D.2 Capital and Operating Costs of Biorefinery

Operation unit	Reference equipment installed cost ^a (million \$)	Reference equipment purchased cost (million \$)
Biomass handling and preparation	22.5	9.11
HTL reactor system	150.8	61.05
Wastewater treatment	22.0	8.91
Utilities	7.9	3.20

 Table D.2:
 The reference equipment installed and purchased costs of biorefinery

^a from [26], based on the plant capacity of 735 tonne bio-oil/day; The equipment installed cost is the product of the equipment purchased cost and an installation factor, which was assumed to be 2.47 as suggested by Dutta et al. [105]

	Plant capacity	Feed rate	Production rate
Biorefinery	tonne bio-oil/day	dry tonne forest residues/day	tonne bio-oil/day
Co-locate with refinery	348	$901^{\mathrm{a}}/898^{\mathrm{b}}$	331
Chilliwack	89	229	84
Squamish	36	94	34
Powell River	141	364	133
Port Alberni	82	214	78
Wood pellet plant	tonne pellet/yr	dry tonne forest residues/yr	tonne pellet/yr
Chilliwack	7.58E + 04	7.64E+04	7.20E + 04
Squamish	3.11E + 04	3.14E + 04	2.96E + 04
Powell River	1.20E + 05	1.21E + 05	1.14E + 05
Port Alberni	1.06E + 05	1.07E + 05	$1.01E{+}05$

Table D.3: Capacity, feed rate and productivity of biorefinery and wood pellet plants

^a Forest residues as feedstock for central integrated refinery; ^b Wood pellet as feedstock for central integrated refinery

Capital investment/million \$	Fr-CIR	Bo-DBR	Wp-CIR
Depreciable cost (DepC)	178.9	265.6	178.9
Total installed cost (TIC)	120.4	178.8	120.4
Total purchased equipment cost (TPEC)	48.7	72.4	48.7
Indirect cost (IC)	58.5	86.9	58.5
Engineering	15.6	23.2	15.6
Construction	16.6	24.6	16.6
Contractor fees	17.5	26.1	17.5
Contingency	8.8	13.0	8.8
Non-depreciable cost (NDepC)	7.1	10.6	7.1
Land cost	2.7	4.0	2.7
Site development	4.5	6.6	4.5
Fixed capital investment (FCI)	186	276.2	186
Star-up cost (SC)	16.7	24.9	16.7
Working capital (WC)	37.2	55.2	37.2
Total capital investment (TCI)	240	356.3	240

 Table D.4: Capital investment of biorefinery for studied scenarios

Operating cost/million $%/yr$	Fr-CIR	Bo-DBR	Wp-CIR
Variable operating cost (VOC)	48.7	29.2	24.7
Feedstock	34.8	15.3	10.8^{a}
Catalyst	10.3	10.3	10.3
Waste treatment	0.3	0.3	0.3
Utilities	3.3	3.3	3.3
Fuel	0.1	0.1	0.1
Electricity	3.1	3.1	3.1
Fixed operating cost (FOC)	13.4	23.9	13.4
Labor	1.8	4.9	1.8
Operating labor	0.8	2.1	0.8
Supervisory labor	0.2	0.4	0.2
Maintenance labor	0.9	2.4	0.9
Maintenance and supplies	4.7	7.1	4.7
Maintenance materials	3.3	5.0	3.3
Operating supplies	1.4	2.1	1.4
Property tax and insurance	5.6	8.3	5.6
Plant overhead	1.3	3.6	1.3
Total operating cost (TOC)	62.1	53.1	38.0
Biochar credit (BC)	6.47	6.48	6.47

 Table D.5:
 Operating cost of biorefinery for studied scenarios

^a The feedstock cost of Wp-CIR scenario stands for pellet transportation cost from FDP to integrated refinery

D.3 Operating Cost of Oil Refinery

Operating cost/million \$/yr	Fr-CIR	Bo-DBR	Wp-CIR
Variable operating cost (VOC)	2.1	5.5	2.1
Feedstock	0	2.7^{a}	0
Catalyst	1.5	1.7	1.5
Waste treatment	0.04	0.04	0.04
Utilities	0.6	1.1	0.6
Fuel	0	0.5	0
Electricity	0.6	0.6	0.6
Fixed operating cost (FOC)	2.6	2.6	2.6
Labor	0.5	0.5	0.5
Operating labor	0.2	0.2	0.2
Supervisory labor	0	0	0
Maintenance labor	0.2	0.2	0.2
Maintenance and supplies	0.8	0.8	0.8
Maintenance materials	0.6	0.6	0.6
Operating supplies	0.2	0.2	0.2
Property tax and insurance	1.0	1.0	1.0
Plant overhead	0.4	0.4	0.4
Total operating cost (TOC)	4.7	8.1	4.7

 Table D.6:
 Operating cost of oil refinery for studied scenarios

 $^{\rm a}$ The feeds tock cost of Bo-DBR scenario stands for bio-oil transportation cost from FDP to oil refinery

D.4 Capital and Operating Costs of Pellet Plant

Operation unit	Reference equipment purchased cost (\$) ^a	Installation factor ^b
Solid fuel burner	184545	2.1
Rotary drum dryer	566813	2.3
Drying fan	49766	2.2
Multiclone	49766	3
Hammer mill	95881	2.8
Pellet mill	510760	2.3
Pellet cooler	51050	2.7
Screen shaker	38352	2
Packaging unit	138380	2
Storage bin	38352	2
Misc. equipment	170112	2.5
Front end loader	200000	2
Fork lift	164000	2

 Table D.7:
 The reference equipment purchased cost and installation factor of wood pellet plants

 $^{\rm a}$ from [102], based on the plant capacity of 1.00E+05 tonnes wood pellet/yr; $^{\rm b}$ from [103]

Capital investment/million \$	Values/million \$
Depreciable cost (DepC)	27.2
Total installed cost (TIC)	17.6
Total purchased equipment cost (TPEC)	7.8
Indirect cost (IC)	9.6
Engineering	2.6
Construction	3.0
Contractor fees	2.6
Contingency	1.3
Non-depreciable cost (NDepC)	1.2
Land cost	0.4
Site development	0.8
Fixed capital investment (FCI)	28.4
Star-up cost (SC)	2.6
Working capital (WC)	5.7
Total capital investment (TCI)	36.6

 Table D.8: Capital investment of wood pellet plants for Wp-CIR scenario

Operating cost/million \$/yr	Values/million \$/yr
Variable operating cost (VOC)	19.9
Feedstock	17.2
Catalyst	0.0
Waste treatment	0.0
Utilities	2.7
Fuel	0.2
Electricity	2.5
Fixed operating cost (FOC)	8.6
Labor	4.1
Operating labor	2.7
Supervisory labor	0.5
Maintenance labor	0.9
Maintenance and supplies	0.7
Maintenance materials	0.5
Operating supplies	0.2
Property tax and insurance	0.9
Plant overhead	2.9
Total operating cost (TOC)	28.5

Table D.9: Operating cost of wood pellet plants for Wp-CIR scenario

E DCFROR Analysis

The tables below summarize the DCFROR analysis for each studied scenario. The unit for the values in the table is million \$/year. The MSP of biofuels from Fr-CIR, Bo-DBR and Wp-CIR scenarios is \$0.89/L, \$0.98/L and \$0.95/L, respectively.

Year		-2	-1	0	1	2	3	4	5	6	7	8	9	10
Fixed capital investment (equity)		22.33	37.21	14.88										
Debt (60% of TCI)		43.20	72.00	28.80										
Loan payment					21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49
Interest		2.81	7.67	10.04	10.04	9.30	8.50	7.66	6.76	5.80	4.79	3.70	2.54	1.31
Loan principal		43.20	118.01	154.48	143.03	130.84	117.86	104.03	89.30	73.62	56.91	39.12	20.18	0.00
Start-up				16.74										
Working capital				31.21										
Revenue														
Biofuel sales					78.03	89.17	89.17	89.17	89.17	89.17	89.17	89.17	89.17	89.17
Biochar (by-product) credit					5.67	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47
Total annual revenue					83.69	96.65	96.65	96.65	96.65	96.65	96.65	96.65	96.65	96.65
Annual operating cost														
Raw materials					32.52	34.69	34.69	34.69	34.69	34.69	34.69	34.69	34.69	34.69
HTL buffer					9.68	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Hydrotreating catalyst					1.42	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Hydrogen production catalyst					0.04	0.00	0.00	0.05	0.00	0.00	0.05	0.00	0.00	0.05
Wastewater treatment					0.28	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Utility					3.61	3.85	3.85	3.85	3.85	3.85	3.85	3.85	3.85	3.85
Fixed operating cost					16.01	16.01	16.01	16.01	16.01	16.01	16.01	16.01	16.01	16.01
Total annual operating cost					63.57	66.69	66.69	66.74	66.69	66.69	66.74	66.69	66.69	66.74
Annual depreciation														
Depreciable cost	178.91													
MACRS schedule (%)					14.29	24.49	17.49	12.49	8.93	8.92	8.93	4.46		
Depreciation					25.57	43.82	31.29	23.35	15.98	15.96	15.98	7.98		
Net revenue					-15.49	-24.16	-10.84	-1.10	6.22	7.19	8.15	17.28	26.41	27.60
Loss forwarad					0.00	-15.49	-39.65	-50.49	-51.59	-45.37	-38.18	-30.03	0.00	0.00
Taxble income					-15.49	-39.65	-50.49	-51.59	-45.37	-38.18	-30.03	-12.75	26.41	27.60
Annual income tax					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.87	7.18
Annual cash flow		-22.33	-37.21	-14.88	-1.37	7.47	7.47	7.42	7.47	7.47	7.42	7.47	0.60	0.25
Discount factor		1.21	1.10	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39
Annual present value		-27.01	-40.93	-14.88	-1.25	6.17	5.61	5.07	4.64	4.21	3.81	3.48	0.25	0.09
Net present value				0.00										

Table E.1: The DCFROR analysis spreadsheet for Fr-CIR scenario

Note: Net revenue = Total annual revenue - Total annual operating cost - Interest - Depreciation; Taxable income = Net revenue + Loss forward; Annual income tax = Taxable income \times Income tax rate; Annual cash flow = Total annual revenue - Total annual operating cost - Loan Payment - Annual income tax.

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Year	11	12	13	14	15	16	17	18	19	20
Fixed capital investment (equity)										
Debt (60% of TCI)										
Loan payment										
Interest										
Loan principal										
Start-up										
Working capital										
Revenue										
Biofuel sales	89.17	89.17	89.17	89.17	89.17	89.17	89.17	89.17	89.17	89.17
Biochar (by-product) credit	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47
Total annual revenue	96.65	96.65	96.65	96.65	96.65	96.65	96.65	96.65	96.65	96.65
Annual operating cost										
Raw materials	34.69	34.69	34.69	34.69	34.69	34.69	34.69	34.69	34.69	34.69
HTL buffer	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Hydrotreating catalyst	1.42	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Hydrogen production catalyst	0.00	0.00	0.05	0.00	0.00	0.05	0.00	0.00	0.05	0.00
Wastewater treatment	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Utility	3.61	3.85	3.85	3.85	3.85	3.85	3.85	3.85	3.85	3.85
Fixed operating cost	16.01	16.01	16.01	16.01	16.01	16.01	16.01	16.01	16.01	16.01
Total annual operating cost	66.69	66.69	66.74	66.69	66.69	66.74	66.69	66.69	66.74	66.69
Annual depreciation										
Depreciable cost										
MACRS schedule (%)										
Depreciation										
Net revenue	28.96	28.96	28.91	28.95	28.95	28.91	28.95	28.95	28.91	28.95
Loss forwarad	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxble income	28.96	28.96	28.91	28.95	28.95	28.91	28.95	28.95	28.91	28.95
Annual income tax	7.53	7.53	7.52	7.53	7.53	7.52	7.53	7.53	7.52	7.53
Annual cash flow	21.43	21.43	21.39	21.43	21.43	21.39	21.43	21.43	21.39	21.43
Discount factor	0.35	0.32	0.29	0.26	0.24	0.22	0.20	0.18	0.16	0.15
Annual present value	7.51	6.83	6.20	5.64	5.13	4.66	4.24	3.85	3.50	3.18
Net present value										

Year		-2	-1	0	1	2	3	4	5	6	7	8	9	10
Fixed capital investment (equity)		33.15	55.24	22.10										
Debt (60% of TCI)		64.14	106.90	42.76										
Loan payment					31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90
Interest		4.17	11.39	14.91	14.91	13.80	12.63	11.37	10.04	8.62	7.10	5.49	3.78	1.95
Loan principal		64.14	175.21	229.35	221.36	194.26	174.98	154.45	132.58	109.30	84.50	58.09	29.96	0.00
Start-up				24.86										
Working capital				55.24										
Revenue														
Biofuel sales					85.19	97.36	97.36	97.36	97.36	97.36	97.36	97.36	97.36	97.36
Biochar (by-product) credit					5.67	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47
Total annual revenue					90.85	103.83	103.83	103.83	103.83	103.83	103.83	103.83	103.83	103.83
Annual operating cost														
Raw materials					16.95	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08
HTL buffer					9.68	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Hydrotreating catalyst					1.54	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65
Hydrogen production catalyst					0.02	0.00	0.00	0.02	0.00	0.00	0.02	0.00	0.00	0.02
Wastewater treatment					0.28	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Utility					4.07	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35
Fixed operating cost					26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44
Total annual operating cost					58.98	61.13	61.13	61.15	61.13	61.13	61.15	61.13	61.13	61.15
Annual depreciation														
Depreciable cost	265.62													
MACRS schedule (%)					14.29	24.49	17.49	12.49	8.93	8.92	8.93	4.46		
Depreciation					37.96	65.05	46.46	33.18	23.72	23.69	23.72	11.85		
Net revenue					-20.99	-36.15	-16.38	-1.86	8.95	10.39	11.86	25.37	38.93	40.74
Loss forwarad					0.00	-20.99	-57.14	-73.52	-74.38	-66.43	-56.04	-44.18	0.00	0.00
Taxble income					-20.99	-57.14	-73.52	-75.38	-66.43	-56.04	-44.18	-18.81	39.93	40.74
Annual income tax					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.12	10.59
Annual cash flow		-33.15	-55.24	-22.10	-0.03	10.80	10.80	10.78	10.80	10.80	10.78	10.80	0.68	0.19
Discount factor		1.21	1.10	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39
Annual present value		-40.11	-60.77	-22.10	-0.02	8.93	8.11	7.37	6.71	6.20	5.53	5.04	0.29	0.07
Net present value				0.00										

 Table E.2:
 The DCFROR analysis spreadsheet for Bo-DBR scenario

Year	11	12	13	14	15	16	17	18	19	20
Fixed capital investment (equity)										
Debt (60% of TCI)										
Loan payment										
Interest										
Loan principal										
Start-up										
Working capital										
Revenue										
Biofuel sales	97.36	97.36	97.36	97.36	97.36	97.36	97.36	97.36	97.36	97.36
Biochar (by-product) credit	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47
Total annual revenue	103.83	103.83	103.83	103.83	103.83	103.83	103.83	103.83	103.83	103.83
Annual operating cost										
Raw materials	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08
HTL buffer	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Hydrotreating catalyst	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65
Hydrogen production catalyst	0.00	0.00	0.02	0.00	0.00	0.02	0.00	0.00	0.02	0.00
Wastewater treatment	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Utility	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35
Fixed operating cost	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44	26.44
Total annual operating cost	61.13	61.13	61.15	61.13	61.13	61.15	61.13	61.13	61.15	61.13
Annual depreciation										
Depreciable cost										
MACRS schedule (%)										
Depreciation										
Net revenue	42.70	42.70	42.69	42.70	42.70	42.69	42.70	42.70	42.69	42.70
Loss forwarad	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxble income	42.70	42.70	42.69	42.70	42.70	42.69	42.70	42.70	42.69	42.70
Annual income tax	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10
Annual cash flow	31.60	31.60	31.59	31.60	31.60	31.59	31.60	31.60	31.59	31.60
Discount factor	0.35	0.32	0.29	0.26	0.24	0.22	0.20	0.18	0.16	0.15
Annual present value	11.08	10.07	9.15	8.32	7.57	6.87	6.25	5.68	5.17	4.70
Net present value										

Year		-2	-1	0	1	2	3	4	5	6	7	8	9	10
Fixed capital investment (equity)		25.73	42.89	17.16										
Debt (60% of TCI)		49.79	82.99	33.20										
Loan payment					24.77	24.77	24.77	24.77	24.77	24.77	24.77	24.77	24.77	24.77
Interest		3.24	8.84	11.57	10.72	9.80	8.83	7.79	6.69	5.52	4.26	2.93	1.51	0.00
Loan principal		49.79	136.02	178.06	164.87	150.81	135.85	119.91	102.93	84.85	65.60	45.10	23.26	0.00
Start-up				19.30										
Working capital				42.89										
Revenue														
Biofuel sales					85.86	98.13	98.13	98.13	98.13	98.13	98.13	98.13	98.13	98.13
Biochar (by-product) credit					5.67	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47
Total annual revenue					91.53	104.60	104.60	104.60	104.60	104.60	104.60	104.60	104.60	104.60
Annual operating cost														
Raw materials					26.15	27.89	27.89	27.89	27.89	27.89	27.89	27.89	27.89	27.89
HTL buffer					9.68	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Hydrotreating catalyst					1.42	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Hydrogen production catalyst					0.04	0.00	0.00	0.05	0.00	0.00	0.05	0.00	0.00	0.05
Wastewater treatment					0.29	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Utility					6.14	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55
Fixed operating cost					24.56	24.56	24.56	24.56	24.56	24.56	24.56	24.56	24.56	24.56
Total annual operating cost					68.29	71.20	71.20	71.20	71.20	71.20	71.20	71.20	71.20	71.20
Annual depreciation														
Depreciable cost	206.12													
MACRS schedule (%)					14.29	24.49	17.49	12.49	8.93	8.92	8.93	4.46		
Depreciation					29.46	50.48	36.05	25.75	18.41	18.39	18.41	9.19		
Net revenue					-16.93	-26.88	-11.48	-0.14	8.30	9.50	10.73	21.27	31.89	33.40
Loss forwarad					0.00	-16.93	-43.82	-55.30	-55.44	-47.14	-37.64	-26.92	0.00	0.00
Taxble income					-16.93	-43.82	-55.30	-55.44	-47.14	-37.64	-26.92	-5.64	31.89	33.40
Annual income tax					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.29	8.68
Annual cash flow		-25.73	-42.89	-17.16	-1.53	8.63	8.63	8.63	8.63	8.63	8.63	8.63	0.34	-0.05
Discount factor		1.21	1.10	1.00	0.91	0.83	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39
Annual present value		-31.14	-47.18	-17.16	-1.39	7.13	6.48	5.89	5.36	4.87	4.43	4.03	0.14	-0.02
Net present value				0.00										

 Table E.3: The DCFROR analysis spreadsheet for Wp-CIR scenario

Year	11	12	13	14	15	16	17	18	19	20
Fixed capital investment (equity)										
Debt $(60\% \text{ of TCI})$										
Loan payment										
Interest										
Loan principal										
Start-up										
Working capital										
Revenue										
Biofuel sales	98.13	98.13	98.13	98.13	98.13	98.13	98.13	98.13	98.13	98.13
Biochar (by-product) credit	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47	6.47
Total annual revenue	104.60	104.60	104.60	104.60	104.60	104.60	104.60	104.60	104.60	104.60
Annual operating cost										
Raw materials	27.89	27.89	27.89	27.89	27.89	27.89	27.89	27.89	27.89	27.89
HTL buffer	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32
Hydrotreating catalyst	1.42	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52	1.52
Hydrogen production catalyst	0.00	0.00	0.05	0.00	0.00	0.05	0.00	0.00	0.05	0.00
Wastewater treatment	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Utility	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55	6.55
Fixed operating cost	24.56	24.56	24.56	24.56	24.56	24.56	24.56	24.56	24.56	24.56
Total annual operating cost	71.20	71.20	71.20	71.20	71.20	71.20	71.20	71.20	71.20	71.20
Annual depreciation										
Depreciable cost										
MACRS schedule (%)										
Depreciation										
Net revenue	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40
Loss forwarad	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxble income	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40
Annual income tax	8.68	8.68	8.68	8.68	8.68	8.68	8.68	8.68	8.68	8.68
Annual cash flow	24.71	24.71	24.71	24.71	24.71	24.71	24.71	24.71	24.71	24.71
Discount factor	0.35	0.32	0.29	0.26	0.24	0.22	0.20	0.18	0.16	0.15
Annual present value	8.66	7.87	7.16	6.51	5.92	5.38	4.89	4.45	4.04	3.67
Net present value										