University of Alberta

Life Cycle Assessment of Biomass Conversion Pathways

by

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A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfillment of the requirements for the degree of

Master of Science

in

Engineering Management

Department of Mechanical Engineering

Spring 2012

Edmonton, Alberta

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Abstract

This study has investigated the life cycle of three biomass feedstocks including forest residue (FR), agricultural residue (AR), and whole forest (WF) for biohydrogen and biopower production in Alberta. Three technologies are studied for biohydrogen production; these include the Battelle Columbus Laboratory (BCL) gasifier, the Gas Technology Institute (GTI) gasifier, and fast pyrolysis. The life cycle net energy ratios (NERs) for nine biohydrogen pathways lie in the range of 1.3–9.3. In contrast, the life cycle greenhouse gas (GHG) emissions lie in the range of 1.20–8.1 kg CO_{2eq}/kg H_2. This study also analyzes the intensities for acid rain precursor (ARP) and ground level ozone precursor (GOP) emissions for various biohydrogen pathways. Biomass feedstocks in various forms (chip, bale, pellet, and torrefied pellet) are analyzed for direct (DC) and parallel co-firing (PC) technology. Biomass can be co-fired with coal in the scale of 7.53−20.45%, depending on the types of feedstocks and densification technologies. FR-, WF-, and AR-based co-firing pathways demonstrate NERs in the range of 0.39−0.42, 0.39−0.41, and 0.37−0.38, respectively. On the other hand, life cycle GHG emissions for them are found in the range of 957−1004, 967−1014, and 1074−1091 kgCO_{2eq}/MWh, respectively. Like biohydrogen, life cycle ARP and GOP emissions are also evaluated for various co-firing pathways.

Acknowledgement

The author would like to express his sincere gratitude to Dr. Amit Kumar for his supervision, advice, guidance, and tireless inspiration throughout the course of this study. It was a great pleasure and learning experience working with Dr. Kumar.

The author is grateful to Mr. Susanjib Sarkar for his assistance in understanding the technical aspects of biohydrogen production and distribution in Alberta.

The author would also like to thank the members of the Sustainable Energy Research Laboratory including Arifa Sultana, G. D. Malinga Dassanayake, Arun Bhogal, and Veena Subramanyam, for their advice and support.

Lastly, the author would like to express his sincerest gratitude to his most beloved family including his parents, siblings, and wife.

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Acronyms and Abbreviations

AESO	Alberta Electric System Operator
AR	Agricultural Residue
ARP	Acid Rain Precursor
atm	Atmospheric pressure
BCL	Battelle Columbus Laboratory
CAPP	Canadian Association of Petroleum Producers
CCS	Carbon Capture and Storage
CFB	Circulating Fluidized bed
CH_4	Methane
CO_2	Carbon Dioxide
DC	Direct Co-firing
dtpd	dry tonne per day
EIA	Energy Information Administration
ERCB	Energy Resources Conservation Board
FERIC	Forest Engineering Research Institute of Canada
FR	Forest Residue
FU	Functional Unit
GHG	Greenhouse Gas
Gj	Gigajoule
GOP	Ground-level Ozone Precursor
GTI	Gas Technology Institute

ha	Hectare
HDPE	High Density Polyethylene
HHV	Higher Heating Value
hr	Hour
km	Kilometer
kW	Kilowatt
kWh	Kilowatt-hour
LCA	Life Cycle Assessment
MPa	Megapascal
N_2O	Nitrous Oxide
NER	Net Energy Ratio
NO_x	Nitrogen Oxides
NREL	National Renewable Energy Limited
PC	Parallel Co-firing
SCO	Synthetic Crude Oil
SO_2	Sulfur Dioxide
t	Tonne
TOP	Torrefied pellet
UP	Unit Process
VOC	Volatile Organic Compound
wt.%	Weight %
WF	Whole Forest

Chapter 1. Introduction

1.1. Background

Fossil fuels are one of the main sources of primary energy supply in the world. By 2035, the energy consumption in the world is expected to increase to 770 quadrillion Btu from 505 quadrillion Btu in 2008 (EIA, 2011). In 2009, the net energy supply and consumption in Canada were found to be 9832 and 7650 petajoules, respectively. In contrast, for the Province of Alberta they were found to be 2775 and 1645 petajoules, respectively, for the same year (Statistics Canada, 2011). Note that, Energy demands in Alberta and Canada are expected to reach 3200 and 11,000 petajoules, respectively, by the year of 2025 (NEB, 2003; Kumar et. al., 2011).

Utilization of fossil fuels is associated with environmental impacts. One of the key environmental impacts is emission of greenhouse gases (GHG). Energy related GHG emissions in the world and Canada are found to be 30 and 0.75 gigatonnes, respectively (IEA, 2011; Environment Canada, 2009). Alberta contributes 33.2% of Canada's total GHG emissions (Environment Canada, 2009). Power generation sector and fossil fuel industries (petroleum refining and upgrading) in Alberta are responsible for most of the emissions from the Province, 55 and 17%, respectively. In addition to the GHG, acid rain precursor (ARP) and ground level ozone precursor (GOP) emission levels of these two

sectors are high as well since they consume coal and natural gas in abundance (Environment Canada, 2009).

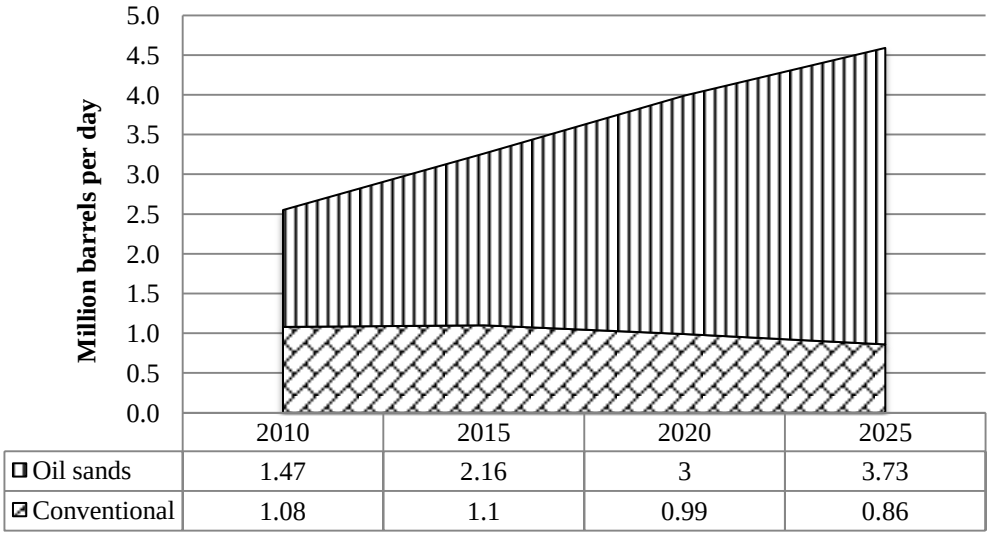
Energy production from renewable sources involves lower environmental impacts. Renewable share in the world's total energy use will rise from 10% in 2008 to 14% in 2035, which makes the renewable energy to be the fastest growing form of energy in the world (EIA, 2011). There are various sources of renewable energy such as biomass, geothermal, hydro, solar, wind, etc. Among these, biomass is the only energy-containing renewable carbon resource that can replace fossil fuels for conversion to liquid, gaseous, and solid fuels (Balat and Ayar, 2005). Biomass supplies 14% of the world's total primary energy demand, while in developing countries it accounts for 35% of the total primary energy demand (Balat and Ayar, 2005). In contrast, biomass contributes 6 and 2.5% to the primary energy demand in Canada and Alberta, respectively (Kumar et al., 2011; Bradley, 2006).

Energy content of the annual biomass harvest in Canada is equivalent to 62% of the fossil fuel energy consumed in Canada (Wood and Layzell, 2003). Residual forestry and agricultural biomass can substitute 18−27% of the current fossil fuel energy demand in the country (Wood and Layzell, 2003). Every year, Alberta produces a large quantity of forestry (3.29 million dry tonne) and agricultural (6.8, 6.3, and 0.72 million dry tonne of wheat, barley, and oat straw, respectively) residue biomass (Kabir and Kumar, 2011). This massive biomass pool can be

utilized to produce energy and minimize the environmental emissions in the Province. This study aimed at integration of biomass-based energy and products with the Alberta's fossil fuel based power, oil and gas sector to minimize the environmental impacts.

1.1.1. Growth of the oil sand industry and hydrogen demand in Alberta

Alberta is ranked second only to Saudi Arabia in world's oil reserves. Bitumen contained in the oil sands is the main source of this reserve (Government of Alberta, 2008). The estimated crude bitumen and crude oil reserve in Alberta are 169 and 1.5 billion barrels, respectively (ERCB, 2011). Figure 1-1 presents a forecast of crude bitumen and crude oil production in Alberta (CAPP, 2011). As suggested by Figure 1-1, there is an increasing trend of crude bitumen production in Alberta, while for the conventional crude oil the trend is decreasing. In 2010, crude bitumen production was 1.5 million barrels/day, which is likely to increase up to 3.7 million barrels/day by 2025.



	2010	2015	2020	2025
Oil sands	1.47	2.16	3	3.73
Conventional	1.08	1.1	0.99	0.86

Figure 1- 1: Conventional and crude oil production forecast for Alberta [adapted from (CAPP, 2011)]

Bitumen upgrading requires significant amount of hydrogen. Each barrel of bitumen requires 3−5 kg of hydrogen for upgrading. Hydrogen requirement for the bitumen-upgrading industry of Alberta is enormous (Ordorica-Garcia et al., 2007). Based on the projected growth of oil sand industries in Alberta, hydrogen requirement is likely to reach 5.5 million tonnes/year by 2025 from 2.2 million tonnes/year in 2010 (CAPP, 2011; Ordorica-Garcia et al., 2007).

Hydrogen production from natural gas and coal is associated with massive environmental impacts. Hydrogen production is solely responsible for 28% of the total GHG emissions from the oil sands industry (Ordorica-Garcia et al., 2007). Detrimental effects on the environment due to production of hydrogen from fossil

fuels are not limited to GHG, ARP and GOP emissions are also significant environmental concerns.

GHG emissions from the oil sands industry can be considerably reduced when biomass resources are used for hydrogen production. However, the extent of reduction has not been assessed in detail for the Province of Alberta. There has been very limited focus on assessment of environmental impacts of using a range of biomass feedstocks for the production of hydrogen. This research is an effort to address these gaps.

1.1.2. Growth of the power generation sector in Alberta

Alberta generates only 11% of the total electricity in Canada, but it emits 42% of the total electricity-related GHG emissions (Environment Canada, 2009). This is mainly because of the extensive use of coal (82%) for power generation in Alberta. ARP and GOP emissions are also high for the same reason. Figure 1-2 shows the projected electricity demand for the Province (AESO, 2010).

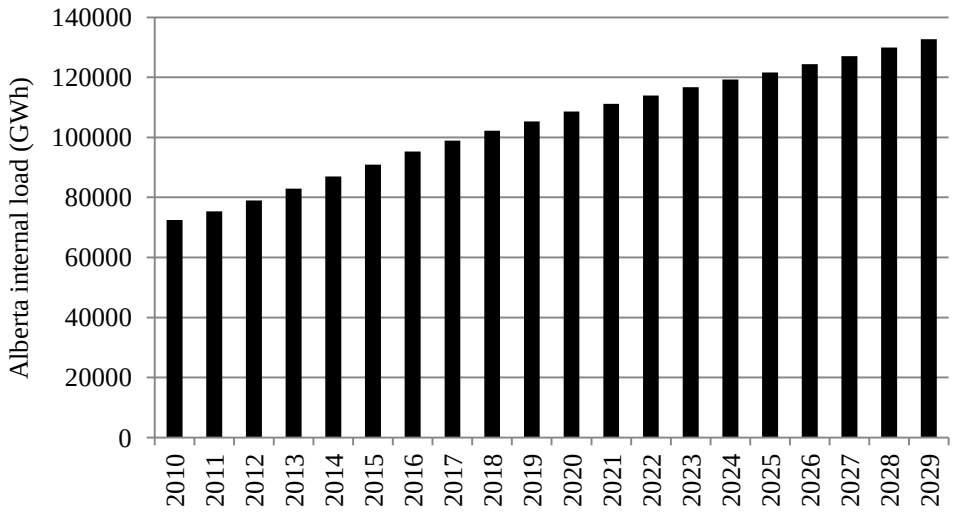


Figure 1- 2: Forecast of Alberta's electricity demand [adapted from (AESO, 2010)]

Biomass based power in Alberta is not economical compared to coal (Kumar et al., 2003). Biomass co-firing could be an option that can be implemented in the existing coal-fired power plant with minor plant retrofitting and can result in reduced emissions. Co-firing could be an attractive option for integrating biomass in the fuel mix for power generation (James, 2009). In order to optimize the economical and environmental aspects of co-firing, biomass must be densified. Biomass is a dispersed resource that has low bulk and energy density. Densification process improves the volumetric energy density of biomass (Sultana et. al., 2010). It also improves the storing, shipping, and conversion efficiency. Densification may improve the durability, grindability, hydrophobicity, and combustion nature of biomass as well (Bergman, 2005). Thus, densification makes biomass handling easier and saves transport and handling cost, energy, and

emission. Though most of the life cycle studies have paid attention to GHG emissions, ARP and GOP emissions are yet to be scrutinized for biomass co-firing pathways. Very limited literatures have evaluated the life cycle of co-firing power generation pathways for a range of biomass densification technologies. This study has made an effort to explore these unknowns.

1.2. Life cycle assessment

Life cycle assessment (LCA) is the collection and assessment of the inputs, outputs and the prospective environmental impacts of a product system from its very inception to the final disposal. The framework of LCA is depicted in Figure 1-3 (ISO, 2006). For any LCA study, the first and foremost step is to clearly articulate the goal and scope followed by inventory analysis and environmental impact assessment. The interpretation phase of the LCA conveys the results that are in coherence with the defined goal and scope. The results of the LCA study play a major role in decision-making process including product development, public-policy making, marketing, etc. (ISO, 2006).

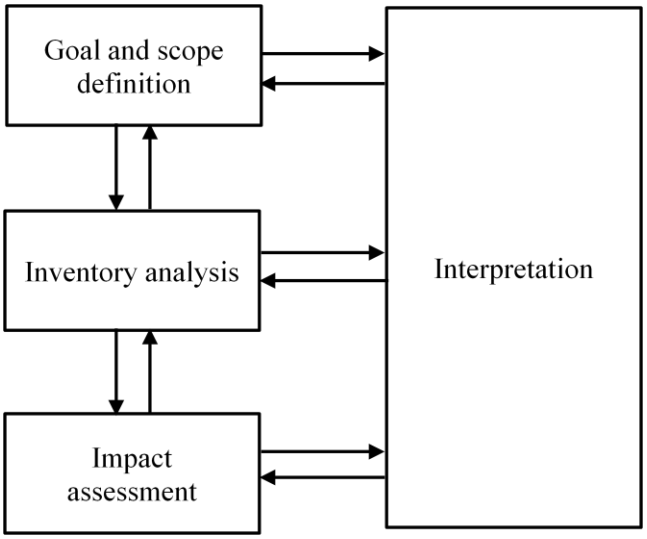


Figure 1- 3: LCA framework [adapted from (ISO, 2006)]

1.3. The objectives of this thesis

The overall objective of this study is to conduct life cycle assessment of biohydrogen production and co-firing of biomass with coal for power generation. The specific objectives are outlined below.

- Identify and analyze various biohydrogen production pathways.
- Quantify the life-cycle GHG, ARP, and GOP emissions from the biohydrogen production pathways.
- Evaluate the net energy ratio for all the biohydrogen production pathways.

- Compare the life cycle assessment of biohydrogen with the fossil-fuel-based hydrogen.
- Identify and characterize the biopower generation pathways.
- Assess different pathways of biomass densification and co-firing.
- Assess the life-cycle GHG, ARP, and GOP emissions from the biopower generation pathways.
- Quantify the net energy ratio for all the biopower generation pathways.
- Estimate the real energy and environmental benefits of co-firing-based biopower generation in contrast to the coal-based power.

This work has looked into three biomass feedstocks including whole forest (WF), forest residue (FR), and agricultural residue (AR). The methodology of the life cycle study is explained in the subsequent chapters.

1.4. Scope and limitations of this thesis

While considering biohydrogen production only thermo-chemical conversion pathways (gasification and fast pyrolysis) are considered. However, conversion pathways including biochemical and fermentation are disregarded. While investigating the biopower pathways, energy and environmental implications related to the grid connection, power transmission and distribution are not considered.

This study has only assessed biomass feedstocks including WF, FR, and AR. Life cycle results obtained from this study are well applicable for other jurisdictions. However, the inventory data and life cycle results should be modified accordingly to ensure the conformity of these results with other geographic regions. This study does not consider environmental issues like land use change, forest carbon, eco-toxicity, noise/soil pollution, and organic/inorganic respiration. Scope and limitations of this study are further discussed in Chapters 2 and 3.

1.5. Organization of thesis

This thesis is organized into four chapters and is in paper format. Each chapter is intended to be read independently. Therefore, some of the assumptions and data are presented at more than one occasion.

Chapter 2 details the life cycle assessment of biohydrogen production and distribution to a bitumen upgrading facility of Alberta from a range of biomass feedstocks and conversion pathways. In addition to the environmental emissions, this chapter also quantifies the net energy ratio for biohydrogen.

Chapter 3 presents the life cycle assessment of biopower generation through co-firing in an existing coal-fired power plant of Alberta. This chapter offers a

comparative life cycle assessment study of different biomass densification and co-firing technologies for biopower. Like chapter 2, this chapter has evaluated the net energy ratio and environmental emissions for all the biopower pathways.

Chapter 4 discusses the findings of this study and presents some recommendations for future work.

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Chapter 2. Development of net energy ratio and emission factor for biohydrogen production pathways*

2.1. Introduction

With the focus today on the development of renewable fuels and chemicals, there is a lot of interest in the utilization of biomass feedstock for producing these fuels and chemicals. Lignocellulosic biomass, including agricultural residue (i.e. straw, corn stover), forest residue (branches and tops of the trees), whole tree, and energy crops can be used to produce a range of fuels and chemicals. One of the important fuels which can be produced from biomass is hydrogen, also called biohydrogen (Sarkar and Kumar, 2009). There are several studies available in the literature on producing biohydrogen from lignocellulosic biomass (Spath et al., 2005; Larson et al., 2005, Sarkar and Kumar, 2010a; 2010b). These are discussed later in this paper.

The Western Canadian sedimentary basins of Alberta hold the world's largest natural reservoir of bitumen. This Province is experiencing an enormous growth in the oil sands industry. Oil sands are used to produce bitumen which is further modified to make petroleum products. Currently, the fossil fuel industries of

*A version of this chapter has been published. Kabir, M.R. and Kumar, A. 2011. Development of net energy ratio and emission for biohydoregn production pathways. Bioresource Technology 102 (19): 8972-8985.

Alberta (mainly petroleum refining and upgrading) of Alberta account for 17% of the overall greenhouse gas (GHG) emissions from the Province; this is the second largest share after the power generation sector (55%). Note that, GHG emissions from fossil fuel industries of Alberta correspond to about 6% of Canada's total GHG emissions (Environment Canada, 2009). The cumulative GHG emissions from the oil sands industry in Alberta increased from 16.8 to 37.2 megatonnes of CO_{2eq} between 1990 and 2008 (Droitsch et al., 2010). Based on the projected growth of the oil sands industry in Alberta, by 2020 the emissions will be three times higher than the level for 2008 (Droitsch et al., 2010). The bitumen extracted from oil sand needs to be upgraded to synthetic crude oil. In 2009, crude bitumen production in Alberta totaled 1.5 million barrels/day, which is likely to increase to 3.2 million barrels/day by 2019 (ERCB, 2010). To upgrade each barrel of bitumen, 3−5 kg of hydrogen is essential (Ordorica-Garcia et al., 2007); therefore, the hydrogen requirement for the bitumen-upgrading industry of Alberta is enormous. Natural gas and coal are the primary sources of the hydrogen produced. Since these fossil fuels have a large carbon footprint, the production of hydrogen is solely responsible for 28% of the total GHG emissions from the oil sands industry in Alberta (Ordorica-Garcia et al., 2007). By 2030, the demand for hydrogen for bitumen upgrading is expected to increase to six times that for the base year (2003); therefore, it is necessary to mitigate the overall GHG emissions from the oil sands industry. This can be done by replacing fossil fuels with hydrogen produced from renewable biomass sources. Note that, using biohydrogen in bitumen upgrading is a regional interest of Alberta. This study

assesses the biohydrogen production pathways for their possible application in a bitumen-upgrading plant. In addition to its use in bitumen upgrading, biohydrogen can be used in the transportation sector and the food, petrochemical, and manufacturing industries. The results of this study could be used in other jurisdictions for application in the areas mentioned above.

Alberta has a large amount of forest residue (3.29 million dry tonnes per year) (Sarkar and Kumar, 2010a) and agricultural residue (6.8, 6.3, and 0.72 million tonnes of wheat, barley, and oat straw per year, respectively) (Sultana et al., 2010) that can be allocated entirely to hydrogen production. Forest harvest residue (FR) refers to the limbs, tops and branches left behind by logging operations. In Alberta more than 90% of all logging operations involve cutting the tree in the stand, skidding it to the roadside, and delimbing tops and branches from the tree on the roadside. The stem is used or it is chipped and transported to a plant. The delimbed tops and branches are then piled up and burnt to prevent forest fires. This residue is a large potential source of biohydrogen (Sarkar and Kumar, 2010a). Agricultural residues (AR) are mainly wheat and barley straw. Most are left in the field to rot and this releases carbon back into the atmosphere. Whole forest (WF) biomass, i.e. whole tree, is used in Alberta for pulp and lumber. As the demand for paper decreases, pulp mills close. In Alberta this provides an opportunity to integrate the forest industry with the hydrocarbon industry. Utilizing different forest resources for purposes other than pulp and lumber has been discussed in early studies by the authors (Kumar et al., 2003; Sarkar and

Kumar, 2009; 2010a). These biomass resources can be used to produce biohydrogen.

The different biomass sources can be directly gasified to produce hydrogen (Sarkar and Kumar, 2010a). Large scale production of hydrogen from biomass using the Battelle Columbus Laboratory (BCL) gasifier and the Gas Technology Institute (GTI) gasifier are two key technologies which have been demonstrated (Spath et al., 2005; Larson et al., 2005) and studied in detail. The techno-economic assessment of employing these technologies to produce biohydrogen in Alberta through direct gasification of WF, FR and AR employing these technologies was studied earlier (Sarkar and Kumar, 2009; 2010a). Biomass is a dispersed resource that has low bulk and energy density, resulting in high transportation cost. To increase energy density, biomass for biohydrogen production can be converted into bio-oil by fast pyrolysis. This bio-oil can later be gasified and steam-reformed to produce biohydrogen. The techno-economical feasibility of this pathway of hydrogen production for Alberta was also studied earlier by Sarkar and Kumar (2010b). They found that, even at the economic optimum plant size, the cost of producing hydrogen from biomass is significantly higher than the cost of producing it from natural gas/coal. Biohydrogen could be competitive with natural-gas/coal-based hydrogen given carbon credits. Hence, GHG mitigation provides key motivation for the development of biomass-based hydrogen.

GHG is not the only detrimental effect on the environment due to producing hydrogen from coal and natural gas; acid rain precursor (ARP) and ground level ozone precursor (GOP) are also significant environmental concerns (Spath and Mann, 2001; Koroneos et al., 2004 ; Koroneos et al., 2005). It is very important to estimate the environmental benefits achievable if fossil fuels are replaced with biomass for hydrogen production. The most appropriate and widely-accepted methodology for environmental-impact accounting is life cycle assessment (LCA). LCA evaluates the environmental impact from any product or system throughout its life cycle, starting with raw material production and acquisition and ending with disposal. Like environmental impact analysis, energy output−input ratio i.e. net energy ratio (NER) is also critical. Evaluating the life cycle NER for renewable systems helps with understanding the effectiveness of a particular system compared to other renewable and fossil-fuel-based systems.

The objective of this study is to quantify environmental impact in terms of emissions and NERs for different biohydrogen production pathways. This study includes biohydrogen production from three biomass sources: FR, AR and WF biomass. Three different technologies for producing biohydrogen are analyzed: BCL, GTI, and pyrolysis process. These technologies are described in subsequent sections. Nine biohydrogen production pathways are compared from a life-cycle energy-and-emissions perspective. The application targeted by this biohydrogen is bitumen upgrading. The environmental stressors considered in this study are: GHG emissions (CO_{2eq}), ARP (SO_{2eq}) and GOP (NO_x + VOC). There are few

studies which do comparative analyses of different biomass feedstock conversion pathways for hydrogen production. There are some LCA studies available for producing hydrogen from different renewable resources (Koroneos et al., 2004; Koroneos, et al., 2008), but none of these studies investigate different biomass conversion technologies for producing hydrogen from different biomass feedstocks. This research work performs LCA for hydrogen production using the optimum plant size for each conversion pathway that was determined earlier by the authors (Sarkar and Kumar, 2009; 2010a; 2010b).

2.1.1. Biohydrogen production pathways

Nine different biomass conversion pathways have been considered in this study. Figure 2-1 shows the different conversion pathways.

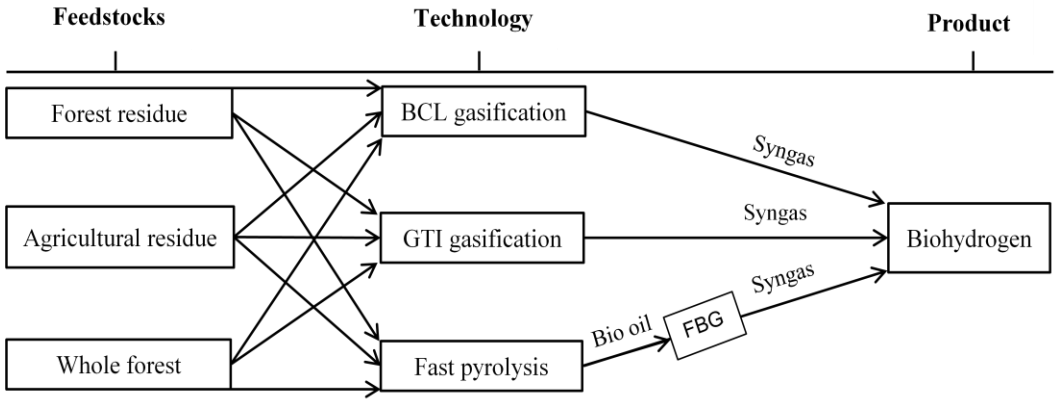

Figure 2-1: Biomass conversion pathways to hydrogen

Biomass is gasified at approximately atmospheric pressure (~0.16 MPa) in a BCL gasifier (Sarkar and Kumar, 2010a). In contrast, the GTI gasifier operates at a higher pressure (~3.45 MPa) to gasify the biomass (Sarkar and Kumar; 2010a). Syngas produced from biomass is purified and then undergoes a water−gas shift reaction that produces hydrogen. Details of the two biomass gasification technologies and the production of biohydrogen using these technologies were given in earlier studies (Sarkar and Kumar, 2010a; Spath et al., 2005; Larson et al., 2005). During fast pyrolysis, biomass is rapidly heated in the absence of air, it vaporizes and the organic vapors are rapidly quenched so they condense to a dark viscous liquid called bio-oil (Bridgwater and Peacocke, 2000; Sarkar and Kumar, 2010b). This bio-oil is gasified in a fluidized bed reactor (FBR) to produce syngas which is then steam reformed in the presence of noble catalysts to produce biohydrogen. Details on this pathway for the production of biohydrogen are given in Sarkar and Kumar (2010b).

This research investigates the life cycle NERs and the environmental impact of all the pathways (Figure 2-1) at their respective optimum plant size. It is important to note that, optimum plant sizes are specific to location, feedstock and technology. The optimum size for each biohydrogen production plant has been derived from earlier studies by the authors for the different feedstocks available in this region. The optimum biohydrogen plant capacity for BCL pathways is 3000 dry tonnes per day (dtpd) for all three feedstocks (AR, WF, and FR) for Alberta (Sarkar and Kumar, 2009; 2010a). The capacity of each BCL gasifier unit is assumed to be

1000 dtpd (Sarkar and Kumar, 2009; 2010a; Spath et al., 2005). Optimum plant capacity for GTI pathways are 3000, 4000, and 3000 dtpd for AR, WF, and FR feedstock, respectively (Sarkar and Kumar, 2010a). The capacity of each GTI gasifier unit is assumed to be 2000 dtpd (Larson et al., 2005; Sarkar and Kumar, 2010a). Optimum plant capacity for the pyrolysis pathways is 2000 dtpd for all three feedstocks (Sarkar and Kumar, 2010b). The capacity of each pyrolysis reactor is assumed to be 1000 dtpd (Sarkar and Kumar, 2010b). The methodology of this study is further described in the following sections.

2.2. Methodology

Each of the biohydrogen production pathways is analyzed as a combination of several unit operations. Material, equipment, and fuel-embodied energy and emissions factors are determined for each of the unit operations involved in a conversion pathway over its life cycle. The energy and emissions associated with each of the unit operations are investigated in detail. Their impact is normalized corresponding to a common reference unit, which is called the functional unit (FU). FUs are crucial to any LCA study; they ensure the obtained LCA results are comparable. The FU chosen for this study is 1 kg H_2 upon delivery to a bitumen-upgrading plant. This study considers all the system's energy input to be derived for primary fossil fuel. This study evaluates the NERs for all biohydrogen production pathways, a crucial ratio for the assessment of renewable systems. The NERs for the pathways are calculated using Equation 2.1.

$$NER = \sum E_{out} / \sum E_{in} \quad (2.1)$$

where, $\sum E_{in}$= life cycle non-renewable primary energy input corresponding to the FU of a pathway, and $\sum E_{out}$= energy available from the FU equivalent biohydrogen produced from the pathway. Note that, this study is based on the higher heating value (HHV) for fuels. Three environmental stressors i.e. net GHG emissions, ARP, and GOP for a particular conversion pathway are calculated using Equation 2.2.

$$Net\ emission = \sum \varepsilon_{out} \quad (2.2)$$

where, $\sum \varepsilon_{out}$= Life cycle emissions corresponding to the FU of a pathway within the defined system boundary (Figure 2-2). GHG stressors are considered to be mainly carbon dioxide (CO_2), carbon monoxide (CO), methane (CH_4), and nitrous oxide (N_2O). GHGs contribute to global warming. The global warming potential (CO_{2eq}) for these gases are assumed to be 1, 3, 21, and 310 respectively. Note that, these factors are based on a 100 year time horizon. In contrast, sulfur dioxide (SO_2) and nitrogen oxide (NO_x) are assumed to be the main ARPs. These compounds are responsible for acidification i.e. proton expulsion in the earthbound/aquatic ecosystem. With regard to ARP intensity, the weighting factor (SO_{2eq}) is assumed to be 1 and 0.7 for SO_2 and NO_x, respectively. NO_x and volatile organic compounds (VOC) are the main GOPs. The weighting factor (NO_x + VOC) is assumed to be 1 for both these compounds. Ground level ozone

is a secondary form of pollutant which occurs due to chemical reaction between NO_x and VOC in the presence of sunlight. Environmental stressors like land use, noise pollution, and organic and inorganic respiration are beyond the scope of this study and, hence, not considered.

The life cycle of all the pathways has four common unit processes: biomass production (UP 1), biomass transportation (UP 2), plant construction, decommissioning and disposal (UP 3), and plant operation and maintenance (UP 4). BCL and GTI pathways have hydrogen transport (UP 5) as the additional unit process. On the other hand, pyrolysis-based pathways have bio-oil transport by truck (UP 6)/pipeline (UP 7) as the additional unit process. Pyrolysis pathways involving UP 6 and UP 7 are denoted by pyrolysis I (P I) and pyrolysis II (P II), respectively, throughout the rest of this study. Figure 2-2 shows the detailed system boundary for each of the pathways.

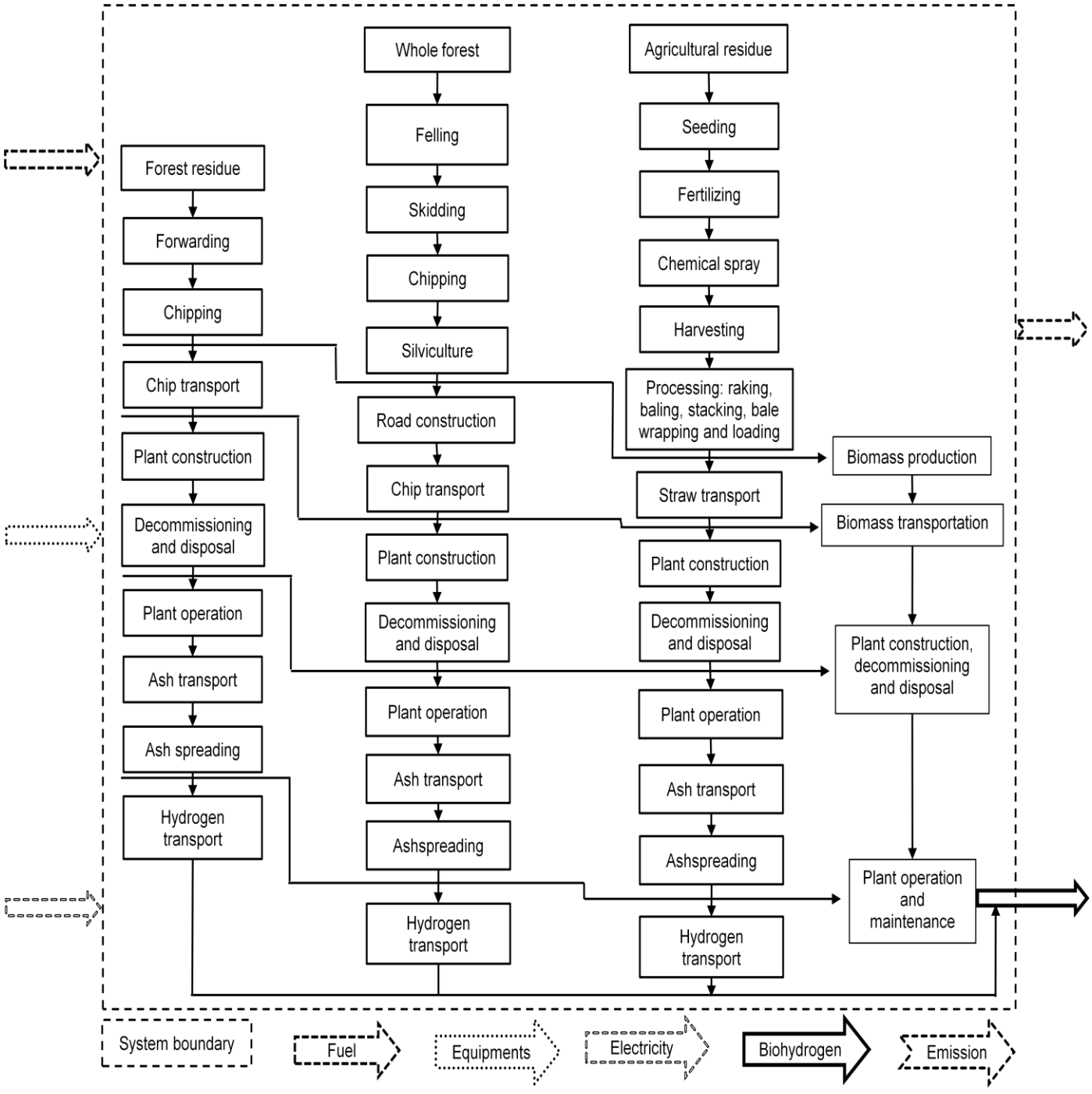

Figure 2-2: System boundary for biohydrogen production pathways

One of the differences between the system boundaries for the pyrolysis pathway compared to the BCL and GTI pathways is an additional unit operation for plant construction that is required for the fast pyrolysis of biomass feedstock. The bio-oil produced by fast pyrolysis plants is transported to a bitumen-upgrading plant for biohydrogen production. In contrast, BCL and GTI technologies produce biohydrogen directly from biomass, and later transport it for bitumen upgrading. The scope of each unit process is explained in the following sub-sections.

2.2.1. Scope and assumptions of unit processes

2.2.1.1. Biomass production

FR refers to limbs, tops, and branches left in the forest during logging operations. The current practice in Alberta is to cut trees in the stand, skid the trees to the roadside, delimb them on the roadside, and take the stem for pulp and lumber operations. Residues left in the forest are the feedstock targeted by biohydrogen plants (Kumar et al., 2003; Sarkar and Kumar, 2010a; 2010b). This unit process involves the impact of energy and emissions related to manufacturing the forwarder and chipper, their operations, and their disposal at the end of their life. The chipper required for FR is different than that required for WF biomass, and the chipping operation is less efficient for the former (Kumar et al., 2003). As a result different chippers are considered for processing FR and WF biomass. Silviculture unit operation (replanting and nutrient replacement) is not included for producing FR-based biohydrogen. Detailed product and machinery

descriptions for producing FR and the associated unit operations are given in the Table A-1 of appendix A.

Producing whole forest biomass requires unit operations which are different from those for FR. Producing WF includes chipping, felling and skidding as unit operations. Impact due to the manufacturing and disposal of the equipment (feller, skidder, chipper) is also considered. For WF biomass, the impact from silviculture operations includes fertilizer and pesticide spraying, and fuel and machinery used for different unit operations; these are included in the base case. All the nutrients (Nitrogen - N, Phosphorous - P and Potassium - K) removed by the harvesting of WF feedstock is replaced. Impact is evaluated based on the product life cycle (i.e. energy and emissions during production of the fertilizer (N, P, K) and the pesticide including the distribution) (Kim and Dale, 2004; Borjesson, 1996a). The effect of calcium replacement is ignored, however, because it is available in profuse amounts in the Western Canadian boreal forest (Kumar et al., 2003). A sensitivity case for WF biomass has been developed excluding the impact of silviculture. Details on the products and machinery involved in the utilization of WF biomass are given in the Table A-1 of appendix A.

The unit operations involved in producing AR are cultivation, fertilization, chemical application, harvesting, and straw processing (including raking, baling, stacking, bale wrapping and loading). All of these unit operations are considered in the base case. The straw-to-grain ratio is assumed to be 1.1:1 on the basis of its

mass fraction (Kumar et al., 2003). Accordingly, a portion of the impact from common operations for straw and grain (from cultivation to harvesting) is allocated to straw. Once again, impact is analyzed over the life cycle of fuels and equipments. Products and machinery are described in the Table A-1 of appendix A. A sensitivity case for agricultural residue has been developed that excludes the farming operations i.e. cultivation, fertilization, and chemical application. This case considers agricultural residue as waste, i.e. as having no economic value.

2.2.1.2. Biomass transportation

This study assumes that FR is chipped at roadside and the chips are hauled using the existing road network, hence, road construction is not included for FR chip transportation. This assumption is valid for agricultural residue bale transportation as well. In contrast, the impact from road construction is included for WF biomass in the base case. It is assumed that both WF- and FR-based chips are transported in large capacity trailer trucks. B-train chip trucks would be more appropriate for chip transport because they have a higher payload, but steep and low class logging roads act as a hindrance to the use of B-train chip trucks, making the trailer truck the only option for chip transport (MacDonald, 2006). It is assumed that similar trailer trucks are used to transport straw bales. For all feedstocks, the impact of truck manufacturing, operation and disposal is included. Products and machinery for all the unit operations related to biomass transportation are described in Section 2.2.2.5.

2.2.1.3. Plant construction, decommissioning and disposal

As stated earlier, six out of the nine pathways (BCL and GTI) require the construction of only one plant to gasify biomass and then produce biohydrogen by reforming syngas. The other three pathways require the construction of a fast pyrolysis plant in addition to a biohydrogen production plant for reforming bio-oil. The life of a plant is assumed to be 20 years in all cases. The construction material required for the different plants is estimated using data given in earlier studies (Spath and Mann, 2001; Mann and Spath, 1997). Scale factors are assumed to be 0.76, 0.68, 0.78 and 0.70, respectively, for BCL, GTI, pyrolysis and bio-oil reforming plants, and are based on detailed analyses reported in earlier studies (Sarkar and Kumar, 2010a; 2010b). Scale factor is defined by Equation 2.3 (Moore, 1959). Note that, material-embodied energy and emissions are considered over their life cycle.

$$C_i/C_o = (S_i/S_o)^n \qquad (2.3)$$

where, C_i, C_o= cost at size i and at reference (o) units, respectively. S_i, S_o= size or rating of the corresponding units, and n is the scale factor. Note that the cost is a function of the amount of material used in a unit. In turn, cost is a function of a unit's volume/surface area (Moore, 1959). Thus, scale factor leads to the proposition of economies of scale (the advantage of size), and material ingestion in any equipment/unit/plant can be determined by Equation 2.3 from given reference equipment/unit/plant data if the corresponding scale factor is known

(Moore, 1959). For example, to build a BCL plant with a capacity of 133,125 kg H_2/day (S_o) the required amount of concrete is 10,242 tonnes (C_o) (Spath and Mann, 2001). For the same plant, the scale factor (n) is 0.76 (Sarkar and Kumar, 2010a), therefore, the concrete requirement (this study: C_i) for a BCL plant with a capacity of 250,200 kg H_2/day (this study: S_i) was estimated using Equation 2.3. Likewise, the raw materials required for other pathways were estimated.

Keeping the issue of weather in mind, when roads are impassable 2 weeks of feedstock storage at the plant is considered (Kumar et al., 2003). Studies show that because stored biomass decomposes, GHG emissions may become significant if it is stored for a long period (Wihersaari, 2005). Since this study assumes the conversion of biomass is GHG-neutral and that storage is for a short time, the impact of these unit operations is ignored.

It is difficult to determine the impact from plant decommissioning because there is little reliable data, however, it is reasonable to assume that the impact from decommissioning a biomass-based plant is 3% of the plant construction (Elsayed and Mortimer, 2001). This unit process includes the cost of disposing of the construction materials. It is assumed that all the concrete and aluminum is landfilled whereas, 25% of the steel is landfilled and the rest is recycled (Spath et al., 2005; Spath and Mann, 2001). It is assumed that landfilling requires 50 km of transport using a truck similar to those used to transport biomass. Emissions related to landfilling, and to manufacturing and operating the landfilling truck are

also included in this LCA. Input data for this unit process are given in Section 2.2.2.6.

2.2.1.4. Plant operation and maintenance

This unit process includes impact of feedstock preparation (drying, comminution, etc.), utilities (mainly natural gas and electricity) required in biomass conversion plants, and ash disposal. Feedstock drying is mandatory for all pathways. Before feeding into the respective reactors, the moisture content of the feedstock should be reduced to 12%, 12% and 10%, respectively, for the BCL, GTI and fast pyrolysis pathways (Spath et al., 2005; Larson et al., 2005; Bridgwater and Peacocke, 2000). Feedstock particle size is not a major concern for the BCL and GTI pathways, therefore, it is assumed that, no further size reduction is required after chipping FR and WF biomass or shredding agricultural residue. Note that, chipping is included as a unit operation in biomass production. Shredding is also included as a unit operation in plant operation and maintenance because it is done after straw is delivered to the plant in the form of bales. To ensure rapid heat transfer during pyrolysis particles should be smaller than 3 mm (Bridgwater and Peacocke, 2000), therefore, it is necessary to drying chips and straw. The impact of all these feedstock pretreatment processes is included in the analysis.

When biohydrogen is produced from FR and WF biomass using a BCL gasifier, a portion of the total plant electricity required can be supplied from electricity that the plant produces itself. Purchasing electricity from the grid is unnecessary when

agricultural residue is converted into hydrogen by a BCL gasifier because the plant generates sufficient electricity for its operation (Spath et al., 2005). There is a potential for generating excess electricity from the plant which can be sold to the grid (Spath et al., 2005), but this scenario is not considered in this LCA study. Purchasing natural gas is required for all the BCL pathways even though steam is generated from waste heat and feedstock is dried using flue gases from the char combustor (Spath et al., 2005). The overall energy requirement for the BCL pathway is estimated based on a plant's energy balance. It is assumed that ash produced by the plant is disposed of 50 km away from the plant, as a complementary nutrient-replacement operation. Ash is transported by trucks used for biomass transport. Ash is spread at a rate of 1 tonne/ha using a commercial spreader (Kumar et al., 2003; Spath et al., 2005). The energy and emissions impact of disposal includes the manufacture, operation, and disposal of the truck and spreader. All are included in this LCA.

In the case of GTI pathways, the electricity produced by the plant is enough to support the feedstock pretreatment processes and other plant operations (Larson et al., 2005). Once again, credits from selling extra electricity to the grid are not considered. In addition, natural gas need not be purchased for these pathways (Larson et al., 2005). So, for GTI pathways ash disposal is the only plant operation that needs to be accounted for. Assumptions related to ash disposal are the same as these for the BCL pathways.

Neither electricity nor any fossil fuel is required to operate a biomass-based large scale fast pyrolysis plant (Ringer et al., 2006). The biomass can be dried using heat generated from the combustion of char produced by the process. Also, heat for the pyrolysis reaction can be produced by re-circulating the non-condensable exhaust gas produced during pyrolysis (Ringer et al., 2006). Assumptions regarding ash disposal are stated above. Because, bio-oil is not stable at room temperature, 10 wt.% methanol is added to it to keep its properties uniform (Sarkar and Kumar, 2010b). The impact of adding methanol is included in the analysis. Inventory data for methanol production have been taken over the life cycle of methanol. A bio-oil and methanol blend is transported to a bitumen upgrader where the bio-oil is steam-reformed to biohydrogen. Note that, though bio-oil reforming is an endothermic process, water−gas shift reaction is an exothermic one (Spath and Mann, 2001; Sarkar and Kumar, 2010b), therefore, more steam can be produced from the exhaust of the water−gas shift reaction than was required as input for it. There is, therefore, no need for natural gas to generate steam for the water−gas shift reaction. Although this is excluded from the analysis, natural gas is required to produce steam to reform bio-oil. This steam, however, can be delivered using the existing cogeneration facility of the bitumen upgrading plant. In addition, the electricity required for running the plant equipment can be easily be produced by the cogeneration facility (Sarkar and Kumar, 2010b; Spath and Mann, 2001). Thus, in the base case it is assumed that, grid electricity and natural gas are not required to operate the reforming plant, however, diversion of thermal and electrical energy from the existing

cogeneration facility of an upgrading plant to the bio-oil reforming plant may affect the overall life cycle of the pyrolysis pathways of biohydrogen production. For this reason, a sensitivity case (Table 2-6: case 4) has been developed which assumes that the thermal and electrical energy required for the bio-oil reforming plant are not provided by the cogeneration plant. The natural gas and electricity required for the bio-oil reforming plant are estimated to be 18.4 MJ/kg H_2 and 0.4 kWh/kg H_2, respectively (Kinoshita and Turn, 2003; Vagia and Lemonidou, 2007). Detailed inventory data for this unit process for all pathways are given in Section 2.2.2.7.

2.2.1.5. Hydrogen transport

Hydrogen transport is relevant to both BCL and GTI pathways. It is assumed that the hydrogen is transported for 500 km to a bitumen upgrader. Even highly compressed (50−70 MPa) hydrogen has so low a density that only 300 kg hydrogen can be carried using a conventional 36 tonne payload truck (Amos, 1998). Therefore, for distances as long as 500 km, truck transportation is an uneconomical option for hydrogen (Amos, 1998). As a result, only pipeline transport of biohydrogen is considered. The impact of manufacturing a pipeline, constructing it, and operating it is included in this analysis. Inventory data for the unit process are given in Section 2.2.2.8.

2.2.1.6. Bio-oil transport

The distance the bio-oil will need to be transported is assumed to be 500 km. In contrast to hydrogen transport, both pipeline and truck are considered for transportation of bio-oil and methanol blend, as both these liquids have a high density. When bio-oil and methanol blend are transported by truck, it is assumed that a high capacity B-train truck will be used. Truck transportation includes the impact from manufacturing and operating the trucks, infrastructure construction, and truck disposal. In contrast, transport of bio-oil via high-density polyethylene (HDPE) pipeline includes the impact from manufacturing the pipeline, pumps, and polyethylene foam insulators, delivering the pipeline material, constructing the pipeline, and operating it (based on an earlier study by the author, Pootakham and Kumar, 2010). Inventory data for this unit process are given in Section 2.2.2.9.

2.2.2. Inventory assessment for life cycle calculation

2.2.2.1. Biomass properties and plant characteristics

The yield and physical properties of biomass are very critical to performing LCA studies for biomass-based systems. These have a significant impact on various upstream and downstream operations of biomass conversion such as transportation, feedstock pretreatment, plant mass and energy balance, plant maintenance, etc. Note that, this study takes into account the higher heating value (HHV) of fuels. When assuming the yield of straw, a significant percentage (20%)

of it is alloted to be left in the field to return nutrients to the soil. The biomass inventory data and general plant assumptions are given in Table 2-1.

Table 2-1: Biomass properties and general assumptions

Properties	FR	WF	AR	Comments/sources
Moisture content (%, wet basis)	45	50	16	These are the moisture contents of as received feedstocks. It is assumed that moisture contents wouldn't change during transportation of feedstocks after preliminary processing (chipping/baling) (Sarkar and Kumar, 2009; 2010a).
Bulk density (kg/m^3)	230	250	175	These values correspond to wet bulk density of as received feedstocks (Angus-Hankin et al., 1995; Sarkar and Kumar, 2010a).
Higher heating value (MJ/dry kg)	20	20	17.6	(Sarkar and Kumar, 2009; 2010a)
Ash content (%)	3	1	4	(Kumar et al., 2003)
Biomass yield (dt/hectare)	0.247	84	0.333	Yield of WF is based on mixed stands of hardwood and spruce in Alberta for hundred-year rotation of forest growth (Kumar et al., 2003). Yield of FR is based on the assumption that 20% of the whole tree consists of forest residues (Kumar et al., 2003). .
Plant operating factor				These are conventional operating factors being used for biomass-based plants (Kumar et al., 2003; Sarkar and Kumar, 2009; 2010a; 2010b).
Year 1	0.7	0.7	0.7	
Year 2	0.8	0.8	0.8	
Year 3 onwards	0.85	0.85	0.85	
Average hauling distance				Hauling distance is related to the plant size and net biomass yield. Geometric and tortuosity factor was assumed 1 and 1.27, respectively while modeling biomass harvesting area requirement (Overend, 1982). Harvesting area for agricultural residue is assumed as a square and agricultural residue fed gasification/pyrolysis plant will be located at
BCL pathways				
Year 1 (km)	84	22.4	102	
Year 2 (km)	90	22.4	109	
Year 3 onwards (km)	93	22.4	113	

Properties	FR	WF	AR	Comments/sources
GTI pathways				the intersecting point of the diagonals. In contrast, harvesting area for FR and WF biomass is assumed circular and respective biohydrogen/pyrolysis plants are assumed to be located at the centre of the circle. This methodology is already used in earlier studies (Sarkar and Kumar, 2009; 2010a). Note that, bitumen upgrading plant is located 500 km away from gasification/pyrolysis plant. Biohydrogen from gasification plant is transported by pipeline to an upgrader and bio-oil from pyrolysis plant is transported by pipeline or truck to the upgrading plant to produce biohydrogen.
Year 1 (km)	84	25.8	102	
Year 2 (km)	90	25.8	109	
Year 3 onwards (km)	93	25.8	113	
Pyrolysis pathways				
Year 1 (km)	69	18.3	83	
Year 2 (km)	73	18.3	89	
Year 3 onwards (km)	76	18.3	92	
Biohydrogen yield				Biohydrogen yield from BCL and GTI pathways are taken from Sarkar and Kumar (2009; 2010a). Bio-oil yield[a] from pyrolysis pathways is assumed 70.7 wt% (10.8 wt% water), 50.53 wt% (20.57 wt% water), and 42 wt% (19.07 wt%) from WF, FR and AR biomass, respectively. Biohydrogen yield from bio-oil reforming is assumed to be 13.92 wt% of water free bio-oil (Sarkar and Kumar, 2010b).
BCL (kg H_2/dt)	83.4	83.4	83.4	
GTI (kg H_2/dt)	83.4	83.4	83.4	
Pyrolysis[a] (kg H_2/dt)	41.7	83.4	31.9	

[a]Higher ash and fixed carbon content results in lower bio-oil yield during fast pyrolysis (Bridgwater and Peacocke, 2000; Sarkar and Kumar, 2010b). Ash content of WF, FR, and AR feedstock is 1%, 3%, and 4% respectively. (Kumar et al., 2003). In contrast, fixed carbon content is found to be 17%, 19.59%, 18-21% respectively (Vamvuka et al., 2003; McKendry, 2002). Unlike ash and fixed carbon, volatile matters in biomass favors the bio-oil production. Volatile matters in WF, FR, and AR are found to be 82%, 79.8%, and 46-59% respectively (Vamvuka et al., 2003; McKendry, 2002). Cellulose and hemi-cellulose are the other important parameters in determining the bio-oil yield. Higher content of them in WF and FR (35-50% cellulose, 20-30% hemi-cellulose) compared to AR (33-40% cellulose, 20-25% hemi-cellulose) result in better bio-oil yield (McKendry, 2002).

2.2.2.2. Fuel, fertilizer, pesticide, and electricity inventory data

Fossil fuels (diesel and natural gas) are the primary energy input for almost all the unit processes. Methanol is required to stabilize bio-oil. Table 2-2 shows the fuels' properties, and the corresponding energy and emissions factors. Almost 82% of all the electricity generated in Alberta comes from coal-fired power plants (Environment Canada, 2009); there are, therefore, high emissions related to grid electricity. These emissions are estimated on life cycle basis and given in Table 2-2. The efficiency with which coal is converted to electricity is assumed to be 35%. Table 2-2 also shows the life cycle energy and emissions factors for different fertilizers and pesticides.

Table 2-2: Energy input/output ratio and emission factors for electricity, different fuels and chemicals

Category	Diesel [a]	Natural gas [a]	Methanol [a]	Electricity [b] (unit/MWh)	Fertilizer [c] (Unit/kg)			Pesticide [c] (unit/kg)	Comments/sources
					N	P	K		
HHV (MJ/kg)	46.03	49.1	22.7	-	-	-	-	-	Fuel energy and emission factors are determined based on the published literature ((S&T)^2 consultants Inc., 2010; Spath and Mann, 2000; Furuholt, 1995; Bernesson et al., 2004)). Fuel heating values and densities are taken from Environment Canada (2009). It is assumed that methanol used to stabilize bio-oil is derived from
Density (kg/m^3)	832	0.78	792	-	-	-	-	-	
kg CO_{2eq}/GJ	94.2	56.6	16	820	3.27	1.34	0.64	24.5	
kg SO_{2eq}/GJ	0.37	0.13	2E-03	0.57	0.38	0.40	0.40	2.96	
kg (NO_x+VOC)/GJ	0.59	0.22	1E-03	0.585	0.40	0.41	0.41	3.01	

Category	Diesel [a]	Natural gas [a]	Methanol [a]	Electricity [b] (unit/MWh)	Fertilizer [c] (Unit/kg)			Pesticide [c] (unit/kg)	Comments/sources
					N	P	K		
GJ/GJ	1.22	1.11	0.04	2.86	0.05	0.01	0.004	0.12	biomass. Energy and emission factors of Alberta are estimated from earlier studies (Cuddihy et al., 2005; Environment Canada, 2009). Fertilizer and pesticide factors are derived from literature (Kim and Dale, 2004 and Borjesson, 1996a).

[a]All of the factors are estimated based on the respective life cycle of the fuel. Impact factors for utilization of diesel include impacts from operations like dispensing, distribution and storage, production, transmission, land use change, feedstock recovery, leaks, flares and combustion. Natural gas and methanol impacts factors also include these operations. All the values are given as per GJ of fuel content.

[b]Energy and emission impacts are corresponding to 1MWh electricity generation and estimated based on the life cycle of Alberta grid.

[c]Energy and emission impacts are based on the life cycle of 1kg fertilizer/pesticide production.

2.2.2.3. Material inventory data

Steel is the main raw material used in manufacturing all kinds of equipment and machines e.g. forwarders, fellers, skidders, chippers, trucks, pipelines, spreaders, etc. Concrete, along with steel and aluminum is the main raw material used to construct plants. The life cycle energy and emissions factors for different raw materials are presented in the Table A-2 of appendix A. These factors are presented for different materials over a life cycle that includes procurement, processing, transporting, usage, and disposal.

2.2.2.4. Inventory data for biomass production

The machinery and products needed for biomass (FR, WF, and AR) production are described in the Table A-1 of appendix A.

2.2.2.5. Inventory data for biomass transportation

It is assumed that biomass will be transported using the high capacity trailer trucks. A trailer truck is capable of carrying 23 wet tonnes of biomass per trip. Each truck is manufactured out of 14 tonnes of steel. A typical fuel efficiency of 6 miles per gallon and 5 miles per gallon is assumed for trailers traveling without and with load, respectively (Mann and Spath, 1997).

Note that, it is difficult to determine the exact amount of road construction required for WF biomass hauling. In forests, two types of roads are required, namely, primary and secondary roads. Secondary roads are required for the

operation of forwarders, fellers and skidders. Whole trees are skidded to the primary roadside and chipped; the chips are then transported by truck to the plant. Quality is not a major concern with secondary roads because equipment like fellers/skidders operate at low speed. In contrast, primary roads are as good as highways. The impact from secondary road construction is not considered in this study for two reasons. First, there is a scarcity of reliable data, and, second, overall length is negligible compared with primary roads. Based on the optimal road spacing design for forests provided to us in discussion with the experts (Smyl Fulton, Weyerhaeuser Corporation, 2011), it is estimated that over 20 years, 1050, 1395, and 700 km of primary road network (6 m wide) are required, respectively for the BCL, GTI and pyrolysis pathways of producing biohydrogen from WF feedstock (Demir and Ozturk, 2004). Energy and emissions factors for road construction are 1731 GJ/km, 403,845 kg CO_{2eq}/km, 1015 kg SO_{2eq}/km, and 1155 kg (NO_x + VOC)/km, respectively (Stripple, 2001). A sensitivity case has been developed which excludes road construction for WF biomass.

2.2.2.6. Inventory data for plant construction, decommissioning, and disposal

The steel, concrete and aluminum required to construct a BCL plant (for all the feedstocks) are 5350, 16,535, and 44 tonnes, respectively. To construct a GTI plant (for processing FR and AR), the material required is 5084, 15,720, and 42 tonnes, respectively. A WF-based GTI plant requires 6182, 19,120, and 50 tonnes of materials, respectively (Spath and Mann, 2001; Mann and Spath, 1997).

A FR-based pyrolysis and bio-oil reforming plant together requires 6285, 19,435, and 52 tonnes of steel, concrete and aluminum, respectively. WF-based plants require 7775, 24,040, and 64 tonnes of materials, respectively. Agricultural-residue-based plants require 5880, 18,175, and 48 tonnes of materials, respectively (Spath and Mann, 2001; Mann and Spath, 1997).

For all plants, the decommissioning impact is assumed to amount of 3% of the construction impact (Elsayed and Mortimer, 2001). After decommissioning, materials are transported by truck for 50 km to a landfill. Inventory data for the truck are given above. Emissions from landfilling steel is 0.01 tCO_{2eq}/t of material; for concrete it is 0.044 tCO_{2eq}/t of material (ICF Consulting, 2005; EPA, 2010). There is too little data available on other factors such as energy, ARP, and GOP inventory so these are not considered for landfilling operations. They are assumed to be negligible.

2.2.2.7. Inventory data for plant operation and maintenance

The natural gas required to produce biohydrogen using a BCL gasifier has been found to be 0.38 $m^3/kg\ H_2$ for all three feedstocks (Spath et al., 2005). The grid electricity that must be purchased for forest residue and WF-based BCL gasifiers is 1.14 kWh/kg H_2 and 1.48 kWh/kg H_2 produced, respectively (Spath et al., 2005), however, agricultural-residue-based biohydrogen production using a BCL gasifier does not require any electricity be purchased (Spath et al., 2005). Neither

natural gas nor electricity purchases are required for GTI-gasifier-based biohydrogen production (Larson et al., 2005). No fossil fuel or electricity need be purchased to operate a fast pyrolysis plant (Ringer et al., 2006). Methanol (10 wt.%) is needed for bio-oil stabilization. Inventory data for methanol have been given above. Bio-oil reforming plants also do not require the purchase of natural gas or electricity (Sarkar and Kumar, 2010b). Ash is disposed 50 km away from the plant and is spread (1 tonne ash/ha) to replace nutrients. The ash content in bio-oil is less than 0.1% (Bridgwater and Peacocke, 2000), hence, the impact from ash disposal is ignored for bio-oil reforming plants. The inventory data for trucks used to transport ash are as stated above. It is assumed that 40´ fertilizer spreaders will be used to spread ash. The productivity, fuel consumption rate, and lifetime of a spreader is estimated to be 4.4 ha/hr, 5 L/hr, and 1200 hr respectively (Mann and Spath, 1997).

2.2.2.8. Inventory data for biohydrogen transport

At normal temperature and pressure, the density of hydrogen is very low (0.089 kg/m^3) (Spath and Mann, 2001), therefore, hydrogen must be highly compressed to make transportation cost-effective. As noted earlier, compressing hydrogen to a pressure as high as 70 MPa, does not improve its density significantly. Pipelines are the most viable option for transporting hydrogen over a distance of 500 km. Hydrogen from the BCL and GTI pathways is available in compressed form at 7 MPa and 6 MPa, respectively (Spath et al., 2005; Larson et al., 2005). Biohydrogen produced by a GTI gasifier can easily be compressed to 7 MPa. It is

not necessary to purchase grid electricity because plants produce sufficient amounts of surplus electricity. After hydrogen is separated from syngas, residual syngas (typically 5%) from the pressure swing adsorption (PSA) unit is burned in a boiler to operate a Rankine cycle; in this way extra electricity is generated (Larson et al., 2005). Hydrogen can be directly fed into a pipeline at 7 MPa (Spath et al., 2005). To ensure the comparability of the pathways, pipeline systems are designed so that hydrogen will be delivered to the upgrading plant at 2.5 MPa. Inventory data are given below for transporting biohydrogen by pipeline.

2.2.2.9. Pipeline characteristics

For BCL pathways 12 in. is considered as the nominal pipe size; the pipeline is made of ASTM A 106 (grade B steel). The same material and pipe size are used for forest- and agricultural-residue-based GTI gasification, however, WF-fed GTI plants, though the material is the same, require a 14 in. pipe. Pipeline material is selected from Mohitpour et al. (2007). Nominal pipe size is selected from GPSA (1972).

2.2.2.10. Pipeline manufacturing and construction

The steel required for 12 in. and 14 in. pipelines are 97.5 kg/m and 107.3 kg/m of pipeline, respectively (GPSA, 1972). Pipeline weight is estimated for a wall thickness of 0.5 in. The diesel consumed during pipeline construction is 3612.5 L/km of pipeline (Pootakham and Kumar, 2010).

2.2.2.11. Pipeline operation

The pressure drops for 12 in. and 14 in. pipelines are 18 kPa/km and 31.8 kPa/km, respectively. As a result, one booster station is required for the former and three booster stations are required for the latter in order to supply hydrogen at 2.5 MPa to the upgrader. The former requires 186 MWhr per day of electrical energy, and the latter requires 491 MWhr per day of electrical energy for pipeline operations. Pressure drops were estimated from Mohitpour et al. (2007).

2.2.2.12. Bio-oil transport inventory data

Unlike biohydrogen, bio-oil has a high density of 1200 kg/m^3. This makes trucks as favorable a mode of transportation as pipelines. It is assumed that bio-oil and methanol blend will be transported either using B-train trucks of 60 m^3 capacity or an HDPE pipeline if the distance to bitumen upgrading plant is 500 km or more. Inventory data for bio-oil transportation are presented in Table 2-3.

Table 2-3: Inventory data for bio-oil transport modes

Mode	Category	Values	Comments/ Sources
Truck	Energy impact	0.85 MJ/m^3/km	Impacts include truck manufacturing, infrastructure construction, and truck operation. Energy and GHG emission impact are adjusted for biohydrogen plant (Pootakham and Kumar, 2010). The authors evaluated other impacts based on the material inventory data from Pootakham and Kumar (2010).
	Emission impact	56 gmCO_{2eq} /m^3/km	
		0.23 gmSO_{2eq}/m^3/km	
		0.36 gm(NO_x + VOC) /m^3/km	
Pipeline	Energy impact	3.77 MJ/m^3/km	Impacts include HDPE pipeline manufacturing, pump manufacturing, polyethylene insulator manufacturing, truck delivery of pipeline construction materials, pipeline construction, and pipeline operation. Energy and GHG emission impacts are adjusted for biohydrogen plant (Pootakham and Kumar, 2010). The authors evaluated other impacts based on the material inventory data from Pootakham and Kumar (2010).
	Emission impact	0.31 kgCO_{2eq} /m^3/km	
		0.21 kgSO_{2eq}/m^3/km	
		0.21 kg(NO_x + VOC) /m^3/km	

2.3. Result and discussion

2.3.1. Life cycle energy impact of BCL pathways

The energy impact and NER corresponding to the functional unit for different BCL pathways are shown in Table 2-4. Note that, in order to determine NER, the HHV of hydrogen has been assumed to be 142 MJ/kg (Spath and Mann, 2001). It is evident that for the FR-and WF-based BCL pathways, plant operation and maintenance (UP 4) contributes significantly to the overall energy impact. This unit process is responsible for 65% and 63% of the total energy impact for the two biomass feedstocks, respectively. The key reason is the high requirement for electricity and natural gas to run the plant. On the other hand, for AR, biomass production (UP 1) (54%) has more impact than plant operation and maintenance (UP 4) (29%). There are two reasons for this. First, electricity need not be purchased to run the plant. Second, too many upstream unit operations are involved during AR production. Transporting biomass (UP 2) and biohydrogen (UP 5) together affect the overall energy impact by 6%, 4%, and 5.5% for AR, FR, and WF feedstock, respectively. The impacts from plant construction, decommissioning, and disposal (UP 3) are found to be negligible compared to other unit processes for all the feedstocks. Among the feedstocks, FR to biohydrogen has the highest NER - 3.3. The details of the life cycle energy impact for different BCL pathways are given in Table 2-4.

2.3.2. Life cycle energy impact of GTI pathways

Unlike for BCL pathways, for FR- and WF-based GTI pathways, hydrogen transportation (UP 5) is the main contributor to the overall energy impact. This unit process contributes 45% and 58% of the total energy impact, respectively, for the two feedstocks. Compared to FR-, WF-based GTI plants have a higher impact from transporting hydrogen. WF-based GTI plants have an optimum capacity of 4000 dtpd, compared to 3000 dtpd for FR. The designed pipeline size was found to be 12 and 14 in., respectively, for FR and WF pathways, and the pressure drops were 18 kPa/km and 31.8 kPa/km for the respective pipeline sizes. As a result, three booster stations are required for WF feedstock compared to one for FR if biohydrogen is to be delivered to the bitumen upgrader at 2.5 MPa. As a great deal of electricity is required during hydrogen compression, the overall impact is significant for WF feedstock. In addition, the material (steel) required for 12 in. and 14 in. pipelines was found to be 97.5 kg/m and 107.3 kg/m, respectively, for FR and WF cases; this also had an impact in the two cases. For AR-based GTI plants, biomass production (UP 1) (75%) supplies the largest share of the overall energy impact. For this feedstock impact from transporting hydrogen (UP 5) is found to be 17% of the total. In all cases, NER is higher for GTI pathways than for BCL pathways. This is because, for the GTI-based plant, neither grid electricity nor natural gas need be purchased to run the plant; therefore, the impacts from GTI plant operation and maintenance (UP 4) are also negligible. As with BCL plants, the impact from GTI plant construction, decommissioning, and disposal (UP 3) has been found to be insignificant regardless of the feedstock.

NERs for GTI plants are higher for all the feedstocks compared to their respective BCL plants. FR-based GTI plants exhibit the highest NER - 9.3. The details of the life cycle energy impacts for different GTI pathways are given in Table 2-4.

Table 2-4: Life cycle energy performance of biohydrogen pathways[a]

Feedstock	UP	MJ/kg H_2			
		BCL	**GTI**	**P I**	**P II**
AR	UP 1	30.6	30.6	79.8	79.8
	UP 2	2.9	2.9	6.2	6.2
	UP 3	0.13	0.12	0.6	0.6
	UP 4	16.2	0.1	1.3	1.3
	UP 5	6.9	6.9	-	-
	UP 6	-	-	5	-
	UP 7	-	-	-	23.5
Overall energy impact, MJ/kg H_2 (NER)		57 (2.5)	40.6 (3.5)	92.8 (1.6)	111 (1.3)
FR	UP 1	4.6	4.6	9.3	9.3
	UP 2	3.7	3.7	6	6
	UP 3	0.13	0.12	0.9	0.9
	UP 4	27.8	0.05	1.1	1.1
	UP 5	6.9	6.9	-	-
	UP 6	-	-	4.6	-
	UP 7	-	-	-	21.6
Overall energy impact, MJ/kg H_2 (NER)		43.1 (3.3)	15.4 (9.3)	21.9 (6.5)	38.9 (3.7)

Feedstock	UP	MJ/kg H_2			
WF	UP 1	9.4	9.4	9.4	9.4
	UP 2	2.2	2.3	2	2
	UP 3	0.13	0.12	0.3	0.3
	UP 4	31.3	0.02	0.7	0.7
	UP 5	6.8	16.3	-	-
	UP 6	-	-	3.2	-
	UP 7	-	-	-	15.1
Overall energy impact, MJ/kg H_2 (NER)		49.8 (2.9)	28.1 (5)	15.6 (9.1)	27.5 (5.2)

[a] BCL = Battelle Columbus Laboratory, GTI = Gas Technology Institute, P I: pyrolysis I pathway (includes UP 1 to UP 4 and UP 6), and P II: pyrolysis II pathway (includes UP 1 to UP 4 and UP 7). UP 1: unit process 1 (biomass production), UP 2: unit process 2 (biomass transportation), UP 3: unit process 3 (plant construction, decommissioning, and disposal), UP 4: unit process 4 (plant operation and maintenance), UP 5: unit process 5 (hydrogen transport by pipeline), UP 6: unit process 6 (bio-oil transport by truck), and UP 7: unit process 7 (bio-oil transport by pipeline). AR = agricultural residue, FR = forest residue, and WF = whole forest.

2.3.3. Life cycle energy impact for pyrolysis pathways

Table 2-4 shows the life cycle energy impact of different pyrolysis pathways for producing biohydrogen. NERs for the AR pathway are significantly lower than for the FR and WF pathways. The key reason for this is the lower bio-oil yield (42 wt.%) from AR feedstock compared to FR (50.53 wt.%) and WF (70.7 wt.%) feedstocks. The lower bio-oil yield from AR translates into more upstream operations during biomass production (UP 1) and transportation (UP 2). Note that, the optimum capacity for pyrolysis pathways was 2000 dtpd for all the feedstocks. In contrast to AR, the higher bio-oil yields from WF and FR biomass result in improved energy efficiency for the respective pathways. Bio-oil transportation by pipeline (UP 7) is too expensive in terms of energy consumption (by truck it is UP 6) because compressing bio-oil is very energy intensive. As with the BCL and GTI pathways, plant construction, decommissioning and disposal (UP 3) have a minor impact on the life cycle energy levels of pyrolysis pathways. The WF-feedstock-based pathway has the highest NER for both P I (bio-oil transported by truck) and P II (bio-oil transported by pipeline); they are 9.1 and 5.2, respectively. In brief, for biohydrogen production pathways, NERs lie in the range of 1.3−9.3. In contrast, coal- and natural-gas-based hydrogen production plants demonstrate NERs in the range of 0.57−0.67 (Spath and Mann, 2001; Ruether et al., 2005).

2.3.4. Life cycle emission impact

The life cycle GHG emissions from the BCL pathways are shown in Figure 2-3. As the figure shows, plant operation and maintenance (UP 4) is the main contributor to the overall life cycle GHG emissions from the FR- and WF-based BCL pathways; it accounts for 60% and 54% of the total life cycle GHG emissions from the respective pathways. The key reason for this is the high requirement for electricity and natural gas to operate the respective plants. In contrast, the AR-based BCL pathway, biomass production (UP 1) (57%) has a higher impact on the life cycle GHG emissions than does plant operation and maintenance (UP 4) (22%). There are two major reasons for this. First, no electricity purchase is required to run the plant. Second, there are too many upstream unit operations involved in producing the AR biomass. Transportation of biomass (UP 2) and biohydrogen (UP 5) together contributes 20%, 28%, and 24% to the overall GHG emissions impact for the AR-, FR-, and WF-based BCL pathways, respectively. As transportation of biohydrogen (UP 5) involves high electricity consumption in booster station(s), it is more GHG-emissions intensive than biomass transportation (UP 2). Irrespective of the BCL pathways considered, the impact of GHG emissions from plant construction, decommissioning, and disposal (UP 3) are negligible.

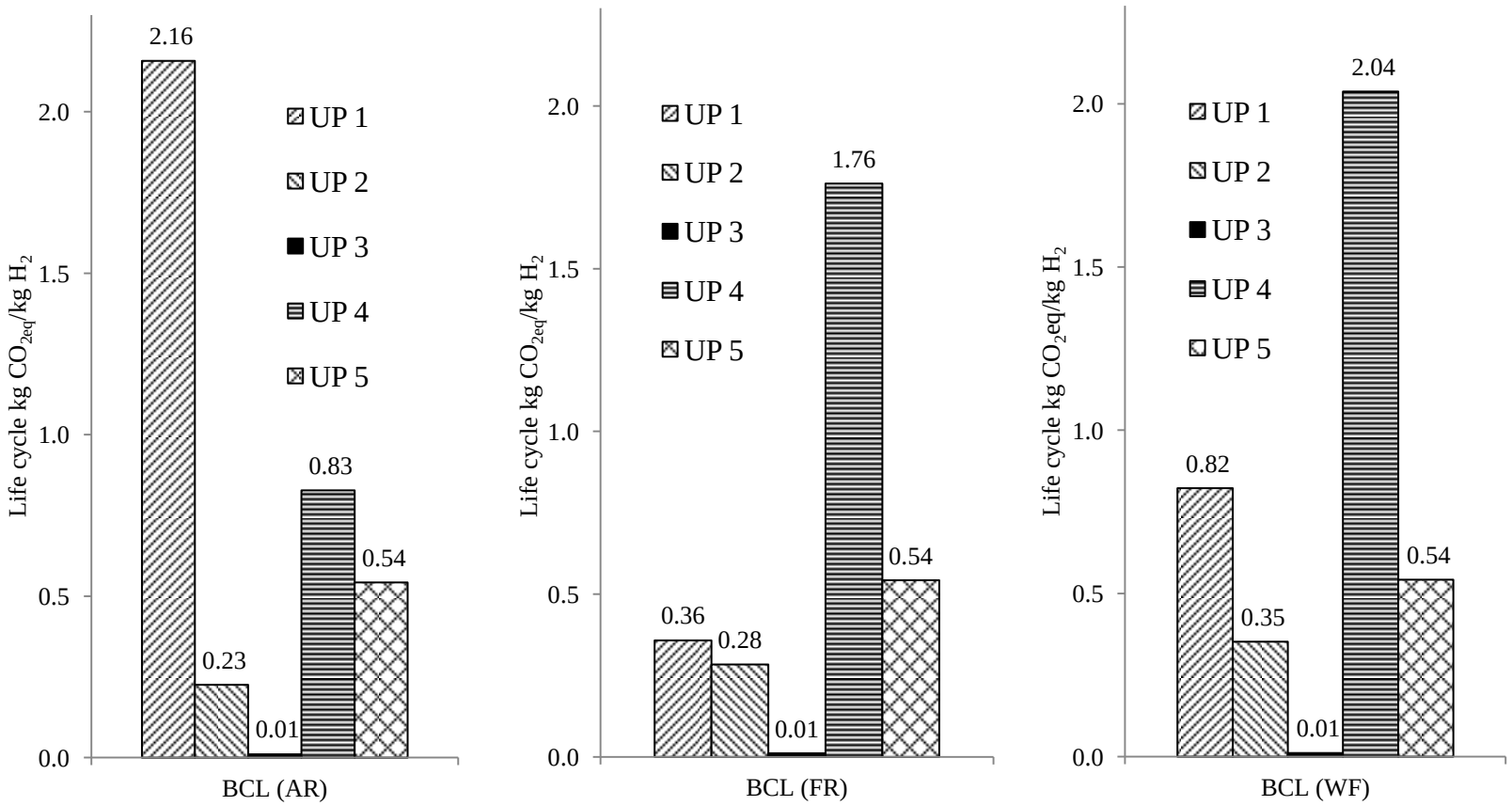

Figure 2-3: Life cycle GHG emission impacts from Battelle Columbus Laboratory (BCL) pathways

Life cycle GHG emissions from the GTI pathways are shown in Figure 2-4. As found in Figure 2-4, biomass production (UP 1) and biohydrogen transportation by pipeline (UP 5) are the main contributors to the overall GHG emissions from the AR-based GTI pathway. For this pathway, the former and the latter unit processes are responsible for 73% and 18% of the overall GHG emissions, respectively. Biomass preprocessing operations and high electricity consumption are the main sources of GHG emissions. For the FR-based GTI pathway, biomass production (UP 1), transportation (UP 2), and pipeline transport of biohydrogen (UP 5) contribute 30%, 23%, and 45% of the overall GHG emissions, respectively. In contrast, for the WF-based GTI pathway these unit processes account for 33%, 15%, and 52% of the life cycle GHG emissions, respectively. The impact from plant construction, decommissioning, and disposal (UP 3), and plant operation and maintenance (UP 4) are found to be negligible for all the GTI pathways.

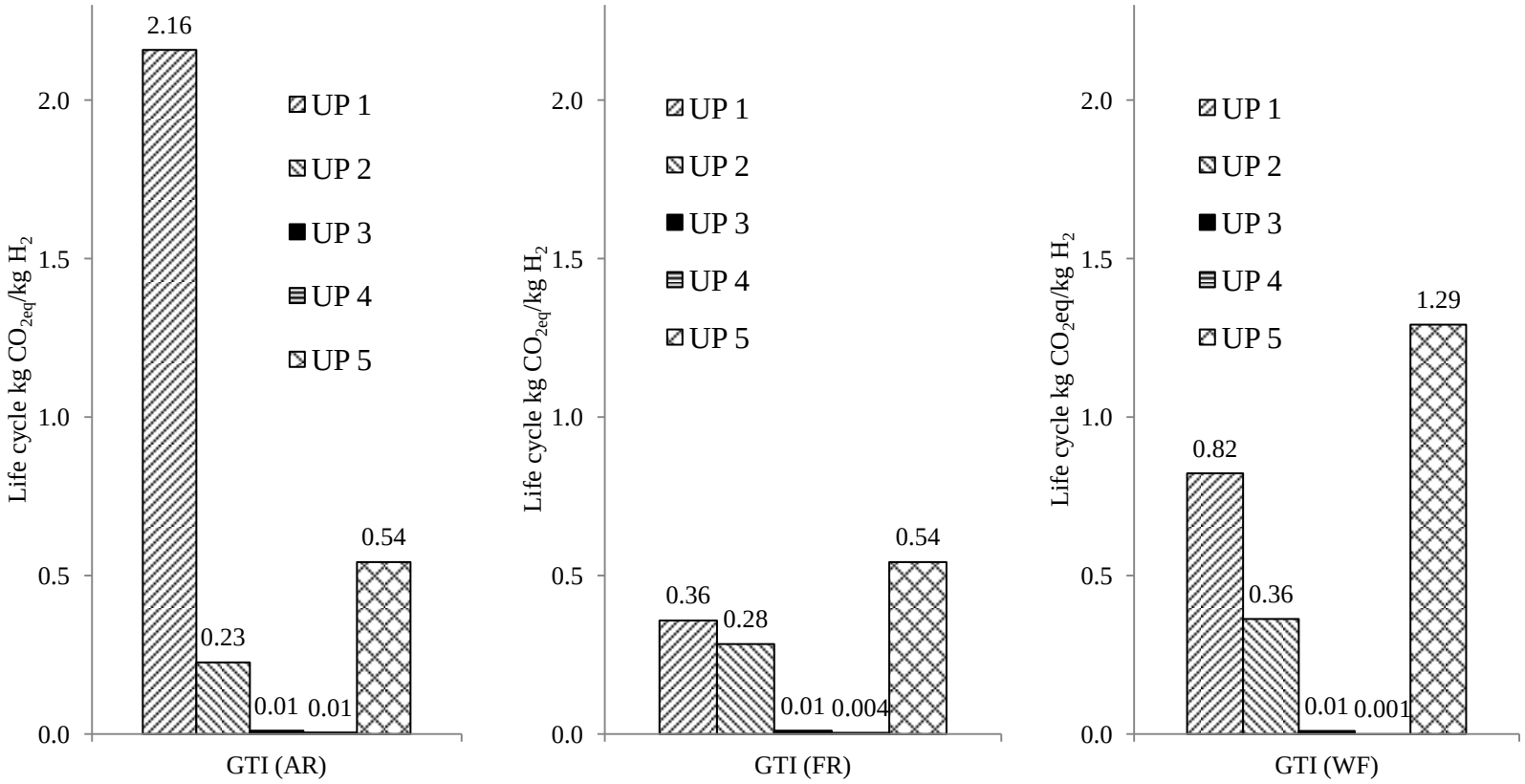

Figure 2-4: Life cycle GHG emission impacts from Gas Technology Institute (GTI) pathways

Figure 2-5 describes the life cycle GHG emissions impact from the pyrolysis pathways. For the AR-based P I pathway, biomass production (UP 1) accounts for 86% of the overall GHG emissions. Once again, preprocessing operations in UP 1 play the key role. In contrast, for the AR-based P II pathway, biomass production (UP 1) and pipeline transport of bio-oil (UP 7) contribute 69% and 24% of the overall GHG emissions, respectively. Pipeline transport of bio-oil (UP 7) is the most expensive unit process in terms of GHG emissions for the FR- (58%) and WF-based (51%) P II pathways. On the other hand, biomass production (UP 1) contributes 46% and 58% of the overall GHG emissions from the FR- and WF-based P I pathways, respectively. Note that, the impact from plant construction, decommissioning, and disposal (UP 3), and from plant operation and maintenance (UP 4) is negligible for all the pyrolysis (P I/P II) pathways irrespective of the feedstock.

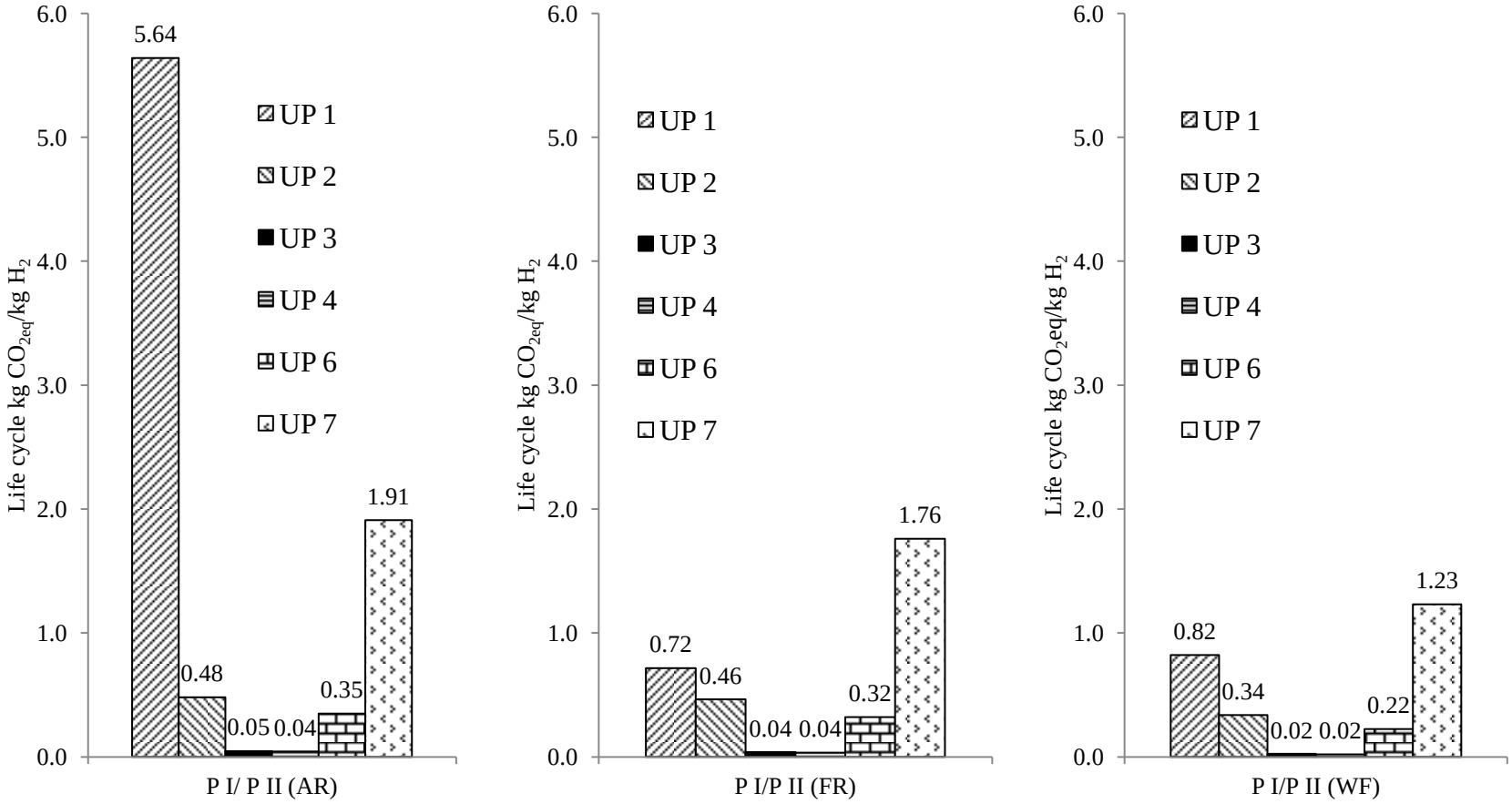

Figure 2- 5: Life cycle GHG emission impacts from pyrolysis pathways

Figure 2-6 compares the life cycle GHG emissions of all the biohydrogen production pathways considered in this study. The FR-based GTI pathway emits the least amount of GHGs (1.20 kg CO_{2eq}/kg H_2) among the pathways. In contrast, the AR-based pyrolysis (II) pathway emits the greatest amount (8.12 kg CO_{2eq}/kg H_2). Among the BCL pathways, FR-based hydrogen emits the fewest GHGs (2.96 kg CO_{2eq}/kg H_2). Life cycle GHG emissions from AR- and WF-based biomass are 27.4% and 27% higher than that, respectively. The life cycle GHG emissions from the GTI pathways of AR and WF are 145% and 108% higher than those from the FR pathway (1.20 kg CO_{2eq}/kg H_2). Because of the low bio-oil yield from AR, GHG emission intensities from its P I (6.56 kg CO_{2eq}/kg H_2) and P II (8.12 kg CO_{2eq}/kg H_2) pathways are significantly higher than that from the other feedstocks.

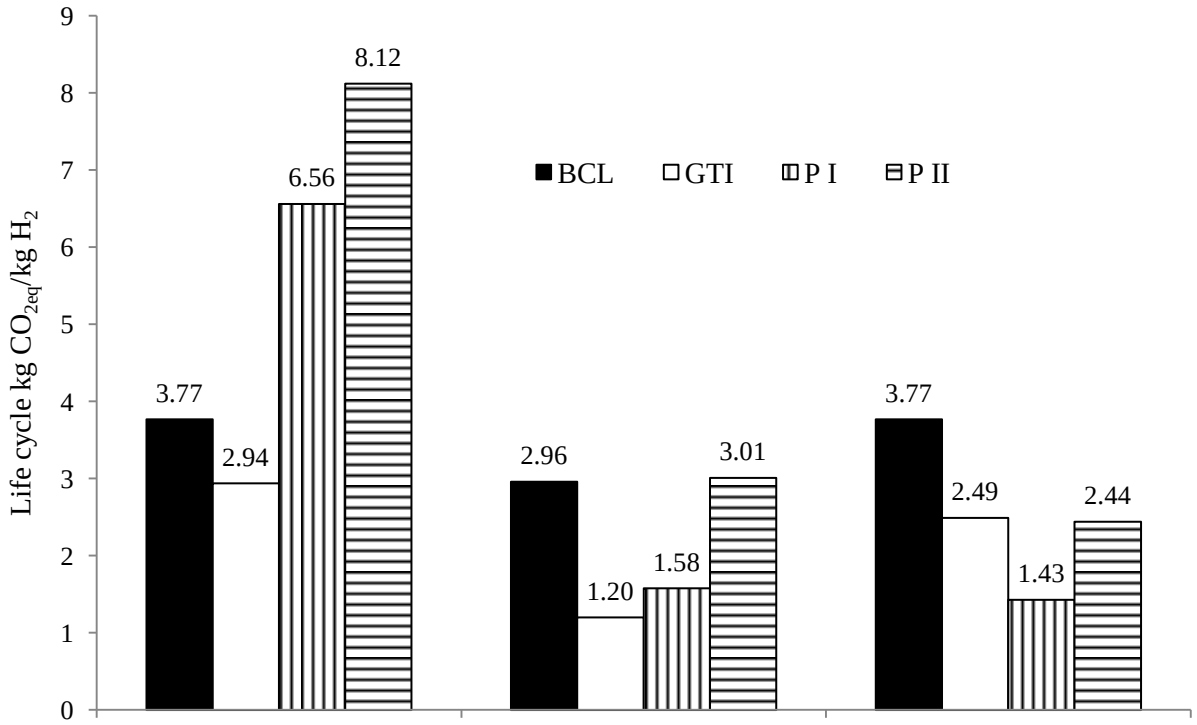

Figure 2-6: Comparison of life cycle GHG emission intensities of biohydrogen production pathways

Life cycle ARP and GOP impact is broken down in Table 2-5. Among the BCL pathways, the lowest ARP (6.23E−03 kg SO_{2eq}/kg H_2) is found for FR-based hydrogen. The impact from WF- and AR-based hydrogen are 26% and 75% higher than that, respectively. As with ARP, the lowest GOP (8.56E−03 kg [NO_x + VOC]/kg H_2) among the BCL pathways belongs to FR. The impacts from WF- and AR-based hydrogen are 25% and 93% higher than that, respectively. As with BCL, FR is found to be the best alternative for biohydrogen production among the GTI pathways from the perspective of ARP and GOP. On the other hand, among the pyrolysis pathways (P I/P II) the lowest ARP and GOP levels are found for WF-based hydrogen generation. For P I, these are 5.11E−03 kg SO_{2eq}/kg H_2 and 7.42E−03 kg (NO_x + VOC)/kg H_2, respectively. In contrast, for P II, these are 5.16E−03 kg SO_{2eq}/kg H_2 and 7.02E−03 kg (NO_x + VOC)/kg H_2. The results are concisely presented in Table 2-6 under the base case. Note that, variations in the levels of ARP and GOP emissions with different feedstocks and pathways strongly follow variations in their respective energy and GHG emissions. They can thus be explained based on the same argument presented earlier.

Table 2-5: ARP and GOP impacts from biohydrogen pathways[a]

Feed	Unit process	kg SO_{2eq}/kg H_2			kg (NOx + VOC)/kg H_2		
		BCL	GTI	P I/P II	BCL	GTI	P I/P II
FR	UP 1	1.4E-03	1.4E-03	2.9E-03	2.2E-03	2.2E-03	4.4E-03
	UP 2	1.2E-03	1.2E-03	1.9E-03	1.7E-03	1.7E-03	2.9E-03
	UP 3	8.5E-05	8.0E-05	3.0E-04	4.4E-05	4.2E-05	1.5E-04
	UP 4	2.5E-03	1.6E-05	8.7E-05	3.9E-03	2.4E-05	7.5E-05
	UP 5	1E-03	1E-03	-	6.6E-04	6.6E-04	-
	UP 6	-	-	1.3E-03	-	-	2.1E-03
	UP 7	-	-	1.4E-03	-	-	1.5E-03
WF	UP 1	3.0E-03	3.0E-03	3.0E-03	4.7E-03	4.7E-03	4.7E-03
	UP 2	1.0E-03	1.1E-03	9.5E-04	1.3E-03	1.3E-03	1.2E-03
	UP 3	8.5E-05	7.3E-05	1.8E-04	4.4E-05	3.8E-05	9.6E-05
	UP 4	2.7E-03	5.3E-06	4.4E-05	4.1E-03	7.9E-06	2.7E-05
	UP 5	1E-03	1.5E-03	-	6.7E-04	1.2E-03	-
	UP 6	-	-	9.1E-04	-	-	1.4E-03
	UP 7	-	-	9.6E-04	-	-	1.1E-03
AR	UP 1	7.0E-03	7.0E-03	1.9E-02	1.1E-02	1.1E-02	2.9E-02
	UP 2	9.3E-04	9.3E-04	2.0E-03	1.4E-03	1.4E-03	3.0E-03
	UP 3	8.5E-05	8.0E-05	3.6E-04	4.4E-05	4.2E-05	1.9E-04
	UP 4	1.9E-03	2.1E-05	1.2E-04	3.2E-03	3.2E-05	1.1E-04
	UP 5	1.0E-03	1.0E-03	-	6.6E-04	6.6E-04	-
	UP 6	-	-	1.4E-03	-	-	2.2E-03

Feed	Unit process	kg SO_{2eq}/kg H_2			kg (NOx + VOC)/kg H_2		
		BCL	GTI	P I/P II	BCL	GTI	P I/P II
	UP 7	-	-	1.5E-03	-	-	1.6E-03

[a] ARP = acid rain precursor and GOP= ground level ozone precursor. BCL = Battelle Columbus Laboratory, GTI = Gas Technology Institute, P I: pyrolysis I pathway (includes UP 1 to UP 4 and UP 6), and P II: pyrolysis II pathway (includes UP 1 to UP 4 and UP 7). UP 1: unit process 1 (biomass production), UP 2: unit process 2 (biomass transportation), UP 3: unit process 3 (plant construction, decommissioning, and disposal), UP 4: unit process 4 (plant operation and maintenance), UP 5: unit process 5 (hydrogen transport by pipeline), UP 6: unit process 6 (bio-oil transport by truck), and UP 7: unit process 7 (bio-oil transport by pipeline). AR = agricultural residue, FR = forest residue, and WF = whole forest.

Based on this LCA study, GHG, ARP, and GOP emissions from producing biohydrogen fall in the range of 1.2 to 8.1 kg CO_{2eq}/kg H_2, 3.72E−03 to 2.25E−02 kg SO_{2eq}/kg H_2, and 4.69E−03 to 3.49E−02 kg (NO_x + VOC)/kg H_2. In contrast, emissions from producing coal- and natural gas-based hydrogen fall in the range of 12−43 kg CO_{2eq}/kg H_2, 2.0E−02 to 1.0E−01 kg SO_{2eq}/kg H_2, and 3.0E−02 to 2.0E−01 kg (NO_x + VOC)/kg H_2 (Koroneos et al., 2005; Spath and Mann, 2001; Ruether et al., 2005; Dufoura et al., 2009). Note that, for all the biohydrogen production pathways emissions levels are significantly less than those from fossil-fuel-based hydrogen (Figure 2-3 to 2-5, Tables 2-5 and 2-6). Emissions from AR-based hydrogen are comparatively higher than those from FR- and WF-based hydrogen. UP 1 is predominantly responsible for that, because the UP 1 of AR-based hydrogen involves more operations in biomass farming, harvesting, and

processing (Table A-1). Due to the lower bio-oil yield from AR compared to FR and WF feedstock, the influence of UP 1 is even more significant in the case of the P I and P II pathways (Figure 2-5 and Table 2-5, Table 2-6).

2.3.5. Sensitivity analysis

A sensitivity analysis with various possible scenarios has been performed in this study. The parameter was changed in each scenario independently of the others so the results could be compared with those from the base case. Results from the sensitivity analysis are summarized in Table 2-6. Case 1 considers AR as waste; therefore, farming operations like seeding, fertilizing, chemical spraying, etc. are excluded from the system boundary of AR-based conversion pathways, though processing operations like harvesting, raking, baling, wrapping, stacking, etc. are included. As suggested by Case 1, farming operations have a huge impact on the overall energetic and environmental performance of AR-based hydrogen. The overall impact of all AR-based pathways drops significantly due to the exclusion of the farming operations. Grid emissions for Alberta are likely to fall if coal is replaced with renewables and other relatively environment-friendly alternatives for power generation. Hence, Case 2 develops a 'what if scenario' involving a 20% drop in grid emissions intensity. As shown in Case 2, a 20% reduction in grid emissions changes the results noticeably, though less significantly than the former case. Case 3 suggests that, excluding silviculture and road construction from WF-based biomass reduces the impact significantly compared to all the pathways. Case 4 has been developed assuming that, energy required in the bio-

oil reforming plant will be purchased instead of consuming from the existing cogeneration facility of the upgrading plant. The impact from Case 5 is very significant for all the pyrolysis pathways (Table 2-6) because bio-oil reforming consumes substantial amounts of natural gas and electricity. The effect of a 10% (Case 5) increase or decrease in biomass yield was also analyzed. This case was developed for all three feedstocks, however, variations in impact were found to be within ±3% of the base case for the WF and FR pathways; hence, only the results from AR are presented in Table 2-6. Case 6 considers two scenarios; one for an increasing operating factor for the plants (0.7 for year 1, 0.8 for year 2 and 0.95 from year 3 onwards) and the other for a decreasing factor (0.65 for year 1, 0.7 for year 2 and 0.75 from year 3 onwards). In this case too, the variations from the base case were found to be insignificant (±4%) for FR and WF feedstocks, thus only results for AR are presented in Table 2-6.

Table 2-6: Key sensitivities and their results[a, b]

Case		Path	Base case value				Variation from base case (%)			
			EI	GHG	ARP	GOP	EI	GHG	ARP	GOP
1	AR	BCL	57	3.77	1.09E-02	1.65E-02	-43	-45	-48	-50
		GTI	41	2.94	9.03E-03	1.33E-02	-57	-58	-57	-63
		P I	93	6.56	2.24E-02	3.49E-02	-67	-68	-61	-63
		P II	111	8.12	2.25E-02	3.43E-02	-56	-55	-61	-65
2	FR	BCL	43.2	2.96	6.23E-03	8.56E-03	-	-10	-3	-2
		GTI	15.4	1.20	3.72E-03	4.69E-03	-	-8	-2	-2
		P I	21.8	1.58	6.48E-03	9.58E-03	-	-	-	-
		P II	38.9	3.01	6.55E-03	9.01E-03	-	-11	-4	-3
	WF	BCL	49.9	3.77	7.83E-03	1.07E-02	-	-9	-3	-2
		GTI	28.1	2.49	5.68E-03	7.24E-03	-	-10	-3	-2
		P I	15.6	1.43	5.11E-03	7.42E-03	-	-	-	-
		P II	27.5	2.44	5.16E-03	7.02E-03	-	-10	-4	-3
	AR	BCL	57	3.77	1.09E-02	1.65E-02	-	-3	-1	-1
		GTI	41	2.94	9.03E-03	1.33E-02	-	-3	-1	-1
		P I	93	6.56	2.24E-02	3.49E-02	-	-	-	-
		P II	111	8.12	2.25E-02	3.43E-02	-	-5	0	0

Case		Path	Base case value				Variation from base case (%)							
			EI	GHG	ARP	GOP	EI		GHG		ARP		GOP	
3	WF	BCL	49.9	3.77	7.83E-03	1.07E-02	-4		-12		-14		-13	
		GTI	28.1	2.49	5.68E-03	7.24E-03	-7		-18		-19		-20	
		P I	15.6	1.43	5.11E-03	7.42E-03	-14		-32		-21		-19	
		P II	27.5	2.44	5.16E-03	7.02E-03	-8		-18		-21		-20	
4	FR	P I	21.8	1.58	6.48E-03	9.58E-03	+103		+87		+13		+45	
		P II	38.9	3.01	6.55E-03	9.01E-03	+58		+46		+13		+48	
	WF	P I	15.6	1.43	5.11E-03	7.42E-03	+144		+96		+17		+58	
		P II	27.5	2.44	5.16E-03	7.02E-03	+82		+56		+17		+61	
	AR	P I	93	6.56	2.24E-02	3.49E-02	+24		+21		+4		+12	
		P II	111	8.12	2.25E-02	3.43E-02	+21		+17		+4		+12	
							H	**L**	**H**	**L**	**H**	**L**	**H**	**L**
5	AR	BCL	57	3.77	1.09E-02	1.65E-02	-5.2	+5	-5.1	+5	-5.6	+5.5	-6	+6
		GTI	41	2.94	9.03E-03	1.33E-02	-7.6	+7.6	-6.3	+6.2	-5.6	+5.6	-6.5	+6.5
		P I	93	6.56	2.24E-02	3.49E-02	-7.5	+7.3	-7.4	+7.3	-6.8	+6.7	-7.2	+7.1
		P II	111	8.12	2.25E-02	3.43E-02	-6	+6	-6	+6	-7	+7	-7.4	+7.3
6	AR	BCL	57	3.77	1.09E-02	1.65E-02	-5.3	+5.8	-5.1	+6.7	-5.6	+7.4	-6	+7.6
		GTI	41	2.94	9.03E-03	1.33E-02	-7.7	+7.9	-6.4	+8.8	-5.6	+7.6	-6.4	+7.9
		P I	93	6.56	2.24E-02	3.49E-02	-8	+10.	-8	+10.2	-11	+10	-11	+9.8

Case	Path	Base case value				Variation from base case (%)							
		EI	GHG	ARP	GOP	EI		GHG		ARP		GOP	
	P II	111	8.12	2.25E-02	3.43E-02	-6	+9	-6.1	+8.3	-7	+9.8	-7.5	+9.9

[a] H and L corresponds to the higher and lower value of the sensitivity parameter, respectively. EI stands for energy intensity (MJ/kg H2), GHG, ARP, and GOP column indicates greenhouse gas intensity (kg CO2eq/ kg H_2), acid rain precursor intensity (kg SO2eq/kg H_2), and ground level ozone precursor intensity (kg [NOx + VOC]/kg H_2) respectively.

[b] BCL = Battelle Columbus Laboratory, GTI = Gas Technology Institute, P I: pyrolysis I pathway (includes UP 1 to UP 4 and UP 6), and P II: pyrolysis II pathway (includes UP 1 to UP 4 and UP 7). UP 1: unit process 1 (biomass production), UP 2: unit process 2 (biomass transportation), UP 3: unit process 3 (plant construction, decommissioning, and disposal), UP 4: unit process 4 (plant operation and maintenance), UP 5: unit process 5 (hydrogen transport by pipeline), UP 6: unit process 6 (bio-oil transport by truck), and UP 7: unit process 7 (bio-oil transport by pipeline). AR = agricultural residue, FR = forest residue, and WF = whole forest.

2.4. Conclusion

Among the BCL pathways, the maximum NER (3.33) is that found for FR-based hydrogen; this is followed by the NERs for the WF (2.9) and AR (2.5) pathways, respectively. As with BCL, for the GTI pathways the maximum NER (9.3) is obtained using FR. For P I and P II, the highest NERs are produced using WF; they are 9.1 and 5.2, respectively. Among the BCL and GTI pathways, the lowest GHGs, ARPs, and GOPs are determined for FR-based pathway. For P I and P II, the lowest GHGs, ARPs, and GOPs are for WF-based pathway. NERs for biohydrogen are always higher than the fossil-fuel-based hydrogen, hence, using biohydrogen can improve overall energy efficiency and environmental performance.

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Chapter 3. Life cycle assessment of co-firing of densified biomass for power generation

3.1. Introduction

Greenhouse gas (GHG) emission is a growing concern in Alberta. With only 10.5% of Canada's population, this Province generates 33.2% (245.7 million tonnes) of Canada's total GHG emission (Environment Canada, 2009). Almost 40% of these emissions come from fossil fuel production and their subsequent use for electricity and heat generation. Coal (81.2%) and natural gas (11.7%) are the major contributors to electricity generation in Alberta. Since these fossil fuels have high carbon footprint, GHG emissions from the Alberta's power generation sector are one of the major contributors to total GHG missions from the Province. Therefore, in response to the climate change issue, Alberta has planned to mitigate 37 million tonnes of GHG by 2050 by greening its energy sector with renewable resources (Kabir et al., 2012).

A significant part of this mitigation can be achieved by replacing the fossil fuels with sustainable biomass feedstocks including agricultural residue (AR), forest residue (FR), and whole forest biomass (WF). Economics of biomass-based power generation in Alberta has been extensively studied earlier (Kumar et al., 2003). However, potential environmental impacts of biomass-based power for the

Province of Alberta have not been assessed fully. This study employs the life cycle assessment (LCA) methodology to illustrate the environmental implications of green electricity production from processed biomass through co-firing with coal in Alberta. Most of the researchers previously have paid attention to global warming impact of GHG emissions (CO_{2eq}) while scrutinizing the biomass-based power generation (Mann and Spath, 2001; Corti and Lombardi, 2004; Hartmann and Kaltschmitt, 1999). However, environmental impacts including acidification (SO_{2eq}: due to acid rain precursors) and smog formation [(NO_x + VOC): due to ground level ozone precursors] from biomass-based power were overlooked. This study has investigated all the aforementioned environmental impacts of power generation from AR, FR, and WF biomass in Alberta.

Instead of analyzing biomass combustion power plant, this study looks at the biomass co-firing options (direct and parallel) in the existing coal-fired power plant of Alberta. Co-firing is a quick option for integrating biomass to the power generation sector since it can be implemented with minor retrofitting of the existing coal-fired power plants (Sebastián et al., 2007). According to the specified gas emitters' regulation of Alberta, any facility that emits more than 100,000 tonne of GHG (CO_{2eq}) per year has to pay $15 tax for each tonne of excess CO_{2eq} emission. Facility that reduces its emission intensity than the threshold, may trade its emission credits with other facilities in Alberta (Alberta Environment, 2007). Like CO_{2eq}, SO_{2eq} credits can be traded as well (Mann and Spath, 2001). Co-firing can also offer near-term solution to the coal-fired power

plants with reduced NO_x emission and solid waste handling (Mann and Spath, 2001). Most importantly, consumers may choose the power plant companies that include renewable fuel in its portfolio.

Conventionally, agricultural (AR) and forest biomass (FR, WF) resources are utilized for power production in the form of bale and chip, respectively. However, low bulk and energy density are the main obstacles with utilizing biomass feedstocks in these forms. Therefore, biomass densification could save transport and handling costs. In addition, it can improve the efficiency of the final conversion stage. One of the most popular technologies of biomass densification is pelletization. In addition to improving the volumetric density, pelletization optimizes the storing, shipping, and conversion efficiency of biomass fuels (Uslu et al., 2008). It also minimizes the dust formation and enables free flowing of biomass fuels, which make the loading and unloading operations easier. However, pelletization process involves energy and emission intensive biomass pretreatment operations including drying, grinding, pressing, etc. (Uslu et al., 2008) when fossil fuels are used for these processes. Therefore, the detailed benefits of using AR, FR, and WF pellets for producing power must be evaluated from the life cycle point of view.

Another pathway of biomass densification is combined torrefaction and pelletization (TOP) technology. TOP pellet has some added advantages over conventional biomass-based pellets including improved durability, grindability,

hydrophobicity, and coal-like combustion nature (Bergman, 2005). This study compares all the aforementioned biomass (AR, FR, and WF) forms (bale, chip, pellet, and TOP) for power generation by direct or parallel co-firing in an existing coal-fired power plant of Alberta based on the LCA methodology.

In addition to the environmental impacts, energy output-input ratio i.e. net energy ratio (NER) is also crucial in assessing renewable energy systems. NER measures the total amount of energy produced by a system corresponding to every unit of energy consumed (Kabir and Kumar, 2011). Evaluating the life cycle NER for a renewable system helps in understanding its effectiveness compared to other renewable and fossil-fuel-based systems. This study investigates the NER for all the power generation pathways discussed earlier. Overall objective of this study is to compare the life cycle energy and environmental implications of co-firing densified biomass feedstocks in different forms in an existing coal-fired power plant of Alberta.

3.2. Biomass feedstocks and densification technologies

In Alberta, more than 90% of the logging operations include cutting of the tree in the stand followed by skidding the tree to the roadside and delimbing of tops and branches. Though the stems are then used for pulp and lumber use in different plants, the delimbed tops and branches are piled up and burnt to prevent the forest

fire. These residues (limbs, tops and branches) correspond to the forest harvest residue (FR). In contrast, wheat and barley straw are the main sources of agricultural residue (AR) feedstock. Whole forest (WF) biomass i.e. whole tree is used in Alberta in either pulp and paper or lumber and wood product industries. Note that, since the demand for paper is decreasing, pulp mills are closing in the Province of Alberta. Therefore, there is prospect for the forest industry to be integrated with the fossil-fuel-based power industry of Alberta.

One of the major drawbacks of as-received biomass feedstock is its low bulk density, which translates into poor energy density. The primary densification process for AR feedstock is either baling or chopping. On the other hand, for FR and WF feedstock, it is chipping. These primary densification processes can improve the bulk density of biomass feedstocks by 1.5−2 times of as-received condition (Sultana and Kumar, 2011a; Sultana et al., 2010). However, further densification is desired, especially for long transportation chain to minimize the cost, energy, and emissions involved during transportation. Pelletization is a secondary form of biomass densification where dried and ground biomass is compressed and extruded under high pressure to produce cylindrical pieces (bio-pellets). Through pelletization, bulk density can be increased up to 4−10 times of the as-received biomass (Sultana et al., 2010). Since densified biomass is tenacious and fibrous in nature with large particle size, they are difficult to grind in a coal-fired power plant using the existing equipment. In contrast, the existing coal crusher in the plant can easily disintegrate the bio-pellet since it is composed

of ground particles. Nevertheless, there are concerns like durability and biological degradation of bio-pellets. When exposed to water, snow, or condensed water, bio-pellets absorb moisture, which makes them swell and disintegrate. Therefore, the probability of dust formation and mechanical strength against crushing increases. The other consequence of moisture absorption is biological degradation including fungal formation and enhanced microbial activity. Hence, bio-pellets are required to be stored in dry place, which is hazardous due to the temperature development in the pellet piles. Therefore, there is need to impart hydrophobic property to bio-pellets. The process of combined torrefaction and pelletization imparts this property to the bio-pellets. During this process, biomass slightly decomposes giving off the various volatiles and retains 70−80% of the original mass as solid products and the rest as torrefied gas. Note that, the former and latter fraction contains almost 90% and 10% of the initial biomass energy content, respectively (Bergman, 2005). Hence, TOP demonstrates higher energy density compared to the conventional bio-pellet and primarily densified biomass.

3.3. Methodology

Power generation pathways considered in this study are summarized in Figure 3-1. Each pathway has been analyzed based on the economic optimum size of the respective biomass densification process. Optimum size for AR-based pellet plant in Alberta was found to be 150,000 dry tonnes/year (Sultana et al., 2010). In

contrast, optimum plant size for either of FR- and WF-based pellet plant was found to be 290,000 dry tonnes/year (Sultana and Kumar, 2011b). Optimum size of the torrefied pellet plant of any feedstock was assumed to be the same as its corresponding bio-pellet plant. To ensure the comparability of different densification processes, it is assumed that, biomass in the form of chips (FR and WF) and bale (AR) will be supplied to the coal-fired power plant at the rate of 290,000 and 150,000 dry tonnes/year, respectively. Each co-firing pathway is investigated for a hypothetical 450 MW coal-fired power plant in Alberta that operates 6000 hours/year (Singh et al., 2001; Sebastián et al., 2007).

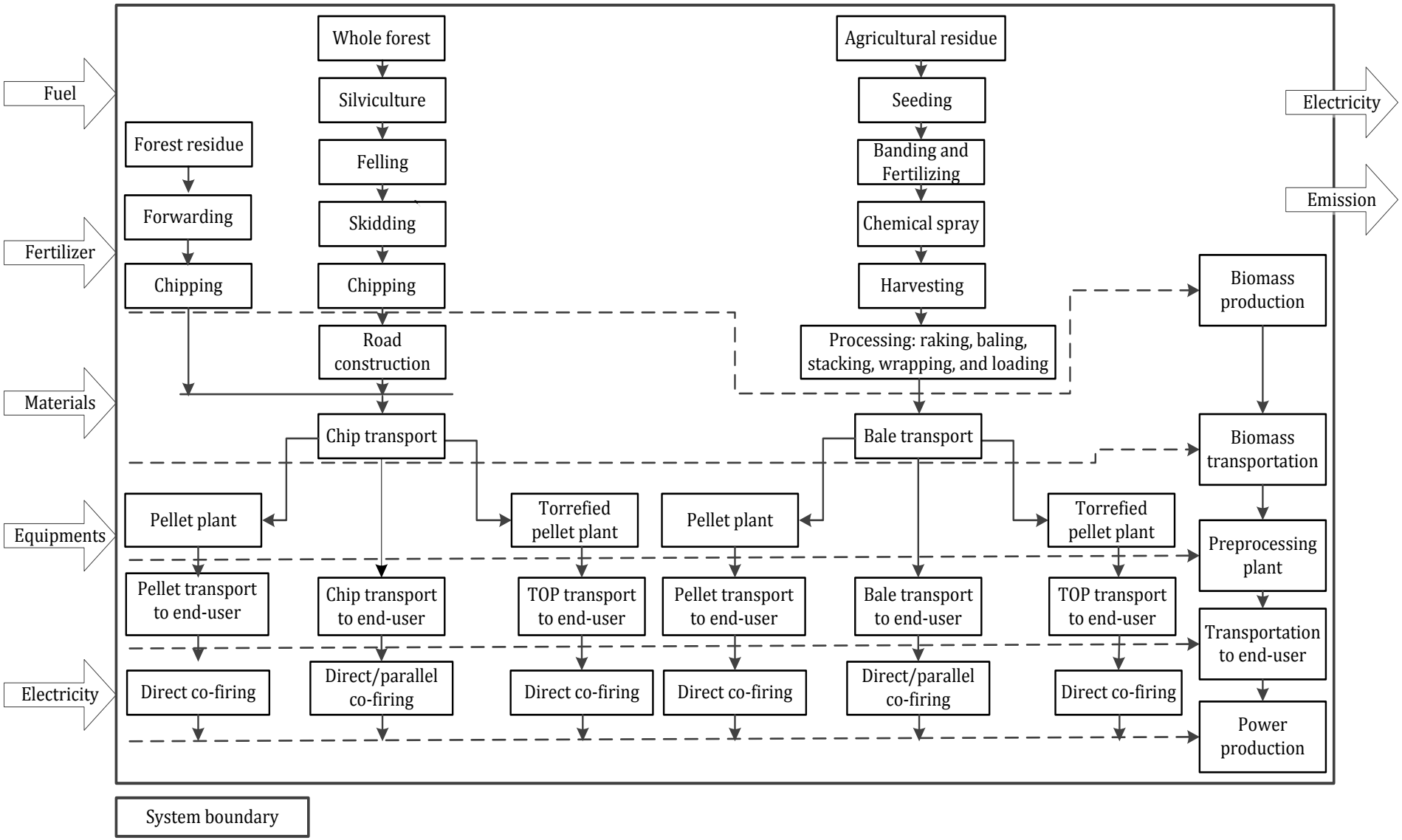

Figure 3-1: System boundary of the study

This life cycle study has been performed based on the system boundary presented in Figure 3-1. The life cycle of each power generation pathway is divided into five unit processes (UP) which are: biomass production (UP 1), biomass transportation (UP 2), preprocessing (UP 3), transportation to end-user (UP 4), and power production (UP 5). Embodied energy and emission factors for all the material, equipment, and energy flows associated with the system have been determined from their respective life cycle. Energy and environmental impacts of a power generation pathway are normalized corresponding to a functional unit (FU). FU is essential for any LCA study since it is considered as a yardstick in comparing the LCA results (ISO, 2006). FU chosen for this study is 1 MWh electricity production through co-firing of densified biomass.

The methodology for evaluating the life cycle NER and environmental emissions is already explained in the earlier study of the authors (Kabir and Kumar, 2011). While converting the electrical energy demand to the primary energy, it was assumed that coal-fired power plants operate with an efficiency of 35%. Environmental stressors considered in this study are: greenhouse gas (GHG: CO_2, CO, CH_4, and N_2O), acid rain precursor (ARP: SO_2 and NO_x), and ground level ozone precursor (GOP: NO_x and VOC). Weighting factors for the different emission compounds are adopted from Kabir and Kumar (2011). Note that, since biomass absorbs CO_2 during its growth, biomass combustion during co-firing has been considered CO_2 neutral. However, other GHG, ARP, and GOP emissions during biomass combustion are included in the study. Note that, the impacts of

grid connection, power transmission, and distribution are beyond the scope of this study.

3.4. Inventory data and assumptions

All the unit processes, relevant inventory data, and assumptions are described in the following sub-sections.

3.4.1. Biomass production (UP 1)

FR produced during logging operations is forwarded to the roadside and chipped for transportation to the biomass preprocessing plant. Biomass production (UP 1) includes the impacts of FR forwarding and chipping. Therefore, impacts of manufacturing, operation, recycling, and disposal of forwarder and chipper are included in UP 1. Since FR is generated during logging operations, impacts from silviculture are disregarded in UP 1 for this feedstock.

Operations involved with UP 1 of WF feedstock are felling, skidding, and chipping. Hence, life cycle impacts from feller, skidder, and chipper are included in the study. Unlike FR, impacts of silviculture (fertilizer and pesticide production and spraying) are included in UP 1 for WF feedstock. Nutrients (N, P, and K) removed from the soil due to the harvesting of WF are replaced by fertilizers.

However, impacts from Ca replacement are disregarded since it is available in abundance in the boreal forest of Alberta (Kumar et al., 2003). A sensitivity case is developed for WF power generation pathways, which excludes the silviculture from the system boundary.

Production of AR includes the unit operations like cultivation, fertilization (N, P), chemical application, harvesting, and straw processing (raking, baling, stacking, wrapping, and loading). AR is transported to the biomass preprocessing plant in the form of bale. Note that, K–fertilizer is not necessary in Alberta's soil to produce barley and wheat (Kabir and Kumar, 2011); hence, its impacts are disregarded. Straw to grain mass ratio is considered as 1.1:1 (Kumar et al., 2003). Accordingly, a fraction of energy and environmental impacts from common operations of straw and grain (from cultivation to harvesting) is allocated to straw. A sensitivity case is developed for AR-based power generation pathways, which excludes the farming operations (cultivation, fertilization, and chemical application) from the system boundary. This case considers that no economic value is associated with AR.

General inventory data for UP 1 for all the feedstocks (FR, WF, and AR) are provided in Table 3-1. The equipment inventory data for UP 1 for all the feedstocks are adopted from the previous study done by the authors (Kabir and Kumar, 2011). The life cycle energy and emission factors for different raw materials, fuels, electricity, fertilizer, and pesticide input to the system boundary of the study are given in Table 3-2.

Table 3-1: Inventory data for biomass production and transportation

Properties	AR	FR	WF	Comments/sources
Moisture content (wt.%)	14	45	50	Values presented here refer to the moisture content of as-received biomass feedstock (Kabir and Kumar, 2011; Sultana and Kumar, 2011a)
Higher heating value (GJ/dry tonne)	17.6	20	20	HHV of FR- and WF-based TOP is 24 GJ/ dry tonne. In contrast, AR-based TOP has HHV of 21.1 GJ/dry tonne (Pastre, 2002; Kumar et al., 2003; Bergman, 2005).
Ash content (wt.%)	4	3	1	(Kabir and Kumar, 2011)
Biomass yield (dt/ha)	0.33	0.25	84	The net yield for AR is based on a straw to grain ratio of 1.1:1 and it is determined considering the factors including harvest machine efficiency, straw retained for soil conservation, and straw removed for animal feeding and bedding (Sultana et al., 2010; Kabir and Kumar, 2011). The net yield for the FR is determined from the net yield of WF biomass based on 100-year rotation of forest growth in Alberta (Kumar et al., 2003).
Plant output (dt/year)	150,000	290,000	290,000	(Sultana et al., 2010; Sultana and Kumar, 2011b)
Plant life (year)	20	20	20	
Operating factor				
Year 1	0.7	0.7	0.7	These are conventional operating factors for biomass based plants (Kumar et al.,

Properties	AR	FR	WF	Comments/sources
Year 2	0.8	0.8	0.8	2003)
Year 3 onwards	0.85	0.85	0.85	
Material loss (%)	5	5	5	For the combined torrefaction and pelletization plants, material loss (25%) is higher due to mass loss during the process (Bergman, 2005)
Average hauling distance (km)				The average hauling distances for AR-based combined torrefaction and pelletization plant are 42, 45, and 47 km, respectively, for Year 1, Year 2, and Year 3 onwards. In
Year 1	39	44	12	contrast, for FR-based plant these are, respectively, 48, 52, and 53 km. On the other
Year 2	41	47	12	hand, for WF-based plant these are 12.9, 13, and 13 km, respectively.
Year 3 onwards	43	49	12	
Biomass collection area (ha)	7,950,595	20,709,775	60,897	The biomass collection area for AR-, FR-, and WF-based combined torrefaction and pelletization plant are 9,465,170, 18,300,188, and 72,504 ha, respectively.

Table 3-2: Life cycle energy and emission factors for materials, fuels, electricity, fertilizer, and pesticide. N – nitrogen, P – phosphorus, and K – potassium.

Raw materials, fuels, and electricity					
Impacts	*Recycled-steel*	*Electricity*	*Diesel*	*Natural gas*	*Comments/sources*
HHV (MJ/kg)	-	-	46.03	49.1	Life cycle energy and emission factors of steel, aluminum, concrete, diesel, and natural gas are directly taken from Kabir and Kumar (2011), hence are not presented here. Factors for recycled-steel are normalized for per tonne (t) of material (Kabir et al., 2012). HHV and density of diesel and electricity are taken from Environment Canada (2009). Energy and emission impacts of electricity are corresponding to 1 MWh of grid electricity generation in Alberta (Zhang et al., 2010; Sultana and Kumar, 2011a;
Density (kg/m^3)	-	-	832	0.78	
GJ/t	9.7	2.86	-	-	
kg CO_{2eq}/t	1819	912	-	-	
kg SO_{2eq}/t	15.4	4.2	-	-	
kg (NO_x + VOC)/t	7.02	1.6	-	-	
Fertilizers and pesticide					
Impacts	*N*	*P*	*K*	*Pesticide*	
kg CO_{2eq}/kg	3.27	1.34	0.64	24.5	Like other energy and emission factors, these are also determined based on the life cycle of fertilizer/pesticide production (Kabir and Kumar, 2011; Kim and Dale, 2004).
kg SO_{2eq}/kg	0.007	0.001	0.001	0.036	
kg (NO_x + VOC)/kg	0.011	0.002	0.002	0.056	
GJ/kg	0.05	0.01	0.004	0.12	

3.4.2. Biomass transportation (UP 2)

Biomass harvesting and collection area have been modeled assuming geometric and tortuosity factor to be 1 and 1.27, respectively (Overend, 1982). Collection area for AR and forest (FR, WF) biomass is assumed to be square and circular shape, respectively. Note that, preprocessing plant will be located at the intersecting point of the diagonals of the square and centre of the circle, respectively (Kabir and Kumar, 2011). Inventory data for biomass transportation are presented in Table 3-1.

It is assumed in the study that FR-chips and AR-bale will be transported by truck to the biomass preprocessing plant using the existing road network (Kumar et al., 2003; Kabir and Kumar, 2011). Hence, impacts of road construction are disregarded for these two feedstocks under biomass transportation (UP 2). However, impacts of truck manufacturing, operation (loaded/empty), recycling, and disposal are included for all three feedstocks. Unlike FR and AR, impacts of primary road construction are included in UP 2 of WF-based power generation pathways. Primary road network is used to transport the WF-chip to the biomass preprocessing plant. Primary road construction required for the whole forest torrefied pellet (WF-TOP) based power generation pathway is estimated to be 350 km. On the other hand, for either of the WF-pellet (WF-P) and chip (WF-Ch) based power generation pathways it is 290 km (Kabir and Kumar, 2011). The disparity in the requirement of road construction is predominantly because of the mass loss in the process of combined torrefaction and pelletization. Energy and

emission factors of road construction are adopted from Kabir and Kumar (2011). Note that, impacts from secondary road construction are disregarded for two reasons. First, lack of credible data and second, their length is negligible compared to the primary road network (Kabir and Kumar, 2011). A sensitivity case is developed for WF-based power generation pathways excluding the road construction impacts from the system boundary. Inventory data for the trucks used in transporting different forms of biomass feedstocks are given in Table 3-3. Note that, transportation of biomass feedstock is constrained by either payload or volumetric capacity of the truck. Whenever a truck carries load lower than the payload (former example, trips for reloading the feedstocks, etc.), actual fuel consumption is calculated using the Equation 3.1 (Sultana and Kumar, 2011a).

$$F_a = F_e + \{ (F_f - F_e) \times (L_a / L_p) \} \qquad (3.1)$$

Where, F_a = actual fuel consumption by truck while transporting load L_a (L/km), F_e = fuel consumption by the empty truck (L/km), F_f = fuel consumption by a fully loaded truck (L/km), L_a = actual load being carried by the truck (t), and L_p = payload of the truck (t).

Table 3-3: Inventory data for biomass transport in different forms [a]

Biomass form	Moisture content, wt.%	Bulk density, kg/m^3	Gross vehicle weight, t	Truck payload, t	Fuel consumption, L/km (empty/full load)	Volumetric capacity of truck, m^3	Weight carried by truck, t	Sources
AR-bale	14	180	38	23	0.24/0.33	70	12.6	Mann and Spath, 1997
AR-pellet	8	600	60	40	0.3/0.48	70	40	Sokhansanj et al., 2010; Sultana and Kumar, 2011a.
AR-TOP	3	800	60	40	0.3/0.48	70	40	Mann and Spath, 1997
FR-chip	45	235	38	23	0.24/0.33	70	16.5	Mann and Spath, 1997
FR-pellet	8	600	60	40	0.3/0.48	70	40	Sokhansanj et al., 2010; Sultana and Kumar, 2011a
FR-TOP	3	800	60	40	0.3/0.48	70	40	Sokhansanj et al., 2010; Sultana and Kumar, 2011a
WF-chip	50	250	38	23	0.24/0.33	70	17.5	Mann and Spath, 1997
WF-pellet	8	600	60	40	0.3/0.48	70	40	Sokhansanj et al., 2010; Sultana and Kumar, 2011a.
WF-TOP	3	800	60	40	0.3/0.48	70	40	Sokhansanj et al. 2010; Sultana and Kumar, 2011a.

[a] The lifetime of the truck is considered to be 540715 km. It is assumed that, the truck contains 98% steel on mass basis (Mann and Spath, 2001).

3.4.3. Preprocessing plant (UP 3)

3.4.3.1. Handling and storage plant

This study assumes the as-received moisture content of AR, FR, and WF to be 14, 45, and 50 wt.%, respectively (Sultana and Kumar, 2011a; Kabir and Kumar, 2011). The maximum allowable moisture content for direct co-firing of biomass is 20 wt.% (Sebastián et al., 2007). Hence, feedstock drying is not imperative for power generation pathways that utilize AR-bale. Feedstock preprocessing operations like milling, grinding, etc. are also not required until the AR-bale reaches the power plant. However, FR- and WF-chips are needed to be dried in case of direct co-firing once these feedstocks reach the power plant. Impacts of building the infrastructure (construction, decommissioning, recycling, and disposal) for AR-bale-, FR-chips-, and WF-chips-based handling and storage plants are assumed to be 5% of their respective preprocessing plant (discussed in the following sub-sections). Impacts of plant decommissioning are determined based on the previous study done by the authors (Kabir and Kumar, 2011). Truck used to transport the plant materials for disposal (landfilling), would be similar to the truck used in biomass transportation. Inventory data for the truck are given in Table 3-3. Impacts of the truck operation for landfilling are evaluated based on the 50 km distance between the plant and landfilling site. Emissions occurring during landfilling are adopted from Kabir and Kumar (2011). During decommissioning phase, concrete and aluminum of the plant are considered to be completely landfilled. In contrast, 75% of the plant steel is recycled and the rest is

lanfilled. Inventory data for the raw material, energy, and equipment in-flow to the handling and storage plant (UP 3) of biomass feedstocks are presented in the Table B-1 of Appendix B.

3.4.3.2. Pellet plant

In a pellet plant, biomass feedstocks go through a series of operations including drying, grinding, conditioning, pelleting, cooling, screening, and bagging. All of these operations are energy intensive. FR- and WF-chips have relatively higher moisture content than AR-bale. To economize the transportation of bio-pellets to the end-user, this study assumes that the moisture level of bio-pellets would be 8 wt.% irrespective of the feedstock. Therefore, significant amount of energy (natural gas and electricity) is used for drying purpose in a bio-pellet plant. Before pelleting, ground biomass feedstocks must be steam-conditioned to produce durable pellets and minimize fines. Steam required for the conditioning is produced from natural-gas-fired boiler with an efficiency of 80% (Sultana et al., 2010). Typically, steam requirement for conditioning is 4% (mass basis) of dry biomass feedstock (Thek and Obernberger, 2004). Total thermal energy requirement for FR-, WF-, and AR-based pellet plant are considered to be 26.9, 33.2, and 2.1 MW_{th}, respectively. Higher thermal energy consumption for the FR- and WF-based plants is driven by two reasons; difference in plant size (290,000 and 150,000 dry tonne pellet/year, respectively, for FR/WF and AR) and

difference in the as-received moisture content (45, 50, and 14 wt.%, respectively, for FR, WF, and AR). This study assumes that, all the thermal energy for drying is supplied by burning natural gas.

Pellet plant based on AR-bale, requires 2895 kW including the power requirement for primary grinder, dryer, hammer mill, boiler, pellet mill, cooler, pellet storage, and others (peripheral equipments, lighting, and heating) (Sultana et al., 2010; Campbell, 2007). In contrast, WF- and FR-based pellet plant consumes 7020 and 6925 kW, respectively (Thek and Obernberger, 2004; Uslu et al., 2008). Energy and environmental impacts of pellet plant construction, decommissioning, recycling, and disposal are also included in this study. Assumptions related to plant decommissioning, recycling, and disposal are stated in section 3.4.3.1. Inventory data for the raw materials input to the pellet plant construction corresponding to all feedstocks are provided in the Table B-1 of Appendix B. The life cycle energy and emission factors for the raw materials are provided in Table 3-2.

3.4.3.3. Torrefied pellet plant

Torrefaction is a mild pyrolysis process performed between 200 and 300°C at atmospheric pressure in the absence of oxygen (Prins et al., 2006). Torrefaction combined with pelletization improves the biomass fuel qualities significantly and the corresponding inventory data are presented in Table 3-1. It has been reported

that, size reduction of torrefied biomass requires 50−85% less electrical energy than the fresh biomass (Prins et al., 2006). Torrefied pellet production process consists of several operations including initial heating, drying, torrefaction, cooling, size reduction, and pelletization. One of the key advantages of this process is that, utility fuel consumption in biomass drying is either eliminated or substantially minimized through the utilization of torrefaction gas (Uslu et al., 2008). Moisture content of torrefied pellet is considered to be 3 wt.% in this study. Torrefied pellet plant fed by AR-bale (150,000 dry tonne pellet/year) consumes 2900 kW. In contrast, plants (290,000 dry tonne pellet/year) fed by FR and WF feedstocks, respectively, expend 6400 and 6500 kW (Uslu et al., 2008; Thek and Obernberger, 2004; Sultana and Kumar, 2011a). Thermal energy requirement for the torrefied pellet plants based on AR, FR, and WF feedstock are considered to be 1.6, 15.3, and 18.7 MW_{th}, respectively (Uslu et al., 2008). This study assumes that natural gas will be utilized to supply the thermal energy to the torrefied pellet plants. Energy and environmental impacts of torrefied pellet plant construction, decommissioning, recycling, and disposal are included in the study. Impacts of decommissioning, recycling, and disposal are investigated based on the assumptions stated in section 3.4.3.1. Inventory data for the material and energy flows for the construction of torrefied pellet plant are provided in the Table B-1 of Appendix B.

3.4.4. Transportation to end-user (UP 4)

This unit process (UP 4) involves the impacts of the transportation of preprocessed biomass feedstocks to the coal-fired power plant. This study assumes that AR will be collected from the central areas of census division 5 in the Province of Alberta since it was found to be the best yield site for AR (Sultana et al., 2010). Boreal forest comprises almost 48% of the land area of Alberta. This study assumes that forest biomass (FR/WF) will be collected from the regions near Drayton Valley. The distance from these biomass collection areas to the existing coal-fired power plant of Alberta varies in the range of 100−500 km (AMEC, 2006). Therefore, in the base case, distance between biomass preprocessing plant and coal-fired power plant is considered to be 500 km. However, two sensitivity cases are developed considering other distances. Energy and environmental impacts of truck manufacturing, operation (empty/loaded), recycling, and disposal are taken into account. Note that, impacts from the primary road construction (required for biomass collection) are considered in UP 2. However, impacts of road construction are disregarded in UP 4 assuming that the biomass feedstocks would be transported to the power plant from biomass preprocessing plant using the existing road network. Table 3-3 provides the specifications of the truck used in feedstock transportation to the end user. Methodologies to calculate the actual load carrying capacity and fuel consumption by truck are described in the section 3.4.2.

3.4.5. Power production (UP 5)

This study investigates the direct and parallel co-firing options of power generation from biomass feedstocks in various forms. During direct co-firing, biomass and coal are simultaneously fed into the same boiler. Direct co-firing involves blending of biomass and coal followed by processing of the mixture through the coal mills, crushers, pulverizer, and burner. However, this technique can be modified for feedstocks in the form of pellet and TOP. Feedstocks in these forms are mixed with coal after the coal milling since these feedstocks can be crushed readily and evenly to mix with the milled coal (Maciejewska et al., 2006). Therefore, biomass feedstocks in the form of pellet and TOP are only analyzed for direct co-firing. The parallel co-firing involves facilitating the power plant with separate biomass pretreatment, feeding, and combustion system. This technique is relevant to feedstocks in the form of chips and bale. Feedstocks in the form of bale and chips may make the fuel preparation, feeding, and combustion system of the power plant complex if these are directly co-fired due to their higher moisture content, particle size, and non-uniform combustion behavior. Nevertheless, feedstocks in the form of chips and bale are analyzed for direct co-firing as well. As mentioned earlier, the maximum allowable moisture content of biomass feedstocks for direct co-firing 20 wt.%. Therefore FR and WF feedstocks needed to be dried before direct co-firing. It is assumed that both FR and WF feedstocks will be dried to a moisture content of 18 wt.% from their respective original moisture content of 45 and 50 wt.%. Thermal energy required in evaporating one tonne of water from biomass feedstocks is estimated to be 3600 MJ (Thek and

Obernberger, 2004). Electrical energy requirement to dry the FR- and WF-chips for direct co-firing are determined to be 665 and 790 kW, respectively (Thek and Obernberger, 2004). Note that, FR- and WF-chips must be pulverized down to 3mm size for successful direct co-firing with coal. Biomass feedstocks in the form of chips (FR/WF) undergo a single-stage size reduction process. On the other hand, feedstock in the form of bale (AR) goes through a two-stage size reduction process. Energy requirement for the former and latter case is 495 and 640 MJ_{th}/tonne of feedstock processed, respectively. Note that, drying and size reduction are not imperative to FR- and WF-feedstocks in case of parallel co-firing. Note that, energy and emission impacts associated with the coal combustion during co-firing are adopted from literature. Life cycle emissions from the coal-fired power plant are considered to be 1160 kg CO_{2eq}/MWh, 6.2 kg SO_{2eq}/MWh, and 1.94 (NOx + VOC)/MWh (McCulloch et al., 2000). The thermal efficiency of the pellet and TOP-based power generation pathways is assumed 34%, for other pathways it is assumed 33% (Sebastián et al., 2007). However, a sensitivity case has been developed to analyze the impact of plant efficiency on the life cycle results.

This study considers biomass combustion as carbon neutral for CO_2 emission only; all other environmental emissions are accounted. Emission factors for the combustion of different biomass feedstocks are presented in Table 3-4.

Table 3-4: Emission factors for the combustion of biomass in different forms. AR = agricultural residue, FR = forest residue, WF = whole forest, and TOP = torrefied pellet.

Emissions	AR-bale	AR pellet/ TOP	Wood (FR/WF) chip	Wood (FR/WF) pellet/TOP	Sources
CO_2	0	0	0	0	
CH_4	8.92E-02	4.60E-03	1.13E-01	5.82E-03	
N_2O	5.36E-02	3.72E-02	6.99E-02	4.85E-02	Pa et al.,
CO	1.07E+01	4.18E+00	3.23E+00	1.26E+00	2011; Pastre,
VOC	1.13E-02	2.91E-02	1.13E-02	2.91E-02	2002
NO_x	1.60E+00	1.67E+00	1.38E+00	1.44E+00	
SO_2	2.31E+00	8.39E-01	1.34E-01	4.85E-02	

This study includes the energy and environmental impacts of power plant retrofitting construction, and associated decommissioning, recycling and disposal (landfilling). It is assumed that impacts from retrofitting would be 5 and 15% of the newly constructed coal-fired power plant (450 MW), respectively, for the direct and parallel co-firing option (Sebastián et al., 2007). The landfilling distance is considered to be 50 km. This study also considers the impacts of ash disposal, which is a complementary nutrient replacement operation. Note that, in case of direct co-firing, ash produced from the power plant is a mix of coal and biomass ash. In contrast, for parallel co-firing ashes from the coal and biomass remain separate. The former case limits the utilization of ash in commercial applications including construction industry and underground mining

(Maciejewska et al., 2006). Therefore, to ensure an identical system boundary, this study assumes that, ash produced from the biomass co-firing plants will be utilized for nutrient replacement through landfilling them at a distance of 50 km from the plant. Ash will be applied at a rate of 1 tonne/ ha using a commercial 40′ fertilizer spreader. The productivity, fuel consumption rate, and lifetime of the spreader is estimated to be 4.4 ha/hr, 5 L/hr, and 1200 hr, respectively (Mann and Spath, 1997). Truck used in the transportation of ash and plant materials for landfilling is similar to the truck used in biomass transportation and relevant inventory data are presented in Table 3-3.

3.5. Result and discussion

3.5.1. Life cycle greenhouse gas emissions impact

As mentioned earlier, the life cycle of each power generation pathway is divided into five unit processes (UP) which are: biomass production (UP 1), biomass transportation (UP 2), preprocessing (UP 3), transportation to end-user (UP 4), and power production (UP 5). The life cycle GHG emission impacts of the direct and parallel co-firing pathways for the feedstocks in the form of bale and chip are shown in Figure 3-2. Over 20 years, a 290,000 dt/yr. plant of FR- and WF-chip can contribute 8932 GWh to a 450 MW coal-fired power plant operating 6000 h/yr.; this is equivalent to a co-firing rate of 16.54% (energy basis). In contrast, a 150,000 dt/yr. plant of AR-bale can supply 4066 GWh at a co-firing rate of 7.53% (energy basis). As shown in Figure 3-2, life cycle GHG emissions from the FR-

chip-based direct and parallel co-firing pathway is 1003 and 986 kg CO_{2eq}/MWh, respectively. Similarly, for WF-chip-based pathways they are 1013 and 992 kg CO_{2eq}/MWh, respectively and for AR-based pathways these are, 1091 and 1090 kg CO_{2eq}/MWh, respectively. For all the feedstocks, GHG emissions from the direct co-firing pathway are higher than the respective parallel co-firing pathway. Size reduction operation (section 3.4.5) involved with the direct co-firing pathways is the main reason for this. For the FR-chip-based direct and parallel co-firing pathways, UP 1, UP 4, and UP 5 are responsible for most of the GHG emissions. These unit processes contribute 0.3, 1.04, and 98.5%, respectively, to the overall GHG emissions from the FR-chip-based direct co-firing pathway. Note that, for this co-firing pathway coal and biomass are responsible for 97.9 and 2.1% of the emission from UP 5, respectively. For FR-chip-based parallel co-firing pathway, UP 1, UP 4, and UP 5 contribute 0.3, 1.06, and 98.5%, respectively, to the overall GHG emissions. Like FR, most of the emissions for WF-chip-based direct co-firing pathway comes from UP 5 (97.93%), followed by UP 4 (1.1%), UP 1 (0.64%), UP 2 (0.35%), and UP 3 (0.0005%). For WF-chip-based parallel co-firing pathway, these unit processes contribute 97.89, 1.1, 0.65, 0.35, and 0.0006%, respectively, to the overall GHG emissions. Impact of UP 5 is less for the latter case since biomass size reduction is not imperative to the pathway. For AR-bale-based direct co-firing pathway, most of the emissions come from UP 5 (98.75%), followed by UP 1 (0.81%), UP 4 (0.40%), UP 2 (0.04%), and UP 3 (0.0003%). For AR-bale-based parallel co-firing pathway, these unit processes contribute almost at the same rate. Note that, the impacts of

UP 1 for AR-based pathways are due to the numerous operations (farming, fertilization, straw processing, etc.) involved in biomass production, which are described in section 3.4.1. Note that, irrespective of the pathway, majority of the GHG emission from UP 5 comes from the coal combustion. GHG emissions from the WF-based pathways are higher than the FR-based pathways due to two key reasons. First, WF feedstock has higher moisture content than FR. Second, unlike FR, WF-based pathways involve the impacts of road construction. Impacts from AR-bale-based pathways are higher than the FR-chips- and WF-chips-based pathways due to their lower rate of co-firing.

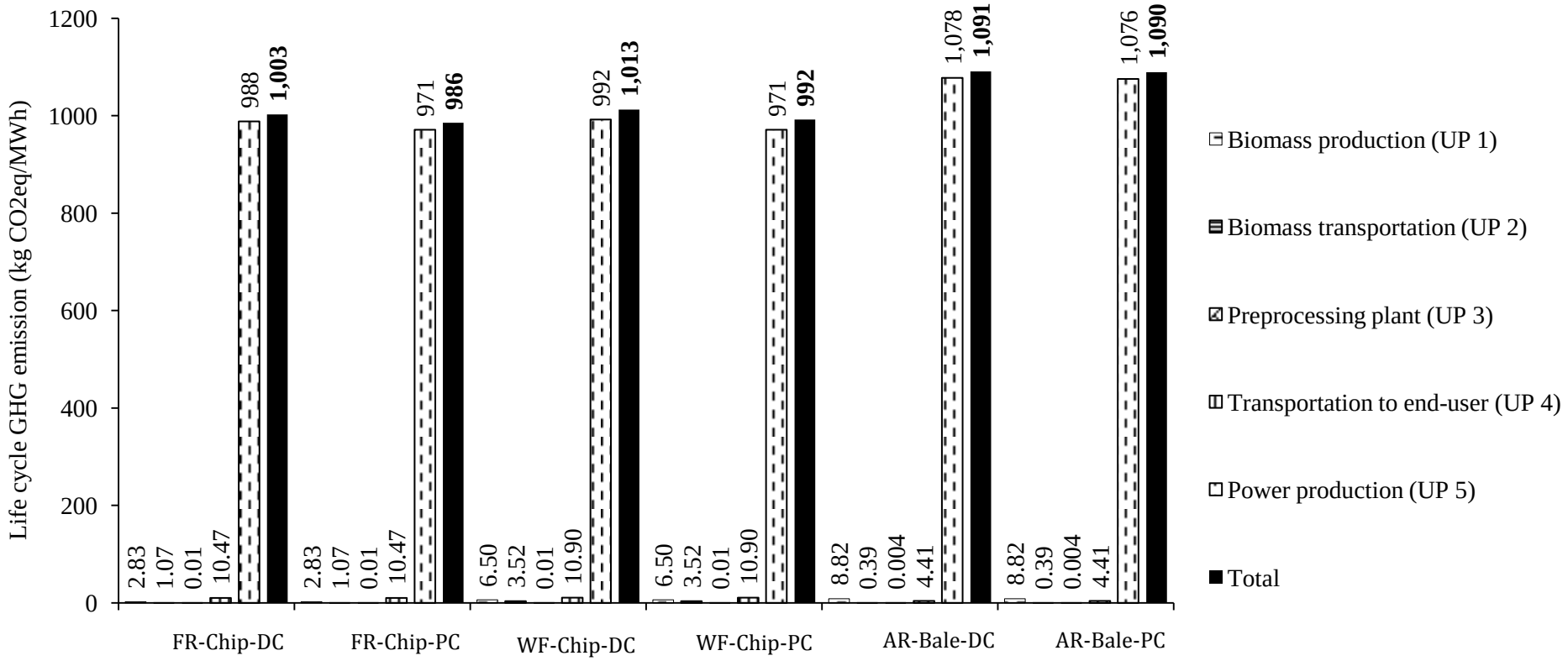

Figure 3-2: Life cycle GHG emissions from the chip- and bale-based co-firing pathways. FR=forest residue, WF= whole forest, AR=agricultural residue, DC= direct co-firing, and PC= parallel co-firing.

Figure 3-3 compares the pellet- and TOP-based power generation pathways of all the feedstocks. Over 20 years, a 290,000 dt/yr. plant of FR- and WF-pellet can contribute 9,203 GWh to a 450 MW coal-fired power plant operating 6,000 h/yr.; this is equivalent to a co-firing rate of 17.04% (energy basis). In contrast, a torrefied pellet plant of any of these feedstocks can supply 11,043 GWh at a co-firing rate of 20.45% (energy basis). An AR-pellet plant of 150,000 dt/yr. capacity, can contribute 4,189 GWh at a co-firing rate of 7.76% (energy basis). On the other hand, a torrefied pellet plant of AR feedstock with a capacity of 150,000 dt/yr can deliver 5,022 GWh; this is equivalent to a co-firing rate of 9.30% (energy basis). As shown in Figure 3-3, for pellet-based power generation, lowest GHG emissions can be obtained using FR feedstock (1004 kg CO_{2eq}/MWh), followed by WF (1014 kg CO_{2eq}/MWh) and AR (1091 kg CO_{2eq}/MWh). Power production (UP 5) is the major contributor to the overall GHG emissions from the pellet-based FR (96%), WF (95%) and AR (98%) pathway. It is apparent from the Figures 3-2 and 3-3 that, for any given feedstocks pellet-based power generation pathway is found expensive than the bale/chips-based pathway from the GHG emissions perspective, despite having significant amount of GHG emissions reduction in UP 4 (transportation to end-user) due to densification. The key reason is that, pellet plant involves extensive consumption of natural gas and electricity (section 3.4.3.2). As Figure 3-3 suggests, for TOP-based power generation, lowest GHG emissions can be obtained using FR feedstock (957 kg CO_{2eq}/MWh) followed by WF (967 kg CO_{2eq}/MWh) and AR (1074 kg CO_{2eq}/MWh). Power production unit process (UP 5) is the major

contributor to the overall GHG emissions from the FR (96.6%), WF (95.6%), and AR (98%) pathway. The GHG emissions' intensity from UP 4 reduces by 66.7 and 68.1% for FR- and WF-TOP-based pathway compared to the FR- and WF-chip, respectively, due to densification. In contrast, AR-TOP-based power generation concedes 59.1% less emission in UP 4 compared to the AR-bale due to densification. For all the feedstocks, TOP-based power generation pathway exhibit lower emission intensity than the respective pellet-based pathway. There are two key reasons for that. First, energy ingestion in the TOP plant is less compared to its respective pellet plant for any given feedstock since it does not require natural gas for feedstock drying (section 3.4.3.3). Second, irrespective of the feedstock, TOP has higher bulk and energy density compared to pellets, which translates into the lower GHG emissions from the transportation to the end-user (UP 4) and higher power output from UP 5, respectively.

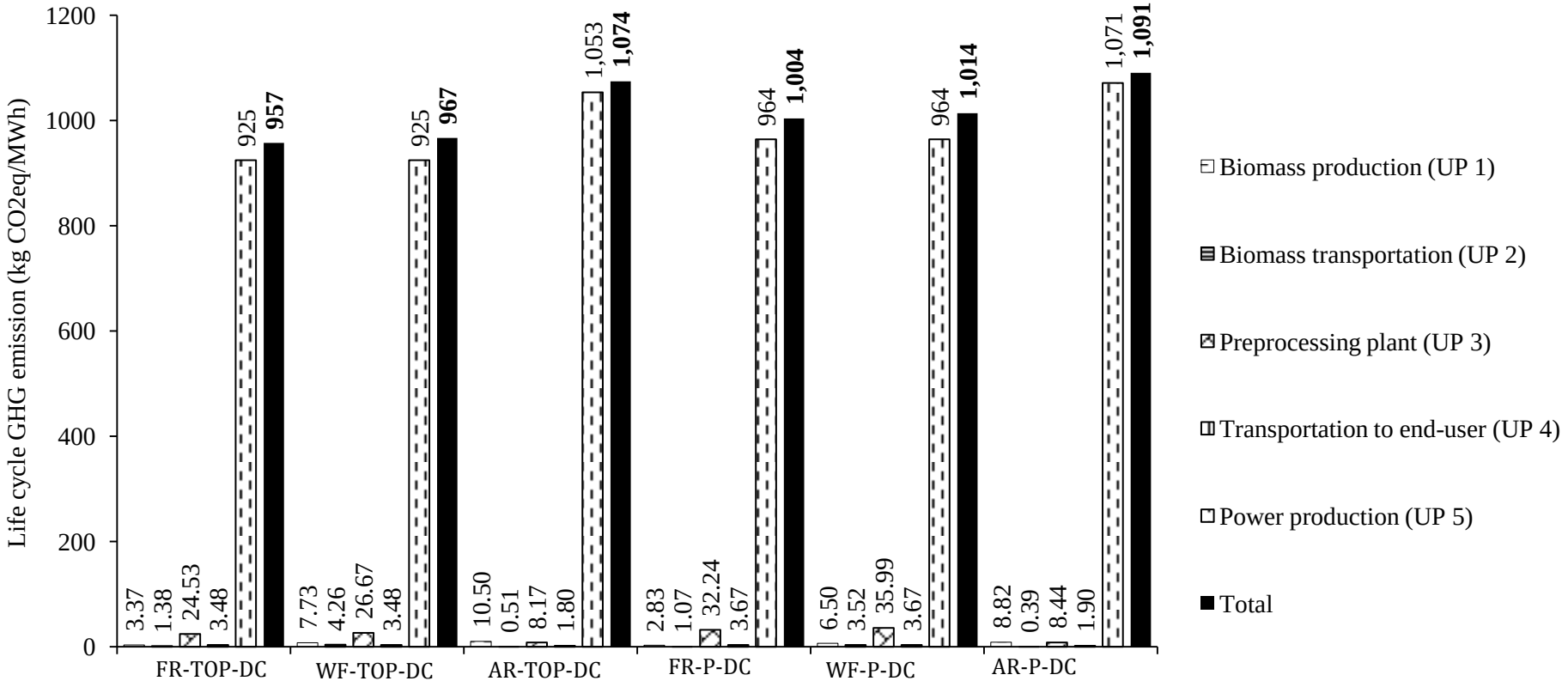

Figure 3-3: Life cycle GHG emissions from the TOP- and pellet-based co-firing pathways. FR = forest residue, WF = whole forest, AR = agricultural residue, TOP = torrefied pellet, P = pellet, DC = direct co-firing, and PC = parallel co-firing.

Overall, FR-based power generation pathways demonstrate life cycle GHG emissions in the range of 957−1004 $kgCO_{2eq}$/MWh. Life cycle GHG emissions from the WF- and AR-based pathways lie in the range of 967−1014 and 1074−1091 $kgCO_{2eq}$/MWh, respectively. Note that, life cycle GHG emissions for coal-fired power generation in Alberta are found to be 1,160 kg CO_{2eq}/MWh (McCulloch et al., 2000). Therefore, GHG emissions from Alberta's grid can be significantly mitigated employing the biomass feedstocks for co-firing. The mitigation potentials of the biomass co-firing pathways are illustrated in Table 3-6. Some of the studies have reported life cycle GHG emissions from the biomass co-fired power in the range of 665−1100 $kgCO_{2eq}$/MWh (Liu et al., 2010; Hartmann and Kaltschmitt, 1999; Mann and Spath, 2001; Zhang et al., 2010). However, some of these studies excluded the impacts from the operations like biomass farming, fertilizing, and processing from their respective system boundary. In addition, the level of co-firing was different for each study. Lastly, some of these studies considered the power plant to be located very near to the biomass collection area and biomass combustion to be GHG emissions neutral.

3.5.2. Life cycle acidification impact

The life cycle acidification impacts from the chips- and bales-based power generation pathways are shown in Figure 3-4. Like GHG emissions, for any

feedstock (chips and bales), ARP emissions are found lower for its parallel co-firing pathway compared to the respective direct co-firing. For FR-chips-DC pathway, most of the ARP emissions originate from UP 5 (98.9%), followed by UP 4 (0.84%), and UP 1 (0.21%). For other three pathways of power generation utilizing FR- and WF-chips, impacts of these three unit processes are predominant in their respective life cycle emissions and for any pathway, their relative contribution to the overall emissions are close to the percentage mentioned earlier. Impact of UP 5 is even more significant for AR-bale-based pathways, where it contributes 99.18 and 99.17% of the life cycle ARP emissions, respectively, for the DC and PC pathways. Like FR- and WF-chips based pathways, impacts of UP 3 are found insignificant for AR-bale-based pathways.

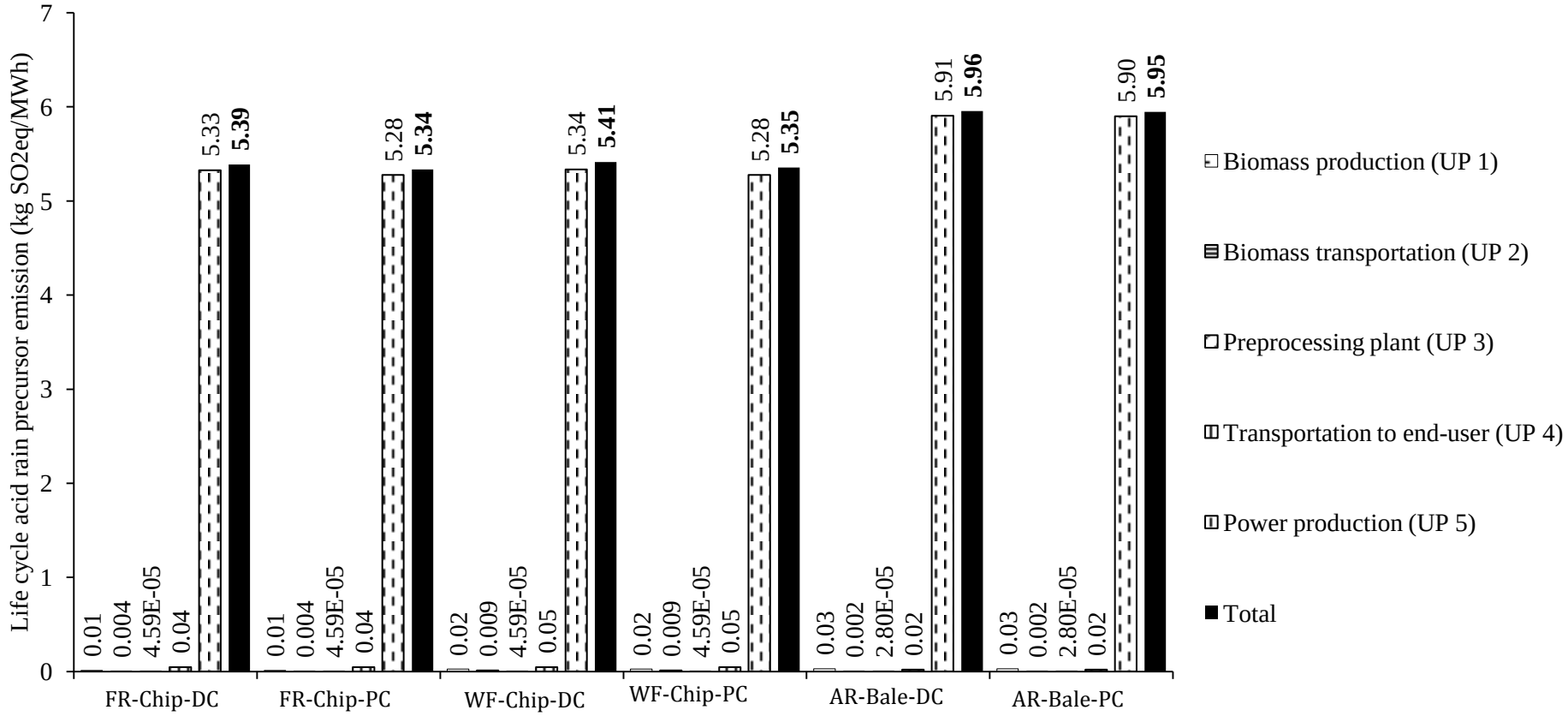

Figure 3-4: Life cycle acidification potential of the chip- and bale-based co-firing pathways. FR = forest residue, WF = whole forest, AR= agricultural residue, DC = direct co-firing, and PC = parallel co-firing.

As shown in Figure 3-5, life cycle ARP emissions from the FR-pellet- and -TOP-based pathways are lowest in comparison with their respective WF and AR pathways. For FR-pellet based pathways, the major contributor to the overall emissions is UP 5 (97.3%), followed by UP 3 (2.1%). For WF-pellet pathway, these two unit processes contribute 96.8 and 2.3%, respectively, to the overall emissions. On the other hand, for AR-pellet-based pathways, these contribute 98.7% and 0.62%, respectively. For FR-TOP-, WF-TOP-, and AR-TOP-based pathways UP 5 (97.5, 97.04, and 98.6%, respectively) is the key contributor to the life cycle ARP emissions followed by UP 3 (1.82, 1.91, and 0.62%, respectively). Note that, impacts of UP1, UP 2, and UP 4 are found insignificant for all pellet- and TOP-based pathways.

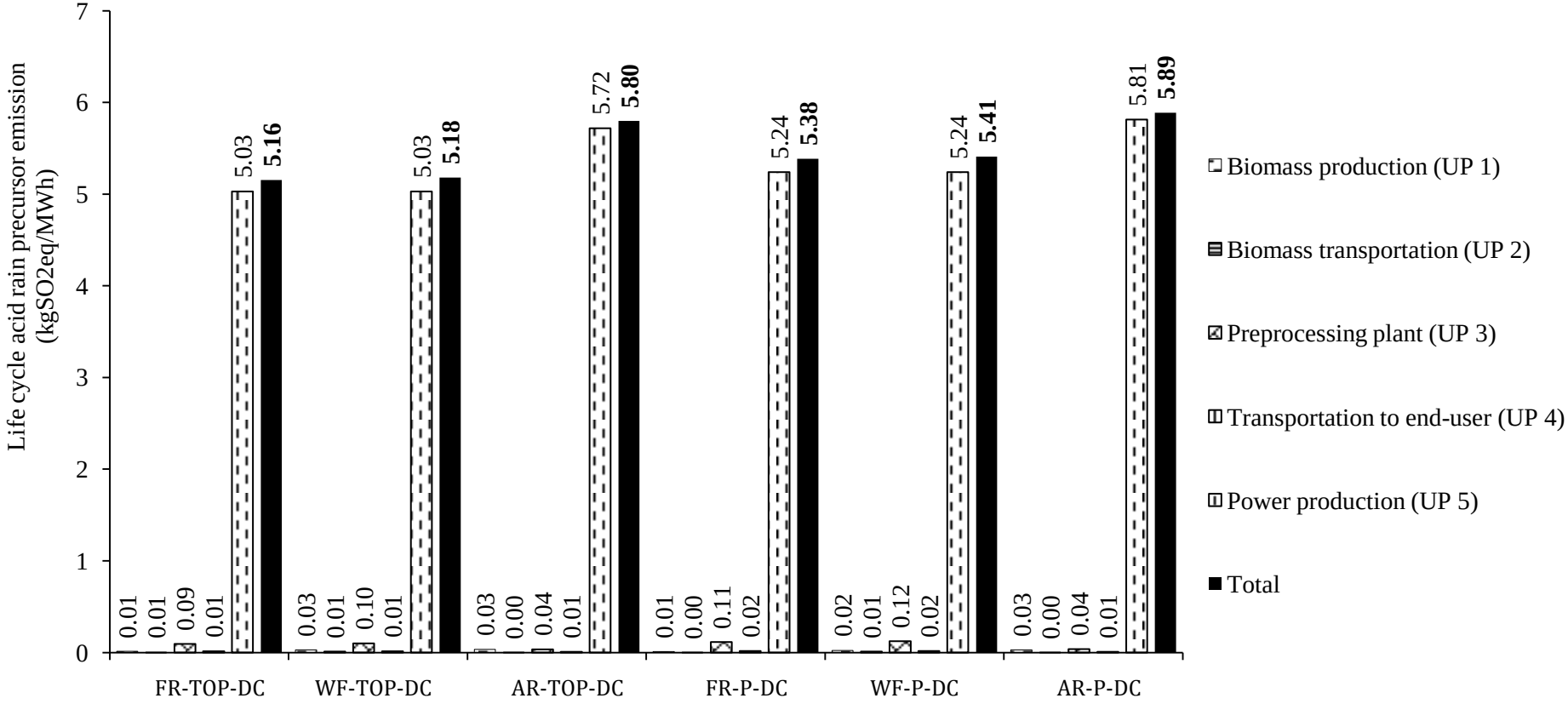

Figure 3-5: Life cycle acidification potential of TOP- and pellet-based co-firing pathways. FR = forest residue, WF = whole forest, AR = agricultural residue, TOP = torrefied pellet, P = pellet, DC = direct co-firing, and PC = parallel co-firing.

Overall, power generation from FR-based pathways demonstrate acidification potential in the range of 5.16−5.39 kg SO_{2eq}/MWh. In contrast, WF- and AR-based pathways show acidification potential in the range of 5.18−5.41 and 5.80−5.96 kg SO_{2eq}/MWh, respectively. Life cycle ARP emissions for Alberta's coal-fired power plant is 6.2 kg SO_{2eq}/MWh (McCulloch et al., 2000). Table 3-6 presents the acidification mitigation scenarios for the co-firing pathways.

3.5.3. Life cycle ground level ozone emission and energy impact

The life cycle GOP emission and energy impacts for the power generation pathways are given in Table 3-5. Among the FR-based pathways, power generation from TOP [1.79 kg (NO_x + VOC)/MWh] demonstrates the lowest GOP emissions, followed by chips-PC [1.83 kg (NO_x + VOC)/MWh], pellet-DC [1.88 kg (NO_x + VOC)/MWh], and chips-DC [1.89 kg (NO_x + VOC)/MWh]. Among these four pathways, UP 5 generates the maximum portion of the emissions (92.8–95.4%). Though impact of UP 4 (transportation to end-user) is significant for FR-chips-based pathways (3.4–3.5%), its impact is trivial for the FR-pellet- and -TOP-based pathways (1.18–1.19%) since the transportation emissions are greatly reduced due to biomass densification. Similar results are obtained for the four WF-based power generation pathways. Like FR and WF, for the four AR-based pathways, UP 5 (95.6–96.2%) is the main contributor to their respective life cycle GOP emissions.

Overall, FR-based power generation pathways exhibit life cycle GOP emissions intensity in the range of 1.79−1.89 kg (NO_x + VOC)/MWh. In contrast, for WF- and AR-based pathways, the intensity lies in the range of 1.82−1.93 and 1.92−1.95 kg (NO_x + VOC)/MWh, respectively. Note that, life cycle GOP emission for coal-fired power generation in Alberta is found to be 1.94 kg (NO_x+VOC)/MWh (McCulloch et al., 2000). Like some other studies (Maciejewska et al., 2006; Baxter, 2005), this study (in some cases) also finds higher GOP emissions intensity for the AR-based power than the coal-based power. This is primarily because of the emissions associated with the biomass production (UP 1) and power production (UP 5). Table 3-6 presents the GOP mitigation potential of co-firing pathways considered in this study.

Table 3-5: Net energy ratio and ground level ozone precursor emissions from the co-firing pathways.

	FR-TOP	WF-TOP	AR-TOP	FR-P	WF-P	AR-P	FR-chip-DC	FR-chip-PC	WF-chip-DC	WF-chip-PC	AR-bale-DC	AR-bale-PC
GJ/MWh												
UP 1	0.04	0.09	0.15	0.04	0.07	0.12	0.04	0.04	0.07	0.07	0.12	0.12
UP 2	0.02	0.02	0.01	0.01	0.02	0.01	0.01	0.01	0.02	0.02	0.01	0.01
UP 3	0.35	0.39	0.10	0.49	0.56	0.11	7.26E-05	7.26E-05	7.26E-05	7.26E-05	4.43E-05	4.43E-05
UP 4	0.05	0.05	0.02	0.05	0.05	0.02	0.14	0.14	0.14	0.14	0.06	0.06
UP 5	8.18	8.183	9.33	8.53	8.53	9.49	8.87	8.59	8.95	8.59	9.54	9.52
Total	*8.64*	*8.73*	*9.61*	*9.12*	*9.23*	*9.75*	*9.06*	*8.77*	*9.18*	*8.82*	*9.73*	*9.71*
NER	*0.42*	*0.41*	*0.37*	*0.39*	*0.39*	*0.37*	*0.40*	*0.41*	*0.39*	*0.41*	*0.37*	*0.37*
NERB[a]	*1.62*	*1.35*	*1.20*	*1.05*	*0.88*	*1.07*	*1.25*	*3.15*	*1.00*	*2.52*	*1.24*	*1.37*
kg (NO_x + VOC)/MWh												
UP 1	0.02	0.04	0.05	0.02	0.04	0.05	0.02	0.02	0.04	0.04	0.05	0.05
UP 2	0.01	0.01	0.00	0.01	0.01	0.002	0.01	0.01	0.01	0.01	0.002	0.002
UP 3	0.06	0.07	0.02	0.09	0.10	0.02	2.38E-05	2.38E-05	2.38E-05	2.38E-05	1.45E-05	1.45E-05
UP 4	0.02	0.02	0.01	0.02	0.02	0.01	0.06	0.06	0.07	0.07	0.03	0.03
UP 5	1.68	1.68	1.84	1.74	1.74	1.87	1.80	1.75	1.81	1.75	1.87413	1.87
Total	*1.79*	*1.82*	*1.92*	*1.88*	*1.91*	*1.95*	*1.89*	*1.83*	*1.93*	*1.86*	*1.94872*	*1.95*

[a] These net energy ratios (NERBs) are corresponding to the life cycle of biomass-based power. Unlike NER, these do not consider the energy inputs from coal during co-firing.

Table 3-5 shows that among the FR-based pathways, TOP-DC (NER: 0.42) proves to be the most energy efficient option followed by chips-PC (0.41), chips-DC (0.40), and pellet-DC (0.39). Most of the energy is consumed in the UP 5 (94.7, 97.8, 97.9, and 93.6%, respectively) for these pathways due to the inclusion of coal during co-firing. AR-based pathways demonstrate NER in the range of 0.369−0.375. In contrast, WF-based pathways exhibit NER in the range of 0.39−0.41. Note that, NER for the coal-based power generation is in the range of 0.31−0.35 (Hartmann and Kaltschmitt, 1999; Heller et al., 2004). For any feedstock, least NER is found for the pellet-based power generation. For the FR- and WF-based pathways, this is mainly because of the large energy consumption in the pellet plant. In contrast, for AR-based pathways, energy consumed in the farming and harvesting operations play a major role.

Table 3-6: Emission mitigation scenarios and comparison of this study with reference systems. AR = agricultural residue, FR = forest residue, WF = whole forest, P = pellet, TOP = torrefied pellet, DC = direct co-firing, and PC = parallel co-firing

Pathways	Net co-firing, % (energy basis)	Power generation in 20 years (GWh)	kg CO_{2eq}/MWh with co-firing [a]	kg SO_{2eq}/MWh with co-firing [a]	kg (NO_x + VOC)/MWh with co-firing [a]	t CO_{2eq} mitigation	t SO_{2eq} mitigation	t (NO_x + VOC) mitigation
FR-TOP-DC	20.45	11043	957.3	5.16	1.79	10943870	56412	8246
FR-P-DC	17.04	9203	1003.9	5.38	1.88	8427968	44045	3425
FR-chip-DC	16.54	8932	1002.8	5.39	1.89	8489362	43957	2859
FR-chip-PC	16.54	8932	985.8	5.34	1.83	9408525	46704	5782
WF-TOP-DC	20.45	11043	966.7	5.18	1.82	10437848	55025	6312
WF-P-DC	17.04	9203	1013.8	5.41	1.91	7895949	42629	1378
WF-chip-DC	16.54	8932	1013.2	5.41	1.93	7930206	42427	663
WF-chip-PC	16.54	8932	992.3	5.35	1.86	9055363	45677	4353
AR-TOP-DC	9.30	5022	1074.3	5.80	1.92	4627181	21736	885
AR-P-DC	7.76	4189	1090.8	5.89	1.95	3737836	16842	-318
AR-bale-DC	7.53	4066	1091.4	5.96	1.95	3706156	13218	-471
AR-bale-PC	7.53	4066	1089.5	5.95	1.95	3804106	13648	-318

[a]Life cycle emissions from the 450MW coal-fired power plant are 1160 kg CO_{2eq}/MWh, 6.2 kg SO_{2eq}/MWh, and 1.94 (NO_x + VOC)/MWh (McCulloch et al., 2000)

3.5.4. Sensitivity analysis

The objective of this parametric sensitivity analysis is to understand the effects of some of the key assumptions and parameters over the life cycle results. Note that, each sensitivity case is developed independent of other cases to ensure the comparability with the base-case. Case 1 excludes all the farming operations prior to harvesting from the system boundary of the AR-based pathways. Due to this, life cycle energy, GHG, ARP, and GOP impacts are reduced by 1.01−1.22%, 0.6−0.8%, 0.4−0.43%, and 1.7−2.1% for the AR-based pathways. Impacts of this sensitivity case are shown in detail in the Figure 3-6. Case 2 keeps the silviculture and road construction out of the boundary of the WF-based pathways. Therefore, impacts are reduced by 0.21−0.94% (Figure 3-6). Since Alberta is looking to incorporate green electricity in its grid, a sensitivity case (Case 3) is developed to realize the impacts of grid emissions intensity reduction (20%) on the co-firing pathways. As a result, the emissions intensities of AR-based co-firing pathways are lessened by 0.01−0.13% (Figure 3-6). For FR- (0−0.34%) and WF-based (0−0.34%) pathways similar results are obtained. Case 4 analyzes the impact of the distance between the biomass preprocessing and co-firing plants by modifying the transportation distances to be (a) 250 km and (b) 100 km, instead of 500 km (in the base-case). Case 4 (a) and 4 (b) causes 0.14−1.74% and 0.23−2.8% reduction in the impacts from the FR-based pathways, respectively (Figure 3-6). Similar reductions are found for the WF- (0.14−1.8% and 0.23−2.9%, respectively) and AR-based (0.06−0.7% and 0.1−1.1%, respectively) pathways, hence are not shown in Figure 3-6. Case 5 considers the power plant thermal

efficiency to be 31% and 30%, respectively, for the pellet/TOP- and chip/bale-based pathways. Due to this assumption, 0.2-0.5% of increase is observed in the base-case energy and emissions. The sensitivity of biomass yield was also analyzed. However, a ±10% change in biomass yield impacts the life cycle results by less than ±1%. Similarly, the sensitivity of plant operating factor was analyzed (0.7 for year 1, 0.8 for year 2, and 0.95 from year 3 onwards; 0.65 for year 1, 0.7 for year 2, and 0.75 from year 3 onwards). However, affects of these operating factors over the life cycle results were found to be very low (less than ±1%), thus are not presented here.

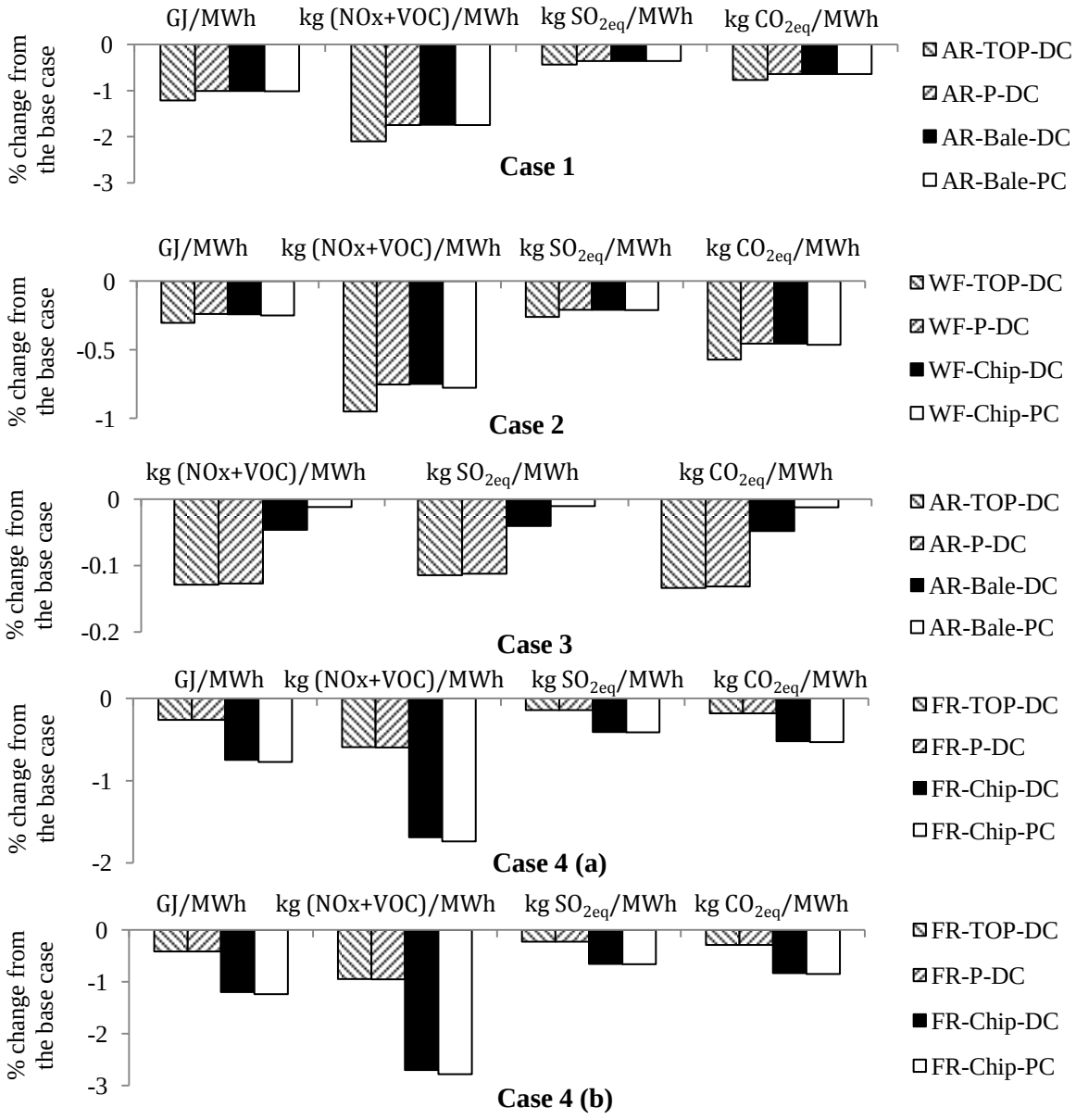

Figure 3-6: Impacts of the sensitivity cases over the life cycle results FR = forest residue, WF = whole forest, AR = agricultural residue, TOP = torrefied pellet, P = pellet, DC = direct co-firing, and PC = parallel co-firing.

3.6. Conclusion

For forest residue, whole forest, and agricultural reside, maximum net energy ratio (0.42, 0.41, and 0.38, respectively) is found for the feedstock in the form of torrefied pellet. Life cycle GHG emissions from the forest residue, whole forest and agricultural residue based pathways lie in the range of 957−1004, 967−1014 and 1074−1091 kgCO_{2eq}/MWh, respectively. On the other hand, acid rain precursor emissions lie in the range of 5.16−5.39, 5.18−5.41 and 5.80−5.96 kg SO_{2eq}/MWh, respectively. Lastly, ground-level-ozone emissions' intensities are found in the range of 1.79−1.89, 1.82−1.93, and 1.92−1.95 kg (NO_x+VOC)/MWh, respectively. Irrespective of the feedstock, least greenhouse gas, acid rain precursor, and ground level ozone emissions are obtained from the feedstock in the form of torrefied pellet which can be directly co-fired without any pretreatment. Note that, unlike conventional pellet plant, combined torrefaction and pellet plant is yet to prove its maturity for large-scale application. Though for forest reside and whole forest chips, parallel co-firing is found significantly advantageous over direct co-firing; for agricultural residue bale, the advantage is negligible. Regardless of the co-firing pathways, it can be concluded that, any of them can significantly improve the energy efficiency and emissions performance of coal-dominated power generation sector in Alberta.

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Chapter 4. Conclusions and recommendations

4.1. Conclusions

This study has investigated the life cycle impacts of three biomass feedstocks including forest residue (FR), agricultural residue (AR), and whole forest (WF) for biohydrogen and biopower production in Alberta. Biopower production pathways are analyzed based on the co-firing of different forms of biomass with coal. Life cycle net energy ratios (NER), greenhouse gas (GHG) emissions, acid-rain precursor (ARP) emissions, and ground-level-ozone precursor (GOP) emissions are evaluated for a range of biohydrogen and biopower pathways. The application targeted by biohydrogen production is bitumen upgrading. Three different technologies for producing biohydrogen are analyzed including Battelle Columbus Laboratory (BCL), Gas Technology Institute (GTI), and fast pyrolysis. Fast pyrolysis pathways to biohydrogen are inspected for both truck (P I) and pipeline (P II) transport of bio-oil. Biohydrogen produced from biomass gasification plant is transported to the bitumen upgrading plant by pipeline. Distance from the biomass gasification/pyrolysis plant to bitumen upgrading plant is considered to be about 500 km. This study has also assessed the biopower pathways for direct (DC) and parallel co-firing (PC) technologies to co-fire biomass in a coal-fired power plant. Biomass feedstocks in various densified forms including chips, bales, pellets, and torrefied pellets are analyzed. Distance

between the biomass preprocessing plant and coal-fired power plant is considered to be about 500 km.

4.1.1. Biohydrogen production from biomass gasification

This study has been performed based on the optimum biohydrogen plant capacity of BCL (3,000 dtpd for all the feedstocks) and GTI technology (3000, 4000, and 3000 dtpd for AR, WF, and FR feedstock, respectively).

Among the BCL pathways, the maximum NER (3.33) is found for FR-chips-based hydrogen; this is followed by the NERs for WF-chips (2.9) and AR-bale (2.5), respectively. As with BCL, for the GTI pathways the maximum NER (9.3) is obtained using FR-chips; this is followed by the NERs for the WF-chips (5) and AR-bale (3.5) pathways, respectively.

Among the BCL pathways, the minimum (2.96 kg CO_{2eq}/kg H_2) GHG emissions corresponds to the FR-chips-based hydrogen; this is followed by the GHG emissions for WF-chips (3.76 kg CO_{2eq}/kg H_2) and AR-bale-based (3.77 kg CO_{2eq}/kg H_2) pathways. FR-chips-based BCL pathway has minimum (6.23E−03 kg SO_{2eq}/kg H_2) ARP emissions, followed by WF-chips (7.83E−03 kg SO_{2eq}/kg H_2) and AR-bale-based (1.09E−02 kg SO_{2eq}/kg H_2) BCL pathways, respectively. As with ARP, for the GOP emissions, the lowest value (8.56E−03 kg [NO_x + VOC]/kg H_2) is obtained using FR-chips-based BCL pathway, followed by the

WF-chips (1.07E−02 kg [NO_x + VOC]/kg H_2) and AR-bale-based (1.65E−02 kg [NO_x + VOC]/kg H_2) BCL pathways.

Among the GTI pathways, FR-chips-based hydrogen exhibits the lowest (1.2 kg CO_{2eq}/kg H_2) life-cycle GHG emissions; this is followed by WF-chips (2.49 kg CO_{2eq}/kg H_2) and AR-bale (2.94 kg CO_{2eq}/kg H_2). Likewise, among the GTI pathways, minimum ARP (3.72E−03 kg SO_{2eq}/kg H_2) and GOP (4.69E−03 kg [NO_x + VOC]/kg H_2) emissions are found for FR-chips derived hydrogen. The emissions from the WF-chips (5.68E−03 kg SO_{2eq}/kg H_2 and 7.24E−03 kg [NO_x + VOC] /kg H_2, respectively) and AR-bale (9.03E−03 kg SO_{2eq}/kg H_2 and 1.33E−02 kg [NO_x + VOC] /kg H_2, respectively) pathways follow this.

For any feedstock, GTI based pathways exhibit higher life-cycle energy efficiency and lower environmental emissions compared to the respective BCL pathways. For any given gasification technology (BCL or GTI), FR-chips is found to be the best alternative among the biomass feedstocks; this is followed by WF-chips and AR-bale.

4.1.2. Biohydrogen production from bio-oil reforming

The life cycle assessment of bio-oil to hydrogen pathway is analyzed considering the optimum size of the fast pyrolysis plant (2,000 dtpd for all the feedstocks). For P I, maximum NER (9.1) is found for hydrogen produced from WF-chips; this is followed by the NERs for the FR-chips (6.5) and AR-bale (1.6) pathways,

respectively. As with P I, for the P II pathways the maximum NER (5.2) is obtained using WF-chips; this is followed by the NERs for the FR-chips (3.7) and AR-bale (1.3) pathways, respectively.

Among P I pathways, lowest GHG emissions are found for hydrogen produced from WF-chips (1.43 kg CO_{2eq}/kg H_2); this is followed by FR-chips- (1.58 kg CO_{2eq}/kg H_2) and AR-bale-based hydrogen (6.56 kg CO_{2eq}/kg H_2). Life cycle ARP (5.11E−03 kg SO_{2eq}/kg H_2) and GOP (7.42E−03 kg [NO_x + VOC]/kg H_2) emissions for producing hydrogen are lowest for WF-chips-based P I pathway. The life cycle ARP and GOP emissions of FR-chips-based P I pathway are, respectively, 6.48E−03 kg SO_{2eq}/kg H_2 and 9.58E−03 kg [NO_x + VOC]/kg H_2. In contrast, for AR-bale-based P I pathway these are 2.24E−02 kg SO_{2eq}/kg H_2 and 3.49E−02 kg [NO_x + VOC]/kg H_2, respectively.

Among the P II pathways, lowest GHG emissions (2.44 kg CO_{2eq}/kg H_2), ARP emissions (5.16E−03 kg SO_{2eq}/kg H_2), and GOP emissions (7.02E−03 kg [NO_x + VOC]/kg H_2) impacts are found for WF-chips-based hydrogen. In contrast, FR-chips-based P II pathway demonstrates life cycle GHG, ARP, and GOP impacts, respectively, 3.01 kg CO_{2eq}/kg H_2, 6.55E−03 kg SO_{2eq}/kg H_2, and 9.01E−03 kg [NO_x + VOC]/kg H_2. On the other hand, for the AR-bale-based P II pathway these impacts are 8.12 kg CO_{2eq}/kg H_2, 2.25E−02 kg SO_{2eq}/kg H_2, and 3.43E−02 kg [NO_x + VOC]/kg H_2, respectively.

Life cycle GHG emission of all biohydrogen production pathways are compared in Figure 4-1.

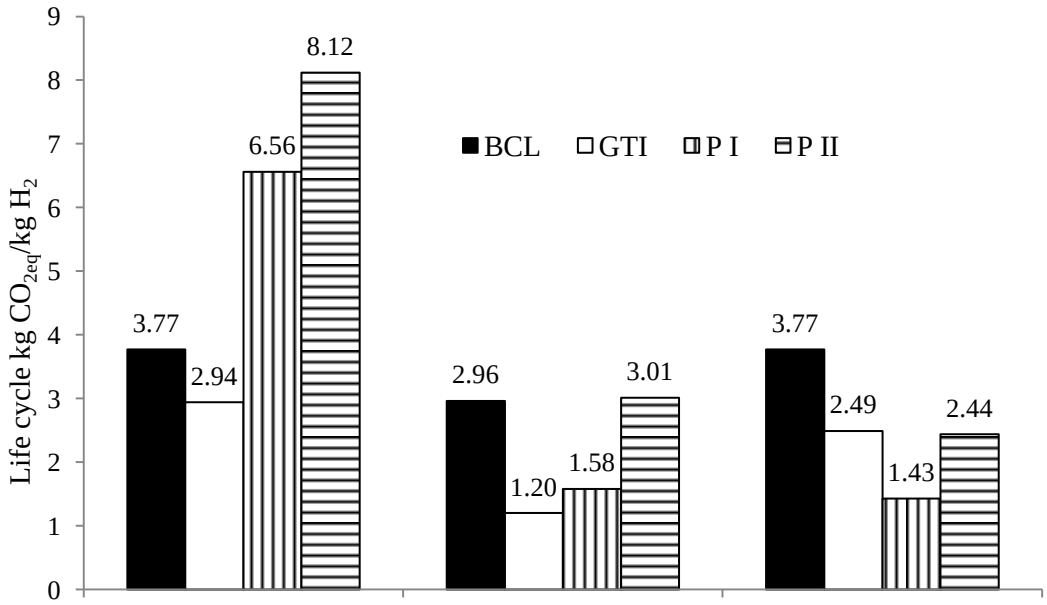

Figure 4- 1: Life cycle GHG emission comparison of all biohydrogen production pathways.

Overall, for any given feedstock, energy and environmental performance of P II pathway was better than the respective P I pathway. Therefore, truck transport of bio-oil is recommended instead of pipeline transport of bio-oil while producing hydrogen. Meanwhile, WF is the best option among the biomass feedstocks for producing hydrogen from bio-oil.

Lastly, NER for biomass-based hydrogen is always found significantly higher than the fossil-fuel-based hydrogen. In addition, the emission intensities are lower

for biohydrogen. Therefore, replacing the fossil fuels with biomass for hydrogen generation can significantly improve the overall energy efficiency and environmental performance of a bitumen upgrading plant in Alberta.

4.1.3. Biopower production from primarily densified biomass

Over 20 years, a 290,000 dt/yr. plant of FR- and WF-chip can contribute 8,932 GWh to a 450 MW coal-fired power plant operating 6,000 h/yr; this is equivalent to a co-firing rate of 16.54% (energy basis). In contrast, a 150,000 dt/yr. plant of AR-bale can supply 4,066 GWh at a co-firing rate of 7.53% (energy basis).

NERs for the FR-chip-based direct and parallel co-firing pathway are 0.4 and 0.41, respectively. For WF-chips, these are 0.39 and 0.41, respectively. On the other hand, for AR-bale these are 0.370 and 0.371, respectively.

The life cycle GHG emissions of the FR-chips-based direct and parallel co-firing pathway are 1003 and 986 kg CO_{2eq}/MWh, respectively. In contrast, for WF-chips-based pathways these are 1013 and 992 kg CO_{2eq}/MWh, respectively. On the other hand, for AR-bale-based pathways these are 1091 and 1090 kg CO_{2eq}/MWh, respectively.

The life cycle ARP emissions of the FR-chip-based direct and parallel co-firing pathways are 5.38 and 5.33 kg SO_{2eq}/MWh, respectively. In contrast, ARP emissions of the WF-chip-based pathways are 5.41 and 5.35 kg SO_{2eq}/MWh, respectively. On the other hand, ARP emissions of the AR-bale-based pathways are 5.95 and 5.94 kg SO_{2eq}/MWh, respectively.

Like GHG and ARP, GOP emissions for the FR-chips-based pathways are lowest for a given co-firing technology; GOP emissions from the direct and parallel co-firing pathways of FR-chip are 1.89 and 1.83 kg (NO_x + VOC)/MWh, respectively. GOP emissions of the WF-chip-based pathways are 1.93 and 1.86 kg (NO_x + VOC)/MWh, respectively. In contrast, for AR-bale-based pathways these are 1.948 and 1.945 kg (NO_x + VOC)/MWh, respectively.

Overall, for any primarily densified feedstock, life cycle energy and environmental profiles are found better for parallel co-firing pathway compared to its direct co-firing pathway. For a given co-firing technology, FR-chips based pathways were found to be the best among all the alternatives.

4.1.4. Biopower production from densified biomass

Over 20 years, a 290,000 dt/yr. plant of FR- and WF-pellet can contribute 9,203 GWh to a 450 MW coal-fired power plant operating 6,000 h/yr; this is equivalent to a co-firing rate of 17.04% (energy basis). In contrast, a torrefied pellet plant based on any of these feedstocks can supply 11,043 GWh at a co-firing rate of

20.45% (energy basis). An AR-pellet plant of 150,000 dt/yr. capacity, can contribute 4,189 GWh at a co-firing rate of 7.76% (energy basis). On the other hand, a torrefied pellet plant of AR feedstock with a capacity of 150,000 dt/yr, can deliver 5,022 GWh; this is equivalent to a co-firing rate of 9.30% (energy basis).

NER of the FR-pellet and -TOP based pathway is 0.39 and 0.42, respectively. In contrast, for the WF feedstock it is 0.39 and 0.41, respectively. On the other hand, for AR feedstock it is 0.369 and 0.375, respectively.

Life cycle GHG and ARP emission intensities of co-firing for different feedstocks in the form of pellet and torrefied pellet are shown in Figures 4-2 and 4-3.

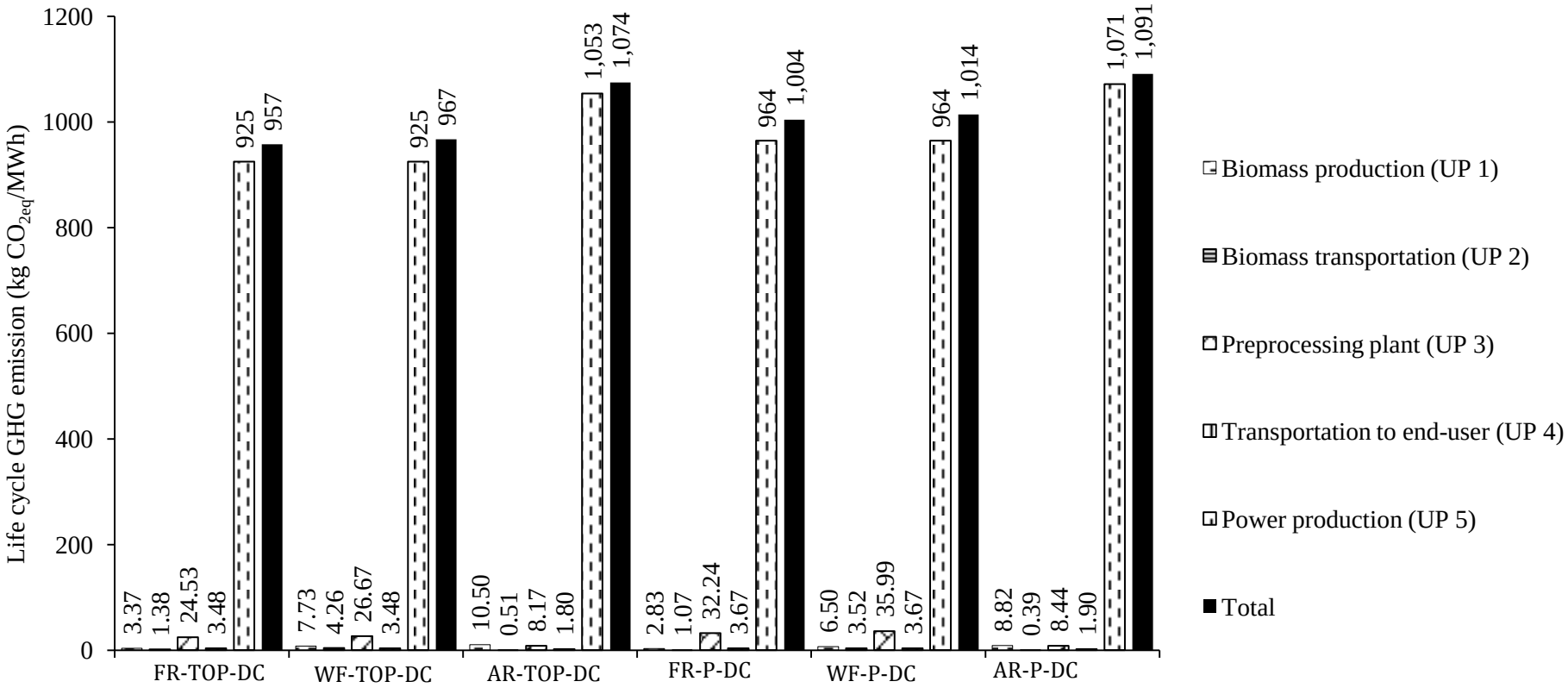

Figure 4- 2: Life cycle GHG emissions from the pellet and torrefied pellet based co-firing pathways

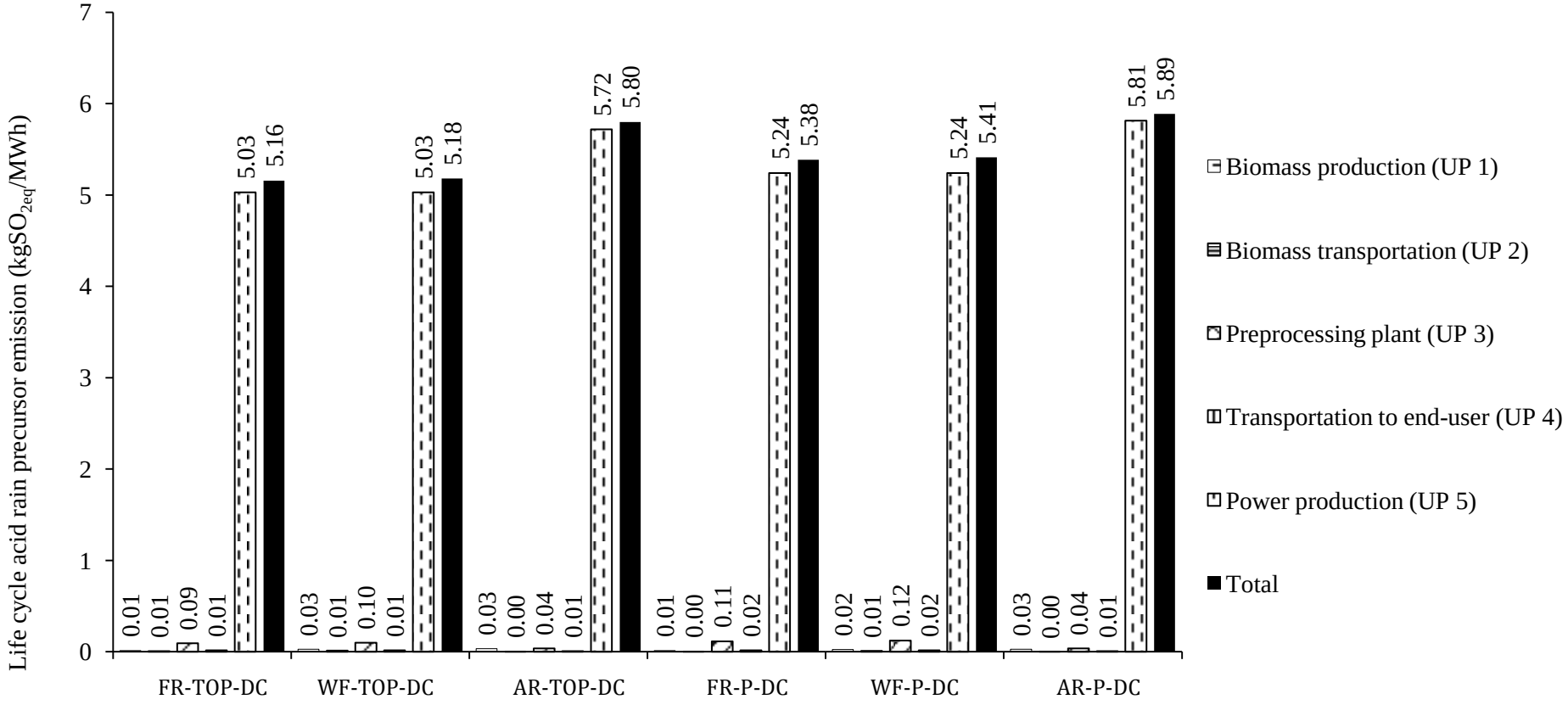

Figure 4- 3: Life cycle acid rain precursor emissions from the pellet and torrefied pellet based co-firing pathways

Life cycle GOP emissions are lowest (1.88 kg[NO_x + VOC]/MWh) for the FR feedstock among the pellet-based power generation pathways; this is followed by WF (1.91 kg [NO_x + VOC]/MWh) and AR (1.95 kg [NO_x + VOC]/MWh) feedstock. Likewise, life cycle GOP emissions are found lowest (1.79 kg [NO_x + VOC]/MWh) for the FR feedstock among the TOP-based pathways; this is followed by the WF (1.82 kg [NO_x + VOC]/MWh) and AR (1.92 kg [NO_x + VOC]/MWh) feedstocks.

For any feedstock, TOP-based power generation pathway exhibits lower emissions intensity and higher energy efficiency than the respective pellet-based pathways.

4.2. Recommendations for future work

This study has looked into the life cycle energy and emissions impacts of biohydrogen and biomass co-firing based power generation pathways in Alberta. Some key recommendations for the future research are outlined below.

- The future work should emphasize on the sustainability factors including socio-economic, water use, land use, soil erosion, biodiversity, etc. Including these factors in conjunction with the factors determined in this study, a multi-criteria assessment study could be carried out to figure out the best option for biohydrogen and biopower production in Alberta.

- Future studies should also assess the biomass feedstocks including corn stover, switchgrass, sawdust, algae, etc. for biohydrogen and biopower generation in Alberta.

- This study has looked into thermo-chemical conversion of biomass feedstocks for hydrogen production. However, future studies could focus on biochemical and fermentation conversion process. In addition to that, hydrogen production from other renewable resources including wind, photovoltaic, geothermal, etc. could also be analyzed.

- This study has investigated the dry torrefaction process of biomass. It has not looked into the wet torrefaction process. Since, not much work has been done on wet torrefaction of biomass yet, a modeling and simulation-based study could be carried out to investigate the wet torrefaction process. In addition, a small scale experimental study is also recommended to validate the modeling results.

- Alberta specific optimum sizes of combined torrefaction and pelletization plant for different biomass feedstocks are not known yet. Further research work to investigate the techno-economics of combined torrefaction and pelletization plant in Alberta would be useful.

- This study did not include the carbon capture and storage (CCS) process in the system boundary of the co-firing-based power generation. An overall life cycle analysis of the biomass co-fired power plant equipped with CCS technology should be assessed.

- This study has found that, for any feedstock, parallel co-firing demonstrates better energy and environmental performance than direct co-firing. However, it is well known that, parallel co-firing option for power generation is more expensive than direct co-firing; parallel co-firing requires facilities to have an additional feedstock processing plant. However, Alberta specific cost penalty for parallel co-firing is not known yet. It would be interesting to estimate these figures for the excess cost associated with the parallel co-firing in terms of per unit emissions and energy saved.

Appendix A

Table A-1: Inventory data for biomass production

Feed	Equipment/operation	Data and sources
FR	Forwarder	Forwarder model is Komatsu WA 250-6 138 HP. It is assumed that, 98% weight of the forwarder comes from steel (Mann and Spath, 1997). Each forwarder requires 11.6 tonne of steel. Forwarder's fuel consumption rate, productivity and lifetime are 26 L/hr, 50 m^3/hr, and 16,000 hour respectively (MacDonald, 2006).
	Chipper	Chipper model is Nicholson WFP3A. It contains 58 tonnes of steel. Fuel consumption rate, productivity and lifetime of the chipper are 110 L/hr, 28 dt/hr, and 9000 hr respectively (Desrochers et al., 1992; MacDonald, 2006).
WF	Feller	Feller model is John Deere 853J, 274 HP. It contains 28.8 tonne steel. Fuel consumption rate, productivity and lifetime of the feller are 47 L/hr, 70 m^3/hr, and 10,950 hr respectively (MacDonald, 2006).
	Skidder	Skidder model is John Deere 748 H, 189 HP. Steel weighs 14.3 tonne in skidder. Fuel consumption rate, productivity, and lifetime of the skidder are 45 L/hr, 60 m^3/hr, and 12,000 hr, respectively (Han and Renzie, 2001; MacDonald, 2006).
	Chipper	Chipper model is Morbark 50/48. It has 28.2 tonne steel. Chipper fuel consumption rate, productivity, and lifetime are 100 L/hr, 30dt/hr, and 9,000 hr respectively (MacDonald, 2006).
	Silviculture	N, P and K content in WF biomass are 0.31%, 0.05% and 0.15%,

Feed	Equipment/operation	Data and sources
		respectively (Kumar et al., 2003). Estimated diesel fuels consumption during silviculture is 2.1 GJ/ha. N, P, and K fertilizer requirement are estimated to be 258, 41 and 125 kg/ha. Pesticide requirement is assumed to be 0.17 kg/ha and operational machinery embodied energy factor is 0.41 GJ/ha (Borjesson, 1996a; Borjesson 1996b).
AR	Seeding	Seeder capacity, embodied energy factor, and fuel consumption rate are 10 ha/hr, 62.3 MJ/ha, and 39.6 L/hr respectively (Nagy, 1999).
	Fertilizing	N and P fertilizer requirements are 5.6 and 11.2 kg/ha respectively. Note that, potassium fertilizer is not required for wheat and Barley growth in Alberta (AAFRD, 2004).
	Banding granular fertilizer	Capacity, embodied energy factor, and fuel consumption rate are 8.9 ha/hr, 68 MJ/ha, and 48.2 L/hr respectively (Nagy, 1999).
	Banding anhydrous ammonia	Capacity, embodied energy factor, and fuel consumption rate are 10 ha/hr, 31 MJ/ha, and 49.8 L/hr respectively (Nagy, 1999).
	Chemical applicator	Capacity, embodied energy factor, and fuel consumption rate are 26.1 ha/hr, 10.8 MJ/ha, and 21.5 L/hr, respectively (Nagy, 1999).
	High clearance sprayer	Capacity, embodied energy factor, and fuel consumption rate are 58.6 ha/hr, 6.2 MJ/ha, and 48.9 L/hr, respectively (Nagy, 1999).
	Harvester	Capacity, embodied energy factor, and fuel consumption rate are 12.2 ha/hr, 37.5 MJ/ha and 43 L/hr respectively (Nagy, 1999).
	Raking	Capacity and fuel consumption rate are 30 dt/hr and 14.1 L/hr respectively (Nagy, 1999). It contains 1,110 kg steel and lifetime is 2,500 hr (Sokhansanj, 2008).
	Baling	Capacity, fuel consumption rate, lifetime and amount of steel

Feed	Equipment/operation	Data and sources
		requirement are 20 dt/hr, 58 L/hr, 1,500 hr, and 9350 kg respectively (Nagy, 1999), (Sokhansanj, 2008).
	Stacking	Capacity, fuel consumption rate, lifetime and amount of steel requirement are 70 dt/hr, 58 L/hr, 20,000 hr, 11.3 tonne respectively. Equipment can handle 8 bales per load. Each bale (4′x4′x9′) weighs about 0.43dt (Nagy 1999; Sokhansanj, 2008)
	Bale wrapper	Capacity, fuel consumption rate, lifetime and amount of steel requirement are 60 bales/hr, 3.3 L/hr, 10,000 hr, and 1,400 kg respectively (Nagy, 1999; Sokhansanj, 2008).
	Bale loader	Capacity, fuel consumption rate, lifetime and amount of steel requirement are 170dt/hr, 56.1 L/hr, 10,000 hr, and 2,800 kg respectively (Nagy, 1999; Sokhansanj, 2008).

Table A-2: Energy and emission impacts from different materials

Impacts	Steel	Aluminium	Concrete	Comments/sources
GJ/t	34	39.15	0.87	Energy and emission factors for steel and aluminium are determined from literature (Schleisner, 2000; White, 2007; ATHENA, 2002). Factors for concrete are estimated based on data from earlier studies (Flower and Sanjayan, 2007; Horvath, 2004 and Meil, 2006). All these factors are normalized for per tonne (t) of material delivery.
kg CO_2/t	2473	3434	120	
kg CO/t	0.93	0.75	-	
kg CH_4/t	0.04	0.07	0.03	
kg N_2O/t	0.07	0.11	8.7E-5	
kg SO_2/t	14.50	21	0.14	
kg NO_x/t	9.50	13	0.75	
kg VOC/t	0.16	0.15	-	

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Appendix B

Table B-1: Raw material inventory data of preprocessing plant (UP 3) and power production (UP 5) unit process for FR-based biopower pathways [a]

Plant type		Comments/sources
Handling and storage plant (FR-Chip)		
Steel (t)	103	This plant facilitates the handling and storage of FR-chips. Due to lack of available data, raw materials requirement for the plant is assumed to be 5% of the respective pellet plant.
Concrete (t)	317	
Aluminum (t)	1	
Pellet plant (FR-P)		
Steel (t)	2050	The scale factor for the pellet plant is considered to be 0.75 (Sultana et al., 2010). Plant materials requirement is estimated from a reference biomass plant size of 3000 dry tonne per day (dtpd) (Kabir and Kumar, 2011).
Concrete (t)	6330	
Aluminum (t)	17	
Torrefied pellet plant (FR-TOP)		
Steel (t)	2330	The scale factor for the combined torrefaction and pelletization plant is assumed 0.75 (Sultana et al., 2010). Plant materials requirement is estimated from a reference plant size of 3000 dtpd (Kabir and Kumar, 2011).
Concrete (t)	7220	
Aluminum (t)	20	
Power production (direct co-firing cases)		
Steel (t)	1155	Direct co-firing plant material requirement has been assumed to be 5% of a newly constructed coal-fired power plant. It is found that, steel, concrete, and aluminum requirement for constructing every MW capacity of a coal-fired plant is 51.3, 158.8, and 0.42 tonne, respectively (Spath et al., 1999).
Concrete (t)	3575	
Aluminum (t)	10	
Power production (parallel co-firing cases)		
Steel (t)	3470	Parallel co-firing plant material requirement has been assumed to be 15% of a newly constructed coal-fired power plant. It is found that, steel, concrete, and aluminum requirement for constructing every MW capacity of a coal-fired plant is 51.3, 158.8, and 0.42 tonne, respectively (Spath et al., 1999).
Concrete (t)	10720	
Aluminum (t)	30	

[a] Raw materials' inventory data for UP 3 and UP 5 corresponding to AR and WF feedstock are obtained employing the same methodology

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