Assessment of likely Technology Maturation (ATM) Project

Assessment of likely Technology Maturation Pathways for biojet production from forest residues

BOEING

NORAM

UBC

WESTJET

SkyNRG

GARDN Green Aviation Research & Development Network

BOMBARDIER

The main funders for this project were the Green Aviation Research and Development Network (GARDN) and Boeing

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BACKGROUND TO THE ATM PROJECT

The ATM Project was funded by GARDN to advance the development of biojet fuels in Canada. This section provides a brief background to the challenge that formed the motivation for this project. This section also describes the objectives of this project, the project partners and their roles, as well as the scope of the project.

Limiting and reducing aviation greenhouse gas (GHG) emissions is a key objective of the aviation industry, who have adopted environmental targets to reduce GHG emissions with the achievement of carbon neutral growth from 2020 and reducing its carbon emissions by 50 per cent by 2050 compared to 2005 levels. Significant progress has been made to reduce emissions through greater fuel efficiency including engineering improvements, technology enhancements, and advanced operations (including efficiency improvements in air traffic management). These improvements will continue to play a major role towards the carbon emissions reduction target, however they are not sufficient in the context of growing air traffic. The use of biojet fuels[1] are therefore critical to reach the targets.

While five biojet fuel production technologies have been approved by ASTM for use in aviation and more than 150,000 commercial flights have been using biojet fuels, only limited volumes of biojet fuels are currently produced on a regular basis, and only one dedicated biojet facility is in operation worldwide (World Energy, formerly AltAir Fuels, in Paramount, California). Virtually all of the commercial volumes of biojet fuels currently available are produced through the hydrogenation of lipids, including vegetable oils, tallow, used cooking oil, etc. These biofuels are known as HEFA-SPK biojet fuels (hydroprocessed esters and fatty acids synthetic paraffinic kerosene). Although this type of biofuel is the most available today due to the availability of feedstock and maturity level of the technology and process, there is a need for diversifying the feedstock base in order to develop value chains in different parts of the world. To produce sufficient volumes of biojet at low cost, which are able to meet or exceed industry/government emissions targets, feedstocks such as sustainably sourced biomass will have to be used. These feedstocks can include a variety of sources such as wood, including sawdust or forest residues, agricultural waste, etc. However, technologies that are able to use such feedstocks are still under development and have not reached commercial stage. To ensure the long-term supply of sustainable biojet fuels, technologies that are able to utilize these feedstocks have to be developed to commercial scale. This forms the rationale for the ATM Project, the Assessment of likely Technology Maturation pathways to produce biojet fuels from forest residues.

Based on work carried out within the International Energy Agency Bioenergy Task 39 on Liquid Biofuels (Karatzos et al. 2014), thermochemical technologies, based on gasification or liquefaction of biomass, have been identified as the most likely to produce high volumes of sustainable and competitive drop-in biofuels, including biojet.

Thermochemical liquefaction technologies, such as pyrolysis and hydrotreatment into finished drop-in fuels were selected by this project as a target for research and development. Many challenges remain for this technology pathway, including the upgrading of liquid intermediates into finished fuels. While this has received a lot of attention from researchers, the focus has been on general production of hydrocarbon fuels. Very little work has been done to examine the specific production of biojet fuels through this pathway. This is the key focus of the ATM Project as we hope to determine whether this

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[1] While the term biojet fuel will be used throughout this document, the aviation industry often use the term Sustainable Aviation Fuel (SAF). However, as this could refer to fuels from non-biomass, the term biojet fuel is preferred in this report.

pathway is a viable route for production of biojet fuels.

a) Description of the ATM Project

The goal of the ATM Project was to assess the potential of producing biojet fuels using thermochemical liquefaction technologies and woody biomass as a feedstock. One of the most likely long-term supplies of biojet will come from woody biomass and using thermochemical technologies such as gasification and pyrolysis (the latter being broadly defined as thermochemical liquefaction in order to include hydrothermal liquefaction and other variations such as catalytic pyrolysis). Canada is in the fortunate position that it has considerable forest resources and an established forest products sector that could potentially provide large volumes of sustainable feedstock to establish a Canadian biojet industry based on thermochemical technologies. Forest residues, a waste product from harvesting trees, are currently underutilized and available in large quantities for value-added production of biojet fuels.

Gasification and Fischer-Tropsch is pursued by several groups/companies around the world, but the ATM Project decided to focus on the thermochemical liquefaction platform as a potentially cost-competitive technology if remaining technical challenges can be overcome. This technology would make use of the available forest residue feedstock to produce biojet fuels and develop domestic production capacity suitable to Canada.

The thermochemical liquefaction process produces a biocrude intermediate which needs to be upgraded, e.g. *via* hydrotreatment, to produce biojet fuels. However, these upgrading steps still pose significant challenges such as catalyst requirements, catalyst cost and lifespan, as well as hydrogen requirements. These challenges present a technical obstacle to the production of biojet fuel using the thermochemical liquefaction platform, but in addition, the economics and sustainability of various biocrude production and upgrading routes have not been assessed. The goal of the ATM project was therefore to:

1) Determine whether thermochemical liquefaction of forest residues and upgrading of biocrude via a hydrotreatment approach was a feasible approach to production of biojet fuels.

2) Elucidate the differences between biocrudes and upgraded products from fast pyrolysis, catalytic pyrolysis and hydrothermal liquefaction in terms of upgrading requirements and technical specifications of products.

3) Compare the differences between and effectiveness of two distinct upgrading approaches of two laboratories, namely the Canmet-Energy Ottawa labs and the US DoE’s Pacific Northwest National Laboratory (PNNL).

4) Based on a common feedstock supply chain chosen in British Columbia, determine the differences in techno-economic and sustainability performance between different technology and upgrading pathways.

5) Based on the results obtained in the project, develop a design for a demonstration scale upgrading facility that is able to progress the domestic production of drop-in biofuels and biojet in Canada.

6) Develop recommendations with regards to technical and policy considerations, including a proposed pathway to certification, that could contribute to the advancement of biojet production from thermochemical liquefaction technologies.

The project sourced three different types of biocrudes from different biocrude producers using fast pyrolysis, catalytic pyrolysis and hydrothermal liquefaction technologies and then evaluated the upgrading of such bio-oils to biojet using two different laboratories with distinct approaches to upgrading.

Although upgrading and hydrotreatment research has been carried out by various companies, a comprehensive study which compares/contrasts and assesses the most promising sustainable biojet options under common criteria has not been done. The uniqueness of this work lies in addressing both upstream and downstream challenges (a complete supply chain), covering everything from the availability of low cost and sustainable Canadian biomass feedstocks through to the technical/economic challenges of producing and converting biocrudes to biojet fuels (i.e. the cost and technology risk associated with hydrotreating the various biocrudes).

After production of sufficient volumes of biojet fuel, preliminary analysis against core ASTM standards were carried out to identify technical characteristics that will need to be addressed in a path to certification. The results obtained in the project will be used as the basis for the design of a Canadian biomass based biojet facility at the pilot/demonstration scale, based on optimal economic/regional conditions.

The project is funded by the Green Aviation Research and Development Network (GARDN) (gardn.org) and Boeing.[2]

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[2] Boeing released the following press Release in December 2015: http://boeing.mediaroom.com/2015-12-02-Boeing-Canadian-Aviation-Industry-Launch-Sustainable-Aviation-Biofuel-Project

b) Project Partners and Roles

Companies or Research institutions	Name of the researchers	Title	Role in project
Industrial:			
NORAM Engineering and Constructors Ltd	**Ira Wolff** **Guy Impey** **Alex Burns** **Christopher Reid**	**Director, Business Development**	Project lead and engineering design
Boeing	**Michael Lakeman** **Olivier Rolland** **Ellie Wood**	**Associate Technical Fellow, Biofuel Strategy**	Strategic direction, assessment of fit for purpose
SkyNRG	**Maarten van Dijk** **Misha Valk** **Oskar Meijerink**	**Managing Director** **Head of business development** **Business development manager**	Techno-economic assessment
WestJet	**Geoffrey Tauvette**	**Director, Environment and Fuel**	
Bombardier	**Kahina Oudjehani** **Miguel Garcia Claro**	**Ecodesign Lead**	Sustainability
Research institutions involved:			
University of British Columbia	**Jack Saddler** **Susan van Dyk** **Fraser Larock** **Anna Ringsred** **Jianping Su** **Mahmood Ebadian**	**Professor**	Co-project management, feedstock supply chain, feedstock certification, policy
Subcontractors:			
CanmetENERGY Ottawa	**Dean Haslip** **Jacques Monnier**	**Director General**	Upgrading
PNNL (Pacific Northwest National Laboratory)	**Doug Elliot** **Corinne Drennan** **Johnathan Holladay** **Huamin Wang**		Upgrading
(S&T)^2 Consulting	Don O’Connor	President	Life cycle assessment

c) Scope and parameters of this project

The project had a very broad scope and the work was carried out to obtain broad conclusions as to the potential for production of biojet fuels through a thermochemical liquefaction platform combined with a hydrotreating upgrading approach. A combination of literature review and experimental work was used to obtain the conclusions.

Feedstock sourcing, cost and supply chain used for this project

Current biojet fuels are based on upgrading of vegetable oil feedstocks, but in order to obtain significant volumes of biojet fuels, lignocellulosic feedstock utilization must be expanded in the long-term. Previous work carried out by Prof Jack Saddler's group has highlighted the significant volumes of sustainable feedstock available in British Columbia, specifically forest residues that are currently underutilized and burnt in slash piles. These forest residues were seen as a clear opportunity for creating a value-added proposition for the forest sector while advancing the production of biojet fuels in Canada. However, direct utilization of such forest residues for this project was not feasible due to budget limitations. Sufficient funding was not available to directly source forest residues from British Columbia, which would have required harvesting, comminution and shipping to biocrude producers in The Netherlands, Denmark and Finland. In addition, the chosen volumes of biocrude used in this project would have been extremely expensive to produce as a dedicated undertaking. The biocrude we were able to obtain was routinely produced by the biocrude producers as part of their ongoing commercial or research operations.

In order to carry out a full life cycle and techno-economic assessment on each biocrude and upgrading approach, it was considered essential to include a notional feedstock supply chain in the models. Data was collected on availability of a range of woody biomass feedstocks in British Columbia, including mill residues, forest residues and wood pellets. A supply chain curve for potential Timber Supply Areas (TSAs) was prepared to determine the estimated cost of feedstock. This information was used to select a potential location of a biocrude production facility based on a realistic transportation distance for feedstock (100km). A further assumption was included in the supply chain model, that the upgrading facility will be co-located with an existing refinery for hydrogen sourcing, waste water treatment and downstream.

Biocrudes selected for this project – technology platforms

The ATM project was based on advancing the upgrading of thermochemical liquefaction biocrude into finished drop-in biofuels, specifically focused on biojet fuel. The main technology in this sphere has been fast pyrolysis and this process is at commercial stage for biocrude production, but the production of biojet fuels via this technology pathway has not been demonstrated. Some challenging characteristics of fast pyrolysis biocrudes, including instability, high oxygen and high TAN have led to the development of alternative thermochemical liquefaction technologies, including catalytic pyrolysis (*in situ* or *ex situ*), hydropyrolysis and hydrothermal liquefaction. As these technologies produce biocrude with improved characteristics, including lower oxygen, they are considered easier to upgrade into finished biofuels as they have greater stability and require less hydrogen during upgrading.

However, most of the studies published in literature have been based on fast pyrolysis biocrude upgrading with very limited information available on other types of thermochemical liquefaction. Some information suggests that biocrudes based on catalytic pyrolysis and hydrothermal liquefaction are more stable and easier to upgrade. Yet limited studies have been carried out to do a side-by-side comparison of different thermochemical liquefaction technologies and upgrading requirements. And no studies have incorporated comparison of technical upgrading, life cycle analysis and techno-economic assessment. Technical upgrading requirements alone are not sufficient to evaluate the production of drop-in biofuels and the ATM project has a unique opportunity to provide a more complete comparative matrix.

How were specific biocrudes selected for assessment in the ATM project?

Companies around the world were identified that were engaged in production of biocrudes. Due to limited availability of biocrudes, it was decided that 50L volumes were the minimum that each upgrading laboratory should receive to allow a general analysis and characterization of fractions, especially the biojet fraction.

Approaches were made to companies in this space to acquire a suitable volume for targeted upgrading experiments. The ATM project had a limited budget for acquiring biocrudes as it was hoped that companies would want to donate biocrudes in order to further the commercialization of their technology platform into finished biofuels. However, at the start of the project it became apparent that some companies were not interested in participating due to concerns over Intellectual Property, while other companies were pursuing their own upgrading strategies. In addition, some of the companies did not have the operational capacity to produce the required volumes of biocrude. Some pilot scale facilities were shut down for upgrading and maintenance and had to be excluded.

The feedstock used by biocrude producers (from which samples were obtained) was softwood. The assumption was made that there was sufficient similarity between feedstocks to allow for comparison of the biocrudes and their upgrading.

Experimental work – upgrading of biocrudes

Two laboratories were engaged to carry out upgrading of biocrudes, CanmetENERGY-Ottawa, a government research laboratory part of Natural Resources Canada; and the Pacific Northwest National Laboratories (PNNL) in Richland, Washington.

PNNL (https://www.pnnl.gov/) has been leaders in the field of production and upgrading of biocrudes using fast pyrolysis and hydrothermal liquefaction and their research in this area dates back to the 1980s. PNNL has published numerous peer-reviewed papers on this subject and many reports, including techno-economic analyses on fast pyrolysis biocrude production and upgrading for a commercial scale facility (Jones et al. 2009; 2013; 2014; 2015;2016). PNNL has a pilot-scale upgrading facility and extensive experience in upgrading based on a hydrotreating approach using commercial catalysts. For fast pyrolysis biocrude upgrading, PNNL has used a two-stage approach with an initial, low severity hydrotreatment step for stabilization of the biocrude, followed by a more severe hydrotreatment step. PNNL was eager to become involved in the ATM Project based on the proposed approach for assessment of biojet production potential using these technology platforms.

Canmet Laboratory in Ottawa is a national laboratory and under the leadership of Dr Jacques Monnier, Canmet-Ottawa has developed a patented upgrading approach using a novel dispersed molybdenum sulfide catalyst, combined with a co-processing approach (biocrudes are mixed with a fossil feedstock such as furnace oil before upgrading) for hydrotreatment of thermochemical liquefaction biocrudes. The lab has pilot scale upgrading facilities and extensive analytical resources and capacity. It is envisaged that the project will provide valuable insight for Canmet to advance their technology for building domestic biojet fuel production capacity.

EXECUTIVE SUMMARY

Air transport accounts for approximately 2% of the global man-made carbon dioxide (CO2) emissions. As the fastest growing transportation sector, these emissions will continue to grow. The aviation sector has committed to carbon neutral growth from 2020 and a 50% reduction in emissions by 2050. While improvements in technology and efficiency can contribute to these goals, it is generally acknowledged that sustainable aviation fuels (biojet fuels) can make the biggest contribution to these climate goals.

Such biojet fuels have to be drop-in biofuels that are functionally equivalent to existing, conventional jet fuels and able to make use of existing infrastructure such as airplanes and fuelling infrastructure. Drop-in biojet fuels should also deliver significant emission reductions to meet climate objectives of the sector towards 2050. Fuels used in aircraft have to undergo strict certification procedures under ASTM and since 2008, five technology pathways have been approved for use in commercial airplanes.

However, current production of biojet fuels is limited, with one technology pathway, hydrotreated esters and fatty acids (HEFA) supplying the vast majority of biojet fuels by using feedstocks such as used cooking oil, fats and vegetable oils. High sustainability demands in the sector limit the use of food feedstocks for biofuel production, but the supply of alternative, waste feedstocks such as used cooking oil, fats and greases is restricted. The most feasible solution for significant volumes of biojet fuel production is the development of technologies that can use feedstocks such as lignocellulosic biomass, including forest residues that are available in large quantities on a global scale and often underutilized. Thermochemical technologies based on these feedstocks have been shown to be very promising. Gasification combined with synthesis of fuels through Fischer-Tropsch has obtained ASTM certification for use as a biojet fuel, although commercial production of these fuels has been slow, partly due to the very high investment costs required. The other type of thermochemical technology, thermochemical liquefaction, produces a liquid intermediate that can be catalytically upgraded into finished biofuels through hydrotreatment or catalytic cracking. Due to the high oxygen content of these liquid intermediates, addition of hydrogen is generally needed for deoxygenation.

Thermochemical liquefaction technologies have not been commercially demonstrated to produce biojet fuels and have not undergone certification under ASTM as a biojet fuel. Such fuels are produced in two distinct stages, the production of a liquid intermediate, followed by the upgrading into finished fuels. Commercial development of the liquid intermediate (biocrude) production has been quite advanced, particularly fast pyrolysis that has reached small commercial stage. Other technologies, such as catalytic pyrolysis and hydrothermal liquefaction is at a less advanced stage of commercialization. However, the upgrading stage to produce finished fuels has been technically challenging and the production of biojet fuels via this route has not been demonstrated.

One of the key objectives of the ATM Project was to demonstrate that biojet production through thermochemical technologies and upgrading through hydrotreatment is feasible from a technical perspective, but also from an economic perspective provided the right policies are implemented. In addition, the ability of these biofuels to provide significant emission reductions was evaluated as this is an essential component of biojet fuel development.

The ATM Project was a comprehensive study and included the following elements:

- A full assessment of a notional feedstock supply chain for forest residues within British Columbia was carried out, determining availability and cost for a biocrude production facility in Prince George, BC and an upgrading facility co-located with a refinery in the Lower Mainland.
- Three different biocrudes based on conventional fast pyrolysis, catalytic pyrolysis and hydrothermal liquefaction was sourced and analysed.
- Upgrading of the three biocrudes was carried out using two different hydrotreatment approaches at the Canmet-Energy laboratories (Ottawa, Canada) and PNNL laboratories in Richland, Washington.
- After hydrotreatment, the refined biocrudes were fractionated through distillation based on boiling point cuts to yield naphtha, jet, diesel and heavy fuel oil fractions. The fractions were characterized through analysis, with a focus on the properties of the jet fractions compared with general standards in ASTM D7566.
- A full life cycle assessment of the entire supply chain was carried out using GHGenius to determine the potential emission reductions from different technology and upgrading pathways, as well as on the full engineering design for a demonstration size facility. Recommendations were included for optimization of pathways with respect to the LCA impact.
- A full techno-economic assessment for an entire supply chain was carried out, assessing the net present value (NPV) and minimum fuel selling price (MFSP) of different technology and upgrading pathways. In addition, a sensitivity analysis was carried out to identify cost elements that have the greatest impact on the TEA.
- Engineering designs were developed out to assess the feasibility of a demonstration scale upgrading facility in BC based on biocrude produced through a hydrothermal liquefaction process and upgrading through hydrotreatment. Recommendations were made for optimization and resolution of engineering uncertainties and challenges.
- The policy environment with respect to liquid biofuels and the feedstock supply and cost was assessed within the context of current and proposed legislation and recommendations proposed.
- The overall suitability of the thermochemical technology pathways combined with hydrotreating was assessed with respect to the quality of the jet fuel fraction and the ability to meet certification through the ASTM D7566 should this process be initiated.
- Finally, a comparative assessment of all the technology and upgrading pathways was completed around three key metrics: technical, LCA and TEA results.
- In conclusion, recommendations for improvements and optimization is made and the value of the project to the Canadian aviation sector evaluated.

The ATM Project represents a significant achievement in advancing the knowledge and identifying key challenges of producing biojet fuels through thermochemical liquefaction technologies. To our knowledge, it is the first integrated study that compared technical, life cycle and techno-economic parameters of three types of thermochemical liquefaction technologies and upgrading into finished fuels. Current research has mainly focused on the technical challenges of biocrude production or the upgrading challenges. While some life cycle and techno-economic assessments have been carried out, this has been limited to individual technologies or individual upgrading methods, and broad use of assumptions has raised questions over the real-world applicability of calculated results for key aspects such as the minimum fuel selling price (MFSP) and carbon intensity. By carrying out the technical upgrading of three different biocrudes: (1) using a co-processing and hydrotreatment strategy within one laboratory (Canmet) and a (2) direct hydrotreating strategy (PNNL), direct comparison of the three biocrudes could be carried out based on real data. This was a significant achievement in itself as it provided an insight into the advantages and disadvantages of different methods which has previously only been the subject of speculation.

HIGHLIGHTS OF RESULTS/ACHIEVEMENTS:

- A significant fraction of high quality biojet was produced from all three biocrudes (fast pyrolysis, catalytic pyrolysis and hydrothermal liquefaction) using a hydrotreating approach (both methods). The jet fraction had a reasonable quality and met many of the general ASTM specifications for jet fuel A1, and it seems likely that all specifications could be met with further optimization. While an ASTM spec for biojet via thermochemical liquefaction does not currently exist, the results from this study show the feasibility and suitability of biojet production through any of these pathways.

- Based on a comprehensive life cycle analysis using GHGenius, between 50-80% reduction in GHG emissions could be achieved with these technologies and upgrading pathways. Optimization of technologies and upgrading pathways could result in even greater potential emission reductions. Fast pyrolysis with two-stage hydrotreatment produced the greatest emission reduction (81%). However, optimized HTL with single-stage, dedicated hydrotreatment could attain similar levels (86%).

- A techno-economic analysis of the various pathways showed a minimum fuel selling price (MFSP) between CAD1,724 - CAD3,545 per metric tonne of fuel for the different pathways. The lowest MFSP was obtained with the HTL pathway with single-stage, dedicated hydrotreatment. Based on current prices for conventional jet fuel (CAD855,25/MT), a premium of CAD963/MT would be required for the lowest cost biojet. Although higher than current prices for jet fuel, the premium is significantly lower than many other biojet pathways currently utilized, and with further development and application at scale, the projected costs for these pathways should continue to decrease It should be noted that the production of multiple fuel products that can be sold has a large impact on lowering the MFSP. The NPV consistently showed the greatest sensitivity in cost variation for the CAPEX (biocrude production), feedstock price and hydrogen price.

- Flow sheets were developed for a 200 bbl/d technology demonstration, including facilities for biocrude production by subcritical hydrothermal liquefaction (HTL), HTL wastewater treatment by anaerobic and aerobic biological treatment, and biocrude upgrading by hydrotreatment. The 200 bbl/d technology demonstration plant could produce enough jet fuel for up to 10 medium-haul flights per day as a 10% blend. The HTL production facility and associated wastewater treatment plant were assumed to be greenfield developments located in Prince George, BC, Canada, with permits to discharge pre-treated wastewater to the municipal sanitary sewer. The biocrude upgrading facility was assumed to be co-located with an existing petroleum refinery in the Lower Mainland region of BC, Canada. This has the advantage of being able to blend the upgraded products into the existing petroleum supply chain, as well as access to unit operations for final fuel polishing to meet specifications.

- The location for a hypothetical biocrude production plant was chosen as Prince George, British Columbia and a detailed analysis of the availability and cost of forest residue feedstock within the supply area was carried out, demonstrating sufficient volumes to support a facility of the proposed size. A delivered feedstock cost of CAD80 was estimated for a 100 km radius of the biocrude facility.

- NPV showed a strong sensitivity to feedstock price and forest policies in BC were evaluated and recommendations made for new policies that could have a significant impact on feedstock cost. The way the current tenure system is structured and the requirement for burning of forest residues presents an obstacle to broader use of these residues.

- British Columbia has a very favorable policy environment for establishing a domestic biojet sector, including a well-developed low carbon fuel standard that has been in operation for many years. Expansion of this policy to include aviation fuel would play an important role in promoting biojet production and consumption, while fuel for international aviation can also be accommodated to incentivize this sector. The flexibility imparted by Part 3 agreements within the BC regulations play a significant role in promoting lower carbon intensity fuels and this can be further expanded to accommodate co-processing and refinery integration. Part 3 agreements could potentially allow earning of credits for establishment of biocrude production and other measures. Other biofuel products, produced simultaneously with jet fuel, could currently earn credits under the regulations based on reduction of carbon intensity of other fuel products.

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CHAPTER 1 -INTRODUCTION AND LITERATURE REVIEW

This section of the report provides an introduction to the aviation sector and the rationale for development of biojet fuels. It further lists the current biojet fuels certified under ASTM and the process that has to be followed by a biojet producer to become certified to use their biojet fuel in commercial flights. We also look at the current availability of commercial volumes of biojet fuels. To provide a background on the technology selected within the ATM Project, we briefly summarise and describe pyrolysis, catalytic pyrolysis and HTL technologies and challenges for biojet production via this pathway. Included in this literature review we describe the types of technologies, characteristics of bio-oils/biocrudes and a summary of the published literature on upgrading of these biocrudes into finished fuels.

1.1 The Aviation Sector and the Rationale for biojet fuel, also known as Sustainable Aviation Fuel (SAF)

Air transport accounts for approximately 2% of the global man-made carbon dioxide (CO2) emissions. In 2017, carbon dioxide (CO_2) emissions from international civil aviation as a whole amounted to 859 million tonnes (Mt), with forecasts projecting increased emissions if no action is taken (ICAO, 2016)[3]. In 2017, nearly 4.1 billion passengers were carried by airlines.

Given this sector's steady growth, aviation will play a key role in meeting the international climate targets in the United Nations Framework Convention on Climate Change (UNFCCC) COP21 agreement, even though aviation emissions were not specifically mentioned in the document. Outside of UNFCCC, the aviation industry has adopted targets to mitigate the CO2 emissions from air transport: (1) An average improvement in fuel efficiency of 1.5% per year from 2009 to 2020, (2) carbon-neutral growth by 2020 and (3) a 50% reduction in GHG emissions by 2050 (relative to 2005 levels).

More recently, and in order to address short term emission reduction, the industry recognized that global market-based measures (GMBM) are needed to fill any remaining emissions gap. As a result, ICAO adopted CORSIA, a global carbon offsetting[4] scheme to address CO2 emissions from international aviation in 2016. In parallel, emissions can be reduced by new technology, more efficient aircraft operations and infrastructure improvements (including modernized air traffic management systems).

Sustainable aviation fuels—such as biojet— represent the single greatest means for airlines to achieve significant, long-term reduction of emissions. (Figure 1). Aviation is unique for its dependency on liquid fuels for today and into the foreseeable future. Research is underway to evaluate the feasibility of alternative technologies such as electric motors or liquid hydrogen for propulsion or in a fuel cell; however, these options are unlikely to be ready for commercial large scale and sector-wide

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[3] This is based on a calculation of 3.16 kg of CO_2 emitted per kg of fuel and forecasts for fuel consumption increases. See Figure 5 on page 19 of the report. Note that fuel consumption for domestic aviation is excluded from this figure.

[4] A **carbon offset** is a reduction in emissions of **carbon** dioxide or greenhouse gases made in order to compensate for or to **offset** an emission made elsewhere.

deployment in the near term. An additional hurdle to such deployment is related to the long lifespan of aircraft and the high fleet renewal costs associated with the commercial aviation industry. Biojet fuels will be an essential measure to achieve significant reductions in aviation emissions by 2050.

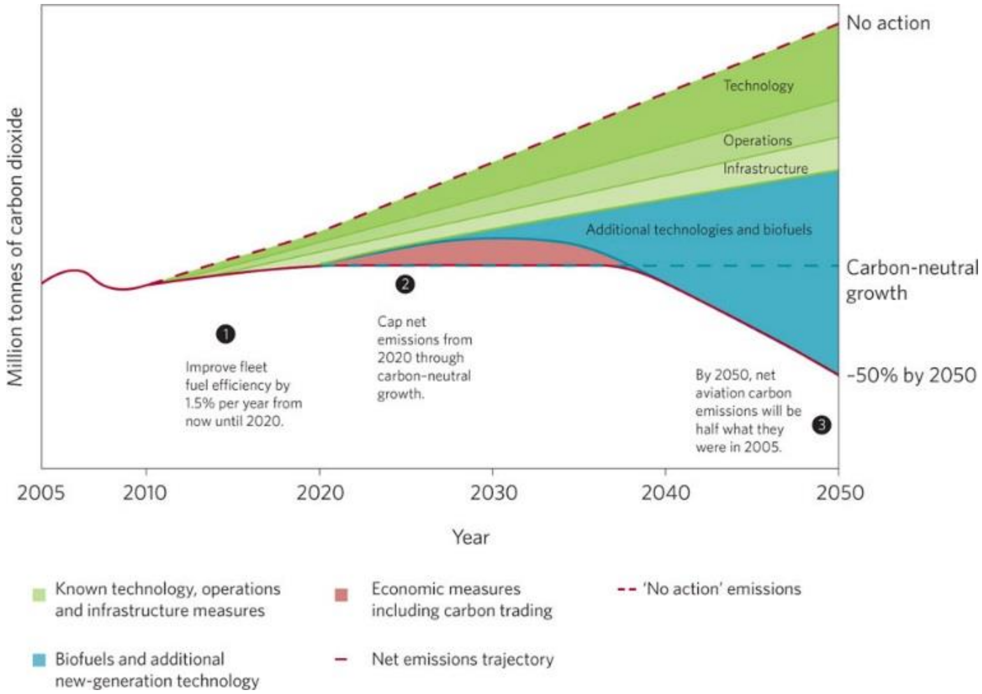

Figure 1. Emissions from aviation in the absence of any action, and emissions-reduction goals set by the industry (Air Transport Action Group)

Biojet fuels can potentially reduce greenhouse gas (GHG) emissions compared to fossil jet fuel (based on a well-to-wheel life cycle analysis). However, the emissions-reduction potential of different feedstocks and technology pathways in a specific geography using local utilities and infrastructure may differ significantly, with values ranging from 50% to 95% reduction potential as compared to fossil jet fuel[5].

Achieving the GHG emissions-reduction targets proposed by the aviation industry in Figure 1, and by organisations such as the International Civil Aviation Organisation (ICAO), will require a significant increase in biojet fuel production and consumption. The exact volumes required to achieve specific goals are not clear because of factors such as the aviation sector's future fuel consumption, the extent of emissions reductions achieved through offsets, and the specific emissions-reduction potential of various options for making biojet fuels, which are called pathways. Fuel consumption for international aviation could be as high as 852 million tonnes (t) by 2050 (ICAO, 2016) and could require 426 m t of biojet fuels to meet the GHG goals. Current production however is still very limited, at less than 0.1% of global total consumption of jet fuels. This section will explain how supply at that level will require significant policy, technological, and supply-chain support for biojet fuel development.

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[5] The Renewable Energy Directive, Annex V, Section B contains default values for biofuels GHG savings which can be used as a guideline. Diesel using a wood-based Fischer-Tropsch process has a default value of 95%, for example, while typical GHG savings values for hydrotreated vegetable oil are from 40% to 65% based on different feedstocks.

Since the dawn of the jet age, commercial aviation has been dependent upon conventional jet fuel – the price of which can represent about 30% of an airline's operating cost. In addition, jet fuel prices are highly volatile resulting in extreme and rapid swings in price, which can dramatically affect the profitability and long-term financial stability of airlines. Biojet fuel produced from sustainably sourced forest biomass offers a potentially attractive alternative to conventional jet fuel. In addition to resulting in more local / regional control of production and supply—as well as reducing price volatility—biojet fuels will have significantly lower carbon footprint and help airlines achieve significant greenhouse gas emission reductions. A future cost effective, sustainable and robust biojet supply chain could provide a key competitive advantage for Canadian airlines.

Aviation in Canada continues to grow and the Canadian carriers have invested billions of dollars in fuel efficient aircraft. However, it is apparent that continued growth in air traffic will result in an increase in the environmental footprint of the Canadian aviation sector. Together with improved fuel efficiency and optimized routing, aviation bio-fuels are the biggest opportunity to reduce GHG emissions and improve the sustainability of the Canadian aviation sector.

The Canadian aerospace industry will benefit from local development and production of biofuels for two main reasons:

- It will help the Canadian airline industry to fulfill their (international) commitments with respect to emission reductions. Canada is a member state of the UN's International Civil Aviation Organization while various airlines (Westjet, Air Canada, Air Transat), and Equipment Manufacturers (Boeing, Airbus, Bombardier) are also members of IATA and ATAG respectively which has set specific targets for emission reductions by 2020 and 2050.

- As fuel represents 30% of airline operating costs, locally produced biojet fuels will contribute by reducing dependence on petrochemical sources with volatile prices, while also offering potential for a cost effective and stable supply to improve energy security and reduce reliance on foreign imports.

1.2 Aviation Fuel Requirements, Specifications and Standards

The aviation sector uses specific fuels to power jet turbine aircraft, and these are usually classified as Jet A/A1 fuels in most regions. All jet fuel has to meet strict specifications defined by the engine and airframe OEMs documentation and approved by the regulatory authorities. Examples of fuel specifications that have been shown to meet the requirements of the engine and airframe OEMs are ASTM 1655 and Def Stan 91-091. A separate standard, ASTM D7566 was created for alternative jet fuels, including biojet fuel, to ensure that the same high standards are maintained. An ASTM D4054 standard was created as a guide for what testing and properties the OEMs evaluate in approving a new fuel from non-conventional sources. Further guidance documents are published by organizations such as CAAFI and IATA to assist in navigating this complex area.

Key documents providing guidance on requirements and certification of alternative jet fuel:

- ASTM D1655 – specification for Jet A/A1
- ASTM D7566 - Standard Specification for Aviation Turbine Fuel Containing

Synthesized Hydrocarbons

- ASTM D4054 - Standard Practice for Qualification and Approval of New Aviation Turbine Fuels and Fuel Additives
- CAAFI – D4054 guidance documents
- IATA Alternative Fuel Factsheet

The guidelines for obtaining certification for new alternative jet fuels is detailed in ASTM D4054 and the full procedure can take several years with four tiers of testing and review of a research report by OEMs. Depending on how novel a fuel type is, not all four tiers of testing may be required. The procedure is illustrated in Figure 2 below.

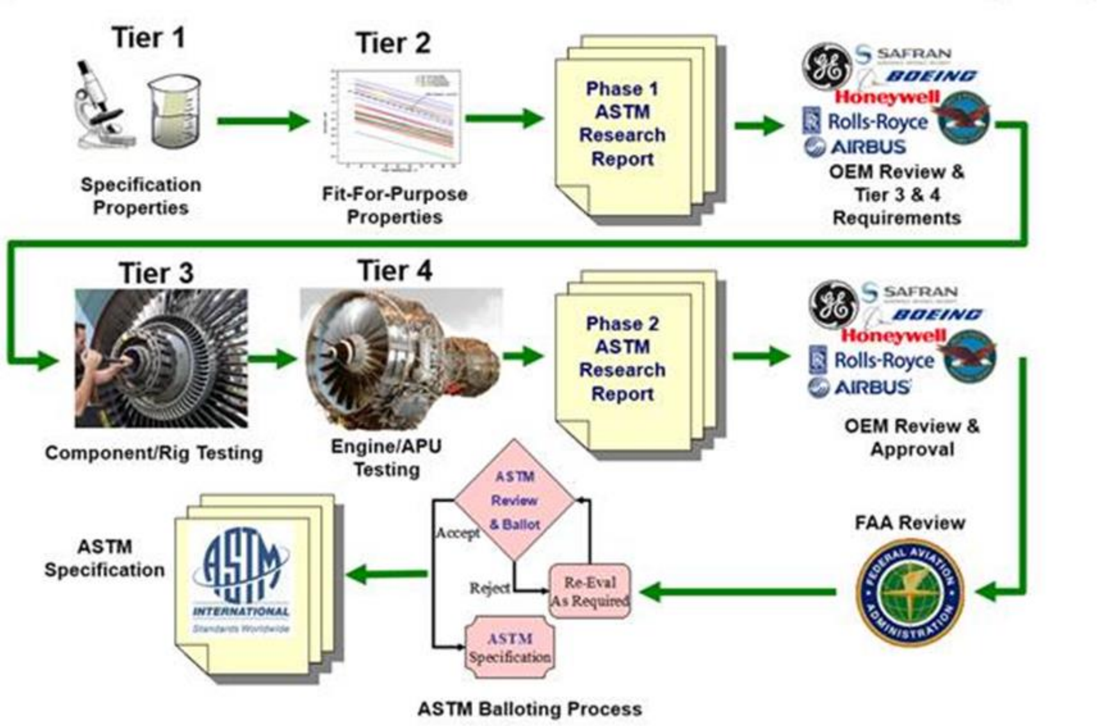

Figure 2. Graphic illustration of the fuels approval process as set out in ASTM D4054 (CAAFI - http://www.caafi.org/resources/pdf/D4054_Users_Guide_V6_2.pdf)

Once an alternative fuel has been approved through this process, a new ASTM specification is created for that specific fuel as part of ASTM D7566 where each fuel production process is described in an Annex to that document. Currently all alternative fuels can only be used in a blend with fossil jet fuel and ASTM D7566 specifies the blend limit, e.g. maximum 50% blends for hydrotreated esters and fatty acids (HEFA). Before an alternative fuel can be used in an aircraft, the neat biojet has to meet the requirements listed for the Annex. This is followed by blending the alternative fuel within allowable blending limits with fossil jet fuel. The blended fuel must meet all the requirements listed in the Table 1 and the Extended table in D7566. Once the blended fuel meets the requirements in D7566 it’s reclassified as D1655 fuel.

There are several alternative jet fuels that have been approved under ASTM D7566. ASTM D7566 is divided in two main parts: the first part, Table 1, contains the specifications for the blended fuel with conventional jet fuel; the second part includes Annexes for the different pathways that have been approved since the introduction of ASTM D7566 (IATA, 2017):

- Annex A1 for Fischer-Tropsch Hydroprocessed Synthesized Paraffinic Kerosene (FT SPK)
- Annex A2 for Synthesized Paraffinic Kerosene from Hydroprocessed Esters and Fatty Acids (HEFA SPK)
- Annex A3 for Synthesized Iso-Paraffins from Hydroprocessed Fermented Sugars (SIP SPK)
- Annex A4. Synthesized kerosene with aromatics derived by alkylation of light aromatics from nonpetroleum (SPK/A)
- Annex A5. Alcohol-to-jet synthetic paraffinic kerosene (ATJ-SPK)

More recently, April 2018, the co-processing of vegetable oils within existing petroleum refineries was granted ASTM certification. However, as the co-processed jet fuel obtained in this manner never exists as a neat fuel, the ASTM certification was granted as a modification of ASTM D1655 rather than an Annex within ASTM D7566.

It should be noted that ASTM D7566 is not only concerned with biojet fuels, but any alternative fuel from non-petroleum sources. Annex A1 and A4 fuels were derived from coal, although biomass-based fuels produced using the same process would also qualify under this standard. It should also be noted that the Annexes contain a brief description of the production process and the feedstock to be used with the implication that similar fuels produced by a significantly different process or feedstock would not qualify under the same Annex. For example, the initial alcohol-to-jet certification was based on conversion of isobutanol to jet fuel (application brought by Gevo). The production of biojet from ethanol was approved separately (application launched by Lanzatech). Efforts are under way by organisations such as CAAFI to simplify the description to be more inclusive, but safety concerns are paramount, and the approach is therefore very conservative. Once the blended fuel meets the requirements of ASTM D7566, it can be comingled with conventional jet fuel handling, storage, and distribution network and is treated as conventional jet fuel.

The ASTM certification process (as set out in D4054) for alternative fuels is a very thorough and rigorous process in which many entities participate. The first step in the process is for the fuel producer to provide a research report with test data to the original equipment manufacturers (OEMs) for review. The OEMs review the reports and provide guidance on what additional testing if any may be required. Fuel volumes that may be required for the process are up to 10 gallons (38 liters) for the Specification Tests; 10 to 100 gallons for the fit-for-purpose tests; 250 to 10,000 gallons (950 to 38,000 liters) for the Component and Rig Tests; and up to 225,000 gallons (852,000 liters) for the engine test. These are estimates because the extent of required fit-for-purpose tests is dependent upon the fuel chemistry and results of the Specification tests. A process that is similar to an already approved alternative fuel may require less testing. Once the OEMs are satisfied with the research report they give approval of the fuel to go to the broader ASTM committee for balloting.

Table 1 of ASTM D7566 establishes the core testing and properties that should be carried out and maximum/minimum ranges while the specific Annex for an alternative fuel process may contain further tests and properties relating to the neat biofuel, and a description of feedstock and process requirements.

The ATM Project pursued the production of biojet fuels through thermochemical liquefaction technologies, combined with upgrading through hydroprocessing (with two different upgrading approaches used: a co-processing strategy by Canmet and dedicated hydroprocessing of neat biocrude by PNNL). Any biojet fuel produced in this project will not be ASTM certified, but the project aimed to establish the feasibility of producing a biojet fuel that could potentially form the basis of a future application under ASTM D4054.

Based on the current approval approach it should be noted that each type of biocrude (from fast pyrolysis, catalytic pyrolysis and hydrothermal liquefaction) may require separate ASTM applications. In addition, the distinct nature of the upgrading strategies will also require distinct applications for approval. Based on our current understanding, the co-processing approach will not produce a neat biofuel and approval of such a process may have to be a modification of ASTM D1655, while upgrading of neat biocrude could form part of ASTM D7566.

As there is no existing ASTM D7566 Annex for thermochemical liquefaction-based biojet fuels, analysis on biojet fraction produced in this project was based on general ASTM specifications for jet fuel. It should be noted, however, that analysis was limited by the volumes of biojet fuel fractions available after upgrading of each biocrude. Where large volumes of sample were required for analytical procedures, testing could not be carried out at this stage. Chapter 8 of this report assesses the results of analysis of biojet fractions derived from this project, evaluates compliance with current specifications and further processing that may be required to meet the standards. A potential pathway to achieving ASTM approval for thermochemical liquefaction biojet fuels are also discussed and outlined.

1.2.1 Status of Commercial Biojet /Sustainable Aviation Fuel (SAF) Production

Biojet fuel can be produced through a multitude of pathways using different feedstocks as starting material and a number of them have been certified for use in aircraft. However, the vast majority of commercial volumes of biojet fuels are produced through the HEFA pathway, the hydrotreatment of lipids, including triglycerides and fatty acids derived from vegetable oils, tallow, used cooking oil, etc. While a number of facilities exist that produce HEFA biofuels, it should be noted that the main product generated is not HEFA (aviation grade) but Hydrotreated Vegetable Oil - HVO (renewable diesel grade). Table 1 below lists the current facilities and total plant capacity. However, only one facility, World Energy (previously AltAir), routinely makes biojet, although renewable diesel is still a major product for this plant, about 4 tonnes of renewable diesel is produced for every tonne of biojet fuel.

Table 1 List of companies producing HEFA fuels (mainly renewable diesel)

Company	Location	Technology	Feedstock	Capacity	Status
Neste	Rotterdam	NEXBTL	Vegetable oil, UCO and animal fat	1.28 bn L/y	Operational
Neste	Singapore	NEXBTL	Vegetable oil, UCO and animal fat	1.28 bn L/y	Operational
Neste	Porvoo, Finland	NEXBTL	Vegetable oil, UCO and animal fat	385 m L/y	Operational
Neste	Porvoo 2, Finland	NEXBTL	Vegetable oil, UCO and animal fat	385 m L/y	Operational
ENI	Venice, Italy	Ecofining^{TM}	Vegetable oils	462 m L/y	Operational
Diamond Green Diesel	Norco, Louisiana	Ecofining^{TM}	Vegetable oils, animal fats and UCO	1.04 bn L /y	Operational
UPM	Lappeenranta, Finland	UPM Bioverno	Crude tall oil	120 m L/y	Operational
World Energy (AltAir)	Paramount, California	Ecofining^{TM}	Non-edible oils and waste	150 m L/y	Operational
Renewable Energy Group	Geismar, Louisiana	Developed by Dynamic Fuels LLC	High and low free fatty acid feedstocks	284 m L/y	Operational
Total	LA MÈDE	Vegan® by Axens	UCO and vegetable oils	641 mL/y	Start-up

The operational capacity of the world's current hydrotreated oil facilities is about 5.5 bn L/y. In order to allow the use of more output towards jet fuel, ASTM has also been evaluating the use of renewable diesel (HEFA+, or high freeze-point HEFA, HFP-HEFA) in blend with jet fuel. If it receives ASTM approval, this strategy could have a significant impact on biojet production capacity as renewable diesel with good cold-flow properties could also be used as a biojet blending component. Order of magnitude wise, if all of this capacity was diverted to biojet production, it would provide up to 1.5% of the world's jet fuel requirements.

Although biojet produced by biomass gasification and subsequent FT conversion is not yet commercial, two facilities are planned and expected to soon be under construction. The companies building them are Fulcrum Bioenergy, with a planned production of 37 M litres per year (L/y) of biofuel from MSW and Red Rock Biofuels, with a planned production of 45 m L/y using wood as the feedstock. A third facility has been proposed in Finland by Kaidi. It would have a capacity of 1 bn L/y. It should be noted that these volumes describe the anticipated total fuel production of each plant, of which biojet would be only one type, if included in the product slate.

Current and future farnesene production capacity is difficult to determine as only one company, Amyris, produces this potential biofuel in sizeable quantities, at its plant in Brotas, Brazil. Due to the high value of farnesene as a biochemical, cosmetics ingredient and lubricant feedstock, most the farnesene that is currently produced is sold into non-biojet markets.

Although the alcohol-to-jet (ATJ) pathway received certification based on Gevo's isobutanol, there is currently no integrated commercial facility for biojet production using this route. The EU, under FP7, is supporting the development of two demonstration projects. One will produce biojet from ethanol (with Swedish Biofuels technology) and the other will produce biojet from the lignin fraction of a cellulosic ethanol plant (with Biochemtex technology). The former will have a capacity of 10 MLY of biojet, and the latter will be smaller. The company, Lanzatech, recently obtained ASTM certification for biojet fuel produced from ethanol but planned capacity for biojet production is not clear. LanzaTech recently began producing ethanol at its first commercial facility in Shougang, China with a production capacity of 48,000 MT per annum. LanzaTech has also announced commercial facilities in Belgium, South Africa, India, and in California. These projects range in size from 34,000 MT per annum (India) to 62,000 MT per annum (Belgium).

In addition, the co-processing of lipids (5% blends) in existing refinery infrastructure was recently approved for the production of biojet fuel as a modification to ASTM D1655. However, the extent of current co-processing is not known.

As of July 2018, a total of 150,000 commercial flights have used alternative jet fuels, and a regular supply of alternative fuels are available in the airport hydrant system at Oslo Airport and Los Angeles Airport.

1.3 Thermochemical liquefaction technologies

The three types of thermochemical liquefaction technologies that are the subject of this project will be discussed in this section:

- Conventional fast pyrolysis
- Catalytic pyrolysis
- Hydrothermal liquefaction

Additionally, variations on these technologies include hydropyrolysis. One of the key differences between all of these technologies is the characteristics of the biocrude product obtained, specifically the level of oxygen. Fast pyrolysis generally produces a biocrude with high oxygen levels (>40%) while much lower levels of oxygen are achievable with catalytic pyrolysis and/or hydrothermal liquefaction (5-25%), depending on process conditions. From a technical upgrading perspective, the oxygen content is very important as it will impact the stability of the bio-oil, the extent of external hydrogen required during upgrading, etc. It should be noted that several other parameters such as yield of biocrude per tonne of feedstock, would also influence the broader feasibility and economics of each process.

Fast pyrolysis exposes small biomass particles, about 3 mm, to heat at 500°C for a few seconds to produce a biocrude with up to 75 wt% yield. Although companies such as Ensyn in Canada have been producing fast-pyrolysis biocrudes for many years, these have mainly been used in niche applications such as food flavouring. Energy applications have been restricted to heavy fuel oil used in stationary heating and power-generating facilities. Ensyn[6] recently obtained regulatory approval for RFDiesel and RFGasoline (in the US), which are fuel products generated via co-processing in petrochemical refineries, but no jet fuel has been produced this way. In the Netherlands BTG has commercialised the flash pyrolysis technology in its EMPYRO[7] project. However, at this point in time, the biocrude is used to replace natural gas in a heating application in a milk factory. BTG has also been testing possible co-processing of bio-oil in a petroleum refinery.

The commercial production of biojet via the pyrolysis route is likely to be challenging as biocrudes derived from fast pyrolysis contain up to 40% oxygen (similar to the biomass itself), whereas a fit-for-purpose jet fuel should contain zero % oxygen This necessitates extensive upgrading to produce biojet, which is typically achieved through hydroprocessing. These processing costs, as well as the need for external hydrogen, represent a large proportion of equipment and production costs (Jones et al., 2009). A further challenge to the hydroprocessing of pyrolysis oils is the cost and stability of the catalysts that are required.

Catalytic pyrolysis or processes such as HTL can produce a bio-oil intermediate with significantly lower oxygen content, 10 to 30%, which would be easier to upgrade to produce fuels, including biojet. Although some studies have indicated that these methods could potentially produce the lowest-cost biojet (de Jong et al. 2016), the high-pressure requirements of HTL during the production of biocrude will impact its potential for scale-up. While production of bio-oil via pyrolysis is at a commercial scale, HTL is currently just at the large pilot stage, as pioneered by Licella's Australian plant. Although there is a scarcity of reliable technical and economic analyses, a recent study projected that a minimum fuel-selling price (MFSP) of USD 3.39 per gallon for an nth plant could be achieved when making diesel and gasoline via fast pyrolysis followed by upgrading (Jones et al, 2013).

The thermochemical liquefaction approach to biojet production has the potential to leverage existing oil refinery infrastructure and thus reduce the capital and operating costs of making biojet. Similarly, significant savings might be achieved by directly sourcing hydrogen from an oil refinery and, in the longer term, through using existing processing units. Co-processing in existing petroleum refineries is considered a key strategy for upgrading pyrolysis-derived bio-oils. Technical challenges include selecting the point of insertion, the extent to which upgrading is required prior to insertion and the disparate types of catalysts needed for bio-oils compared with those used in oil refining (Karatzos et al. 2014). Refinery insertion strategies should be synergistically beneficial but are likely more technically challenging than is generally acknowledged. This is further discussed in section 1.6.

1.3.1 Fast Pyrolysis

Fast pyrolysis is a thermal decomposition process which requires rapid heating of biomass to about 500°C and a subsequent rapid cooling of the resulting vapours to room temperature. Upon cooling, these vapours condense to form the liquid bio-oil product. It has been demonstrated that rapid heating and cooling is crucial to maximizing bio-oil liquid yields at the expense of char and gas production (Bridgwater, 2012). To maximize bio-oil yields (to about 75% of starting biomass by mass) rapid heating to the target temperature must be achieved throughout each biomass particle (i.e., within about one second). These high heat transfer rates (up to 1000 °C/s) ensure maximum devolatilization (vaporization) of the biomass solids and, so far, have only been achieved by a select

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[6] http://www.ensyn.com/2015/08/26/ensyn-receives-key-regulatory-approval-for-its-renewable-diesel/
[7] http://www.empyroproject.eu/

number of reactor designs (Bridgwater, 2012).

Some of the reactor designs used for fast pyrolysis are listed here and discussed briefly:

- Bubbling fluidized bed reactor
- Circulating fluidized bed reactor
- Ablative or rotating cone reactor

The Bubbling Fluidized Bed (BFB) reactor type is well suited for fast pyrolysis (and effective heat transfer). This reactor uses a hot sand fluidized bed to achieve high rates of heat transfer to biomass particles. The reactor beds are fluidized using a compressed carrier gas which is fed through the bottom of the reactor at sufficiently high rates to "fluidize" the solids (sand and biomass) while transferring the gas-entrained char upwards. These types of BFB reactors have been used by the petroleum industry for the gasification of coke since the 1950s. They are robust systems that achieve high heat transfer rates and uniform bed temperatures (Ringer, Putsche and Scahill, 2006), which are both highly desirable attributes for fast pyrolysis reactions.

As depicted in the simplified schematic of a typical BFB fast pyrolysis process (Figure 3) the biomass is first dried and ground to a particle size of about 3 mm to facilitate rapid particle heating and devolatilization. These particles enter the fluidized bed pyrolysis reactor where they are rapidly heated to a temperature of about 500°C. After about a 2 second residence time, the generated vapours are vented to a cyclone where they are separated from the entrained solid char particles. The recovered char can be sold as a value-added product (e.g. soil amendments and activated carbon) or used as fuel for the furnaces that generate and compress the hot recycle gas that feeds the main pyrolyser reactor. The clean vapours are then swiftly transferred to a quench cooler where they are condensed to form the bio-oil. The uncondensed fraction of the vapours along with the permanent gases is then transferred to a second condensation train such as a coalescing filter, scrubber or electrostatic precipitator (e.g. Nexterra) where additional bio-oil is recovered. The remaining flue gas is fed to the furnace that generates hot gas for the main reactor. Fast pyrolysis oils contain up to 75% of the mass and 65% of the energy that was contained in the original biomass feedstock (Bridgwater, 2012). These types of BFB reactors have been used by the Canadian company Dynamotive at a semi-commercial scale as well as at a smaller, demonstration scale such as the 200 kg/hr unit of Union Fenosa in Spain. Both the Dynamotive and the Union Fenosa facilities are based on a design developed at the University of Waterloo and commercialized through its Canadian spin-off company RTI (Resource Transformations International) (Czernik and Bridgwater, 2004; Bridgwater, 2012). Neither plant was operated for long and the technology is no longer under development for commercial interests.

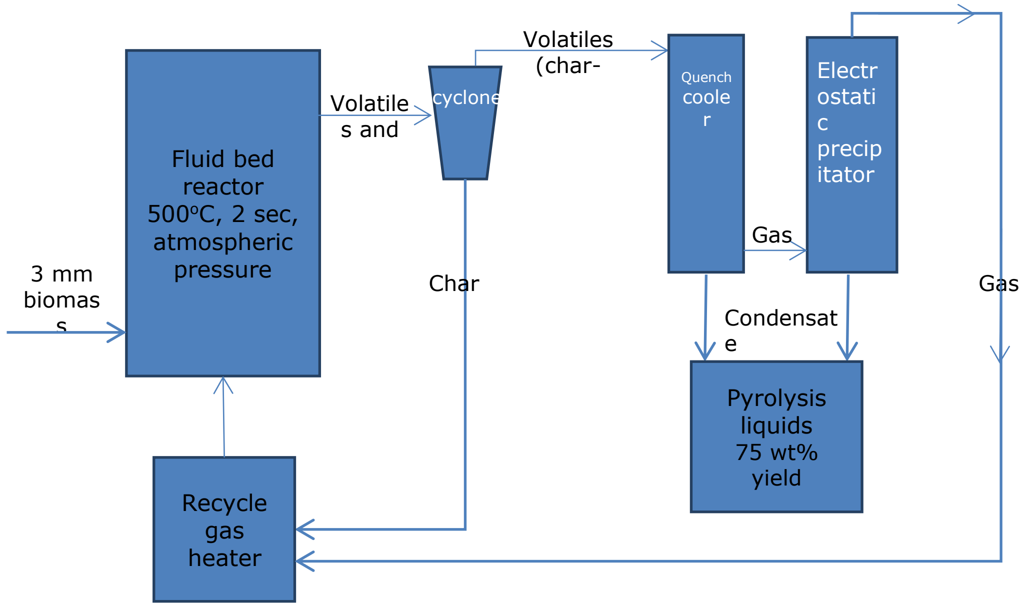

Figure 3 Simplified schematic of bubbling fluidized bed (BFB) fast pyrolysis (adapted from Bridgwater, 2012)

A more complex version of the bubbling fluidized bed (BFB) reactor is the circulating fluidized bed (CFB) reactor (Figure 4). This reactor configuration has been used by the petroleum industry for many decades and it has a long history of industrial operations especially in the fluidized catalytic cracking (FCC) units. This type of system is similar to the BFB process except the compressed recycle gas is fed at much higher velocities, such that the entire loose contents of the reactor (vapors, gases, char as well as the fluidized bed's sand particles) are carried into the downstream cyclone. The char and sand are then recovered from the cyclone and fed together to a combustor, where the char is burned off to heat up the sand. The cleaned hot sand (at about 800 °C) is then fed back to the main reactor entrained in the compressed carrier gas and the process cycle is repeated. This system is more expensive to install and operate than the BFB process but it comes with the advantages of constantly regenerating clean sand bed particles and achieving higher throughputs. CFB requires careful sizing of the biomass particles since the rapid gas flow only permits a very short residence time in the hot zone of the pyrolysis reactor. The CFB pyrolysis is the configuration of choice for the Canadian pyrolysis company "Ensyn" who markets their technology under the name RTP (Rapid Thermal Processing). Other developers of the CFB configuration include CRES (catalytic pyrolysis, Greece) and Ensyn for ENEL (Italy) (Ringer, Putsche and Scahill, 2006) and VTT-led consortium in Finland (Metso, UPM, Fortum).

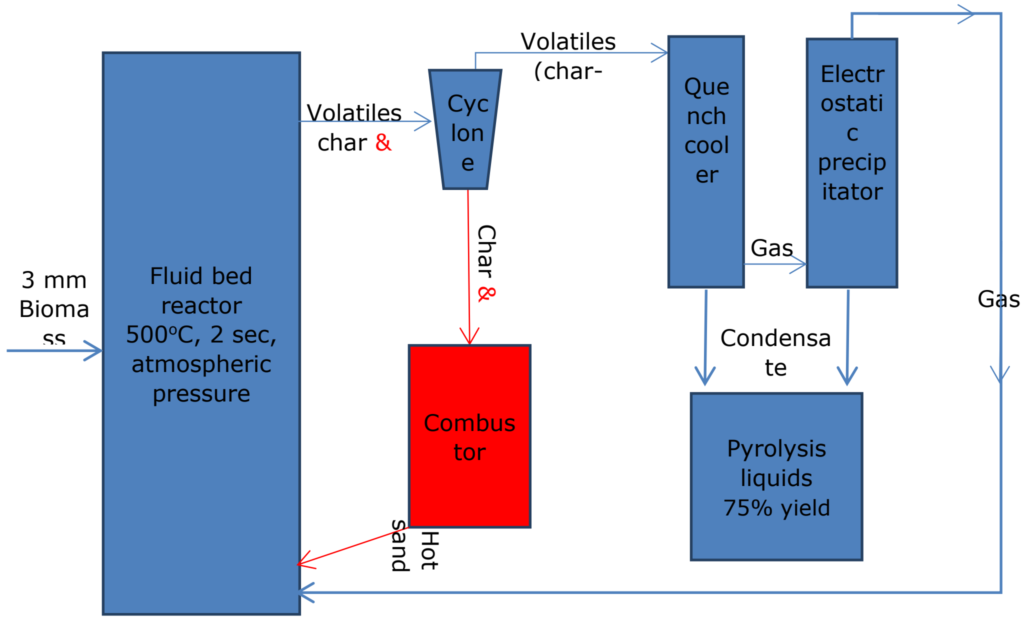

Figure 4: Simplified schematic of circulated fluid bed (CFB) fast pyrolysis (adapted from Bridgwater, 2012)

The main drawbacks of fluidized bed reactors are their reliance on a compressed carrier gas which often carries char contaminants to the bio-oil product. Gas compression also requires high capital and operating costs. The carrier gas, used to mix and circulate the sand bed, carries char particles of such small submicron size that even the solids separation cyclone cannot capture them. Thus, these tiny particles remain entrained in the vapour that enters the quench cooler and they end up in the bio-oil product (Bridgwater, 2012). This can be a problem as char particles can catalyze tar and coke formation and they can plug reactor pipes and filters upon subsequent bio-oil upgrading. It should also be noted that the compressors used to deliver high speed carrier gases are capital-intensive and they are not well suited for small scale applications (Wright *et al.*, 2010).

Alternative reactors that do not use a carrier gas have recently been developed. These reactors use centrifugal forces and mechanical motion to achieve the high rates of heat transfer needed to rapidly volatilize the biomass particles. These types of pyrolysis reactors include ablative and rotating cone designs based on the principle of sliding biomass particles against a hot surface, thus "melting" the fibre in a similar way that a block of butter melts when pressed against a hot surface. Ablative pyrolysis reactors do not use a fluidized bed or sand particles while rotating cone reactors use sand particles contacting biomass particles but without using fluidization by a carrier gas (Venderbosch and Prins, 2011; Bridgwater, 2012). The concept of ablative pyrolysis was first proposed by the CNRS laboratories in Nancy, France. Subsequent ablative reactor designs have been developed by NREL in the USA (vortex reactor) and by Aston University in the UK (plate reactor) (Bridgwater, 2012). The company formerly known as Pytec had a demonstration plant for ablative pyrolysis in Germany. A small development reactor is still in operation at UMSICHT while there are plans for a technology demonstration in California. The rotating cones reactor concept was initially developed by the Dutch Company BTG (a University of Twente spin-off) which currently operates a 5 tonne biomass feed per hour facility in the Netherlands (Empyro BV) and they supply bio-oil commercially through an on-line store[8]. BTG had designed and built a 48 tpd facility which was operated in Malaysia several years ago (see Table below).

Another carrier-gas-free pyrolysis reactor is the "auger" or "screw" reactor which has been used for more than 50 years in coal degassing and heavy oil coking applications (Meier *et al.*, 2013). Due to the relatively poor heat transfer through the auger shell, this technology is not well suited for fast pyrolysis as it is only able to heat up the biomass relatively slowly. Auger reactors also produce lower amounts of bio-oil as their slower heating and longer residence time characteristics favour greater solids formation (a more "charcoal-like" process). However, it has been shown that the low-grade liquid and the char can be recombined after recovery to produce pyrolysis "slurries" which can serve as an improved feed for gasification. The energy density of the slurry can be in the range of 18-25 GJ/m^3, and is typically higher than char-free bio-oils (ca. 21 GJ/m^3) or raw biomass (Dahmen *et al.*, 2012). An example of such a system is the Bioliq™ process from KIT in Germany which proposes to use auger derived slurries to feed central large scale gasification facilities (Meier *et al.*, 2013). If both char and bio-oil are desired as co-products, the auger reactor may be a viable approach.

Although several groups around the world are pursuing biomass pyrolysis, the current production capacity for fast pyrolysis oils is quite low. Bio-oil facilities that have been or will be operated at the semi-commercial scale (> 50 tpd) are listed in Table 2 together with their characteristics and reactor type. Most pyrolysis facilities to date are based on CFB and BFB reactor designs which, as mentioned earlier, are relatively robust, scalable and result in relatively high yields of bio-oil.

Some pyrolysis technology providers focus on small scale (1-5 tpd) and mobile pyrolizers. These units are described as mobile densification facilities that produce liquid bio-oils or bioslurries which are intended to be subsequently transported and processed or upgraded at large, centrally located facilities. These plants can also be co-located with oil refineries to take advantage of co-processing opportunities. Companies that lead this trend for mobile pyrolizer systems development include Canada's ABRI-Tech, California's Cool Planet and ROI, in Alabama (Meier *et al.*, 2013), Battelle's[9] ton-per-day pilot mobile pyrolizer in Ohio can convert pine chips, shavings and sawdust into up to 130 gallons of wet bio-oil per day[10].

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[8] https://www.btg-btl.com/en/technology

[9] http://www.biofuelsdigest.com/bdigest/2013/11/11/is-it-the-future-of-fuel-new-battelle-mobile-pyrolysis-unit-nets-130-gallons-of-bio-oil-per-ton/ http://www.biofuelsdigest.com/bdigest/2013/11/11/is-it-the-future-of-fuel-new-battelle-mobile-pyrolysis-unit-nets-130-gallons-of-bio-oil-per-ton/

[10] http://www.biofuelsdigest.com/bdigest/2015/08/03/the-pyromaniax-class-of-2015-the-top-10-pyrolysis-projects-in-renewable-fuels/ http://www.biofuelsdigest.com/bdigest/2015/08/03/the-pyromaniax-class-of-2015-the-top-10-pyrolysis-projects-in-renewable-fuels/

Table 2: Commercial and pre-commercial (≥ 50 tpd) bio-oil facilities in 2017

Company	Location	Status	Capacity (ODT)	Application	Reactor type
Fortum, Finland[11]	Joensuu CHP plant	Demonstration	303 tpd*	CHP fuel	CFB integrated with CHP system (Metso design)
Ensyn, Canada	Renfrew, Ontario	Commercial	70tpd(nameplate)	Bio-Oil[12]	CFB (Ensyn design)
	Quebec, Canada	Commissioning end 2017	200	Bio-oil	CFB (Ensyn design)
Kerry group/Red Arrow, Ireland/USA	Rhinelander,Wisconsin, USA	Commercial	3x(30-40)tpd[13]	Food flavouring /browning products and CHP fuel	CFB (Ensyn design)
BTG-BtL Malaysia	Palm oil processing facility	Not operating	48 tpd	Cofiring with waste	Rotating Cone (BTG design)
	Hengelo, the Netherlands)[14]	Commercial?	120 tpd (nameplate)	CHP fuel	Rotating Cone (BTG design)

*calculations based on 330 day/year operations. Sources: (Oasmaa and Czernik, 1999; Dynamotive, 2009; BTG, 2012; Starck, 2012; Bayar, 2013; Ensyn, 2013; Fortum, 2013; Green Fuel Nordic, 2013; KiOR, 2013; Landalv, 2013)

1.3.2 Catalytic pyrolysis & others

Catalytic pyrolysis is divided into *in situ* and *ex situ* pyrolysis processes. *Ex-situ* catalytic fast pyrolysis is an uncatalyzed fast pyrolysis integrated with a catalytic post-treatment of pyrolysis vapors before condensation (eg. zeolite such as HZSM-5) to deoxygenate pyrolysis vapors and to produce aromatics and olefins. *Ex-situ* catalytic pyrolysis produces bio-oil with a lower oxygen content (ranging between 4 – 35%) and allows a lower temperature processing regime than conventional uncatalyzed fast pyrolysis. The advantage of *ex-situ* catalytic fast pyrolysis is that some of the polymerization and gum formation reactions are prevented that greatly reduce viscosity and instability of bio-oil (Pham et al., 2014).

In-situ catalytic fast pyrolysis is a process where the biomass is pyrolyzed at a lower temperature (i.e. less than 500°C) with a catalyst (i.e. solid acid, alkali, non-acidic mixed metals, transition metal or precious metal catalysts) in the heating medium or impregnated with the biomass prior to the pyrolysis. Wang et al. (2014) compared *ex-situ* and *in-situ* catalytic pyrolysis using a micro-reactor system. They found that *in-situ* pyrolysis produced more aromatics while *ex-situ* produced significantly more olefins, although this is dependent on the catalyst used. KiOR is an

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[11] https://www.cif-ifc.org/wp-content/uploads/2016/10/First-Commercial-Pyrolysis-Oil-Plant-_-DEMO-2016_-Sikanen.pdf
[12] http://www.biofuelsdigest.com/bdigest/2015/08/03/the-pyromaniax-class-of-2015-the-top-10-pyrolysis-projects-in-renewable-fuels/ http://www.biofuelsdigest.com/bdigest/2015/08/03/the-pyromaniax-class-of-2015-the-top-10-pyrolysis-projects-in-renewable-fuels/
[13] http://www.ensyn.com/licensed-production.html
[14] https://biorrefineria.blogspot.ca/2015/06/empyro-project-commercial-scale-fast-pyrolysis-plant.html

example of a company that employed *in-situ* catalytic pyrolysis, although the company went bankrupt in 2014. KiOR's technology was based on a catalytic fast pyrolysis process using zeolite catalyst to convert the lignocellulose into bio-oil. The bio-oil could then be upgraded to transport fuel blendstock in a hydrotreater. Studies have shown that during the pyrolysis the alkali in biomass is deposited onto the acidic catalyst thereby deactivating it (VTT). Non-acidic catalysts have been more recently under development (Agblevor USU).

Another *in-situ* catalytic pyrolysis process (IH^2) has been developed by the Gas Technology Institute (GTI) in Des Plaines, Illinois in USA (Marker et al., 2012) and is licensed to SenSel Energy, which has proposed three projects in the upper Midwest of USA. The process involves fast pyrolysis of the lignocellulosic biomass in a catalytic fluidized bed at around 400–430°C under 14–35 bar of hydrogen (i.e. hydropyrolysis) with a 500–850 μm in size hydropyrolysis catalyst developed by CRI Catalyst, a project partner. The second stage of the process incorporates a second catalytic step to convert the intermediate products into hydrocarbons, which can be fractionated to fuels.

1.3.3 Hydrothermal liquefaction

Hydrothermal liquefaction (HTL) is another thermochemical process which produces a biocrude intermediate that can be further upgraded into fuels. However, it is quite distinct from pyrolysis as it can utilize wet biomass. The process converts biomass to low oxygen bio-oil (10-20% oxygen), depending on the specific processing conditions. The HTL process uses high pressures (e.g. 50 - 250 bar or more) and moderate temperatures (around 250-450 °C) as well as catalysts for 20-60 min to liquefy and deoxygenate biomass (Goudrian and Peferoen, 1990; Elliott, 2007; Akhtar and Amin, 2011).

The HTL technology is not new and has been extensively studied. As early as the 1920s, Berl proposed the concept of using hot water and alkali catalysts to produce oil out of biomass (Berl, 1944). This was the foundation of later HTL technologies that attracted research interest, especially during the 1970s oil embargo. It was around that time that a high-pressure (hydrothermal) liquefaction process was developed at the Pittsburgh Energy Research Center (PERC) and demonstrated (at the 100kg/h scale) at the Albany Biomass Liquefaction Experimental Facility at Albany, Oregon, US (Elliott, 2007). Subsequently Shell Oil developed the HTU™ process in the Netherlands. The HTU™ process applied pressures in the range 150-180 bar and temperatures in the range 300 to 350°C (Goudrian and Peferoen, 1990; Nielsen, Olofsson and Søgaard, 2012). As an example, eucalyptus chips treated with HTU at 180 °C and 180 bar for 6 min yielded 48.6 wt% DAF (dry and ash free basis) bio-oil, 32.8% gas and 18.6% aqueous phase. The oil contained 10% oxygen (Goudrian and Peferoen, 1990). HTL oils can be very viscous and melting points of about 80 °C have been reported (Elliott, 2007).

Potential feedstocks for HTL include lignocellulosic biomass (non-food), organic waste, sludge, manures, peat, algae, as well as low-grade coals like lignite. While organic substances are insoluble in water under normal conditions, water can be a good solvent for non-polar substances under supercritical conditions (Tekin et al., 2014). An increase in the ionic character of water can facilitate acid-base catalyzed reactions (Elliott, 2011). The hydrothermal liquefaction of biomass usually occurs in the presence of an alkali metal and alkaline earth metal carbonate, bicarbonate or formate catalyst (e.g., Na_2CO_3).

In the hot water environment, the reaction involves both hydrolysis and/or degradation of macromolecules of biomass into small molecules. In this process, a substantial part of the oxygen in the biomass is removed by dehydration or decarboxylation. In comparison with fast pyrolysis, HTL has a lower oil yield around 30% but produces a relatively stable oil and does not require energy to dry the biomass feedstock.

Steeper Energy uses Hydrofaction^{TM} technology which, under supercritical water conditions transforms low-energy biomass feedstocks into a high energy density biocrude which can be further upgraded into finished fuels. In March 2015, Steeper Energy received a $3m grant from the Sustainable Development Technology Canada (STDC) Tech Fund (Lane, 2015b). This funding will be used for the development of an industrial scale pilot plant to commercialize their Hydrofaction^{TM} of lignocellulosic biomass technology. The goal of the project is to produce 100 barrels of biocrude per day (i.e. 4.35 MLPY). The industrial scale pilot plant will be co-located with the Daishowa Marubeni International (DMI) Alberta Peace River pulp mill. The company also indicated future plans for a commercial plant at a scale of 2000 to 5000 barrels per day (i.e. from 87 to 217 MLPY). In December 2017, the company announced a partnership with Silva Green Fuel, a Norwegian-Swedish joint venture, to construct a $59 M demonstration plant at a former pulp in Tofte, Norway. Steeper has licensed its technology to Silva, who hope to build a 4,000 L/day facility over the next 18 months. Start-up is planned for spring 2019[15].

Licella, an Australian company, developed a proprietary catalytic hydrothermal liquefaction (HTC) process using supercritical water to convert lignocellulosic biomass feedstock to produce biocrude. Licella has demonstrated conversion of Radiata Pine sawdust and other energy crops such as corn stover and sugar cane trash into biocrude at their pilot plant in Whyalla, South Australia. The pilot plant was constructed in 2011. In March 2013, Licella received $5.4 million from the Australian Government through the Australian Renewable Energy Agency's (ARENA) Advanced Biofuels Investment Readiness program (Licella, 2013). This funding supported a $8.4 million feasibility study into the construction of its first pre-commercial biofuel plant with a target production capacity of 125,000 barrels of biocrude oil per annum (i.e., 14.875 MLPY). In July, 2014, Licella identified an optimum site for a commercial plant in the "Green Triangle" of South Australia. The target production capacity is between 87 – 217 MLPY biocrude made from 200,000 odt/year of lignocellulosic biomass. In 2017, Licella entered into a joint venture with Canfor, a Canadian company, with the aim of developing a demonstration plant for production of biocrudes from forest residues. The company received a $13M non-repayable contribution through Sustainable Development Technology Canada that will enable Canfor to further develop and demonstrate Licella's technology.[16]

Pacific Northwest National Laboratory (PNNL), with funding from the Bioenergy Technologies Office of the US Department of Energy, has done extensive research and investigation into hydrothermal liquefaction of lignocellulosics, food processing wastes, and algae in subcritical water. The process licensee, Genifuel, has built a demonstration plant for Reliance Industries Limited in India for liquefaction of algae. The team has also evaluated processing wet wastewater treatment sludge through HTL to produce biocrude and upgrade to transportation fuels in collaboration with the WERF and MetroVancouver.

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[15] http://www.biofuelsdigest.com/bdigest/2018/01/16/the-silver-in-silva-the-story-of-steeper-energys-59m-advanced-biofuels-project-in-norway/

[16] http://www.biofuelsdigest.com/bdigest/2017/03/14/the-wonder-from-down-under-and-canadall-fund-er-canfor-picks-up-13m-for-licella-biofuels-project/

1.4 Bio-oils/biocrudes – composition, characteristics and upgrading challenges

Pyrolysis bio-oil (Py oil) is a dark brown liquid composed of more than 300 different carbon molecules. Although referred to as an oil, with a similar physical appearance to crude oil, it is chemically distinct and the term biocrude is more appropriate as a term for lignocellulose-derived liquids/oils, as opposed to lipid-derived liquids/oils. In addition, differences in bio-oil characteristics and composition are found using different process technologies and feedstocks. Generally, references to bio-oil refer to fast pyrolysis bio-oils (FPO) as they have been extensively characterised. Bio-oils or biocrudes from other processes are more specifically identified, e.g. catalytic pyrolysis bio-oil (CPO) or hydrothermal liquefaction biocrudes (HTL biocrudes).

Pyrolysis oils contain about 40% oxygen compared to the typical maximum amount of 2% oxygen found in crude oil (Speight, 2006). The oxygen content of biomass results in biofuels with undesirably high reactivity (low chemical stability) and low energy density. Compared to crude oil, bio-oil has less than 50% of the energy density (16-19MJ/kg vs 40 MJ/kg). Bio-oils/biocrudes based on modified processes such as catalytic pyrolysis or HTL are expected to have significantly lower oxygen content and Table 3 gives an indication in variation of chemical characteristics of bio-oils from a variety of processing platforms. However, it should be noted that, although single data points are provided for catalytic pyrolysis and hydrothermal liquefaction biocrudes, they would typically also display properties over a range as process conditions may vary.

Table 3 Comparison of typical properties of bio-oils and biocrudes from lignocellulosic feedstock via different technologies with crude oil. Variations in process conditions may result in variation in properties for catalytic fast pyrolysis and hydrothermal liquefaction.

	Fast pyrolysis [1]	**Catalytic fast pyrolysis** [2]	**Hydrothermal liquefaction**[3]	**Crude oil**
Water, wt%	15-30	8.3	0.8	0.1
pH	2-3	2.6	~8	--
HHV, MJ/kg	16-19	30.4	38.6	44
$\mu_{50℃}$, Cp	40-100	285*	17,360***	180
C, wt%	55-65	72	81.4	83-86
O, wt%	28-40	21.5	9.8	<1
H, wt%	5-7	6.4	8.7	11-14
S, wt%	<0.05	--	0.01	<4
N, wt%	<0.4	0.02	0.095	<1
Yield, wt%	55-75	32(18**)	45.3	--
HDO's H_2, Scf/bbl fd [4]	~3400	--	~1800	358-1150

[1] Data taken from Mortensen et al. 2011; Dabros et al. 2018

2 Data taken from Passikallio 2016; *measured at 40 °C; **recovered in the bio-oil fraction

3 Data taken from Jensen et al. 2017; ***measured at 40 °C

4 Hydrogen required consumption for hydrotreatment, scf/bb fd (standard cubic feet/barrel feed) (Holladay, 2014)

Bio-oil composition is derived from the decomposition (depolymerisation and fragmentation reactions) of the main biomass components of lignin, cellulose and hemicellulose (Oasmaa and Czernik, 1999). From a compositional perspective, bio-oil resembles woody biomass much more than it resembles crude oil.

Water is a major component of bio-oils and its concentration varies depending on the initial moisture content of the biomass and the pyrolysis conditions used. Severe pyrolysis conditions (high temperature and residence time) remove more water but also promote vapor polymerizations and thus increase the viscosity and solids content of the resulting bio-oil (Oasmaa and Czernik, 1999). Water is derived from both the original water in the feedstock and from the water formed during the dehydration reactions occurring during pyrolysis. An excessive amount of water in bio-oils is undesirable because it acts as a heat sink during combustion and it can also promote destabilization and phase separation of the fuel during storage. To minimize the water content in bio-oil, the moisture content of the biomass feedstock is best kept below about 10 wt% in the case of fast and catalytic pyrolysis, although this is not applicable to hydrothermal liquefaction where much higher moisture levels in feedstock can be tolerated.

As well as water, the other major chemical components of bio-oil include hydroxyaldehydes, hydroxyketones, sugars, carboxylic acids, and phenolics (Bridgwater, 2012). As was the case with water, the amount of these compounds in the bio-oil depends on the composition of the original biomass as well as the pyrolysis conditions used. Some of these components, such as the sugars, are hydrophilic but others, such as the phenolics, are more hydrophobic. Thus, most bio-oils can be considered micro-emulsions. The continuous phase of the emulsion is the aqueous solution containing the polysaccharide decomposition products and the discontinuous phase is the pyrolytic lignin (the emulsion is mainly stabilized by weak hydrogen bonds). The breakdown of this emulsion results in the formation of two phases, a lighter, more aqueous phase and a heavier, less aqueous (Bridgewater, 2012). If the aqueous phase is separated from the heavier phase, a significant amount of feedstock carbon can be "lost".

Pyrolysis oils are prone to "ageing" which is measured as increased viscosity over time and it occurs through reactions between the oxygenated carbon molecules in the bio-oil emulsion. Polymerization reactions between double bonded components as well as esterification and etherification reactions between hydroxyl and carbonyl groups produce high molecular weight, water-insoluble components such as gums. These reactions lead to increased viscosity and, ultimately, to a phase separation of the bio-oil into an upper aqueous phase (containing a higher proportion of acids and sugars) and a lower tar phase (containing less water and a higher proportion of water insoluble solids and lignins) (Lehto *et al.*, 2013).

The main factors that accelerate these undesirable "aging" reactions are:

- Time: most bio-oils destabilize/phase-separate after storage for about 6 months or more) at room temperature.
- Temperature: The viscosity of a hardwood bio-oil could double after a year at room temperature, after a week at 60 °C and after a day at 80 °C.
- Alkali char: catalyzes polymerization reactions thereby increasing bio-oil viscosity.

(Oasmaa and Czernik, 1999)

Processes such as hot filtration to remove char particles can improve the stability of bio-oils (Sitzmann, 2009) or by adding solvents (Lehto *et al.*, 2013) such as methanol. Methanol blending has been shown to greatly improve the stability of bio-oils when used as burner fuels (Diebold, 2000). In earlier work, Diebold & Czernik (1997) showed that a 10% methanol blending reduced the bio-oil aging rate 20-fold. These and other stabilization techniques have been discussed earlier (Diebold, 2000; Oasmaa & Czernik, 1999) but nearly all of the options are costly and/or lead to bio-oil yield loss. The impact of added solvents on the life cycle analysis has not been thoroughly investigated although this project provides some insight into the matter. To our knowledge the ATM Project is the first to assess the LCA implications of additives during upgrading.

Due to the substantial amounts of non-volatile materials found in bio-oils, such as sugars and oligomeric phenolics, etc., they are unsuitable for distillation. The slow heating of the oils during distillation accelerates the polymerization reactions resulting in the formation of heavy and non-volatile compounds. Heavy Fuel Oil typically leaves 1% residue after vacuum distillation whereas a bio-oil leaves up to 50% of the starting material as distillation residue. This poor distillation performance has implications for further processing of bio-oils into drop-in fuels. Whereas crude oils are first subjected to distillation after which fractions are upgraded into finished products, bio-oils have to be subjected at least some upgrading first before any fractionation through distillation.

Bio-oils are already used as fuels for burner/boilers and burner/furnaces for stationary heat and power generation. However, its water content, oxygenated compounds and char particles can be challenging. They also have drawbacks for combustion such as low energy density, ignition difficulties, high viscosity and instability as well as low pH and high particulate levels. Although bio-oils generally produce less NOx and SOx than do fossil fuels (coal and oil), they typically emit more particulate emissions due to the char content of the bio-oil (Lehto *et al.*, 2013).

For bio-oils to be used as transportation fuel, upgrading has to be carried out. This section looks at the two most suitable upgrading methods, hydrotreating and catalytic cracking.

1.5 Upgrading bio-oils/biocrudes to transportation fuels

Physical upgrading of bio-oil can take place through hot-vapour filtration, liquid filtration and centrifugation (Bridgewater, 2013). Hot vapour filtration can reduce the ash content of the oil to less than 0.01% and the alkali content to less than 10 ppm (Diebold et al., 1994). This reported value is much lower than that produced in systems using cyclones only. The filtered bio-oil also has a lower char content; however, the char is catalytically active and can potentially crack the vapours and reduce the bio-oil yields to 20%. The low char content is also supported by the reduction in the bio-oil viscosity and average molecular weight.

Liquid filtration of bio-oil is very difficult when filtering very low diameter particles (around 5 µm). This difficulty is due to complex interactions between the char and viscous components believed to be lignin oligomers which rapidly clog the filter with a gel-like substance. The use of solvents or self-cleaning filters are needed to overcome this problem (Bridgewater, 2012). UOP indicated the desire to reduce the solids in the oil to preferably below 0.01 wt.% and that pressure filtration may require up to 8 bar (Traynor et al., 2012). However, UOP suggested that centrifugation or ionic exchange application may be a better method for removing the char from the bio-oil. Centrifugation has been shown to be successful in reducing char content of the bio-oil. However, this reduces the bio-oil yield as some of the bio-oil is disposed together with the char cake.

As discussed previously, bio-oils can be used in various stationary heat and power applications or they can be upgraded to drop-in transportation biofuels such as diesel, gasoline and jet fuel grade hydrocarbons. However, although the relatively high oxygen content of bio-oils can be tolerated for direct combustion in stationary power applications, it is a significant problem for automobile engines and jet engines.

Upgrading of bio-oils to transport fuels involves extensive deoxygenation with the major challenge being to deoxygenate the bio-oil while maintaining high conversion yields and high hydrogen-to-carbon ratios in the finished fuel.

Various upgrading techniques have been proposed over the last few decades with the top two contenders being hydrotreating and zeolite cracking (Solantausta, 2011). Both processes are catalytic and selectively promote hydrogenation reactions. Hydrotreating uses large amounts of hydrogen to remove water from bio-oils in the form of H_2O molecules. In contrast, zeolite cracking uses no hydrogen but instead rejects oxygen in the form of CO_2, thus lowering the biofuel yield. Both technologies try to elevate the effective H/C ratio of bio-oils from about 0.2 to about 2 in order to fit the functional properties of hydrocarbon motor fuels. Virtually all the current bio-oil upgrading processes originated in the petroleum industry and use specialized catalysts to improve reaction selectivity. As capital costs for upgrading bio-oils are high it would be synergistically beneficial if existing oil refinery equipment could be used to process these biomass derived liquids.

Deoxygenation of biomass intermediates is essential for the production of drop-in biofuels and is achieved through three main chemical reduction processes: (1) decarbonylation (producing CO & H_2O); (2) decarboxylation (DCO) (producing CO_2) and (3) hydrodeoxygenation (HDO) (producing H_2O). These reactions are illustrated for the deoxygenation of fatty acids in Figure 5 but are generally applicable to deoxygenation of any oxygen-containing biomass.

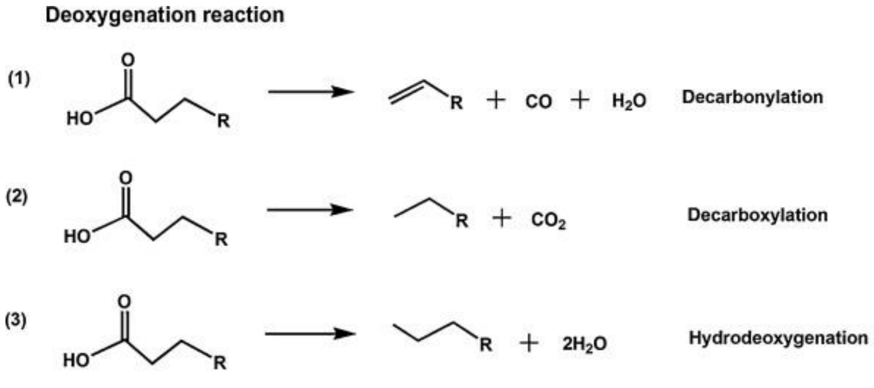

Figure 5 Deoxygenation reactions

During hydrodeoxygenation the hydrogen present in the biomass intermediates (or supplied externally) is oxidized and oxygen can be removed as water (H_2O). During decarboxylation the carboxyl group carbon is oxidized and the oxygen is removed as carbon dioxide. During decarbonylation, oxygen is removed as carbon monoxide with a water molecule also formed. While reaction conditions can be adjusted to favour one reaction (e.g. the type of catalyst used), in practice these processes take place simultaneously. The HDO process is typically favoured when hydrogen is externally added (e.g. hydrogen gas derived from natural gas) while, in the absence of hydrogen, the DCO route is favoured (NSF, 2011; Pearlson, 2011). However, it is interesting to note that some co-processing studies in a fluid catalytic cracker (where no additional hydrogen is added), resulted in hydrogen transfer between molecules and all three reactions still took place (from fossil molecules to biomolecules) (Pinho et al. 2015, 2017).

When decarboxylation or decarbonylation takes place, feedstock carbon is lost by oxidation and, as a result, the yield of hydrocarbons is reduced. When hydrogen inputs are used to remove oxygen, yields of hydrocarbons are generally higher, but the cost and sustainability of the imported hydrogen has to be considered.

1.5.1 Hydrotreating

Hydrotreatment is a hydrogen-intensive process for deoxygenating and upgrading bio-oils to drop-in- transportation fuels. Higher levels of hydrogen are needed to hydrotreat bio-oils because they contain about 40-50 wt% oxygen compared to the 10% typically found in vegetable oils. Thus bio-oils require extensive hydrogen and processing effort to become functionally equivalent to petroleum diesel. The targeted chemical reaction in bio-oil hydrotreating is the rejection of oxygen in the form of H_2O. This hydrodeoxygenation (HDO) reaction of bio-oil is conceptually represented as:

$C_1H_{1.33}O_{0.43} + 0.77H_2 \rightarrow CH_2 + 0.43H_2O$ (Bridgwater, 2012)

However, in practice, hydrotreatment is not highly selective and the HDO reaction described above does not take place in isolation but rather in association with other reactions which divert carbon and/or hydrogen from the targeted liquid fuel product. These reactions include polymerization and condensation to form tars and coke, gasification to form methane or CO_x and reactions that form low H/C hydrocarbons such as aromatics and olefins (Bridgwater, 2012). Thus, the low selectivity for hydrodeoxygenation and hydrogenation reactions often leads to low fuel yields and high hydrogen requirements.

In most of the hydrotreating processes modelled so far the biomass to fuel yield is around 25% by mass (55% by energy) when hydrogen is provided externally and 15% (33%) when hydrogen is produced by gasifying the biomass (Brown, 2011; Bridgwater, 2012; Dynamotive, 2013). These relatively poor carbon yields and hydrogen use efficiencies can be improved through the development of more selective catalysts and optimized processes.

Owing to the highly heterogeneous, oxygenated and reactive nature of bio-oils, their hydrotreatment is a lot more complex than that of petroleum. In oil refineries, hydrotreatment is mainly used to remove sulfur from petroleum feeds in a process known as hydrodesulfurization (HDS). The process conditions include temperatures that range between 300 and 600 °C, hydrogen pressures of 35 to 170 bar and liquid hourly space velocities (LHSV) of 0.2 to 10 per hour. The catalysts used in petroleum HDS are typically sulfided Co-Mo and Ni-Mo supported on porous alumina or aluminosilicate matrices. Unfortunately, as described below, these conditions are not suitable for processing bio-oils for a number of reasons:

- Sulfided Co-Mo and Ni-Mo catalysts, when in contact with bio-oils, are rapidly stripped of their sulfur and require constant resulfurization (addition of H_2S) to prevent catalyst deactivation (Huber, 2007). This deprives bio-oils of their low sulfur content advantage (Wang et al., 2013)

- Alumina supports create an acidic environment and they are not stable in the presence of water (irreversible dealumination) (Mortensen *et al.*, 2011)
- Bio-oils are unstable at high temperatures as they can rapidly become viscous and eventually phase separate.
- Bio-oils tend to form coke residues, particularly in acidic environments and at high temperature and pressure. Coke is undesirable as it deactivates the catalysts by depositing on their active sites and it can severely plug reactor components (Wang et al., 2013).
- The water in bio-oil inhibits hydrotreating by modifying and deactivating the catalysts and by adsorbing onto active sites (Furimsky and Massoth, 1999). Aside from the water content of bio-oils (up to 30%), more water is produced upon hydrotreatment.

These and other limitations have motivated the search for hydrotreating processes and catalysts that are better suited to the highly oxygenated and heterogeneous nature of bio-oils. Early research focused on adjusting process conditions and working with model bio-oil mixtures while using the same sulfided catalysts that oil refineries use for desulfurization (Corma et al., 2007). Although these alumina supported Co-Mo and Ni-Mo catalysts have various problems in processing bio-oils, they improve hydrotreating selectivity and they are widely available at relatively low cost.

Bio-oils are thermally unstable and it is generally thought that they would likely have to first be pretreated at lower temperatures in order to form a stable oil intermediate that can then be further hydrotreated at high temperatures. Although single stage hydrotreating of bio-oil at high temperatures has been attempted, it resulted in a heavy, tar like product (de Miguel Mercader et al., 2010; Jones et al., 2009) due to the polymerization, charring and eventually coking reactions which, at high temperatures, take place faster than the desired hydrotreating reactions. However, effective hydrotreatment often requires high temperatures and hydrogen pressures and extended reaction times (up to 4 hours) (Elliott, 2007). To fulfil these disparate condition requirements for stabilization and complete hydrotreatment of bio-oils, a two-stage bio-oil upgrading approach is commonly used (Elliott, 2007; Jones et al. 2009). The first, mild, catalysed hydrotreatment stabilizes the bio-oil and a second, higher severity hydrotreatment stage deoxygenates the fuel to transport-grade liquids. The first hydrotreatment typically forms at least two phases, one hydrophobic and one hydrophilic and effectively separates out a large proportion of the water within the bio-oil. The resulting hydrophobic liquid is more stable and amenable to further catalytic upgrading. Fast pyrolysis bio-oils, catalytic pyrolysis bio-oils and hydrothermal liquefaction biocrudes may require significantly different approaches.

When earlier workers (Centeno, Laurent and Delmon, 1995; Ferrari *et al.*, 2001) investigated the fundamentals of bio-oil hydrotreatment using traditional sulfide molybdenum catalysts on model bio-oil compounds such as ketones, esters and phenolics (while alcohols and carboxylic acids where formed in the process), they concluded that ketones react first at lower temperatures (> 200 °C) to form alkenes while carboxylic and phenolic groups are converted at higher temperatures (> 300 °C). This early work lead to a proposed reactivity scale for the major components of bio-oils; the scale is plotted in Figure 6. The olefins and other double bond species are the most reactive and can be hydrogenated to more stable components such as alcohols and alkanes at temperatures around 250 °C and below. Alcohols are dehydrated to olefins at temperatures closer to 300 °C while carboxylic groups are more recalcitrant than alcohols and aromatics are the most recalcitrant and will only react at temperatures in the vicinity of 400°C. This reactivity scale is a very useful rule of thumb in the absence of precise reaction kinetics.

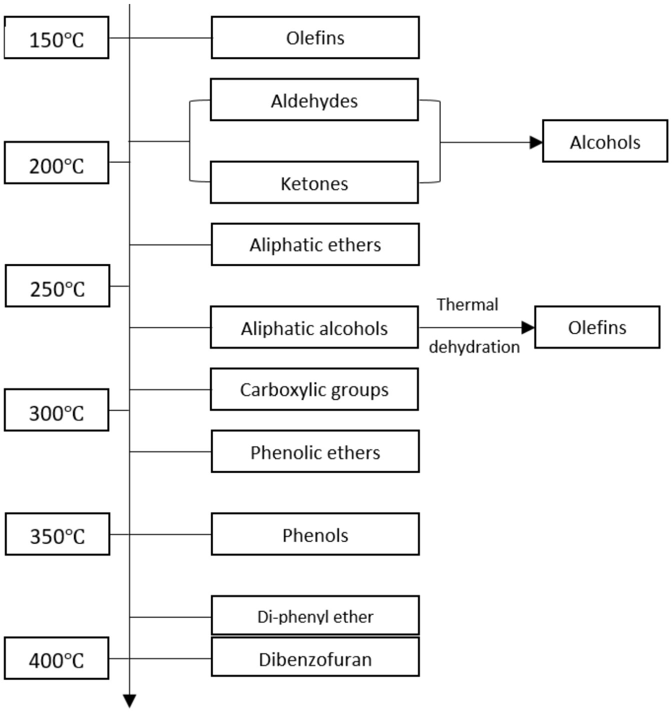

Figure 6: Reactivity scale of oxygenated compounds under hydrotreatment conditions.

Source: copied from Wang et al., 2013, based on work from Delmon and co-workers (Centeno, Laurent and Delmon, 1995; Ferrari *et al.*, 2001) as adapted and plotted by Elliott, 2007.

As noted earlier, coking is a major problem during hydrotreatment as it can lead to catalyst deactivation and reactor plugging. In general, the parameters that promote coking are high temperatures, low hydrogen pressures, high acidity, and the presence of low H/C components such as phenolics, alkenes and highly oxygenated carbon molecules (Huber, 2007; Mortensen, 2011). Double bond molecules such as olefins, ketones and aldehydes are particularly prone to polymerization and coking. Fortuitously, these species can be hydrogenated relatively easily during the first, low severity, hydrotreatment stage. This improves the thermal stability of the resulting bio-oil before the second hydrotreatment step. Refinery HDS catalysts promote the formation of coke by creating an acidic environment and promoting the formation of aromatics. Aromatics are desirable up to certain concentrations since they form part of transport fuel blends, particularly gasoline (40% aromatics) (Bauen, 2009). However, aromatics are a low H/C ratio species and can act as precursors for coking reactions upon upgrading. The hydrogenation of aromatic rings is the most challenging as it requires high temperatures and hydrogen pressures (around 4.0 to 8.0 MPa of H_2) as well as highly active catalysts such as precious metals (Wang, Male and Wang, 2013). Another way in which hydrogen can reduce coke formation is by converting catalyst-absorbed reactive species, such as alkenes, to stable molecules such as alkanes. In general the presence of hydrogen appears to play a pivotal role in minimizing the formation of coke.

While this more fundamental work has built an invaluable body of knowledge around the hydrotreatment and coking mechanisms of bio-oils, these studies have been mainly based on "model" as opposed to "real" bio-oils (Butler *et al.*, 2011). In contrast, Elliott and co-workers (Elliott, 2007) used sulfide Co-Mo and Ni-Mo catalysts on real bio-oil substrates and developed a two stage process that brings the oxygen content of the bio-oil down to < 1 wt%. The first stage of the process is conducted at 270°C and 136 bar and the second at 400°C and 136 bar. Consistent with the known challenges of these catalysts, the authors reported catalyst deactivation and formation of gums as major drawbacks of the process.

More recent research has focused on developing catalysts that may circumvent the challenges encountered with traditional HDS catalysts such as CoMo and NiMo supported on alumina materials. Precious metals such as Ruthenium, Palladium and Platinum have been assessed as bio-oil hydrotreatment catalysts (Bridgwater, 2012). These metals performed better than CoMo and NiMo catalysts in terms of both hydrocarbon yields and H/C ratio of final product (Wildschut *et al.*, 2009; Lin *et al.*, 2011; Wang, Male and Wang, 2013). They are also more stable, less acidic and do not promote coking particularly when supported on non-acidic carbon. The company UOP has been a leader in using precious metal catalysts for hydrotreatment of petroleum. Together with PNNL they have assessed the potential of non-sulfided metal catalysts such as Ruthenium on bio-oils. Ruthenium seems to be the lowest cost and most promising of the precious metal catalysts assessed so far (Wildschut *et al.*, 2009, 2010; Wildschut, Melian-Cabrera and Heeres, 2010). When Lin et al. (2011) assessed various precious metal catalysts using the model compound guaiacol, they reported that the Ru-based catalyst showed the best HDO activity and a preference to saturate benzene rings. Although Ruthenium is less expensive than Palladium and Platinum, on June 28, 2013 the spot price for Ru was about USD $3 million/t which is more than a 100 times the same day price of Cobalt (ca. USD $30,000 USD/t), Nickel (ca. USD $10,000/t) or Molybdenum (ca. USD $20,000/t) (IndexMundi, 2013; InvestmentMine, 2013). Although precious metal catalysts are more favoured for bio-oil hydroprocessing, as they are more active in comparison to NiMo and CoMo based catalysts, their cost is so prohibitive that their use in industrial applications may be very limited.

The ability to recycle and the stability of Ru/C catalysts has been challenged by Wildschut (2009). When he conducted three successive hydrotreatment reactions (200 bar, 350°C and 4.3 h each) where the catalyst was reused after repeated acetone washes, he found that the activity of the catalyst deteriorated even after the first repeat. After 2 repeats the oil yields dropped significantly (55 to 30%-wt.), whereas the amount of gas phase (5 to 11%-wt.) and solids (3 to 20%-wt.) increased, all indicating significant catalyst deactivation. This deactivation mostly affected the ability of the process to hydrogenate while it did not affect much of its ability to deoxygenate. The deactivation was attributed to sintering and coke formation on the surface of the catalyst. It would therefore be desirable if the catalysts could have been regenerated with a more effective technique than acetone washing.

The prohibitive price of precious metals means that novel catalysts have to be designed which will achieve high hydrotreating activity at lower cost. Although phosphide catalysts have been suggested as alternatives to sulfide catalysts they face similar issues. Once in contact with water they form phosphates which can deactivate the active sites on the catalyst (Wang et al. 2013).

Other than deoxygenation, the hydrotreatment of bio-oils has many favourable side effects such as decreasing its water content, increasing its energy density (from 18 MJ/kg in crude bio-oil to 40 MJ/kg in hydrotreated bio-oil), decreasing its bulk density (from >1 in bio-oils to <0.8 in deoxygenated bio-oils), decreasing the coking propensity, and decreasing its viscosity (from > 100cps in raw bio-oil to <5 cps in bio-oil that contains <5% oxygen) (Elliott, 2007). All of these advantages result in higher yields and the higher H/C_{eff} ratio of the final transport fuel product. These benefits are generally absent in any bio-oil upgrading technologies that do not entail any hydrogen inputs.

1.5.2 Catalytic cracking

Catalytic cracking is a process used in the Fluid Catalytic Crackers (FCCs) of oil refineries and it has potential in bio-oil upgrading as a non-hydrogen consuming, non-pressurized alternative to hydrotreatment. The main deoxygenation mechanism of catalytic cracking is the rejection of oxygen in the form of coke and CO_2. The conceptual reaction of this mechanism is summarised below:

$$C_1H_{1.33}O_{0.43} + 0.26O_2 \rightarrow 0.65CH_{1.2} + 0.34CO_2 + 0.27\ H_2O$$

When this formula is compared with the earlier equivalent formula for hydrotreating it is apparent that, in the absence of hydrogen, as occurs in zeolite cracking, bio-oil upgrading is poor. The theoretical carbon yields for catalytic cracking are low (65% compared to 100% in hydrotreatment) and the hydrocarbons produced have a low H/C ratio (1.2 compared to 2 for hydrotreatment). This low H/C ratio indicates that the upgraded bio-oil is rich in aromatics and olefins and that the resulting fuel will have a low heating value, typically about 20-25% lower than crude oil (Balat *et al.*, 2009; Mortensen *et al.*, 2011). Similar to what occurs in hydrotreatment, the cracking reaction takes place alongside other undesirable reactions such as polymerization and coking which results in the diversion of some of the carbon from the targeted liquid biofuel. Thus, even in the presence of catalysts, cracking typically results in bio-oil-to-fuel yields in the range of 14-23 wt% of bio-oil (Balat *et al.*, 2009), which is much lower than the theoretical 45 wt% yield which can be calculated from the equation above. This is largely because 26-39 wt% of the starting bio-oil goes towards the formation of solid tar and cokes (Balat *et al.*, 2009).

Zeolites such as ZSM-5 and HZSM-5 are made of a highly porous aluminosilicate matrix and, as a result, they are typically not stable in the presence of bio-oils at high temperatures and pressures. Zeolite catalysts such as ZSM-5 have a strong acidity, high activities and shape selectivities which work well for upgrading petroleum feeds. However, for bio-oils, zeolite cracking poses severe catalyst coking and deactivation issues.

On the more positive side zeolite cracking requires no hydrogen gas and can operate at atmospheric pressures. This means that FCC-type systems can be used for bio-oil processing where the heavily coked catalyst can be rapidly regenerated in the FCC combustor. These systems have great potential to utilise the coke formed on catalysts as a fuel for heat and power generation. However, these systems often convert more biomass carbon to thermal energy than to liquid fuel products. Operating costs of FCCs are higher than regular fixed bed reactors because the faster recycling of carrier gas needed to regenerate the rapidly coked catalyst is highly energy intensive.

Other workers (Vispute *et al.*, 2010) have proposed an approach that involves a mild hydrotreating step prior to zeolite cracking. The advantage of this approach is that it converts the most reactive oxygenated compounds, the carbonyls, to more thermally stable alcohols. In zeolite cracking carbonyl functionalities go directly to coke formation whereas alcohols contribute to the formation of valuable molecules such as olefins and aromatics. The introduction of a mild hydrotreatment step prior to zeolite cracking appears to result in bio-oil conversion yields (aromatics) as much as three times higher than direct zeolite cracking. This is particularly desirable for BTX (benzene, toluene, xylene) production which is the target of the Huber group's spin off company AnelloTech. However, the alkane yields are low and, while this technology may be relevant to making aromatic fractions for gasoline, it is not directly applicable to the production of the longer chain hydrocarbons that are needed for the production of diesel and jet fuels.

1.6 Refinery integration of liquefaction platform as an upgrading strategy

The ATM Project selected two laboratories with distinct upgrading approaches and this is described in Chapter 3. Canmet followed a "co-processing" approach which involved mixing the bio-oil/biocrude with furnace fuel oil (fossil-based) prior to single-stage hydrotreating. The products were therefore a mixture of fossil hydrocarbons and renewable hydrocarbons and this was identified through C14 methods. The second approach was carried out by PNNL with hydrotreatment conducted on the bio-oils/biocrudes either in single stage or two-stage approach (for fast pyrolysis bio-oil). Both of these approaches were carried out at pilot scale. Part of the ATM Project is the development of a demonstration-scale engineering design for scaling up the upgrading.

Hydrotreating approaches were followed for upgrading, but this is not the only approach possible. As shown in the previous section, catalytic cracking is an alternative approach to upgrading. As this is generally used in refineries for producing gasoline, rather than jet, this approach was not followed in the ATM Project.

A further distinction can be made between dedicated upgrading of biobased feedstocks; and upgrading methods based on fossil feedstocks, but with a co-processing strategy (insertion of biobased feedstocks/intermediates into an existing refinery in low concentrations and processing as normal.)

As mentioned earlier, the majority of the processes and catalysts used to upgrade pyrolysis oils originate in the oil refining industry. It has also been suggested that pyrolysis oils or their derivatives could be "dropped into" existing refineries for final processing (Corma et al., 2007; Solantausta., 2011). The main benefit of this approach is capital cost savings by utilizing facilities and off-take infrastructure that has already been built. For example, the USDA "Regional Roadmap to Meeting the Biofuels goals of the Renewable Fuels Standard" (2010) concluded that 527 new biorefineries would be needed to meet the requirements of the RFS 2, at a cost of about 168 billion USD (Weyen, 2012). A big part of this capital cost could be avoided if biomass intermediates could be upgraded to biofuels using existing oil refinery equipment. An important trend that is projected for the next three decades is that refineries in the US and around the world will be producing less gasoline and more diesel and jet fuels (more middle distillates). This shift translates to refineries directing petroleum feed away from FCC units and towards hydrocracking units. According to the US EIA 2013 Annual Energy Outlook (EIA, 2013), the already decreased utilization of FCCs (83% in use in 2011) in US refineries is expected to decline further and approach 62% in 2040. In contrast the US hydrocracking capacity is expected to increase from 1.8 million bpd in 2012 to 3 million bpd in 2040.

More recently, OPEC's World Oil Outlook (2016)[17] projected utilization of hydrocracking units to be in the low 80% range, through the period to 2040 while FCC unit utilization peak at 81% close to 2020 due to short-term gasoline demand increase and then gradually down to 75% after 2030.

It has been suggested that oil refiners could either dedicate whole process units such as hydrotreaters exclusively to bio-oil processing or they could co-process bio-oils together with petroleum feeds (Corma et al, 2007, Egeberg et al., 2010). Dedicating whole refinery units to upgrading bio-oil derivatives would save capital costs and avoid complications of co-processing. However, candidate refinery units for biomass liquids processing such as hydrotreating and hydrocracking facilities are very large scale and as noted earlier, they typically process around 100,000 barrels of fuel per day. Commercial pyrolysis facilities are usually envisioned to be about 30 times smaller at around 3,000 barrels per day, at a scale large enough to benefit from economies of scale while small enough to avoid transporting bulky and wet biomass over prohibitively long distances (Stephen, Mabee and Saddler, 2010). Thus sourcing, transporting and utilising the biomass feedstock needed to occupy a whole refinery unit will be challenging. Thus, co-processing is a more likely integration pathway than dedicating entire refinery units to biomass feeds. Co-processing also has the advantage that small amounts of biomass derived liquids can be blended with petroleum feeds mitigate the problems that come with neat pyrolysis oil processing.

As mentioned earlier, neat pyrolysis oil is challenging to co-process with petroleum feeds as they typically contain up to 30% water and 40% oxygen and has limited miscibility with the apolar petroleum liquids (Venderbosch and Prins, 2011). As the oxygen content of bio-oils also increases coking and deactivation of zeolite and HDO catalysts they cannot be readily inserted in oil refineries before at least partial deoxygenation (hydrotreated). However, it will be important to deoxygenate only enough to meet the minimum requirements of the refinery since deoxygenation gets disproportionately costlier when approaching oxygen-free bio-oils (Ringer, Putsche and Scahill, 2006; Elliott, 2007).

Once the oxygen content of the bio-oil has been reduced by hydrotreatment, it becomes a liquid hydrocarbon intermediate (such as hydrodeoxygenated oil, (HDO)) that can potentially be inserted into an oil refinery. As HDO bio-oils, even when partially deoxygenated, are unstable at 400 °C or 500 °C (temperatures that are often used in petroleum distillation) they cannot be directly inserted with crude oil at an early process stage of the refinery. Thus bio-oil insertion is likely to occur at the refinery's hydroprocessing (hydrotreatment and hydrocracking) or fluid catalytic cracking reactors. As described earlier, these two processes are similar to the processes used for hydroprocessing and zeolite cracking of neat pyrolysis oils in stand-alone setups. A simplified schematic showing HDO bio-oil insertion points (red arrows) within a typical refinery is outlined in Figure 7.

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[17] https://woo.opec.org/images/woo/WOO_2016.pdf

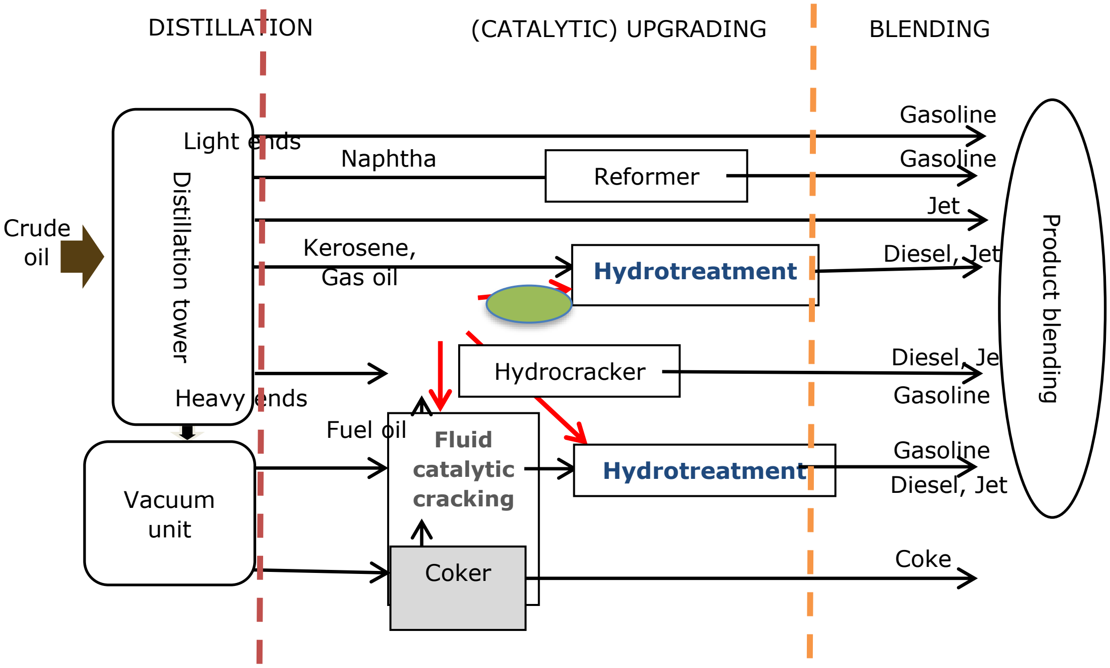


Figure 7: Refinery insertion points (red arrows) for HDO Bio-oils. (adapted from (US EIA, 2007)

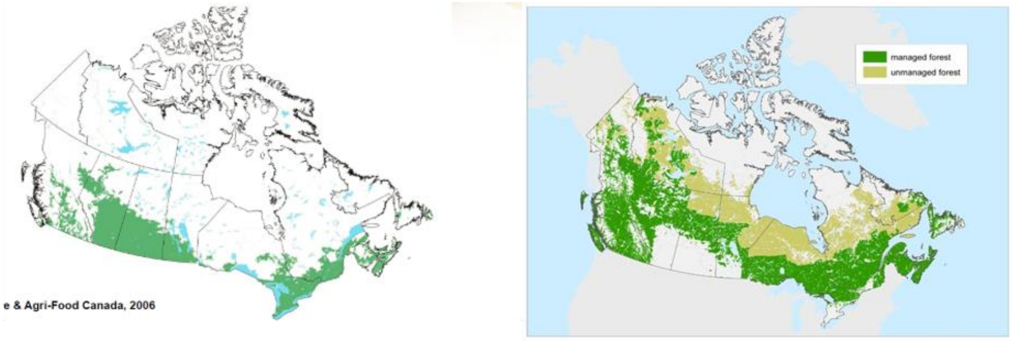
It is important to clarify that the use of the term hydrodeoxygenated oil (HDO) is not well defined as it simply refers to a bio-oil that has been stabilized through hydrotreatment. However, the degree of hydrotreatment can vary markedly and it largely depends on the co-processing insertion point and the blending ratio. The FCC insertion point can take more oxygen while hydrocrackers are far more sensitive to oxygen as they operate under very high temperatures and pressures. Fluid catalytic cracking capacity is closely linked with demand for gasoline and is more common in refineries in the USA as there is a higher demand for gasoline, while refineries in Europe have a higher demand for diesel and jet produced through hydrocracking (OPEC WOO 2016). These two HDO-petroleum co-processing strategies are discussed in greater detail in Appendix A.

CHAPTER 2 – FEEDSTOCK AND SUPPLY CHAIN

2.1 Availability and cost of forest residues and other lignocellulose feedstock in Canada

Canada is the second largest country in the world, with forest or other wooded land making up 40% of its 979 million hectares. In addition, Canada has 68 million ha of agricultural land, producing over 100.6 million tonnes of agricultural products each year. With active forest and agricultural industries, Canada has substantial biomass resources that can be used to produce bioenergy and biofuels (Canadian Council of Forest Ministers, 2018; Li et al., 2012). Figure 8 shows maps of agricultural (a) and forest lands (b) in Canada.

Sustainable forest practices are at the forefront and Canada is the leading country in forest certification on a global scale. Only 10% of the world’s forests are certified, and Canada holds 40% of the world’s forest certification (i.e. 170 million ha). Forest certification provides independent assurance that forest products are legally sourced from sustainably managed forests (Canadian Council of Forest Ministers, 2016). With vast forest and agricultural resources and an innovative and sustainable forestry and agriculture industry, Canada could potentially support an evolving advanced biofuel sector.



(a) Agricultural land

(b) Forest land

Figure 8. Map of agricultural and forest lands in Canada covering about 7% and 40% of total landmass in Canada, respectively (AAFC, 2012; NRCan, 2018).

Biomass is currently the second largest source of domestic renewable energy (i.e. heat, power and biofuels) in Canada (26%) after hydropower (69%), as shown in Figure 9. The share of biomass in total primary energy supply in the Canada has been relatively stable around 4.5% over the past five years (IEA Bioenergy, 2018).

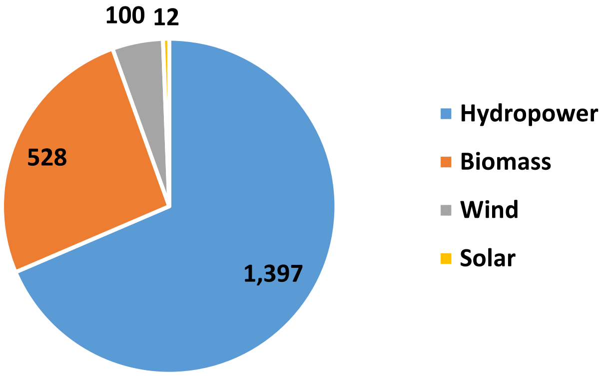


Figure 9. Total primary energy supply of renewable energy sources in Canada in 2016 (Petajoule -PJ). After hydropower, the second largest single source of renewable energy is biomass, representing about 26% of total renewables supply and around 4.5% of the total primary energy supply in 2016 (IEA Bioenergy, 2018).

The most used source of biomass to produce electricity and steam in Canada is industrial wood waste, particularly from the pulp and paper industry. Every year, more than 400 PJ of bioenergy are produced and used in the industrial sector. The pulp and paper industry is by far the largest industrial user of bioenergy, which accounts for more than half of the energy used in this industry. The 2013 Canadian Bioenergy Data Survey showed cogeneration taking place at 39 pulp and paper mills. Large heat and power are not only found at pulp and paper companies and there are also 23 independent heat and power producers in Canada, including eight in BC (Bradburn, K., 2014). The majority of the used woody biomass is black liquor and sawmill residues, the byproduct of chip and sawmill plants.

Biofuels are a growing form of renewable energy and Canada accounted for 2% of world biofuels production (5th highest in the world after the United States, Brazil, the European Union and China) (NRCan, 2018). The principal agricultural feedstocks for producing ethanol in Canada are corn and wheat. Canola, animal fat, and recycled oils remained the primary biodiesel feedstocks (USDA, 2018).

2.1.1 Lignocellulosic biomass resources in Canada

Although forest biomass, agricultural crops and waste have been used as feedstocks for production of bioenergy and biofuels, there are still significant quantities of underutilized lignocellulosic biomass resources in Canada that can be used as feedstock for the production of advanced biofuels such as biojet. Table 4 shows different types of potential biomass sources, their estimated availability in Canada and cost (as a range for delivered feedstock). The available quantities and average delivered costs of these biomass resources will be discussed in the next sections.

Table 4. Biomass availability and cost estimations in Canada

(National Forestry Database, 2017; International Wood Markets Grou Inc., 2014; Industrial Forestry Service Ltd. et al., 2015; Mobini, 2015; Roach and Berch, 2014; Wood Pellet Association of Canada, 2018; Li et al., 2012; Statistics Canada, 2016)

Biomass type	Average availability/year (million dry tonnes)	Average delivered cost ($/dry tonnes)[d]
Roundwood	33.3	76-259
Harvest/logging residues	13.2	69-90
Sawmill residues (woodchips, sawdust, wood shaving and hog fuel)	-[a]	Hog fuel: 12-13 Sawdust/yard waste: 20-30 Wood shaving: 25-52 Residual chips: 70-110
Wood pellets	-[b]	100-117[e]
Agricultural residues	52.8	82-94
Municipal solid waste (MSW)	28.77	(67-133)[c](negative cost)

[a] A significant proportion of sawmill residuals in Canada is already committed to the existing pulp and paper mills, bioenergy plants, board mills and pellet plants or used internally by mills for their own energy consumption. There are surplus quantities of sawdust, wood shavings and hog fuel available in the country. However, these are widely dispersed and are not available in sufficient volumes in a specific region of the country to meet the annual feedstock demand of a commercial-scale biofuel plant. The change in the dynamics of the forest products industry can increase the availability of this forest biomass source, for example the increase in the production capacity of sawmills or downturn in pulp production in Canada.

[b] About 95% of the produced wood pellets in Canada is currently exported to the EU, USA, and Asia and 5% is consumed in the domestic market

[c] Tipping fee paid to MSW receivers

[d] All dollar values in this report are Canadian

[e] Price of wood pellet at the pellet plant

2.1.2 Forest biomass resources in Canada

The main source of biomass in Canada is forest biomass. Forest-based biomass include: 1) roundwood (the trunk of the tree); 2) harvest residues (tops, branches, and non-merchandise timber from harvest operations); 3) mill residues (chips, sawdust and shavings, and hog fuel); and 4) intermediates such as wood pellets. The amount of wood permitted to be harvested in Canadian Provinces on an annual basis is called the Annual Allowable Cut (AAC). All forest-based feedstocks originate from harvesting under the AAC. Typically, trees are logged on site and tops and branches (harvest residues) removed and left at the harvesting site. The roundwood is transported to sawmills where it is cut to a predetermined length, while the mill residues are generated at sawmills, representing chips, shavings and sawdust. Figure 10 shows the typical yield of sawlog components in British Columbia. A processed log at the sawmill typically yields 46% lumber (lumber and trim blocks), 30% wood chips, 15% sawdust/shavings, and 9% bark by weight (Figure 10) (AEBIOM et al., 2013).

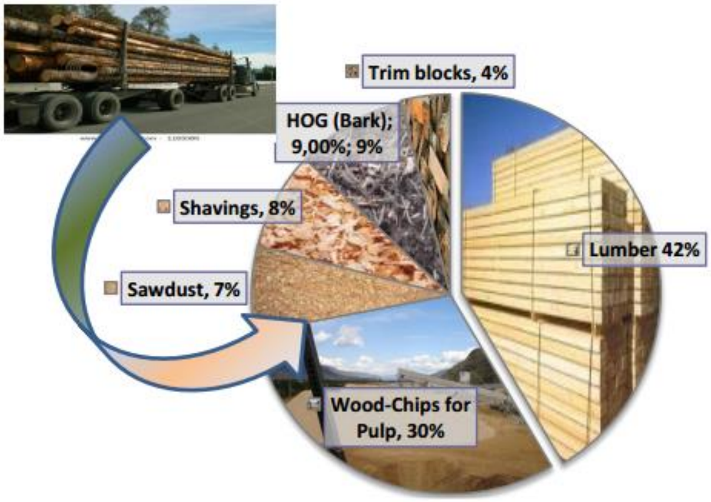


Figure 10. Typical yield of sawlog components in British Columbia (AEBIOM et al., 2013)

Roundwood availability and cost

Figure 11 illustrates the annual harvest versus total wood supply available for harvest (the AAC) in Canada and the difference is used to calculate the potential amount of unharvested wood under the AAC. The annual amount of unharvested wood has been about 63-122 million m^3 since 2000. Annually, approximately 25-49 million dry tonnes (dt) (average 33.3 million dt) of standing timbers have not been harvested since 2006 and is potentially available for valorization. The reasons why these standing timbers have not been harvested by forest companies include distance from the marketplace, low quality of tree species, such as Hemlock and Balsam, with limited value for lumber. Other reasons are steep terrain, resulting in expensive harvesting operations and the current market price of forest products that make a portion of the standing timbers commercially unattractive to harvest.

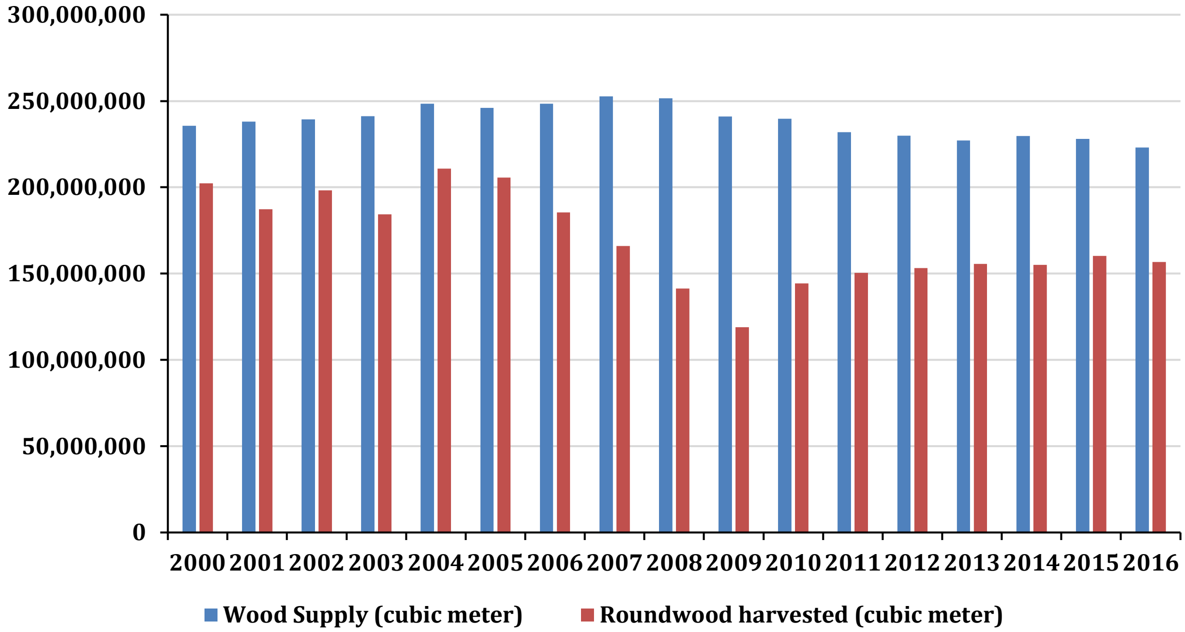


Figure 11. Annual harvest versus wood supply (based on the AAC) in Canada (National Forestry Database, 2017)

Table 5 shows the wide range of delivered costs for sawlogs that are currently harvested in Canada, depending on the forest region, the forest practices and the number of operations involved. The delivered cost can be as low as 75 $/dt for ground harvesting to as high as 258 $/dt for Aerial Heli harvesting. This wide range shows the extent of variability in the cost structure of harvesting standing timbers.

Table 5. Delivered cost of sawlogs based on 1.5-hour hauling cycle time and the contribution of various cost items (International Wood Markets Group Inc., 2014; Industrial Forestry Service Ltd. et al., 2015; Timberline Natural Resource Group Ltd., 2009; Timmenga & Associates Inc., 2008; Murray, 2010; FPInnovations, 2010)

Cost component	$CAD/dt
Silviculture	0.27-20.61
Overhead and administration	4.88-21.95
Crown charge	0.61
Road construction	2.39-10.41
Road maintenance	1.22-4.27
Logging and loading (Ground skid)	37.61-54.95
Logging and loading (Cable)	79.80-127.24
Logging and loading (Aerial Heli)	144.56-161.71
Road transportation ($/m^3-hr)	4.39-4.88
Chipping	20.73-24.39
Delivered cost- Ground skid	75.39-151.15
Delivered cost- Cable	117.58-223.44
Delivered cost- Aerial Heli	182.34-257.90

There is a large volume of unharvested roundwood in Canada which is potentially available for biofuel production. The majority of the available roundwood is produced in British Columbia, followed by Quebec, Alberta and Ontario. However, harvesting standing timbers for energy applications is generally not considered economical in Canada because the recovery costs entail full costs of planning, developing, and harvesting in addition to costs for biomass handling and preprocessing as well as the relatively low price of transportation fuels in the current market situations. Therefore, we consider other biomass sources in the following sections, including sawmill and forest residues as the more affordable feedstock for biofuel production.

2.1.2.1 Sawmill residues availability and cost

Sawmill residues are usually the least expensive source of woody biomass compared with other sources such as forest residues and roundwood/sawlogs. They are the by-product of mill operations and available at sawmills. Logistics operations would include loading, transportation to and unloading at the biorefinery site. Table 6 shows the delivered cost of sawmill residues.

Table 6. Delivered cost of sawmill residues based on 1.5-hour hauling cycle time (Mobini, 2015; Industrial Forestry Service Ltd. et al., 2015; Timberline Natural Resource Group Ltd., 2009)

Sawmill residues	$/dt
Hog fuel	
Fibre price at the sawmill	2.00-3.00
Transportation cost	10.00
Delivery at the biorefinery	12.00-13.00
Sawdust/yard waste	
Fibre price at the sawmill	10.00-20.00
Transportation cost	10.00
Delivery at the biorefinery	20.00-30.00
Wood shaving	
Fibre price at the sawmill	15.00-42.00
Transportation cost	10.00
Delivery at the biorefinery	25.00-52.00
Residual chips	
Fibre price at the sawmill	60.00-100.00
Transportation cost	10.00
Delivery at the biorefinery*	70.00-110.00

* Value of chips depends on the tree species.

A significant proportion of sawmill residuals in Canada is already utilised by the existing pulp and paper mills, bioenergy plants, board mills and pellet plants or internally by mills for their own energy consumption. While there are surplus quantities of sawdust, wood shavings and hog fuel available in the country, these are widely dispersed and are not available in sufficient volumes in a specific region of the country to meet the annual feedstock demand of a commercial-scale biofuel plant (e.g. 30 million gallons/year) (Industrial Forestry Service Ltd. et al., 2015). A change in the dynamics of the forest products industry could increase the availability of this forest biomass source, for example, an increase in the production capacity of sawmills or downturn in pulp production in

Canada.

The availability of mill residues could be a challenge for new markets in the future due to the existing competition for this resource and limited volumes. However, if log harvest volume increases in the future, it would also lead to an increase in production of mill residues. Thus, they can be a viable feedstock for biojet production in Canada.

2.1.2.2 Forest residues availability and cost

Depending on the utilization specifications for sawlogs and the extent of the damage to the trees in a forest stand as a result of the Mountain Pine Beetle epidemic, 20-40% of each tree harvested remain in the forest after conventional roadside harvesting in Canada. Roughly 25% of these residues are left behind in the forest stands as debris to provide nutrients and for health and biodiversity of the forest (Bradburn, 2014; AEBIOM, 2013; Roach and Berch, 2014). At current harvest levels (over 150 million m^3), ~13.2 million dry tonnes of forest residues are produced each year in Canada. This includes about 25% that need to remain in the forest for sustainability and nutrient recycling. The rest is usually piled and burned to reduce the risk of fire and to avoid the risk of disease and pest infestation. Under Section 7 of the Wildfire Act in BC, the forest residues must be disposed of within 6 to 12 months after it is determined that a fire hazard exists (Industrial Forestry Service Ltd. et al., 2013).

Thus, there is a large volume of harvest residues potentially available for biofuel production in Canada. The majority of the harvest residues are produced in British Columbia followed by Quebec, Alberta and Ontario. Figure 12, Figure 13 and Figure 14 show the supply curves for forest residues for three locations in BC and Alberta. Supply curves demonstrate the amount of available forest residues at a specific delivered cost.

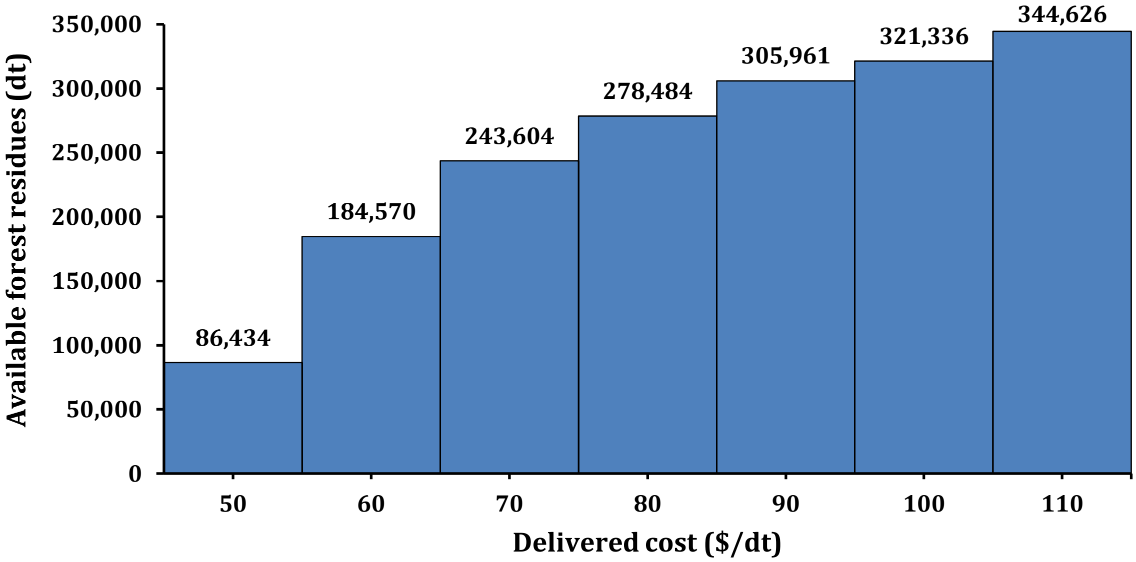


Figure 12. Supply curve of forest residues for Anahim Lake, Williams Lake Timber Supply Area, BC (FPInnovations, 2018a). Average delivered cost is 68.78 $/dt.

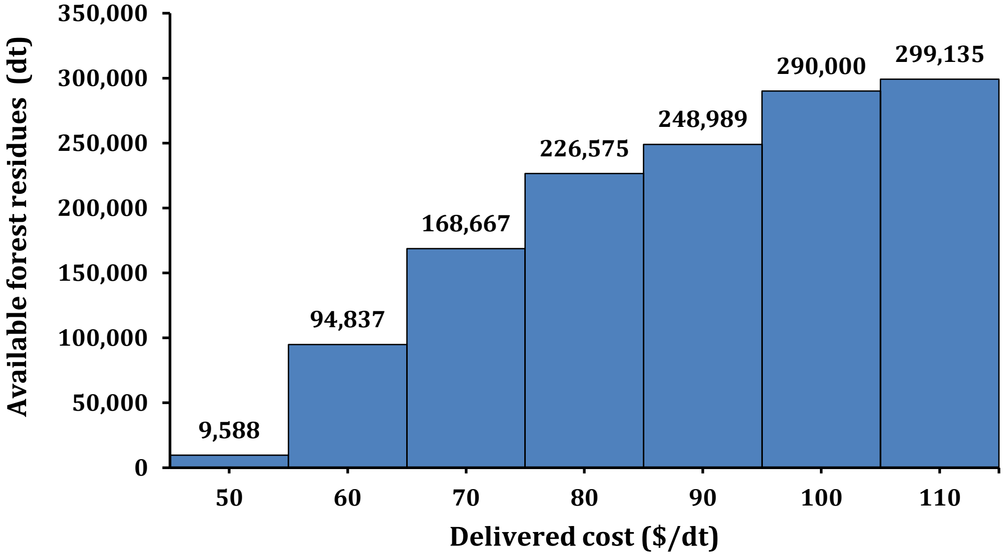


Figure 13. Supply curve of forest residues for Fort St. James, Prince George Timber Supply Area, BC (FPInnovations, 2018b). Average delivered cost is 75.71 $/dt.

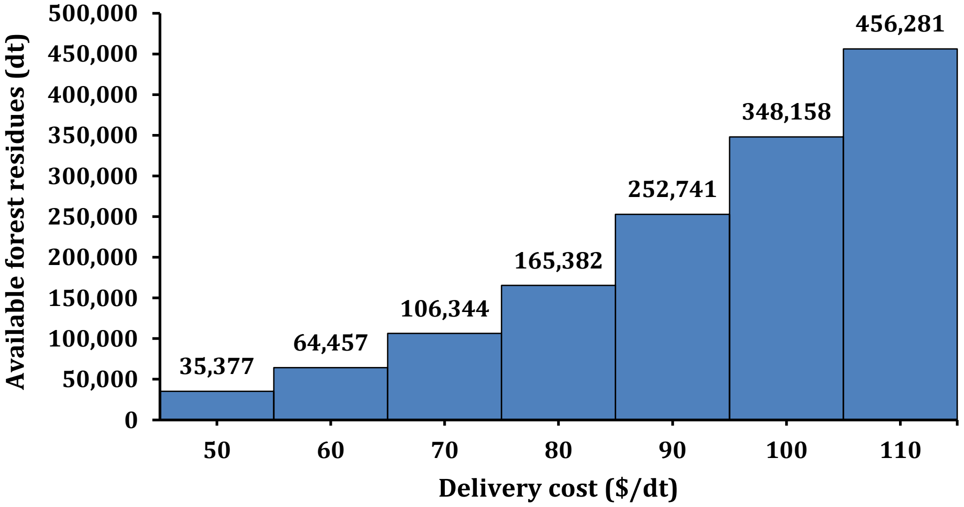


Figure 14. Supply curve of forest residues for Whitecourt, Upper Athabasca region, Alberta (BIMAT, 2018). Average delivered cost is 88.69 $/dt.

The Mountain Pine Beetle epidemic resulted in large volumes of standing dead trees in BC (MPB trees). Most MPB trees are not suitable for lumber production and are considered as a portion of the forest residues basket available for other industrial applications such as bioenergy and pellet production. However, the challenge of using MPB trees is the high cost of harvesting. The average harvest cost for the full tree stem is in the range of $68.45-86.63/dt. This biomass source will appear in the supply curve above $110/dt (FPInnovations, 2018). This makes MPB trees an expensive source of feedstock for biofuel production.

2.1.2.3 Wood pellets

Wood pellets are a potential source of feedstock for biofuel production in Canada. There are currently 44 operating wood pellet plants in Canada. The annual production capacity of these plants is about 4 million tonnes with the actual production level of 3 million tonnes. About 95% of Canada's wood pellet production is exported to the EU, USA, and Asia and 5% is consumed in the domestic market. BC has the highest pellet capacity utilization in Canada at 85% with world-class pellet plants and efficient infrastructure including tailored ports and rail to accommodate pellet handling. These plants are able to ramp up their capacity to near 100% if they have access to affordable woody biomass and a high market demand (Personal communication with Wood Pellet Association of Canada, 2018). Table 7. Wood pellet production and transportation costs (Mobini, 2015; International Wood Markets Group Inc., 2014; Pinnacle Renewable Energy Inc., 2014; Strauss, 2013; Murray, 2010;) shows the cost components of wood pellets. As can be seen in Table 4, wood pellets are more expensive per tonne compared to forest residues. However, key processing steps such as drying and size reduction is already incorporated in the wood pellet price. Although wood pellet is produced at commercial volumes in Canada, the majority of production is exported and it is a relatively expensive feedstock compared to sawmill and forest residues. However, it would have some advantages as a feedstock as it will be homogenous from a quality and size perspective.

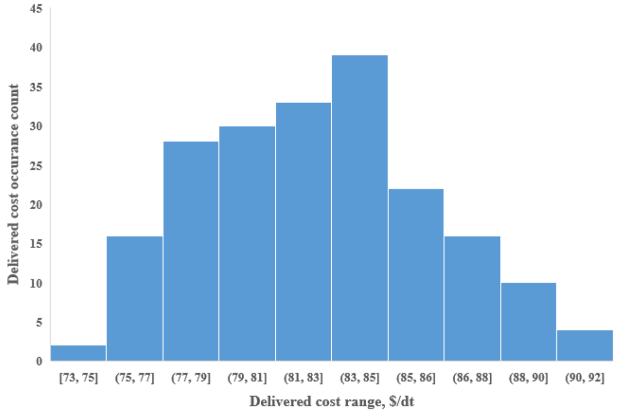
Table 7. Wood pellet production and transportation costs (Mobini, 2015; International Wood Markets Group Inc., 2014; Pinnacle Renewable Energy Inc., 2014; Strauss, 2013; Murray, 2010;)

Cost component	**$/dt**
Feedstock (woody biomass)	**30.00-35.00**
Pellet production	**40.00-42.00**
Producer EBITDA*	**30.00-40.00**
Total cost at the pellet mill	**100.00-117.00**
Transportation mode	**$/dt-mile**
Transportation (road)	**0.30**
Transportation (railway)	**0.067**
Transportation (ocean)	**0.0042**

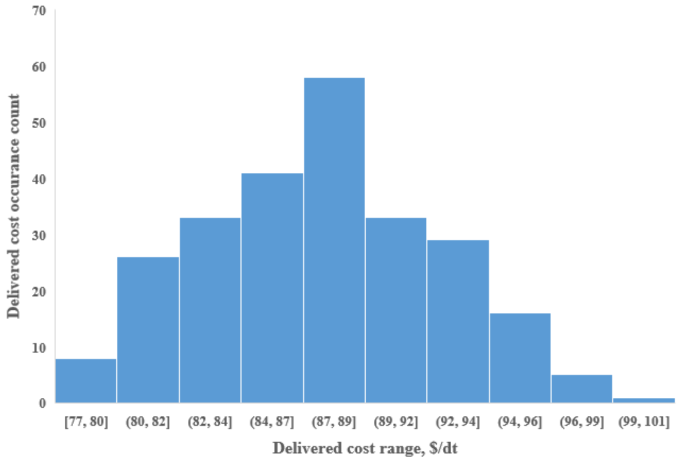
*Earnings before interest, taxes, depreciation, and amortization

2.1.2.4 Agricultural biomass availability and cost

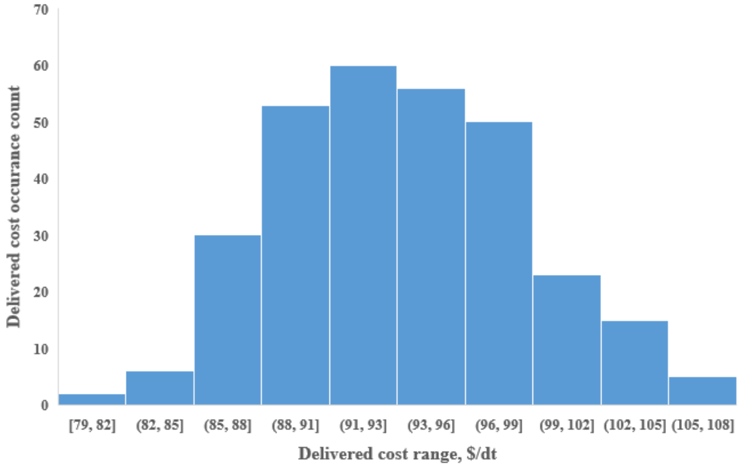
Agricultural residues are left on the fields after harvesting the grain as the primary agricultural product. Each year, about 52.8 million tonnes of agricultural residues are produced in Canada. The majority of this biomass is produced in Saskatchewan followed by Alberta, Ontario and Manitoba (Li et al., 2012). Sustainable removal and utilization of crop residues for biofuel production have been demonstrated by several cellulosic ethanol facilities. Figure 15 shows the distribution of delivered cost for corn stover in Southwestern Ontario for three different biorefinery sizes. The average corn stover delivered costs are estimated to be $82.09/dt, $87.49/dt and $93.75/dt for a small size biorefinery (175 dt/day), a medium-size biorefinery (520 dt/day) and a large size biorefinery scenario (860 dt/day), respectively (Wang et al., 2017).



a. Small size scenario (175 dt/day)



b. Medium size scenario (520 dt/day)



c. Large size scenario (860 dt/day)

Figure 15. Distribution of corn stover delivered cost for three biorefinery scenarios in Southwestern Ontario (Wang et al., 2017)

A key challenge in utilizing agricultural biomass is its affordability due to the wide distribution and the inefficiency of the existing logistics systems to deliver large quantities of agricultural residues to commercial-scale biorefineries. Thus, the availability of these residues for industrial uses such as biofuel production depends on the annual feedstock demand of the biorefinery and the fibre paying capability of the biorefinery. Agricultural residues generally have a higher ash content than forest biomass which poses some different challenges for their utilization in a biorefinery.

Although agricultural residues are available in commercial quantities for biofuel production in Canada, they were not further considered in this project as the supply chain was focused in BC where this feedstock is not available in any significant volumes.

2.1.2.5 Municipal Solid Waste (MSW) availability and cost

MSW availability depends on local population, waste management, and recycling practices. Currently, 28.77 million tonnes of MSW are disposed in landfills in Canada annually (Statistics Canada, 2016). From a cost perspective, MSW is an attractive feedstock for biofuel production as tipping fees are paid to dispose of waste. Local municipalities set their tipping fees to offset the disposal facility capital and operations. For example, in Metro Vancouver, on average, Transfer Stations charge $110/tonne for disposal of garbage. For a commercial hauler, the tipping fee is around $80/tonne and for small deliveries, it is around $133/tonne (Personal communication with Metro Vancouver). In contrast, the Oxford County in Ontario charges a tipping fee of $67.83/tonne for garbage, and $70.30/tonne for construction & demolition (C&D) material (Personal communication with Oxford County). The potential tipping fee (available as a "negative cost feedstock", ie. as revenue) for using MSW for biofuel production depends on the long-term contract between the municipalities and biofuel facilities.

MSW is a heterogeneous feedstock with high levels of contaminants, such as metals, that make it less attractive as a feedstock for biofuel production, as it will require extensive pre-processing clean-up. The inconsistent quality of MSW can significantly impact the cost-efficiency of the conversion process.

In summary, Canada has abundant and diverse biomass resources that can be used for different conversion technologies to produce transportation biofuels. A review of the availability and estimated delivered cost of these biomass resources and the technical aspects of using these lignocellulosic biomass resources as feedstock for the production of biojet reveal that forest residues have a significant potential to be considered as feedstock of choice for production of biojet in mid-term and long-term. In the next section, the availability of forest residues in Western Canada will be discussed in greater detail.

2.1.2.6 Potential forest residue availability in Western Canada

British Columbia (BC) and Alberta respectively constitute 18% (55 million hectares) and 11% (35 million hectares) of Canada's total forested area (310 million hectares). This ready availability of wood fibre and the use of sustainable forestry practices have facilitated the development of various industries including the primary (e.g. lumber, panels, engineered wood, etc.), secondary (pulp and paper) and tertiary sectors (bioenergy, wood pellets, etc.). As well as a valued forest resource, the sector also contains other assets such as skilled labour and knowledge/expertise within the wood fibre supply chain, from forest stands, via wood processing to international markets. Thus, Western Canada is well placed to develop more of a biorefinery approach to enhancing the value from its forest resource, with biojet being a valued and integrated product. About 6 million dt and 1.8 million dt of forest residues are produced annually in BC and Alberta, respectively. To ensure the sustainability and the regeneration and health of future forests it has been calculated that at least 25% of these residues must remain behind on the forest floor. Currently about 0.6 million dt of forest residues are utilized in BC for pellet and bioenergy (heat and power) production (International Wood Markets Group Inc., 2014; Industrial Forestry Service Ltd. et al., 2015; Roach and Berch. 2014).

The location and amount of forest residues available in BC is indicated in Table 8 and Figure 16. The average delivered cost of these forest residues has been estimated to be in the range of $60-82/dt. Forest residues are also available in other regions of the province but the available volumes are not significant (less than 100,000 dt/year) to support large-scale biorefineries for biofuel production.

Table 8. Potential locations in BC where large volumes of forest residues are available and the average delivered cost (Industrial Forestry Service Ltd. et al., 2015; FPInnovations, 2018). The biomass availability, cost and supply radius are estimated based of the size of forest stands in the region and the location of the delivery point.

Region	Delivery point	Estimated Supply radius (km)	Annual availability of forest residues (dt)	Average delivered cost ($/dt)
Vancouver Island	Parksville	155	200,000	66.67
BC Coast-Mainland	Aldergrove	155	200,000	66.67
Cariboo	Hanceville	220	747,519	81.57
Cariboo	Anahim Lake	166	344,626	68.78
Prince George	Fort St. James	195	299,135	75.71
Mackenzie	Mackenzie	178	297,442	71.59
Quesnel	Quesnel	177	236,104	71.32
West Kootenay	Castlegar	216	203,760	80.55
Peace	Chetwynd	192	166,320	75.00
East Rupert	Burns Lake	168	164,473	69.38
East Kootenay	Canal Flats	170	162,000	69.45
Cariboo	100 Mile House	126	110,192	59.50
Total			3,131,571	60-82

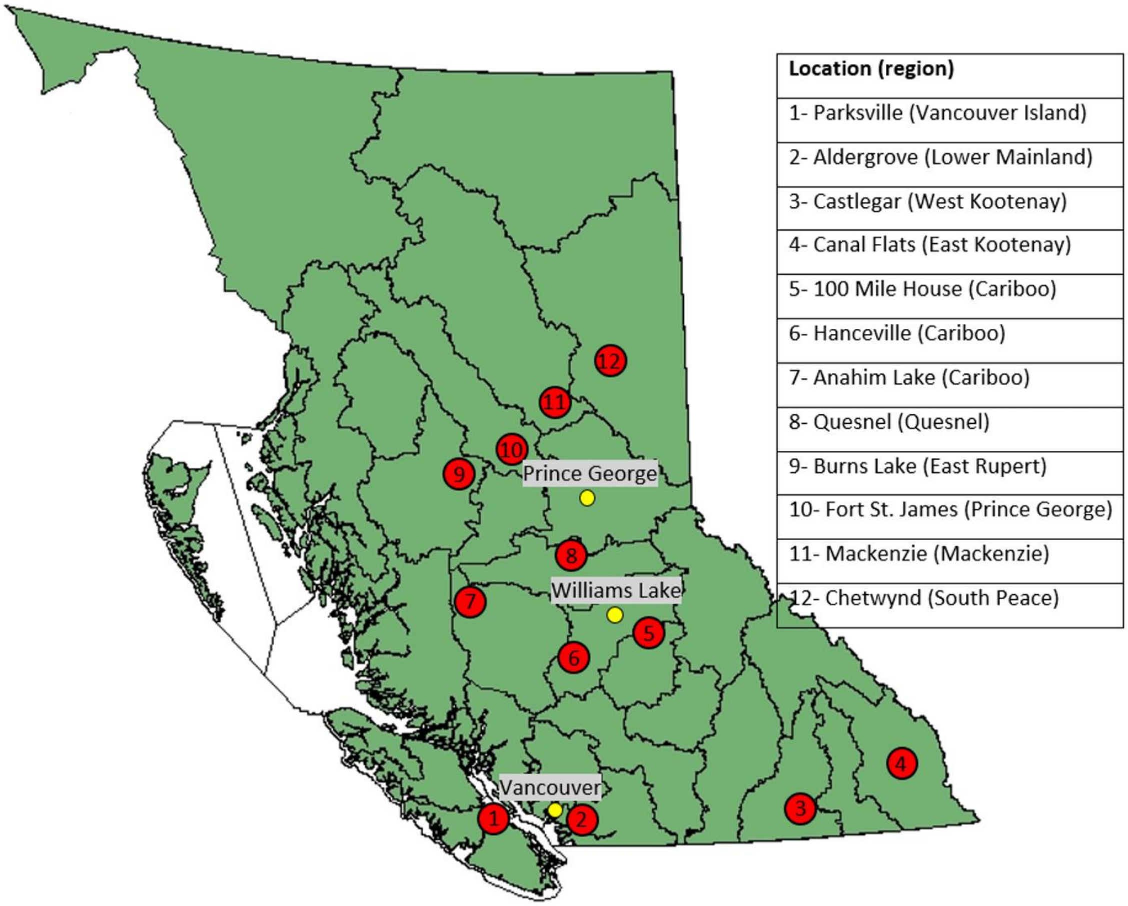


Figure 16. Potential locations in BC where large volumes of forest residues are available (Industrial Forestry Service Ltd. et al., 2015; FPInnovations, 2018)

As a result of forest operations in the Upper Athabasca, Upper Peace and Lower Peace, large volumes of forest residues are available in these regions in Alberta (Table 9). For the basis of the current study, the available forest residues within a supply radius of 120 km were estimated. For this type of supply area, the average delivered cost is estimated to be within the range of $85-89 /dt and the possible locations are shown in Figure 17. Although additional forest residues are also available in other regions of the province, the volumes are too widely dispersed to make it economically viable to collect and transport for a large-scale biorefinery.

Table 9. Potential locations in Alberta where large volumes of forest residues are available (BIMAT, 2018)

Region	Delivery point	Available forest residues (dt/yr)	Average delivered cost ($/dt)
Upper Athabasca	Whitecourt	456,281	88.96
Upper Athabasca	Slave Lake	409,196	83.73
Upper Peace	High level	280,662	85.13
Lower Peace	Grand Prairie	342,986	87.42
Total		1,489,125	

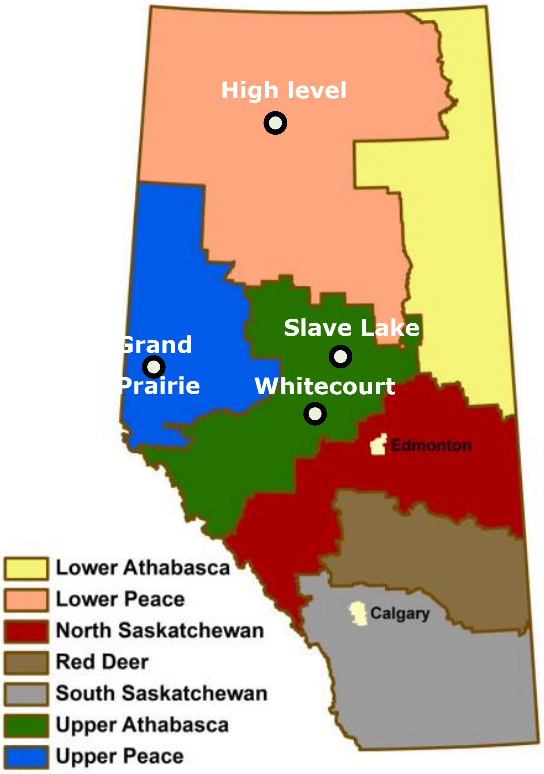


Figure 17. Alberta's land-use framework planning regions (Government of Alberta, 2014)

To provide more of a "real-world" scenario, we assessed the regional availability of BC and Alberta sourced forest residues that would be needed to supply the feedstock demand of a biocrude facility with the production capacity of 2000 barrels/day which requires approximately 300,000 dry tonnes of forest biomass annually (varies depending on the biocrude production technology)[18].

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[18] This volume was based on (refer to Appendix? Or add here)

Assuming 20% mass loss in the biomass logistics and preprocessing, about 375,000 dry tonnes of biomass needs to be collected at the roadside of forest stands. As discussed in the previous section, the feedstock of choice for the biocrude facility is assumed to be forest residues. The next section explains the regional supply chain for the considered biocrude facility.

As shown in Figure 12-14, the average delivered cost of sourcing these forest residues has been estimated to be in the range of $60-82/dt (FPInnovations, 2018a,b; BIMAT 2018). Forest residues are also available in other regions of the province but the available volumes are not significant (less than 100,000 dt/year) for industrial applications such biofuel production.

2.1.3 Regional biocrude supply chain scenario

The development of an optimal regional biojet supply chain would likely be through integrating the existing wood fibre and fossil fuel supply chains in Western Canada, for example, the existing fossil fuel supply chain and infrastructure could be used in a co-processing strategy for upgrading the intermediate products of a biorefinery (e.g. biocrudes or FT liquids) and storing/distributing drop-in biofuels to the marketplace[19]. This could potentially reduce capital and operating costs. Integration of biojet production with existing wood fibre logistical operations could also reduce the costs for delivery of forest residues to the biorefinery. Wood processing infrastructure such as wood yards, grinders and dryers could also be utilized in an integrated manner to store and pre-process woody biomass before conversion into biofuels.

Utilisation of this existing infrastructure is reflected in the criteria used for the site selection of the biorefinery and the development of the biofuel supply chain in Western Canada. The supply chain for the ATM Project was based on the biorefinery producing an intermediate biocrude or bio-oil which is then transported to a central upgrading facility integrated with an existing petroleum refinery.

The criteria to determine the potential location of the biorefinery and to develop the regional biojet supply chain include:

- Availability of woody biomass in the region.
- Proximity of the region to wood processing facilities, including sawmills, pulp and paper mills, bioenergy plants and pellet plants.
- Proximity of the region to oil refineries/upgraders: The close proximity of the biorefinery to existing petroleum refineries and upgraders provide an opportunity for co-location and co-processing.
- Proximity to petrochemical plants: the synergy between a biorefinery and the petrochemical industry could center around production and storage of hydrogen as both industries need hydrogen to produce the final marketable products.
- Available transportation infrastructure in the region.
- Proximity to major airports and populated areas.

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[19] As many different supply chain options are possible, only a few were selected for study in this report.

Table 10 shows seven potential locations for the development of a regional supply chain scenario for biocrude production. Five of these locations are in BC and two in Alberta: Prince George (BC); Vancouver Island (BC), Coastal Mainland (BC), Kamloops (BC), Quesnel (BC), Slave Lake (AB) and Whitecourt (AB). Among these locations, Prince George city has all the elements for the development of a regional supply chain for biocrude production in Western Canada.

Table 10. Potential locations for the development of a regional supply chain scenario for biocrude production in Western Canada

Potential locations	Biomass Availability	Proximity to wood processing facilities	Available transportation infrastructure (road, rail and water)	Proximity to oil refineries and airports
Prince George- BC	✓✓✓	✓✓✓	✓✓✓	✓✓✓
Coastal Mainland- BC	✓✓	✓✓✓	✓✓✓	✓✓✓
Vancouver Island- BC	✓✓	✓✓	✓✓	✓✓
Kamloops- BC	✓	✓✓✓	✓✓	✓
Quesnel- BC	✓	✓✓✓	✓✓✓	✓
Slave Lake- Alberta	✓✓	✓✓	✓✓	✓✓
Whitecourt- Alberta	✓✓	✓✓	✓✓	✓✓

The Prince George timber supply area (TSA) is in British Columbia’s north-central interior and covers about 7.97 million hectares and is one of the province’s largest forest management units. Approximately 3 million hectares of the total TSA land base is considered available for timber harvesting. The leading tree species are lodgepole pine, spruce and subalpine fir. Currently, there are 13 lumber mills, three pulp mills, one utility mill, four pellet operations, two cogeneration facilities and a bioenergy facility operating in the timber supply area. Combined these mills can process up to 11 million cubic metres of logs annually. Prince George TSA’s current allowable annual cut (AAC) is 8,350,000 cubic metres as of October 11, 2017. Major communities in the region include Prince George, Vanderhoof, Fort St. James and Fraser Lake. Figure 18 shows the map of the Prince George TSA (Nicholls, 2017).

The Prince George TSA is subdivided into eight supply blocks. The AAC level includes three partitions: (1) A maximum of 1.5 million cubic metres per year is attributed to supply blocks A and B; (2) A maximum of 6.1 million cubic metres per year is attributed to the remaining supply blocks (and reduced to 5.1 million cubic metres in October 2022), and (3) A maximum of 750,000 cubic metres per year is attributed to bioenergy stands, which are mature, damaged pine-leading stands with less than 140 cubic metres per hectare net merchantable sawlog volume.

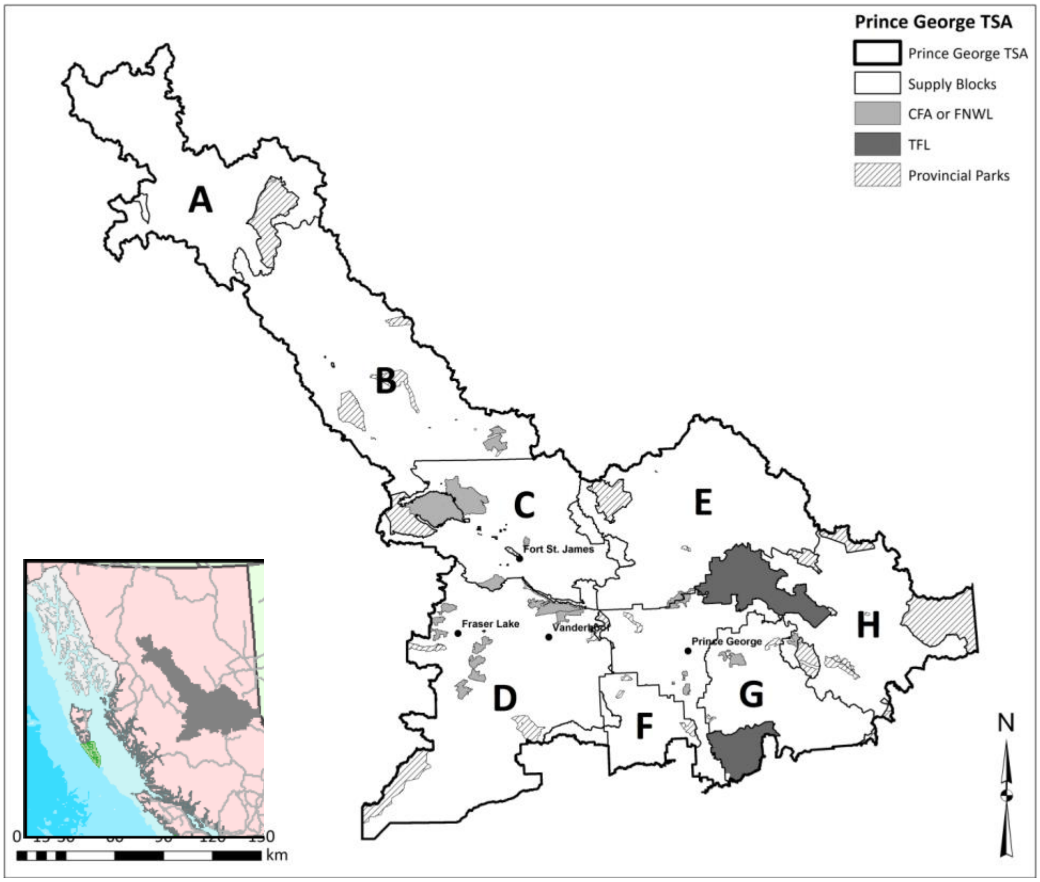

Figure 18. Map of the Prince George TSA (Nicholls, 2016). FNWL: First Nation Woodland Licence; TFL: Tree Farm Licences; CFL: Community Forest Licenses

Opportunities continue to exist in the Prince George TSA for bioenergy and biofuel production from biomass associated with utilization of logging residues from traditional sawlog harvesting or from the harvest of stands where salvageable volume has declined below levels which are considered economically operable. These opportunities for harvest of standing dead timber for bioenergy vary by region. Bioenergy is currently produced at several co-generation facilities in Fort St. James, Vanderhoof and Prince George (Nicholls, 2017).

Figure 19 shows the cost-supply curve for roadside residues in Prince George TSA. It is estimated that over 0.56 million dt of roadside forest residues can be recovered from forest stands in this TSA. This supply of forest residues can meet the annual biomass demand of the considered biocrude facility (300,000 dt). More than half of the forest residues are available in Fort St. James region. The delivered cost of forest residues at the gate of the biocrude facility is estimated be $80/dt. However, the local competition from co-generation facilities and wood pellet plants could reduce the biomass availability and increase the cost of forest residues for the biocrude facility.

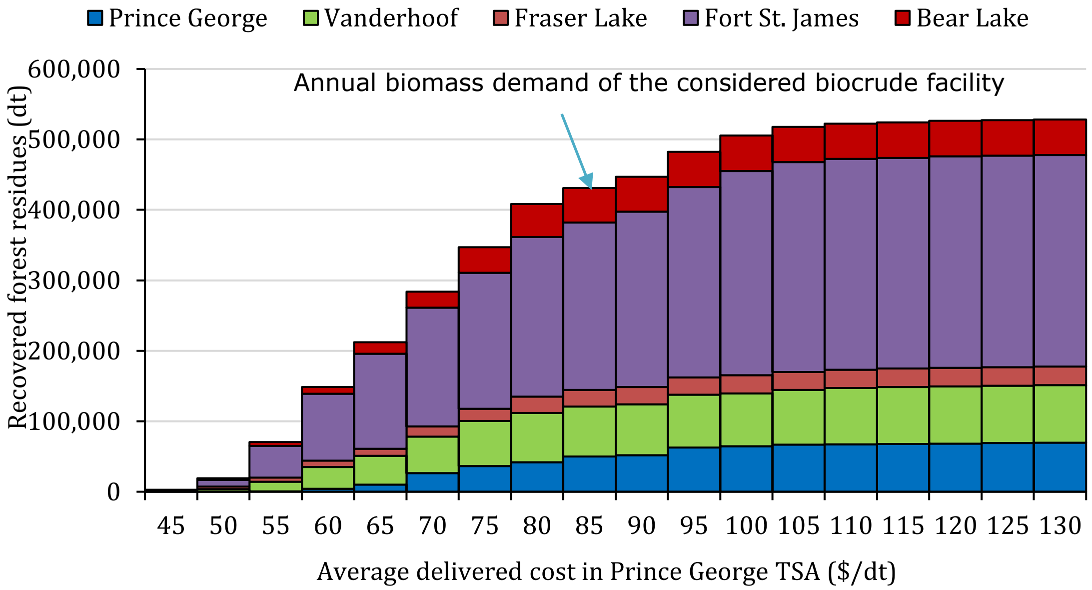

Figure 19. Cost-supply curve of forest residues for Prince George TSA. There are sufficient quantities of forest residues to meet the annual biomass demand of a biocrude facility with the production capacity of 2000 barrels/day that requires 300,000 dry tonnes of forest biomass annually (Biomass data source: FPInnovations, 2018b).

As Figure 19 shows, only a small portion of the forest residue demand for the biocrude facility can be met in the Prince George supply block (10%). A large portion of the annual feedstock demand of the biocrude facility would have to be fulfilled from nearby supply blocks in Fort St. James (52%), Vanderhoof (16%) and Bear Lake (11%). Figure 20 shows the distribution of transportation distances between forest biomass collection points in supply blocks and the biocrude production facility. The minimum, average and maximum transportation distances are estimated to be 7.9 km, 52.8 km and 121.58 km, respectively. The size of the supply radius is estimated to be 100 km.

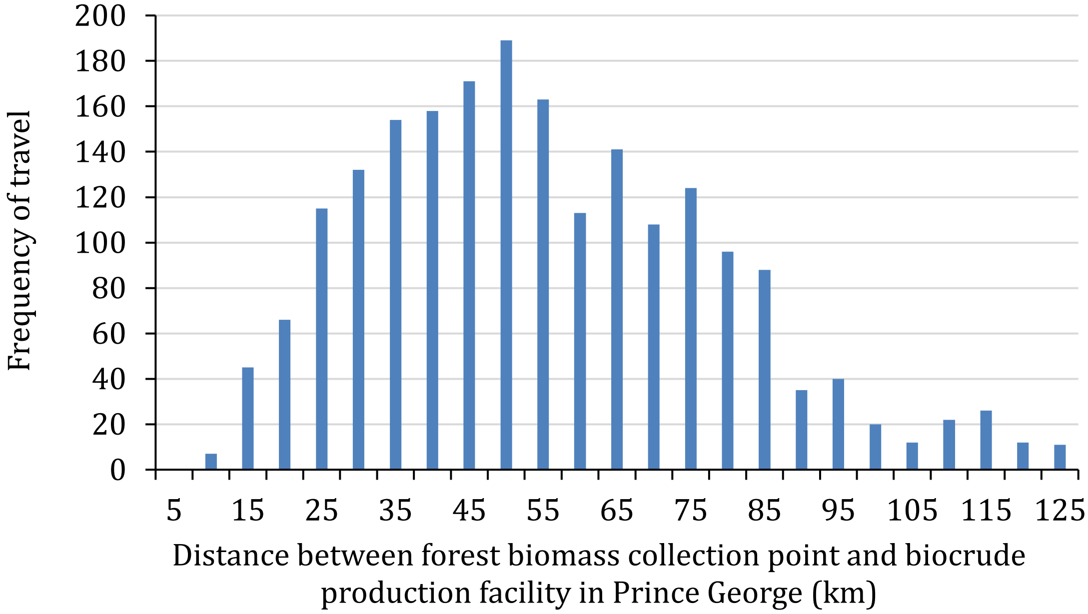

Figure 20. Distribution of transportation distance between forest biomass collection points in forest stands and biocrude production facility in Prince George (km)

The delivered cost of forest residues has three components: comminution, transportation and road network construction and maintenance. Comminution is the process of loading forest residues into the grinding equipment at the roadside of forest stands, grinding and loading them into a truck. The truck then transports the chipped forest biomass to the destination point. The comminution operation is estimated at a cost of $25-32/dt. The next cost component is transportation which depends on road conditions and truck configuration. For a 3-axle chip truck, transportation costs are estimated to be in the range of $0.37-2.00/dt/km for the delivery point in Figure 18. Such a wide range is due to the different road classes which impact the speed of the truck and the associated costs. The transportation costs average $0.70/dt/km. The last cost component of the delivered cost is the road construction and maintenance. End users of the forest residues are usually charged for using the roads constructed by forest companies to transport sawlogs to their wood processing facilities. These costs are in the range of $0-2.51/dt with an average cost of $0.80/dt. In summary, the delivered cost of forest residues for the case study include $5.50/dt for pre-piling, $26.30/dt for grinding, $2.10/dt for road network and $46.10/dt for transportation (FPInnovations, 2018a,b).

In recent years, the industry has been able to reduce the grinding costs by improving the efficiency and the fuel consumption of this operation. In some regions, a grinding cost of $20/dt has been reported (International Wood Markets Group Inc., 2014). More development and research is ongoing to integrate the forest biomass logistics system with the existing forest supply chain to further reduce the biomass logistics cost. This reduction can potentially make forest residues a more affordable feedstock for biofuel and bioenergy applications.

2.1.4 Feedstock Conclusions

There are sufficient quantities of forest residues available in BC and Alberta to meet the annual demand of a biocrude facility with a capacity of 2000 barrels/day. Such facility requires approximately 300,000 dry tonnes of forest biomass annually. Assuming 20% mass loss in the biomass logistics and preprocessing, about 375,000 dry tonnes of biomass needs to be collected at the roadside of forest stands. Prince George City was proposed for the location of the biocrude facility as it has all the elements for the development of a regional supply chain for biocrude production in Western Canada such as biomass availability, proximity to wood processing facilities, available transportation infrastructure (road, rail and water) and proximity to oil refineries and airports. The annual biomass demand for the considered biocrude facility (300,000 dt) would be met at a delivered cost of $80/dt within a 100-km supply radius. The average transportation distance is estimated to be 52.8 km.

2.2 Potential policy and economic tools to increase access and use of BC forest residues for bioenergy and biofuels production

Economic sustainability is critical to the development of bioenergy and biofuels production, as well as a reliance on large-scale feedstock supply chains. The BC forestry industry is uniquely positioned to leverage the existing forest product supply chain and annually provide enough forest biomass for biofuels production. Worldwide, policies have been used to promote development of bioenergy and biofuels. Chapter 7 looks at the types of policies that would be needed to facilitate the development of biojet production and consumption. Within the whole supply chain, feedstock is, however, the kickoff point for production of biojet fuels. The forest sector has traditionally used woody biomass for lumber and pulp and paper. Policies in the sector have therefore not accommodated the use of residues and poor quality wood for other purposes such as bioenergy and biofuels. In BC, some of the policies in the forest sector are in fact presenting an obstacle to the expanded utilization of woody biomass and forest residues for alternative purposes.

BC forest policies limit the accessibility of companies to forest residues. Under the current tenure system, the rights to harvest a public resource (i.e. timber) for forest products excludes other non-timber values such as carbon and optimizes most aspects of the supply chain for log extraction and traditional forest products.

This section outlines the challenges to forest residue collection and use in BC and analyzes the potential policies and economic tools that could facilitate increased forest residue use for bio-products. As bioenergy has developed more rapidly than biofuels, many policies used to promote bioenergy is described here as an example with the potential to expand these to biofuels production.

2.2.1 Introduction

Renewable energy subsidies in some markets (i.e. EU-Member States) have driven the demand for wood pellets for biomass-fired power plants and have encouraged the development of BC's wood pellet industry over the past decade (Murray, 2015). To date, BC wood pellet producers have primarily relied on saw and pulp mill residues as their biomass feedstock, which is very economical and the lowest cost fibre available. Only small quantities of forest residues are being used by pellet producers due to the higher cost and problems with accessibility.

Increased demand for wood pellets from EU Member States and other countries, such as Japan, has increased pressure on BC wood pellet producers to seek additional sources of forest biomass, including forest residues. This has placed increased pressure on fibre supply in the province which has been influenced by additional factors. For example, the recent mountain pine beetle epidemic has caused an enormous reduction in the midterm timber supply in BC. In response, in their efforts to remain in operation, sawmills have increased their log recovery through new technology investments, resulting in reduced wastage and residue generation (Personal communications, S. Ferguson, July 2017). This has resulted in a reduced supply of (cheap) mill residues for wood pellet production, placing additional pressure on fibre supply for bioenergy applications.

However, there are significant limitations to the large-scale collection and use of forest residues due to two major challenges in BC forests: cost of forest residues; and current policies in BC.

First, the cost of removing forest residues is relatively high ($60-80) compared with mill residues. Mill residues are generated as a waste product at the mill, while forest residues are generated in the forest during harvesting. As a result, forest residues require comminution on site and transport to a facility, which increases the cost associated with this feedstock. BC forests are vast and mountainous geography make access to forest biomass challenging, requiring high investments in road construction and transportation. While these costs are acceptable for high-value products such as lumber, products made from forest residues, such as wood pellets or biofuels, are generally lower value. High feedstock costs and low-value products cannot support a sustainable multi-national supply chain on its own and integration with existing supply chains will be essential.

Second, current BC forest policies pose some obstacles to accessibility to forest residues by companies. Under the current tenure system, the rights to harvest a public resource (i.e. timber) for forest products excludes other non-timber values such as carbon and optimizes most aspects of the supply chain for log extraction and traditional forest products (e.g. lumber). The access to and utilization of forest residues have to be integrated with the current supply chain and policies have to be modified to accommodate and facilitate this.

This section outlines the challenges to forest residue collection and use in BC and analyzes the potential policies and economic tools that could facilitate increased forest residue use for bio-products. The BC wood pellet supply chain is best positioned to define how BC forest residues are managed and their economic availability. The work described in this section has focused on current and developing forest residue policies and economic tools in the wood pellet industry. Economic tools refer to the technical changes or direct-action government can take to decrease costs along the supply chain, from standing tree to product. Policies refer to the regulations and amendments available to the provincial government to incentivize or influence company behavior and get more value out of BC forests or achieve other objectives, such as operational forestry legislation (i.e. Forest Range and Practices Act (FRPA)).

To implement effective policies capable of encouraging companies to enter the forest to collect additional forest biomass, this policy analysis has looked at the economic and policy tools that have been successfully used in other countries, such as Sweden and the US south east.

It is highly likely that accessing BC forest residues will be heavily dependent on the existing supply chain and markets of traditional forest products (i.e. pulp, paper and lumber). Due to the low economic value of forest residues they are typically collected into slash piles on a harvest block and burned. This practice has been adopted as it simultaneously recycles nutrients from biomass back to the forest soil and removes unwanted biomass that can impede future tree growth. In fact, BC forest policy requires forest fire prevention methods, which include the burning of unavoidable waste wood from harvesting activities, particularly where regular forest fires are part of a resilient ecosystem cycle such as in the BC interior (Government of British Columbia, 2002). Although controlled burns (forest fires that are intentionally set and managed by forest managers to reduce forest fire risk) are not common, burning relatively small slash piles in the winter months is very common. Enabling increased utilization of forest residues would necessarily involve changing policies related to the burning of slash piles, allowing diversion of this resource to additional value-added products. In addition to the policy implications, the economic viability of removing these residues based on current conditions has to be addressed.

In summary, the two major challenges limiting the increased access to and utilization of BC forest residues, based on the current forest supply chain are:

- Economic limitations of the BC forest residue supply chain which impacts the business viability of forest residue utilization; and
- Provincial regulations on forest harvesting focus on traditional forest products rather than maximum utilization of biomass.

These challenges are discussed below, in the context of better accessing and using forest residues.

2.2.2 Economic challenges of increasing BC forest residue use

Perhaps the largest barrier to increased use of forest residues is the economic viability of forest residue removal. The costs of collecting, processing and transporting forest residues from a harvest block to a mill makes large-scale removal economically challenging. Thus, although large quantities of residues are available, their actual availability based on economics is more challenging. Availability and cost within various timber supply areas (TSA) within BC was described earlier in this Chapter.

Some of the studies that have been carried out in BC to access forest residues have suggested ways to reduce costs (Friesen and Goodison, 2011; Friesen, 2016; Pledger, 2016). These studies outline approximately four steps in the forest residue supply chain that could be further optimized. One major recommendation is to use a separate transportation network than the one currently used for traditional forest products, implying that biomass producers will have to enter the harvest block twice, once for harvesting timber and once for residual biomass. The key steps in a forest residue supply chain include; pre-piling, comminution (processing), transport and other costs (road maintenance etc.). Although some costs would be shared, such as pre-piling and road maintenance, the cost of comminution and transportation of forest residues would be borne solely by the biomass user.

A major cost is comminution, referring to the grinder or processor that must be transported into a cut block to reduce the size of forest residues for transportation. Grinding involves a separate machine that crushes or chips up forest residues into smaller pieces to optimize the transport of large volumes of forest residues. Other harvesting costs, such as felling trees etc. is included in the price for traditional forest products, not allocated to forest residue processing. However, forest residue access is included in road maintenance costs.

It is apparent that the costs of a forest residue supply chain are such that significant policy support will be required to encourage greater forest residues collection for products such as wood pellets. However, increases in wood pellet pricing and other traditional forest products could also motivate increased forest residue collection.

The high costs of forest residues are especially challenging in low-value products that compete with fossil fuel alternatives. The price of oil has reached historically low levels in the past few years and is subject to volatile markets and geo-political influences. Therefore, energy subsidies and other support programs are most likely required to influence additional changes in supply chain costs to incentivize companies to maximally utilize forest biomass to reduce GHG emissions.

2.2.3 Provincial regulations and limitations

The other significant challenge to increased forest residue collection and use is BC's current forest policies. The government of BC supports its forest sector by establishing an updated annual sustainable harvesting yield. The extensive policies that regulate industrial forestry in BC have resulted in some challenges for forestry and biomass companies as it relates to the collection and use of forest residues. For example, the Annual Available Cut (AAC), which is adjusted every 5 years according to numerous factors, significantly influences forest residue availability by limiting harvesting activities. This affects the quantity of residues that could be available in each year. However, other constraints limit the accessibility of BC forest residues to forest companies as well as secondary producers, such as wood pellet producers.

Currently, BC regulations primarily focus on traditional forestry products, missing opportunities to extract other potential "value" out of forest biomass, such as reducing GHG emissions and supporting the growth of a bioeconomy. Currently, there is little incentive for forest companies to diversify or maximize the value they can extract from BC forests given current forest policies. For example, the current BC forest tenure systems grants the right to harvest publicly owned trees for profit if a certain amount of taxes and revenue is given to the province, stipulated in the Forest Act, Part 4 (Government of British Columbia, 1996). The current tenure system only grants the rights to timber, not additional values such as carbon or other non-timber forest values. Therefore, the section below discusses possible alternative policies and economic tools that could be used to leverage BC's existing forest residue supply and support the growth of a potential bioeconomy using forest residues.

BCs forest management and supply chain are complex. There are multiple industry partners involved in the current forest harvesting supply chain, in addition to the international forest products markets. Consequently, balancing international demand fluctuations and local (often-rural) livelihoods and environmental values means that the regulatory framework can quickly become punitive with well-intended policies negatively affecting one group over another. To identify possible policy and economic tool alternatives to overcome the challenges of encouraging a BC forest residue supply chain, proven policies or economic tools used in countries that actively promote forest residues use effectively and serve domestic or international markets are discussed. For example, The US south east and Sweden are two jurisdictions where different policies and methods have been used to encourage increased use of forest residues for wood pellet production and co-generation. While both regions differ from Canada in many aspects, the outcome, commercial-scale removal and use of forest residues for energy purposes, are comparable.

Given the current political climate and regulatory regime of BC, the two most important criteria in assessing economic and policy drivers for forest residue use are the degree of change each driver requires to be implemented and the expected negative stakeholder impacts (if any) of a driver.

For example, carbon pricing could be a critical component of BC's renewable energy efforts and, consequently, BC's forestry industry could be incentivized to retrieve additional forest biomass for uses such as bioenergy, biofuels and bio-products. However, the likelihood of such a change, such as a $100/tonne of CO_2eq is politically unlikely at present, barring any drastic changes to the salience of climate change in Canada[20].

2.3 Expanding the use of forest residues for bioenergy and biofuels

As mentioned earlier, the main challenge is economic with significant economic limitations impeding large scale forest residue removal. Therefore, a major focus of the policy analysis is to assess potential economic and policy tool alternatives to either reduce the costs of the BC forest residue supply chain or incentivize companies to retrieve biomass.

2.3.1 Policy alternatives for expanded use of residues

There are a variety of policies and economic tools that could be used to incentivize companies to retrieve forest residues. To narrow the search for possible alternatives, existing policies used in the EU/US south east wood pellet supply chain and Sweden's national bioenergy sector were assessed.

Various researchers (Greig & Bull, 2009; St-Laurent et al., 2017; St-laurent, Hoberg, Kurz, Lemprière, & Smyth, 2017; Upham et al., 2011) have proposed policy alternatives to encourage expanded use of BC forest residues for bio-products. These include:

- Changing BC forest policy to grant rights to non-timber forest values such as carbon;
- Changing operational-level regulations to behavior changes in forest residue management; and
- Developing programs to encourage and implement downstream incentive programs for bio-product production (e.g., UK Renewable Obligation Certifications)
- Applying a negative carbon price to BC's forest biomass;

Currently, BC's forest, climate and energy policies are not unified on all objectives or coverage, leaving some gaps in BC's policies and opportunities that will be needed to achieve Canada's climate targets under the Paris Agreement (St-laurent et al., 2017). The policy and economic alternatives outlined here could have varied impacts on the availability and accessibility of BC forest residues. However, they can also have unintended effects on stakeholders in the supply chain. Given the current political climate and regulatory regime of BC, it is likely that the two most important criteria will be the degree of change each driver requires to be implemented and the expected stakeholder impacts (if any) of a tool.

2.3.2 Potential policy and economic tool alternatives

2.3.2.1 Carbon Pricing

It is possible that carbon pricing could provide the incentives for forestry companies to enter the forest and reduce the amount of slash piles they burn annually. BC has a $35/tonne of CO_2 tax

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[20] CH_4 and N_2O emissions from slash burning is currently taxed at $35 per tonne, but not CO_2

applied to fossil products, currently excluding forest products. However, a critical question is whether the price will affect forest management-related emissions, such as burning forest residues in the forest rather than redistributing the residues to processing facilities (Hoberg *et al.*, 2016). Another related aspect is the possible inclusion of wildfire emissions and other natural disturbance in the provincial carbon tax. BC's 2017 wildfire season was triple the provincial GHG emissions of a typical year while, over the last decade, the Mountain Pine Beetle epidemic changed BC's forests from a carbon sink to a carbon source. It has been suggested that taxing carbon in the forest could improve forest fire prevention activities through the removal of additional forest biomass from BC forests, as well as improving forest management practices to reduce GHG emissions due to preventable natural disturbances.

However, pricing forest carbon could drastically change the objectives of forest management as a key influencer of forest sequestration over the short to long term. A forest carbon price could broaden the potential of using forests as carbon sinks and as renewable substitutes to fossil fuel as a feedstock for products. As part of the United Nations Framework Convention on Climate Change (UNFCCC), BC has reported harvested wood products (HWP) in its GHG calculations. Currently it is considering how and whether to include forest management net emissions in its accounting (Hoberg *et al.*, 2016). Additionally, recent foreign policy proposals (i.e. EU-Land-Use, Land-Use Change and Forestry, 2016; EU-RED II, Article 26, 2016) are considering new requirements regarding carbon management of forests that provide biomass for energy products. Currently, some models account for forest carbon and sequestration rates. If this becomes more common, its inclusion could influence the future of SFM in BC and provide more opportunities to incentivize companies to consider carbon as a necessary and potential beneficial asset to manage, in addition to traditional timber for forest products. The negative impacts of putting a price on forest derived carbon could be detrimental to the traditional forest supply chain, as it is a commodity business and relies on global markets. Therefore, the likely political acceptability is low, relative to the other alternatives.

2.3.2.2Regulation changes if a BC forest residue supply chain was to be established

The BC's forest tenure system consists largely of Forest Licenses and Tree Farm Licenses (TFLs) (Government of British Columbia, 1996). The structure of the tenure system, taxation on logs and FRPA affects what companies have rights to, company values, the public's expectations of those companies in managing BC forests and the objectives that are prioritized in forest management plans (Government of British Columbia, 2002). Therefore, the regulatory framework that governs BC forest companies and forests offers several opportunities to incentivize the removal of forest residues for bioproduct production.

The BC tenure system changed recently, with the addition of the Fiber Forestry License to Cut (FFLTC) and the Fiber Supply License to Cut (FSLTC) to encourage the use of forest residues that are left behind on landings and roadsides, by the primary license holders, such as the primary harvester (Government of British Columbia, 2016). While these new tenures do offer the opportunity for additional companies to use biomass, it does not solve the economic challenges of removing large volumes of forest residues from BC forests. However, a tenure system designed to include the 'rights' of other ecosystem services and not just timber, such as forest carbon, could provide the additional revenue streams for companies to manage for carbon, not just traditional wood products.

Thus, it is possible that accounting for carbon in BC forests could change the management objectives of forest management and encourage companies to consider the potential of substituting fossil fuels with forest residue wastes. Although adapting current tenure systems to support forest residue removal does not provide direct economic support, it does provide a framework in which forestry companies can measure and manage in-forest carbon. Although models do exist to measure forest carbon within an acceptable degree of accuracy, implementing a new system into the forestry supply chain could pose a significant challenge.

2.3.2.3 Wildfire management

The BC Wildfire Act explicitly requires forest managers to assess fire risk and develop plans to mitigate that risk through industrial activity. Burning piles of forest residues is a common practice in cut blocks in BC as it is a cheap way to drastically reduce the risk of wildfires and clear the land for replanting. Changing the BC Wildfire Act may be the cheapest way to change the perspective on BC forest residues and forest prevention methods. Current practices result in the loss of forest biomass that could be used to displace fossil fuels in some capacity. Therefore, an option to incentivize companies to change their behavior is to adapt current wildfire policies to include forestland carbon. However, a recent study completed by the Forest Practices Board found that there is little assessment or consideration of other options to remove forest residues in BC beyond burning them on site (Forest Practices Board, 2015). Changing the Wildfire Act in certain sections could result in a change in behavior, such as including carbon as a ‘forestland resource and value’ in Section 18 (St-laurent et al., 2017). Another example would be to require companies to measure slash piles and record their potential impacts on air quality, wasted fiber and GHG emissions when conducting wildfire risk assessments, aiding in the future management options for forest residues in BC.

Changes to the Wildfire Act and FRPA could result in a moderate change to BC forest practices relating to forest residues. However, funding forest management initiatives, such as fire prevention, has historically been challenging. Government programs that support the removal of ‘ladder fuels’, fuels that elevate the risk of forest fires in summer months, aren’t a political priority compared to other job creation programs. The historical allocation of BC’s forest fire budget has been spent on fire suppression, not fire prevention activities, such as removing forest residues from the forest.

2.3.2.4 Operational regulations that would be required to support diverse uses of forest biomass

Part of the economic challenge companies face when collecting and removing forest residues is the operational constraints of the traditional harvesting supply chain. Forest companies optimize the current supply chain for traditional products derived from logs, not forest residues. Therefore, any change in truck configuration or equipment means additional costs to the supply chain, such as road usage.

To reduce the costs of transporting forest residues, or at the very least distributing the costs across all forest products, there are a couple of operationally related drivers that could allow for the flexibility necessary for lower-cost equipment to be used. For example, BC logging roads are a costly necessity to access the remote areas of BC’s 55 million ha harvestable forestland. While FRPA and other operational guidelines do outline specific road requirements for companies to follow, they are optimized for long logging trucks, not for other vehicles such as dump trucks. Although this is nuanced, additional road maintenance and accessibility contributes to the ongoing economic challenges of reaching additional forest fiber.

Operational regulations create opportunities for different equipment to be used in the forest, and the opportunity to share the costs of extracting forest residues with higher value forest products.

The potential for negative stakeholder impacts are moderate given the changes to the existing supply chain, such as road construction costs. This also results in political acceptability to be moderate.

2.3.2.5 Downstream incentives that could be used to raise the value of BC forest residues

Renewable energy incentive programs from downstream markets are driven by government subsidies. Two main strategies could be pursued regarding downstream partnerships and end-users of forest residues (e.g., jet-fuel producers). First, international markets could provide downstream product producers with incentives to use forest biomass for bio-product production. Prominent renewable energy incentives, such as electricity certificates or subsidies, have resulted in many countries rapidly adopting low-carbon energy alternatives and reducing their reliance on fossil fuels. Sweden's use of bioenergy increased since the 2000s with the Tradeable Renewable Energy Certificates (TREC) program and associated subsidies (Ericsson and Werner, 2016).

BC's version of renewable electricity credits consists of long-term contracts with BC Hydro, the crown corporation energy utility in BC, signed with low-carbon energy producers, such as Conifex, KDL and other forestry/bioenergy companies (Government of British Columbia, 2008). While this does provide the certainty of price per MW and subsequently investment and development of the sector, it does not support the collection and processing of forest residues from BC forests, given the current prices set in those contracts. Retrieving forest residues from the forest are still restricted to $35-$40 CAD/odt at current energy prices set in 20-year contracts.

As mentioned earlier, the US south east, although different to Canada in many ways, does rely heavily on forest residues to support the growing wood pellet industry, which supplies wood pellets to the UK and other EU-Member States (Drax Group plc, 2015). A declining pulp and paper sector in the US SE coupled with increased interest from European energy utility companies have led to large-scale collection and use of forest residues. Canada could capture more interest from the EU, if the value of wood pellets were to increase beyond their current ~$150 USD/odt price-point.

The second potential strategy is for the Canadian and BC government to promote and facilitate partnerships between forestry companies, technology providers and downstream providers/producers, such as the recent partnership between Canfor and Licella (Canfor Inc., 2016). Although Licella is a technology company, they have provided the necessary expertise to produce 'biocrude,' a chemical input used for a variety of products and processes within the oil refinery industry. Funding research and development within the forestry industry and promoting the sustainable supply of BC forest residues can support the growth of multi-national partnerships between Canada's established forestry industry and key industries/markets in the bio-economy. The economics of forest residues is such that downstream partnerships will be necessary to access high-value markets to justify the capital investment. However, it is likely that forestry companies will have to lead the charge. Currently, in initiatives such as biojet-fuel development, forestry companies are largely left out and lack the knowledge or risk profile to further advance the potential of forest biomass use in various aspects of the bio-economy.

It is apparent that supportive policies have and will be key in the global transition to a low-carbon economy and at least partially led to the rapid development of the wood pellet sector in BC and the US south east. It should be noted that the potential for negative stakeholder impacts, such as increasing costs, in the forest supply chain is low given the 'market pull' of incentive programs. Assessing the political acceptability of this type of strategy requires an assessment of the national and international context. It is likely that Canada and BC recognize the value of supporting renewable energy strategies with forest biomass. However, currently, there is a lack of subsidies or support at the provincial and federal level (Bloomberg Magazine, 2017). This will be needed if BC and Canada are to facilitate the expansion of forest biomass for the expansion of the emerging bioeconomy.

2.3.3 Sustainability certification of forest residues in BC

The ATM Project looks at the production of biojet fuel from forest residues in British Columbia. Use of forest residues as a feedstock for biofuels raises questions about the sustainability of this practice within the broader framework of forest certification. While forest certification has been a long-standing measure of sustainability in the forest sector, the removal of and utilization of forest residues have not been covered under these certification schemes. Within the bioenergy sector, wood pellet producers have developed specific sustainability certification schemes for their product, but this does not address in-forest practices. This section of the ATM Project report looks at incorporation of forest residues under the umbrella of current forest certification schemes to facilitate the sustainability verification of this feedstock for production of biojet fuels.

British Columbia (BC) has a world-renowned forest sector and the highest percentage of third party certified sustainable forests in the world. Thus, BC is well positioned to supply sustainable forest biomass for bioenergy/biofuels.

Currently, underutilized forest residues could provide a major source of biomass for bioenergy/biofuels. However, the use of forest residues under current BC forest management standards does not fulfill some sustainability requirements defined by trade policies. Therefore, an improved sustainability verification system would support the growth of bioenergy/biofuels globally. Most forest certification systems were initially developed for traditional forest products such as lumber and pulp. In contrast, the evolving bioenergy sector uses biomass-sourcing certification standards that have limited connection to in-forest certification procedures. As a result, gaps between these certification standards challenge the potential of forest residues being used as sustainable feedstocks for the current and future bioeconomy.

A partnership between forest and biomass-sourcing sustainability standards would be beneficial, potentially by connecting GHG emissions data and other key metrics along the supply chain. The Programme of Endorsed Forest Certifications (PEFC) has begun developing a GHG tracking system for forest managers and is considering partnership opportunities with the Sustainable Biomass Program (SBP), a prominent wood pellet certification organization.

2.3.3.1Third-party certification standards

Certification systems have become the de facto due diligence tools to verify that multi-national supply chains are sustainable, particularly in the forestry industry. However, 'new' products and supply chains, such as wood pellets or biojet fuels, often develop faster than certification standards can adapt and create new verification procedures. Therefore, new feedstocks and products often require overlapping standards or new modules to define and verify sustainable practices. Wood pellet production using forest residues is one such case, where there is no 'one-size-fits-all' solution to help verify the sustainability of a forest residue. Similarly, biojet fuels made from forest residue will require innovative certification solutions to ensure sustainability within the forest.

2.3.3.1 Forest management certification

Over the last two decades, sustainable forest certification has become a large part of the management of Canada's forests, with more than 43% of the world's third-party certified forests located in Canada (Natural Resources Canada, 2017). Forest certification authorities, such as the Forest Stewardship Council (FSC) and the Sustainable Forest Initiative (SFI), emerged globally in the early 1990s due to concerns about unsustainable harvesting in the pulp and paper industry (Auld, Gulbrandsen and McDermott, 2008). ENGOs continue to play a pivotal role in the growth of private governance systems or forest certifications in BC, which have become a due diligence tool for multinational supply chains of traditional forest products. Forestry is among the first industries to rapidly adopt and adapt private governance systems directly addressing sustainability, in response to a variety of pressures including global consumer trends to buy products that have additional transparency and sustainable practices.

2.3.3.2 Sustainability considerations of harvesting additional forest biomass

Forest residues in BC typically consist of treetops, branches and non-merchantable trees (e.g., crooked or damaged trees) from harvest blocks that have undergone, or are being, harvested for traditional forest products. Historically, BC forest residues have been collected, piled and burned during the winter months of the harvesting period. In fact, the provincial legislation mandates forest companies to reduce the fire risk in harvest-blocks by removing 'unavoidable waste' from their sites. Some of BC's forest residues are currently used in small quantities in power generation facilities next to sawmills and pulp and paper mills, or in wood pellet production where mill residue supplies do not fulfil current feedstock demand (Drax Group plc, 2015). However, regardless of the end use of forest residues as a feedstock, there are significant sustainability concerns when managing a forest more intensively through biomass removal beyond merchantable timber and products.

The rotation age of trees in BC (how long it takes a tree to grow until it is harvested) is approximately 80-100 years. The long rotation age, relative to other areas, results in larger trees used for construction products, panels and other high-quality products. Comparing BC's forest residues and its use in other areas that utilize forest residues for energy products can demonstrate how BC forest residues can achieve sustainability requirements in bioenergy/biofuels. In the US SE, North America's largest wood pellet producing region, forest residues are different. Given the nature of the forest products industry and dominant tree species, the US south east has much smaller diameter trees, thus aiding in the removal of tree tops/branches and other biomass considered forest residues. The decline of the pulp and paper industry has resulted in the increased availability of smaller trees unfit for sawmills. Therefore, the US south east relies on forest residues and pulp and paper logs for wood pellet production, exporting close to 4M t/year of wood pellets, 90% to the UK, Belgium and Denmark (U.S. Department of Commerce, 2016).

Similarly, Finland's forest residues consist of smaller treetops or pulp and paper logs, which are 'whole-tree harvested'. The whole tree is cut and used, leaving little residues left on site. Forest managers in Finland use every part of a tree in most cases, selling larger portions to sawmills and using residues for domestic combined heat and power systems and other bioenergy applications (Berndes *et al.*, 2016). Despite the lack of certification, studies have shown the use of forest residues for energy in Finland results in an increase in sequestered carbon and an overall reduction in GHG emissions. The US south east and Finland provide unique perspectives on the development of wood pellet production, forest residue sustainability and the role of certification standards. There has been extensive research into the impacts of removing additional forest biomass from forests and these studies generally indicate that, when managed sustainably, forest residues can be a sustainable feedstock for the evolving bioeconomy (Stupak et al., 2011).

Despite these studies, the verification of sustainable forest management practices will be an ongoing necessity, to ensure the availability of enough forest residues for bioenergy/biofuels applications. Key environmental sustainability considerations in forest management include forest productivity, forest ecosystem resilience and quality (soil nutrients, biodiversity, and water resources), the ecological integrity of the landscape and the reduction of harmful pollutants (Hennenberg et al., 2010; Stupak et al., 2011).

2.3.3.3 Extending forest certification systems for bioenergy and biofuels markets

The existence of biomass-sourcing certification standards and forest certification standards in a supply chain results in a complex governance landscape, in addition to state/provincial and federal level forest management and biomass trade policies. Due to the complexity, there are overlapping biomass sustainability requirements, standards, and potential gaps that could affect the use of BC forest residues in the future. It should be noted that 'non-timber' forest products, such as forest residues, will likely require a larger scope than a management unit or even landscape to fulfill downstream policy requirements.

Although many studies point to a 'harmonization' between certification standards as the answer to the complexity and assurance of a transparent/sustainable supply chain, a pairing or coupling is more likely and more effective. For a variety of reasons, SFI (through PEFC) and SBP are best-positioned to develop a partnership to verify sustainable business practices across the entire wood pellet supply chain and likely into other products that use forest biomass. First, one of the major extensions to forest certification standards likely to occur is the development of a GHG emissions tracking module. GHG emissions reporting is a current requirement for wood pellet production and trade to the EU (European Parliament and the Council of the European Union, 2009). There are several methods used to calculate GHG emissions, which unfortunately vary between each EU Member State. Additionally, emissions tracking within the forestry supply chain is becoming particularly important, as ENGOs lobby EU policy markets, arguing against the use of wood pellets sourced from BC or the US south east, due to their 'high GHG emissions'.

Although biomass-sourcing certification standards have GHG emissions tracking systems in place, they do not enter the forest at the forest management unit (FMU)-level. Current tracking systems do not report on emissions from the forest or from forest management practices. The EU Forest Strategy (2013) indicates the growing need and interest in maximizing the use of woody biomass, thus requiring additional GHG emissions tracking. Life Cycle Analysis (LCA) has become a well-used tool to measure and manage GHG emissions in a variety of industries around the world for products. Forestry companies will most likely need to adapt to include LCA GHG emissions tracking to ensure feedstocks (e.g. forest residues and low-grade logs) adequately fulfill a net decrease in GHG emissions when converted into a product.

Currently, the PEFC has initiated a Working Group to develop its own GHG emissions tracking module for SFM and/or CoC certification. There is a potential additional module that will apply to PEFC certifications aimed at tracking and managing FMU-level GHG emissions (Programme for Endorsed Forest Certifications, 2015). While the working group is ongoing, PEFC has presented results of their developments to the SBP in stakeholder meetings (Personal communications, G. Bull, August, 2017). SBP is a likely and preferred collaborator on a GHG module, as the SBP 'Data Transfer Platform' (DTP), one of the most robust solutions for data transfer, ensures all of the GHG data along the supply chain is tracked and entered into calculations that are reported to EU Member States (Personal communications, I. Stupak, July 2017). The DTP allows energy producers to use all the data needed for a specific region or supply chain and do their GHG calculations using an acceptable model, such as Biograce (required in Denmark). Tracking GHG emissions in this way shows compliance with national requirements for GHG emission savings. However, a major challenge is still the varied requirements for GHG emission savings for solids between the UK, Denmark, the Netherlands and Belgium.

The FSC has an Online Claims Platform (OCP), which 'digitally connects certified FSC suppliers and customers' and could manage the tracking and reporting of GHG emissions data from a variety of sources. However, FSC OCP does not currently include GHG emissions tracking or reporting. While this type of certification is likely to have minimal impact on harvesting forest residues, it does involve some adaptations to include the GHG emissions of biomass cultivation, harvest and transport (Rosenbaum, Schoene and Mekouar, 2006). The FSC OCP or the CoC standard could be the tracking system necessary to integrate the forestry supply chain with downstream standards, such as SBP or RSB, subsequently fulfilling GHG reporting requirements. CoC's will need to be adapted to handle the new or modified equipment and processing of forest residues for collection and production and be able to include large scale downstream organizations, such as a biorefinery.

Second, the recognition between standards will become increasingly important as more businesses use forest biomass to produce various bioproducts, to reduce the reliance on fossil fuel alternatives. To accommodate the overlap of sustainability standards, SBP, ISCC and RSB have recognized some forest certification standards, ensuring equivalency and at times collaborating to ensure future requirements align. Many standard authorities are recognized by others or EU Member States, based on their equivalent fulfillment of policies or Principles and Criteria. However, there are ongoing issues with the recognition or selection of certain certification standards over others.

It is apparent that the stakeholders and underlying politics involved in both biomass-sourcing and forest certification authorities have resulted in a complex private-governance landscape. For example, the RSB, to support environmentally focused standards, which are supported by their broad membership, recognizes the FSC as a credible and equivalent sustainability standard for bioenergy and biofuels feedstocks. This recognition of one forest certification over another, may limit the applicability of the RSB approach for BC forest residue use as, currently, SFI or CSA-SFM certification dominates BC forests. Recognizing only some upstream standards limits other businesses who certify with other certification schemes (i.e. SFI), which contain nuanced differences to FSC. The fact that RSB preferentially recognizes FSC is part of a larger movement, supported by environmental organizations, such as the World Wildlife Fund (WWF), to develop and support for broad-stakeholder driven sustainability standards rather than accepting industry-driven standards. The ISEAL Alliance represents this movement.

The relationship between forest certification standards, biomass-sourcing certification standards and stakeholders in the market can apply additional restrictions or market access burdens on forest residue use in some markets. For example, the Sustainable Aviation Fuel User Group (SAFUG) has publicly supported the ISEAL Alliance standards in the pursuit for a globally recognized sustainable supply chain. However, ISEAL recognizes the FSC as the only forest management standard to meet their requirements for membership, thus excluding most of BC's forest residues, while they remain under only SFI or CSA-SFM certification.

The recognition of one standard over another can exclude, or present a market barrier to, large amounts of BC forest residues based on a political decision between forest certification standards. Therefore, a significant challenge is in ensuring forest residues are properly and consistently certified and that governments support all credible certification standards. While FSC may already be fully supported by RSB, the SBP which includes all forest certification schemes likely makes them better positioned to partner with the wood pellet industry and other bio-product industries as they develop. Compared to FSC and RSB, which excludes industry-driven standards outside of the ISEAL Alliance, a possible PEFC and SBP partnership would likely be more successful in providing a fully transparent, verified sustainable supply chain for increased forest residue use.

2.4 Source and cost of hydrogen for production of biojet fuel

Conversion of biomass into drop-in biofuels requires removal of oxygen from feedstock and addition of hydrogen to obtain hydrocarbon molecules with a high effective hydrogen to carbon ratio (H_{eff}/C) (Karatzos et al. 2014). Removal of oxygen takes place with the addition of hydrogen, either through externally applied hydrogen during hydrotreatment or through hydrogen transfer within the solution. A hydrotreatment approach was used in the ATM Project as the main method for upgrading biocrudes into drop-in biofuels such as biojet. The higher the oxygen level in the starting feedstock, the more hydrogen will be required to upgrade it into drop-in fuels that are fully fungible with existing vehicles and infrastructure. In the case of fast pyrolysis bio-oils, the oxygen content could be as high as 50%, with catalytic pyrolysis and HTL biocrudes having less oxygen and therefore requiring less hydrogen.

The impact and role of hydrogen is important because large volumes of external hydrogen inputs are required compared with the upgrading of fossil crudes. The cost of hydrogen would have an impact on the final cost of the biofuel, while the source of the hydrogen will have an impact on the life cycle assessment of the final fuel. An overview of sources of hydrogen, production methods, cost and supply, with specific reference to hydrogen production and supply in BC can be found in Appendix B.

CHAPTER 3 – BIOCRUDES – SOURCES, PRODUCTION AND CHARACTERISATION

3.1 Bio-oil Production

Three different bio-oils were sourced from three suppliers as part of the project. Each bio-oil was then subjected to two different upgrading schemes. The bio-oil suppliers provided information on their processes.

3.1.1 Fast Pyrolysis

The fast pyrolysis oil for the project was supplied by BTG of The Netherlands. The oil was obtained from the commercial production of the Empyro 20 million litres/year facility at Hengelo, Netherlands, as shown in the following Figure 21.

Figure 21 **Empyro Facility, Hengelo Netherlands**

The BTG process is shown in the following Figure 22.

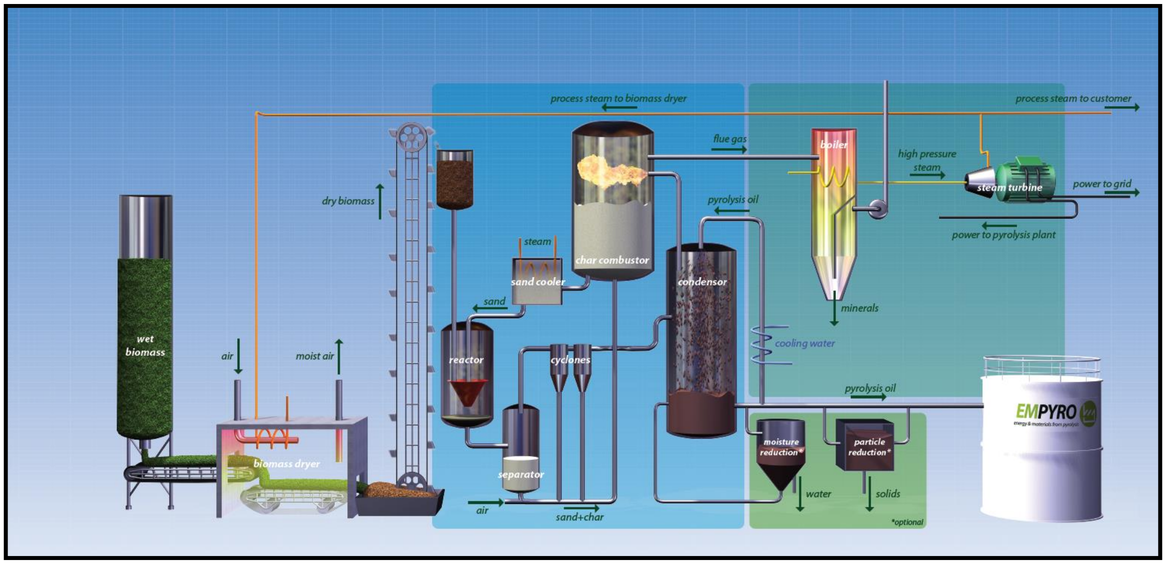

Figure 22 BTG Process Flow

Like most pyrolysis processes the BTG process produces bio-oil, a combustible gas and some char. In this process the char is consumed internally to provide the heat for the process. There is a hot, combustible gas stream that can be used to supply heat and/or electricity.

The feedstock will have to be dried before being used in the process so the gas stream will be used for drying. There is likely to be excess heat available but to be conservative it will be assumed that it is all used for drying.

The process parameters used for modelling are shown in the following Table 11.

Table 11. **BTG Process Parameters**

Parameters	**Value**
Feedstock, kg/litre	**1.875**
Power, kWh/litre	**0.0975**
Natural gas for start-up, MJ/litre	**0.48**
Nitrogen, kg/litre	**0.035**

The natural gas is used for start-up and the nitrogen is used for purging tanks during shutdowns.

3.1.2 Catalytic Pyrolysis

The second bio-oil was obtained from VTT in Finland. It was produced in their pilot plant and the sample was a composite of several runs.

The bio-oil properties of the catalytic pyrolysis oil are different than the fast pyrolysis oil. In addition to the gas, oil, and char, this process has an aqueous phase that has a significant organic content. For this analysis the organics have not been included as a credit or a debit in the GHG analysis. In the worst case the material could be processed in a waste water treatment facility that would require energy and chemical inputs. It may also be possible to process the material to a gas which could be used to displace natural gas.

The catalytic pyrolysis oil process is similar to the fast pyrolysis process except that the sand bed is replaced with a catalyst, HZSM-5 catalyst.

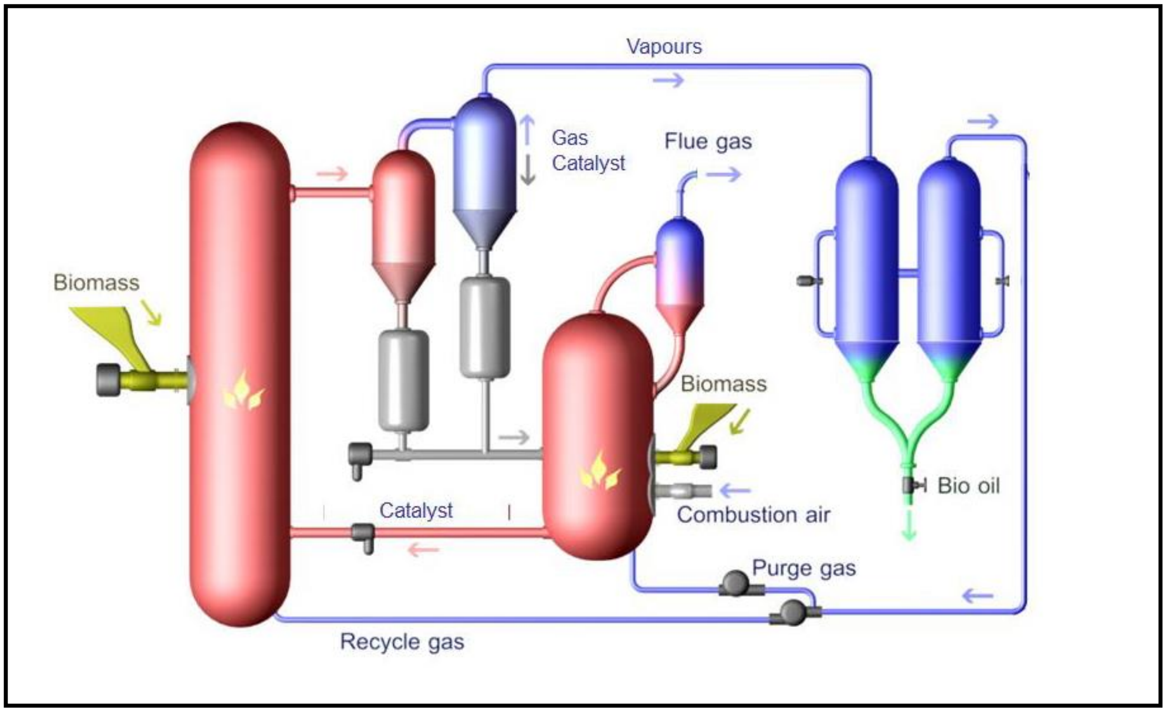

Figure 23 VTT Process Flow

The feedstock will have to be dried before being used in the process so the gas stream will be used for drying. There is less gas available that with the fast pyrolysis process but there should be sufficient to dry the feedstock.

Less detail is available on the operating requirements than with the fast pyrolysis system. The power demand, the natural gas requirements and the make-up catalysts are estimates. The process parameters used for modelling are shown in the following Table 12.

Table 12 VTT Process Parameters

Parameters	**Value**
Feedstock, kg/litre	**6.55**
Power, kWh/litre	**0.20**
Natural gas for start-up, MJ/litre	**0.5**
Make-up catalyst, kg/litre	**0.012**

3.1.3 Hydrothermal Liquefaction

The third bio-oil is a hydrothermal liquefaction oil produced by Aarhus University in Denmark. The oil was produced in a pilot plant with a capacity of about 20 litres/hour of oil.

The system is as shown in the following Figure 24.

Figure 24. Aarhus University Facility

The HTL process is shown in the following Figure 25.

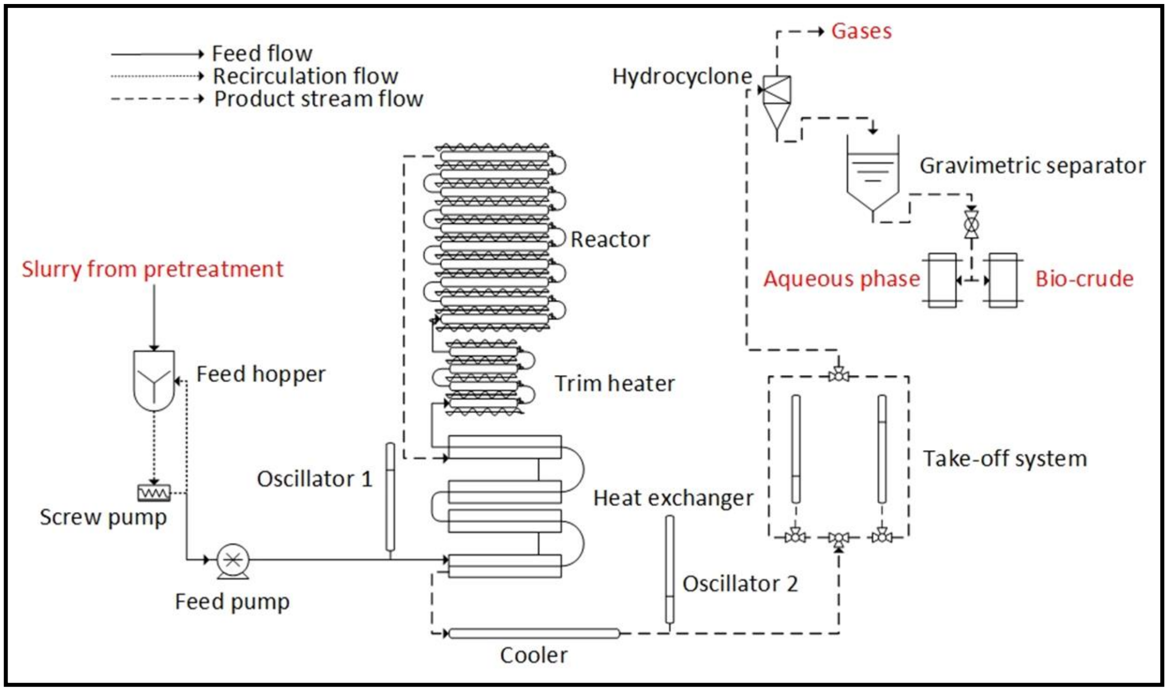

Figure 25 HTL Process Flow

There is limited information available on the quantity and composition of the gases produced from the process. It is likely that there is minimal combustible gas formation during the process as the operating conditions are sub-critical. The primary products are the oil phase product and an aqueous phase. As with the VTT system neither a credit nor debit is charged for the aqueous phase as little is known about the product.

The process does not have to have dry wood as the feedstock, so no drying is required. The pilot plant is electrically heated, but a larger plant would use natural gas to supply the energy required to keep the system at the appropriate operating condition after as much heat is captured from the produced product as possible.

The process parameters used for modelling are shown in the following Table 13.

Table 13. HTL Process Parameters

Parameters	Value
Feedstock, kg/litre	3.05
Power, kWh/litre	0.20
Natural gas for start-up, MJ/litre	7.7
Potassium Hydroxide, kg/litre	0.0305
Carboxymethyl cellulose, kg/litre	0.0076

3.2 Characterisation of biocrudes (results of analysis)

Biocrudes were shipped to the upgrading labs and analysis was carried out on the biocrudes prior to commencement of the upgrading process. Select results are shown in Table 14 below.

Table 14 Comparison of three biocrudes

Parameter	BTG	VTT (filtered)	Aarhus
Heating Value, MJ/Litre (HHV)	21.52	32.3	35.87
Density, g/litre	1,197	1,168	1,120
Carbon fraction %	44.1	74.2	78.2
Sulphur fraction %	0	0	0
Hydrogen fraction %	7.5	6.0	7.2
Oxygen fraction %	47.5	16.5	14.5
Aromaticity, %	42.9	63.9	60.9
Ash Content, wt %	0.013	0.92	0.61
pH	2.66	3	4.53
Pour point, °C	-36	-6	33
Solids, wt%	0.03	1.34	0.5
TAN, mg KOH/g	125	82.6	28.6
Water content, wt %	25.7	7.6	5.6

Figure 26 shows the elemental composition of the three biocrudes graphically, illustrating the large oxygen content of the BTG pyrolysis biocrude while the other two biocrudes had relatively similar oxygen content.

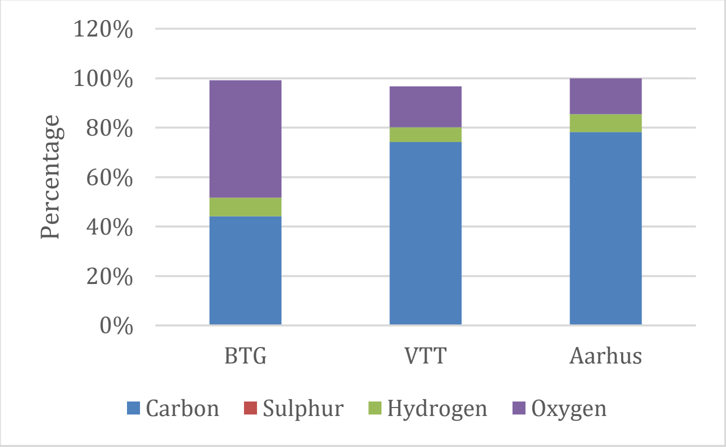

Figure 26. Comparison of three biocrudes - elemental composition

3.3 CanmetENERGY-Ottawa upgrading

CanmetENERGY-Ottawa's (CE-O) upgrading approach involves hydroprocessing biocrudes, in a one-stage reactor, with petroleum distillates (reaction medium) using a highly dispersed unsupported molybdenum sulfide (MoS_2) catalyst that is generated in-situ from an emulsified precursor (Monnier et al. 2015; Monnier et al. 2016; Ikura et al. 1994). We also use a "biocrude-in-reaction medium" microemulsion as feeding strategy to suppress undesirable solids formation in the reactor inlet caused by biocrude polymerization, especially fast pyrolysis biocrude. Figure 27 shows a schematic of the upgrading process where feed blend microemulsion, catalyst precursor and sulphiding solution are co-currently fed into a bubble column reactor with hydrogen. Hydrodeoxygenation (HDO) and hydrogenation reactions are taking place in the reactor and generating a stable oil-phase stream as well as aqueous-phase liquids, gaseous products and solids (catalysts and organic solids). The formulation of the feed blend microemulsion was adapted from previous CE-O research on preparation of fast pyrolysis bio-oil-diesel blends for combustion applications (Ikura et al. 2003; Ikura et al. 1998).

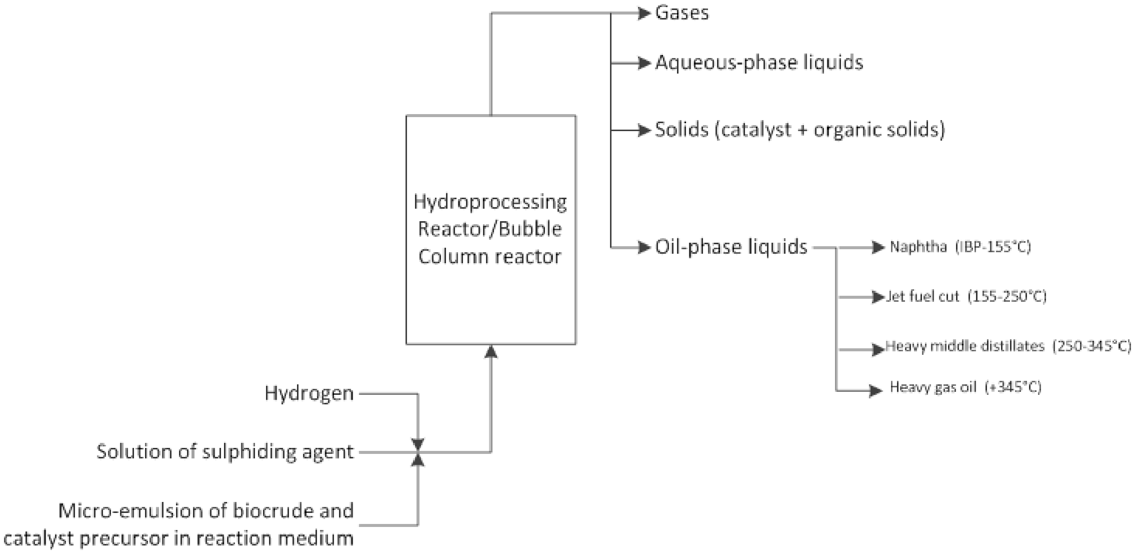

Figure 27– Diagram of CanmetENERGY-Ottawa's processing approach to convert biocrudes into biojet fuel fraction

Hydrodeoxygenation (HDO) using conventional hydrotreating catalysts in a packed bed reactor has been extensively investigated as a potential upgrading approach to remove oxygen from fast pyrolysis (FP) biocrudes. However, operational problems caused by the instability and coking propensity of raw FP biocrudes have made the upgrading process very challenging (Baldauf et al. 1994; Ardiyanti et al. 2011; Mortensen et al. 2011; Butler et al. 2011). Tubes and valves could get plugged and coated with gum-like deposits (Baldauf et al. 1994). A major problem encountered in using a packed bed catalyst is rapid catalyst deactivation due to carbon deposition, principally formed by polymerization and polycondensation reactions on the catalyst surface, resulting in the blockage of the active sites on the catalysts (Ardiyanti et al. 2011; Mortensen et al. 2011; Butler et al. 2011). In addition, catalyst deactivation can occur through poisoning by water, sintering of the active metal sites, and metal leaching due to the attack by water and organic acid (Mortensen et al. 2011). Instead of using supported catalysts in packed bed reactors, CE-O utilize a dispersed unsupported catalyst for hydrodeoxygenation of fast pyrolysis biocrude to suppress coke formation and avoid catalyst deactivation. Dispersed unsupported catalysts have been reported to be better suited for catalytic upgrading of petroleum residual oil and co-processing of heavy oil and coal (Panariti et al. 2000; Tian et al. 1998; Tye & Smith 2004). Dispersed unsupported catalysts have a number of characteristic advantages over supported catalysts, i.e. little deactivation, processing of poor quality feed, maximum interaction of oil and hydrogen with the catalyst active sites to inhibit coke formation, and a high degree of active site utilization due to the absence of diffusional limitation of reactants (Tian et al. 1998; Tye & Smith 2004; Al-Marshed et al. 2015). In our approach, highly dispersed unsupported MoS_2 catalysts were generated in-situ by thermal decomposition of the microemulsion catalyst precursor. The microemulsion catalyst precursor was adapted from earlier research on co-processing of heavy oil and coal as reported in a patent by Ikura et al. (1994).

CanmetENERGY-Ottawa's upgrading approach is ideally suited for biojet components that can be incorporated into an oil refinery jet fuel stream. **Figure** 28 presents two potential insertion points of the biocrude upgrading unit in an oil refinery, i.e. prior to either the middle distillates hydrotreater or the kerosene hydrotreater where straight-run (SR) middle distillates or SR kerosene streams are refined. We envision that a fraction of the SR middle distillates or SR kerosene streams would be diverted to the biocrude upgrading unit to be used as reaction medium and be enriched with biogenic hydrocarbons (renewable content) before being returned to the middle distillates or kerosene hydrotreater (oil phase products only). For this project, we use a furnace fuel oil as the reaction medium, which has a boiling range close to straight-run middle distillates, in order to evaluate biojet component production. The upgraded oil products are fractionated into naphtha (IBP-155°C), jet fuel (155-250°C), heavy middle distillates (250-345°C) and heavy gas oil (+345°C) fractions. Refiners may or may not fractionate the oil products prior to further refining. The properties of these four fractions containing biogenic components derived from biocrudes are evaluated, with a special focus on jet fuel fraction.

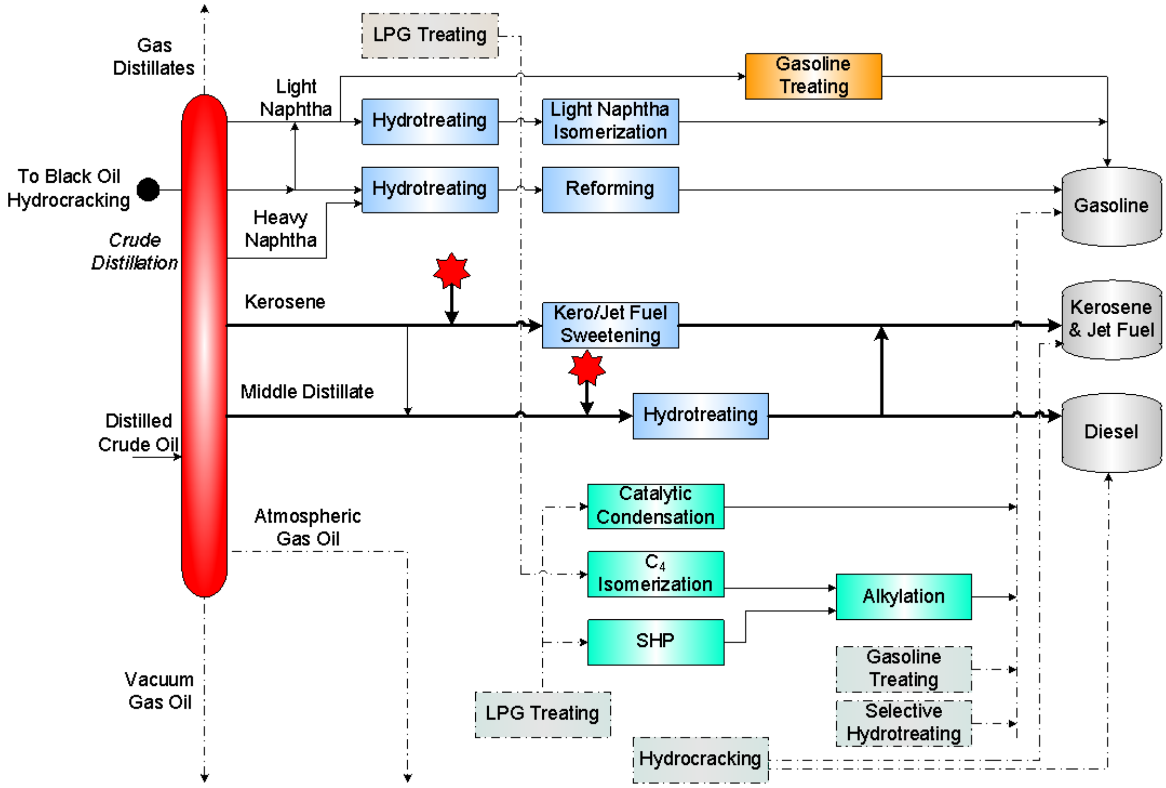

Figure 28– Two potential insertion points for the upgrading unit prior to the middle distillates and kerosene hydrotreaters (oil refinery diagram based on www.uop.com/refining -flowscheme-2/)

3.3.1 Canmet upgrading results

3.3.1.1 Preparation of biocrude feed blends

CanmetENERGY-Ottawa (CE-O) performed production tests for each biocrude using a feed blend containing 18 wt% biocrude (composition selected based on preliminary tests). All biocrudes were tested as received and were not filtered prior to blending. Biocrude feed blend composition is listed in **Table** 15.

Table 15: Biocrude feed blend composition (in wt%)

	BTG FP	VTT CP	Aarhus U. HTL
Biocrude	**18.08%**	**17.96%**	**17.97%**
Furnace fuel oil	**76.03%**	**69.67%**	**68.33%**
Surfactant	**2.74%**	**4.09%**	**4.15%**
Methanol	**1.11%**	**1.64%**	**1.66%**
TPBS	**1.08%**	**1.15%**	**1.76%**
Water	**0.64%**	**0.67%**	**1.03%**
Ammonium paramolybdate	**0.24%**	**0.24%**	**0.37%**
Ammonium hydroxide	**0.08%**	**0.08%**	**0.13%**
DEGMME	**—**	**4.49%**	**4.61%**

A "biocrude-in-reaction medium" microemulsions was used as feeding strategy in order to suppress undesirable solids formation and pressure buildup in the reactor inlet caused by biocrude polymerization, especially for fast pyrolysis biocrude. The "biocrude-in-reaction medium" microemulsion was prepared by emulsifying biocrude, furnace fuel oil and a surfactant solution (2.5:1 surfactant to methanol mass ratio) using a Polytron homogenizer. The preparation of the biocrude microemulsion was adapted from the method used by Ikura et al. for making stable microemulsions with 5-30 wt% bio-oil in diesel fuel (Ikura et al. 2003). In the case of the VTT catalytic pyrolysis (CP) and Aarhus U. hydrothermal liquefaction (HTL) biocrude microemulsions, a diluent (diethylene glycol monomethyl ether, DEGMME) was added to reduce the viscosity of the biocrude prior to preparing the microemulsion. Meanwhile, more surfactant was used for VTT CP and Aarhus U. biocrude blends. Being solid at room temperature, the Aarhus U. HTL biocrude was heated to 70°C before mixing with DEGMME, furnace fuel oil, and surfactant solution. The catalyst precursor solution and the sulphiding agent (TPBS) were subsequently mixed with each biocrude microemulsion prior to feeding into the reactor system.

3.3.1.2 Distillation, fractionation and characterisation

The Combined oil products were fractionated by spinning band distillation into naphtha (IBP-155°C), jet fuel (155-250°C), heavy middle distillates (250-345°C) and heavy gas oil (+345°C) fractions.

The product distribution data after fractionation indicates that 47.4 wt% and 49.4 wt% of the oil produced respectively from HDO of the BTG FP and VTT CP biocrude blends are in the jet fuel boiling range compared to 38.8 wt% of the oil from the Aarhus U. HTL biocrude blend. The other major fraction of the oil phase products is the heavy middle distillates (250-345°C), varying between 33.6 wt% and 49.7 wt% depending on feed blend. The fractions of naphtha and heavy gas oil are minor compared to the jet fuel and heavy middle distillates fractions. Naphtha is high for BTG FP and VTT CP (10.6 wt% and 8.5 wt%) and low for Aarhus U. HTL (2.1%). Heavy gas oil fractions are high for VTT CP and Aarhus U. HTL biocrude blends (8.4 wt% and 8.9 wt%) while it is low for BTG FP (3.3 wt%).

The jet fuel fraction yield was estimated to 40.2 g/100 g feed blend (BTG FP), 42.8% (VTT CP) and 30% (Aarhus U. HTL) respectively. It should be noted that the BTG FP and VTT CP HDO tests were performed with furnace fuel oil containing 49.2 wt% hydrocarbons boiling in the jet fuel range (Batch I) whereas the Aarhus U. HTL tests used a second batch of furnace fuel containing 38.8 wt% jet fuel range hydrocarbons (Batch II). Results show that the yields of different cuts are mostly predetermined by the reaction medium used.

3.3.1.3 Biogenic carbon content in oil products

Since a fossil-based reaction medium is used in CanmetENERGY-Ottawa's upgrading approach, it is essential to quantify the biogenic carbon in the different oil fractions. The biocarbon content in liquid products (combined oil product and four fractions obtained by spinning band distillation) was determined using ^{14}C analyses (radiocarbon method) performed on a 3MV tandem accelerator mass spectrometer (AMS) built by High Voltage Engineering Europa B.V. (HVE) at University of Ottawa. The biocarbon fractions, calculated relative to the fraction modern carbon $F^{14}C$ of the corresponding biocrude, are presented in Table 16.

As shown in Table 16, ^{14}C analyses indicated that biocarbon accounted for 14.2% of all carbon in the oil-phase liquid product from VTT CP biocrude. This is higher than that for the oil product (8.0%) from the BTG FP biocrude feed blend. In the case of Aarhus U. BTL-derived oil, the biocarbon fraction of total C reached 26.7%. However, based on carbon balance calculations, we have concluded that this percentage is too high. Carbon balance data gave a biocarbon fraction of 16.5%, which is slightly higher than the value obtained with the VTT CP biocrude-derived oil.

For VTT CP oil products, the ^{14}C analyses of the four fractions obtained by spinning band distillation indicate that biocarbon accounts for about 9.6% of total carbon in the jet fuel fraction, 26.9% of C in naphtha, 14.7% of C in heavy middle distillates and 34.4% of C in heavy gas oil fractions. These biocarbon content values for the VTT CP-derived fractions are generally higher than those for the BTG FP-derived jet fuel (3.4%), naphtha (15.0%), heavy middle distillates (10.1%) and heavy gas oil (32.8%). The biocarbon content of Aarhus HTL-derived jet fuel reaches 12.7%, with 21.5%, 13.5% and 50.1% in naphtha, heavy middle distillates and heavy gas oil fractions respectively.

Note that the variation in biocarbon contents among four fractions is the combined results of the boiling point distribution of the reaction medium and that of components derived from biocrudes. As each biocrude blend contains only 18 wt% biocrude and the major component, furnace fuel oil, is made of about 45 wt% jet fuel fraction, the biogenic carbon contents in jet fuel fraction ended up relatively low for the first two biocrudes investigated, i.e. 9.6 % for VTT CP and 3.4% for BTG FP blend. The highest biocarbon content (12.7%) is found in Aarhus HTL-derived jet fuel. However, it is expected that higher biogenic carbon contents in jet fuel fraction can be achieved by either blending more biocrudes into the feed blend or using a reaction medium containing less jet fuel fraction.

Table 16: Biocarbon fraction of total C in oil-phase products obtained by 14C analysis

	BTG FP derived products	VTT CP derived products	Aarhus U. HTL derived products
The biocarbon fraction of total C, %			
Oil-phase products	**8.0**	**14.2**	**16.5**[a]
Naphtha (IBP-155°C)	**15.0**	**26.9**	**21.5**
Jet fuel fraction (155-250°C)	**3.4**	**9.6**	**12.7**
Heavy middle distillates (250-345°C)	**10.1**	**14.7**	**13.5**[b]
Heavy gas oils (+345°C)	**32.8**	**34.4**	**50.1**

[a]: From mass balance calculations; [b]: Calculated value.

The distribution of biogenic carbon in the oil products is calculated and presented in Figure 29. The distribution data indicates that 31.6% of biogenic carbon is in the jet fuel fraction for VTT CP biocrude, 29.8% in the corresponding Aarhus U. HTL-derived fraction and 20.0% in the BTG FP-derived fraction. Significantly more biogenic carbon is found in the heavy middle distillate fractions (250-345°C), ranging from 33.8% to 47.7%. The biogenic carbon fraction in naphtha is 19.0%, 15.1% and 2.5% respectively, for BTG FP, VTT CP and Aarhus U. HTL biocrudes and it is 13.3%, 19.5% and 26.8% in heavy gas oils. For three biocrudes, in general, the majority of biocarbon is in heavy middle distillates, followed by the jet fuel cut. Depending on biocrudes, 67.7%, 65.4% and

70.7% of biocarbon is in the diesel cut, i.e. middle distillate fraction (155-345°C).

This distribution of biogenic carbon is useful information because raw biocrudes cannot be effectively distilled to determine the boiling point distribution without coking or significant material loss.

The yields of biogenic carbon in the oil products, expressed in g bioC/100 g C in biocrude (or simply % thereafter), are estimated based on ^{14}C analysis for three biocrudes. Results are shown in Table 17. For the VTT CP biocrude, the biogenic carbon yield in the oil phase product is higher than that for the BTG FP biocrude, i.e. 91.7% vs. 75.2%, indicating a better biocarbon retention in the oil product. Carbon retention in Aarhus U. HTL-derived oil-phase product is 86.7%, which is better than BTG-FP but lower than VTT CP.

Moreover, for the VTT CP biocrude, the biocarbon yield in jet fuel is 29.0% while it is 25.8% for Aarhus U. HTL and 15.0%, for BTG FP biocrude. It should be pointed out that the biogenic carbon yields in heavy middle distillates are high for all biocrudes (from 31.0% to 35.9%). For naphtha fractions, the biocarbon yields are similar for BTG FP and VTT CP biocrudes (14.3% vs. 13.8%) while it is low (2.1%) for Aarhus U. HTL. The biocarbon yield in heavy gas oil fraction increases in the following order: BTG FP, VTT CP and Aarhus U. HTL. The biocarbon yield in diesel cut with boiling points from 155°C to 345°C, i.e. the sum of jet cut and heavy middle distillates, is 50.9%, 60.0% and 61.3% for BTG, VTT and Aarhus U. HTL biocrudes respectively.

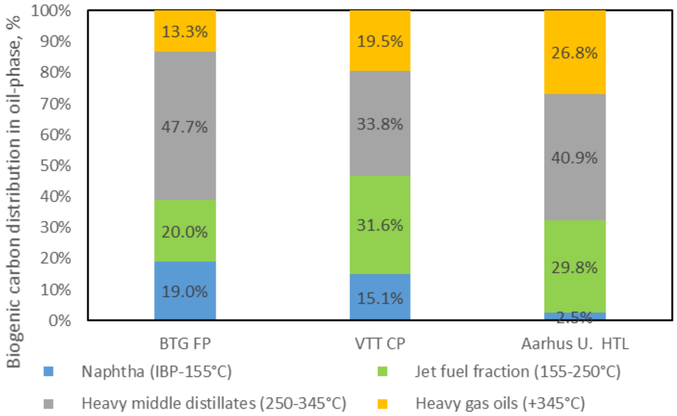

Figure 29: The distribution of biogenic carbon in the oil-phase product

Table 17: Product yield of biogenic carbon

	BTG FP	**VTT CP**	**Aarhus U. HTL**
Biocarbon yield in oil-phase, g bioC/100 g C in the biocrude	**75.2%**	**91.7%**	**86.7%**
Naphtha (IBP-155°C)	**14.3%**	**13.8%**	**2.1**
Jet fuel fraction (155-250°C)	**15.0%**	**29.0%**	**25.8**
Heavy middle distillates (250-345°C)	**35.9%**	**31.0%**	**35.5**
Heavy gas oils (+345°C)	**10.0%**	**17.9%**	**23.2**

3.3.2 Summary of CE-O results

Concluding observations were made by the CE-O scientists based on the upgrading tests performed by CE-O.

CE-O's upgrading approach uses a "biocrude-in-reaction medium" microemulsion as feeding strategy to suppress undesirable solids formation in the reactor inlet caused by pyrolysis oil polymerization. This microemulsion formula was typically developed for pyrolysis oil, thus it is working with BTG FP biocrude without any issues. However, for preparing the feed blend with VTT CP and Aarhus U. HTL biocrudes, the original proprietary microemulsion formula had to be modified to accommodate the high viscosities of these two biocrudes. This was done by adding more surfactant and a supplementary additive. At this point, the current microemulsion formulas for VTT CP and Aarhus U. HTL biocrudes require further optimization.

CE-O processed three biocrudes at similar operating conditions although higher pressure and higher Mo concentration were used for Aarhus U. HTL biocrude. We found that the oxygen content in the oil products and the degree of deoxygenation are quite different from each other. At 93.4%, the degree of deoxygenation for BTG FP feed blend is the highest of all three biocrudes with the lowest oxygen content in the oil product (0.4 wt%). The degree of deoxygenation is lower with more oxygen left in the oil products for VTT CP and Aarhus U. HTL biocrudes. This indicates that VTT CP and Aarhus U. HTL biocrudes require upgrading at more severe operating conditions. But due to time constraints, no such tests could be conducted within the timeframe of the R&D contract.

In terms of jet fuel properties, the jet fuel fraction produced from BTG FP biocrude feed blend meets 14 out of 17 ASTM D7566 specifications, while 10 out of 17 ASTM D7566 specifications are met by the jet fuel fraction derived from VTT CP biocrude[21]. In the case of the jet fuel fraction obtained from HTL biocrude feed blend, we assessed 14 ASTM D7566 specifications due to the limited sample available and met 11 out of them. We observed that for all biocrude-derived jet fuel fractions, properties related to "contaminants" (existent gum, microseparometer rating) fell outside the acceptable limits, although the microseparometer rating is significantly better for the HTL-derived jet fraction. Neither BTG FP-derived nor VTT CP-derived jet fuel meets specifications for thermal stability. The electrical conductivity and corrosion fell outside the acceptable limits for the VTT CP-derived fraction. The specifications that are not met can be mostly linked to the presence of partially converted oxygenated compounds in the jet fuel fractions. Therefore, it is expected that additional fuel polishing would be performed to help meet all the ASTM D7566 jet fuel specifications. There are several possible approaches that can be further examined to reduce the oxygen content in the oil products and jet fuel fractions. The impact of increasing the operating severity of the upgrading stage on the reduction of the oxygenated compounds in the oil products requires further investigation. Other post-treatments such as extraction or adsorption can be explored. Reduction of oxygen at refinery downstream hydrotreating stage requires collaborative investigation (for example, incorporation of biogenic carbon in kerosene or middle distillates hydrotreaters).

The biogenic carbon content in the jet fuel fraction is 12.7% for Aarhus U. HTL, 9.6% for VTT CP and 3.4% for BTG FP biocrudes-derived products. The biogenic carbon content is expected to increase by blending more biocrude into the feed blend. Feed blends containing more biocrude thus

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[21] Note that this was based on the total co-processed fuel, not just the biogenic fraction

need to be tested using CanmetENERGY-Ottawa approach. Alternatively, a refinery stream with less jet fuel fraction can be used as reaction medium and the produced jet fuel will be more concentrated with biocarbon.

The yields of biogenic carbon in the oil products, expressed in g bioC/100 g C in biocrude, are estimated based on ^{14}C analysis for three biocrudes. The biocarbon yield in jet fuel is 29.0% for the VTT CP biocrude-derived oil product while it is 25.8% for Aarhus U. HTL and 15.0% for the BTG FP-derived oils. Moreover, the biogenic carbon yields in heavy middle distillates are high for all biocrudes (35.9%, 31.0% and 35.5%). These biogenic carbon yields are mostly dependent on the type of biocrude because, at current operating conditions, very little thermal cracking and catalytic cracking are expected with the unsupported catalyst. However, there is potential to increase the jet fuel yield by shifting the heavy middle distillates to the jet fuel range by promoting more thermal cracking or catalytic cracking during upgrading.

Based on the lifecycle analysis (LCA), the use of petroleum-derived additives, such as sulfiding agent and surfactant, has a negative impact on the CO_2 emission intensity (carbon intensity). Carbon intensity can be lowered by reducing the use of additives (DEGMME and TBPS) and substituting petroleum-based additives with renewable ones (surfactant) for the processing. For example, the amount of sulfiding agent, TBPS, can be significantly reduced because the currently used S/Mo ratio of 16 is 8 times higher than the stoichiometry required for forming MoS_2. The reduction in TBPS would also reduce the S content in the oil products. Moreover, the current surfactant can be produced from 100% biomass-based materials.

3.4 PNNL upgrading

Hydrotreating (HT) tests were performed at the Pacific Northwest National Laboratory, Richland Washington, USA, (PNNL) on three biocrude products provided by the ATM project: a fast pyrolysis (FP) bio-oil from BTG in Hengelo, Netherlands, a catalytic fast pyrolysis (CFP) bio-oil from the Technical Research Centre of Finland, Espoo, Finland (VTT), and a hydrothermal liquefaction (HTL) biocrude from Aarhus University, Denmark. This chapter includes both the analytical methods and data relative to the biocrudes and HT products, as well as the HT processing methods and results.

3.4.1 Characterization of biocrude feedstocks

Detailed analysis of the received products was performed. Elemental components including carbon, hydrogen, nitrogen (ASTM D5291/D5373), O (ASTM D5373mod), S (ASTM D1552/D4239) and water content (Karl Fischer titration, ASTM D6869) were measured. The reported elemental components data (C, H, O, N, S) in Table 19 are calculated on dry basis (subtracting the H and O found in the moisture and then normalized to 100). Viscosity and density measurements were conducted on a Stabinger viscometer (Anton Paar SVM 3000) at 20 °C for HT products but done at higher temperature for the biocrudes due to high viscosity at room temperature. The carbonyl contents of the biocrude samples were determined using a modified titration method (the modified Faix method). A modified ASTM standard method D664 for determining the acid content of petroleum products was used to determine both carboxylic acid numbers (CAN) and total acid numbers (TAN) of biocrudes. The TAN includes carboxylic acids as well as weaker acidic compounds such as phenolics. Therefore, the phenolic number (PhAN) was calculated by the difference between the TAN and the CAN. Inductively coupled plasma atomic emission spectroscopy (ICP-AES) analysis was done on a sample digested in a mixture of HNO_3 and HF followed by a second step addition of boric acid. Solids content was determined by ASTM D7579, heating value was determined by calorimetric bomb method (ASTM D7544).

Table 18 is the summary of the characterization of the raw FP bio-oil originated from BTG. Solids content in the raw bio-oil was very low (<0.1 wt%), which minimized catalyst fouling and enabled the bio-oil to be hydrotreated without filtration.

The as-received CFP bio-oil from VTT was first analyzed for its solid content. Our previous experience with hydrotreating of a similar VTT CFP bio-oil showed that the HT reactor plugged in 30 h because of high solid content in their CFP bio-oil. As shown in Table 19, high solid and ash content were observed in this bio-oil as well. Inorganic content analysis by ICP-AES showed that it was primarily from zeolite catalyst used for CFP. Therefore, filtration was conducted to lower the solid content for possible hydrotreating of the bio-oil. As shown in Table 19**,** filtration at 1 micron lowered the solid content to below 0.05 wt%, which was acceptable for being processed without reactor plugging within the planned hydrotreating test period. Density and viscosity of bio-oil decreased after filtration, indicating the removal of some heavy component in bio-oil as well. Around 2 L filtered bio-oil was produced. Approximately 5 % weight loss of bio-oil was observed, including solids and some residual bio-oil in filter body. Such weight loss should be lower at a larger scale.

Table 18 Analysis of raw FP bio-oil

Test	**Raw FP bio-oil**
Density, g/ml at 20 °C	**1.20**
Viscosity, cSt at 20 °C	**87.5±0.05**
Water content, wt%	**25.7 ± 0.2**
Carbon, wt%, dry	**62.8±0.3**
Hydrogen, wt%, dry	**7.5±0.1**
Nitrogen, wt%, dry	**<0.05**
Sulfur, wt%, dry	**<0.07**
Oxygen, wt%, dry	**29.8±0.3**
CAN, mg KOH/g	**71.5±5.5**
PhAN, mg KOH/g	**77.3±0.5**
TAN, mg KOH/g	**148.9±6**
Carbonyl (mmol/g)	**4.07±0.08**
HHV (kJ/kg)	**17,640**

Table 19. Analysis of the VTT CFP bio-oils before and after filtration

	As received	**Filtered at 3 micron**	**Filtered at 1 micron**
Solid content, wt%, ASTM D7579	**1.35 +/- 0.003**	**0.24 +/- 0.01**	**0.042 +/- 0.015**
Ash content, wt%, ASTM D482	**0.91 +/- 0.01**	**-**	**-**
Total Inorganic content, ppm, ICP	**4337 +/- 337 (Al: 740; Si: 2682)**	**-**	**-**
Density, g/ml at 20°C	**1.176**	**-**	**1.168**
Viscosity, cSt at 20 °C	**10717**	**-**	**7012**

The filtered CFP bio-oil was then characterized and the results are listed in Table 20.

Table 20. **Analysis of the filtered VTT CFP bio-oil**

Test	CFP bio-oil filtered at 1 micron
Density, g/ml at 20 °C	1.168
Viscosity, cSt at 20 °C	7012
Water content, wt%	7.60 +/- 0.13
Carbon, wt%, dry	74.17 +/- 0.03
Hydrogen, wt%, dry	6.02 +/- 0.11
Nitrogen, wt%, dry	0.21 +/- 0.02
Sulfur, wt%, dry	0.06 +/- 0.005
Oxygen, wt%, dry	19.53 +/- 0.39
CAN, mg KOH/g	39.0 +/- 0.7
PhAN, mg KOH/g	150.5 +/- 2.4
TAN, mg KOH/g	189.4 +/- 1.7
Solid content, wt%	0.042 +/- 0.015

The HTL biocrude originated from Aarhus University, Denmark. The feed as-received had a high solids content (1.6 wt%). ICP-AES analysis showed high amount of potassium (K) at 3186 ppm followed by some iron, sodium, calcium at 100 ppm or more, and the rest of the inorganics <100 ppm were silica, alumina, sulfur and phosphorus. It was necessary to have it filtered through a nominally 5-micron stainless steel screen (at 80 ˚C before processing at hydrotreater. Table 21 is the summary of the characterization of both the unfiltered biocrude and the filtered biocrude actually used in the HT.

Table 21. Analysis of raw biocrude and filtered biocrude

Test	ATM-HTL unfiltered	ATM-HTL filtered @ 5 micron
Density, g/ml at 80 °C	1.12	Not determined
Viscosity, cSt at 80 °C	Not be able to measure due to high viscosity	
Water content, wt%	5.6±0.2	Not determined
Carbon, wt%, dry	Not determined	78.2±0.3
Hydrogen, wt%, dry	Not determined	7.2±0.03
Nitrogen, wt%, dry	Not determined	0.14±0.03
Sulfur, wt%, dry	Not determined	<0.07
Oxygen, wt%, dry	Not determined	14.5±0.6
CAN, mg KOH/g	73.6±11.4	Not determined
PhAN, mg KOH/g	17.8±2.0	Not determined
TAN, mg KOH/g	91.4±13.3	Not determined
Solids content, wt%	1.6	0.5
Heating value (kJ/kg)	Not determined	31,009
Inorganic content (by ICP-AES, ppm)	K: 3186; Fe: 137; Na: 120; Ca: 117; Si: 91 Other: <30	Not determined

The filtration process was challenging due to the very high viscosity of the sample, and the feed oil was successfully filtered only after warming up to 80 ˚C. The filter cake is seen below to contain black material resembling agglomerated char particles, and fibrous materials, both of which could have potentially cause plugging in the HT system. Approximately 1.1 % weight loss of biocrude was observed, including solids and some residual biocrude in filter body. Such weight loss should be lower at a larger scale.

Figure 30. Filter cake on the 5-micron screen of the ATM-HTL biocrude.

3.4.2 Hydrotreating of the Biocrudes

All three biocrudes were hydrotreated in the same reactor system, but in separate tests. The reactor system was built around a continuous, down-flow packed-bed reactor loaded with a commercial Ni-Mo sulfide based hydrotreating catalyst. Detailed information on reactor is described in a previous publication (Olarte et al., Top. Catal., 2016, 59, 55).

The biocrude was not preheated before entering the catalyst bed, but the mass of the heated reactor vessel and the exothermic nature of the HT reactions served to bring the biocrude to temperature. Similarly the hydrogen gas was fed at room temperature into the reactor system and mixed with the biocrude prior to entering the catalyst bed. The hydrogen was fed at large excess to the reaction requirement so as to maintain a high partial pressure of H_2 in the reactor. The biocrude was fed by a high-pressure metering syringe pump. Hydrogen was introduced into the reactor via high-pressure lines and mass flow controller from a gas cylinder manifold. The products were cooled and collected in a dual cylinder sampling system with the uncondensed gases sampled, measured and vented. The recovered liquid products were phase separated, weighed and sampled for further analysis. Manually recovered gas samples were analyzed by gas chromatography. A schematic drawing of the reactor system is shown below in Figure 31.

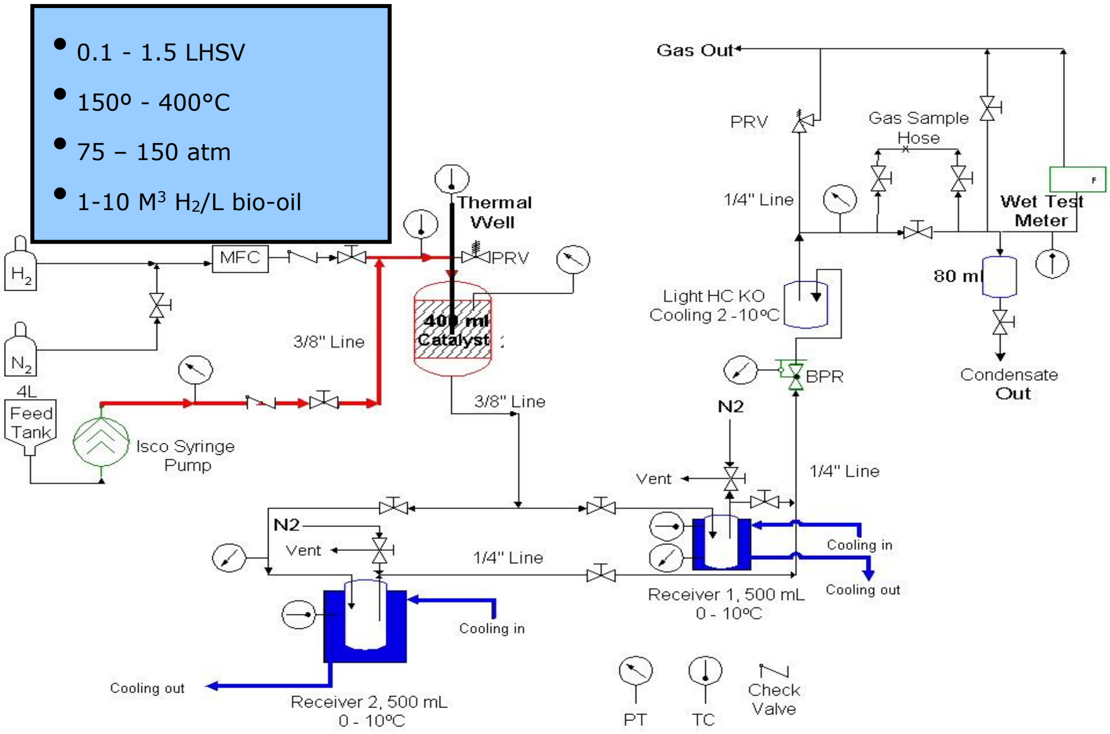

Figure 31. **Schematic of bench-scale hydrotreater at PNNL**

FP HT

As shown in Table 18**,** the raw FP bio-oil contains high water content, high oxygen content, and highly acidic components, and thus not compatible for direct integration in the hydrocarbon fuels infrastructure. The raw FP bio-oil requires further upgrading in order to be more compatible for liquid fuels application. However, FP bio-oil is thermally and chemically unstable, mainly because of the presence of reactive species such as carbonyl compounds (aldehydes and ketones, see Table 18 for high carbonyl content in this bio-oil). These compounds present a major challenge for HT of bio-oil because of the occurrence of severe catalyst deactivation and even reactor plugging by carbonaceous species formed by thermal polymerization of the reactive species. Hydrogenation over a metal catalyst at a moderate temperature is known to convert active species, such as carbonyl groups, to stable alcohols. This approach has been shown to be the most promising and efficient method for stabilizing FP bio-oil. A two-step process with a low-temperature hydrogenation step to stabilize the bio-oil prior to the high-temperature hydrodeoxygenation/hydrocracking step for oxygen removal has been developed at PNNL. This process represents the state of the art for upgrading for FP bio-oil to fuels.

Here, the FP bio-oil was first treated at a low temperature over a Ru catalyst bed for stabilization. Two tests were conducted in the continuous, down-flow packed-bed reactor to produce sufficient stabilized FP bio-oil (carbonyl content <1.5 mmol/g). The reaction conditions are listed in Table 22.

Table 22. Reaction conditions of hydrotreating test

Parameter	Stabilization	Finishing hydrotreating	
		This test	Typical
Catalyst	Ru/C	50/50 vol of Ru/C and $NiMo/Al_2O_3$; Presulfided in reactor prior to hydrotreating test	$NiMo/Al_2O_3$; Presulfided in reactor prior to hydrotreating test
Catalyst size, mm	0.25 - 1.19	0.25 - 1.19	
Catalyst density, g/ml (bulk)	0.48	0.48 (Ru/C) and 0.49 ($NiMo/Al_2O_3$)	0.49 ($NiMo/Al_2O_3$)
Reaction temperature,°C	140	170 for Ru/C section 400 for $NiMo/Al_2O_3$ section	400 for $NiMo/Al_2O_3$ bed
Pressure, MPa	12.4	12.4	
LHSV, L/(L catalyst h)	0.23	0.1	0.23
H_2/bio-oil, L H_2/L bio-oil	998	2340	

For the stabilization step, the average yield data at steady-state is reported in Table 23. The observed mass recovery was high at 100%. The yield of stabilized bio-oil was 98% on wet basis with 1.4% loss to gas product. The composition of gas product is reported in Table 24. The produced stabilized bio-oil were collected at different time on stream but was then combined and analyzed in detail. In general, significant hydrogen addition was observed and H/C molar ratio in stabilized bio-oil (H/C: 1.7) was much higher than in the raw bio-oil (H/C: 1.4). Carbonyl content dropped significantly, suggesting a much improved stability of the bio-oil.

Table 23. Yield from stabilization and finishing step of hydrotreating of pyrolysis oil

		Stabilization
Stabilized bio-oil	Yield, w/w	0.98
	Carbon yield, w/w	0.94
Gas product	Yield, w/w	0.014
	Carbon yield, w/w	0.014
H2 consumption, w/w bio-oil		0.007
Mass balance, %		100
Carbon balance, %		95

Table 24. Gas yield from both stabilization and finishing hydrotreating step.

Gas Concentration (vol %)	CH_4	C_2H_6	C_3H_8/C_3H_6	C_4H_{10}	C_5H_{12}	CO	CO_2
Stabilization	21.1	4.0	1.7	0.4	1.9	0.0	70.8

Table 25. Analysis of stabilized bio-oil

Test	**Results**
Density, g/ml at 20°C	**1.136**
Viscosity, cSt at 20°C	**23.38±0.77**
Water content, wt.%	**34.2 ± 0.16**
Carbon, wt.%, dry	**63.79±0.04**
Hydrogen, wt.%, dry	**9.02±0.06**
Nitrogen, wt.%, dry	**<0.05**
Sulfur, wt.%, dry	**<0.06**
Oxygen, wt.%, dry	**27.18±0.51**
CAN, mg KOH/g	**63.7±1.8**
PhAN, mg KOH/g	**31.7±3.6**
TAN, mg KOH/g	**95.4±5.4**
Carbonyl (mmol/g)	**1.159±0.015**
HHV (KJ/Kg)	**15,519**

The stabilized bio-oil was then hydrotreated by using a combined sulfide Ru/C and NiMo/Al_2O_3 catalyst in the reactor. The reaction conditions are listed in Table 22. Adding a Ru/C bed before the the NiMo/Al_2O_3 was to ensure the success of the run by providing additional hydrogenation capability to prevent any possible reactor plugging, considering the limitation of budget, time, and experience on this specific bio-oil. This is also the previous version of multi-stage hydrotreating technologies developed at PNNL. Our current technology includes only two stages, a stabilization stage with supported reduced Ru hydrogenation catalyst and a final hydrotreating stage with sulfided NiMo/Al_2O_3 catalyst. The two-stage process has been demonstrated to be an efficient and robust process by upgrading of various FP bio-oils. Therefore, a typical condition in Table 22 is suggested to be used for techno-economic analysis to be consistent with the FY2016 SOT (state of technology) for the FP bio-oil hydrotreating process.

Table 26 reports average yield data, based on stabilized bio-oil, at steady-state for the final hydrotreating step. In general, the fuel yield, in dry basis, is expected to be 47%, which represents 61% of carbon in bio-oil. The remaining carbon ended as gas products, and its composition is reported in Table 27.

Table 26 Yield data of final hydrotreating of stabilized bio-oil

		Observed	Estimated
Fuel product	**Yield, w/w, dry**	**0.47**	**0.47**
	Carbon yield, w/w, dry C/feed C	**0.72**	***0.61**
Gas product	**Yield, w/w, dry**	**0.38**	**0.38**
	Carbon yield, w/w, dry C/feed C	**0.46**	***0.39**
Produced water yield, w/w, dry		**0.18**	**0.18**
H_2 consumption, w/w dry bio-oil		**0.064**	**0.074**
Mass balance, %		**100**	**100**
Carbon balance, %		**118**	**100**

*Values are normalized

Table 27. Gas yield from finishing hydrotreating step.

Gas Concentration (vol %)	**CH_4**	**C_2H_6**	**C_3H_8/C_3H_6**	**C_4H_{10}**	**C_5H_{12}**	**CO**	**CO_2**
Final upgrading	**8.2**	**14.0**	**15.6**	**27.0**	**9.1**	**1.8**	**24.3**

The overall yield from raw bio-oil to final liquid hydrocarbon product is then calculated and reported in Table 28. In overall, the fuel product yield of 42% with carbon yield of 61%. The rest 39% of carbon was as gas products.

Table 28. Overall yield from raw FP bio-oil to final products for combining both stabilization and hydrotreating step

		Calculated
Fuel product	**Yield, w/w, g/g dry bio-oil**	**0.42**
	Carbon yield, w/w	**0.61**
Gas product	**Yield, w/w, g/g dry bio-oil**	**0.36**
	Carbon yield, w/w	**0.39**
Produced water yield, w/w, g /dry bio-oil		**0.28**
H_2 consumption, w/w g/g dry bio-oil		**0.081**
Mass balance, %		**100**
Carbon balance, %		**100**

The produced fuel was collected at different time on stream but was then combined and analyzed in detail. The analysis methods are the same as described in previously in this section. As shown in Table 29, deep oxygen removal was achieved, consistent with the low oxygen content (1.1 wt%), low water content, and non-detectable acid number of the produced fuel. The heating value has increased, approached three-fold the energy of from starting FP bio-oil.

Table 29. Final characterization of hydrotreated fuel from bio-oil.

Test	**Hydrotreated fuel from the FP**
Density, g/ml at 20 °C	**0.843**
Viscosity, cSt at 20 °C	**2.345**
Water content, wt%	**<0.1%**
Carbon, wt%, dry	**85.8±0.3**
Hydrogen, wt%, dry	**13.1±0.2**
Nitrogen, wt%, dry	**<0.05**
Sulfur, wt%, dry	**<0.07**
Oxygen, wt%, dry	**1.1±0.1**
CAN, mg KOH/g	**Not detected**
PhAN, mg KOH/g	**Not detected**
TAN, mg KOH/g	**Not detected**
HHV (kJ/kg)	**44,439**

The hydrotreated fuel was also analyzed by gas chromatography simulated distillation (ASTM D2887). This method is standardized for the analysis of diesel fuels; its application to the product, which is more comparable to sweet crude oil, shows differences in the low-temperature distillate range when compared to diesel fuels. The results are shown in Figure 32 for the simulated distillation curve and in Table 30 for the calculated distribution of the fractions. There was a significant portion of the hydrotreated fuel that fell in the naphtha range (36 wt%) and a longer tail that fell into the distillation range of heavy residual. In total, 78% of products were in the gasoline and distillate range and 28% were in the jet fuel range.

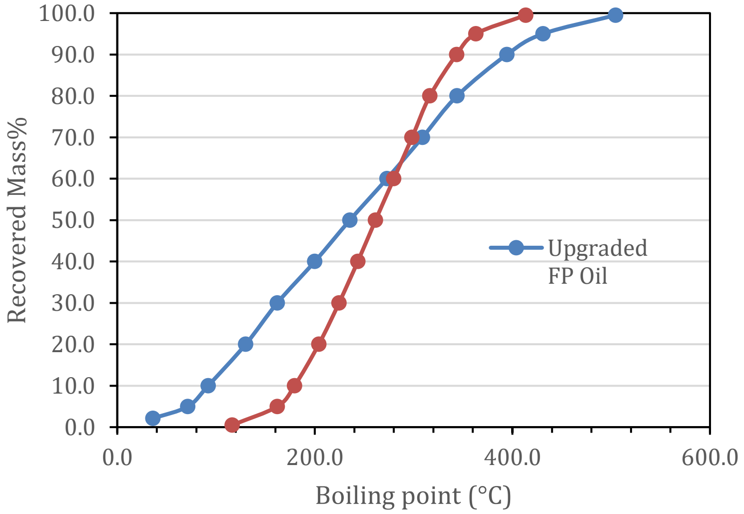

Figure 32. Simulated distillation curve of hydrotreated product from fast pyrolysis.

Table 30 Mass approximation of hydrocarbon product

Fraction	**Distribution, wt.%**
Naphtha, IBP-184 °C	**36**
Jet, 150-250 °C	**28**
Diesel, 184-338 °C	**42**
Gas oil, >338 °C	**22**

The produced aqueous products were also analyzed, as shown in Table 31. The analysis methods are described previously in this section. Total organic carbon (TOC) is measured by using EPA Method 9060A. Relatively clean water was produced, with carbon, nitrogen, and sulfur content of 0.36, 0.11, and below 0.05 wt%, respectively, and TOC of 2560mg/L.

Table 31. Characterization of the aqueous product from the finishing upgrading step.

Test	**Aqueous products**
Density, g/ml at 20 °C	**1.0**
Viscosity, cSt at 20 °C	**1.0**
Water content, wt%	**100.0**
Carbon, wt%	**0.36±0.06**
Nitrogen, wt%	**0.11±0.01**
Sulfur, wt%	**<0.05**
CAN, mg KOH/g	**Not detected**
PhAN, mg KOH/g	**Not detected**
TAN, mg KOH/g	**Not detected**
TOC (mg/L, ppm)	**2560**

CFP HT

The filtered CFP bio-oil was hydrotreated in the continuous, down-flow packed bed reactor loaded with a commercial Ni-Mo sulfide based hydrotreating catalyst. The reaction conditions are listed in Table 32**.** For this specific test, the bio-oil LHSV of 0.10 h^{-1} was used for a better control of exotherm. Our recent research on a smaller scale reactor for hydrotreating of CFP bio-oil with different properties showed that a similar HDO performance regarding oxygen removal could be achieved at bio-oil LHSV of 0.20 h^{-1}. A higher LHSV of 0.30 h^{-1}, however, could lead to a hydrotreated product with higher oxygen content (~3 wt.% instead of <1 wt.% below for LHSV at <0.20 h^{-1}). Therefore, the typical condition in table 3 are suggested to be used for techno-economic analysis.

Table 32. Reaction conditions of hydrotreating test

Parameter	This test	Typical
Catalyst	Commercial supported Ni-Mo sulfide catalyst; Presulfided in reactor prior to hydrotreating test	
Catalyst size, mm (ave. diameter) x mm (ave. length)	1.26 x 2.77	
Catalyst density, g/ml (bulk)	0.60	
Reaction temperature, °C	400	
Pressure, MPa	125	
LHSV, L/(L catalyst h)	0.10	0.20
H_2/bio-oil, L H_2/L bio-oil	2400	2400

The average yield data at steady-state is reported in Table 33. The observed mass balance is around 90%. It is mainly because of the possible hold-up of liquid in the hydrotreater system. Therefore, the product yield are further estimated based on the observed data in this test and also other hydrotreating tests using similar CFP bio-oils in a smaller scale hydrotreater. In general, the fuel yield, in dry basis, is expected to be 71%, which represents 84% of carbon in bio-oil. The loss of carbon is mainly by producing gas products; composition is reported in Table 34.

Table 33. Yield, carbon yield, H2 consumption, mass balance of hydrotreating of the VTT CFP oil

		Observed	Estimated
Fuel product	Yield, w/w, dry	0.64	0.71
	Carbon yield, w/w, dry C/feed C	0.76	0.84
Gas product	Yield, w/w, dry	0.11	0.12
	Carbon yield, w/w, dry C/feed C	0.10	0.11
Produced water yield, w/w, dry		0.21	0.23
H_2 consumption, w/w dry bio-oil		0.07	0.07
Mass balance, %		90	99
Carbon balance, %		86	95

Table 34. Composition of the produced gas from hydrotreating of the VTT CFP oil

Gas	CH_4	C_2H_6	C_3H_8/ C_3H_6	C_4H_{10}	C_5H_{12}	CO	CO_2
Concentration (vol %)	42.8	21.4	19.0	7.3	1.3	2.2	6.0

The produced fuel at different time on stream was then combined and analyzed in detail. The analysis methods are the same as described in section 1. As shown in Table 35, deep oxygen removal was achieved, consistent with the low oxygen content (<1 wt%), low water content, and non-detectable acid number of the produced fuel.

Table 35. Analysis results of the hydrotreated fuel from the VTT CFP bio-oil

Test	Hydrotreated fuel from the VTT CFP bio-oil
Density, g/ml at 20 °C	0.857
Viscosity, cSt at 20 °C	2
Water content, wt%	<0.5
Carbon, wt%, dry	88.27 +/- 0.26
Hydrogen, wt%, dry	10.77 +/- 0.05
Nitrogen, wt%, dry	0.015 +/- 0.005
Sulfur, wt%, dry	<0.04
Oxygen, wt%, dry	0.95 +/- 0.05
CAN, mg KOH/g	n.d.
PhAN, mg KOH/g	n.d.
TAN, mg KOH/g	n.d.

The hydrotreated fuel was also analyzed by gas chromatography simulated distillation. This method is standardized for the analysis of diesel fuels; its application to the product, which is more comparable to sweet crude oil, shows differences in the low-temperature distillate range when compared to diesel fuels. The results are shown in Figure 33 for the simulated distillation curve and in Table 36 for the calculated distribution of the fractions. There was a significant portion of the hydrotreated fuel that fell in the naphtha range (45 wt%) and a small tail that fell into the distillation range of heavy residual. In total, 86% of products were in the gasoline and distillate range and 35% were in the jet fuel range.

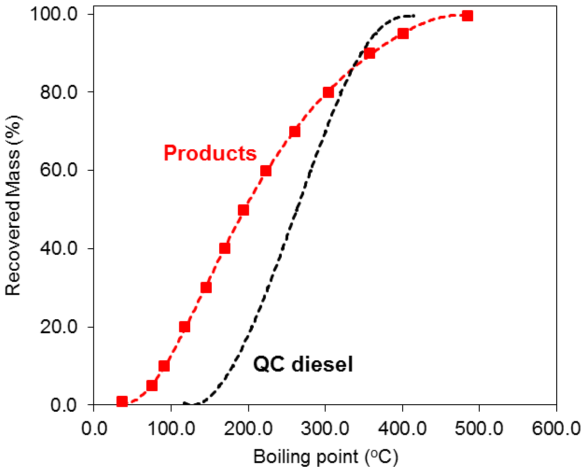

Figure 33. Simulated distillation curve of the hydrotreated fuel from the VTT CFP bio-oil

Table 36. Calculated weight distribution of different fractions of hydrotreated fuel from the VTT CFP oil based on simulated distillation results

Fraction	Distribution, wt.%
Naphtha, IBP-184 °C	45.0
Jet, 150-250 °C	35.1
Diesel, 184-338 °C	40.6
Gas oil, >338 °C	13.6

The hydrotreated oil was then fractionated by distillation using a bench-scale distillation setup. Cuts were made as follows: (a) fraction 1: 20 to 150 °C (b) fraction 2: 150 to 184 °C; (c) fraction 3: 184 to 250 °C; (d) fraction 4: 250 to 338 °C; and (e) fraction 5: >338 °C. Fractions 4 and 5 were collected under vacuum (8 torr) to prevent oil degradation and coking at higher temperatures. As shown in Table 37, 90% of the hydrotreated oil were in naphtha and diesel fractions and 37% of it were in jet fuel range.

Table 37. Mass yields from fractionation of hydrotreated oils.

Fraction	**Distribution, wt.%**
Fraction 1, 20-150 °C	**27.0**
Fraction 2, 150-184 °C	**14.9**
Fraction 3, 184-250 °C	**21.7**
Fraction 4, 250-338 °C*	**25.6**
Fraction 5, >338 °C*	**10.3**
Mass balance	**99.5%**
Naphtha, 20-184 °C	**41.9**
Jet, 150-250 °C	**36.6**
Diesel, 184-338 °C	**47.3**
Gas oil, >338 °C	**10.3**

* Atmospheric equivalent temperature

By combining fraction 2 and 3 as jet fraction, we obtained four samples for fuel quality analysis. Their total weight and distribution are listed in Table 38.

Table 38. Quantity of each fuel fraction obtained

Fraction	**Quantity, g (ml)**
Total hydrotreated fuel	**755 (880)**
Light Naphtha, 20-150 °C	**204 (~240*)**
Jet, 150-250 °C	**276 (~320*)**
Heavy Diesel, 250-338 °C	**194 (~220*)**
Gas oil, >338 °C	**78 (~85*)**

* Approximated volume based on estimated density

The produced aqueous products were also analyzed, as shown in Table 39. The analysis methods are the same as described in section 3.4.1. TOC is measured by using EPA Method 9060A. Relatively clean water was produced, with carbon, nitrogen, and sulfur content of 0.33, 0.49, and 0.07 wt.%, respectively, and TOC of 2400 mg/L.

Table 39 Analysis results of the aqueous products from hydrotreating of the VTT CFP bio-oil

Test	**Aqueous products**
Density, g/ml at 20 °C	**1.008**
Viscosity, cSt at 20 °C	**1.017**
Water content, wt%	**100.0**
Carbon, wt%	**0.33 +/- 0.03**
Nitrogen, wt%	**0.49 +/- 0.02**
Sulfur, wt%	**0.07 +/- 0.005**
CAN, TAN, mg KOH/g	**n.d.**
TOC (mg/L, ppm)	**2400**

HTL HT

The filtered HTL biocrude was hydrotreated with the reaction conditions are listed in Table 40. For this specific test, the biocrude LHSV of 0.10 h^{-1} was used for a better control of exotherm, the typical condition in Table 40 are suggested to be used for techno-economic analysis. The typical condition is determined based on our experiences on hydrotreating of similar woody HTL biocrudes.

Table 40. Hydrotreating process parameter

Parameter	**This test**	**Typical**
Catalyst	**Commercial supported Ni-Mo sulfide catalyst; Presulfided in reactor prior to hydrotreating test**	
Catalyst size, mm	**0.25 - 1.19 mm**	
Catalyst density, g/ml (bulk)	**0.49**	
Reaction temperature, ˚C	**400**	
Pressure, MPa	**12.4**	
LHSV, L/(L catalyst h)	**0.10**	**0.20**
H_2/biocrude, L H_2/L biocrude	**2327**	

The average yield data at steady-state is reported in Table 41. The observed mass balance is at 104% and carbon balance is at 92 wt%. In general, the fuel yield, in dry basis, is 80%, which represents 91% of carbon in biocrude. The remaining carbon ended as gas products, and its composition is reported in Table 42.

Table 41. Yield from finishing step of hydrotreating of biocrude.

		Observed
Fuel product	**Yield, w/w, dry**	**0.80**
	Carbon yield, w/w, dry C/feed C	**0.91**
Gas product	**Yield, w/w, dry**	**0.11**
	Carbon yield, w/w, dry C/feed C	**0.11**
Produced water yield, w/w, dry		**0.16**
H_2 consumption, w/w dry biocrude		**0.08**
Mass balance, %		**104**
Carbon balance, %		**102**

Table 42. Gas yield from finishing the hydrotreating step.

Gas	**CH_4**	**C_2H_6**	**C_3H_8/ C_3H_6**	**C_4H_{10}**	**C_5H_{12}**	**CO**	**CO_2**
Concentration (vol%)	**23.0**	**18.7**	**23.4**	**13.8**	**4.6**	**0.0**	**16.6**

The produced fuel was collected at different time on stream but was then combined and analyzed in detail. The analysis methods are the same as described in section 3.4.1. As shown in Table 43, deep oxygen removal was achieved, consistent with the low oxygen content (<0.5 wt%), low water content, and non-detectable acid number of the produced fuel. The heating value of the liquid fuel has increased to 43.8 MJ/kg.

Table 43. Final characterization of hydrotreated fuel from biocrude.

Test	**Hydrotreated fuel from the HTL**
Density, g/ml at 20°C	**0.899**
Viscosity, cSt at 20 °C	**5.478**
Water content, wt.%	**<0.1**
Carbon, wt%, dry	**87.7±0.2**
Hydrogen, wt%, dry	**11.8±0.1**
Nitrogen, wt%, dry	**<0.05**
Sulfur, wt%, dry	**<0.05**
Oxygen, wt%, dry	**<0.5**
CAN, mg KOH/g	**Not detected**
PhAN, mg KOH/g	**Not detected**
TAN, mg KOH/g	**Not detected**
HHV (kJ/kg)	**43,824**

The hydrotreated fuel was also analyzed by gas chromatography simulated distillation (ASTM D2887). This method is standardized for the analysis of diesel fuels; its application to the product, which is more comparable to sweet crude oil, shows differences in the low-temperature distillate range when compared to diesel fuels. The results are shown in Figure 34. Simulated distillation curve of hydrotreated product from fast pyrolysis.for the simulated distillation curve and in Table 44 for the calculated distribution of the fractions. There was a significant portion of the hydrotreated fuel that fell in the naphtha range (25 wt%) and a longer tail that fell into the distillation range of heavy residual. In total, 71% of products were in the gasoline and distillate range and 28% were in the jet fuel range.

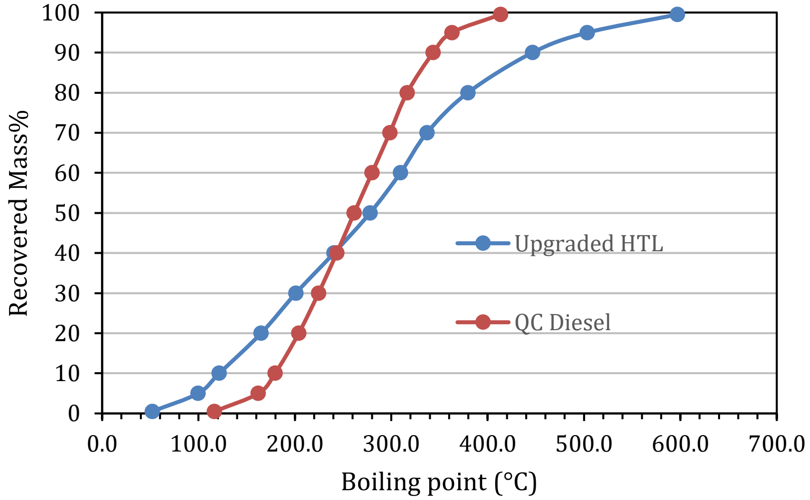

Figure 34. Simulated distillation curve of hydrotreated product from fast pyrolysis.

Table 44. Mass approximation of hydrocarbon product

Fraction	Distribution, wt.%
Naphtha, IBP-184 °C	25
Jet, 150-250 °C	28
Diesel, 184-338 °C	46
Gas oil, >338 °C	29

The produced aqueous products were also analyzed, as shown in Table 45**.** The analysis methods are the same as described earlier in this Section. TOC is measured by using EPA Method 9060A. Relatively clean water was produced, with nitrogen and sulfur content of 0.3 and below 0.09 wt%, respectively, and TOC of 2930 mg/L.

Table 45. Characterization of the aqueous product from the HTL biocrude upgrading step.

Test	Aqueous products
Density, g/ml at 20°C	1.0
Viscosity, cSt at 20 °C	1.0
Water content, wt%	98.0
Carbon, wt%	2.55+/- 1.58*
Nitrogen, wt%	0.3+/- 0.04
Sulfur, wt%	0.09+/- 0.005
CAN, mg KOH/g	Not determined
PhAN, mg KOH/g	Not determined
TAN, mg KOH/g	Not determined
TOC (mg/L, ppm)	2930

* The direct carbon analysis was inconsistent and is likely in error considering the much lower TOC measured and historically low carbon numbers in HT byproduct waters.

CHAPTER 4 - ENVIRONMENTAL SUSTAINABILITY, EMISSIONS AND LIFE CYCLE ANALYSIS

4.1 General background to Sustainability considerations of biojet fuels

The main rationale for alternative fuel development is the ability of these fuels to offer emission reductions in order to meet global climate commitments, including specific goals of the aviation sector (including the long-term goal of 50% reduction by 2050, compared to a 2005 baseline). While emission reductions are crucial, the overall sustainability of biofuel production is of paramount importance to the sector, including a range of environmental impacts (soil, water, air, biodiversity etc), social impacts (human rights, land rights, labor rights etc) and economic factors (continuous improvement, legal compliance etc). Alternative fuels that are not demonstrably sustainable are unlikely to achieve market acceptance. Sustainability commitments and guidelines in the aviation sector has mostly been based on voluntary actions from stakeholders in this sector, although increasingly, regulatory schemes that provide credit for low-carbon fuel use are including sustainability requirements.

One such regulatory scheme is the International Civil Aviation Organisation's Carbon Offsetting and Reduction Scheme for International Aviation, CORSIA. Low carbon fuels in can be used by an airline under CORSIA to reduce their offsetting requirement, provided these fuels are sustainable. The meaning of sustainability in this context and the sustainability criteria for alternative fuels are currently still under development by ICAO, but it is expected to take the form of a meta-standard, under which existing voluntary and regulatory sustainability schemes will be assessed for their eligibility to comply.

4.1.1 Biojet Fuels and emission reductions within the aviation industry

The UNFCCC COP21 Paris agreement was a global commitment to reduce greenhouse gas emissions. However, international aviation and shipping fell outside the scope of this agreement and these sectors were tasked to develop their own policies for reducing emissions at international bodies with jurisdiction, ICAO and IMO (International Maritime Organisation).

Prior to this, the aviation sector had already taken several voluntary actions to reduce emissions, including measures to improve fuel efficiency, air traffic management, operations and aeronautics. Organisations like IATA developed voluntary, ambitious, aspirational goals for reducing emissions in the sector in 2009 based on the following targets (IATA, 2009):

- An average improvement in fuel efficiency of 1.5% per year from 2009 to 2020;
- A cap on net aviation CO_2 emissions from 2020 (carbon-neutral growth);
- A reduction in net aviation CO_2 emissions of 50% by 2050, relative to 2005 levels.

It was recognized by the aviation industry that biojet fuels were a key component of the strategy for reducing greenhouse gas (GHG) emissions in the aviation sector and ICAO Member States were unlikely to achieve aspirational goals for reducing emission emissions from international aviation without such fuels. That such biojet fuels should be sustainable is such an essential metric that the aviation sector refers to them as "Sustainable Aviation Fuels" or SAF[22].

While the objective to reduce GHG emissions has been the core of sustainability, the industry has also emphasized a commitment to sustainability beyond emission reductions, extending to broader aspects like biodiversity, land use change, etc.

Sustainability is assessed against set criteria and guidelines, the scope of which is defined by a specific sector. Several voluntary certification schemes currently operate in various sectors, e.g. the Roundtable on Sustainable Biomaterials (RSB). Companies or organisations can become members of such schemes and obtain a sustainability certification based on an independent audit carried out on behalf of the certification scheme. In this manner, many certification bodies have been established in different industries and sectors for reasons such as access to markets, etc.

Against this background, ICAO is developing a meta-standard as a framework for CORSIA and the aviation sector, defining the principles and criteria for sustainability that are directly applicable to the aviation sector and biojet fuels. This meta-standard will use the standards and principles in existing voluntary certification schemes, such as RSB, ISCC etc, as a guideline. However, rather than the establishment of a new certification scheme, the meta-standard will likely be used as a guide against which existing certification schemes could become approved under ICAO. The biojet fuel producer or user therefore has the option to choose membership of a voluntary scheme, provided that the scheme meets the criteria of the meta-standard.

4.1.1.1 ICAO perspective

The International Civil Aviation Organization (ICAO) is an UN agency established in 1944 to reach consensus on international civil aviation standards as well as on "policies in support of a safe, efficient, secure, **economically sustainable and environmentally responsible** civil aviation sector"[23]. On 4th October 2013 the **ICAO resolution A38-184[24]** "Consolidated statement of continuing ICAO policies and practices related to environmental protection — Climate change" entered into force. Amongst other aspects this resolution also covers proposed sustainability criteria for alternative fuels.

The following environmental and social sustainability criteria are listed in §32.j and k of the resolution:

[The Assembly … Requests States to: …]

j. recognize existing approaches to assess the sustainability of all alternative fuels in general, including those for use in aviation which should:

i. achieve net **GHG emissions reduction** on a life cycle basis;

ii. **respect the areas of high importance for biodiversity, conservation and benefits**

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[22] This definition also goes beyond biofuels to include any alternative fuel.
[23] http://www.icao.int/about-icao/Pages/default.aspx
[24] http://www.icao.int/Meetings/a38/Documents/Resolutions/a38_res_prov_en.pdf

for people from ecosystems, in accordance with international and national regulations; and

iii. **contribute to local social and economic development, and competition with food and water should be avoided**;

k. adopt measures to ensure the sustainability of alternative fuels for aviation, building on existing approaches or combination of approaches, and monitor, at a national level, the sustainability of the production of alternative fuels for aviation."

Of note is that the sustainability criteria included in paragraph 32.j iii. go beyond the current mandatory requirements in place for biofuels sustainability in both EU and US legislation, although **these aspects are commonly included in voluntary standards**.

4.1.1.2 Airlines perspective

There is general agreement amongst the airlines that a minimum sustainability ambition level should be defined under CORSIA. However, the view is that sustainability criteria should find the right balance between sufficient stringency to ensure effectiveness and credibility of the industry's actions towards sustainable aviation and avoiding excessive limitation of available feedstock through overly stringent constraints. Furthermore, significant competitive distortion between alternative fuels for aviation and for other applications should be avoided. Despite this trade-off in the development of a regulatory scheme, airlines could voluntarily meet higher sustainability levels than the minimum level.

For discussions on alternative fuel sustainability it is helpful to use the criteria and guidelines of RSB, which cover a comprehensive set of sustainability standards, that are publically available. Most of the biojet fuel flights made to date have used fuels certified to RSB in the absence of other standards. Table 46presents the principles and criteria developed by RSB through a broad multi-stakeholder consultation process.

Table 46: The RSB Principles and Criteria for sustainability certification

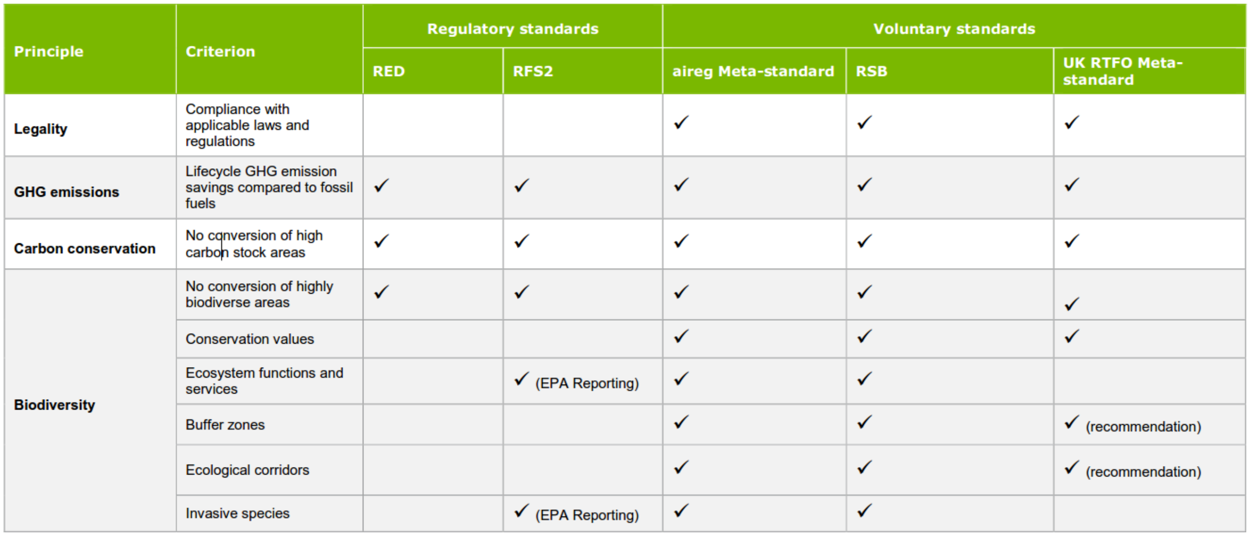
Principles	**Criteria**
1. Legality	1.1 Sustainable alternative jet fuel shall comply with all applicable national and local laws and regulation.
2. Greenhouse gas emissions	2.1 Sustainable alternative jet fuel shall achieve net greenhouse gas emissions reductions on a life-cycle basis.
3. Carbon stock conservation	3.1 Sustainable alternative jet fuel shall not be made from biomass obtained from land with high carbon stock.
4. Biodiversity conservation	4.1 Sustainable alternative jet fuel shall not be made from biomass obtained from land with high biodiversity value. 4.2 Basic ecosystem services in critical situations shall be maintained or enhanced. 4.3 Biodiversity within the area of operation shall be maintained or enhanced. 4.4 Biodiversity within the area of operation shall not be compromised by the use of genetically modified plants, microorganisms or algae.
5. Soil conservation	5.1 Good agricultural practices shall be implemented to maintain or enhance soil physical, chemical, and biological conditions.
6. Sustainable water use	6.1: Good agricultural practices shall be implemented to maintain or enhance water quality. 6.2 Good agricultural practices shall be implemented to use water efficiently, and to avoid the depletion of surface or groundwater resources beyond replenishment capacities.
7. Air quality	7.1 Open-air burning as part of land clearance, or the burning of agricultural residues and wastes shall not be practised, unless there are no viable alternatives. 7.2 Air pollution emissions shall be minimized.
8. Use of chemicals, wastes and byproducts	8.1 Chemicals, wastes or by-products arising from fuel production shall be stored, handled and disposed of responsibly to safeguard the environment and to minimise the risk to people.
9. Land and water rights and community engagement	9.1 Sustainable alternative jet fuel operations shall respect existing land rights and land use rights. 9.2 Sustainable alternative jet fuel operations shall respect the existing water rights of local and indigenous communities. 9.3 Sustainable alternative jet fuel operations shall only be established with the free,prior and informed consent of land and water users or owners.
10. Human rights and labour rights	10.1 Human rights and labour rights governing child labour, forced labour, discrimination, freedom of association and the right to organise and bargain collectively shall not be violated.
11. Local food security	11.1 Sustainable alternative jet fuel operations shall not adversely impact the human right to adequate food and shall not adversely impact food security in food insecure regions.
12. Rural, social and economic development	12.1 In regions of poverty, alternative jet fuel operations shall contribute to the social and economic development of local, rural and indigenous people and communities.

4.1.4 Current regulatory and voluntary certification standards

Sustainability certification of biojet fuel is a means of demonstrating that the fuel meets the compliance levels required by national laws, regulatory standards, or voluntary schemes. Current schemes will have to demonstrate compliance with the sustainability requirements of CORSIA and will likely undergo a benchmarking process against the specific requirements of the meta-standard.

Current standards will include: legislated requirements such as the EU Renewable Energy Directive (RED), the Renewable Fuel Standard (RFS) in the USA, and the UK Renewable Transport Fuel Obligation (RTFO); Other voluntary standards likely to meet the meta-standard sustainability criteria include: Roundtable on Sustainable Biomaterials (RSB) standard; and International Sustainability and Carbon Certification (ISCC).

The following table (Alberici & Spoettle, 2016) illustrates the current compliance of various regulatory and voluntary standards with a consolidated set of principles and criteria as might be found in a meta-standard.



Principle	Criterion	Regulatory standards		Voluntary standards		
		RED	RFS2	aireg Meta-standard	RSB	UK RTFO Meta-standard
Legality	Compliance with applicable laws and regulations			✓	✓	✓
GHG emissions	Lifecycle GHG emission savings compared to fossil fuels	✓	✓	✓	✓	✓
Carbon conservation	No conversion of high carbon stock areas	✓	✓	✓	✓	✓
Biodiversity	No conversion of highly biodiverse areas	✓	✓	✓	✓	✓
	Conservation values			✓	✓	✓
	Ecosystem functions and services		✓ (EPA Reporting)	✓	✓	
	Buffer zones			✓	✓	✓ (recommendation)
	Ecological corridors			✓	✓	✓ (recommendation)
	Invasive species		✓ (EPA Reporting)	✓	✓	

Principle	Criterion	Regulatory standards		Voluntary standards		
		RED	RFS2	aireg Meta-standard	RSB	UK RTFO Meta-standard
	GMO			✓	✓	
Soil conservation	Implement good agricultural practices to maintain or enhance soil physical, chemical, and biological conditions	✓(Commission reporting)	✓ (EPA Reporting)	✓	✓	✓
	Integrated plant protection and crop management			✓		
	Use of agricultural residues			✓	✓	✓ (recommendation)
Water conservation	Efficient water use	✓(Commission reporting)	✓ (EPA Reporting)	✓	✓	✓
	Water quality			✓	✓	✓
Air quality	Air pollution	✓(Commission reporting)	✓ (EPA Reporting)	✓	✓	
	No burning			✓	✓	✓
Land and water rights and Community engagement	Land use rights	✓(Commission reporting)		✓	✓	✓
	Water rights			✓	✓	
	Stakeholder consultation			✓	✓	✓
Human and Labour rights	Freedom of association and right to collective bargaining	✓Commission reporting)		✓	✓	✓
	No forced and slave labour			✓	✓	✓
	No child labour			✓	✓	✓
	No discrimination			✓	✓	✓
	Fair wages and compensation			✓	✓	✓
	Health and safety			✓	✓	✓
	Subcontracting				✓	✓
	Contracts			✓		✓
	Provision of information to employees					✓
	Working hours				✓	✓ (recommendation)
	Education and training			✓		
	Basic schooling for children			✓		
Local food security	Local food security	✓(Commission reporting)		✓	✓	
Rural, Social and Economic development	Rural, Social and Economic development	✓(Commission reporting)		✓	✓	
	Information on technology use				✓	✓

Principle	Criterion	Regulatory standards		Voluntary standards		
		RED	RFS2	aireg Meta-standard	RSB	UK RTFO Meta-standard
Use of Technology, Inputs, and the Management of Waste	Minimising technology risk or damage to the environment and people (including GMO, micro-organisms, algae)				✓	
	Containment of micro-organisms to prevent release into the environment				✓	
	Storage, handling, use and disposal of agrochemicals			✓	✓	✓
	Management of residues, wastes and byproducts to safeguard soil, water and air			✓	✓	✓
	Safe use of field crop production equipment and machinery			✓		
	Emergency systems and procedures for accidents			✓		
Economic performance	Economic performance			✓	✓	
	Energy efficiency			✓		

4.1.5 Key aspects of sustainability

Sustainability is measured throughout the entire life cycle of the fuel. Three of the most significant areas of sustainability include GHG performance, food security, and biodiversity.

Life cycle Assessment (LCA) is a tool that calculates the environmental impact of a product or process over the entire lifecycle. The most prominent parameter in LCA is the total greenhouse gas (GHG) emissions of every part of the lifespan including feedstock cultivation, transportation, conversion and end use. The combination of all these emissions gives the overall lifecycle GHG emissions of a product that can then be compared against other fuels or alternatives to determine the potential emission reductions achievable with an alternative fuel. LCA and GHG reductions for each biocrude and upgrading pathway in this project is presented in section 4.2 in great detail and will not be further discussed here.

Different fuels using different technologies and feedstocks can result in different GHG emission profiles, with some pathways giving far better GHG reductions than another pathway. It is critical that any potential biojet supply chain be compared with one another and against the fossil fuel baseline by looking at the full life cycle emissions utilizing equivalent system boundaries. Once passing a 10% reduction threshold, the amount of GHG reduction calculated for an eligible fuel will form the basis of the credit that can be earned under the CORSIA scheme. Therefore airlines using a biojet with greater GHG reduction will earn more credit, therefore encouraging the production of biojet fuels with better GHG sustainability.

Many first-generation biofuel feedstocks, such as corn for ethanol and soybeans or canola for biodiesel, are derived from crops that have multiple uses in the food, feed, and/or fibre sectors. Concerns with food security are important and it is generally agreed that the development of a biojet supply chain should not contribute to food insecurity. Major sustainability certification systems include indicators that seek to monitor impacts on local food security from biofuel development activities.

Each feedstock source and supply chain must be evaluated on its own merits. Where sustainability is considered holistically, annual crops with multiple uses (including fuels) can have better sustainability performance vs. purpose grown feedstocks.

Land-use impacts may result in the loss of valuable natural ecosystems and biodiversity. These impacts are not solely limited to biofuel feedstocks, they apply to the entire agricultural system. For example, significant tracts of Southeast Asian tropical forest—critical habitat for endangered species such as orangutans—have been degraded due to clearing for palm oil plantations.

4.2 Life cycle analysis and results of the ATM Project

One of the primary drivers for biojet fuels is the need to reduce the lifecycle greenhouse gas emissions of aviation fuels. Looking at the lifecycle emissions rather than just the fuel production or fuel use emissions ensures that real reductions in GHG emissions over the full product lifecycle are achieved.

The general approach to life cycle analysis and other background material is shown in Appendix C.

The feedstocks for the fuel production process studied in this project are forest residues. The resource was discussed in an earlier section of the report. Since these feedstocks are a waste material the attributional LCA approach is the appropriate approach to use for this analysis.

Goal and Scope: The goal of the LCA study is to determine the GHG emissions of the production and use of biojet from forest residues through various pyrolysis oil and hydrothermal liquefaction biocrude production and upgrading systems. The GHG emissions will be used as part of the evaluation process of the six different approaches analyzed (three biocrudes and two upgrading systems for each bio-oil). The GHG emissions may also be used to guide the further development of the technologies.

Information Used in the LCA: The project has collected primary data for the production of three bio-oils and two different approaches to upgrading the oils. Secondary data for feedstock collection and transportation, transportation of intermediate and final products, and the reference fuel pathway is drawn from the GHGenius model.

Of the primary data collected, only the fast pyrolysis oil production system has data from actual commercial scale production. The other two bio-oils were produced in laboratory settings and do not necessarily represent optimized processes.

The upgrading experiments were not optimized either. The operating conditions for the upgrading trials were based primarily on past experience with similar kinds of products. Given the lack of optimization the upgrading results are encouraging with respect to product quality. However, due to the quality of the data and the potential for further optimization of the production and upgrading processes the results are more indicative than definitive.

Functional Unit: The functional unit for this work is one GJ (HHV) of refined bio-oil fuel.

System Boundaries: The system boundary starts with the collection of the forest residue and ends with the use of the refined bio-oil in an aircraft.

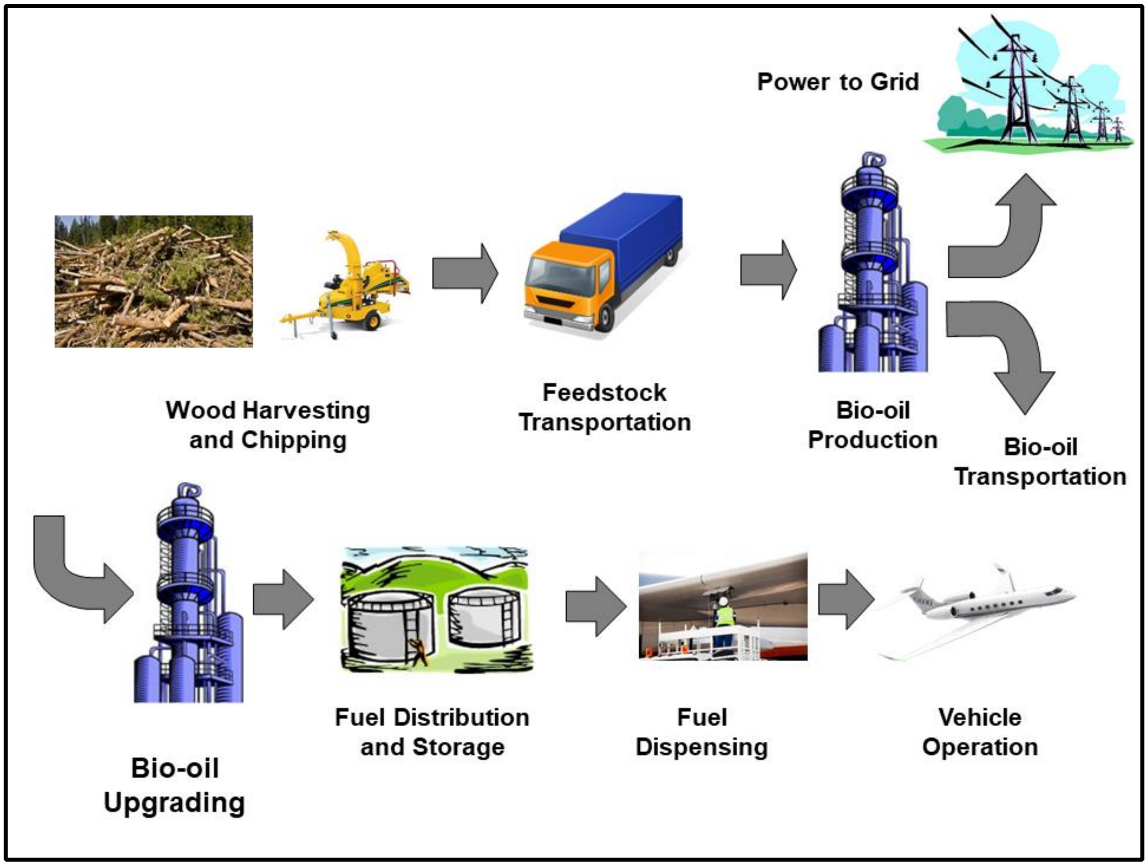


Figure 35 Lifecycle Stages – Forest Residue Biojet

Allocation: Many real-world systems produce more than one product and an important issue for LCA practitioners is to determine what portion of the emissions should be assigned to which product. The finished refined bio-oils that are produced in the upgrading process can be fractionated into fuels that have properties similar to gasoline, jet fuel, diesel fuel, and heavy fuel oil. The emissions from the processes were allocated to the components based on their energy content.

For non-liquid fuel co-products the gaseous fuels are provided a displacement credit based on natural gas production and use where it can be demonstrated that there is an existing natural gas load that could be displaced. If electricity is produced it is assumed to displace grid power, which in British Columbia is 99% hydro, wind, or biomass power.

Impact Analysis: This work considers only the GHG emissions associated with the production and use of the refined bio-oils. The GHG emissions are calculated using the 100 year global warming potentials from the 2007 IPCC fourth assessment report, as these are the values currently being used for government reporting: Carbon dioxide=1; Methane=25; Nitrous Oxide=298. The GHG emissions of carbon monoxide and unburned hydrocarbons will be calculated based on the assumption that these short lived gases are oxidized to carbon dioxide; this is consistent with IPCC methodology.

LCA model: GHGenius 5.0c has been used for modelling. The year has been set to 2018 and the region is set to British Columbia. All of the other user inputs are set to their default values unless specified in this report. Higher heating values are used in the model and in this report. The GHGenius model is used in fuel regulations in several Canadian Provinces and has the most complete inventory of Canadian data for fuel production processes available.

Reference Fuel: One of the ISO LCA principles is that the analysis is done relative to another product. The focus of the project is on the production of a biojet fuel so the natural reference fuel is jet fuel produced from petroleum.

The lifecycle GHG emissions for jet fuel using the GHGenius model as described above are as follows:

Fuel dispensing	91
Fuel distribution and storage	642
Fuel production	6,383
Feedstock transmission	78
Feedstock recovery	5,647
Feedstock upgrading	4,720
Land-use changes, cultivation	210
Fertilizer manufacture	0
Gas leaks and flares	2,280
CO_2, H_2S removed from NG	0
Emissions displaced - co-products	-138
Fuel Production	**19,913**
Fuel Use	67,637
Total	**87,550** g CO_2eq/GJ

4.2.1 Forest Residues and the impact of current policy on slash burning

The feedstocks for all of the bio-oil production processes are forest residues. It is assumed that they are sized in the forest and transported an average distance of 100 km to the bio-oil production site. The emissions associated with the sizing and the transportation are included in the system boundaries. Forest residues include harvest residue and non-merchantable residuals such as insect and fire killed trees.

Forest residues are currently either gathered into piles and combusted in the forest (slash burning) or some is left to decay on the forest floor. The current regulations in BC require pile burning in the winter following harvest. This practice releases methane from incomplete combustion and nitrous oxide. These emissions are currently included in Canada's National GHG Inventory Report. These emissions have been added to GHGenius using the emission factors reported by Akagi et al (2011). These emission factors for methane and nitrous oxide are similar to the factors used in the National Inventory Report but the report also provides a more complete set of emission factors for other contaminants. The emissions for slash burning are shown in the following Table 47.

Table 47 Slash Burning Emissions

Parameters	Value (Kg/dry tonne)
Aldehydes (as HCHO) exhaust	1.9
Fuel evaporation or leakage	0.0
NMOC exhaust	6.0
Evaporation +NMOC exhaust	6.0
Carbon in evap. + NMOC exhaust	0.0
Ozone-weighted total NMOC	3.0
CH_4 (exhaust)	6.0
CO	127.0
N_20	0.4
NOx (NO_2)	0.9
SOx (SO_2)	0.9
PM	20.0
PM_{10}	20.0
$PM_{2.5}$	15.3
Non biogenic CO_2	0
Total Non-CO_2 pollutants, CO_{2eq}	255

GHG emissions of 255 kg CO_2eq/tonne of forest residue are quite significant. Avoiding these emissions would provide a significant emission benefit to any fuel produce from forest residue. However, slash burning is a controversial practice due to the GHG emissions and the impact on local air quality and there is no guarantee that the regulations won't be changed in the future to remove slash burning as the required or preferred practice. Accordingly, all of the base case fuel production emissions will be undertaken without the credit for reduced slash burning, a conservative approach, and the impact of including this emission credit will be investigated in the discussion section.

4.2.2 Biocrudes used in the ATM Project

Three different biocrudes were sourced from three suppliers as part of the project. Each biocrude was then subjected to two different upgrading schemes. The biocrude suppliers provided information on their process so that the carbon intensity of each bio-oil could be calculated prior to upgrading. Details of the biocrudes and production processes can be found in Chapter 3. It has been assumed that the biocrude would be produced in the Prince George, BC area. Each plant receives forest residues that have been sized in the forest and transported 100 km to the fuel production site.

The three biocrudes can be compared but care must be taken in interpreting the results because the properties of each of the biocrudes are so different (Table 48). A comparison of many of the key properties is shown in the following table. The per litre values don't provide fair comparisons but the per MJ of oil values do. The kg of feed per MJ of oil is a key parameter for the economics and the GHG emissions and the results are a valid comparison.

Table 48 Biocrude Comparison

	BTG Bio-oil	VTT Bio-oil	HTL Bio-oil
Density, kg/litre	1.197	1.168	1.120
Oxygen, %	47.5	16.5	14.5
MJ/litre, (HHV)	21.5	32.3	35.9
kg wood/litre oil	1.88	6.55	3.05
kg wood/MJ oil	0.087	0.203	0.085
MJ gas/MJ oil	0.62	0.38	0
kWh/litre oil	0.10	0.20	0.20
NG, MJ/litre oil	0.5	0	7.7
Nitrogen, kg/litre oil	0.035	0	0
Other, per litre oil	0	0.012 kg ZSM-5	0.0305 kg KOH
			0.0076 kg CMC

The following Table 49 compares the GHG emissions. The functional unit is a GJ of biocrude and thus the emissions can be compared since data is on a comparable basis.

Table 49 GHG Emission Comparison

	BTG Bio-oil Forest Residue g CO_2eq/GJ	VTT Bio-oil Forest Residue g CO_2eq/GJ	HTL Bio-oil Forest Residue g CO_2eq/GJ
Fuel dispensing	0	0	0
Fuel distribution and storage	0	0	0
Fuel production	2,320	5,008	12,910
Feedstock transmission	2,277	5,303	2,222
Feedstock recovery	3,572	8,319	3,486
Feedstock upgrading	0	0	0
Land-use changes, cultivation	11	26	11
Fertilizer manufacture	0	0	0
Gas leaks and flares	0	0	0
CO_2, H_2S removed from NG	0	0	0
Emissions displaced - co-products	0	0	0
Fuel Production	8,180	18,656	18,629

The fast pyrolysis oil has the lowest emissions as it has a high yield and minimal fossil energy inputs to the system. The other two oils have similar emissions, but the emission profile is quite different. The catalytic pyrolysis oil has high feedstock emissions due to the low yield and the HTL oil has low feedstock emissions but high process emissions due to the fossil energy input into the system.

4.2.3Biocrude Upgrading and comparison of refined biocrudes

The bio-oil upgrading was assumed to take place in the Vancouver area and the product was shipped 750 km by rail from the production location near Prince George to the upgrading site.

Each bio-oil was processed with two different upgrading systems. Both systems were hydrotreaters but PNNL employed a fixed bed catalyst with the bio-oil fed directly to the hydrotreaters and Canmet Ottawa used dispersed catalysts system with the bio-oil diluted in a carrier oil with emulsifiers to provide a single-phase liquid.

The results for both systems for each bio-oil are presented below.

Both upgrading systems produce a liquid fuel product, a gaseous product, and an aqueous phase. The liquid fuel could be distilled to produce naphtha, jet fuel, diesel fuel, and heavy fuel oil. Energy allocation was applied to the different liquid streams so that emissions per MJ of liquid fuel are the same for each of the fractions.

It was assumed that the gaseous fuel could be utilized to displace natural gas used to produce hydrogen or used in heaters in the refinery. In either case the fuel gas was provided a displacement credit based on fossil natural gas.

4.2.3.1 PNNL pathway comparison

The hydrotreating parameters for the three oils from the PNNL process are summarized in the following Table 50.

Table 50 Refined Bio-oil Comparison for the PNNL upgrading process

	BTG Bio-oil	VTT Bio-oil	HTL Bio-oil
Kg wood/litre RBO	5.08	8.58	3.63
Kg bio-oil/litre RBO	2.70	1.31	1.19
Kg bio-oil/MJ RBO	0.072	0.037	0.030
MJ Gas/litre RBO	0.715	0.145	0.124
Hydrogen, kg/litre RBO	0.163	0.091	0.101
Refined Bio-oil			
Density	0.843	0.857	0.899
Oxygen	0.011	0.010	0.005
HHV, MJ/litre	37.46	35.57	39.40

The HTL crude is the most efficient in terms of the amount of feedstock required to produce an energy unit of refined bio-oil. The least efficient is the catalytic pyrolysis crude.

The lifecycle GHG emissions for the three oils are shown in the following table and compared to the reference fuel. These emissions start with the forest residues in the forest and end with the fuel used in the plane. While the biofuels are considered to be carbon neutral the methane and nitrous oxide emissions must still be included in the combustion emissions and are shown in the fuel use row.

Table 51 GHG Emission Comparison for the PNNL upgrading process

	Jet fuel	BTG Bio-oil	VTT Bio-oil	HTL Bio-oil
	Crude Oil	Forest Residue	Forest Residue	Forest Residue
	g CO_2eq/GJ			
Fuel dispensing	**91**	**95**	**94**	**96**
Fuel distribution and storage	**642**	**626**	**636**	**652**
Fuel production	**6,383**	**51,617**	**28,467**	**30,463**
Feedstock transmission	**78**	**3,892**	**5,446**	**2,454**
Feedstock recovery	**5,647**	**4,629**	**7,843**	**3,230**
Feedstock upgrading	**4,720**	**3,006**	**4,722**	**11,961**
Land-use changes, cultivation	**210**	**14**	**24**	**10**
Fertilizer manufacture	**0**	**0**	**0**	**0**
Gas leaks and flares	**2,280**	**0**	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**	**0**	**0**
Emissions displaced - co-products	**-138**	**-42,038**	**-10,846**	**-7,603**
Fuel Production	**19,913**	**21,841**	**36,386**	**41,263**
Fuel Use	**67,637**	**626**	**626**	**626**
Total	**87,550**	**22,467**	**37,027**	**42,889**
% change		**-74.3**	**-57.7**	**-51.0**

The fast pyrolysis oil produces five to six as much gas as the other two oils. It has been assumed that this gas is available to displace natural gas and thus the emission credit for this pathway is quite large and more than offsets the extra hydrogen required for the upgrading.

All of the bio-oil pathways for the PNNL upgrading pathway show significant GHG emission reductions.

4.2.3.2 Canmet pathway Comparison

The comparison of the three bio-oils processed by Canmet is shown below in Table 52. Up to 25% of the hydrogen consumption in the Canmet system is consumed by the reaction medium and not the bio-oil.

Table 52 Refined Bio-oil Comparison- Canmet

	BTG Bio-oil	VTT Bio-oil	HTL Bio-oil
Kg wood/litre RBO	4.14	8.19	3.27
Kg bio-oil/litre RBO	2.21	1.25	1.07
Kg bio-oil/MJ RBO	0.058	0.032	0.033
MJ Gas/litre RBO	12.37	9.2	5.65
Hydrogen, kg/litre RBO	0.180	0.115	0.070
Refined Bio-oil			
Density	0.829	0.857	0.839
Oxygen	0.005	0.010	0.018
HHV, MJ/litre	37.72	38.39	36.24

The HTL oil is the most efficient in terms of the amount of feedstock required to produce an energy unit of refined bio-oil. The least efficient is the catalytic pyrolysis oil.

The lifecycle GHG emissions for the three oils are shown in the following Table 53 and compared to the reference fuel. These emissions start with the forest residues in the forest and end with the fuel used in the plane. While the biofuels are considered to be carbon neutral the methane and nitrous oxide emissions must still be included in the combustion emissions and are shown in the fuel use row.

Table 53 GHG Emission Comparison - Canmet

	Jet fuel	**BTG Bio-oil**	**VTT Bio-oil**	**HTL Bio-oil**
	Crude Oil	**Forest Residue**	**Forest Residue**	**Forest Residue**
	g CO_2eq/GJ			
Fuel dispensing	**91**	**95**	**94**	**97**
Fuel distribution and storage	**642**	**626**	**636**	**615**
Fuel production	**6,383**	**93,640**	**85,324**	**73,421**
Feedstock transmission	**78**	**3,186**	**5,196**	**2,397**
Feedstock recovery	**5,647**	**3,789**	**7,484**	**3,156**
Feedstock upgrading	**4,720**	**2,461**	**4,505**	**11,686**
Land-use changes, cultivation	**210**	**12**	**23**	**10**
Fertilizer manufacture	**0**	**0**	**0**	**0**
Gas leaks and flares	**2,280**	**0**	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**	**0**	**0**
Emissions displaced - co-products	**-138**	**-19,425**	**-14,093**	**-9,171**
Fuel Production	**19,913**	**84,384**	**89,170**	**82,211**
Fuel Use	**67,637**	**626**	**626**	**626**
Total	**87,550**	**85,010**	**89,796**	**82,837**
% change		**-2.9**	**2.6**	**-5.4**

4.2.4 Opportunities for Improvements

The only process that could be classified as optimized is the production of the fast pyrolysis oil as it was produced in a commercial demonstration plant, although there are probably still some opportunities for improvements in the process. The production of the other two oils and the two upgrading processes were not optimized at all.

4.2.4.1 Bio-oil Production

There has been some optimization of the HTL system undertaken by NORAM. NORAM developed a preliminary design for a 200 bbl/day HTL plant and hydrotreater. The mass balance is based on assumed product yields for each operation. These assumptions are informed from the engineering assessment of GARDN ATM project test results, published literature, and conversations with technology experts from PNNL and Aarhus University.

One of the features of the design is that there appears to be sufficient fuel gas available from the HTL production process to supply the heat for the process. This eliminates the natural gas requirement which should reduce the GHG emissions for the production of HTL. It is noted that there are still some uncertainties with respect to the design including; gas and aqueous yields and compositions after reaching steady state with recycled water; heat transfer properties (thermal conductivity, viscosity, etc.) of the HTL slurry feed at high temperatures and pressures; testing on actual forestry residue; and wastewater treatment.

The modelling parameters for the 200 bbl/day design are shown in the following Table 54. It is assumed that the system can be operated without the CMC additive. The yield is significantly higher due to the steady state operation but the power requirement is higher than used in the pilot plant. The fuel gas from the system is sufficient to provide the thermal energy.

Table 54 Modelling Parameters – 200 Bbbl/day HTL

Parameter	**Value**
Feedstock, kg/litre	**1.93**
Power, kWh/litre	**0.50**
Natural gas, MJ/litre	**0.0**
Potassium Hydroxide, kg/litre	**0.03**

The GHG emissions for the HTL bio-oil are shown in the following Table 55. The GHG emissions are significantly reduced compared to the pilot plant data.

Table 55 GHG Emissions - 200 Bbl/day HTL

HTL Bio-oil **Forest Residue (g CO_2eq/GJ)**		
	Pilot	**200 Bbl/day**
Fuel dispensing	**0**	**0**
Fuel distribution and storage	**0**	**0**
Fuel production	**15,042**	**2,728**
Feedstock transmission	**2,222**	**1,406**
Feedstock recovery	**3,486**	**2,206**
Feedstock upgrading	**0**	**0**
Land-use changes, cultivation	**11**	**7**
Fertilizer manufacture	**0**	**0**
Gas leaks and flares	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**
Emissions displaced - co-products	**0**	**0**
Fuel Production	**20,761**	**6,347**

In the 200 Bbl/day plant the hydrogen requirements are 0.08 kg H_2/kg biocrude for the upgrading portion of the plant. This is the same rate used in the analysis of the pilot plant data. The upgrading system has power requirements of 0.8 kWh/litre of oil but produces bio-gas from the waste water treatment system of 9.3 MJ/litre of RBO. The GHG emissions for the HTL refined bio-oil are shown in the following Table 56.

Table 56 HTL Refined Bio-oil GHG Emissions - 200 Bbl/day

HTL Bio-oil Forest Residue (g CO_2eq/GJ)		
	Pilot	**200 Bbl/day**
Fuel dispensing	**96**	**96**
Fuel distribution and storage	**652**	**652**
Fuel production	**30,463**	**31,365**
Feedstock transmission	**2,454**	**1,698**
Feedstock recovery	**3,230**	**2,044**
Feedstock upgrading	**11,961**	**2,528**
Land-use changes, cultivation	**10**	**6**
Fertilizer manufacture	**0**	**0**
Gas leaks and flares	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**
Emissions displaced - co-products	**-7,603**	**-13,892**
Fuel Production	**41,263**	**24,496**

If the optimized process design proposed by NORAM is correct, the GHG emissions of the optimized HTL production system may be reduced by almost 40% and are just slightly higher than the refined bio-oil produced from the fast pyrolysis oils with much better wood use efficiency.

4.2.4.2 Upgrading

The Canmet upgrading process is designed to minimize fouling issues with the bio-oil and is still in the development process. For this work the composition of the diluent was design to ensure that there were minimal problems during the test. Canmet believe that surfactant, and the sulphiding agent concentrations could be reduced by at least 50%. There are also other surfactants that could be used that are produced from biomass feedstocks rather than fossil feedstocks. The impacts of these changes on the fast pyrolysis oil system are shown in Table 57.

Table 57 Canmet Optimized Upgrading Fast Pyrolysis

BTG Bio-oil Forest Residue (g CO_2eq/GJ)		
	Base Case	**Optimized**
Fuel dispensing	**95**	**95**
Fuel distribution and storage	**626**	**626**
Fuel production	**93,640**	**75,182**
Feedstock transmission	**3,186**	**3,186**
Feedstock recovery	**3,789**	**3,789**
Feedstock upgrading	**2,461**	**2,461**
Land-use changes, cultivation	**12**	**12**
Fertilizer manufacture	**0**	**0**
Gas leaks and flares	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**
Emissions displaced - co-products	**-19,425**	**-19,425**
Fuel Production	**84,384**	**65,925**

The results are still higher than the PNNL upgrading process but further improvement is probably still possible.

4.2.5Sensitivity Analysis

There is significant uncertainty with the reported results for the different biocrudes and upgrading schemes investigated. None of the results could be considered optimized as generally only one set of operating conditions were evaluated and only enough product for laboratory testing was produced. The impact of two of the most important parameters from a GHG emission perspective are investigated below for the HTL PNNL system.

4.2.5.1 Hydrogen

The largest contributor to the overall GHG emissions from the upgrading stage is the hydrogen consumption. The operating conditions chosen by PNNL were based on their experience with processing similar oils in the past but in a real-world situation the hydrogen consumption could be higher or lower depending on the catalysts used, the operating conditions and the efficiency of the recovering and recycling of the excess hydrogen processed through the system.

The impact of varying hydrogen requirements from 50 to 150% of the base value used for modelling (0.10 kg/litre refined bio-fuel) is shown in the following Figure 36. The impact is significant.

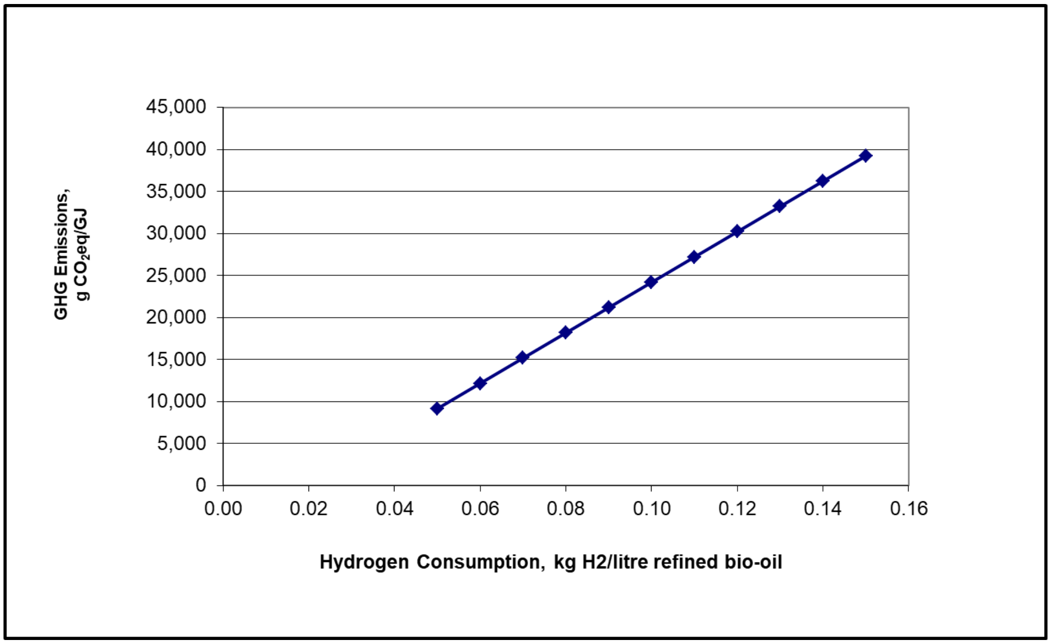


Figure 36 Sensitivity to Hydrogen Consumption

4.2.5.2 Fuel Gas

The 200 bbl/day design is based on the assumption that the fuel gas can supply the thermal energy requirements for the HTL process. If this is not the case and some natural gas is required to maintain the reactor temperature, then the emissions will be higher. The impact of supplementing the fuel gas with natural gas is shown in Figure 37. The impact is smaller than the hydrogen impact.

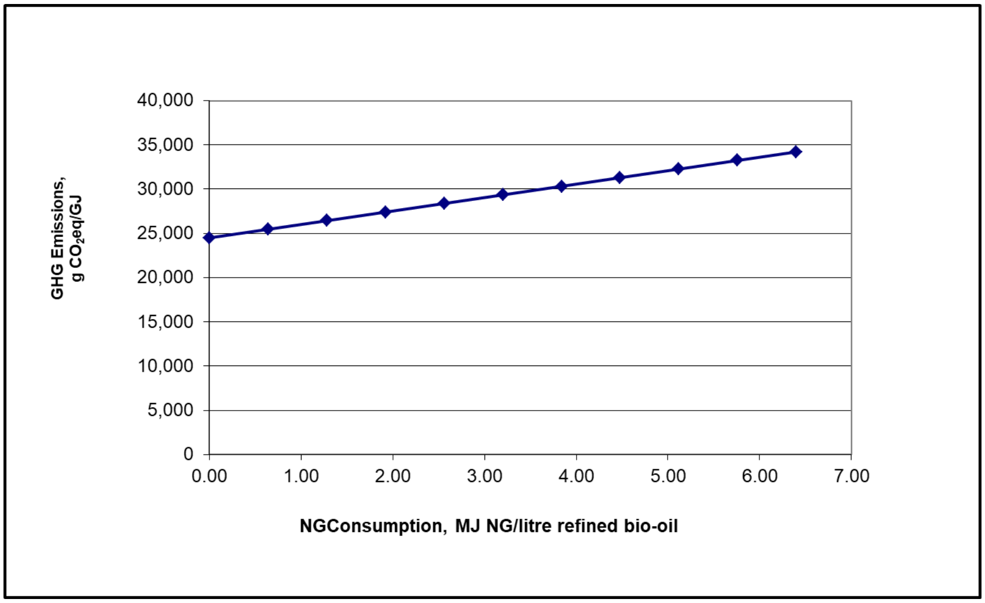


Figure 37 Sensitivity to Natural Gas Use

The impact of both variables is shown in Figure 38.

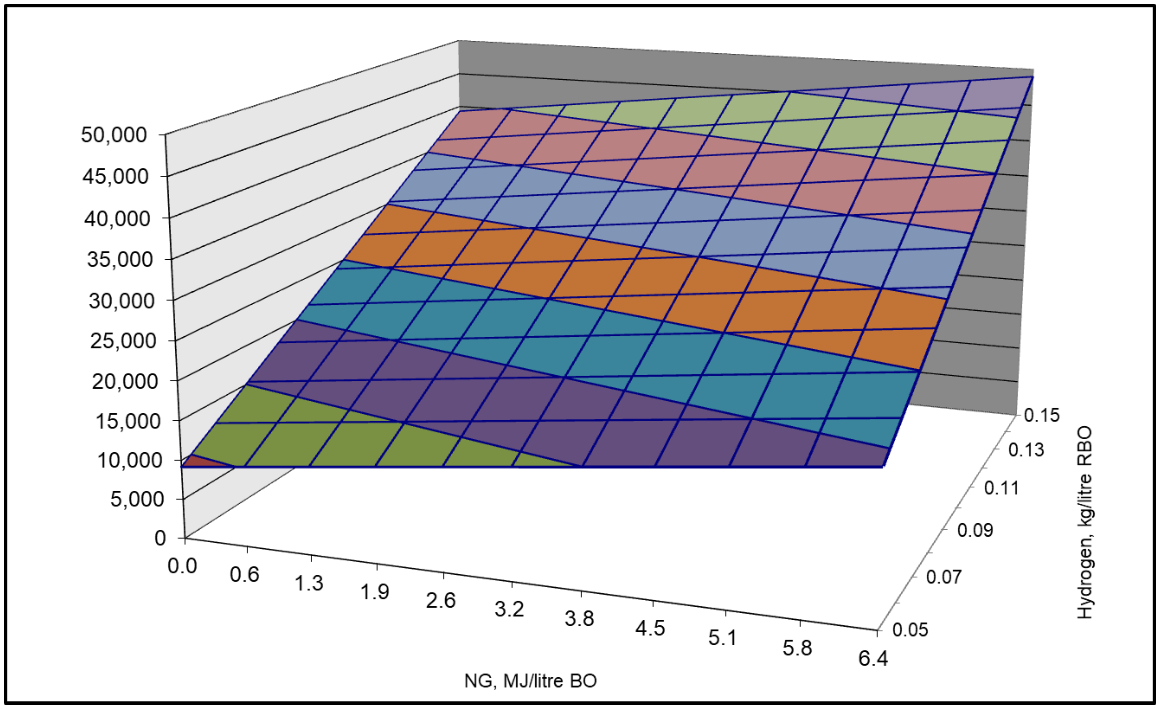


Figure 38 Sensitivity to Both Variables

4.2.6 Discussion of LCA Results

The lowest GHG emissions are produced by the fast pyrolysis oil system although there is more opportunity for improvements in the other systems as they are at earlier stages of development. The development work undertaken for the 200 Bbl/day HTL system suggests that it can produce GHG emissions at the same level as the fast pyrolysis system, although there is some uncertainty associated with the 200 Bbl/day design, particularly around the heating value of the off-gas.

The PNNL hydrotreating system results in lower GHG emissions than the Canmet system. The chemicals that are added to the Canmet system have a significant impact on the GHG emissions of the refined bio-oil as they are not recovered and recycled. When the dosage rates are compared to the bio-oil almost 0.75 kg of chemicals are added for every kg of refined bio-oil produced. In addition to the negative impact on the GHG emissions it is likely to have an unattractive cost.

The GHG emissions for the refined bio-oil systems, using the PNNL approach, show up to a 75% reduction in GHG emissions compared to fossil jet fuel. These large emission reductions are achieved by the fast pyrolysis system and the optimized HTL system. The emissions summary is shown in Table 58.

Table 58 GHG Emission Comparison

	Jet fuel	**BTG Bio-oil**	**VTT Bio-oil**	**HTL Bio-oil**	
	Crude Oil	**Forest Residue**			
				Pilot	**Forecast 200 Bbl/day**
	g CO_2eq/GJ				
Fuel dispensing	**91**	**95**	**94**	**96**	**96**
Fuel distribution and storage	**642**	**626**	**636**	**652**	**652**
Fuel production	**6,383**	**51,617**	**28,467**	**30,463**	**31,365**
Feedstock transmission	**78**	**3,892**	**5,446**	**2,454**	**1,698**
Feedstock recovery	**5,647**	**4,629**	**7,843**	**3,230**	**2,044**
Feedstock upgrading	**4,720**	**3,006**	**4,722**	**11,961**	**2,528**
Land-use changes, cultivation	**210**	**14**	**24**	**10**	**6**
Fertilizer manufacture	**0**	**0**	**0**	**0**	**0**
Gas leaks and flares	**2,280**	**0**	**0**	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**	**0**	**0**	**0**
Emissions displaced - co-products	**-138**	**-42,038**	**-10,846**	**-7,603**	**-13,892**
Fuel Production	**19,913**	**21,841**	**36,386**	**41,263**	**24,496**
Fuel Use	**67,637**	**626**	**626**	**626**	**626**
Total	**87,550**	**22,467**	**37,027**	**42,889**	**25,112**
% change		**-74.3**	**-57.7**	**-51.0**	**-71.3**

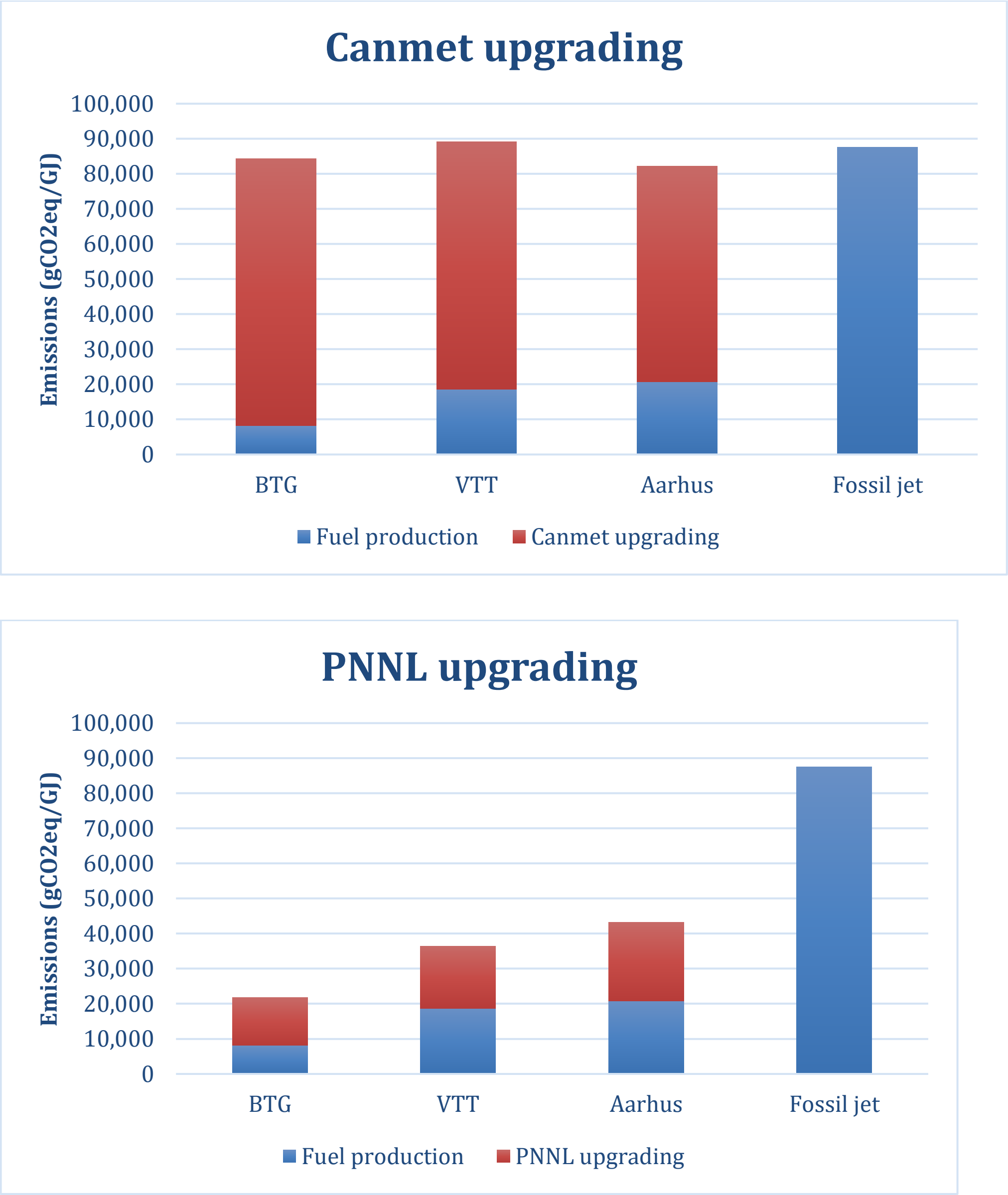


Figure 39 Emissions for fuel production and upgrading pathways relative to fossil jet fuel

4.2.7 Impact of avoided slash burning emissions on LCA results

As noted earlier, the feedstocks that would be used for these processes are currently burned in the forest. Due to the poor combustion characteristics of the open pile burning there are significant GHG emissions associated with this practice. If the avoided emissions from the current practice are applied to the biojet fuel systems the overall processes look very different from a GHG emission perspective. The impact on the base case and the optimized HTL systems are shown in Table 59.

Table 59 HTL Refined Bio-oil GHG Emissions – Avoided Forest Burning Emissions

	HTL Bio-oil	
	Forest Residue	
	Pilot	**200 Bbl/day**
	g CO_2eq/GJ	
Fuel dispensing	**96**	**96**
Fuel distribution and storage	**652**	**652**
Fuel production	**30,463**	**31,365**
Feedstock transmission	**2,454**	**1,698**
Feedstock recovery	**3,230**	**2,044**
Feedstock upgrading	**13,936**	**2,528**
Land-use changes, cultivation	**10**	**6**
Fertilizer manufacture	**0**	**0**
Gas leaks and flares	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**
Emissions displaced - co-products	**-27,687**	**-26,600**
Fuel Production	**23,154**	**11,787**

The emission profile of the optimized 200 Bbl/day plant now indicates an 86% reduction in GHG emissions compared to fossil jet fuel on a full lifecycle basis. The improvement on some of the other pathways will be even larger since they require more feedstock per unit of fuel produced and thus will have even higher avoided GHG emission reductions.

The other two biocrude oils consume more feedstock per unit of refined bio-oil produced and thus the avoided emissions are greater. Since the avoided emissions are greater than the collection and processing emissions there is effectively a GHG incentive for the less efficient conversion processes. The GHG emissions for the BTG and VTT oils upgraded using the PNNL approach are shown in the following table.

Table 60 Avoided Forest Burning Emissions – BTG and VTT Refined Bio-Oil

	BTG	**VTT**
	Forest Residue	
	g CO_2eq/GJ	
Fuel dispensing	**95**	**94**
Fuel distribution and storage	**626**	**636**
Fuel production	**51,617**	**28,467**
Feedstock transmission	**3,892**	**5,446**
Feedstock recovery	**4,629**	**7,843**
Feedstock upgrading	**3,006**	**4,722**
Land-use changes, cultivation	**14**	**24**
Fertilizer manufacture	**0**	**0**
Gas leaks and flares	**0**	**0**
CO_2, H_2S removed from NG	**0**	**0**
Emissions displaced - co-products	**-70,822**	**-59,620**
Fuel Production	**-6,943**	**-12,388**

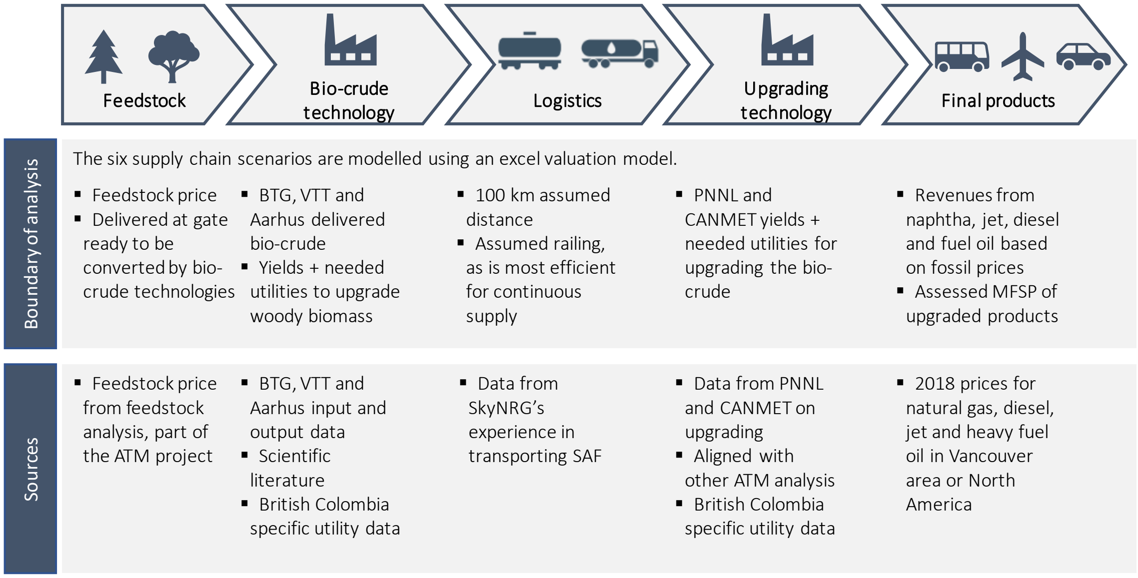
The inclusion of the avoided slash burning emissions results in negative emissions for both of these pathways due to the low conversion of the feedstock to refined bio-oil. The high feedstock use has negative implications for the economics and the total quantity of fuel that can be produced.

CHAPTER 5 – TECHNO-ECONOMIC ANALYSIS

This Techno-Economic Assessment (TEA) was developed as part of the ATM project. The purpose of this work was to assess the techno-economic performance of six pathways as outlined in the Background section. These pathways are based on the combination of the three different biocrude production technologies and two (hydrotreating) upgrading technologies, as has been already detailed in previous sections of this report.

Although none of the pathways are currently ASTM certified for use in commercial aviation, the TEA assumes the fuel (naphtha, jet, diesel and fuel oil) could be delivered to its final markets. As discussed in Chapter 3 biocrude production and upgrading was not optimized and upgraders used existing protocols for hydrotreatment. Maximum jet fuel production was not specifically targeted, but rather maximum production of total upgraded products. Further optimization of upgrading will be required to meet exact specifications of fuel products. This TEA will focus on the total volume of the upgraded bio-oil products (jet, diesel and the heavy fraction) and assess the parameters influencing the pathways and finding promising pathways with potential for further (technical) development.

Figure 40 shows the set-up of the TEA model and the main boundaries and sources used as input for the assumptions. In the next section the main assumptions and output components of the TEA will be further elaborated upon. This is followed by detailed results of each pathway and concluded by final recommendations for further research.



	Feedstock	Bio-crude technology	Logistics	Upgrading technology	Final products
Boundary of analysis	The six supply chain scenarios are modelled using an excel valuation model.				
	▪ Feedstock price ▪ Delivered at gate ready to be converted by bio-crude technologies	▪ BTG, VTT and Aarhus delivered bio-crude ▪ Yields + needed utilities to upgrade woody biomass	▪ 100 km assumed distance ▪ Assumed railing, as is most efficient for continuous supply	▪ PNNL and CANMET yields + needed utilities for upgrading the bio-crude	▪ Revenues from naphtha, jet, diesel and fuel oil based on fossil prices ▪ Assessed MFSP of upgraded products
Sources	▪ Feedstock price from feedstock analysis, part of the ATM project	▪ BTG, VTT and Aarhus input and output data ▪ Scientific literature ▪ British Colombia specific utility data	▪ Data from SkyNRG's experience in transporting SAF	▪ Data from PNNL and CANMET on upgrading ▪ Aligned with other ATM analysis ▪ British Colombia specific utility data	▪ 2018 prices for natural gas, diesel, jet and heavy fuel oil in Vancouver area or North America

Figure 40 Schematic representation of the supply chain and most important sources used

5.1 Assumptions

The TEA assumes a business case timing of 20 years from the start of operation. The financial parameters shown in Table 61 are used in the model and are based on international industry standards. The model assumes 90% operational time. Two tax rates are applicable in Canada: federal taxes (15%) and provincial taxes (12% in BC), for an overall corporate tax rate of 27%. Other general assumptions are shown below:

Table 61. General financial parameters

Parameter	**Value**	**Unit**
Plant Lifetime	**20**	**year**
Depreciation period	**20**	**year**
Debt share	**20%**	**%**
Equity share	**80%**	**%**
Duration debt payment	**10**	**years**
Corporate Tax rate	**27%**	
Discount rate	**10%**	
Interest rate on debt	**8%**	
Working Capital	**5%**	
Operational time	**90%**	

The capital costs of the facilities were estimated based on a number of different sources. The scale of the facilities was based on the feedstock input scale of 300,000 oven-dried tonnes (odt) of forest residues and yields for biocrude and upgraded product. CAPEX numbers were taken from literature or based on current demonstration facilities and a scaling factor of 0.6 was used. The CAPEX includes material, installation costs and capital required for utilities surrounding the facility. For the HTL facility, a more intensive demonstration facility design was conducted by NORAM in Chapter 6, which included a waste water treatment facility. The BTG pyrolysis plant was scaled based on the actual cost of the pilot facility built in the Netherlands. The VTT catalytic pyrolysis plant was assumed to have the same CAPEX as the fast pyrolysis plant, as literature on the catalytic fast pyrolysis is limited and the process is very similar in terms of the equipment and processes.

For the upgrading the CAPEX value for hydrotreatment as assessed by NORAM in Chapter 6 was used and scaled. The two upgrading processes of PNNL & CANMET are not the same, as CANMET used a co-processing approach with conventional fuel oil while PNNL used a dedicated hydrotreatment approach. The co-processing approach would therefore need a significantly (5x) larger facility, however due to a faster residence time the plant can be scaled down as well (by 1.28x). Only the equipment cost of the hydrotreatment unit (excl. fractionation and hydrogen supply) are assumed to scale, representing 53% of total costs, the capacity scaling factor of 0.6 was used as well. This results in the CANMET CAPEX being 22% higher than PNNL's.[25]

Furthermore, due to the different yields of the biocrude processes there is a need to scale the CAPEX values for the hydrotreatment facility between the three biocrudes as well. We therefore distinguish between thee upgrading CAPEX values for each of the upgrading processes. CAPEX assumptions are summarised in Table 62.

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[25] The CAPEX for Canmet-Energy upgrading was calculated by scaling the PNNL estimate using a simple capacity factor. Other differences between the processes were not taken into account. Therefore a significant margin of error could exist for this calculation.

Table 62. CAPEX assumptions

Biocrude CAPEX	**Value**	**Unit**	**Source**
HTL Aarhus	**134,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**
BTG Fast Pyrolysis	**106,000,000**	**CAD**	**Based on their small commercial facility (NL) costs + scale**
VTT Catalytic Pyrolysis	**106,000,000**	**CAD**	**As catalytic fast pyrolysis is assumed similar as the fast pyrolysis process, same CAPEX as BTG is assumed**
Upgrading CAPEX			
Upgrading PNNL - HTL	**54,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**
Upgrading PNNL - Fast Pyrolysis	**73,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**
Upgrading PNNL - Catalytic Pyrolysis	**34,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**
Upgrading CANMET – HTL	**65,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**
Upgrading CANMET – Fast Pyrolysis	**89,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**
Upgrading CANMET – Catalytic Pyrolysis	**41,000,000**	**CAD**	**Scaled from modelled facility ATM project (NORAM, Chapter 6)**

The three biocrude production processes and upgrading paths were detailed in Chapter 3. As not all information was available to execute the TEA, the following assumptions were made regarding the processes:

- It is assumed that the gas produced in the biocrude processes can be used to heat the process and no additional external heating is necessary.
- The HTL process yields water that needs processing and thus additional waste water treatment costs are included.
- Although the HTL process requires water, it is assumed that the feedstock contains enough water, so no additional fresh water is inserted in the system.
- The catalysts used for the processes are included as utility input. KOH for HTL and ZSM-5 for the catalytic pyrolysis process were used as catalysts.

An important value for this TEA is the biocrude production yield from the woody biomass, shown in Table 63.

Table 63. Biocrude production yields from woody biomass

Process	**Value**	**Unit**	**Source**
HTL Aarhus	**0.38**	**Kg Biocrude/Kg Feedstock**	**Process values from tests at Aarhus**
BTG Pyrolysis	**0.64**	**Kg Biocrude/Kg Feedstock**	**Process value, from literature**
VTT Catalytic Pyrolysis	**0.18**	**Kg Biocrude/Kg Feedstock**	**Process value, from literature**

The biocrudes are upgraded in the model by a hydroprocessing facility, assumed to be in the Vancouver area and co-located with an existing refinery. Both PNNL and CANMET have upgraded the three biocrude sources into a hydrocarbon mixture of different fuel fractions which can be separated by distillation. Hydrotreating of the biocrudes also produce gas and aqueous-phase liquid. The aqueous phase is assumed to be disposed in the waste water treatment facility of the refinery, and no additional CAPEX is assumed. The gas is assumed to be sold at an equivalent price to natural gas. The yields of the 6 pathways are shown in Table 64-69.

The values for CANMET (*) are based on the bio-carbon fractions. CANMET uses a fossil fuel as a diluent during upgrading (Chapter 3), which caused measurement irregularities in its yield from the biocrude. By tracking the biocarbon (C14 analysis) the mass percentage yields were estimated.

Table 64. Yields upgrading PNNL-HTL

Yields from biocrude	**Value (wt%)**
Oil-phase liquids	**70.20%**
Aqueous-phase liquids	**19.30%**
Gas	**9.70%**
Distillation cuts from oil-phase	
Naphtha (lights)	**18.80%**
Jet fuels	**22.90%**
Diesel (heavy middle distillates)	**28.80%**
Heavy fuel oil	**29.50%**

Table 65. Yields upgrading PNNL-Pyrolysis (BTG)

Yields from biocrude	**Value (wt%)**
Oil-phase liquids	**29.40%**
Aqueous-phase liquids	**43.90%**
Gas	**25.20%**
Distillation cuts from oil-phase	
Naphtha (lights)	**30.40%**
Jet fuels	**24.70%**
Diesel (heavy middle distillates)	**24.40%**
Heavy fuel oil	**20.50%**

Table 66. Yields upgrading PNNL-Catalytic Pyrolysis (VTT)

Yields from biocrude	**Value (wt%)**
Oil-phase liquids	**61.60%**
Aqueous-phase liquids	**27.10%**
Gas	**10.40%**
Distillation cuts from oil-phase	
Naphtha (lights)	**27.00%**
Jet fuels	**36.60%**
Diesel (heavy middle distillates)	**25.60%**
Heavy fuel oil	**10.30%**

Table 67. Yields upgrading CANMET-HTL

Yields from biocrude	**Value (wt%)**
Oil-phase liquids	**72.2%***
Aqueous-phase liquids	**17.40%***
Solids	**9.30%***
Gas	**1.10%***
Distillation cuts from oil-phase	
Naphtha (lights)	**2.70%***
Jet fuels	**29.80%***
Diesel (heavy middle distillates)	**40.50%***
Heavy fuel oil	**26.90%***

Table 68. Yields upgrading CANMET-Pyrolysis (BTG)

Yields from biocrude	**Value (wt%)**
Oil-phase liquids	**37.30%***
Aqueous-phase liquids	**52.40%***
Solids	**1.20%***
Gas	**9.10%***
Distillation cuts from oil-phase	
Naphtha (lights)	**19.60%***
Jet fuels	**19.80%***
Diesel (heavy middle distillates)	**47.30%***
Heavy fuel oil	**13.30%***

Table 69. Yields upgrading CANMET-Catalytic Pyrolysis (VTT)

Yields from biocrude	**Value (wt%)**
Oil-phase liquids	**69.10%***
Aqueous-phase liquids	**25.00%***
Solids	**2.60%***
Gas	**3.30%***
Distillation cuts from oil-phase	
Naphtha (lights)	**15.50%***
Jet fuels	**32.80%***
Diesel (heavy middle distillates)	**34.90%***
Heavy fuel oil	**20.20%***

Revenues

Fossil values: The revenue for the fuel products is based on the refinery gate with no further logistics assumed towards the final markets. Current values of fossil fuel products, based on a 2018 average, are shown in Table 70.

Table 70. Fossil value prices

Product	Value	Unit	Source
Light gases	**220**	**CAD/MT**	**Assumed natural gas value for the gases produced in this project. Based on estimated Vancouver values in 2018**
Jet fuel	**855**	**CAD/MT**	**Based on US Gulf Coast average 2018 corrected for currency**
Diesel	**720**	**CAD/MT**	**Based on Vancouver values in 2018**
Heating oil	**733**	**CAD/MT**	**Based on Vancouver values in 2018**

Premium: In the analyses of the Minimal Fuel Selling Price (MFSP) and the Profit & Loss statements the premium required to return an NPV of 0 is calculated. This premium shows the needed value per MT of upgraded fuel products to make a financeable business case. The premium could in reality consist of both governmental programs or a voluntary premium on the fuel; this is not specified. It is important to note that an average value for the upgraded fuel is used, while in reality the premium per type of fuel may differ. An optimized pathway in which we show the potential of a potential opt-in system for aviation under the British Columbian Low Carbon Fuel standard program is shown at the end of the results section. The premium was calculated based on the LCA performance and the 2018 credit value of CAD200/Credit. This is shown in the final section of the results.

Costs

Feedstock: A feedstock price of CAD80/ODT, delivered to the refinery gate, was used based on the assessment in Chapter 2. This price includes transport and comminution, and feedstock is therefore ready to be inserted in the system without further pre-treatment.

Hydrogen: The hydrogen price used in the model (3,019 CAD/MT) is based on the Pedersen report (2018) and verified by the IEA (2006) and US Drive (2017) reports. This price is based on using Steam Methane Reforming (SMR) technology and a natural gas price of 210 CAD/MT. The sensitivity analysis is carried out with a 50% increase of this price to 4,528 CAD/MT. If electrolysis was used to produce the hydrogen, an electricity price as low as 0.05 CAD/kWh will be required to reach the max price of 4,528 CAD/MT[26].

Catalysts: The catalysts necessary in the biocrude processes are KOH and ZSM-5, with CMC used in the HTL process to achieve consistent viscosity (this will not be required at large scale). The prices for the various catalysts are retrieved from industrial values, corrected for the currency.

Transport The transport of the biocrude towards the upgrading facility is assumed to be 750 km. Using rail as a mode of transport the costs are estimated at 26 CAD/MT.

There are some additional operational costs to run the two facilities (both biocrude and upgrading facility) (Table 71&Table 72).

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[26] https://www.hydrogen.energy.gov/pdfs/14004_h2_production_cost_pem_electrolysis.pdf

Table 71. Utility prices assumed

Parameter	**Value**	**Unit**
Electricity	**0.07**	**CAD/kWh**
Natural Gas Price	**220**	**CAD/MT**
Water price	**0.06**	**CAD/M3**
Waste Water Treatment	**0.73**	**CAD/MT**

Table 72. Other fixed operational costs.

Element	**Value**	**Unit**	**Source**
Operating labor	**20**	**CAD/MT**	**Other TEA´s used (PNNL, SkyNRG 2017, Jones et al. 2013)**
Maintenance	**4%**	**% of CAPEX**	**Industry values for TEA**
Overhead	**2%**	**% of CAPEX**	**Industry values for TEA**
Insurances, permits and local taxes	**3%**	**% of CAPEX**	**Industry values for TEA**

5.2 Results

The performance of each pathway is discussed according to three metrics: the Minimum Fuel Selling Price (MFSP), Profit & Loss statement (P&L) and a sensitivity analysis, discussed in more detail below.

Profit & Loss Statement: The P&L will show the main revenue and costs components of the process. This will also give an indication of the profitability of the process. It is important to note that this P&L is generated with an NPV of 0, as with the MFSP method explained below.

MFSP: The contribution of each cost element (e.g. feedstock, utilities, CAPEX, etc.) is summed towards a total minimal fuel selling price (MFSP) of the hydrotreated biocrude (jet, diesel and fuel oil). The results are presented in a waterfall graph to show the relative contribution of each element. Each cost component is summed and averaged over the lifetime of the plant and calculated per metric tonne (MT) of upgraded biocrude product. As none of the cases can currently compete with the fossil prices, the NPV is set to 0 by using 'Goal Seek' and adjusting the price premium until the NPV is found to be 0.

NPV & Sensitivities: The net present value (NPV) is used as an indicator of the economic viability of the six different pathways. The NPV method is a valuation tool that calculates how much value a project adds with regards to the investment made in the project. To get the NPV, the future cash flows of the project's lifetime are discounted for the devaluation of money over time. The sum of these discounted cashflows (including the investment in year 0), results in the NPV. The influence of the most important assumptions is tested on the NPV by using the following percentual changes. Where the min case is the worst case and the max case is the best-case scenario.

Assumption	Worst - case	Best - case
CAPEX biocrude	**50%**	**-50%**
CAPEX upgrading	**50%**	**-50%**
Yield biocrude from woody biomass	**-30%**	**30%**
Feedstock costs	**25%**	**-50%**
Hydrogen costs	**50%**	**-50%**
Hydrotreatment catalyst	**50%**	**-50%**

Before further discussion of the specific results of each pathway it is important to note that results from single data sets were used to compile this report. The various pathways, both biocrude production and upgrading, are still in development and extensive optimization is likely to take place over time. Technologies for biocrude production and (co-processed) upgrading are also not all at the same level of technological readiness and thus caution should be used in drawing rigid conclusions. Looking at the overall techno-economic performance of the various pathways it is apparent that they are significantly influenced by the overall performance of the combined yield from woody biomass to upgraded oil products. The HTL pathway combined with the PNNL and CANMET upgrading process performed best with an overall efficiency of 27%, see Table 73 below.

Table 73. Overall yields in wt% of biocrude production and upgrading

PNNL			
	Bio-crude	**Upgrading**	**Total**
HTL (Aarhus)	38%	70%	27%
Fast Pyro (BTG)	64%	29%	19%
Cat Pyro (VTT)	18%	62%	11%

CANMET			
	Bio-crude	**Upgrading**	**Total**
HTL (Aarhus)	38%	72%	27%
Fast Pyro (BTG)	64%	37%	24%
Cat Pyro (VTT)	18%	69%	12%

5.2.1 HTL – PNNL pathway

Producing biocrude with the HTL technology and upgrading with PNNL's process is the overall best performing pathway. This can be attributed to the highest combined yield from woody feedstock towards upgraded oil products (27% red.). This results in significant income based on a fossil-equivalent price as well as a high impact on the business case when adding a premium on the fuel products. Due to the more robust HTL biocrude process there is an initial lower wood to biocrude yield (38%), however also a relatively low oxygen content (15%). This reduces the volume of biocrude to be transported between the biocrude facility (close to the forest) and the upgrading facility (Vancouver area). Due to the low oxygen content, the hydrogen use is therefore reduced in this pathway. The main cost contributors compared to the other pathways is the high CAPEX, which is also reflected in the 'other fixed costs' category, which is almost 14 million CAD per year. A profit and loss (P&F) analysis over a 5-year period is shown in Table 74.

Table 74. P&L first 5 years HTL + PNNL pathway – based on a yearly 300,000 ODT feedstock input and 73,000 MT upgraded fuel output.

			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues								
Revenue from fossil products		CAD	-	25,137,133	50,274,266	50,274,266	50,274,266	50,274,266
Revenue from price premium on products		CAD	-	31,826,920	63,653,840	63,653,840	63,653,840	63,653,840
Total revenues		**CAD**	**-**	**56,964,053**	**113,928,107**	**113,928,107**	**113,928,107**	**113,928,107**
Costs								
Feedstock (	Feed	CAD	-	10,800,000	21,600,000	21,600,000	21,600,000	21,600,000
Electricity	Bio-crude	CAD	-	848,269	1,696,538	1,696,538	1,696,538	1,696,538
Natural gas	Bio-crude	CAD	-	-	-	-	-	-
Water	Bio-crude	CAD	-	-	-	-	-	-
Catalysts	Bio-crude	CAD	-	2,706,808	5,413,616	5,413,616	5,413,616	5,413,616
Waste wat	Bio-crude	CAD	-	83,872	167,744	167,744	167,744	167,744
Other fixed	Bio-crude	CAD	-	13,004,562	13,913,422	13,913,422	13,913,422	13,913,422
Transport	Bio-crude - Hydroupgrading	CAD	-	1,346,887	2,693,773	2,693,773	2,693,773	2,693,773
Hydrogen	Hydroupgrading	CAD	-	12,329,977	24,659,955	24,659,955	24,659,955	24,659,955
Catalysts	Hydroupgrading	CAD	-	3,589,300	3,589,300	3,589,300	3,589,300	3,589,300
Other fixed	Hydroupgrading	CAD	-	5,728,803	6,637,663	6,637,663	6,637,663	6,637,663
Total costs		**CAD**	**-**	**(50,438,477)**	**(80,372,010)**	**(80,372,010)**	**(80,372,010)**	**(80,372,010)**
EBITDA		CAD	-	6,525,576	33,556,097	33,556,097	33,556,097	33,556,097
Depreciation		CAD	-	9,397,580	9,397,580	9,397,580	9,397,580	9,397,580
EBIT		CAD	-	(2,872,005)	24,158,516	24,158,516	24,158,516	24,158,516
Interest		CAD	(3,946,984)	(3,552,285)	(3,157,587)	(2,762,889)	(2,368,190)	(1,973,492)
EBT		CAD	(3,946,984)	(6,424,290)	21,000,929	21,395,628	21,790,326	22,185,024
Taxes		CAD	-	-	(5,670,251)	(5,776,819)	(5,883,388)	(5,989,957)
Net result		**CAD**	(3,946,984)	(6,424,290)	15,330,678	15,618,808	15,906,938	16,195,068

The HTL-PNNL pathway, considering no premium value, yields a negative NPV of CA$465,966,949, where the most influential factor is the CAPEX of the biocrude section (Table 41). This is mainly due to the process conditions (high temperature and high pressure) and the fact that the HTL CAPEX includes a more expensive waste-water treatment unit. The feedstock and hydrogen prices are also quite influential on the case. Although the yield of the biocrude process seems to have a limited influence, when adding a premium in the TEA, this sensitivity is increased and has a significant impact as well.

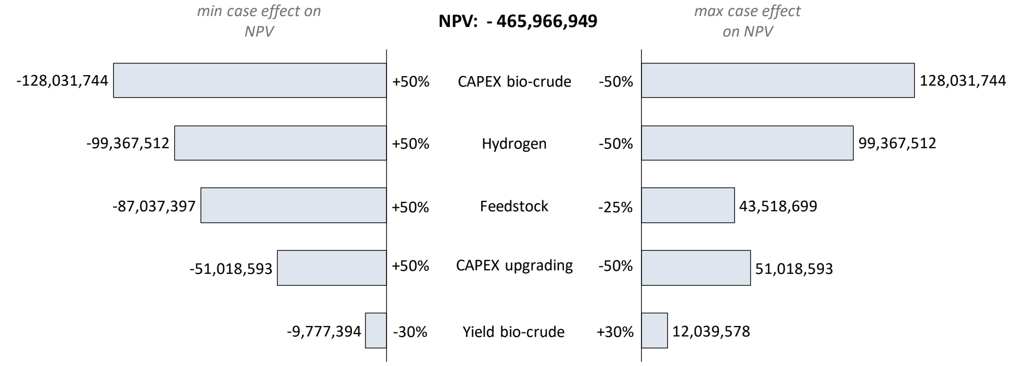

Figure 41. NPV Sensitivity of HTL + PNNL pathway – based on a yearly 300,000 ODT feedstock input and 73,000 MT upgraded fuel output.

The MFSP for this pathway is shown in Figure 42. The large contribution of the feedstock costs, hydrogen costs as well as the effect of the large CAPEX costs (on other fixed costs and interest) can clearly be seen. The MFSP of this process comes down to 1,724 CAD/MT upgraded oil products. This results in an average premium of 963 CAD/MT. Although expensive, it is the most positive pathway in this research and comparable with the current sustainable aviation fuel projects in the market.

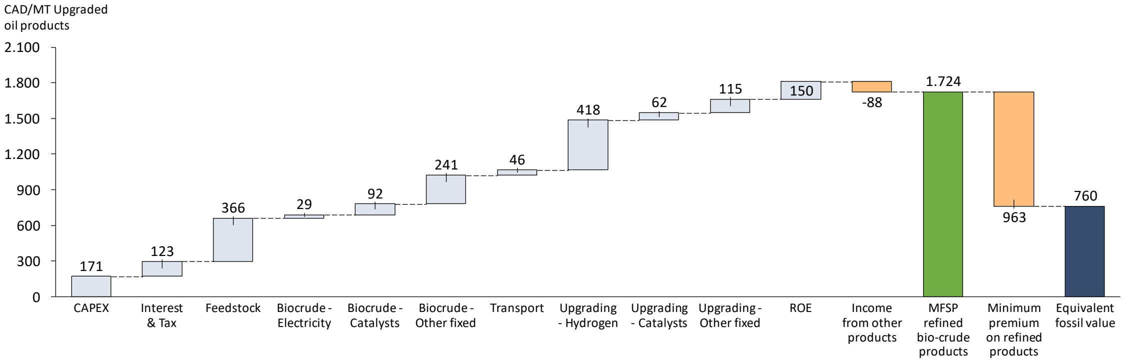

Figure 42. MFSP of HTL + PNNL pathway

5.2.2 Fast pyrolysis (BTG) – PNNL

When using the PNNL upgrading process on the fast pyrolysis biocrude of BTG, there are significant differences observed in the TEA analysis. This is as a result of the combined yield from woody feedstock towards upgraded oil products being significantly lower than the HTL pathway (19% red.). This is in spite of the fact that the initial conversion of woody biomass to biocrude has a very high yield (64%). However, the biocrude still contains significant amounts of oxygen (47.5%), which causes the transport to the upgrading facility to be inefficient and more expensive. To remove the oxygen with the hydrotreating process, more hydrogen per MT of upgraded product is needed. A significant cost saver with the BTG process is the absence of catalysts during biocrude production and the absence of waste water treatment.

Table 75. P&L first 5 years Pyrolysis (BTG) + PNNL pathway – based on a yearly 300,000 ODT feedstock input and 51,000 MT upgraded fuel output.

			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues								
Revenue from fossil products		CAD	-	20,056,702	40,113,405	40,113,405	40,113,405	40,113,405
Revenue from price premium on products		CAD	-	35,493,473	70,986,945	70,986,945	70,986,945	70,986,945
Total revenues		**CAD**	**-**	**55,550,175**	**111,100,350**	**111,100,350**	**111,100,350**	**111,100,350**
Costs								
Feedstock (	Feed	CAD	-	10,800,000	21,600,000	21,600,000	21,600,000	21,600,000
Electricity	Bio-crude	CAD	-	720,215	1,440,430	1,440,430	1,440,430	1,440,430
Natural gas	Bio-crude	CAD	-	-	-	-	-	-
Water	Bio-crude	CAD	-	-	-	-	-	-
Catalysts	Bio-crude	CAD	-	-	-	-	-	-
Waste wat	Bio-crude	CAD	-	-	-	-	-	-
Other fixed	Bio-crude	CAD	-	10,172,195	10,803,963	10,803,963	10,803,963	10,803,963
Transport	Bio-crude - Hydroupgrading	CAD	-	2,235,534	4,471,068	4,471,068	4,471,068	4,471,068
Hydrogen	Hydroupgrading	CAD	-	14,750,988	29,501,977	29,501,977	29,501,977	29,501,977
Catalysts	Hydroupgrading	CAD	-	3,589,300	3,589,300	3,589,300	3,589,300	3,589,300
Other fixed	Hydroupgrading	CAD	-	7,164,157	7,795,925	7,795,925	7,795,925	7,795,925
Total costs		**CAD**	**-**	**(49,432,390)**	**(79,202,663)**	**(79,202,663)**	**(79,202,663)**	**(79,202,663)**
EBITDA		CAD	-	6,117,785	31,897,687	31,897,687	31,897,687	31,897,687
Depreciation		CAD	-	8,929,342	8,929,342	8,929,342	8,929,342	8,929,342
EBIT		CAD	-	(2,811,557)	22,968,344	22,968,344	22,968,344	22,968,344
Interest		CAD	(3,750,324)	(3,375,291)	(3,000,259)	(2,625,227)	(2,250,194)	(1,875,162)
EBT		CAD	(3,750,324)	(6,186,849)	19,968,085	20,343,118	20,718,150	21,093,183
Taxes		CAD	-	-	(5,391,383)	(5,492,642)	(5,593,901)	(5,695,159)
Net result		**CAD**	(3,750,324)	(6,186,849)	14,576,702	14,850,476	15,124,250	15,398,023

Looking at the sensitivity of the NPV of the fast pyrolysis pathway, a higher dependency on the hydrogen for upgrading is observed. Together with this additional hydrogen requirement, the sensitivity towards upgrading CAPEX becomes more apparent due to the larger scale upgrading facility required to deal with the larger amount of biocrude to be upgraded compared to the HTL pathway.

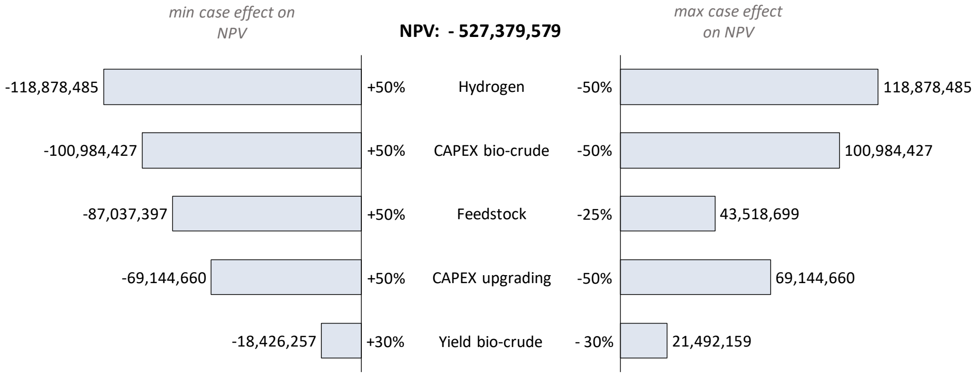

Figure 43. NPV sensitivity analysis of pyrolysis (BTG) + PNNL – based on a yearly 300,000 ODT feedstock input and 51,000 MT upgraded fuel output.

Figure 44 shows the MFSP of the BTG + PNNL pathway, at CAD2,518 this fuel is about 3.5 times the price of the fossil equivalent. Although this is more expensive than the HTL pathway, it is still reasonable compared with many other alternative fuel pathways. Especially, considering the lack of optimization in the current study. Due to the lower overall yield, compared with the HTL case, all components are more expensive per MT. As the oxygen content is quite high in this biocrude, it is important to focus development on the reduction of this content to reduce hydrogen and transport costs.

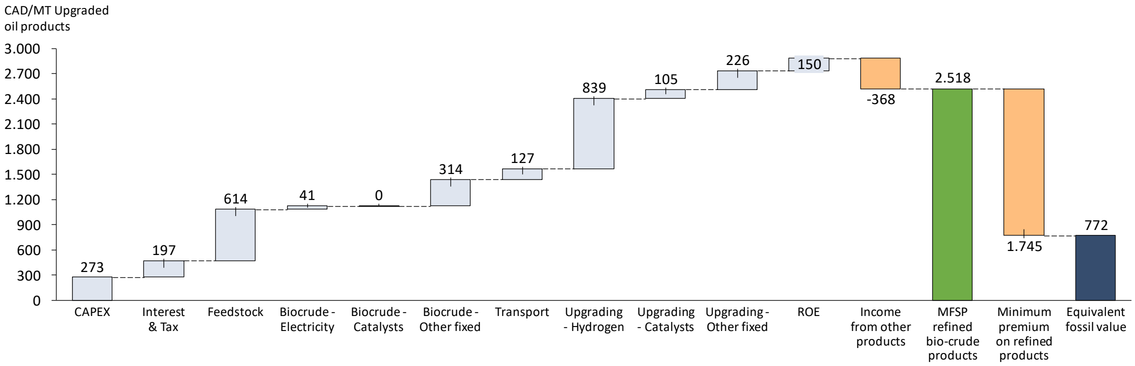

Figure 44. MFSP of BTG + PNNL pathway

5.2.3 Catalytic pyrolysis (VTT) – PNNL

Compared to the other two pathways, the catalytic pyrolysis process has a significantly lower upgraded biocrude output. With an overall wood to upgraded biocrude yield of 11% the overall amount of product that can be sold on the market is significantly lower than the two other pathways. This is reflected in the P&L analysis below in both low revenues from fossil products as well as overall lower cost and revenues. The low costs are a result of the lower amount of biocrude to be upgraded, creating lower transport and hydrogen costs. An important factor with the catalytic fast pyrolysis process is the price of the catalyst used to create the biocrude - the ZSM-5 catalyst is quite expensive (11,2 CAD/kg considered in this research). This creates significant additional costs to the project. For future development, it is important to assess the possibility for lowering the requirement or price of this catalyst.

Table 76. P&L Catalytic pyrolysis (VTT) + PNNL pathway – based on a yearly 300,000 ODT feedstock input and 30,000 MT upgraded fuel output.

			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues								
Revenue from fossil products		CAD	-	9,937,090	19,874,181	19,874,181	19,874,181	19,874,181
Revenue from price premium on products		CAD	-	31,779,301	63,558,602	63,558,602	63,558,602	63,558,602
Total revenues		**CAD**	**-**	**41,716,392**	**83,432,783**	**83,432,783**	**83,432,783**	**83,432,783**
Costs								
Feedstock (	Feed	CAD	-	10,800,000	21,600,000	21,600,000	21,600,000	21,600,000
Electricity	Bio-crude	CAD	-	393,646	787,293	787,293	787,293	787,293
Natural gas	Bio-crude	CAD	-	-	-	-	-	-
Water	Bio-crude	CAD	-	-	-	-	-	-
Catalysts	Bio-crude	CAD	-	3,779,005	7,558,009	7,558,009	7,558,009	7,558,009
Waste wat	Bio-crude	CAD	-	-	-	-	-	-
Other fixed	Bio-crude	CAD	-	9,911,156	10,281,884	10,281,884	10,281,884	10,281,884
Transport	Bio-crude - Hydroupgrading	CAD	-	626,104	1,252,208	1,252,208	1,252,208	1,252,208
Hydrogen	Hydroupgrading	CAD	-	4,774,469	9,548,938	9,548,938	9,548,938	9,548,938
Catalysts	Hydroupgrading	CAD	-	3,589,300	3,589,300	3,589,300	3,589,300	3,589,300
Other fixed	Hydroupgrading	CAD	-	3,412,781	3,781,656	3,781,656	3,781,656	3,781,656
Total costs		**CAD**	**-**	**(37,286,461)**	**(58,399,288)**	**(58,399,288)**	**(58,399,288)**	**(58,399,288)**
EBITDA		CAD	-	4,429,931	25,033,495	25,033,495	25,033,495	25,033,495
Depreciation		CAD	-	6,991,296	6,991,296	6,991,296	6,991,296	6,991,296
EBIT		CAD	-	(2,561,365)	18,042,199	18,042,199	18,042,199	18,042,199
Interest		CAD	(2,936,344)	(2,642,710)	(2,349,075)	(2,055,441)	(1,761,807)	(1,468,172)
EBT		CAD	(2,936,344)	(5,204,075)	15,693,123	15,986,758	16,280,392	16,574,027
Taxes		CAD	-	-	(4,237,143)	(4,316,425)	(4,395,706)	(4,474,987)
Net result		**CAD**	(2,936,344)	(5,204,075)	11,455,980	11,670,333	11,884,686	12,099,040

Although the overall yields are low compared to the other two biocrudes, due to the limited amount to be upgraded the CAPEX for upgrading, transport and hydrogen are all lower as well. A 100% yield improvement would result in similar overall values as the HTL process. The pathway is most sensitive for changes in the CAPEX of the biocrude production as well as the feedstock price.

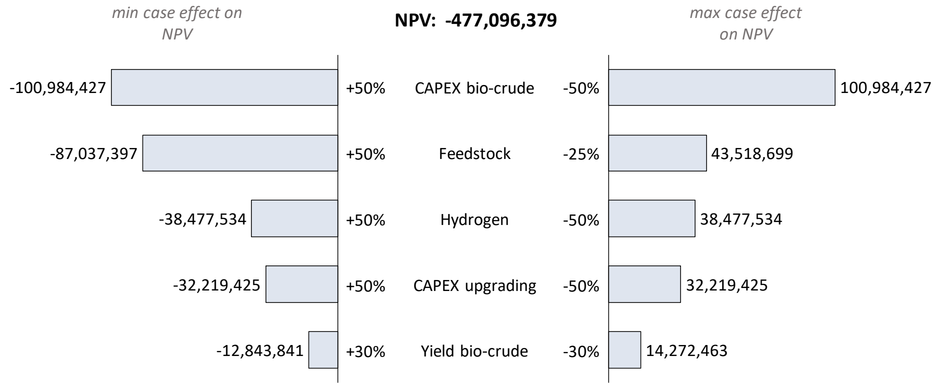

Figure 45. NPV sensitivity of catalytic pyrolysis (VTT) + PNNL pathway – based on a yearly 300,000 ODT feedstock input and 30,000 MT upgraded fuel output.

As explained in the previous section, the low output, with many fixed costs for the facilities results in an expensive fuel. The MFSP per output unit is therefore 3,354 CAD/MT. About 4 times the average fossil price.

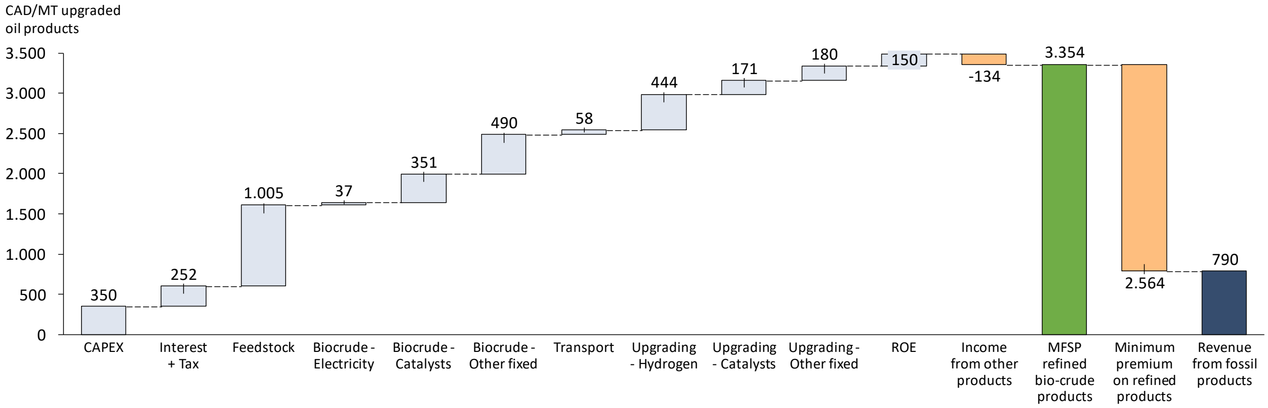

Figure 46. MFSP of catalytic pyrolysis + PNNL pathway

5.2.4 HTL (Aarhus) - CANMET

The HTL biocrude combined with CANMET's co-processing upgrading approach yields the best result compared to the other two biocrudes processed with this upgrading approach. Although the performance is financially better than the PNNL approach, the de-oxygenation and the quality of the output products is lower. Some differences can be noted compared to the PNNL approach. The hydrogen use of this pathway is significantly lower than with the PNNL approach (hence the lower de-oxygenation levels) and the yield towards valuable products is also high, as almost no lights are produced. This could have multiple reasons, e.g. due to the co-processing approach the hydrogen numbers as well as the green carbon yields might be skewed. As a different fuel oil batch was used in the co-processing of the HTL-crude, comparison with the other pathways is difficult and should be done with caution. Although the HTL biocrude had the lowest oxygen content to start with, the resulting oil-phase is only deoxygenated with 47%, whereas the FP and CFP biocrudes where deoxygenated with 93% and 72% respectively. This implies that too little hydrogen has been used to upgrade the biocrude.

Table 77. P&L HTL + CANMET pathway – based on a yearly 300,000 ODT feedstock input and 75,000 MT upgraded fuel output.

			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues								
Revenue from fossil products		CAD	-	28,162,713	56,325,427	56,325,427	56,325,427	56,325,427
Revenue from price premium on products		CAD	-	27,513,180	55,026,361	55,026,361	55,026,361	55,026,361
Total revenues		**CAD**	**-**	**55,675,894**	**111,351,788**	**111,351,788**	**111,351,788**	**111,351,788**
Costs								
Feedstock (	Feed	CAD	-	10,800,000	21,600,000	21,600,000	21,600,000	21,600,000
Electricity	Bio-crude	CAD	-	848,269	1,696,538	1,696,538	1,696,538	1,696,538
Natural ga	Bio-crude	CAD	-	-	-	-	-	-
Water	Bio-crude	CAD	-	-	-	-	-	-
Catalysts	Bio-crude	CAD	-	2,706,808	5,413,616	5,413,616	5,413,616	5,413,616
Waste wat	Bio-crude	CAD	-	83,872	167,744	167,744	167,744	167,744
Other fixed	Bio-crude	CAD	-	13,030,455	13,965,209	13,965,209	13,965,209	13,965,209
Transport	Bio-crude - Hydroupgrading	CAD	-	1,346,887	2,693,773	2,693,773	2,693,773	2,693,773
Hydrogen	Hydroupgrading	CAD	-	9,417,525	18,835,049	18,835,049	18,835,049	18,835,049
Catalysts	Hydroupgrading	CAD	-	3,589,300	3,589,300	3,589,300	3,589,300	3,589,300
Other fixed	Hydroupgrading	CAD	-	6,814,149	7,747,967	7,747,967	7,747,967	7,747,967
Total costs		**CAD**	**-**	**(48,637,264)**	**(75,709,196)**	**(75,709,196)**	**(75,709,196)**	**(75,709,196)**
EBITDA		CAD	-	7,038,630	35,642,592	35,642,592	35,642,592	35,642,592
Depreciation		CAD	-	9,986,685	9,986,685	9,986,685	9,986,685	9,986,685
EBIT		CAD	-	(2,948,055)	25,655,907	25,655,907	25,655,907	25,655,907
Interest		CAD	(4,194,408)	(3,774,967)	(3,355,526)	(2,936,085)	(2,516,645)	(2,097,204)
EBT		CAD	(4,194,408)	(6,723,022)	22,300,381	22,719,822	23,139,263	23,558,703
Taxes		CAD	-	-	(6,021,103)	(6,134,352)	(6,247,601)	(6,360,850)
Net result		**CAD**	(4,194,408)	(6,723,022)	16,279,278	16,585,470	16,891,662	17,197,853

Without any premium on the output products the NPV of the HTL + CANMET approach is better than the PNNL approach, mainly as a result of the lower hydrogen consumption and the high yield to upgraded middle distillates. Similarly, the CAPEX of the biocrude component is very sensitive to price changes as is the feedstock price.

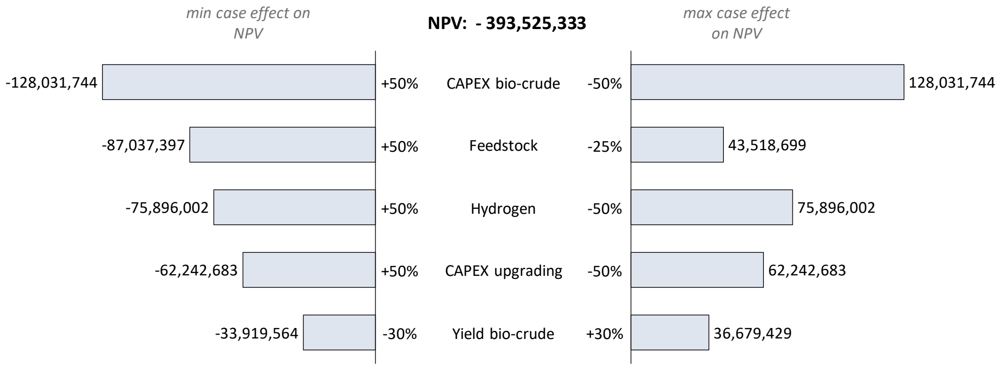

Figure 47. NPV sensitivity of HTL + CANMET pathway – based on a yearly 300,000 ODT feedstock input and 75,000 MT upgraded fuel output.

Looking at the MFSP in Figure 48, some interesting insights are shown. The feedstock and hydrogen components as well as the components linked to the CAPEX are the largest contributors to the MFSP. The MFSP of this process comes down to 1,442 CAD/MT upgraded oil products. This results in an average premium of 679 CAD/MT. As said, this value should be treated with caution as the final product was less deoxygenated than the other pathways. Nonetheless this is the best performing pathway in this study.

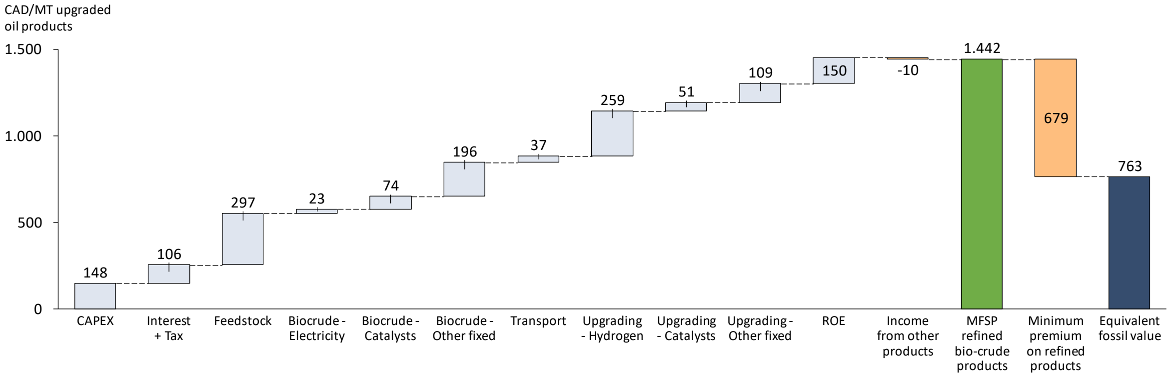

Figure 48. MFSP of HTL + CANMET pathway

5.2.5 Fast pyrolysis (BTG) - CANMET

The pyrolysis pathway performs relatively well and slightly better compared to the PNNL pathway, mainly due to the better yields, which although a correction took place might also be caused by the method of fossil dilution. A big difference lays with the amount of hydrogen needed in this pathway, the hydrogen costs are responsible for over 40% of the total costs. This is twice as high as the feedstock input costs. The large biocrude yield also impacts the transport cost.

Table 78. P&L of pyrolysis (BTG) – CANMET – based on a yearly 300,000 ODT feedstock input and 64,000 MT upgraded fuel output.

			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues								
Revenue from fossil products		CAD	-	22,606,306	45,212,612	45,212,612	45,212,612	45,212,612
Revenue from price premium on products		CAD	-	41,680,401	83,360,803	83,360,803	83,360,803	83,360,803
Total revenues		**CAD**	**-**	**64,286,707**	**128,573,415**	**128,573,415**	**128,573,415**	**128,573,415**
Costs								
Feedstock	Feed	CAD	-	10,800,000	21,600,000	21,600,000	21,600,000	21,600,000
Electricity	Bio-crude	CAD	-	720,215	1,440,430	1,440,430	1,440,430	1,440,430
Natural ga	Bio-crude	CAD	-	-	-	-	-	-
Water	Bio-crude	CAD	-	-	-	-	-	-
Catalysts	Bio-crude	CAD	-	-	-	-	-	-
Waste wat	Bio-crude	CAD	-	-	-	-	-	-
Other fixed	Bio-crude	CAD	-	10,341,956	11,143,484	11,143,484	11,143,484	11,143,484
Transport	Bio-crude - Hydroupgrading	CAD	-	2,235,534	4,471,068	4,471,068	4,471,068	4,471,068
Hydrogen	Hydroupgrading	CAD	-	21,015,541	42,031,081	42,031,081	42,031,081	42,031,081
Catalysts	Hydroupgrading	CAD	-	3,589,300	3,589,300	3,589,300	3,589,300	3,589,300
Other fixed	Hydroupgrading	CAD	-	8,771,043	9,572,572	9,572,572	9,572,572	9,572,572
Total costs		**CAD**	**-**	**(57,473,589)**	**(93,847,936)**	**(93,847,936)**	**(93,847,936)**	**(93,847,936)**
EBITDA		CAD	-	6,813,118	34,725,479	34,725,479	34,725,479	34,725,479
Depreciation		CAD	-	9,727,746	9,727,746	9,727,746	9,727,746	9,727,746
EBIT		CAD	-	(2,914,627)	24,997,733	24,997,733	24,997,733	24,997,733
Interest		CAD	(4,085,653)	(3,677,088)	(3,268,523)	(2,859,957)	(2,451,392)	(2,042,827)
EBT		CAD	(4,085,653)	(6,591,715)	21,729,211	22,137,776	22,546,342	22,954,907
Taxes		CAD	-	-	(5,866,887)	(5,977,200)	(6,087,512)	(6,197,825)
Net result		**CAD**	(4,085,653)	(6,591,715)	15,862,324	16,160,577	16,458,829	16,757,082

Looking at the sensitivities of the NPV we can conclude that due to the large amount of hydrogen needed to upgrade the pyrolysis oil, the NPV is very sensitive to price changes of the hydrogen, compared to the other pathways. Other elements such as the CAPEX and upgrading yields show relatively similar sensitivities to the other pathways assessed.

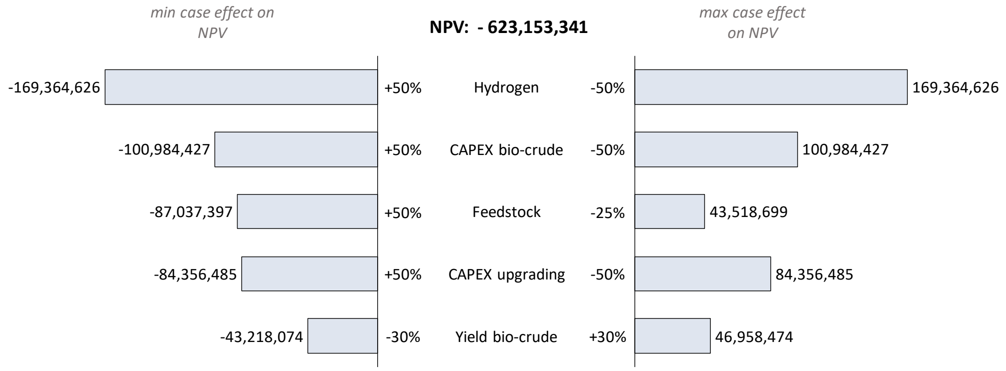

Figure 49. NPV sensitivity of Pyrolysis (BTG)- CANMET pathway – based on a yearly 300,000 ODT feedstock input and 64,000 MT upgraded fuel output.

The MFSP of this process comes to a total of 2,209 CAD/MT of upgraded oil product. With a premium of approximately 3x the fossil value this is on the high end compared with other biojet pathways, but with further development and enabling policy in place this could potentially be a feasible pathway. However, as this pathway yields relatively high heavier oil products (61%), and only 20% jet fuel, it might be harder to get these premium values in the market without further processing of the fuel.

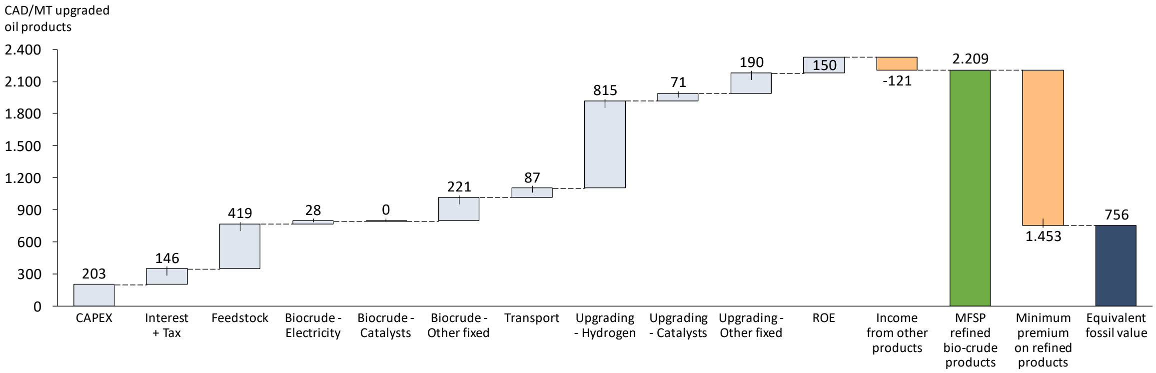

Figure 50. MFSP analysis of pyrolysis (BTG) - CANMET pathway

5.2.6 Catalytic pyrolysis (VTT) - CANMET

Similar to the PNNL pathway, the catalytic pyrolysis biocrude production step combined with CANMET's upgrading process yields a lower amount of upgraded oil products. This has an impact on the business case, where significant premiums are needed to compensate for the lower production. As with the other CANMET pathways, the hydrogen required covers a significant portion of the costs (approximately 20%). Similar to the PNNL pathway, the catalysts used in the biocrude process take over 10% of the costs.

Table 79. P&L of Catalytic pyrolysis (VTT) - CANMET pathway – based on a yearly 300,000 ODT feedstock input and 33,000 MT upgraded fuel output.

			Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues								
	Revenue from fossil products	CAD	-	11,630,645	23,261,290	23,261,290	23,261,290	23,261,290
	Revenue from price premium on products	CAD	-	33,135,323	66,270,646	66,270,646	66,270,646	66,270,646
Total revenues		**CAD**	**-**	**44,765,968**	**89,531,936**	**89,531,936**	**89,531,936**	**89,531,936**
Costs								
	Feedstock (Feed	CAD	-	10,800,000	21,600,000	21,600,000	21,600,000	21,600,000
	Electricity Bio-crude	CAD	-	393,646	787,293	787,293	787,293	787,293
	Natural gas Bio-crude	CAD	-	-	-	-	-	-
	Water Bio-crude	CAD	-	-	-	-	-	-
	Catalysts Bio-crude	CAD	-	3,779,005	7,558,009	7,558,009	7,558,009	7,558,009
	Waste wat Bio-crude	CAD	-	-	-	-	-	-
	Other fixed Bio-crude	CAD	-	9,956,293	10,372,159	10,372,159	10,372,159	10,372,159
	Transport Bio-crude - Hydroupgrading	CAD	-	626,104	1,252,208	1,252,208	1,252,208	1,252,208
	Hydrogen Hydroupgrading	CAD	-	6,738,668	13,477,336	13,477,336	13,477,336	13,477,336
	Catalysts Hydroupgrading	CAD	-	3,589,300	3,589,300	3,589,300	3,589,300	3,589,300
	Other fixed Hydroupgrading	CAD	-	4,129,015	4,544,465	4,544,465	4,544,465	4,544,465
Total costs		**CAD**	**-**	**(40,012,032)**	**(63,180,771)**	**(63,180,771)**	**(63,180,771)**	**(63,180,771)**
EBITDA		CAD	-	4,753,936	26,351,165	26,351,165	26,351,165	26,351,165
	Depreciation	CAD	-	7,363,329	7,363,329	7,363,329	7,363,329	7,363,329
EBIT		CAD	-	(2,609,393)	18,987,836	18,987,836	18,987,836	18,987,836
	Interest	CAD	(3,092,598)	(2,783,338)	(2,474,079)	(2,164,819)	(1,855,559)	(1,546,299)
EBT		CAD	(3,092,598)	(5,392,731)	16,513,757	16,823,017	17,132,277	17,441,537
	Taxes	CAD	-	-	(4,458,714)	(4,542,215)	(4,625,715)	(4,709,215)
Net result		**CAD**	(3,092,598)	(5,392,731)	12,055,043	12,280,803	12,506,562	12,732,322

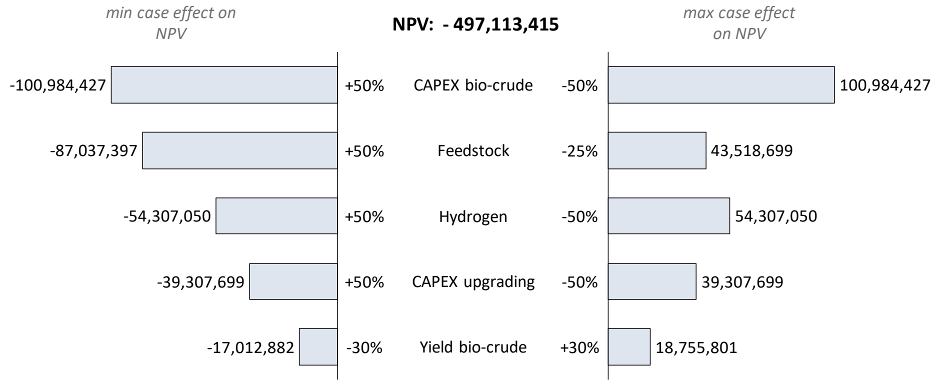

Figure 51. NPV sensitivity of Catalytic pyrolysis (VTT) - CANMET pathway – based on a yearly 300,000 ODT feedstock input and 33,000 MT upgraded fuel output.

The overall low yield of the catalytic pyrolysis + CANMET pathway results in a MFSP per ton of upgraded product of 2,845 CAD. This is similar but slightly better than the catalytic pyrolysis pathway combined with the PNNL upgrading technology. Main elements of improvement are the biocrude yield and hydrogen consumption on the upgrading side.

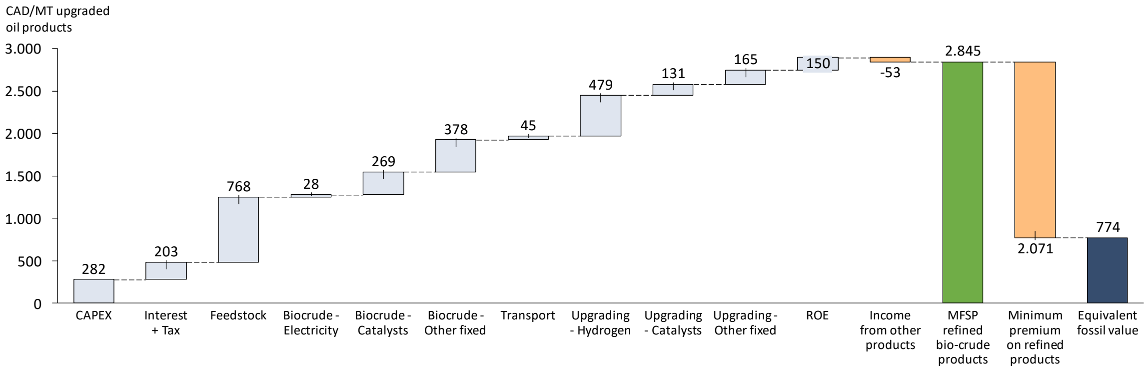

Figure 52. MFSP analysis of catalytic pyrolysis (VTT) - CANMET pathway

5.3 Review of the results

When looking at the financial performance of the six pathways (Table 80 & Table 81), we can see that the overall yield is reflected in the amount of upgraded fuel output as well as the lowest MFSP of the pathways. What also becomes apparent is that although the catalytic pyrolysis process of VTT has an overall yield lower than the fast pyrolysis and HTL processes, the jet output on a volume basis is still quite substantial. This is due to the fact that the jet cut of the VTT process (considering PNNL upgrading) yields 37% compared with 25% from BTG's biocrude and 23% of the HTL biocrude.

A final note on these TEA results show that the HTL and BTG processes have a high CAPEX value, for HTL due to the more expensive biocrude facility, while the BTG process and CANMET's process in general, is impacted by its high biocrude yield requiring a larger upgrader. This estimate is still uncertain which needs to be considered when assessing the results (for the PNNL upgrading process NORAM has done a Class 5 estimate with a -50% +100% uncertainty).

Table 80. PNNL pathways overview of results

PNNL	HTL (Aarhus)	Fast Pyro (BTG)	Cat Pyro (VTT)
Upgraded fuel output (MT/Year)	72,709	50,541	29,658
Jet cut output (MT/Year)	16,650	12,484	10,855
OPEX (CAD/Year)	80,372,010	79,202,663	58,399,288
MFSP to get NPV 0 (CAD/MT)	1,724	2,518	3,354
NPV without a premium	(465,966,949)	(527,379,579)	(477,096,379)
Total CAPEX investment	187,951,609	178,586,850	139,825,922

Table 81. CANMET pathways overview of results

CANMET	HTL (Aarhus)	Fast Pyro (BTG)	Cat Pyro (VTT)
Upgraded fuel output (MT/Year)	74,780	64,122	33,269
Jet cut output (MT/Year)	22,285	12,696	10,613
OPEX (CAD/Year)	75,709,196	93,847,936	63,180,771
MFSP to get NPV 0 (CAD/MT)	1,442	2,209	2,845
NPV without a premium	(393,525,333)	(623,153,341)	(497,113,415)
Total CAPEX investment	199,733,692	194,554,912	147,266,580

What is also important to note when assessing the results is the oxygen content in the three biocrudes (Table 82) as this impacts the hydrogen requirement, CAPEX for upgrading and transport cost for the biocrude. It should be noted that the HTL-CANMET approach was less successful than the other biocrudes resulting in a remaining 1.8% oxygen content in the oil-phase, while FP and CP had 0.4% and 1.2% remaining. This implies that the hydrogen consumption of CANMET's HTL approach should be higher than currently assumed.

Table 82. Oxygen content in biocrudes

Oxygen content	HTL (Aarhus)	Fast Pyro (BTG)	Cat Pyro (VTT)
Percentage in bio-crude (weight%)	15%	48%	19%

Table 83. Indication of costs in CAD cents/litre for different blends of fossil jet and biojet

MFSP blending	100% (CAD/MT)	100% (Cents/L)	50% blend (CAD/MT)	10% blend (CAD/MT)	10% blend (Cents/L)
Conventional jet	CAD 855				CAD 1.06
PNNL					
HTL	CAD 1,724	CAD 2.14	CAD 1,290	CAD 899	CAD 1.12
BTG	CAD 2,518	CAD 3.13	CAD 1,687	CAD 938	CAD 1.17
VTT	CAD 3,354	CAD 4.17	CAD 2,105	CAD 980	CAD 1.22
CANMET					
HTL	CAD 1,442	CAD 1.79	CAD 1,149	CAD 885	CAD 1.10
BTG	CAD 2,209	CAD 2.75	CAD 1,532	CAD 923	CAD 1.15
VTT	CAD 2,845	CAD 3.54	CAD 1,850	CAD 955	CAD 1.19

5.3.1 Potential of policy incentives

The initial results indicate a good potential for pyrolysis and HTL pathways to be used as a pathway for biojet production. Although still expensive, further refinement of the processes and optimization of the facilities could result in a favourable business case. Especially considering the policy that is being developed in Canada. The BC Low Carbon Fuel Regulations (BC-LCFS) is currently providing an incentive for sustainable fuels being used in road transport. When aviation is included in such a policy mechanism, a definite impact is expected.

In Figure 53, the MFSP assessment is shown for the HTL + PNNL pathway including BC-LCFS credits. This pathway is currently assumed to be the most favourable, in terms of LCA and TEA, and is assessed and optimized in more detail in terms of the needed CAPEX and LCA performance in this report (Chapters 6 & 4). The BC-LCFS takes the carbon intensity of the fossil fuel and works towards reducing the CI by 10% in 2020. For 2019, 8% is stated as the proposed reduction. Combining this with the actual CO_2 emissions of the HTL-PNNL pathway, we can calculate the potential credits that could be generated.

- CI of fossil jet: 87.55 g CO_2eq/MJ (Chapter 4)

- CI of optimized HTL-PNNL jet pathway: 25.11 g CO_2eq/MJ
- The goal of BC-LCFS is 8% reduction in 2019. Therefore the CI target is: (92% of 87.55) = 80.55 g CO_2eq/MJ
- Amount of credits generated: (80.55-25.11) * Energy density = 2.4 credits

The credits had a value of 200 CAD/credit on average in the second half of 2018, resulting in credits worth 482 CAD/MT. This results in a MFSP of 1241 CAD/MT, which is 1.5x the fossil value and very competitive with current biojet production pathways, such as HEFA-based technologies.

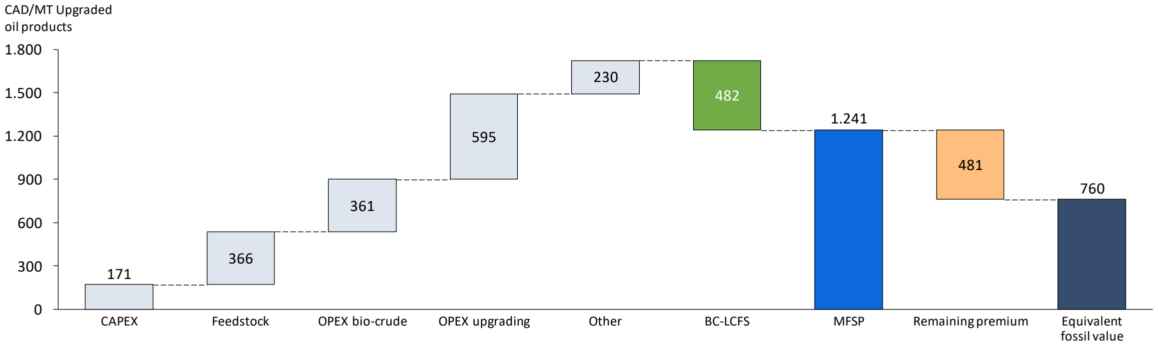

Figure 53. Impact of BC-LCFS on HTL-PNNL case

5.3.2 Concluding remarks

In this TEA the six production pathways to convert woody biomass towards jet fuel are assessed. They are all in a relatively early stage of development, so although none are directly competitive with existing fossil fuel prices, there will be ample opportunity for these technologies to "come down the cost curve" through additional R&D and learning-by-doing. It can be concluded that overall the HTL process seems most efficient in producing a biocrude that can be efficiently transported from a location near the feedstock source (low on oxygen %) and yields an interesting spread of products (23% jet, 29% diesel). As a downside the CAPEX of this process is high due to its waste water treatment system and high temperature and pressure operating conditions compared with the other processes in this study. In the following section the most important influencing factors are discussed and recommendations for future development are made.

5.3.2.1 CAPEX

The CAPEX values currently used are based on small scale pilot/demonstration facilities (BTG), high-level industry estimates (HTL + upgrading) or literature-based numbers (VTT). As demonstrated in the sensitivity analysis, the influence of the CAPEX is substantial in all pathways, but caution is advised with catalytic pyrolysis and HTL CAPEX values until the technology moves to demonstration/commercial scale.

5.3.2.2 Role of hydrogen on TEA

Removing oxygen from the biocrude is an important step in the upgrading process. With the high oxygen containing biocrude of BTG we see the significant need for hydrogen. With CAPEX of 30

MCAD and 42 MCAD for the PNNL and CANMET upgrading processes, this has a significant impact on the overall financial performance of these pathways. We assumed the use of a steam methane reforming (SMR) process for hydrogen production, which uses natural gas as input and influences the LCA performance (Chapter 4). Looking at the future, the development of electrolysis in combination with large scale implementation of low-cost sustainable electricity (<3 CAD/kWh) might be a game changer for these pathways, both in terms of economics as well as LCA.

5.3.2.3 Hydrotreatment and potential of co-processing in an existing refinery

During the assessment of the various pathways, the successful removal of oxygen and upgrading towards the right jet specifications was in some cases challenging. To reach the right jet fuel characteristics and work towards a better techno-economic performance, an alternative approach which could be considered is to perform a lighter (dedicated) hydrotreatment step to upgrade the biocrude up to a level where it could be co-processed in existing fossil refinery infrastructure. In this case significant investments in new infrastructure could be avoided. It would be very interesting for future projects to specifically assess this pathway in more detail, as there is (over)capacity in fossil refineries. Making them ready for new feedstocks such as biocrudes might be beneficial on multiple fronts.

CHAPTER 6 – POTENTIAL FEASIBILITY OF ESTABLISHING A DEMONSTRATION SCALE PRODUCTION AND UPGRADING FACILITY IN BRITISH COLUMBIA

6.1 Background and design guidelines

The purpose of this part of the ATM project was to conduct a preliminary engineering assessment (or "scoping study") for a demonstration-scale facility to produce bio-jet from lignocellulosic feedstock via one of the processing routes identified in the GARDN ATM project. This study includes a block diagram, preliminary flow sheets, a capital cost estimate, and an assessment of the engineering uncertainty and challenges.

The ATM project consortium agreed to the following design guidelines for the demonstration facility:

- Processing capacity of 200 bbl/d biocrude;
- Located in BC, Canada;
- Chosen technology - sub-critical hydrothermal liquefaction (HTL) for biocrude production according to the method practiced at the Aarhus University pilot plant;
- Catalytic hydrotreating of the HTL biocrude on a solid catalyst without dilution according to the method practiced by the Pacific Northwest National Laboratory (PNNL) and CanmetENERGY;
- Inclusion of auxiliary operations (e.g. gas processing, hydrogen production, wastewater treatment), as required;
- Co-location with existing facilities, e.g. petroleum refinery, where appropriate and reasonable.

Flow sheets were developed for a 200 bbl/d technology demonstration, including facilities for biocrude production by subcritical hydrothermal liquefaction (HTL), HTL wastewater treatment by anaerobic and aerobic biological treatment, and biocrude upgrading by hydrotreatment. The 200 bbl/d technology demonstration plant could produce enough jet fuel for up to 10 medium-haul flights per day as a 10% blend.

The HTL **production** facility and associated wastewater treatment plant were assumed to be greenfield developments located in Prince George, BC, Canada, with permits to discharge pre-treated wastewater to the municipal sanitary sewer.

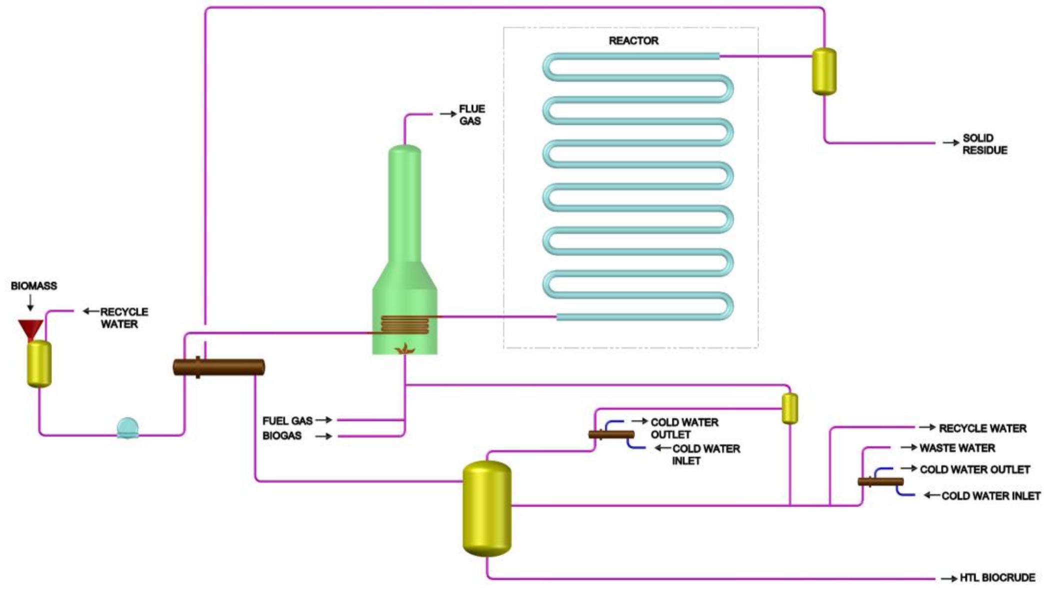

Figure 54 Simplified block diagram for the hydrothermal liquefaction facility design

The biocrude **upgrading** facility is assumed to be co-located with an existing petroleum refinery in the Lower Mainland region of BC, Canada. This is so the plant can “piggyback” on the various utilities and operations already available at a refinery, such as fractionation columns, a catalytic cracker, hydrogen supply, cooling water, sour water treatment, sour gas treatment, product distribution network, etc. This allows the new technology to be demonstrated at a fraction of the cost of installing all of these services separately.

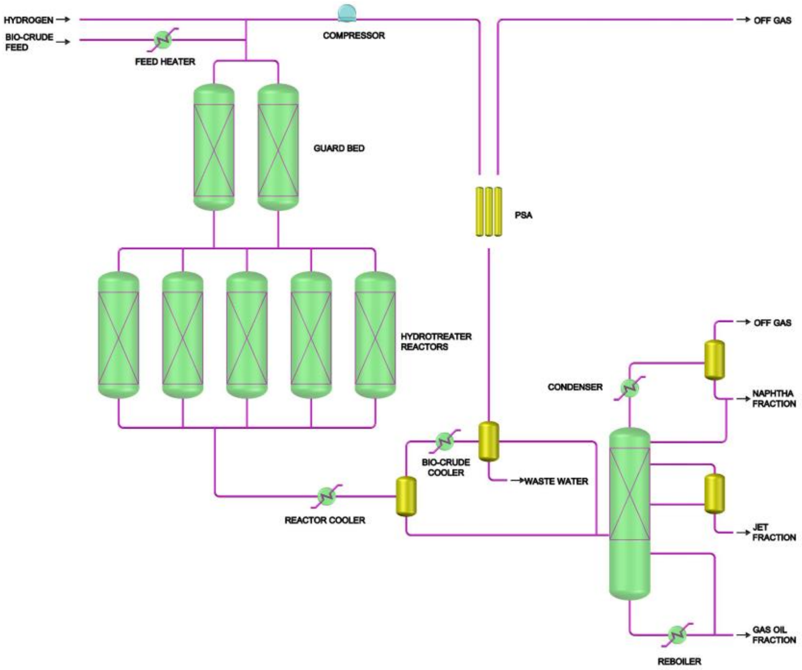

Figure 55. Simplified block diagram showing the upgrading facility design

The installed fixed capital cost of a 200 bbl/d technology demonstration project is estimated to be 62 M CAD (2018). This Class 5 (-50%/+100%) estimate was made using a factored equipment cost approach, and includes major equipment, equipment erection, piping, instrumentation, electrical, buildings, basic site development, design and engineering, and a 10% contingency. It also includes the cost of installing utilities (cooling water, steam, electrical) at the Prince George locations, but not at the upgrading facility, as it is assumed that utilities will already exist at the chosen site. Upgrading wastewater treatment is excluded on the assumption that no modification to the existing refinery's wastewater system is required.

Future engineering development work on HTL (further expanded in Table 79) should focus on the following uncertainties: gas and aqueous yields and compositions after reaching steady state with recycled water; heat transfer properties (thermal conductivity, viscosity, etc.) of the HTL slurry feed at high temperatures and pressures; testing on actual forestry residue; and wastewater treatment. Future engineering development work on upgrading should focus on the following uncertainties: catalyst type, physical arrangement, and lifetime; and recycling of gas oil back to the hydrotreater.

The overall mass and carbon balances for the demonstration-scale flow sheet are summarized in Table 84, and represented graphically in Figure 56. In total, 53% of the carbon in the feed forestry residue reports to liquid fuel products (jet, naphtha, and gas oil), 33% reports to fuel gases that can be burned on site for energy (but not easily transported), and the remainder reports to residues and waste water.

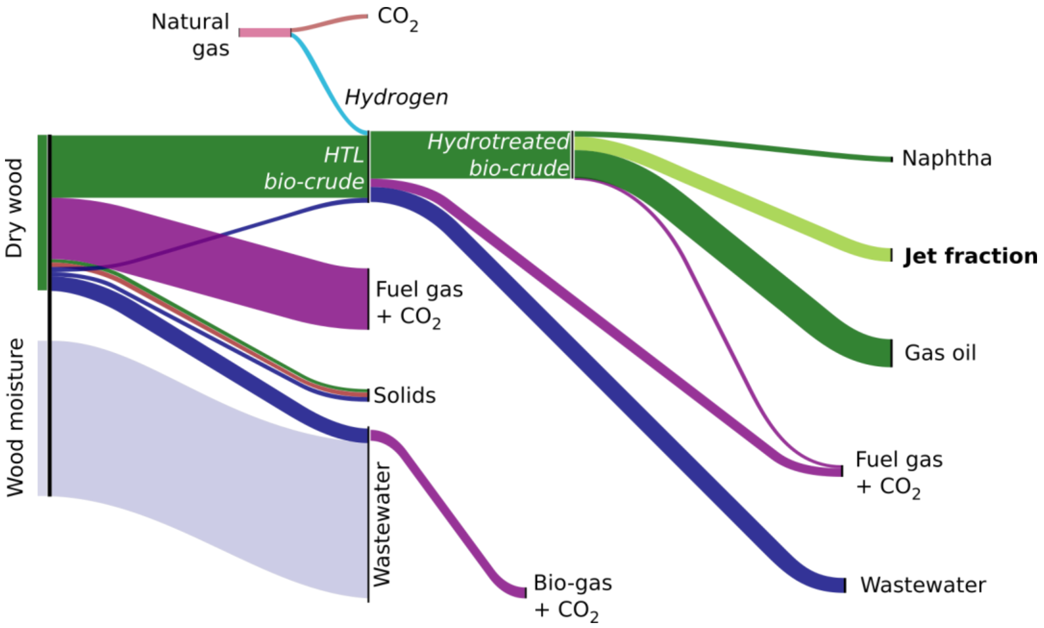

Figure 56 Mass yield diagram from wet forestry residue through to final products for the HTL route

Table 84 Overall process mass and carbon balance for a 200 bbl/d technology demonstration

	Mass balance (kg/h)		Carbon balance (kg/h)		
	Input	Output	Input	Output	Notes
Location 1: HTL biocrude production and wastewater treatment					
Forestry waste (wet)	7005		1783		50% moisture
Combustion oxygen	570				
Biocrude		1549		1116	
Solids / char		213		111	
Fuel gas		2085		443	Combusted to provide heat
Bio-gas		149		77	22 MJ/kg
Pre-treated wastewater + sludge		3577		35	
Total*	7575	7573	1783	1782	
Location 2: Biocrude upgrading					
Biocrude	1549		1116		
Hydrogen	115		-		
Jet fraction		307		266	
Fuel gas		209		149	
Naphtha fraction		125		106	
Gas oil fraction		638		575	
Solids / char		39		11	
Pre-treated wastewater + sludge		341		9	
Total*	1664	1659	1116	1116	

* Stream compositions were based on actual sample analysis from the GARDN ATM project, and the mass balance was closed using a "carbon tie." As a result, the overall mass balance may not close perfectly for all operations.

Table 85 shows the overall Class 5 cost estimate for a complete 200 bbl/d HTL production and upgrading facility, including wastewater treatment.

Table 85. Overall Class 5 (-50%/+100%) cost estimate for a complete 200 bbl/d HTL biocrude production, upgrading, and wastewater treatment demonstration project (M CAD)

Area	Equipment cost (M CAD)	Avg. installation factor	Installed cost (M CAD)
Hydrothermal liquefaction	2.3	4.9	11.2
HTL wastewater treatment	9.8	2.9†	28.4
Biocrude upgrading	3.6	4.0	14.4
Biocrude upgrading wastewater treatment*	-	-	-
Hydrogen production	1.9	4.0	7.6
Total			61.6

* Biocrude upgrading wastewater treatment is assumed to rely on existing refinery infrastructure for the 200 bbl/d demonstration plant. Therefore no additional capital expenditure is required. A full-scale, independent facility would require the construction of a wastewater treatment plant.
† A lower installation factor is used for wastewater treatment because the equipment price shown is for a quoted package system, which as a pre-engineered system is generally less costly to engineer and install than a comparable custom-designed system.

6.2 Discussion

6.2.1 Analysis of capital cost

Roughly half of the estimated installed capital cost for a 200 bbl/d technology demonstration is for an HTL wastewater treatment plant by anaerobic and aerobic biological treatment. Although the relative cost of wastewater treatment should decline with scale, it is nevertheless clear that it will be a costly component of the overall process. The cost reflects the very high BOD loading of this waste stream compared to a typical wastewater treatment application and serves to emphasize that wastewater processing will be a major challenge for the HTL technology. It also highlights the importance of focusing research and development on this area, since any reduction in wastewater loading, whether through improved biocrude or gas yields, precipitation as solid residue, the recovery of byproducts, or the application of an innovative technology like catalytic hydrothermal gasification (CHG), could have an immense impact on the economic viability of the overall process.

The cost of the HTL portion may be underestimated because it does not account for the inevitable challenges that accompany the first trial of a new technology. In particular, it may be necessary to add or replace equipment for inline solids filtration and phase separation, since continuous systems for these steps have not received much attention so far in pilot testing. It may also be necessary to add a process to purify the fuel gas or bio-gas, depending on the requirements of the fired heater and the composition of the gas, which is yet to be confirmed.

The capital costs of biocrude upgrading and hydrogen production can be viewed with somewhat more confidence because these operations are based on well-understood operations from the petroleum industry. The main uncertainties can be considered operational costs, such as catalyst regeneration and replacement. However, the cost will likely be higher than forecast if there are other operational requirements that have not been considered here, such as feed flexibility (e.g. pyrolysis oil, other biocrudes).

6.2.2 Integration at a Canadian airport

The 200 bbl/d technology demonstration facility described in this report is capable of producing enough jet fuel for up to 10 medium-haul flights per day as a 10% blend.[27] The fuel could be transported to the airport using the same infrastructure currently in use, directly from the upgrading facility. This volume of fuel could easily be consumed by domestic flights from the Vancouver airport. The bio-jet could also be blended at a lower or higher fraction, as regulations and testing requirements dictate.

6.2.3 Scientific and engineering challenges

The 200 bbl/d technology demonstration described in this report is ambitious and complex. Neither HTL production or biocrude upgrading have previously been demonstrated on this scale, with the HTL technology in particular still in the earliest stages of commercial development. This adds significant risk and uncertainty to the proposed technology demonstration.

The flow sheets for this project were constructed by relying on a number of critical assumptions, some of which could have a major impact on the outcome. Before proceeding to a 200 bbl/d technology demonstration, NORAM strongly recommends validating these assumptions in the laboratory, and preferably also in targeted pilot testing. A non-exhaustive list of outstanding gaps and

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[27] Assuming 7400 kg/d jet fuel production, 2700 km flight distance, and 2.75 kg per km fuel burn. This is approximately equivalent to a flight between Calgary and Toronto on a new, efficient plane. Assumes 100% operational uptime with 24/7 operation. Actual production will be lower.

challenges in the science and engineering of the demonstration plant is given in Table 86.

Table 86 Scientific gaps and engineering challenges

Challenge / gap	Description	Priority
Effect of HTL aqueous phase recycle on biocrude yield	Evidence presented in the literature suggests that the HTL biocrude yield increases once the system reaches steady state with its recycle water. However, the data provided by Aarhus University on this contain a huge amount of scatter. A continuous test campaign with integrated aqueous phase recycle, including an appropriate feed of fresh water and bleed of aqueous phase to maintain the water balance, is essential for the demonstration plant to be designed and sized with confidence.	High
Effect of HTL aqueous phase recycle on gas yield and composition	The yield and composition of gas from HTL is of critical importance to the design of the overall system. This is particularly true with respect to the energy balance of HTL, since the fuel gas can be burned to provide the thermal energy required to operate the process. The test results provided by Aarhus University suggest that using recycle water causes a marked shift away from the production of aqueous-phase dissolved organics in favour of fuel gas. However, this conclusion is derived from the mathematical closure of the mass balance, not experimental proof. Furthermore, it’s not clear whether the composition of the fuel gas also changes, which could impact its heating value. It is therefore essential that fuel gas flow and composition be measured with and without aqueous phase recycle in order to close the mass balance with confidence.	High
HTL on actual forestry residue	Actual forestry residue has never been tested by HTL. Although pine chips and pellets are a fair proxy for the chemistry, there are likely physical differences, such as with plugging and solids filtration. This should be tested at the pilot scale before proceeding to the demonstration scale.	High
HTL reactor design	Engineering of the hydrothermal liquefaction (HTL) reactor may present a challenge at large scale. Flows in large-diameter pipes tend to stratify, especially at low velocity as is the case in the present design. This may require the inclusion of baffles, inline mixers, or a new reactor design altogether. Also, materials of construction can be challenging in aqueous reactions that approach supercritical conditions, as might become apparent as high corrosion rates and equipment failure after a number of years of operation.	Medium
HTL temperature-yield diagram	It is currently understood that having a slow heating rate results in higher solids yield, while a fast heating rate results in higher liquid and/or gas yield. It would be helpful to have a deeper understanding of the yields as a function of temperature for designing the pre-heating process and	Medium

Challenge / gap	**Description**	**Priority**
	equipment, so that undesirable temperature zones can be avoided.	
HTL wastewater anaerobic treatment	The HTL wastewater must be treated before it can be released. NORAM has recommended anaerobic treatment, largely because the technology is mature. However, the anaerobic operating conditions, as well as the bio-gas yield and composition, must be pilot tested in the laboratory before an anaerobic biological treatment system can be properly designed. A contract laboratory specializing in wastewater treatment should be able to assist with these tests, in conjunction with a suitable high rate anaerobic treatment process vendor. Although the demonstration plant will likely confirm that anaerobic treatment is technically possible, the very high cost may make the process economically unviable in a competitive market. A new approach to aqueous phase organic removal, such as catalytic hydrothermal gasification (CHG), precipitation, or distillation of value-added organic products, may be essential to the economics of the process, and should be the subject of continuing development work.	Medium
HTL hot filtration design	The hot HTL must be filtered to remove residual wood, ash, and precipitates. So far this has not received strong attention at the piloting scale, although it is essential in order to test the continuous recycle of aqueous phase. A solids separation design that takes advantage of the pressure letdown is a possibility. NORAM is confident that an appropriate filter is available on the market. However, certain HTL properties, such as viscosity and solids content, will need to be measured in order to choose the filter properly.	Low
HTL cross-exchanger and pump design	The HTL cross-exchanger is a critical piece of equipment for heat recovery. The combination of high pressure, high temperature, potentially high viscosity (especially during startup), and the propensity to precipitate/plug, will necessitate a careful design. Another challenge for the exchanger is the preference of reaching temperature as quickly as possible to minimize undesired side reactions. The high-pressure pump will also be a specialized piece of equipment for similar reasons. NORAM is confident that an appropriate exchanger and pump are available on the market, since similar conditions do exist in other industrial processes. However, to do so properly will require the measurement of fluid properties, such as thermal conductivity and viscosity.	Low
Hydrotreating catalyst type,	Numerous catalysts have been proposed and tested for hydrotreating biocrudes. Although suitable catalysts do appear to be commercially available, it is uncertain how long they will last in service, whether they can be	Medium

Challenge / gap	Description	Priority
lifetime, and regeneration	regenerated, the preferred physical form, etc. These questions can be answered with the assistance of a catalyst supplier.	
Recycle of gas oil back to hydrotreater	It has been proposed that the gas oil fraction after hydrotreating and distillation can be recycled back to the hydrotreater, thus improving the net yield of jet fuel. However, it is not clear whether repeated hydrotreatment under the same conditions would have any effect on this stream. Alternatively, it might be possible to feed this stream into another refinery operation (e.g. hydrocracker, FCC) to create more bio-jet. This has the potential of greatly increasing the yield of useful liquid fuel.	Medium
Hydrotreating wastewater composition and behaviour	It has been assumed that the wastewater from hydrotreating will be processed in through an existing wastewater treatment system at a refinery. Preliminary calculations suggest that the volume and loading is small enough that it will not negatively impact on the existing operation. However, this must be known with confidence before a refinery will allow the operation to take place. Some uncertainties are ammonia loading, and whether the stream will cause foaming.	Low

CHAPTER 7 – THE POLICY ENVIRONMENT AND POLICY RECOMMENDATIONS

The ATM Project specifically targets the production of biojet fuels that can be used in the aviation sector to reduce emissions. The focus of this policy section is therefore primarily concerned with aviation and the use of policies to promote the production and usage of biojet fuels in this sector. Policies that are generally used to promote all types of biofuels will be briefly discussed.

Chapter 1 gave an overview of the aviation sector and the rationale behind emission reduction targets and the essential role of biojet fuels to achieve these objectives. The results from this study (Chapter 4) demonstrated that very high emission reductions (between 50-80%) could be achieved based on the feedstock and technology pathways considered in this project. However, compared to the current price of conventional jet fuel, biojet fuel via this technology route will only be economical to produce if a significant premium is paid for the biojet. Arguably, the key to bridging the gap between conventional jet and biojet is the right type of policies.

The International Energy Agency has shown that subsidization of fossil fuels is quite significant and that one of the first ways to create a level playing field is the removal of such subsidies. The IEA calculated that annual subsidies to fossil fuels amounted to over $300 billion dollars in 2017 [28].

The next important approach is putting a price on carbon in the form of a carbon tax or similar mechanism such as an emissions trading scheme, cap and trade scheme or carbon offset mechanisms, etc. The impact of this price on the negative externalities of emissions depend on the price placed on emissions. It should be high enough to modify behavior and motivate companies to reduce emissions through technology, optimization or any other suitable measures. While many believe that a price on carbon alone will be sufficient for all sectors, this is not considered by all to be effective in the transportation sector where policy measures such as low carbon fuel standards are more appropriate. Offsets may be cheaper than technology required to bring about real change in the aviation sector. However, limited availability of offsets and limited “real” impact of such offsets requires that technologies for biojet production be developed and commercialized if long-term emission reductions are to be achieved.

This section will briefly look at existing policy measures for promoting the production and consumption of biojet fuel, additional policies that can be considered and recommendations based on this project. Firstly we have to look at the unique context of the aviation sector and its implications for policies and regulations.

7.1 Aviation perspective

Emissions from aviation, although only 3% of total global emissions, are considered a significant problem due to the fast growth of the industry and the inevitable increase in emissions to 2050. It is also recognized that biojet fuels will be essential for reducing emissions in this sector. However, the sector falls under the jurisdiction of the International Civil Aviation Organisation (ICAO)

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[28] https://www.iea.org/newsroom/news/2018/october/hard-earned-reforms-to-fossil-fuel-subsidies-are-coming-under-threat.html

and did not form part of the Paris agreement on emission reductions. ICAO is expected to agree to their own targets and mechanisms for decreasing emissions in this sector. The sector previously had set their own voluntary targets for reductions in emissions, including carbon neutral growth by 2020 and a 50% reduction by 2050. The agreement on the Carbon Offsetting and Reduction Scheme in International Aviation (CORSIA) was a significant step in the sector to formally regulate emissions from aviation.

The jurisdiction of ICAO is limited to international aviation and this essentially creates two systems of regulating emissions from aviation. On the one hand, domestic flights within a country fall under national regulation by each country and through signing the Paris agreement, countries have undertaken to address these emissions. Included in domestic emissions are the take off and landing emissions that take place within a certain distance from an airport, even when an international flight. On the other hand, emissions from international aviation fall under ICAO and is regulated by agreements at this level. At national level, further differences could apply between provinces, for example British Columbia applies a carbon tax to internal flights but not to interprovincial flights. This creates increased complexity for airlines, but also makes a systematic approach to emission reduction challenging for the policy maker in the aviation sector.

Any policy recommendations must take into account these tiers of policy and regulations, how they interact and whether they achieve the desired objective – to incentivize the production and consumption of biojet fuels and achieve emission reductions in the aviation sector.

7.2 Policy at international level and likely effectiveness for achieving objectives

In 2016, the International Civil Aviation Organization (ICAO) adopted the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) to address CO2 emissions from international aviation. CORSIA aims to stabilize net CO2 emissions from international civil aviation at 2020 levels in line with previous targets. The aviation sector is committed to advances in technology, operations and infrastructure to continue to reduce the sector's carbon emissions and offsetting is not intended to replace these efforts.

CORSIA is intended to complement emissions reduction initiatives within the aviation sector. The sector is committed to reduce its net CO2 emissions to half of what they were in 2005, by 2050 and this will require continued investment in new technologies and strong support mechanisms for the deployment of sustainable aviation fuels.

Offsets can take the form of projects for wind energy, clean cook stove, methane capture and other emissions-reducing or avoidance projects. To ensure the environmental integrity of CORSIA, ICAO will adopt a list of emissions units that can be used for compliance. It is estimated that CORSIA will mitigate around 2.5 billion tonnes of CO2 between 2021 and 2035.

How does CORSIA promote the production and consumption of biojet fuels? Will this be sufficient to set up the long-term development of biojet fuels for the aviation sector? ICAO's Alternative Fuels Task Force (AFTF) is in the process of determining how an airline can reduce their offsetting requirements under CORSIA through the use of sustainable alternative fuels. Emission credits could potentially be generated by sustainable alternative fuels projects and the credits used under CORSIA. However, CORSIA alone will not be sufficient to promote production and use of sustainable aviation fuels as indicated in the following statement from Michael Gill, IATA Director

Aviation Environment[29]:

“The next step is to move into large-scale production in order to create a lasting and increasing reduction in aviation’s carbon emissions. This is where public policy becomes crucial. Biofuels for the automotive sector have long received encouragement or even outright subsidy from the public sector to incentivise production. It is now high time that SAF is put on the same pedestal. This is all the more crucial as aviation, unlike automotive, has no alternative to liquid-energy fuels in the short-medium term. Hitherto, fuel refiners have not had sufficient incentive to generate aviation fuels at price levels the industry could afford. Why should they, when the policies encouraged them to go for automotive biofuels? Slowly, this is changing. In the United States, policies exist to ensure that a proportion of alternative fuels refined must be for aviation use. And in Europe, the Renewable Energy Directive is being revised. Already the European Parliament has indicated that aviation biofuels should be encouraged. Now we’re urging the European Commission and the European Council to agree to this enhancement.

- In addition, globally we are calling for measures including:
- Implementing the policy to de-risk investments into SAF production plants, including loan guarantees and capital grants for production facilities;
- Support for brokering aviation off-take agreements;
- Support for SAF demonstration plants and supply chain research and development;
- Tax incentives for public-private partnerships for early-stage plant development and;
- Developing a harmonised transport and energy policy including inter-department coordination, such as agriculture, transport, energy and military.” (Michael Gill, IATA Director Aviation Environment)[30]

Thus, there seems to be a clear acknowledgement that policies at national level should support development of biojet fuels, which has not been the case in the past. However, some jurisdictions are finding policy solutions for promoting biojet fuels.

7.3 Policy at national level and likely effectiveness for achieving objectives

Policy support for biofuels have been used for decades. This has included volumetric mandates, loan guarantees, producer incentives, etc. More recently, low carbon fuel standards, linking incentives with emission reductions and penalizing failure to meet reduction targets, have been used in jurisdictions such as California and British Columbia. Germany also introduced legislation for specific emission reduction targets for fossil fuels, with blending of biofuels one way of achieving these targets.

Canada currently has renewable fuel regulations that require fuel producers and importers to have an average renewable fuel content of 5% (gasoline) and 2% (diesel and heating distillate oil). Provinces can introduce higher blend levels and this is done in many cases. Importantly, kerosene and aviation has never been part of these regulations.

More recently, the federal government has proposed a Federal Clean Fuel Standard with a far greater scope. We will briefly look at the proposed CFS and then discuss its potential impact on

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[29] https://www.openaccessgovernment.org/sustainable-aviation-fuels-the-next-frontier-for-air-transport/44547/
[30] https://www.openaccessgovernment.org/sustainable-aviation-fuels-the-next-frontier-for-air-transport/44547/

aviation.

7.3.1 Federal Clean Fuel Standard

The Government of Canada announced in late 2016 that it would consult with provinces and territories, Indigenous peoples, industries, and non-governmental organizations to develop a Clean Fuel Standard to reduce Canada's greenhouse gas emissions (GHG) through the increased use of lower carbon fuels, energy sources and technologies. The intent is that the Clean Fuel Standard would be a performance-based approach that would incent the use of a broad range of low carbon fuels, energy sources and technologies, such as electricity, hydrogen, and renewable fuels, including renewable natural gas. It would establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels, and would go beyond transportation fuels to include those used in industry and buildings. The approach would not differentiate between crude oil types produced in Canada or imported. The Clean Fuel Standard would complement the pan-Canadian approach to pricing carbon pollution. The objective of the Clean Fuel Standard is to achieve 30 megatonnes of annual reductions in GHG emissions by 2030.

Implementation:

- for liquid fuels: publish proposed regulations in spring 2019 and final regulations in 2020, with requirements coming into force by 2022.
- for gaseous and solid fuels: publish proposed regulations in fall 2020, final regulations in 2021 with requirements coming into force by 2023

The Clean Fuel Standard will achieve reductions from each of the transportation, building and industry sectors. Reductions will be achieved by setting separate carbon intensity requirements for subsets of fuels, as well as through rules on credit trading.

The Clean Fuel Standard will set separate carbon intensity requirements for liquid, gaseous and solid fuel streams. This approach will lead to emission reductions from fuels used in industries and buildings. For gaseous fuels, consideration will be given to setting volumetric requirements for renewable content or a hybrid approach, such as volumetric requirements with GHG performance standards.

Approximately 80% of liquid fuels are used for transportation. Setting a separate carbon intensity target for liquid fuels will ensure GHG reductions are achieved from transportation fuels.

Consideration may be given to further groupings of fuel types within fuel streams (e.g. grouping transportation fuels together in the liquid fuel stream). Some trading of credits between the fuel streams will be considered. This approach offers compliance flexibility to regulated parties to achieve emission reductions across the fuel types within the separate fuel streams.

The Clean Fuel Standard will complement the Pan- Canadian approach to pricing carbon pollution. The Clean Fuel Standard will focus on reducing carbon intensity across the lifecycle of fuels, from production to use, reducing GHGs along the value chain of individual fuels and incenting innovation and technology. Carbon pricing will price fossil fuels, as well as emissions from industrial activities, to send a price signal to markets and end users and further incent GHG emission reductions.

In the short term, the volumetric requirements in the federal Renewable Fuels Regulations will be maintained but will be replaced in the long term.

The Clean Fuel Standard will provide a range of pathways for complying other than reducing the carbon intensity of the fuel produced or imported for use in Canada. A key pathway for fossil fuel suppliers will be to include renewable fuel content in their product.

It will also be possible to generate compliance credits for actions that improve carbon intensity throughout the lifecycle of the fuel. One issue to be determined is whether to specify a minimum threshold for process improvements that qualify for credit creation. It will also be possible to generate credits through fuel switching and the deployment of energy sources and technologies that displace fossil fuels, such as electric vehicles.

Credits will be tradeable among regulated parties within each stream of fuels (liquid, gaseous, solid). There will also be limited banking of credits. Consideration is being given to allowing some use of credits across streams of fuels.

Jet fuel that is used domestically will be subject to the Clean Fuel Standard but jet fuel that is used for international flights will not. Renewable or other low-carbon intensity aviation fuel produced and imported will be eligible to generate credits under the Clean Fuel Standard. Consideration is being given to the use of a multiplying factor for low carbon aviation fuel credits.

7.3.2 Evaluation of the CFS in the context of this project

The CFS will be applicable to domestic aviation with carbon intensity requirements for these fuels. However, development of domestic production capacity and infrastructure of biojet fuels must take place as global availability of these fuels is very small so unless domestic production is developed the ability of the aviation sectors to decarbonize will be restricted. Brand new facilities will require billions in investment and will come at a higher cost that ethanol and biodiesel production facilities due to the greater complexity of the technology. Unless policy targets the specific development of drop-in biofuel production (that produces jet fuel as part of their product suite) it will be very difficult for fuel suppliers to meet the carbon intensity requirements (unless offsets can be used).

One possible alternative is the use of refinery integration through a co-processing strategy which could overcome some of the obstacles for large financial investment, specifically for the upgrading of liquid intermediates into finished fuels. Fuel producers or importers, including refiners, can comply with the CFS through taking steps to reduce the carbon intensity of fuels, clearly providing an avenue for co-processing under the CFS. It is not clear whether co-processing will be included in the CFS.

7.4 Policy at provincial level and likely effectiveness for achieving objectives

The federal Renewable Fuel Regulations specify blending levels for ethanol and biodiesel into the gasoline and diesel pools respectively. In parallel to the federal mandate, some Canadian provinces currently have their own biofuels mandates which, in most cases, are more ambitious than those put in place by the federal government. As the ATM Project focused on a supply chain and production based in British Columbia, only the policies in this province will be considered. Arguably, BC has the most advanced policies for promotion of drop-in biofuel production and consumption, with further policy additions for specific promotion of biojet fuel production under consideration.

Provincial biofuels mandates have been operational in BC since 2010, with a target for 5% annual average renewable content in gasoline and a 4% (initially 3%) annual average renewable content in diesel (the highest blending mandate in the country). Although BC produces some biodiesel it has no commercial-scale ethanol production capacity. BC has a low carbon fuel standard in the form of Renewable and Low Carbon Fuel Requirements. The carbon intensity of transportation fuels is reduced through two major requirements: Part 2 of the Fuel Requirement (Renewable) makes provision for blending mandates for gasoline (5% renewable content) and diesel (4% renewable content). In addition, Part 3 of the Fuel Requirement (Low Carbon) provides for a 10% reduction in carbon intensity by 2020. Under Part 3 of the regulations, anyone can apply to become a "Part 3 fuel supplier". Such suppliers have three ways to ensure compliance with the low carbon fuel standard. First, through the supply of low carbon fuels, i.e. by reducing the overall carbon intensity of supplied fuels to below the prescribed limit in each compliance period. Second, through credit trading, whereby they acquire credits from other suppliers. Finally, and/or through "Part 3 Agreements":

"Part 3 Agreements promote innovation, diversity and greater uptake of lower carbon transportation fuels – all contributing to accelerated market transformation. Projects and activities supported by Part 3 Agreements should reduce, or enable reductions of, GHG emissions resulting from the use Part 3 fuels. It is expected that Part 3 Agreements will help fuel suppliers undertake actions that are not otherwise economically viable, and that will help create future pathways for compliance. For example, the lack of demand certainty has been cited as a barrier to E85 supply initiatives. Supplying E85 under a Part 3 Agreement could establish this as a fuel that contributes to the supply of more low carbon fuel".[31]

Part 3 fuels are currently limited to gasoline and diesel class fuels and renewable substitutes, but this may be expanded to also include biojet fuels on a voluntary basis under a Part 3 agreement. This will allow a fuel supplier of jet fuel which includes biojet to earn credits under the regulations, without these fuels forming part of the compulsory reductions in carbon intensity which could result in penalties if not met. Jet fuel for international aviation does not fall under the jurisdiction of provincial or national jurisdictions and therefore a voluntary opt-in system is the most feasible way to incentivize biojet fuel development.

British Columbia was North America's first jurisdiction to introduce a carbon tax, currently at $35 per tonne of CO^2eq. The tax has a broad base and is paid by all fossil fuel consumers in the province, including jet fuel for intra-provincial flights. Practically *all* emissions from fuel combustion in BC (as measured by Environment Canada's National Inventory Report) are taxed, thereby covering 70% of all carbon emissions in the province. Nonetheless, there are a few fuels which are exempt from the tax, which include:

- Jet fuel purchased by an international air service that is a registered consumer (also exempt from motor fuel tax);
- Fuel purchased by a registered consumer (e.g. inter-provincial air services), a

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[31] British Columbia Ministry of Energy and Mines, Part 3 Agreements (2015). http://www.empr.gov.bc.ca/RET/RLCFRR/Documents/BC%20RLCFRR%20Part%203%20Agreements%202015.pdf

registered air service or a registered marine service;

Therefore, jet fuel purchased by *international airlines,* as well as jet fuel for inter-provincial flights, is exempt from the carbon tax, but domestic flights between two points within BC are subject to carbon tax.

Potential application of current BC policy could involve inclusion of jet fuel under BC regulations and using of Part 3 agreements to specifically promote development of drop-in biofuels (including jet fuel), as well as to promote co-processing of biobased intermediates at refinery level. In this way, low carbon intensity jet fuel with renewable content could be produced.

7.5 Policy conclusions and Recommendations

Those jurisdictions where biofuels have been produced and used have all had benefited from strong policies and mandates that have "encouraged" their production and use. Volumetric mandates for bioethanol and biodiesel have been used worldwide in over 60 countries. More recently, jurisdictions such as California and BC have developed policies such as low carbon fuel standards that set targets for emission reductions and place emphasis on the carbon intensity of the biofuel, not simply the volume. It is highly likely that policies such as low carbon fuel standards will provide the basis of effective decarbonisation and incentivise biofuel production. In addition, the broad provisions described in the Part 3 agreements under current BC policy have proven to be important for the launching of various initiatives, such as co-processing.

Conventional policies such as grants and loan guarantees will continue to play an essential role in promoting drop-in biofuels and biojet by overcoming some of the risk associated with investment in these new technologies. On a broader level, supply chain policies that can improve the access to and cost of feedstock (as discussed in Chapter 2) will form an important element of the policy framework.

British Columbia is well positioned to put in place flexible policies to promote the production and use of biojet fuels (as part of drop-in biofuel production). The federal CFS will only come into force in 2022 for liquid fuels and some of the drawbacks may be ironed out. However, BC has the distinct advantage of existing policies that have been in place for several years and have been shown to be effective in reducing emissions from transportation. Building on these existing policies are therefore likely to have a quicker and more direct impact on the province. The BC regulations should serve as an excellent example to other provinces of an effective and viable policy system.

Specific proposals and recommendations based on the BC regulations can therefore be highlighted. A co-processing strategy could be very effective to decarbonize transportation, including lowering the carbon intensity of current liquid fuels and lowering the carbon intensity of fuel production. The existing regulations could be expanded to include incentives for production of specific low carbon fuels such as biojet fuels. While the aviation sector is regulated at international level, it has become apparent that incentives could be used for this sector without clashing with international regulations that prohibit taxation of fuel for international flights.

Key policy issues that should be considered include:

- Specific recommendations for inclusion of biojet fuels under the LCFS, taking into account both domestic and international flights;

- Specific provisions for co-processing in existing refineries that regulate life cycle assessment and calculation of carbon intensity for the purpose of calculating credits.

The policy measures at all three levels will make a significant contribution to bridging the price gap between fossil fuel and biofuel as set out in the techno-economic assessment. However, this may not be sufficient and further novel policies should be considered. A charge per passenger per flight is one example and has been introduced in Sweden.

CHAPTER 8 – RESULTS AND DISCUSSION

8.1 Comparison of biocrudes and upgrading approaches

The following Table 87 shows a comparison of the different pathways and key data while Table 88 is an evaluation of the different pathways for specific factors.

Table 87. Combined results of all pathways

	FP-CM	FP-PNNL	CP-CM	CP-PNNL	HTL-CM	HTL-PNNL
Biocrude – oxygen content (%)	47.5		16.5		14.5	
Biocrude – kg wood/litre biocrude	1.88		6.55		3.05	
Biocrude - kg wood/MJ biocrude	0.087		0.203		0.085	
Biocrude production – TRL level	Demonstration scale		Pilot scale		Pilot scale	
Upgrading – TRL level	Pilot	Pilot	Pilot	Pilot	Pilot	Pilot
Upgrading – Extensive optimization req	Yes	No	Yes	No	Yes	No
Quality of jet fraction	High	High	High	High	High	High
Total yield of biocrude & upgrading (wt%)	23	19	12	11	26	27
MFSP – jet (CAD)	2,196	2,518	2,873	3,354	1,432	1,724
CAPEX (CAD)	178 m	178 m	140 m	140 m	188 m	188 m
Upgrade fuel output (MT/year)	61,887	50,541	31,295	29,658	70,430	72,709
Jet fuel output (MT/year)	12,515	12,484	10,107	10,855	20,998	16,650
Jet fraction (%)	20.8	24.7	32.8	36.6	29.8	22.9
Greatest cost Sensitivities in TEA	1.Hydrogen 2.CAPEX biocrude 3.Feedstock	1.CAPEX biocrude 2.Feedstock 3.Hydrogen	1.CAPEX biocrude 2.Feedstock 3.CAPEX upgrading	1.CAPEX biocrude 2.Feedstock 3.CAPEX upgrading	1.CAPEX biocrude 2.Feedstock 3.Hydrogen	1.CAPEX biocrude 2.Feedstock 3.Hydrogen
Potential emission reduction RBO (%)	-2.9	-74.3	2.6	-57.7	-5.4	-51.0 (-71.3*)
Total emissions (gCO2eq/GJ) Ref: fossil jet (87550)	92,564	30,021	107,826	55,042	102,972	63,999
Emissions (Biocrude production) (gCO2eq/GJ)	8,180		18,656		20,761	
Emissions (upgrading into RBO) (gCO2eq/GJ)	84,384	21,841	89,170	36,386	82,211	43,238
Yield – Kg wood/litre RBO	4.14	5.08	8.19	8.58	3.27	3.63
Hydrogen consumption kg/litre RBO	0.180	0.163	0.115	0.091	0.07	0.101
HHV RBO (MJ/litre)	37.72	37.46	38.39	35.57	36.24	39.40
Feedstock availability for multiple facilities at commercial scale	Medium	Medium	Medium	Medium	Medium	Medium
Feedstock cost per odt	High	High	High	High	High	High
Feedstock quality (forest residues)	Low	Low	Low	Low	Low	Low
Feedstock existing supply chains	yes	yes	yes	yes	yes	Yes

*Value for optimized scenario (demo plant)

Table 88. Comparison of pathways with respect to specific factors

	TRL level Biocrude prod	**TRL level upgrading**	**Significant Jet fraction (>20%)**	**>50% emission reduction**	**MFSP < CAD2000 /MT**
FT-CM	**Demo/comm**	**Pilot**	✓	✗	✓
FT-PNNL	**Demo/comm**	**Pilot**	✓	✓	✗
CP-CM	**Pilot**	**Pilot**	✓	✗	✗
CP-PNNL	**Pilot**	**Pilot**	✓	✓	✗
HTL-CM	**Pilot**	**Pilot**	✓	✗	✓
HTL-PNNL	**Pilot**	**pilot**	✓	✓	✓

8.2 Analysis of jet fractions and suitability of thermochemical liquefaction and hydrotreating as a strategy to produce biojet fuel

After upgrading of the biocrudes used in this study, distillation was carried out to separate product fractions based on their boiling point. The jet fraction was the oil phase distillation fraction between 155°-250°C.

For use in commercial aviation, a biojet fuel has to go through a rigorous approval process as described in Chapter 1. Once approved for commercial use, the specification for the particular alternative technology and upgrading pathway is published as part of ASTM D7566.

The pathways used in this study are not currently included in ASTM D7566, but in order to evaluate the jet fractions generated in this study, general specifications and analytical procedures specified in ASTM D7566 were used to make a broad assessment as to the suitability of these technology and upgrading pathways for production of biojet fuel.

Table 1 in ASTM D7566 lists the minimum and maximum specifications of the biojet fuels listed in the Annexes *after* blending with conventional jet fuel (already certified through ASTM D1655) according to the blending limits specified in the standard. Once the blended fuel has met all the specifications in Table 1, it is considered equivalent to ASTM D1655 for conventional jet fuel.

Every "batch" of biojet fuels, that are listed in the Annexes of D7566, have to be certified after production according to batch requirements listed in each Annex. After the batch certification, blending with conventional jet fuel takes place according to the specified blending limits and recertification of the blend in accordance with Table 1 of ASTM D7566.

Table 89 below shows the results of the jet fraction analyses from the ATM Project, each biocrude and upgrading pathway yielded a jet fraction that was analysed to determine how well the jet fraction compared with a conventional jet/biojet blended fuel. This will provide insight into the suitability of these pathways to produce biojet fuels.

It should be noted that the upgrading processes in this study was not optimized. Upgraders used standard in-house protocols to carry out the upgrading before fractionation and analysis was done. It should also be noted that the Canmet upgrading results reflect the co-hydrotreated product and is therefore a mixture of biofuel and fossil fuel. Due to limited sample volumes, all tests from Table 1 of ASTM D7566 could not be performed, e.g. thermal stability.

Based on the results shown in Table 89, it can be concluded that this study has been very successful in demonstrating that thermochemical liquefaction and upgrading through hydrotreatment is very suitable for production of biojet fuel from woody biomass. Deviations from Table 1 specifications are relatively minor and could be overcome through further optimization of the hydrotreating and additional polishing steps. As the parameters for these specifications are based on the *blended* fuel, the batch specifications for the specific technology pathway may differ. We will briefly examine some of the main specifications below and examine the extent to which biojet "batches" as contained in the Annexes vary with respect to the required minimum or maximum, as well as additional analyses that may be required based on previous examples.

Table 89. Results of analysis of jet fractions from the ATM Project compared with specifications as listed in Table 1 of ASTM D7566. (FP-fast pyrolysis, CP-catalytic pyrolysis, HTL-hydrothermal liquefaction, C-Canmet upgrading, P-PNNL upgrading) Highlighted values fall outside the specification.

	FP-C	**FP-P**	**CP-C**	**CP-P**	**HTL-C**	**HTL-P**
COMPOSITION						
Acidity, total mg KOH/g Max 0.10	0.064	0.11	0.101	0.012	>0.100	0.014
Aromatics, volume percent Max 25	17.7	18.6	19.3	30.4	14.1	20.9
Sulfur, mercaptan,*C* mass percent Max 0.003	0.0019	<0.0003	0.0003	0.0021	-	<0.0003
Sulfur, total mass percent Max 0.30		<0.25		<0.25	0.0518[a]	<0.25
VOLATILITY						
Flash point, °C Min 38	61	43	58.5	34.5	59.0	34.5
Density at 15 °C, kg/m3 775 to 840	818.9	843.4	827.8	852.6	829.0	853
FLUIDITY						
Freezing point, °C Max −47 Jet A-1*I*	-57.6	-46.7	-58.3	<-80	-45	-84
Viscosity −20 °C, mm2/s*J* Max 8.0	5.164	5.176	5.306	3.499	6.6	4.431
COMBUSTION						
Net heat of combustion, MJ/kg Min 42.8	42.92	42.245	42.32	42.477	42.85	42.55
One of the following requirements shall be met: (1) Smoke point, mm, or Min 25.0 (2) Smoke point, mm, and Min 18.0	21	18.3	20	14.3	19.7	17
Naphthalenes, volume, percent Max 3.0	0.51	2.17	1.51	0.36	1.07	0.44
CORROSION						
Copper strip, 2 h at 100 °C Max No. 1	1b	1a	3a	3b	1a	3a
CONTAMINANTS						
Existent gum, mg/100 mL Max 7	15	28	65	<1	41	3
Microseparometer,*O* Rating Without electrical conductivity additive Min 85 With electrical conductivity additive Min 70	nd	54	nd	94	55	62

Select analytical results	**FP-C**	**FP-P**	**CP-C**	**CP-P**	**HTL-C**	**HTL-P**
Nitrogen, mg/kg Max 2		270		9.7	<0.75	81
Water, mg/kg Max 75	138ppm	440	159	66		74
Sulfur, mg/kg Max 15	480	11	423	39.3	0.0518	
Oxygen wt %	0.3	1.08	1.18	<0.01	Nd	0.13

Table 89shows that there are only small variations from the specifications that should not be difficult to correct. While sulfur levels appear to meet specifications, the oxygen and nitrogen components are notable. Nitrogen limits are contained in the Annexes at 2 mg/kg. Oxygen could be reduced to a lower level through optimization of the hydrotreater operation and this will also improve the density and heat of combustion. Excellent results were obtained with freeze points. The flash point is a little low in the HTL case, but it is likely a function of the distillation cut point. Removing some of the lower boiling components will raise the flash point. Variations from spec in the smoke point is likely due to high levels of aromatics and additional hydrogenation could reduce the aromatic content.

8.3 Specific considerations and specifications relevant to biojet fuels

In some cases, the specification for a biojet fuel varies from the standard specification as found in Table 1 of the ASTM D7566. Initial certification of batches has to follow the standards listed in the Annexes, which take into account the specific process and characteristics of the biojet fuel prior to blending. Some of the differences with Table 1 of ASTM D7566 are listed below:

- Density – Standard specification 775-840 kg/m^3
  - Variations
    - Fischer-Tropsch biojet and HEFA-SPK – 730-770 kg/m^3
    - SIP (farnesane) – 765-780 kg/m^3
    - SPK/A – 755-800 kg/m^3
    - ATJ – 730-770 kg/m^3
- Maximum freezing point – Standard specification Maximum -47°C
  - Variations
    - FT and HEFA-SPK – Maximum -40°C
    - SIP - -60°C
    - SPK/A - -40°C
    - ATJ - -40°C
- Aromatics – part of standard specification 8.4-26.5% by volume
  - Variations
    - FT and HEFA-SPK – Maximum aromatic mass content 0.5%
    - SIP – Maximum 0.5% mass content
    - SPK/A – Maximum aromatic mass content 20%
    - ATJ – 0.5%
- Cycloparaffins, paraffins and olefins are not specified in the main standard and variations included in the Annexes are
  - FT, HEFA-SPK – maximum cycloparaffin mass content 15%
  - SIP – Maximum olefin mass content 300 mg (Br)/100g
  - SPK/A – maximum cycloparaffin content – 15%
  - ATJ – 15%
- Nitrogen is not included in the standard specification for conventional or blended fuels, but included in Annexes – Maximum 2 mg/kg
- Water – maximum 75 mg/kg

- Metals (Al, Ca, Co, Cr, Cu, Fe, K, Li, Mg, Mn, Mo, Na, Ni, P, Pb, Pd, Pt, Sn, Sr, Ti, V, Zn) - Maximum 0.1 mg/kg per metal
- Halogens – Maximum 1 mg/kg
- Flash point – Minimum 38oC for most Annexes except SIP – 100^{o}C
- FAME (fatty acid methyl esters) in HEFA-SPK <5 ppm
- Thermal stability measurements – standard carried out at 260^{o}C
  - Variations
    - FT, HEFA-SPK – at 325^{o}C
    - SIP at 355^{o}C
    - SPK/A at 325^{o}C
    - ATJ at 325^{o}C

One important parameter that is worth discussing is the level of aromatics. While the blended fuel can contain between 8-25% aromatics, it is notable that the approved biojet fuels in FT, HEFA, SIP and ATJ have a limit of 0.5% aromatics. These biojet fuels generally contain low levels of aromatics, but this will not be the case with thermochemical liquefaction-based fuels that generate a lot of aromatics based on the lignin content in the lignocellulosic biomass feedstock. The only current approved biojet fuel with aromatics is SPK/A in Annex 4 which is based on blending of FT-SPK with aromatics before further processing. The limit on aromatics for the biojet batch is at 20%. If this limit is also adopted for thermochemical liquefaction based biojet fuels, the only results in this study that far exceeds this is the Catalytic pyrolysis biocrude as upgraded by PNNL. But as earlier mentioned, aromatics can be reduced through more aggressive hydrotreating.

In conclusion, the ATM Project has shown that biojet fuel could be produced through upgrading of biocrudes and this can pave the way for obtaining ASTM certification. Additional optimization could correct slight deviations from specifications. Although not all tests were carried out due to limited volumes available, the results are very positive and clearly illustrate that biojet production via these pathways could be successfully pursued.

CHAPTER 9 – CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

GHG emissions is a significant threat to our planet. One of the biggest contributors to these emissions is the transportation sector which contributes 23% to global emissions. While electrification is viewed as one of the most promising ways to decarbonize, this technology has limited application in a sector such as aviation. It is recognized that aviation requires drop-in biofuels that are functionally equivalent to existing, conventional jet fuels and able to make use of existing infrastructure such as airplanes and fueling infrastructure. Drop-in biojet fuels can deliver significant emission reductions to meet climate objectives of the sector towards 2050.

However, current production of biojet fuels is limited, with one technology pathway, hydrotreated esters and fatty acids (HEFA) supplying the vast majority of biojet fuels using feedstocks such as used cooking oil, fats and vegetable oils. High sustainability demands in the sector limit the use of food feedstocks for biofuel production, but the supply of alternative, waste feedstocks such as used cooking oil, fats and greases is restricted. The most feasible solution for significant volumes of biojet fuel production is the development of technologies that can use feedstocks such as lignocellulosic biomass, including forest residues that are available in large quantities on a global scale and often underutilized. Thermochemical technologies based on these feedstocks have been shown to be very promising. Gasification combined with synthesis of fuels through Fischer-Tropsch has obtained ASTM certification for use as a biojet fuel, although commercial production of these fuels has been slow, partly due to the very high investment costs required. The other type of thermochemical technology, thermochemical liquefaction, produces a liquid intermediate that can be catalytically upgraded into finished biofuels through hydrotreatment or catalytic cracking. Due to the high oxygen content of these liquid intermediates, addition of hydrogen is generally needed for deoxygenation.

Thermochemical liquefaction technologies have not been commercially demonstrated to produce biojet fuels and have not received ASTM certification as a biojet fuel. As explained above, such fuels are produced in two distinct stages, the production of a liquid intermediate, followed by the upgrading into finished fuels. Commercial development of the liquid intermediate production has been quite advanced, particularly fast pyrolysis that has reached small commercial stage. Other technologies, such as catalytic pyrolysis and hydrothermal liquefaction is at a less advanced stage of commercialization. However, the upgrading stage to produce finished fuels has been technically challenging and the production of biojet fuels via this route has not been demonstrated.

One of the key objectives of the ATM Project was to demonstrate that biojet production through thermochemical technologies and upgrading through hydrotreatment is feasible from a technical perspective, but also from an economic perspective provided the right policies are implemented. In addition, the ability of these biofuels to provide significant emission reductions was evaluated.

Key conclusions from this project are:

Biocrudes produced through thermochemical liquefaction technologies, including fast pyrolysis, catalytic pyrolysis and hydrothermal liquefaction can be successfully used to produce a significant volume of biojet fuel.

Several other fuel products were produced simultaneously that can be used in gasoline, diesel and marine or heating fuels.

The jet fractions were analysed and demonstrated a high level of compliance with general standards for jet fuel based on ASTM certification. Some minor off-spec results could be corrected with further upgrading. As none of the upgrading processes were optimised for jet production, these results were significant.

Assessment of potential emission reductions of these pathways through life cycle analysis demonstrated that significant emission reductions were possible with most of the pathways.

The highest potential emission reductions could be achieved with the fast pyrolysis and dedicated hydrotreating approach (81%). Optimization of the hydrothermal liquefaction process could achieve similar levels of emission reductions. In British Columbia, forest residues are currently burnt in slash piles and inclusion of the avoided emissions would make a significant contribution to potential emission reductions in all the pathways.

Dedicated hydrotreatment was more successful with respect to emission reductions compared with a co-processing hydrotreatment approach. Although the co-processing hydrotreatment approach could be further optimised, the main challenge was caused by the additional chemicals required to ensure miscibility of the liquid bio-intermediate with the fossil fuel fraction. Reduction of these chemicals through optimization or substitution with renewable alternatives could significantly improve the life cycle performance of the co-processing hydrotreatment pathway. It should be noted that the approach to co-processing followed by CanmetEnergy-Ottawa is just one of several co-processing methods and other methods may perform differently with regards to LCA assessment.

A thorough techno-economic analysis of all the pathways demonstrated that the minimum fuel selling price (MFSP) was higher compared with fossil jet fuel, given the current state of the technologies The best performing pathway was based on hydrothermal liquefaction and dedicated hydrotreating with an MFSP of CAD1,724.

Yield of the liquid intermediates based on mass of feedstock and yield after upgrading were significant factors in the TEA with catalytic pyrolysis having the lowest yield of biocrude and hydrothermal liquefaction the overall highest yield.

The CAPEX of the hydrothermal liquefaction was quite a bit higher than the fast pyrolysis or catalytic pyrolysis due to higher pressures used. A sensitivity analysis demonstrated that the CAPEX of the liquefaction stage (production of the liquid intermediate was one of the biggest cost factors and reduction would have an influence on the overall net present value (NPV).

A sensitivity analysis of all the pathways revealed that the greatest sensitivities were with respect to CAPEX of biocrude production, feedstock and hydrogen price.

A feedstock supply chain analysis was carried out for British Columbia with respect to availability and cost. Significant feedstock is available in the region, with a large price variation. A supply chain was selected in the Prince George region and based on a 200 bbl/day biocrude facility, sufficient feedstock was available at an average cost of CAD80 (delivered and comminuted).

An 80 dollar feedstock cost is quite high and makes the economics challenging, and larger facilities might have to access feedstock at an even higher cost. Reduction of feedstock cost should be an important goal for domestic biofuel production in BC and various policy changes are suggested that could make access to and cost of feedstock in the region more economical.

Sustainability across the entire supply chain is absolutely essential for the aviation sector. British Columbia and Canada has a forest sector with extensive sustainability certification (largest in the world). However, the use of forest residues does not currently fall under forest certification schemes and some changes will have to be implemented to extend forest certification to in-forest residue collection and utilisation.

As the liquid intermediates produced contain high amounts of oxygen, significant volumes of hydrogen are required for deoxygenation. The majority of hydrogen is currently produced through steam methane reforming of natural gas and this is the cheapest and most economical pathway. The TEA demonstrated that the NPV is highly sensitive to the cost of hydrogen and until renewable hydrogen production technologies such as electrolysis becomes cheaper (or natural gas becomes very expensive), current production methods will continue to be used for the near future.

However, the source of hydrogen is one of the biggest factors in the life cycle analysis with a linear relationship between kg of H2 used for upgrading and CO2 emissions generated. Suitable biojet fuel pathways have to find a balance between economically viable routes that also produce significant emission reductions.

While technical feasibility of a pathway is a necessary first step in production of biojet fuels, this cannot be considered sufficient on its own, as a matrix of factors must inform the overall suitability of a pathway. The ATM Project was able to assess the entire matrix of factors over the entire supply chain, offering a unique insight into biojet fuel production through the thermochemical technology pathways.

As all pathways demonstrated technical feasibility for the production of biojet fuels, and all pathways were based on the same feedstock supply chain, the two factors considered most significant were the potential emission reductions based on a life cycle assessment and the NPV and MFSP of the different pathways.

Based on an assessment across all factors, the HTL process combined with dedicated hydrotreatment was selected for development and design of a demonstration scale facility based in British Columbia, with production of biocrude in Prince George and upgrading taking place in the Lower Mainland co-located with an existing refinery for access to over-the-fence hydrogen and integration with downstream polishing steps and distribution. This allows biocrude production situated in proximity to the feedstock, allowing a densified intermediate to be transported for separate upgrading and distribution of biojet in proximity to a major airport. The selection of the lower mainland as a location for upgrading is due to the fact that the refinery is the only jet producer in BC, but theoretically the engineering designs could be applied in any location adjacent to a refinery.

The results from the techno-economic analysis clearly demonstrates that production of biojet fuels according to this pathway, based on current conditions such as oil price, will require a substantial premium to make it equivalent to conventional fossil jet fuel. Due to the high demand and low availability of biojet fuels, current biojet is purchased at a much higher price than conventional jet and the premium is thus simply an indication of equivalence.

The right policies will be essential to help bridge the price gap between conventional jet fuel and biojet fuel. Policy support has played a crucial role in the development of biofuels and similar policies can be used, including volumetric blending mandates, producer incentives, loan guarantees and grants for development of facilities, etc. However, the aviation sector, operating across borders, has unique considerations under international law with separate emission reduction targets agreed under ICAO, including an offsetting scheme (CORSIA) that will come into effect in 2021.

Three tiers of policy are applicable to production of biojet fuels in British Columbia, at international, national and provincial level. A synergistic relationship between policies at different levels is ideal, but this is not currently the case. The proposed federal Clean Fuel Standard (CFS) will come into effect in 2022 and could have a positive impact on the production and consumption of biojet fuels.

Currently, British Columbia has the most advanced policy environment for the production and consumption of biojet fuels based on a low carbon fuel standard which includes the flexibility of Part 3 agreements to have a substantial impact on development of technologies for reduction of emissions from transportation fuels. Expansion of these policies to include aviation under the low carbon fuel standard, and proposed inclusion of co-processing, which is currently under consideration, could contribute significantly to promotion of biojet production and consumption.

9.2 Recommendations

Based on the results of the ATM Project, it is recommended that the production of biojet fuels through thermochemical liquefaction and upgrading should be further pursued. From a technical point of view upgrading seems feasible as two completely disparate upgrading methods were successfully used. While the focus is often placed on technical challenges this is not adequate to determine the overall potential of a pathway and should be combined with life cycle assessment and techno-economic analysis which provides a broader and more complete assessment of a technology pathway. The LCA and TEA results are important tools to inform the optimization and improvement of the technical aspects.

Forest residue feedstock is available in significant quantities in British Columbia (and Canada) but the average cost for a biocrude production facility is CAD80. The TEA demonstrated that feedstock cost has a significant impact on the NPV and that reduction of this cost should be targeted. Specific factors that influence cost of feedstock in the region was examined and showed that various policy measures could increase access to feedstock and reduce the cost of such feedstock. A big advantage of basing a biojet production facility in Canada (and BC) is the sustainability of their forests, verified through third-party certification. However, forest residues are not currently part of the in-forest certification standards and ensuring a sustainable supply chain for biojet fuels require additional modules to be added to certification standards that will include in-forest certification of residues and their removal and utilization.

The LCA demonstrated that significant emission reductions could be obtained through many of the biojet pathways. The results could inform biocrude producers and upgraders of the factors that influence the potential emission reductions to allow optimization of these processes. The central importance of emission reductions in biojet fuel consumption means that pathways that are technically feasible but does not produce emission reductions will have limited opportunity for commercialization. Hydrogen consumption and the source of hydrogen has a large impact on the LCA and renewable sources of hydrogen, e.g. electrolysis, or the use of waste industrial gases as a feedstock, could have a significant impact on potential emission reductions. However, at low natural gas prices, the cost of current steam reforming methods is an important consideration. Improving the LCA by using renewable or waste feedstocks could utilize the same technology (steam reforming) but reduce the impact on the overall process.

The TEA showed a wide range of possible minimum fuel selling prices, although they were all higher than the current price for conventional jet fuel (based on current oil prices). This is not unexpected as the technologies being assessed are still under development and have ample opportunity for further optimization and enhancement of key performance metrics. Yield of biocrude from feedstock and overall yield of upgraded/refined biocrude was an important factor in the TEA, with catalytic pyrolysis delivering the lowest yields. The overall yield of the hydrothermal liquefaction and dedicated hydrotreatment process was the highest, making this pathway the best performer. Thus it is recommended that improvement of yields should be an important target of optimization. The factors contributing the most in the sensitivity analysis are CAPEX of biocrude, feedstock cost and hydrogen cost and these factors could be targeted for improvement. The CAPEX of HTL biocrude production is greatly impacted by the need for a waste-water treatment facility and this is recommended for further study and optimization.

While not considered as part of the hands-on research in this project, more extensive refinery integration through co-processing could have a significant impact on CAPEX of upgrading. Co-processing through hydrotreatment is expected to have miscibility problems similar to what was experienced in this project and this will have to be considered. Co-processing through catalytic cracking and separate injection might be more suitable for liquid intermediates and has been demonstrated to some extent, but not for biojet production and further study will have to be conducted to determine is this could be a suitable route for biojet fuel production. A combination of dedicated hydrotreatment and co-processing could be very effective, with partial upgrading carried out in a small hydrotreater and final upgrading as a co-processing approach.

The engineering design for a demonstration facility based on hydrothermal liquefaction and dedicated hydrotreatment is based on several assumptions as no real-world data exists for this technology at this scale. Recommendations include further study and testing of these assumptions to improve the accuracy of the data used.

It is apparent that an essential component for the successful development of biojet fuel production will be the right policies. The proposed ICAO off-setting scheme (CORSIA) in international aviation is not expected to have a big impact on biojet development as purchase of offsets is expected to be much cheaper. However, ICAO is still developing some of its regulations with respect to use of biojet fuels under CORSIA. The proposed Canadian federal Clean Fuel Standard could potentially have a positive impact on development of biojet fuel production and consumption in Canada based on inclusion of aviation fuel and a proposed fuel multiplier. To the extent that the CFS may promote drop-in biofuel production, this could also have a spin-off effect on biojet fuels where a blendstock with a jet fraction is produced. But refineries can make selective cuts so that the jet fraction could be diverted into the gasoline and diesel fraction unless there is an incentive to make jet fuel. The further impact that the CFS may have on refineries to consider and pursue a co-processing strategy to reduce fuel emissions, could also result in a spin-off effect for biojet production. However, as the CFS implementation is only in 2022, BC is considered the most favourable jurisdiction in Canada for biojet development as it already has good policies in place. It is recommended that the current low carbon fuel regulations be expanded to include aviation fuels to allow earning of credits for production of biojet fuels. In addition, it is recommended that the Part 3 agreements be expanded to incorporate co-processing in refineries and separate production of biocrudes and upgrading of biocrudes. This could be used as a temporary measure to boost the development of biojet fuels. It is also recommended that additional studies are carried out to explore novel policy solutions which could help bridge the price gap between conventional and biojet fuels which could initially be trialled at one airport prior to expansion at other airports. As biojet production is further developed with commercial availability of biojet volumes, a mandate could be considered. It is not recommended that a volumetric mandate alone is used and that an emission reduction approach is adopted.

9.3 Significance of this project to advancing biojet fuels

As shown in chapter 1, several technology pathways have received ASTM certification for biojet fuel to be used in commercial aviation. However, the majority of biojet fuels currently available at commercial scale is limited to HEFA jet fuel, produced through the hydrotreatment of fats and oils, with only one company producing dedicated volumes of biojet fuels. The feedstocks used, such as tallow or used cooking oil, has limited availability on a global scale. In order to produce the significant volumes required in terms of climate targets (>200 BL/year) will require the development and commercialisation of multiple technologies. Technologies based on lignocellulosic feedstocks such as wood waste will play a significant role in delivering large volumes of drop-in biofuels and biojet. This is due to the widespread availability and significant volumes of such feedstocks globally. Potentially, the lignocellulosic feedstocks could also be cheaper than other types of feedstocks such as vegetable oils and sugars.

Thermochemical technology pathways can use the lignocellulosic feedstocks and are most appropriate for the production of drop-in biofuels and biojet. These technologies can be broadly grouped into gasification and liquefaction. While gasification with Fischer-Tropsch synthesis was the first type of biojet to receive ASTM certification, the commercial development of this technology based on lignocellulosic feedstocks has been slow due to technical and cost challenges (very high CAPEX).

Alternatively, thermochemical liquefaction technologies show great promise for lower CAPEX commercialisation and economically competitive fuel prices. However, several technical challenges remain, particularly with respect to the upgrading of the liquid intermediates into finished fuels. Overcoming key challenges could make a significant contribution to development and commercialisation of these technologies. This was the primary objective of the ATM Project, to advance the knowledge and address some of the challenges associated with the thermochemical liquefaction technologies and upgrading of liquid intermediates.

The further unique aspect of the ATM Project is the simultaneous assessment of technical, life cycle and techno-economic parameters from the same dataset which will allow for a more comprehensive evaluation of pathways. Taking into account the impact of multiple factors simultaneously allows for comprehensive optimisation of processes and clear recommendations could be made from the results of this project.

The ATM Project demonstrated that biojet fuels could be successfully produced through thermochemical liquefaction technology and a hydrotreating upgrading approach. Many of the pathways could result in significant emission reductions to achieve the objectives of the aviation sector. The outcomes of this project could be used worldwide by researchers, biofuel companies and the aviation sector for decision-making.

9.4 Benefits of this project to Canada

Canada’s aviation sector forms an important and essential component of transportation in the country. Reducing emissions from this sector is imperative for Canada’s commitments under climate agreements, and essential for airlines such as Westjet and Air Canada in order to reduce the financial burden of the carbon offsetting scheme under ICAO that will come into effect.

While Canada has several facilities that produce ethanol and biodiesel, there are no domestic facilities producing drop-in biofuels (and potentially biojet fuels). As the production of jet fuel is one of multiple products, fractionated through distillation from a fuel blendstock, drop-in biofuels production is considered essential for the development of biojet fuels. Jet fuel and other fuels are produced simultaneously and the other fuel products are also important for improving the economic viability of a facility.

Canada has a commercial gasification facility, Enerkem, that produces fuels from the gasification of municipal solid waste. However, the company only produces methanol and ethanol and not drop-in biofuels.

With regards to thermochemical liquefaction technology, Canada has companies such as Ensyn, using fast pyrolysis of woody biomass to produce pyrolysis oil which can be upgraded into drop-in biofuels, including biojet. In addition, two hydrothermal liquefaction companies, Steeper Energy and Licella are both actively developing their technology in Canada, with progress underway to build small-scale pilot/demo facilities in Alberta and British Columbia for production of HTL biocrudes. These biocrudes will still need upgrading into finished fuels and the results from the ATM project could assist these companies in furthering the commercialisation of their technology through freestanding upgrading or co-processing.

Canada has extensive resources of sustainable forests that could contribute as a feedstock to drop-in biofuel/biojet production. In many cases the forest residues wastes are not currently used and burnt in slash piles. Utilisation of these residues through fuel production could reduce the emissions from slash burning, while also contributing to the economic development of the forest sector through new products.

While the ATM project focused on forest residues as a feedstock, technologies such as hydrothermal liquefaction can utilise a large variety of wet feedstocks such as sewage sludge, manure, etc. The results from the ATM project could also make a significant contribution in this respect as the engineering designs for a demonstration scale facility and upgrading could be adjusted for any feedstock.

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APPENDIX A

Co-processing of biocrudes in existing refineries

Insertion of bio-oils/biocrudes in the fluid catalytic cracker

Recently Stefanidis et al. (2017) (Bezergianni *et al.*, 2018) discussed the possible insertion of bio-oil/biocrudes in the fluid catalytic cracker. These authors suggested that increased coking and reactor plugging due to char and coke formation made raw bio-oil unsuitable for co-processing unless the bio-oil was first upgraded through hydrotreatment to remove oxygen. However, they also indicated that these findings were a result of the experimental set-up as the conditions did not resemble a real FCC as different conclusions were obtained when using a pilot scale FCC under more realistic conditions. In related work de Rezende Pinho et al. (2015, 2017) (Pinho *et al.*, 2015, 2017) looked at the co-processing of bio-oil in the FCC after appropriate reactor modifications, including separate injection of bio-oil. However, other workers (F. de Miguel Mercader *et al.*, 2010) have argued that only the most reactive compounds and functional groups needed to be stabilised and thus, up to a 28% oxygen can be tolerated.

Despite these differences in opinion, there seems to be a general consensus that partial deoxygenation of bio-oil is probably required before insertion, if potential suppliers are to meet the minimum requirements of the refinery. However, complete deoxygenation of bio-oil is expensive since deoxygenation gets disproportionately costlier when approaching an oxygen-free status. (Ringer, Putsche and Scahill, 2006; Elliott, 2007; Arbogast *et al.*, 2017) Catalytic pyrolysis bio-oils and biocrudes from hydrothermal liquefaction are already partially deoxygenated and could potentially bypass intermediate steps prior to catalytic cracking. However, many partially deoxygenated bio-oils and HTL biocrudes have very high viscosities, making pumping difficult. (Elliott, 2007; Choudhary and Phillips, 2011; Elliott *et al.*, 2015)

Earlier FCC-based trials which looked at co-processing bio-oil in blends with vacuum gas oil (VGO) demonstrated that lower H/C ratio products were produced when compared to processing VGO alone. (Corma *et al.*, 2007; Lappas, Bezergianni and Vasalos, 2009) It was also concluded that heavier (coke and tar) and lighter (gasoline and gases) fractions were produced at the expense of middle distillates while the gasoline produced was generally poorer in saturates and richer in aromatics. (Lappas, Bezergianni and Vasalos, 2009)

In related studies, a mixture of 20% HDO bio-oil (at 20% oxygen) was co-processed in an FCC with petroleum VGO (Fogassy *et al.*, 2010) while de Miguel Mercader et al. (2010) (F. de Miguel Mercader *et al.*, 2010) co-processed an HDO bio-oil (28% oxygen) with a Long Residue heavy petroleum feed. Both of these studies reported a decrease in the coking propensity of HDO bio-oils when they were blended as compared to fossil feeds catalytic cracking. This was attributed to the transfer of hydrogen from the petroleum to the biomass feed during co-processing.

In more recent work, where FCC co-processing of raw bio-oils with a 51% oxygen content was tested, (Pinho *et al.*, 2015, 2017) the oxygen was primarily removed as H_2O, while CO yields were higher than CO_2 yields. Co-processing resulted in gasoline and diesel products with some renewable content, as determined by ^{14}C isotopic measurement. A 10 wt% blend of bio-oil resulted in a 2% renewable content in the total liquid product. (Pinho *et al.*, 2015) It was also concluded that oxygen removal took place through hydrogen transfer from the fossil feed molecules. This resulted in a higher aromatic content in the final products, with higher levels of phenolics found in the naphtha product. It is important to note the experimental set-up for this FCC demonstration study, in contrast to the many previous laboratory/pilot scale tests, featured a circulating riser with different feed nozzles. This allowed the separate insertion of the bio-oil (at 50°C) at a higher point in the riser, compared with the temperature of the VGO at 220-280°C. It also resulted in lower coke formation than the FCC labscale test using Micro Activity Testing (MAT) where the feed was blended and heated prior to insertion into the reactor. Thus, de Rezende Pinho et al (2015) (Pinho *et al.*, 2015) concluded that lab-scale testing was not adequately able to predict the behaviour of co-processing of bioblends in an FCC, as it was difficult to replicate real reactor conditions. Bezergianni et al. (Bezergianni *et al.*, 2018) came to a similar conclusion, although they thought the observation was mostly applicable to raw bio-oil cracking. However, in earlier work, Bryden et al. (2013) (Bryden, Weatherbee and Habib Jr, 2013) found increased coke formation in spite of using a pilot-scale circulating riser reactor and modified feed delivery system. This was similar to the subsequent results reported by Zacher et al. (2015) (Zacher, 2015) where changes in yield of products were also reported, specifically a reduced gasoline yield.

Other related work has suggested that the co-processing of hydrogen deficient bio-oils with hydrogen-rich petroleum feeds can have a positive synergistic effect in mitigating the production of solid by-products. (Stefanidis, Kalogiannis and Lappas, 2017) This indicated that the characteristics of the fossil feed will impact potential synergy, as hydrogen transfer between the fossil feed and bio-components takes place.

In summary, while catalytic cracking of raw pyrolysis oil is possible, when certain modifications are made to overcome miscibility problems, the processing of hydrodeoxygenated oils (HDO) and catalytic pyrolysis oils (CPO) is usually easier. (Stefanidis, Kalogiannis and Lappas, 2017)

Insertion of bio-oils/biocrudes into the hydrotreater

The lack of miscibility of bio-oils with the fossil feed is a key problem as hydrotreating cannot take place unless mixing takes place. However, most studies on co-processed hydrotreatment have used model compound and the results have therefore been difficult to apply to real bio-oils. (Bezergianni *et al.*, 2018)

As mentioned earlier, hydrotreatment units are sensitive to oxygen and unlikely to be used to process bio-oils with an oxygen content that exceeds about 5% at blending ratios of less than 10%. (Solantausta, 2011) Depending on the molecular weight distribution of the bio-oil, cracking of molecules may be required, although this is not usually carried out in the hydrotreater as mild conditions are used. However, hydrocracking typically follows hydrotreating in an oil refinery and it is even less tolerant to oxygen than hydrotreatment (due to higher pressures and temperatures).

There is limited experimental data on co-feeding of real bio-oils with petroleum feeds in hydrotreating units. This is not unexpected as problems such as increased coking and catalyst deactivation, increased hydrogen demand and potential irregular hydrogen pressure drops inside the reactor can be anticipated. (Butler *et al.*, 2011).

It is apparent that both FCCs and hydroprocessing refinery units can accept bio-oils that have been partially deoxygenated (HDOs). However, the two facilities differ in their relative suitability for biofeed insertion (Table 86). It has been shown that FCCs can handle lower grade (up to 20% oxygen) HDOs without the need for hydrogen and this results in low conversion yields, large amounts of waste energy production and lower value end products (low H/C ratio) which will contribute mostly to marine and bunker fuel blendstocks. In this regard FCC can be viewed as the "workhorse" of bio-oil co-processing. Alternatively, hydroprocessing could be considered the refinery's "boutique" upgrading unit as it requires more deoxygenated bio-oil co-feed (max of 3-5%) and it is designed to produce higher grade diesel and jet fuels.

Table 90: **Comparison of FCC and hydroprocessing as refinery co-processing platforms for bio-oils**

	FCC (Fluid Catalytic Cracking)	Hydroprocessing (hydrotreating followed by hydrocracking)
Tolerable oxygen content in bio-oil feed	**Up to 20% (<5% blend)**	**No more than 3-5%**
Pre-refinery hydrotreatment	**Single stage/mild**	**Two-stage/severe**
Hydrogen use (NL / L of bio-oil)	**ca. 300**	**>800**
Yields	**Low (10-15% in standalone)**	**High (25% in standalone)**
Downstream contamination risk with oxygenates	**High**	**Low**
Opportunity for power generation through coke combustion	**High**	**Low**
Chemistry of product	**Favors aromatics (low H/Ceff ratio)**	**Favors short paraffins (high H/Ceff ratio)**
Fuel pool (most contribution)	**Gasoline and Marine fuels**	**Middle distillates: Diesel and Jet fuels**

Source: (adapted from Solantausta, 2011)

APPENDIX B

Source and cost of hydrogen

Introduction

Hydrogen supply is generally divided into "captive" hydrogen, produced at refineries for production of fuels and chemicals, and "merchant" hydrogen, produced for trading purposes. While both use similar methods for hydrogen production, merchant hydrogen has the added cost of compression or liquefaction and transportation due to its low energy density. This can add a significant cost as specialized equipment and containers are required. Therefore hydrogen is used as close to the source of production as possible.

As a biofuel production facility will require large volumes of hydrogen, options for sourcing include:

- Building its own infrastructure for production of hydrogen based on a variety of different technologies;
- Purchasing merchant hydrogen from a trader;
- Co-location of the biofuel facility next to a petroleum refinery or facility with excess hydrogen production capacity, called "over-the-fence" hydrogen;
- Sourcing by-product hydrogen, which is produced as a waste product from an industrial facility and is usually flared and not utilized for further value addition. This will likely require purification of the hydrogen before use.

While the cost of different production technologies will play a role in selection, the environmental impact of the hydrogen production must play an important role if production of biofuels with low carbon intensity is the objective. The environmental impact of hydrogen production is based on the feedstock used, as well as the source of electricity. Natural gas is the most common feedstock used for hydrogen production, but other feedstocks could include coal, biomass or renewable natural gas. Coal is considered the least environmentally friendly feedstock. Electrolysis of water can be very sustainable provided renewable electricity (solar, wind, hydro) is used.

On a global scale, about 96% of all hydrogen is derived from fossil fuels, with natural gas being by far the most prominent source at an estimated 49%, followed by liquid hydrocarbons at 29%, 18% from coal, and about 4% from electrolysis and other by-product sources of hydrogen (IHS, 2015) (Figure 66).

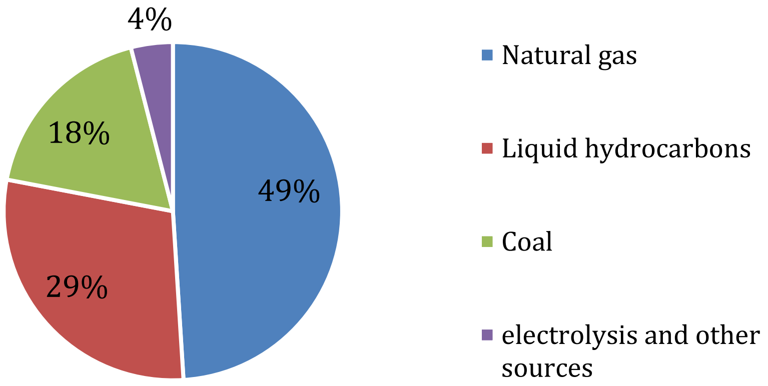


Figure 57. Feedstock used to produce hydrogen on a global scale (IHS, 2015)

Global demand for hydrogen in petroleum refining is increasing due to a higher demand for distillates and stricter fuel regulations which place greater limits on sulfur and nitrogen levels in fuels to reduce emissions. This results in increased hydrogen requirements at refineries for desulfurization and denitrogenation of fuels. Removing sulfur and nitrogen components allows gasoline and diesel to burn cleaner and to prolong the lifetime of catalysts in emission control systems. This makes hydrogen a critical component in the production of cleaner fuels to reduce SOx and NOx emissions from combustion of fuels. A recent agreement at the International Maritime Organisation (IMO) to reduce sulfur in bunker fuels from 3.5% to 0.5% by 2020 is expected to have a large impact on hydrogen demand and refinery capacity for desulfurization. Against this background, we consider different technologies for hydrogen production.

Hydrogen production technologies

Depending on the customer requirements and the feedstock, various technologies can be used to produce hydrogen. A list of major hydrogen production technologies is provided in Table 87. Each technology has unique needs in terms of energy sources, such as heat, electricity, and light, and generates unique byproducts or emissions (SDTC, 2006).

Table 91. Major hydrogen production technologies (SDTC, 2006)

Primary method	Process	Feedstock(s)	Energy required	Emissions
Thermal	Steam Reformation	Natural gas, other gaseous or light hydrocarbons	High temperature steam	GHG and other emissions
	Gasification	Coal Heavy Hydrocarbons	Steam & oxygen at high temperature & pressure	GHG and other emissions
	Autothermal Reformation (Partial Oxidation)	Natural gas, other gaseous or light hydrocarbons	Steam generated by heat from the exothermic process	GHG and other emissions
	Catalytic Reforming	Napthas from oil refining	Heat from the oil refining process	GHG and other emissions
	Pyrolysis	Biomass	Moderately high temperature steam	GHG emissions
	Thermochemical Water Splitting	Water	High temperature heat (e.g. from gas cooled nuclear reactor)	No emissions during electrolysis process
Electrochemical	Electrolysis	Water	Electricity from renewable sources	No emissions during electrolysis process.
	Electrolysis	Water	Electricity from fossil fuel sources	GHG and other emissions from fossil fuel sources.
	Thermal Catalytic Dry Reformation	Methane, landfill gas, water	Heat (solar energy or other heat source)	GHG missions (depending on feedstock)
	Plasma Dissociation	Biomass, Natural Gas	Electricity (plasma discharge)	No emissions
Byproduct Recovery	Recover H2 from another Process	(No specific feedstock for hydrogen production)	Incremental energy required for gas clean-up and possible compression	No emissions from collection of hydrogen
Biological	Photobiological	Water and algae strains	Direct sunlight	No emissions
	Anaerobic Digestion	Biomass	High temperature steam	GHG and other emissions
	Fermentative Microorganisms	Biomass	High temperature steam	GHG and other emissions

Customer requirements for quality and cost

The quality and cost of hydrogen production depends on the customer requirements. The main specifications considered by a hydrogen producer are:

a) Quantity required – i.e. at what rate is hydrogen consumed and is the rate constant?;

b) Storage state – i.e. will this be liquid or gaseous?;

c) Pressure – i.e. what pressure is needed for gaseous storage, downstream conditioning, and feeding to chemical processes?;

d) Purity – i.e. what are the specific impurity limits based on storage and requirements of process?;

e) Reliability of supply – i.e. are storage or redundant units needed?

f) Availability of utilities – i.e. is natural gas, heat, and/or electricity available?

g) Emissions – i.e. what are the local air quality requirements/emission regulations? On a full cycle basis, what are the global emission implications?

h) Are capture and sequestration options available where CO2 emissions are produced?;

i) Operating characteristics – i.e. are these continuous or intermittent? Is there the ability to turndown output? and

j) Siting – i.e. what codes and regulations will impact permitting and approvals? (SDTC, 2006)

Table 88 shows the connection between the production technologies and the customer requirements. The size of hydrogen production facilities can be divided into three categories: (1) large scale: >1000 tonnes/year; (2) Medium: 10-1000 tonnes/year and (3) small: <10 tonnes/year. Large scale production fits the central production model of hydrogen infrastructure and favours SMR and gasification, whereas distributed production would favour less complicated processes and designs which could be "skid assembled" (SDTC, 2006). This table also shows the relationship of market segments to the preferred mechanism for hydrogen production and related requirements or considerations, such as emissions and major gas impurities.

Table 92. Hydrogen production technologies and customer requirements (SDTC, 2006)

Hydrogen Production Technology	Size	Storage state	Emissions per kg of H2	Major gas impurities
Gasification	Large	Gaseous or liquid	Approx. 15 kg CO2	CO, S
SMR	Medium to large	Gaseous or liquid	10 kg CO2	Co,S
By-Product Hydrogen Recovery	Small to large	Gaseous	0 based on marginal rate of Emission	Cl, HCl, H2O
Electrolysis a) Grid connected	Small to medium	Gaseous	Depends on electricity supply	O2, H2O
Electrolysis b) Renewable	Small to medium	Gaseous	0	O2, H2O
Auto-thermal	Small to medium	Gaseous	10 kg of CO2	CO, S
Plasma Dissociation	Small to medium	Gaseous	CO2 can be CO, S Intermittent captured as carbon black in Carbon-saver™	CO, S
Thermal Dissociation	Small to medium	Gaseous	Using landfill gas (SHEC process) converts methane to CO2 for GHG credit	CO, S

Hydrogen cost

It is generally agreed that steam methane reforming of natural gas is still the most economical production method for hydrogen, but extensive research is ongoing to find renewable, cost-competitive methods. Acar and Dincer (2014) carried out a comparative study on the cost of hydrogen production using different technologies.

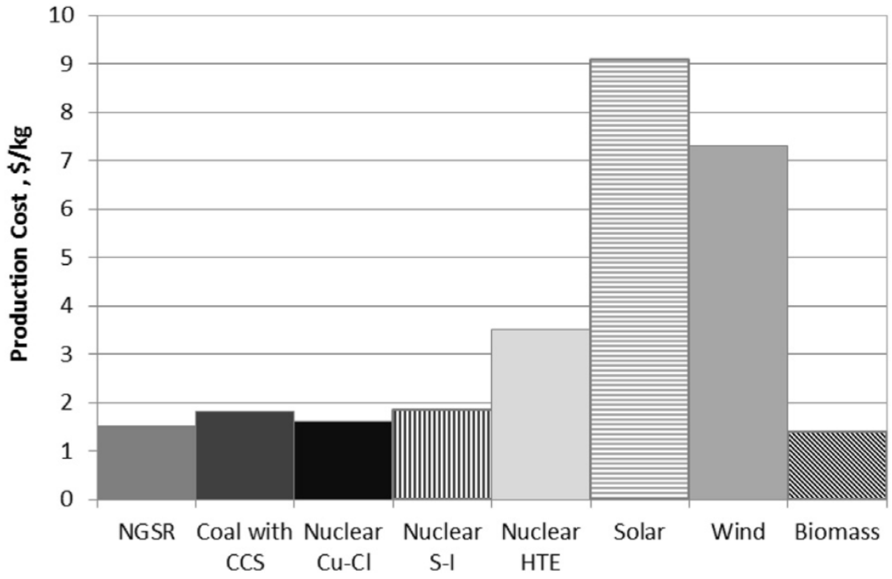
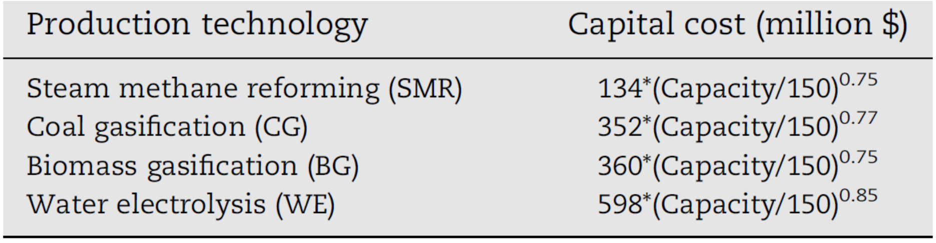


Figure 58. Average cost of hydrogen production (Acar & Dincer 2014)

Table 93. Hydrogen production capital cost comparison as a function of plant capacity (ton/day, tpd). Acar & Dincer 2014.



Production technology	Capital cost (million $)
Steam methane reforming (SMR)	$134*(\text{Capacity}/150)^{0.75}$
Coal gasification (CG)	$352*(\text{Capacity}/150)^{0.77}$
Biomass gasification (BG)	$360*(\text{Capacity}/150)^{0.75}$
Water electrolysis (WE)	$598*(\text{Capacity}/150)^{0.85}$

Hydrogen storage and transportation

Hydrogen is a widely used and stored industrial gas with a well-developed set of codes and standards governing its use. Two main modes of transportation are trucks and pipelines, and storage vessels are certified by ASME or national and regional transportation standards. Hydrogen is stored and transported in compressed or liquified form.

Pipelines are considered the only cost-efficient option to move large amounts of H2 and have been used to transport H2 for more than 70 years. Several thousand kms of H2 pipelines are currently in operation worldwide. The energy required to pump H2 through pipelines is about 4.5 times higher than for natural gas per unit of delivered energy. As a result long distance H2 transportation for energy use may not be economically competitive. Transportation costs to deliver gaseous H2 to refueling stations are in the range of $1-$2/GJ, assuming that H2 compression to refueling pressure is included in the cost of the refueling station (IEA, 2007).

Liquid H2 transport by truck, rail or ship is more expensive than gas piping. Transportation of liquid H2 by ship over long distances is also more expensive than for natural gas (LNG) since very low-temperature cryogenic technology is needed (IEA, 2007).

The various methods of hydrogen storage have trade-offs with regard to the energy penalties involved, along with their characteristics related to safety, weight, cost, rate of energy transfer, and other factors (Lipman, 2011).

Hydrogen supply in Canada and BC

In Canada, merchant hydrogen is delivered to the upgrading and oil refineries mainly through pipeline. Air Products' existing hydrogen pipeline network supplies refiners, upgraders, chemical processors and other industries in the Alberta Industrial Heartland region. Air Products' two existing hydrogen production facilities located in Strathcona County near Edmonton, are joined via a 30-mile pipeline network to provide a very reliable source of hydrogen for these industries. Dow Chemical Canada ULC, Evonik Degussa Canada Inc, Shell Canada Energy, Sherritt International Corporation, and Williams Energy (Canada) Inc are examples of industries that receive hydrogen through this pipeline. Ninety five percent of the Heartland pipeline followed the path of existing pipelines in Alberta to minimize the need for environmental disturbances. Besides the Heartland Hydrogen Pipeline system in Alberta, Air Products also has a hydrogen pipeline in Sarnia, Ontario and operates the world's largest hydrogen pipeline network in the United States Gulf Coast, as well as pipeline systems in California in the U.S. and Rotterdam, the Netherlands (Air Products, 2010 and 2016).

In BC, the Parkland Refinery in Burnaby, as well as the Husky Refinery in Prince George, produce their own hydrogen through steam reforming of natural gas which is used for upgrading of crude oil into petroleum products. Merchant hydrogen is under development and currently at smaller scale for hydrogen fuel cell vehicles. The first hydrogen fueling station was opened by

Shell in Vancouver in June 2018[32]. HTEC is a hydrogen fuel supplier with a presence in BC[33] with technology based on electrolysis and by-product hydrogen purification.

Production of renewable natural gas (RNG) and hydrogen from biomass streams such as agricultural wastes and forest residues (and landfills) have been pursued by some pioneering companies in BC such as G4 Insights (Fortis BC, 2017). G4 Insights is a renewable energy producer that transforms waste products from Canada's forestry industry into a valuable fuel product. However, the low price of natural gas for the foreseeable future and immaturity of the existing clean conversion technologies make the production of RNG and hydrogen uneconomical, especially at commercial scales. The growth of this sector can diversify Canada's energy mix, reduce greenhouse gas emissions, improve industrial efficiency and create new economic opportunities for Canadian companies and good middle-class jobs that benefit rural communities (Fortis BC, 2017).

Hydrogen is also produced as waste or as an industrial by-product. Such hydrogen streams are often disposed of through venting or flaring, or otherwise are burned to generate heat. These hydrogen streams can be harnessed as a fuel for power generation, transportation and for the removal of oxygen in hydrotreatment processes. British Columbia is well situated to take advantage of this industrial by-product by simply re-positioning the hydrogen that is already being produced without the need for expensive infrastructure investments. Currently, BC has three chemical industrial plants in Prince George, North Vancouver and Nanaimo that produce hydrogen as an industrial by-product. These companies have been trying to capture the hydrogen in their production processes and use it as a source of clean energy or feedstock for fuel-cells. The hydrogen required by the entire fleet for one day is produced in less than one hour by the North Vancouver plant (PICS, 2010).

By-product or waste hydrogen from industrial facilities throughout BC is currently underutilised. Using these hydrogen streams for the removal of oxygen from feedstock and to obtain hydrocarbon molecules with a high effective hydrogen to carbon ration offers a ready opportunity for significant energy savings and cost recovery. Moreover, hydrogen consumers can gain a reliable fuel supply (PICS, 2010).

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[32] https://www.cbc.ca/news/canada/british-columbia/hydrogen-fuel-pump-opens-in-vancouver-1.4709016

[33] https://www.htec.ca/

APPENDIX C

Approach to Life Cycle Analysis in this project

The concept of life cycle assessment (LCA) emerged in the late 1980's from competition among manufacturers attempting to persuade users about the superiority of one product choice over another. As more comparative studies were released with conflicting claims, it became evident that different approaches were being taken related to the key elements in the LCA analysis:

- Boundary conditions (the "reach" or "extent" of the product system);
- Data sources (actual vs. modeled); and
- Definition of the functional unit.

ISO 14040

In order to address these issues and to standardize LCA methodologies and streamline the international marketplace, the International Standards Organization (ISO) has developed a series of international LCA standards, specifications, and technical reports under its ISO 14000 Environmental Management series. In the 1997-2000 period, ISO developed a set of four standards that established the principles and framework for lifecycle assessment (ISO 14040:1997) and the requirements for the different phases of LCA (ISO 14041-14043). The main contribution of these ISO standards was the establishment of the LCA framework that involves the four phases in an iterative process:

Phase 1 - Goal and Scope Definition;

Phase 2 - Inventory Analysis;

Phase 3 - Impact Assessment; and

Phase 4 – Interpretation

By 2006, these LCA standards were consolidated and replaced by two current standards: one for LCA principles (ISO 14040:2006); and one for LCA requirements and guidelines (ISO 14044:2006). Additionally, ISO has published guidance documents and technical reports (ISO 14047-14049) to help illustrate good practice in applying LCA concepts.

The ISO 14040:2006 standard describes the principles and framework for life cycle assessment including: definition of the goal and scope of the LCA, the life cycle inventory analysis (LCI) phase, the life cycle impact assessment (LCIA) phase, the life cycle interpretation phase, reporting and critical review of the LCA, limitations of the LCA, the relationship between the LCA phases, and conditions for use of value choices and optional elements. ISO 14040:2006 covers life cycle assessment (LCA) studies and life cycle inventory (LCI) studies. It does not describe the LCA technique in detail, nor does it specify methodologies for the individual phases of the LCA. The intended application of LCA or LCI results is considered during definition of the goal and scope, but the application itself is outside the scope of this International Standard.

ISO Principles

It is useful to consider seven basic principles in the design and development of life cycle assessments as a measure of environmental performance. The seven principles outlined below are the basis of ISO Standard 14040:2006:

- Life Cycle Perspective (the entire stages of a product or service);
- Environmental Focus (addresses environmental aspects);
- Relative Approach and Functional Unit (analysis is relative to a functional unit);
- Iterative Approach (phased approach with continuous improvement)
- Transparency (clarity is key to properly interpret results)
- Comprehensiveness (considers all attributes and aspects)
- Priority of Scientific Approach (preference for scientific-based decisions).

LCA Modelling Issues

Even with the ISO Principles and Guidelines for undertaking life cycle assessments there are different approaches that have been used for modelling fuel systems and these can lead to different results from different studies.

Attributional vs. Consequential

There are many different types of Life Cycle Assessments that can be utilized to determine the emissions output for any given product. These different types of LCAs can produce dramatically different results that are largely dependent on the defined system boundaries within the selected LCA mode. Two of these LCAs that can, and often will, produce very different results are the Attributional and Consequential LCAs.

Attributional LCA (ALCA) provides the user with information about the impacts of the production, consumption, and disposal of a product, without considering any indirect emissions that may occur, whereas a Consequential LCA (CLCA) models the causal relationships that originate from a decision to change the level of output and are highly dependent upon economic models that represent the relationship between demand, supply, price elasticity, and market effects of co-products. ALCA is useful for consumption based carbon accounting because it provides information on the average unit of a product. CLCA models the consequences of a change in output by considering effects both inside and outside of the life cycle of the product. The table below outlines key differences between these two systems. (Brander et. al, 2009).

Table 94 Comparison of Attributional and Consequential LCAs

	Attributional LCA	Consequential LCA
Question the method aims to answer	What are the total emissions from the processes and the material flows directly used in the life cycle of a product?	What is the change in total emissions as a result of a marginal change in the production (and consumption and disposal) of a product?
Application	ALCA is applicable for understanding the emissions directly associated with the life cycle of a product. ALCA is also appropriate for consumption-based emissions accounting. ALCA is not an appropriate approach for quantifying the change in total emissions resulting from policies that change the output of certain products.	CLCA is applicable for informing consumers and policy-makers on the change in total emissions from a purchasing or policy decision. CLCA is not appropriate for consumption-based emissions accounting.
System boundary	The processes and material flows directly used in the production, consumption and disposal of the product. The vehicle may be an important consideration for some fuels.	All processes and material flows, which are directly or indirectly affected by a marginal change in the output of a product (e.g. through market effects, substitution, use of constrained resources etc).
Marginal or average data	ALCA tends to use average data, e.g. the average carbon intensity of the electricity grid. Though, some models offer a choice.	CLCA tends to use marginal data e.g. the marginal carbon intensity of the electricity grid.
Market effects	ALCA does not consider the market effects of the production and consumption of the product.	CLCA considers the market effects of the production and consumption of the product.
Allocation methods	ALCA allocates emissions and process energy inputs to co-products based on either economic value, energy content, co-product energy displacement, or mass.	CLCA uses system expansion to quantify the effect of co-products on emissions.
Time-scales, means by which change is promoted, and magnitude of the change	ALCA aims to quantify the emissions attributable to a product at a given level of production at a given time.	CLCA aims to quantify the change in emissions, which result from a change in production. It is necessary to specify the time-scale of the change, the means by which the change is promoted, and the magnitude of the change.
Uncertainty	ALCA has low uncertainty because the relationships between inputs and outputs are generally stoichiometric.	CLCA is nearly always highly uncertain because it relies on models that seek to represent complex socio-economic systems that include feedback loops and random elements.

Attributional LCA Approaches

From the literature there appear to be two primary means of determining the emissions that are embedded in energy production facilities: a process-chain analysis (PCA) and an input/output analysis (IOA). The PCA calculates the energy embedded in and the emission-equivalents caused by the production of materials used in the application. The IOA works with economic sectors related to the manufacturing activities. The PCA approach requires some knowledge of the materials included in the facility whereas the IOA only requires an understanding of the costs of construction and the economic structure of the country or region where the construction is occurring.

Consequential LCAs

The practice of consequential LCA has gained prominence over the past decade. The topic of indirect land use from biofuels is one that can only be addressed through consequential LCA. Since economic modelling is at the core of a consequential analysis, most of the developing CLCA models are built upon existing macro-economic models that are modified to consider physical changes or environmental impacts. Brander et al (2009) suggest that CLCA models should not be used for consumption based carbon accounting as CLCA is less well defined than ALCA, and therefore allows a much greater degree of interpretation.