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ADVANCEFUEL

D3.4 A description of key European fossil-fuel infrastructures, which can facilitate the ramp-up of biomass use

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ADVANCEFUEL at a glance

ADVANCEFUEL (www.ADVANCEFUEL.eu) aims to facilitate the commercialisation of renewable transport fuels by providing market stakeholders with new knowledge, tools, standards and recommendations to help remove barriers to their uptake. The project will look into liquid advanced biofuels – defined as liquid fuels produced from lignocellulosic feedstocks from agriculture, forestry and waste – and liquid renewable alternative fuels produced from renewable hydrogen and CO2 streams.

In order to support commercial development of these fuels, the project will firstly develop a framework to monitor the current status, and future perspectives, of renewable fuels in Europe in order to better understand how to overcome barriers to their market roll-out. Following this, it will investigate individual barriers and advance new solutions for overcoming them.

The project will examine the challenges of biomass availability for second-generation biofuels, looking at non-food crops and residues, and how to improve supply chains from providers to converters. New and innovative conversion technologies will also be explored in order to see how they can be integrated into energy infrastructure.

Sustainability is a major concern for renewable fuels and ADVANCEFUEL will look at socio-economic and environmental sustainability across the entire value chain, providing sustainability criteria and policy-recommendations for ensuring that renewable fuels are truly sustainable fuels. A decision support tools will be created for policy-makers to enable a full value chain assessment of renewable fuels, as well as useful scenarios and sensitivity analysis on the future of these fuels.

Stakeholders will be addressed throughout the project to involve them in a dialogue on the future of renewable fuels and receive feedback on ADVANCEFUEL developments to ensure applicability to the end audience, validate results and ensure successful transfer and uptake of the project results. In this way, ADVANCEFUEL will contribute to the development of new transport fuel value chains that can contribute to the achievement of the EU's renewable energy targets, and reduce carbon emissions in the transport sector to 2030 and beyond.

To stay up to date with ADVANCEFUEL's stakeholder activities, sign up at: www.ADVANCEFUEL.eu/en/stakeholders

Executive Summary

Given the importance of climate change and the various policies required for its mitigation, it is important to assess opportunities for the greening of the fossil fuel infrastructure and its associated systems, since using the existing energy infrastructure for green fuels may offer near term and low risk options for emission mitigation. Co-processing of biomass towards production of renewable fuels in existing infrastructures such as power plants, gasifiers, refineries, and chemical plants, can benefit from existing knowledge and human resources in order to establish new biomass supply practices.

The work presented within this report is a starting point to presenting opportunities that could contribute to the development of increased use of biomass including its specific refinement concerning transportation fuels. Thus, the greening of the existing fossil fuel infrastructure could potentially be a driver in the development of advanced biofuel production facilities, as it can reduce the initial risk in terms of cost and technological constraints, while also creating stepping-stones by determining synergies with other sections of the energy sector. At the same time, it is of course important to make sure that such greening strategies are a segment of a more long-term strategy, which would phase out the fossil fuel infrastructure, by avoiding lock-in effects.

The technological options, which are included in the analysis of this WP, are divided into direct and indirect categories. A technological option that is considered “direct” is characterised by options, which lead to the incorporation of renewable carbon in the final molecule of the fuels. An example of this would be the blending of a biogenic feedstock in a fossil-based process stream, and then co-processing in a downstream conventional unit, or substituting a conventional part of the production chain of a liquid fuel by a bio-based one (e.g. gasification for Fischer-Tropsch synthesis, pyrolysis oil in FCC units of oil refineries). A technological option that is considered “indirect”, do not focus on the production of liquid biofuels themselves, but they can indirectly contribute to prepare the conditions for the development of the biomass market and infrastructures.

In this work, we discuss two basic technologies as direct integrated options, one being through biomass gasification (for productions of intermediates), and another by the means of biomass pyrolysis (substituting fossil feedstock). The former case refers, to gasification of Fischer-Tropsch synthesis (Biomass to Liquid-BTL) using biomass substituting a conventional part of the production chain for liquid fuels. The latter case applies to the blending of pyrolysis oil in an FCC unit or hydrotreatment units in an oil refinery.

The oil refining industry provides the opportunity for using existing equipment for co-processing renewable feedstocks (e.g. pyrolysis oil) into typical petroleum oil-based production lines. These feedstocks can be added to petroleum refineries at different insertion points for blending or conversion (hydrocracking, FCC) and finishing processes (hydro treating), considering that the petroleum industry already has the necessary knowledge to provide efficient integration of renewable feedstocks as well as the necessary safety routines in place.

Pyrolysis oil processing requires a greater effort in commercial development since it has significantly different properties than petroleum feedstocks, requiring large efforts regarding the development of catalysts specifically designed for upgrading bio-oils. In addition, most of the biomass conversion processes carried out in a refinery need a significant amount of hydrogen in order to remove oxygen and yield high energy density fuels. Regarding the BTL integration option, important parameters are required concerning feed preparations of biomass, as well as for the scaling up of the gasification plants and the performance of catalysts.

Indirect option examples presented in this WP are mainly co-firing biomass in coal-fired power plants, as well as integrating biomass gasification plants in district heating networks, in order to produce SNG and other synthetic fuels. These options do not represent technologies for direct production of renewable streams (for blending or substitution) which can be used in the production of liquid fuels. Nevertheless, these options are still included in this WP, as they are important to acknowledge concerning potential stepping stone pathways that establish biomass supply chains and markets, which can be further developed for production of transportation fuels. For instance, the integration of gasification-based biofuel plants in district heating systems increases the overall energy efficiency of the integrated system, which improves the economic and environmental performance of biofuel production. Biomass co-firing with coal clearly reduces the risks associated with capital investments and it is evaluated as a near-term option to stimulate bioenergy markets and the build-up of the biomass supply infrastructure.

This WP also assesses the potential of biomass use regarding many different industries such as the pulp and paper industry (e.g. black liquor gasification). Another industry that is continuously assessed is the iron and steel industry (e.g. replacement of fossil carbon with carbon from biomass, either as a reducing agent in the blast furnace or as a fuel in heating furnaces). A final example of an industry that contains potentials for biomass use are oil refineries (by means of installing biomass boilers and the gradual development of biomass infrastructures towards biofuels production).

It is important to make sure that such biofuels production processes (e.g. pyrolysis and BTL) are part of a long-term strategy, which needs incentives (financial and legislative) in order to overcome technological barriers to phase out fossil fuel infrastructures. However, fossil fuel infrastructures can act as drivers for the development of advanced biofuels production as they can reduce the initial risk in terms of cost and technological maturity level, by offering the opportunity to increase the demand for biomass gradually, and building up the logistic infrastructures needed to receive biomass.

Contents

1. Introduction

Introduction of biofuels to the transportation sector (and bio- energy in general), is hampered by barriers on both supply and demand sides. On the supply side, there are significant potentials for establishing biomass supply systems however; many are unexploited, including many types of lignocellulosic feedstock supply chains coming from forests and short rotation crops (D2.2, D2.3.). However, this is not concerning countries like Sweden and Finland, who have a well-developed forest industry , which includes production of some liquid biofuels (e.g. bio-ethanol). On the conversion side, biomass-to-energy conversion infrastructure is lacking in most countries (Berndes, et al., 2010). Although cost-effectiveness of the biomass investments is a critical factor, there is also a need to establish what near-term bioenergy markets exists that, regardless of what type biomass will be utilised, will dominate in the long term.

In thermo-chemical conversion systems there are significant differences between Greenfield and retrofitting existing energy infrastructures with respect to normal costs as well as to intangible costs (e.g. knowledge), i.e. it should be within the existing fossil-fuelled petroleum and chemical industries where the necessary knowledge and competences are found for developing green routes for production of transportation fuels. The main aspects considered when it comes to investments in energy infrastructure are the economic, technological, social, and supply chain aspects of the sector. Considering upgrading the existing energy infrastructures with biomass use, the following potential advantages can be expected:

Economic Aspect

Investment costs can be lower in the development of biofuel facilities exploiting opportunities of existing infrastructures such as raw material handling systems or conversion units (e.g. FCC in oil refineries).

Technological Aspect

Currently, there exists different technologies (e.g. thermochemical, biochemical, mechanical) which can convert lignocellulosic feedstock into high quality and sustainable liquid biofuels. Yet, these technologies are at different stages of development covering a wide range of TRL levels. With respect to conversion technologies, the ADVANCEFUEL project focuses on technology readiness levels (TRL) of 5 to 9 as presented in D3.2. In this range, methanol, ethanol, butanol, dimethylether, Fischer-Tropsch products (gasoline, diesel, kerosene), and methane pose as potential biofuels for road, aviation, and maritime transport.

The amendment of a fossil-based infrastructure towards biomass use could lead to reduced technical risks since the experience and know-how concerning operation (of a part) of the process already exists. In the same way, there could be opportunities to capitalise on experience and expertise concerning raw materials and their supply, as well as and the products and their markets.

Biorefineries can also use existing infrastructures when co-located with existing industrial plants or clusters of plants (e.g. use of black liquor of pulp mills or co-locating the ethanol production plant and the ethanol dehydration plant producing ethylene in a petrochemical cluster) and plants in district heating systems. This to benefit from the heat integration of the biorefinery with an existing industrial process, as well as to recover wasted heat from the fuel process. Another advantage of integration is that the existing infrastructure (boilers, utility systems, air separation plant etc.) is already in place.

In summary, it can be concluded that in order to reduce the initial risks for liquid biofuels production installations in terms of cost and technological constraints; different “stepping stone” systems may be created by locating synergies with other parts of the energy and the process industry sector.

Social Aspect

By using the existing infrastructure, the transition to a renewable transportation system can maintain jobs as well as potentially create new job opportunities. Reduction of carbon emissions from the transportation in line with the Paris Agreement will require a combination of measures including direct and indirect electrification, change of transportation mode, and more efficient logistics. Considering the almost 100% fossil-fuel dependency within the transport sector, it is likely that the future of the fossil-fuel infrastructure must involve significant downsizing. Thus, biofuel production can help in the transformation of the transportation fuel production sector by repositioning jobs to renewable fuel production – as well as other carbon-based chemicals from renewables.

Supply Chain and Logistic Factors

The existence of an effective and efficient supply and logistics chain is a vital factor for the success of liquid fuels production. Since transportation costs influence the total biomass fuel costs, site selection for new biomass facilities are an important factor when designing biomass supply chain networks (although dependent on type of biomass, siting in the proximity of currently available biomass resources is most likely preferable).

One barrier for the utilisation of biomass is the inherent cost of transporting low-density and high moisture content (MC) biomass feedstock to biomass facilities over longer distances. Significant considerations for selecting a suitable location for a biofuel/biorefinery facility, are: the distance to where the biomass raw material is taken from, which will influence emissions and costs associated with distribution of the raw material, the distance to a harbour (surface transportation can lower transportation costs and limit emissions), the distance to the relevant markets (i.e. end users) and possibilities for co-location with existing industrial facilities (e.g., refineries, industrial clusters) to utilise potential heat sinks and sources as well as existing experience and know-how. Further, the entire upgrading process from raw material to end products does not necessarily have to be located at the same place. Intermediate products could be produced and transported to other sites for further upgrading. Thus, suitable location for a biofuel/biorefinery facility depends on a trade-off between different parameters. In this context, it is easier to quantify the effect of parameters such as transportation distances for raw materials and products of the degree of heat integration, than the effect of “soft” parameters such as the benefit (e.g. knowledge/human capital) from utilising existing experience and expertise in operating existing infrastructures.

2. Technological options for greening fossil-fuel infrastructures

In the framework of the ADVANCEFUEL project and the goal of this WP, technological options are presented which aim at the production of liquid fuels from partial or a full substitution of fossil carbon. We divide the possibilities for integrating biofuel production into two options; direct and indirect as shown in Figure 1.

1. We denote the “direct options”. In practice, the substitution is achieved by:
    - drop-in (blending) of a biogenic feedstock in a fossil-based process stream and then co-processing in a downstream conventional unit
    - substituting a conventional part of the production chain of a liquid fuel by a bio-based one (e.g. gasification for Fisher Tropsch synthesis).

    In both these cases, the biogenic feedstock (or intermediate stream) can be produced either within the system boundaries of the fossil-fuel infrastructure or in a decentralized level and then transported to the fossil-fuel infrastructure for processing .
2. There are also indirect technological options, such as co-firing or combined heat and power in district heating networks, which combine bio- and fossil-based infrastructures and contribute indirectly to the ramp-up of biomass use. These options can be characterized as “indirect options”. Even if these options are not a priority of the ADVANCEFUEL project, as they do not focus on the production of liquid biofuels themselves, they can indirectly contribute to enable environment for the development of biomass market and infrastructures.

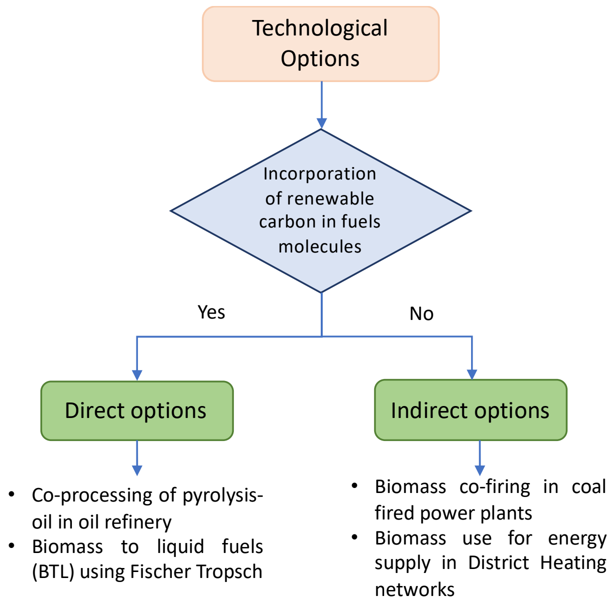


Figure 1: Technological options which can facilitate biomass use and green fossil fuel infrastructures

For direct options, oil and syngas platforms provide a number of opportunities of processing biomass or biomass-derived intermediates by utilizing existing facilities, such as oil cracking, hydrotreating, gasification, and chemical synthesis. In a future system, the intermediates can be produced within refinery sites or at other locations, for example in connection to existing power or combined heat and power plants (Cintas et al., 2019). The resulting products could include gasoline, diesel, olefins, alcohols, acids, waxes, and many other commodity chemicals derivable from syngas. Figure 2 gives an overview of the different routes from biomass to fuel within the scope of the ADVANCEFUEL project through various conversion technologies (including hydrogen from renewable electricity which is not the focus in ADVANCEFUEL project). In Figure 2, two conversion technologies are highlighted which are adopted and used in the study of direct and indirect options: the case of syngas via gasification which can replace a coal or natural gas based syngas for downstream Fischer Tropsch synthesis. In addition, FT synthesis paths can provide waste heat in existing district heating networks. The pyrolysis case can contribute to co-processing bio-oil with Vacuum Gas Oil (VGO) in Fluid Catalytic Cracking (FCC).

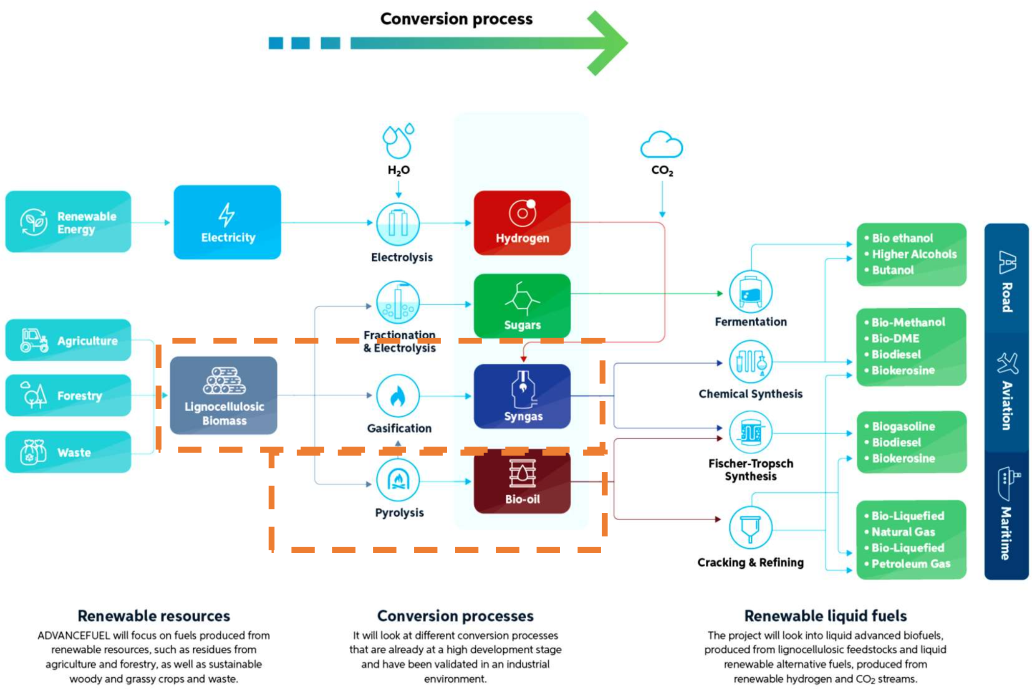


Figure 2: Overview of liquid fuels production according to ADVANCEFUEL highlighting technological paths which can be integrated with fossil infrastructures.

The gasification-based pathways in the ADVANCEFUEL project comprise chemical synthesis of methanol, dimethyl ether (DME), ethanol and higher alcohols and liquefied methane and Fischer-Tropsch synthesis of gasoline, diesel and kerosene and liquefied methane. Gasification routes concern the integration of biomass gasification with FT synthesis BTL (Biomass-To-Liquids) technology in oil refineries by heat integration and potential FT syncrude co-processing in oil refinery installations. The case of the substitution/conversion of CTL (Coal-To-Liquids) and GTL (Gas-To-Liquids) to BTL (Biomass-To-Liquids) and combined feedstock options is analysed in this report.
The pyrolysis-based pathways in the ADVANCEFUEL project focus on the utilisation of pyrolysis oil via cracking and refining mainly toward gasoline, diesel and kerosene, and liquefied methane. Thus, greening fossil infrastructures may refer to the partially substitution and blending of pyrolysis oil into existing oil refineries.
Another possible way to implement these integration options would be also by taking advantage of existing energy infrastructures in and around power plants and combined heat and power plants, firstly, by starting e.g. with co-firing of biomass or by exploiting excess heat from biomass gasification plants in District Heating networks, i.e. applying indirect integrated technological options. When the existing solid fuel supply infrastructures (road and water way transportation) and the on-site thermal plants, coal power plants and combined heat and power plants (burning various fuels)

are phased out, the sites can partially or fully replaced by pyrolysis units for the production of intermediates which can be transported to refineries as analyzed by Cintas et al. (2019). To use existing infrastructure also includes taking advantage of existing knowledge and know-how on thermal processes as well as utilizing existing sites which keeps transaction costs low. Wherever it is difficult to build Greenfield plants due to various constraints (e.g. financial, legal, technical etc.), new biomass-conversion plants could be built in already existing industrialized areas to benefit from existing process know how in energy plants and refineries.

3. Direct options for greening fossil-fuel infrastructures

3.1 Incorporation of bio-oil feedstock into existing oil refineries

3.1.1 Technology description

As mentioned above, the oil refining industry could provide the opportunities for using and/or modifying existing process units for refining of biomass. Renewable feedstocks can be added to petroleum refineries at different locations as illustrated in Figure 3.

The insertion of renewable feedstock which can possibly impact the entire refinery operation, insertion Point #1 (blending renewable materials into crude), is not viable unless the material is essentially purely composed of carbon and hydrogen, with minimal levels of olefins (PNNL, 2014).

Point #2 refers to Conversion and Finishing processes. In this case, biomass intermediates (such as pyrolysis oil) which match with conventional intermediate products of an oil refinery regarding their physicochemical properties may require additional treatment to lower impurity levels and change composition to better fit into blends with conventional products. These biomass intermediate products (e.g. pyrolysis oil) may require both conversion and hydrotreating to convert them into products capable of being blended with conventional petroleum products. These feedstocks will require refineries with conversion (hydrocracking, FCC) and finishing (hydrotreating) capacities.

The most direct way of greening fossil infrastructures is insertion at Point 3 (in Figure 3) as a blendstock or near finished fuel. These streams require the least amount of refinery processing (e.g. product streams such as ethanol, butanol, renewable diesel blendstocks, hydrocarbons). It should be noted that with regard to the option of insertion at Point 3 the state of TRL of the existing technologies is not high and more research is required to succeed appropriate compositions and capacities for mixing. For example, gasification pathways which produce diesel, gasoline and kerosene from lignocellulosic feedstock through Fischer – Tropsch are generally considered to have a TRL between 5 to 8, with the lower TRL part mainly referring to the gasification part with only very few demonstration plants reaching an adequate operational performance due to technological barriers (such as the suitability of biomass syngas for Fischer – Tropsch Synthesis (FTS) using the conventional catalysts.

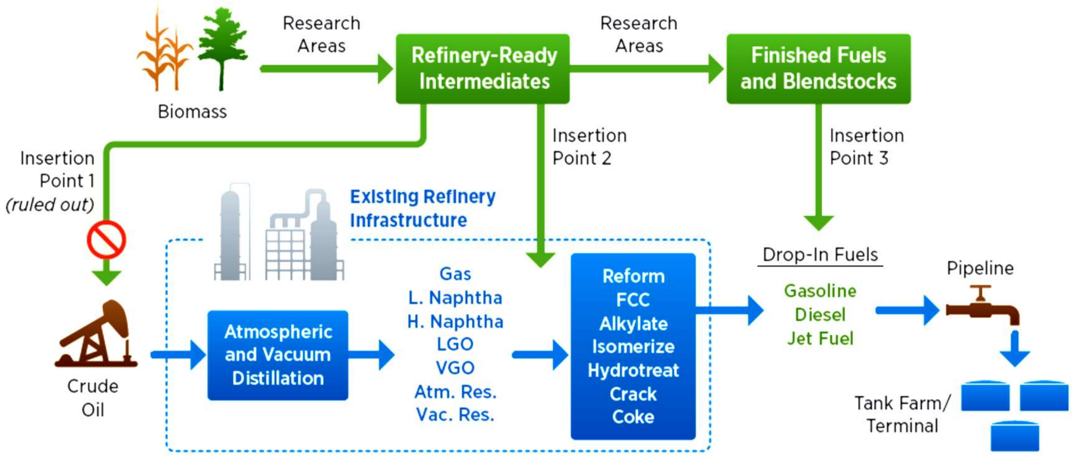


Figure 3: Co-Processing Bio-oil with Crude Oil Integration with Existing Refining Infrastructure (NREL, 2016)

The use of lignocellulosic biomass as a refinery feedstock is a promising alternative to conventional crude oil because of its abundancy and variety. Given that it is rather difficult to establish a specific way to provide a stable biomass feedstock in a unit, it is quite effective to transform it into bio-oil.
Bio-oils can be considered as an energy-dense form of biomass, produced by pyrolysis treatment. Bio-oils are produced by direct thermal decomposition of biomass feedstock in the absence of oxygen, or at least in presence of significantly less oxygen than required for complete combustion. From pyrolysis, a liquid bio-oil (or pyrolysis oil as an equivalent term) is produced together with a solid carbonaceous residue, named char, and gaseous products. Pyrolysis oil is reported to have high oxygen content ranging from 8 to 63 percent (dry basis) depending on feedstocks and pyrolysis conditions (Gollakota, et al., 2016), with typical values ranging from 35 to 40% (dry basis) (Lehto, et al., 2013). For this reason, it is characterised by a low heating value, depending on the initial composition of the starting material. One relevant constraint is the immiscibility of bio-oil with hydrocarbon fuels because of the high polarity of oxygenated compounds. Bio-oil is chemically unstable, displays low volatility and has a high viscosity and corrosivity. Nevertheless, the liquid nature of this intermediate is an asset as it makes easier to handle biomass-derived feedstock than on their initial form, as solids (Melero, et al., 2012).
Fluid catalytic cracking (FCC) process is the most widely used in refineries for the conversion of crude oil into gasoline and other hydrocarbons because of its flexibility to match the feedstock with product demands. One important advantage of this process is that it operates under milder reaction conditions, minimizing the yield towards by-products such as gases, coke and heavy fractions while

maximizing the production of the liquid fraction suitable for use as transport fuel, showing an effective hydrogen index in the range from 1 to 2 (Melero, et al., 2012).

Hydrotreatment is an indispensable unit operation in conventional refineries. The objective of hydrotreating is to remove sulfur (hydrodesulfurization, HDS), nitrogen (hydro-denitrogenation, HDN), metals (hydrodemetalation, HDM) and oxygen (hydrodeoxygenation, HDO) from the heavy gas oil feedstock. Thus, bio-oils can be upgraded to transport fuels via hydrotreatment if the existing fuel standards are reached.

Co-processing of bio-oil in FCC together with vacuum gas oil (VGO) removes oxygen present in feedstocks in the form of water, CO and CO_2 via simultaneous dehydration, decarboxylation, and decarbonylation. Co-processing in an FCC unit has an advantage compared to other processing units in a refinery because additional hydrogen or energy inputs are typically not required, saving both costs and additional GHG emissions. Unlike hydroprocessing reactors, FCC operates at atmospheric pressure and efficiently regenerates the coke deposited by the catalysts by circulating them through a circulating fluidized bed combustor system, which is beneficial for the energy balance of the refinery process.

However, the direct use of bio-oils in refineries is not possible as they typically contain up to 30% water and 40% oxygen and the direct mixing with petroleum liquids is not a viable solution. The oxygen content of bio-oils also increases coking and deactivation of catalysts. A way to tackle the insertion of bio-oils in a conventional refinery is by hydrotreating it. The hydrotreatment conditioning step results in a partial hydrodeoxygenation (HDO) where the acid numbers and the oxygen content of the stream are reduced. Deoxygenation is applied at a point which meets the minimum requirements of the refinery since to approach oxygen-free bio-oil it can be expensive.

Thus, hydrotreatment allows stabilizing of bio-oil, increasing its energy density and leading to an intermediate product which can be blended with petroleum oils. However, HDO bio-oils, even when partially deoxygenated, are unstable at 400 °C or 500 °C (i.e., temperatures that are often used in petroleum distillation) and they cannot be directly mixed with crude oil at an early process stage of the refinery. Co-processing of raw bio-oil in FCC was shown to be technically feasible. Bio-oil could be directly co-processed with a regular gasoil FCC feed up to 10 wt% (Pinho, et al., 2017).

Thus bio-oil insertion is likely to occur at the refinery's hydroprocessing (hydrotreatment and hydrocracking) or fluid catalytic cracking reactors. These two types of 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 4. Among the three options mentioned above, FCC is more tolerant than hydroprocessing to higher oxygen content biomass liquids than hydrotreatment. Especially, hydrocracking is a more severe form of hydrotreatment and it aims at cracking the heavy portions of bioderived hydrocarbons. This process follows hydrotreating in an oil refinery and it is even less tolerant to oxygen than hydrotreatment (due to higher pressures and temperatures).

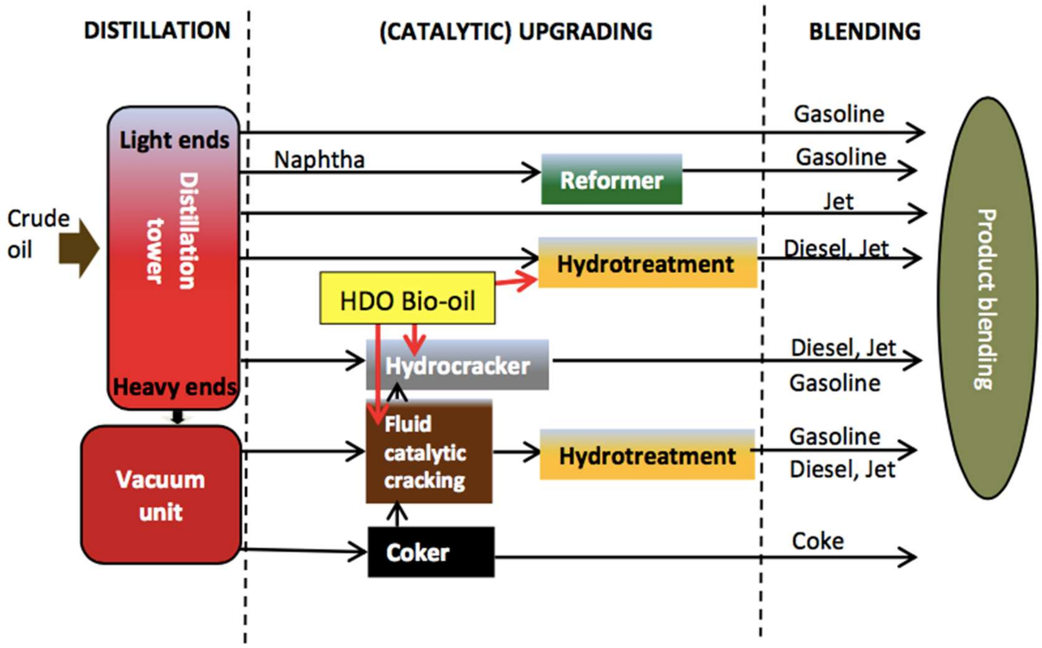


Figure 4: Refinery insertion points (red arrows) for HDO Bio-oils (Karatzos, et al., 2014)

3.1.2 Current technology status

Oleochemical derived fuels (i.e based on liquid feedstocks such as vegetable oils and animal fats) are the only drop-in biofuels that are being produced at relatively large commercial scale today. The production of these fuels are considered well established procedures (e.g., regarding their specifications, and infrastructures) for developing and handling drop-in fuels compared to other fuel production technologies for drop-in biofuels (such as pyrolysis and gasification). Oleochemical raw materials such as fats and vegetable oils are primarily water insoluble, hydrophobic substances that are comprised almost completely of triglycerides and small amounts of mono- and diglycerides. Triglycerides can be easily converted into liquid transportation fuels because of their low oxygen content (Melero, et al., 2012). Additionally, these processes require a simple hydroprocessing step to catalytically remove oxygen from the fatty acid chains present in the lipid feedstock to convert them to diesel-like hydrocarbon mixtures (Karatzos, et al., 2014). Comparable to bio-oils which can also be upgraded to drop-in biofuels, oleochemical feedstock requires also significant hydrogen inputs (extensive hydrocracking) (Karatzos, et al., 2014).

Other examples, mainly focused on hydroprocessing and oleochemicals feedstocks are presented in literature (de Jong, et al., 2015; Melero, et al., 2012): Neste Oil, a Finnish petroleum refining company, currently the world’s largest producer of drop-in biofuels, operates 3 Hydrotreated Ester and Fatty Acids (HEFA) facilities in Finland, Rotterdam and Singapore (annual total capacity of 630 million gallons (2.4 billion L) of palm oil- derived diesel marketed as “NexBtL” (Neste Oil, 2013a)). Other examples of hydrotreated esters and fatty acids (HEFA) manufacturers exist in the USA. e.g.

a collaboration of Syntroleum and Tyson foods, in Louisiana, that licensed their “Biosynfining” technology to a Dynamic Fuels commercial plant, producing 75 million gallons (284 million L) per year of green diesel. Another example is that of Honeywell-UOP which licensed its Ecofining technology to the Diamond Green Diesel facility in Kentucky for a 515 million L facility in Norco, Louisiana. Preem (Sweden) has started to produce diesel with a 30% renewable content in a modified mild hydrocracker unit ((Sandén, et al., 2013) (Karatzos, et al., 2014)). This unit has a capacity of 330,000 m^3 diesel per year (11 PJ per year). The renewable feedstock is raw tall oil, which is a by-product from kraft pulp mills.

A specific example of the use of lignocellulosic raw materials in a conventional refining scheme is the co-processing of raw bio-oils from pine woodchips with a standard Brazilian VGO where two different bio-oil/VGO weight ratios were tested - 5/95 and 10/90 (Pinho, et al., 2017). This pilot scale study was tested in a 200 kg/h FCC demonstration-scale unit using a commercial FCC equilibrium catalyst and bio-oil was fed directly without any other pre-processing in order to test the sensitivity of production yields in diesel, gasoline, coke, CO and CO2. The study for these blending ratios revealed that 30% of renewable carbon in pyrolysis oil would end up in total liquid products, gasoline, light cycle oil (LCO) and bottoms. This suggests that an appreciable amount of carbon in pyrolysis oil ends up as LPG, coke, CO, and CO2, thereby reducing overall liquid product yields (Pinho, και συν., 2017).

3.1.3 Potential for integration options of oil refineries with biomass use

The refining sector in the European Union is comprised of 85 refineries (according to data from years 2015-2016), spread across 22 Member States, Norway, and Switzerland (Figure 5). In total, EU has a combined throughput capacity of over 14.5 Mb/d, accounting for roughly 14.5% of global refining capacity in 2015. Overall, the sector exhibits a wide variety in levels of configuration, integration, and production with capacity ranges between 40 Kb/d and 425 Kb/d. Europe’s largest refineries (>250Kb/d) are located in the Netherlands, Poland, Germany, Belgium, Italy, UK and Spain (Nivard, et al., 2017).

Figure 5 presents the oil refineries, spread across 22 of the EU27[1] Member States, Switzerland and Norway taken from Nivard, et al., (2017). They are mainly developed near major sea ports, large rivers or pipelines. Although refineries are evenly distributed across the EU, refining capacity is slightly more concentrated in the North-Western part of the EU (NWE), close to the North Sea crude oil sources (European Commission, 2016).

Since most refineries in the EU are equipped with FCC units as presented in Table 1 (values for oil refinery installations for 2013), these units can be considered as a potential infrastructure for co-processing pyrolysis oil (Barthe, et al., 2015).

[1] Now, there are 28 Member States in EU

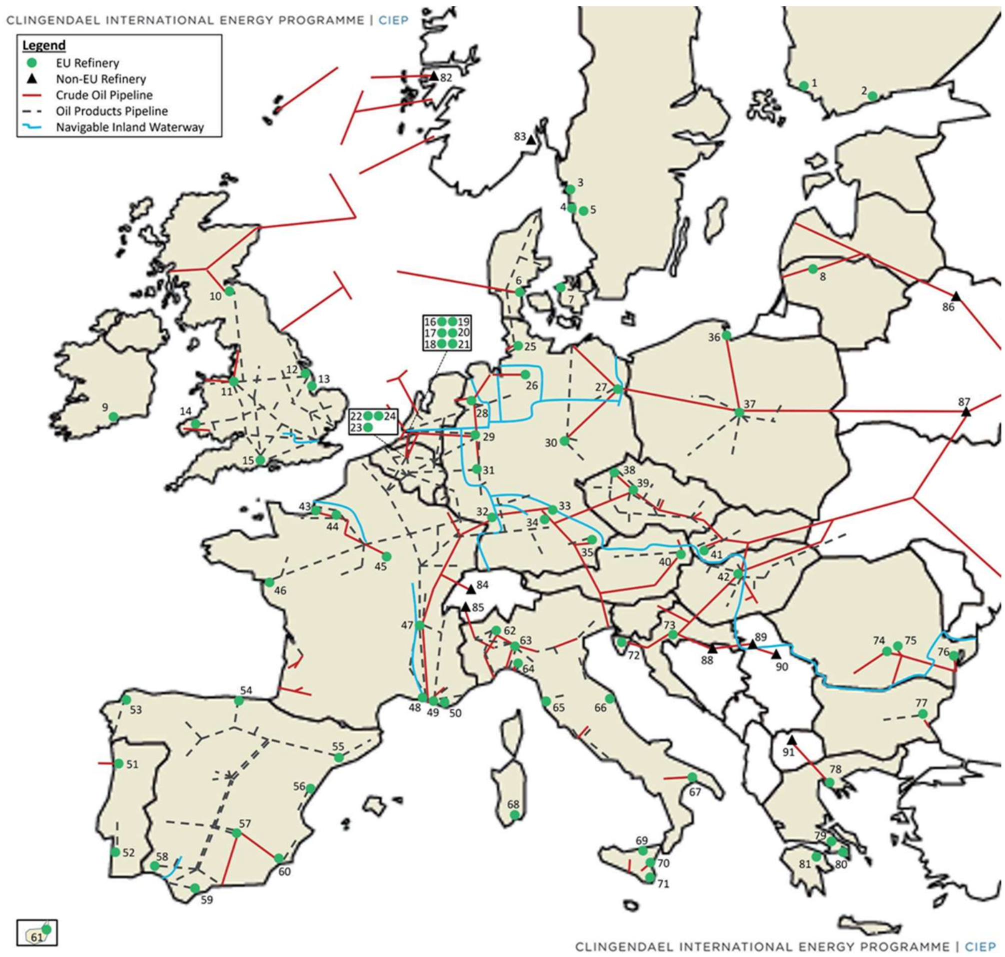


Figure 5 Refineries in the 22 of the EU member states (situation by 2012) (Nivard, et al., 2017)

Table 1 Refinery capacity in EU 27, including mineral oil refining and for FCC units (Barthe, et al., 2015)

Charge capacity in Mm^3/yr					
Country	No of oil refineries	Crude	Catalytic cracking	Catalytic hydrocracking	Catalytic hydrotreating
Austria	1	12.1	1.5		8.1
Belgium	4	42.9	7.8		39.9
Bulgaria	1	6.7	1.4		3.7
Cyprus	0				

Charge capacity in Mm^3/yr					
Country	No of oil re-fineries	Crude	Catalytic cracking	Catalytic hydrocracking	Catalytic hydrotreating
Czech Re-	4	10.6		2	6
Denmark	2	10.1			2.5
Estonia	0				
Finland	2	15.1	3.3	5.2	17.3
France	11	86.9	18.1	4.2	68.4
Germany	13	140.3	20.3	11.8	116.74
Greece	4	24.5	4.4	2.5	21
Hungary	1	9.3	1.4		7
Ireland	1	4.1			2.6
Italy	15	135.6	18.7	17.6	72.58
Latvia	0				
Lithuania	1	11	2.5		8.9
Luxem-	0				
Malta	0				
Netherlands	5	68.9	5.9	11.5	59
Poland	5	28.6	1.9	8.5	15.1
Portugal	2	17.7	2.4	0.5	11.7
Romania	9	31.2	6.4	0.1	13.8
Slovakia	1	6.7	1	2.4	5.1
Slovenia	0	0.8			
Spain	10	73.8	11.1	7.6	47.9
Sweden	5	25.4	1.7	2.8	15.6
United Kingdom	9	102.5	25.8	2.1	73.8
EU-27	**106**	**864.8**	**135.4**	**78.9**	**616.7**

According to the reported ranges of 2-10% of blending bio-oil in FCC units (where the 10% would refer to the case of HDO bio-oil) an estimation of the potential HDO bio-oil could be done. The potential used HDO bio-oil would be approx. 10 Mm3/yr HDO to be blended in the FCC units for the whole FCC capacity in Europe (given on data of Table 1). This corresponds to approx. 6,400 MW bio-oil production (e.g., 64 plants in Europe of 100 MW each). This would require 10,000-11,000 MW of lignocellulosic biomass (e.g., woody residues) in total in Europe to be converted in this bio-oil. The greening effect on diesel, gasoline and kerosene product can be calculated on the basis of 30% of the renewable carbon in bio-oil ending up to liquid fuels. (Note: Calculations are based on LHV of approx. 20 MJ/l for bio oil, and the blend ratio of 10%.)

3.2 Bio-based syngas for liquid fuels (BTL) using Fischer Tropsch synthesis

3.2.1 Technology description

The Fischer–Tropsch synthesis (FTS) process was originally developed in the early 1920s as an alternative way to produce hydrocarbon products under conditions of petroleum scarcity (e.g. war time). The Fischer–Tropsch synthesis process converts syngas into a wide range of hydrocarbon products, from gases to waxes, including liquid hydrocarbons of commercial interest. The reaction produces non-oxygenated hydrocarbon chain products in a reaction generally catalyzed by a supported metal (e.g. Fe, Co).

$$nCO+2nH_2 \rightarrow -(CH_2 - CH_2)_n - + nH_2O$$

where "$-(CH_2 - CH_2)_n -$" stands for various liquid hydrocarbons with different chain lengths.

The FTS process has undergone continuous investigation over the years and currently the term FTS applies to a wide variety of processes referring to the production of hydrocarbons from syngas originating from any carbon-containing feedstock including coal, natural gas (most widely employed feedstocks) and, more recently, biomass. Depending on the feedstock, the process is referred as CTL (Coal-To-Liquids), GTL (Gas-To-Liquids) or BTL (Biomass-To-Liquids). One of the basic advantages of FTS is its versatility regarding feedstock and products. Another advantage is that synthetic fuels have also distinct environmental advantages over conventional crude-refined fuels since they are free of sulfur, nitrogen and aromatics as well as, being compatible with conventional fuels (Luque, et al., 2012).

The production of synthetic fuels from biomass comprises of the four basic steps of all FT processes: (1) biomass pre-treatment, (2) gasification of the biomass feedstock to synthesis gas (syngas, CO + H_2) followed by gas cleaning/conditioning; (3) FTS production and (4) upgrading of the FT liquids to high quality fuels. A schematic of a typical integrated BTL process is shown in Figure 6.

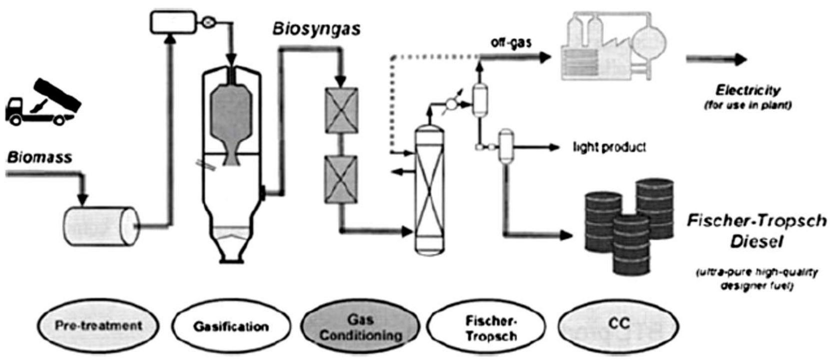


Figure 6 Schematic lineup of the integrated BTL plant [(Shah, 2013)

Shah (2013) proposes to divide available FTS schemes of an integrated BTL process in two design approaches: the “front-end approach” and the “back-end approach”. The principal idea of the former approach is that FT liquid, heat and electricity are all the desired products. This is generally used for smaller gasifiers of the size 1–100 MW_{th}.
The latter approach refers to FTS processes which have the aim to maximize the FTL yield from the process, i.e. converting as much as possible of feedstock into FT liquid while heat and electricity generation are considered secondary products. In this approach the size of the plant is governed by the size of the gasifier. This would lead to gasifiers at least greater than 1,000 MWth. Since the FT process has a high fixed cost, economies of scale is important for cost efficient production of FT liquid. Moreover, the economic viability of the FT process largely depends on the price of crude oil due to the high price of synthetic FT fuels owing to its energy demanding nature and the large capital cost requirements of FT plants (Luque, et al., 2012)
Compared to the fossil based syngas, biomass derived syngas is less energy dense, contains more impurities and presents lower H/C ratio. As a result, biomass syngas needs to be enriched in hydrogen and its impurities, such as CO2, H2O, CH4, higher hydrocarbons (C_2+) and N_2 that can deactivate synthesis catalysts must be removed prior to FT synthesis. Hydrogen is typically produced by “water-gas shift” reaction. This reaction requires feedstock carbon and thus affects the overall biomass-to-fuel yields. Generally, gasification technologies entail high capital costs to both gasify the biomass and convert the resulting syngas to Fischer-Tropsch liquids or partially oxygenated liquid hydrocarbon products such as mixed alcohols. A representative value for an investment intensity is 3,000 EUR/kW for a FT product capacity of 200MW which is chosen as an average sized production in the work of (Landälv, et al., 2017).

3.2.2 Current technology status

Several coal-to-liquid and gas-to-liquid FT plants are running or are planned, while biomass-based conversion for production of FT fuels is only at pilot or demonstration scale. Table 2 gives an overview of FT plants that have been installed (or are in study) worldwide.
The Fischer-Tropsch process is currently being operated at an industrial scale by two main fossil fuel companies, Sasol in South Africa and Shell in Malaysia and Qatar. The world’s first commercial-scale Gas-To-Liquid (GTL) plant based on FT synthesis was completed in 1993 by Shell in Bintulu, Malaysia and continues producing about 15,000 bpd of ultra-pure GTL products (50% middle distillates, and 50% specialty products, such as detergent feedstocks and waxes).
The Sasol plant in South Africa produces 160,000 bpd of FT-diesel from coal derived syngas to provide 41% of South Africa’s transport fuel requirements. Sasol has also converted one of its CTL facilities to accept natural gas from Mozambique. Sasol also owns a 34,000 bpd Oryx GTL facility in Qatar and, based on the experience gained from building and operating this facility, it expanded its operations in other countries with significant natural gas reserves such as Nigeria, Uzbekistan, the USA and Canada (Luque, et al., 2012).

The world’s largest GTL facility was built by Shell in collaboration with Qatar Petroleum. It has a capacity of 140,000 bpd and it has been fully operational since 2012. The construction of this facility began in 2007 with an original timescale of 2 years and a budget of $5b.

Over the last several decades, a continuous effort to improve catalyst activity, selectivity, and stability has been carried out. Thus, it is likely that a biomass FT gasification process will encounter similar or even more challenging problems (such as the suitability of biomass syngas for FTS using the existing catalysts) (Luque, et al., 2012).
Literature suggests that when a biomass-to-liquids process is compared to a GTL plant the main challenges are: processing a more heterogeneous biomass feedstock, producing a lower quality syngas and the feedstock availability risks (Hileman et al., 2009).

Table 2 World FTS plants (Luque, et al., 2012).

Company	Country	Output Capacity*/barrels per day	Raw material	Status	Catalyst type
Sasol	South Africa	150.000	Coal	In operation	Fe/K
	China	2 80.000	Coal	Abandoned	-
	Australia	30.000	Natural gas	Study	-
	Nigeria	34.000	Natural gas	Under construction	
	Qatar	34.000	Natural gas	In operation	Co/Al_2O_3
Shell	Malaysia	14.700	Natural gas	In operation	Co/SiO_2
	Qatar	140.000		In operation	Proprietary Co-based
	Indonesia	75.000		Study	-
	Iran	70.000		Abandoned	-
	Egypt	75.000		Study	-
	Argentina	75.000		Study	-
	Australia	75.000		Study	-
Shell Choren	Germany	300	Biomass	Scale up never completed	-
Mossgas	South Africa	22.500	Natural gas	In operation	Fe/K
EniTechnologie	Italy	20	Natural gas	In operation	-
BP	USA	300	Natural gas	In operation	Proprietary Co-based
Rentech	USA	1.000	Natural gas	In operation	Proprietary Co-based
	South Africa	10.000		Study	-
	Bolivia	10.000		Under Construction	-
Rentech pertamina	Indonesia	15.000	Natural gas	Study	-
Syntroleum	USA	70	Natural gas	Closed	-
	Australia	11.500	Natural gas	Under Construction	-
	Chile	10.000	Natural gas	Study	-
	Peru	5.000	Natural gas	Study	-

Company	Country	Output Capacity*/barrels per day	Raw material	Status	Catalyst type
Syntrol.-Tyson Foods	USA	5.000	Biomass	In operation	Proprietary catalyst
Gazprom syntroleum	Russia	13.500	Natural gas	Study	-
Repsol-YPF	Bolivia	13.500	Natural gas	Study	-
Syntroleum	Bolivia	90.000		Study	-
ExxonMobil	Qatar	90.000	Natural gas	Abandoned	-
Conoco	Qatar	60.000	Natural gas	In operation	Proprietary catalyst
	USA	400		In operation	
Bioliq	Germany	-	Biomass	Under Construction	-

*Output capacity refers either to final products (diesel, gasoline) or to crude FT synthesis products depending on the type of facility

3.2.3 Potential integrations with fossil infrastructures

While the FT process does not depend on how the syngas is produced (as long as its composition is not significantly varied), the gasification technology is the key to the integration of GTL, CTL, and BTL processes. In order to take advantage of the economy of scale, significant efforts are being made to examine CBTL processes (mixture of coal and biomass to liquid) (Shah, 2013). While existing commercial technology for GTL and CTL can be used for BTL, the scale of BTL plant is important.

Biomass gasification process is usually limited to small scale as it is difficult to transport big amounts of biomass in a central plant and due to difficulties in biomass supply, it has high capital (fixed) cost, presents lower thermal efficiency than coal fired plants, and and it is subject to long term supporting policies. Unlike coal and natural gas, biomass is difficult to transport and store (due to reasons such as seasonality, moisture low density, etc.), and the cost of feed preparation of biomass can become an important factor in the scale of BTL process.

Co-gasification (i.e. biomass and coal feedstock mixture) is benefited from use of coal. The mixture of coal and biomass provides a stable and reliable feed supply and potential feedstock disturbances of biomass supply cause less consequences in the production (Shah, 2013).

Co-gasification combined with Fischer-Tropsch technology can be used to produce liquids from coal and biomass. CBTL (Coal-Biomass to liquids) helps to reduce GHG emissions from diesel when compared to the petroleum-derived one. NETL (National Energy Technology Laboratory) reported that the use of 30% switchgrass (Biomass) with coal for producing diesel (CBTL) with carbon capture and storage technology (CCS) produced 63% less GHG emission compared to a fossil-derived diesel. GHG emission can further be decreased up to 75% by using more aggressive capturing technique of auto-thermal reformer in CCS (Brar, et al., 2012). In Europe BtL R&D has shown some demonstration cases such as the case of Frieberg Saxony in Germany utilising the Choren Carbo-V!Process (now out of operation), BioTfuel in France which produces biodiesel and biokerosene based on biomass gasification. Forschungszentrum Karlsruhe GmbH in partnership with LURGI GmbH constructed a pilot plant (due 2016) for production of BTL and ‘‘gasoline type fuels’’ and CEA (Atomic and Alternative Energy Commission) France announced the construction of a pilot BTL plant in Bure Saudron which produces $23 000 tonnes per year of biofuel (diesel, kerosene and naphtha). However, a fully scaled-up commercial BTL process has not been completely established to date (Luque, et al., 2012).

One of the successes of the story of co-gasification is that the plant erected at Buggenum and Schwarze Pumpe, in the year 1994 and 1996 respectively, in which large proportions of biomass and coal have been co-gasified for liquid fuel and syngas (Kamble, et al., 2019).

Representative disadvantages of co-gasification are feed preparation and complex feed systems which can be expensive. The choice of gasifier operation parameters (temperature, gasifying agent, and catalysts) decide product gas composition and quality. Biomass decomposition occurs at a lower temperature than coal and therefore different reactors (fluidized bed, or downdraft gasifier) compatible to the feedstock mixture are required. Heavy metal and impurities such as sulfur and mercury present in coal can make syngas difficult to use and unhealthy for the environment. Also, at high temperature, alkali present in biomass can cause corrosion problems in downstream pipes. Biomass containing alkali oxides and salts with ash content above 5% causes clinkering/slagging problems (Brar, et al., 2012).

3.3 Summary of direct technological options

Table 3 summarizes direct options biomass to liquid fuels in existing fossil infrastructures (oil refineries and FT plants. The options are characterized with respect to opportunities and barriers for integration together with real world examples with some references.

Table 3: Direct integration options of biomass to liquid fuels in fossil infrastructures.

Integration option	Opportunities	Barriers	Real world examples	References/Supplementary Data	Feasibility to scale up (Low, High, Medium)
Bio-oil co-processing within a petroleum refinery	**Technological** ▪ TRL of biomass pyrolysis: 6 or higher (obtained from D3.2) **Economic** ▪ Co-processing (e.g. hydrotreating, cracking) bio renewable feeds and fuels in existing refinery units, more profitable than the stand-alone case (Jones, et al., 2009) **Supply chain** ▪ Established infrastructure of refineries for long-distance sea transport ▪ Bio-oil imports can be facilitated together with oil imports. (Doug, 2006) Cintas et al. (2018)	**Technological** ▪ Current blending ratios of 2-10% would render the scale-up feasibility rather low (Directorate-General for Mobility and Transport , 2018). ▪ Presence of water and oxygenated organic compounds (Air Resources Board, 2017) ○ affects yields and conversion rates ○ need for stainless steel piping ▪ Alkali metals deactivate catalysts (Air Resources Board, 2017) ▪ Differences in yields between pilot and commercial scale projects (Air Resources Board, 2017) **Economic** ▪ Co-processing is highly sensitive to parameters re-	▪ Petrobras/NREL CRADA international partnership ○ co-processing of pine-based bio-oil with petroleum-based fuel intermediate oil in the fluidized catalytic cracking process (FCC), a common unit of a petroleum refinery ▪ No commercial case studies exist, just demonstration cases **Other cases but not from lignocellulosic feedstock** ▪ Neste Oil, NExBTL process – for the production of green diesel from pure vegetable oils and fats. **"Indirect" lignocellulosic feedstock** Preem tall oil (Crude tall oil is a byproduct of the kraft processing of pinewood for pulp and paper. Crude tall oil starts as tall oil soap separated from recovered black liquor in the	▪ **Capacities of all European refineries:** (Nivard, et al., 2017) ▪ Data for FCC units (Barthe, et al., 2015) ▪ Other research studies suggest co-processing of up to 20 percent (wt.) biogenic oils with VGO in FCC units (Fogassy, et al., 2010) ▪ Example of estimation of co-processing and production of bio-renewable fuel potential in California (Air Resources Board, 2017) ▪ Study of co-locating a plant of 2000 dry ton/day of hybrid poplar to produce gasoline and diesel from fast pyrolysis with an existing refinery in the USA with capital investment data (Jones, et al., 2009) ▪ Economic analysis of potential co-processing bio-oil with residue in an FCC unit in petroleum refinery. (Asmaa, et al., 2018) ▪ Co-location eliminates the need for a PSA (pressure swing adsorption) unit in the hydrotreating section (the	▪ Low[1]

Integration option	Opportunities	Barriers	Real world examples	References/Supplementary Data	Feasibility to scale up (Low, High, Medium)
		lated to the petroleum refinery such as the crude prices and refinery feed rates. The sensitivity to feedstock prices decreases with increasing crude oil prices (e.g. due to the relatively low blending ratio of pyrolysis oil). ▪ **Supply chain** ▪ Discontinuous production, variety of biomass feedstock to be supplied to the refinery, transportation chains, storage of biomass feedstock and/or the required pretreatments to accomplish energy densification ▪ Challenge of the decentralized production, i.e., where the pyrolysis oil is produced and what is actually transferred to the oil refineries	kraft pulping process) (https://www.greencarcongress.com/2008/07/preem-sdra-and.html)	upgrading unit off-gas sent to refinery hydrogen generation) (Jones, et al., 2009). In case the bio-oil treatment is done in the refinery, the H_2 demand can also come from a SMR (steam methane reformer)	
Biomass to liquid fuels (BTL) using Fischer Tropsch	**Technological** ▪ Existing commercial technology for GTL and CTL can be used for BTL. ▪ Options for Combined Coal and Biomass to Liquid are studied as future directions (CBtL) Sasol in South	**Technological** ▪ A fully scaled-up commercial BTL process not being completely established to date. (Luque et al 2012) ▪ The largest BTL (biomass-to-liquids) plant that may be built will most likely produce 50,000 Bbl/day ▪ Significant pretreatment of biomass to allow stable	The case of Sweden's GoBiGas plant which is a 32MW_{th} gasifier and produces SNG. Potential scaling up in 200MW would produce liquid fuels from FT, DME etc. (Thunman, et al., 2018).	**Database on facilities for the production of advanced liquid and gaseous biofuels** for transport per Country & TRL https://demoplants.bioenergy2020.eu ▪ The capital cost estimates for a first-of-its-kind commercial (2000 tonnes of biomass (dry basis) per day) gasification-based facility are in the region of USD $600-900 million. (IEA Bioenergy Task 39 report)	Low (risky investment with regard to scaling up gasification)[2]

Integration option	Opportunities	Barriers	Real world examples	References/Supplementary Data	Feasibility to scale up (Low, High, Medium)
	Africa has investigated the feasibility of co-gasifying biomass and coal in their fixed bed coal-to-liquids gasifier (Kamble, et al., 2019) ▪ Synthetic fuels have also distinct environmental advantages over conventional crude-refined fuels (free of sulfur, nitrogen and aromatics as well as being compatible and blendable with conventional fuel) (Luque et al 2012) **Economic** ▪ Technical advances in the FT process and the increasing crude oil prices (in combination with the depletion of the crude reserves) (Luque et al 2012)	feeding to the gasifier without excessive inert gas consumption. ▪ Many investigations are ongoing to test the suitability of biomass syngas for FTS using the traditionally employed catalysts (Luque et al 2012) **Economic** ▪ Cost of feed preparation of biomass can become an important factor in the scale of BTL process ▪ Fixed cost for BTL plant is generally 60% higher than the one required for GTL plant of the same size. **Supply chain** ▪ Biomass is difficult to transport and store ▪ No consistent supply		▪ **Overview of FT units in EU countries** reference (Luque et a; 2012) ▪ The size of FT process depends on the size of the gasifier for an integrated process. For example, a BTL (biomass to liquid) plant producing 2,100 Bbld will require a gasifier producing 250 MWth (Shah, 2013) ○	

[1] Based on the argument that significant challenges need to be resolved such as matching the scale, sizing and catalyst design for two distinctly different feedstocks (bulky and reactive solid biomass versus relatively inert petroleum liquids (crude oil)) (Ref: IEA bioenergy task 39)
[2] Risky to scale up due to biomass related infrastructures for processing and logistic issues

4. Indirect options for greening fossil-fuel infrastructures

As discussed in the Introduction, indirect options contribute to the establishment of favorable conditions for biomass use such as the development of market conditions and supply infrastructures in the future. The following paragraphs describe two options (integration of biofuels production in district heating networks and co-firing of biomass and coal for power production). Even these two options enhance the conditions for the development of installations of liquid biofuels nearby, or they can gradually be favored from biofuels plants in the case of potential integration schemes (e.g. retrofitting of existing DH boilers in gasifiers etc.).

4.1 Integration of biofuel production into existing district heating infrastructure

The fundamental idea of district heating (DH) is to recover heat from other processes that use primary energy or to directly use primary energy resources for heating purposes – typically from renewable resources in the form of biomass residues from forest industry. DH offers opportunities to both decrease the use of fossil fuels and achieve high overall energy conversion efficiency (when assuming both electricity and heat have a value). The three major heat recovery practices are: combined heat and power (CHP), waste incineration (often in a CHP scheme), heat pumps and recovering industrial excess heat. The option described here, that is biofuel production integrated with DH networks, refers to the case of biomass gasification with subsequent synthesis to biofuels such as FT diesel, DME, methanol and methane. This option prerequisites the existence of a DH network. In this case, these biofuel plants generate excess heat and energy efficiency can be succeeded if using the excess heat in district heating systems (DH). Therefore, heat integration of biofuel plants with DH networks can improve the economic and environmental performance of the integrated system as a whole especially when replacing decommissioned heat generation capacity for existing DH systems or when investments are made to extend the DH systems.. Broad implementation of gasification-based biofuel production in European DH systems is discussed by (Berndes, et al., 2010), who concluded that the DH systems in EU represent a large heat sink in relation to the amount of excess heat that could be delivered from biomass gasification plants with subsequent synthesis to biofuels, if such plants provided biofuels sufficient for meeting the EU 2020 target for biofuels for transport.

4.1.1 Current technology status

District heating provides 9% of the EU's heating. In 2012 the main fuel was gas (40%), followed by coal (29%) and biomass (16%). (European Commission, 2016).

In EU25, for which there are data (Berndes, et al., 2010), in some Member States the DH heat comes primarily from combined heat and power (CHP) plants and waste heat from other industrial processes, while other Member States also apply direct heat production in heat only boilers (HOB) (Figure 7). In 2003, about 80% of the heat used in the more than 5,000 DH systems in EU25 was produced in fossil fuel fired CHP plants (about 60%) or HOB plants (about 30%).

It is obvious as fossil fuels dominate the energy supply for district heating, there is a strong potential for the transition in other renewable sources such as biomass.

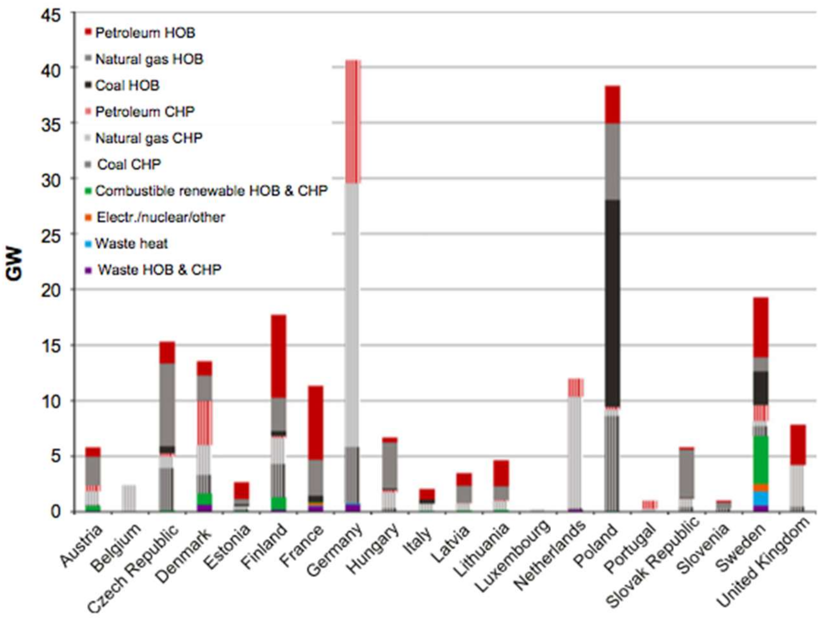


Figure 7 The distribution of DH heat generation options in the EU25 DH countries for which DH contribute significantly to the heating, then excluding Ireland and Greece, which have relatively small DH systems; Malta, Cyprus and Spain, which completely lack DH systems. Note that the installed capacity does not reflect the fuel use. For instance, more coal was burned in Finnish CHP plants in 2003 than petroleum in HOB plants, which had a much shorter average operation time. (Berndes, et al., 2010)

Examples: The technology paths towards biomass transition in Sweden

The Swedish experience is an example of introducing and expanding the use of biomass in the district heating systems and preparing the conditions for developing a mature biomass market, in general. Biomass introduction and expansion was supported by national energy policy tools (e.g. investment subsidies for oil substitution) oil and carbon dioxide taxes, Tradable Renewable Electricity Certificates (TRECs). etc.

According to the study of Ericsson, et al., (2016) the transition from oil and coal to biomass (mainly wood biomass) in the Swedish district heating sector occurred gradually in three discrete periods of technical development.

The first step (late 1970s and early 80s) involved co-firing of biomass with coal or oil as well as conversion of existing oil-fired boilers to biomass only. The conversion to biomass or co-firing of biomass was relatively easy for those boilers that were originally constructed for burning coal as retrofitting was the most direct option. The first fuel shifts to biomass use involved conversion of the oil-fired heat-only boilers in Mora (1978) and Vaxjo (1979/1980).A few years later, the first oil boiler in a CHP plant was converted to biomass in Växjö (1983). In the CHP plants in Borås (1984) and Linkoping (1985), coal- and oil-fired boilers were converted to co-firing of biomass.

The second step (in 1980s) involved investments in biomass-fired boilers. The combustion technologies applied, included conventional grates, bubbling fluidized beds, and circulating fluidized beds. These boilers were mostly built as heat-only boilers, since electricity generation from biomass was not promoted by the energy tax legislation. Later years, biomass was, often co-fired with fossil fuels in CHP plants since it was allowed to allocate the fossil fuels to electricity generation and biomass to heat generation, whereby avoiding taxes (Ericsson, o.a., 2016).

The third step involved investments in biomass-fired CHP plants. All biomass CHP plants have utilized traditional steam technology with boilers, turbines and back pressure condensers for DH generation – typically 120°C water. The currently largest Swedish biomass-fired CHP plant is Igelsta in Södertälje that was built in 2009 and has a capacity of 85 MW of electricity and 145 MW of heat from the back-pressure condenser, giving a power-to-heat ratio of 0.59 in standard operation. An additional flue gas condensation unit can supply further 55 MW of heat. An even larger CHP plant was recently put into operation at the Värtan site in Stockholm, (the capacity of which is 130 MW of electricity and 280 MW of heat) with the final testing phase commenced in 2016. . The use of flue gas condensation units has become very common in the supply of district heat from biomass due to the high moisture content of biomass. In Year 2014, the total heat recovered by flue gas condensation units in Sweden was 18 PJ, adding 16% of energy to the total biomass input of 114 PJ (based on the lower calorific value).

So far, gasification technologies have only been applied in some demonstration projects. An early project was the Värnamo biomass integrated gasification combined cycle (IGCC) demonstration plant commissioned in 1993. The most recent project is the GoBiGas demonstration plant of 20 MW in Gothenburg that was put into operation during 2014.

The Swedish example presents the gradual incorporation of biomass in existing infrastructures and highlights the possibility for the development of infrastructures for the production of liquid biofuels which can be favored from the existence of a DH network (e.g. the case of GoBiGas plant).

4.1.2 Potential future applications of DH based on biofuel plants

Introducing biomass in DH will create a supply system which later may be used to feed biomass fuel plants. The DH systems could contribute to meeting the EU-targets for increased energy efficiency, for renewable energy, as well as for biofuels for transportation. The study of Berndes et al. (2010) illustrates the size of the current DH systems in EU25 in relation to the EU biofuels for transportation targets for 2020: If 10% of the projected transport energy demand in EU by 2020 was to be met with biofuels from biofuel production units integrated in the DH system in a way that these would deliver 0.2 energy units of DH heat per energy unit of biofuel produced, these biofuel plants would cover roughly 15% of the total heat demand in the current DH systems in EU25. Of course, the possibility for implementation of DH integrated biofuel production is highly dependent on the competitiveness against other heat supply options and in particularly CHP, which is dominating the DH heat supply in most Member States (MS). It is also dependent on whether an economic feasibility requires that the DH integrated biofuel plant becomes a base load heat provider for the DH system.

4.1.3 A low-cost low risk option for biofuel production

The study of (Thunman, et al., 2018) presents a potential strategy of how fluidized bed boilers can be retrofitted to become biomass gasifiers which can then be operated for integrated production of fuels and chemicals with DH systems heat delivery. Figure 8 presents the fluidized boilers (circulating fluidized bed (CFB) and bubbling fluidized bed (BFB)) currently installed in the Swedish energy system together with the possible capacity for two types of add-on boilers (BFB or CFC) with which they need to be combined to operate as (Dual Fluidized Bed) DFB gasifiers. This scenario represents a low-cost, low risk options for large penetration of biofuel (or biogas or biochemical) production.

In terms of the required level of investment, retrofitting an existing biomass boiler from district heating or the combined production of electricity and district heating to a gasifier with full downstream synthesis would reduce the cost of the investment by 10–20% compared to a new stand-alone plant. But equally important, this is an example of how the existing energy infrastructure (including knowledge and competence) could be utilized for fast introduction of biofuel production.

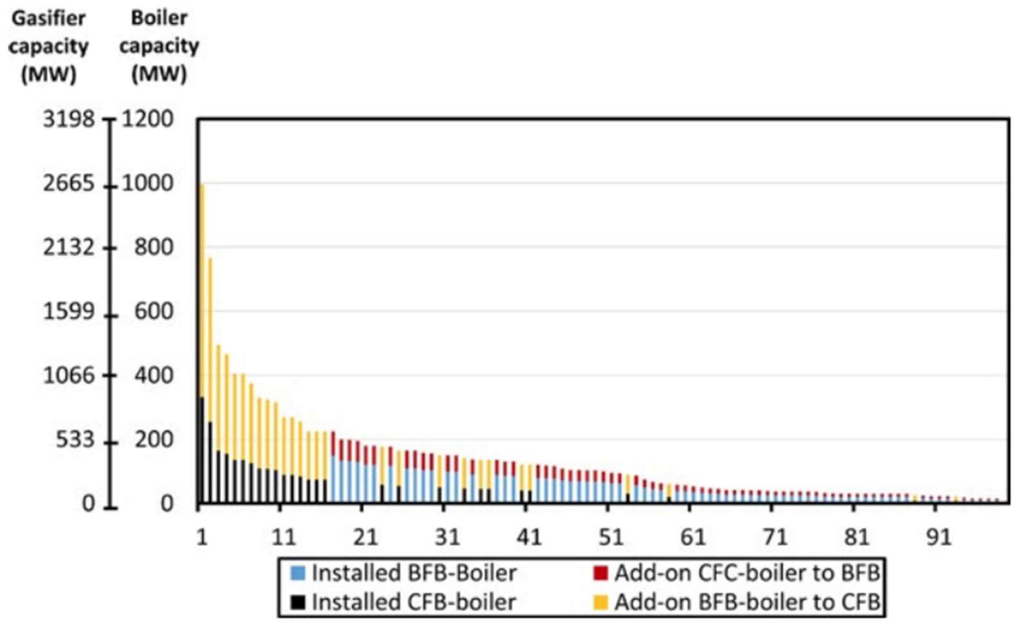


Figure 8 Existing installed capacity of fluidized bed boilers in the Swedish energy system and the corresponding additional boiler sizes needed to realize their conversion to dual fluidized bed gasifiers (Thunman, et al., 2018)

Thunman et al. (2018) presented the potential in a numerical estimation, that to the 6,400-MW_{th} installed boilers, the required boiler capacity needs to be added is 6,800 MW_{th} to create a gasification potential of 35,000 MW. With an assumed annual operation of 8,000 h, this correspond to a fuel demand of 280 TWh of biomass (59 million dry tonnes of biomass per year), which can produce between 170 TWh and 200 TWh (14.6–17.2 MTOE) of advanced biofuels or bio-based materials. This corresponds to a potential production that is 5-times greater than the Swedish target for biofuel production required to reach the Swedish goal of fossil free nation in Year 2045.
Thunman et al. (2018) also considered logistic constraints in their analysis which then lowers the potential. Thus, for most locations it is not feasible to have units with fuel inputs greater than 500 MW (2,500 dry tonnes of biomass/day) and if considering this, the annual potential fuel demand is reduced by around 30% i.e. to around 200 TWh (42 million dry tonnes of biomass). This is, nevertheless, a substantial demand for fuel and corresponds to the total forest growth in Sweden, implying that biomass must be imported if this scenario is to be realized. In other words, there is a low risk option for introduction of biofuel production at an extent that is in fact the national biomass supply which will limit the amount of fuel production – in spite of that Sweden has large amounts of forestry derived biomass.

4.2 Biomass co-firing with coal

This is included as an indirect option since biomass co-firing should be a low risk option for regions without any developed biomass supply infrastructure but with coal fired power plants. Thus, this option takes advantage of existing energy infrastructures in the form of power plants and combined heat and power plants. Once the biomass supply infrastructure has been established, the fossil fuel plant with associated fossil fuel infrastructure can be replaced with a biomass-only process such as a biofuel production unit in the form of a gasification or pyrolysis unit. It should be stressed that the biomass co-firing option should not be used as an excuse of maintaining the fossil fuel units, but the option should go hand in hand with a clear plan on how to phase out the fossil fuel use in the longer run.

4.2.1 Technology description

Co-firing is the simultaneous combustion of two or more fuels in the same plant in order to produce one or more energy carriers. In the case of biomass use, co-firing with coal can be an attractive energy generating option both from economic and environmental point of view.

From the economic perspective, biomass co-firing can be beneficial in the sense that it does not require major capital investments since it applies the existing coal-fired power plant infrastructure. Co-firing biomass with coal in existing boilers costs around 2–5 times less to implement than other bio-electricity generating options and it is also in the lower cost range compared to other renewable energy-based electricity options. Biomass co-firing with coal is more efficient than other available bio-electricity options since the impact on conversion efficiency from low levels of biomass co-firing (10% share of biomass on energy basis) seems to be modest.

For most coal-fired power plants, the conversion efficiencies are commonly in the range 30–38% (higher heating value basis). These efficiency levels are much higher than those associated with smaller, conventional, dedicated biomass power-only systems and rival or exceed the estimated efficiencies of most of the proposed, advanced biomass-based power systems. The addition of biomass to a coal-fired boiler has only a modest impact on the overall generation efficiency of the power plant, depending principally on the moisture content of the biomass. (Al-Mansour, et al., 2010)

Co-firing biomass in existing coal-fired power plants offers the possibility of significantly increasing the share of biomass in fossil fuel rich regions through a relatively small boiler-upgrade investment, while maintaining a high conversion efficiency compared to biomass-only plants, in which steam properties are limited due to the risk of alkali-related high-temperature corrosion. Typical co-firing shares—in the order of 10%—reduces the risk of alkali-related high-temperature corrosion.

Moreover, co-firing is a low-risk option for the production of renewable electricity (and heat) since the risks associated with major capital investments and raw material supplies are much smaller compared to other alternative uses of biomass (e.g., biomass to biofuel production). Uncertain biomass supply can be managed by varying the share of co-fired biomass. Thus, co-firing biomass in coal plants can provide a near-term biomass market that stimulates the build-out of the biomass supply infrastructure that can facilitate the implementation of other bioenergy options once those technologies are commercially available (Cintas, et al., 2018).

Additionally, direct co-firing is one of the most interesting and effective means of reducing GHG emissions from the coal-fired power plants. Finally, co-firing is a near term market for biomass.

4.2.2 Current technology status

Currently, the EU has an installed coal power capacity of 164 GW (2016), which generates 24.5% of the total electricity mix (Cintas, et al., 2018).

Worldwide, approximately 230 power and combined heat and power plants are in operation which apply co-firing and a significant portion of them are in Europe. Aside from UK, Denmark, Germany, and Netherlands, many other European countries such as Finland, Sweden, Russia, Belgium, Austria, Hungary, Italy, and Spain are using biomass co-firing technologies in their power plants (Roni, et al., 2017).

For the past decade, various forms of biomass fuels have been co-combusted in existing coal-fired boiler and gas-fired power plants

Denmark is one of the most ambitious countries with renewable energy goals especially in wind power but also in biomass. Denmark has a total of five co-combustion plants in which straw, wood chips, and wood pellets are the predominant co-firing fuels (Roni, et al., 2017). Among them, straw is the most popular one since this feedstock is readily available in the domestic market. Approximately, two-thirds of the annual demands of wood chips are met by the domestic production. However, Denmark relies heavily on importing wood pellets from external markets (Canada and Eastern Europe) it is obvious that the scenario of co-firing of biomass is heavily contingent upon domestic availability of straw, wood chips, and wood pellets. Therefore, if demand for these biomass sources increase to an extent that Denmark fails to supply them in a sustainable way, the country may become susceptible to high and possible volatile biomass prices.

In total, 14 biomass co-firing plants are located in Finland. Finland is strong in the area of biomass for energy with a long lasting tradition in the Pulp and Paper industry, two global boiler manufacturing companies (Valmet and Amec Foster Wheeler). This is obviously since Finland, similar to Sweden, has large forest resources with biomass as one of the main sources for fuel and feedstock in the industry. Peat is also another important fuel contributing almost 10% of energy consumption.

In Belgium, the initiation of biomass co-firing to produce electricity started after the “green certificate” system implemented in 2001. There are seven co-firing power plants in Belgium.

Biomass co-firing first started in Austria in the early 1990s. There are five co-firing power plants in Austria. which (in their majority) use pulverized coal as primary fuel, whereas wood chips (mostly bark) are used as biomass.

Although Sweden, similar to Finland, has large biomass resources in the form of a well developed forest industry and large use of biomass in the pulp and paper industry using residues from the forest industry for electricity and heat production, there is little use of coal for electricity and heat generation. The reason is that Sweden introduced a tax on CO_2 in 1991 for heat production from fossil fuels. Yet, there are nine co-firing biomass plants in Sweden.

In Germany, 30 co-firing plants are reported (Roni, et al., 2017). The most commonly used fuel is sewage sludge which is used in almost 50% of all plants. Sewage sludge can be co-fired up to 3% without making any significant change on the technical aspects of a plant. The most important barriers to co-firing biomass in Germany are the limited security of biomass availability (e.g., lack of suppliers, seasonality), high requirements regarding the operating license for waste co-firing plants, and increased competition in liberalized power markets (Roni, et al., 2017).

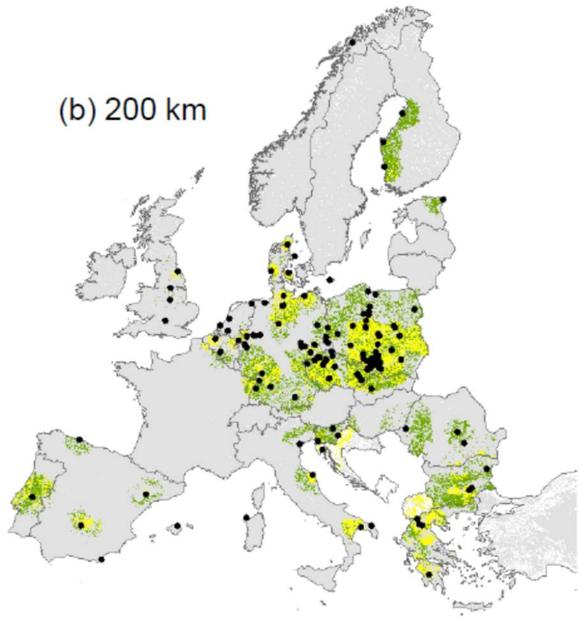
4.2.3 The potential of greening coal-fired plants in EU

Hansson et al. (2009) assessed biomass co-firing with coal in existing coal-fired power plants in EU-27, and Bertrand, Dequiedt, and Le Cadre (2014) matched the demand for biomass-based electricity with the potential biomass supply in Europe. While Hansson et al. (2009) only focused on mapping biomass demand, Bertrand et al. (2014) compared the demand with the supply based on previously published biomass supply estimates at the country level. Higher resolution assessment of biomass demand and supply patterns in Europe can provide a more comprehensive understanding of how the biomass demand for co-firing and other applications can be met.

The study of Cintas et al (2019) (Cintas, et al., 2019) provides two scenarios for potential greening of existing coal-fired plants in EU countries either converting the power plants to 100% biomass-firing

plants *(Scenario 1*) or using the sites of the power plants to establish pyrolysis units for producing a raw bio-oil to be transported to petroleum refineries (*Scenario 2*).
Scenario 1 assumes that all existing co-firing plants, and the coal-fired power plants identified as suitable for co-firing have been retrofitted to allow coal to be completely substituted by biomass; i.e., the plants will only use biomass, provided it is available. This kind of transition has been seen in the United Kingdom (UK), for instance, where three coal plants co-fired while they were converted to biomass (Roni et al., 2017). Suitable plants in the same study are economically feasible if the plant was constructed after 1990.- considering 30 years as maximum plant age. Older boilers in general have lower efficiency and are of less interest for upgrading to support co-firing due to the few remaining years of operation.),
In Figure 9 a plant data are taken from the Chalmers Power Plant Database for Europe (CPPD; Kjärstad & Johnsson, 2007;), where black dots represent plants constructed after 1990, for which retrofitting for biomass co-firing is considered economically feasible (Hansson et al., 2009) (142 boilers) and purple dots correspond to plants that are constructed before 1991 (i.e., assumed to not be available for retrofitting) or have already been retrofitted for co-firing. Fig. 4 b shows the results of the study for Scenario 1, that is the distribution of forest residue collection and SRC (short rotation coppice) biomass cultivation (green and yellow colors, respectively) to meet the biomass demand in retrofitted plants considering 200 km transport distance limits from the plant .

a

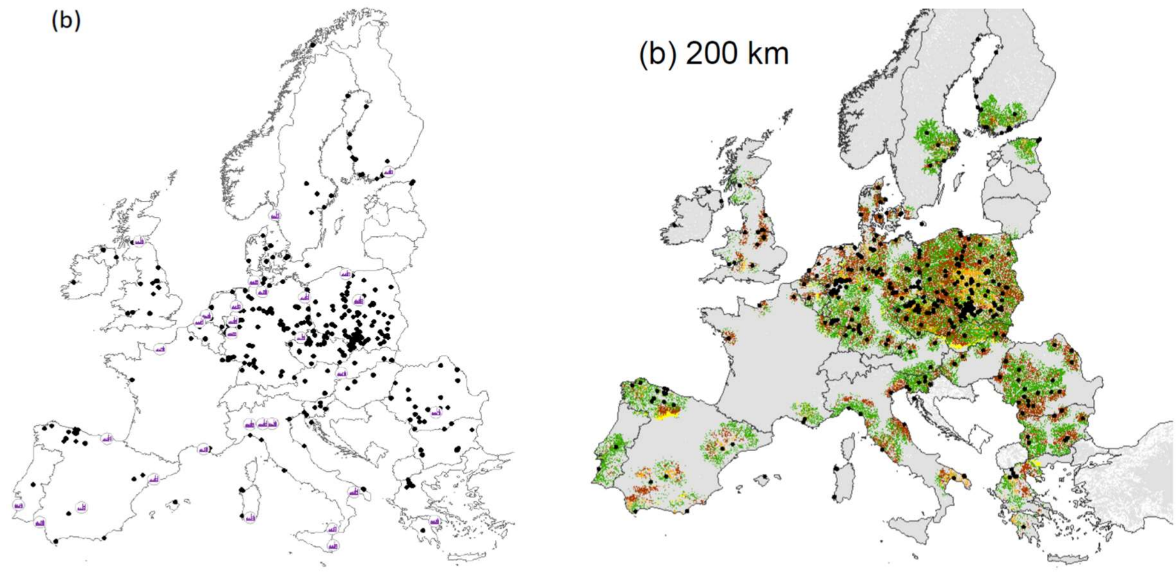


b

Figure 9 (a) Demand points corresponding to coal-fired power plants included in the CPPD. Black dots represent the plants identified in Cintas et al. (2018) for which retrofitting for biomass co-firing was considered economically feasible (b) Feedstock used to meet the demand for *Scenario 1* with transport distance limited to 200 km[2]

[2] Maximum transport distances in the study of Cintas et al. (2018) assumed are 100km, 200km and 300km. The second one is presented in this report

In Scenario 2, it is assumed that pyrolysis units are built on current coal power plant sites. (In Figure 10 (a) black dots represent all the existing coal power plant sites that are assumed suitable for construction of bio-oil units to feed bio-refineries). All coal power plants available in the CPPD are assumed to represent suitable sites for bio-oil production. Then existing refineries with hydrocrackers are assumed to shift from petroleum to bio-based oil. The capacity of each pyrolysis unit is set to 100 MW bio-oil, corresponding to the planned size of the GoBiGas phase two project (100 MW bio-methane) (Alamia et al., 2017). Figure 10 (b) shows where residues are collected and SRC biomass cultivated to meet the biomass demand in each country.
The results of the analysis of this scenario showed that Bio-oil plants (each 100 MW) are built on all the existing coal power plant sites, producing 970 PJ of bio-oil and using about 1493 PJ biomass. Results also showed that the largest bio-oil producers are naturally the countries with most coal power plants, i.e., Poland (97 units), Germany (93), the Czech Republic (43), Spain (20), Romania (17), Italy (15), and the UK Scenario 2:



a b

Figure 10 (a) Demand points corresponding to coal-fired power plants included in the CPPD.
black dots represent all the existing coal power plant sites that are assumed suitable for construction of bio-oil units to feed bio-refineries. Purple dots represent refineries identified as suitable for biobased feedstock, i.e., refineries with hydro crackers, (b) Feedstock used to meet the demand for *Scenario 2* with transport distance limited to 200 km.

4.3 Summary of indirect technological options

Table 4 summarizes the options for indirect biomass to liquid fuels technologies into existing fossil infrastructures. The information is arranged in order to be clear what the current status, opportunities and barriers for of the integration of these technologies into existing fossil infrastructures are.

Table 4: Indirect integrated options of biomass use in fossil infrastructures

Integration option	Opportunities	Barriers	Real world examples	References/Supplementary Data	Feasibility to scale up (Low, High, Medium)
Biomass co-firing with coal	**Technological** ▪ Exploiting existing infra-structures as a stepping-stone for establishing bio-mass-supply infrastructure where such is lacking. ▪ Large number of coal-fired power plants makes bio-mass co-firing an option in many EU countries. ▪ Roughly two-thirds of about 150 coal-fired power plants in Europe either as pilot tests or in commercial use **Economic** ▪ Co-firing biomass with coal in existing boilers costs about 2–5 times less to im-plement than other bio-elec-tricity generating options ▪ It is in lower cost range com-pared to other renewable energy based electricity (RES-E) options (Berndes et al 2010)	**Technological** ▪ Risk of delaying the phase-out of fossil-fuel power plants. ▪ A steady growing biomass de-mand for co-firing may be con-sidered a lock-in risk. ▪ Local availability of large amounts of quality biomass. **Economic** ▪ Cost of collection, handling, preparation and transportation of biomass, in comparison with the relatively low cost of coal. **Supply chain** ▪ Cost of co-firing sensitive to the plant location, and the key cost element is the biomass feed-stock. ▪ A substantial increase in bio-mass co-firing poses the ques-tion of the sustainability and availability of the feedstock supply, which could also be	▪ Data for **location and capacity of coal co-fired power plants** in the MS (Berndes et al 2010) ▪ **Biomass co-firing projects and costs in China and the US** (http://bioelectric.se/wp-con-tent/uploads/2015/09/Updated-RMI-TEP-US-China-biomass-co-firing-10-19-2014-FINAL-FOR-CEQ-2.pdf)	▪ 20% co-firing (as energy content) is cur-rently feasible and more than 50% is tech-nically achievable, the usual biomass share today is below 5% and rarely ex-ceeds 10% ▪ **Reporting of the existing co-firing plants** with technologies and availability of biomass resources in different coun-tries of the world Roni M. et al. 2017 (Bio-mass co-firing technology with policies, challenges, and opportunities: A global re-view) ▪ The costs of retrofitting an existing coal-fired power plant to enable biomass co-fir-ing are typically in the range of USD 300-700/kW for co-feed plants (IPCC 2011; IEA 2012; IRENA 2012) with European estimates around £200/kW or €220/kW (Mott McDonald 2011; (data obtained from IEA-ETSAP and IRENA Technology Brief E21 2013) ▪ Coal power plants in the EU are mainly lo-cated in Germany, Poland, Belgium, Netherlands and the Czech Republic, rep-resenting 75% of the total assessed de-mand for co-firing and bioelectricity and	High[3]

Integration option	Opportunities	Barriers	Real world examples	References/Supplementary Data	Feasibility to scale up (Low, High, Medium)
	▪ Cost of retroffiting a coal based plant is lower than a dedicated 100% biomass plant. **Supply chain** ▪ Starts up biomass supply chains, also suitable as feedstock for 2nd generation biofuels ▪ Uncertain biomass supplies do not jeopardize the fuel supply for power plant	used for the production of biofuels and bio-ethylene (ETSAP P10, I13).		60% of the assessed demand for pyrolysis in the EU.	
Integration of DH with biofuel production processes based on biomass gasification with subsequent synthesis to biofuels)	**Technological** ▪ Integration of biofuel plants with DH systems would improve the cost-competitiveness of these biofuels ▪ Potential to convert fluidized bed boilers to dual fluidized gasifiers (Case in Sweden)	**Technological** ▪ Highly dependent on the competitiveness against other heat supply options and in particularly CHP, which is dominating the DH heat supply in most MS **Economic** ▪ Dependence of existence of financial incentives to retrofit boilers into gasifiers	▪ The case of Sweden's GoBiBas plant which is a $32MW_{th}$ gasifier and produces SNG (Thunman, et al., 2018)		High[3]

[3]A near-term option to displace fossil fuels and pave the way for 2[nd] generation biof (High)

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5. Indirect integration options of biomass in processing industry

In many cases, industrial facilities are beneficial for the development of biofuels processes either by preparing the conditions for the related infrastructures (e.g. logistics) or by integrated process schemes such as the exploitation of by-products and heat integration (gasification of by products in saw mills). Thus, these industries do not only contribute to the maturity for biomass utilization but can also take advantage to become “greener” themselves from the identification of synergies and the substitution fossil based sources from renewable ones.

5.1 Incorporation of biofuels processes in oil refineries

To introduce the production of advanced biofuels, chemicals, and materials into an oil refinery or petrochemical industry that currently lacks both a biomass boiler infrastructure and established logistics for using biomass as fuel, requires a dedicated strategy. In both types of industries, there is a large steam demand that is currently covered by combusting the gases that emanate from the internal distillation or conversion processes. As the compositions of the gases burned in present processes to cover the heat demand are similar to those of the gases that are produced in a biomass gasifier, they can be upgraded (by mixing) to a syngas and further synthesized to desired hydrocarbons or extracted as hydrogen (Thunman et al, 2018).

For this purpose, a low-cost and low-risk option would be to first incorporate a biomass boiler for part of the steam production. Then after the maturity of the infrastructures development, the CFB boiler primarily used for heat production can be upgraded in a gasifier through its connection to a bubbling fluidized bed (BFB) boiler in the form of an indirect dual-bed gasifier (Thunman et al, 2018). Syngas produced can be further synthesized to desired hydrocarbons or extracted as hydrogen (Thunman, et al., 2018). In this way, the synthesis process for the intended system could be put into operation using the excess gases already produced within the industry, where the heat demand is covered by intensified heat integration and the combustion of biomass. This first step of greening the fossil-based refinery infrastructure also provides the opportunity to increase gradually the demand for biomass and to build up the logistic infrastructure needed to receive biomass at the plant by starting with the installation of a circulating fluidized bed (CFB) boiler. With a CFB that initially can be operated at 30% of maximum capacity, which corresponds to just 4% of the final dual fluidized bed (DFB) gasifier capacity, the level

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of biomass utilization on-site can be gradually increased. In summary the intension with these steps would be to constitute a low-risk stepwise development to the production of liquid biofuels with partial integration in an oil refinery.
Heat integration can also reveal opportunities for utilising excess heat at relatively high temperature levels in an oil refinery. If, for instance, there is no district heating system or other heat-consuming industry in the vicinity and no planned internal novel use (e.g., in CCS technologies), the heat can be used for biomass drying where the biomass is either used in biofuel production technologies that can be integrated with the oil refinery (e.g., bio-oil co-processing).

5.2 Incorporation of biofuels processes in steel industry

Most of the metallurgical processes of iron and steel-making industry are energy intensive and are conducted at temperatures above 1,000°C. Biomass could be used as a potential source even though the range of application in this type of industry is limited and it is not competitive to fossil fuels. One way is to replace fossil carbon with carbon from biomass, either as a reducing agent in the blast furnace or as a fuel in heating furnaces. Another possibility is to develop an industrial symbiosis together with a stand-alone biorefinery where excess heat from the iron and steel industry can be used in processes at the biorefinery (Sandén, et al., 2013).
For example, excess heat from the steel plant can be used by an ethanol plant and the ethanol can be used as reducing agent in the blast furnace or as transportation fuel in the steel plant's vehicles. (Ljungstedt, et al., 2011).
The production of bio-coke (coal and biomass blend) with desired physical and chemical properties is still representing a challenge for ironmakers as it negatively affects the physical and chemical properties of the product coke. Thus, the biomass addition to the coal blend is quiet low (2–10%).
Sintering involves the transformation of iron ore fines into large, hard, and porous agglomerates to become suitable for the high pressure and gas flow in the blast furnace. The coke breeze, which is undersize coke generated from screening of metallurgical blast furnace coke, is the main fuel used in sintering process. The utilization of coke-biochar composite is able to enhance the replacement ratio of coal up to 60%.
In blast furnace, biomass can replace some of the coke used as reducing agent, with biomass derived products such as charcoal, syngas, methane and ethanol. However, it is not possible to substitute all the coke in the blast furnace as coke acts as a physical support material and hence ensures correct gas permeability, process temperature and process drainage. The economic evaluation for biomass implementation in the iron and steel industry indicated that the biomass fuels cannot compete with fossil fuels unless carbon tax is imposed (the reported carbon taxes for examined countries varied from 47.1 and 198.7 USD/t-CO_2) (Mousa, et al., 2016).
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5.3 Incorporation of biofuels processes in pulp, paper, and saw mills

For various reasons pulp and paper industry is especially interesting for co-location with biorefineries including closeness to biomass resources, mature infrastructure for handling large volumes of biomass, access to heat sinks and/or heat sources (depending on the type of mill) and, for some biorefinery technologies, existing process units and experience concerning their operation. The extraction of hemicelluloses and lignin in the pulping process, black liquor gasification, biomass gasification and ethanol production as a part of the pulping process are important examples of possibilities to be integrated in the pulp and paper industry. For example, the pulp and paper industry can use pyrolysis to convert by-products into bio-oil for use either internally or to other demand points. Possible disadvantages of co-location of bio-processes with the pulping industry could be long distances to and lack of knowledge about the products and their markets, e.g. motor fuels or chemicals, as well as limited possibilities to deliver (more) low temperature excess heat to district heating networks (Sandén, et al., 2013).

Another industry, closely related to the pulp and paper industry, is the saw mill industry. Existing saw mills are potential integration sites because of closeness to and experience regarding handling of the raw material. Sawmill-integrated bio-SNG production has been investigated by (Ahlström, et al., 2017) and it was proposed that process integration of an indirect biomass gasifier for Liquified Biogas LBG production is an effective way for a sawmill to utilize its by-products. Integration of this type of biorefinery can be done in such a way that the plant can still cover its heating needs whilst expanding its product portfolio in a competitive way, both from a carbon footprint and cost perspective (Ahlström, et al., 2017).

5.4 Other applications

The case of integration of 1st and 2nd generation biofuels can be implemented by co-location of plants that could potentially share energy services, logistics infrastructure and human resources. With respect to CHP units integration of 1st and 2nd generation biofuel production is another case as heat integration options can replace CHP plants which provide energy needs. Several 2G biofuel facilities (e.g., in Brazil, Finland, US) are already co-located with 1G biofuel production facilities especially for 2G bioethanol and an increasing number of US 1G biofuel companies are exploring how to retrofit their processes to incorporate cellulosic feedstocks into their production lines. Furthermore, 2G renewable diesel from residues and wastes (a.k.a. “green diesel”) increasingly comes from Hydrotreated Vegetable Oils HVO plants integrated into existing refineries, with either partial or complete conversion to green products. (IEA-RETD, 2016). “

6. Conclusions

This report shows different ways to produce biofuels by means of using existing industrial and energy infrastructures. To illustrate the potential, mapping of relevant European fossil-based facilities is presented, which constitutes the starting point for the integration of biomass resources. In this context, the following options were thoroughly analysed, and arranged either as direct (pyrolysis, BTL) or indirect integrated options (DH, co-firing for heat and power).

Pyrolysis oil processing requires a greater effort in order to reach commercial development, since the commercial production of this intermediate product is still in preliminary stages. The various draw-backs found in its upgrading to biofuels is concerning the poor quality of the bio- oils. Thus, the con-ventional hydrotreating catalysts are expected to have a considerably lower catalyst life in bio-oil up-grading operations than that observed with petroleum feedstock. While the current generation com-mercial catalysts are excellent hydro processing catalysts, they are optimised for petroleum feedstock. In addition, most of the biomass conversion processes carried out in a refinery need a large amount of hydrogen in order to remove oxygen and yield high energy density fuels. In the long term, pyrolysis-oil from lignocellulosic biomass may substitute crude oil, and furtherance of this technology would be important due to high amounts of lignocellulosic wastes that are available.

BTL production is constrained by scaling up issues from a technological perspective, stability in biomass supply, and catalyst selection issues, which make this option difficult in regards to reaching commercial scale. High costs of biomass transportation and the design of appropriate gasification plants are constraints for the enhancement of this technology. Thus, combined feedstock selection (biomass and coal) is considered as a favorable option.

Among the indirect options analysed in the current WP, and DH and biomass co-firing are included. These are important short term options which can reduce costs and risks which can deliver a wide range of liquid biofuels.

DH integrated biofuel production showed that the DH systems in EU represent a large heat sink in relation to the amount of excess heat that could be delivered from biofuel plants that are based on biomass gasification. However, factors such as the competitiveness of DH with other technologies (CHP) and the technical barriers of retrofitting existing boilers in gasifiers influence the implementation potential for this biofuel option, and therefore, require further analysis. Biomass co-firing has the potential to reduce emissions from fossil-based fuel generation (mostly coal) without substantially increasing the investment or operational costs. Biomass co-firing has already received solid ground in many of the European countries, e.g., United Kingdom, Germany, Finland, and Denmark.

Thus, the greening of the existing fossil fuel infrastructure (mainly for the indirect options) can be a driver for the development of advanced biofuel production facilities, as it can reduce the initial risks in terms of cost and technological constraints, and create stepping stones by finding synergies with other parts of the energy and industrial sectors. At the same time, it is of course important to make sure that such biofuel production processes (such as pyrolysis and BTL) are part of a more long-term strategy which phase out the fossil fuel infrastructure, and which needs financial and legislative incentives paired with technological progress to be applied.

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