ADVANCEFUEL

D3.2 Definition of biomass reference technologies with respect to TRL and performance indicators

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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 CO_2 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

This document contains information for the present status of technology readiness level (TRL), operating (OPEX) and capital investment (CAPEX) expenditures of conversion technologies in the context of the ADVANCEFUEL project. The cost data represent a top-down perspective being derived from reported overall efficiencies of biomass conversion to ADVANCEFUEL relevant end-products, ranges of CAPEX and OPEX from operating processing plants and/or relevant engineering studies, and typical percentages of OPEX breakdown to biomass feedstock costs and other material and energy utilities and maintenance related costs. This TRL, CAPEX and OPEX data will be used in the rest of the deliverables of WP3 as reference points for the relevant key performance indicators (KPIs) regarding the conversion technologies as defined in D1.2, namely "well-to-wheel" system efficiency and the potential for increase due to innovative processes, the CAPEX needed to increase the TRL of selected technologies, and the CAPEX and OPEX reduction due to opportunities for greening the fossil fuel infrastructure (i.e., comparing the total costs of an integrated system to a stand-alone system).

The data cover the thermochemical and biochemical conversion technologies reported in D3.1, targeting at methanol, ethanol, butanol, dimethylether, Fischer-Tropsch (FT) products (gasoline, diesel, kerosene) and methane as potential biofuels for road, aviation and maritime transport. With respect to TRL, the biochemical pathways for the production of ethanol are more mature technologies but with relatively wide ranges of their economic KPIs (e.g., 102-228 €[1]/MWh-product), subject to many non-technological factors, such as the type and cost of feedstock, the on- or off-site enzyme production, and the lignin and other by-products utilization; only few demonstration plants are reported for butanol production. The gasification based pathways are well established with respect to the Syngas based synthesis technologies but lower TRL of the gasification part; the economic KPIs for methane and methanol production lie within narrower range compared to FT liquids (i.e., total production cost of 73-89 €/MWh-product compared to 95-136 €/MWh-product, respectively). With respect to TRL, the most marginal case is the pyrolysis oil upgrading technologies; this makes the reported CAPEX and OPEX ranges for the production of advanced biofuels by this pathway to resemble rough order of magnitude estimates and are thus the most uncertain from those presented in this report (i.e., total production cost of 83-102 €/MWh-product).

[1] The data in this report are based on references in the period of 2012-2018. No time adjustment is performed with respect to the value of the Euro currency in this time interval. Moreover, wherever the original data were reported in a different currency (e.g., US dollars, Swedish krona, etc.) average currency rates in 2018 were used.

Contents

1. Introduction

The rationale of the ADVANCEFUEL project in terms of feedstocks, conversion technologies and targeted fuels is described in deliverables D1.1 and D1.3. In Chapter 4 of D1.3 the main definitions with respect to feedstock supply, infrastructure and specifications, conversion technology parameters and efficiencies, sustainability performance, and end use specifications and infrastructure are provided.

With respect to conversion technologies in particular, the ADVANCEFUEL project focuses on technology readiness levels (TRL) of 5-9. Besides TRL, the terminology presented in the previous deliverables referred also to specific conversion technology aspects, such as process complexity, description of operating principle, process feedstock and product fuel specifications, typical operating capacities, material and energy flow analysis and the respective efficiencies, and process investment and operating costs (i.e., accounting also for the synergistic potential of integration by utilising existing on- and off-site infrastructure), as well as labour requirements of typical installations.

Complementing this generic terminology, specific parameters for biomass conversion technologies of the ADVANCEFUEL project were defined in deliverable D3.1, for the following categories:

- Pre-treatment technologies (i.e., after mechanical size reduction of the biomass and potential pelletisation), categorised in physical, chemical, physicochemical (including thermal), and biological methods, such as drying, steam explosion, torrefaction, fractionation and hydrolysis of lignocellulosic biomass
- Thermochemical technologies, including gasification (direct and indirect), and pyrolysis
- Biochemical technologies, including fermentation
- Downstream technologies, including Fischer-Tropsch (FT) synthesis of liquid fuels, methanol and dimethyl ether synthesis, cracking and refining technologies of pyrolysis oil, towards gasoline, diesel, kerosene and liquefied methane (bio-LNG).

This deliverable focuses on reporting the present status of TRL and cost related KPIs (OPEX and CAPEX) for the biomass reference technologies defined in D3.1, targeting at methanol, ethanol, butanol, dimethylether, Fischer-Tropsch products (gasoline, diesel, kerosene) and methane as potential biofuels for road, aviation and maritime transport. The cost data represent a top-down perspective being derived from overall efficiencies of biomass conversion to ADVANCEFUEL relevant end-products, ranges of CAPEX and OPEX for operating processing plants, and typical percentages of OPEX breakdown to biomass feedstock costs and other material and energy utilities and maintenance related costs. The data represent the relevant costs around the conversion technologies boundaries, namely the part of the value chain starting from the point where lignocellulosic biomass is available at the processing plant of the respective conversion technology and ending at the point where the respective biofuel is derived as end-product to be further distributed locally or globally, namely the costs of upstream to or downstream from the processing plant ,referring to biomass cultivation and transport, distribution of the biofuel to end-users and the end-use are not explicitly included in the data; however the upstream cost is implicitly included as reference values for biomass prices is taken into account.

This TRL, CAPEX and OPEX data will be used in the rest of the WP3 deliverables as reference values for the relevant KPIs defined in D1.2, namely the potential for increase due to innovative processes, the CAPEX needed to increase the TRL of selected technologies, and the CAPEX and OPEX reduction due to opportunities for greening the fossil fuel infrastructure (i.e., comparing the total costs of an integrated system to a stand-alone system). By extension, the data are also a valuable source of information for the value chain analysis of advanced renewable transport fuels in WP5 (e.g., D5.2) and the integrated assessment of innovative approaches in WP6 (e.g., D6.2). As WP5 and WP6 include the whole value chain and the potential market uptake, the assessment (i.e., with respect to economic, environmental and social performance) in these deliverables has a broader scope.

It should also be noted that on the basis of these KPIs additional profitability related economic metrics can be calculated (e.g., net present value, payback periods, return on investment) based on current or future prices of the respective fuel products. These will be included in future deliverables of WP3 (i.e., D3.5 and D3.6) as well as of relevant deliverables of WP5 and DW6, on the basis of detailed input/output process inventories and scenarios of economic background data for the technologies in the scope of the ADVANCEFUEL project.

2. TRL of pretreatment technologies

Table 1 presents the TRL of the pretreatment technologies defined in D3.1. The respective TRL ranges are mainly based on the Final report for the European Commission Directorate-General Energy (E4tech et al., 2015), complemented with information from the final report of the BIOCORE project especially for the Organosolv status (BIOCORE, 2014), the biomass technology roadmap of the European Technology Platform on Renewable Heating and Cooling (RHC, 2014), and the WIDER working paper on biofuels technology (Stafford et al., 2017). The KPIs of the pretreatment technologies are lumped with the costs of the conversion technologies presented in the next paragraphs, unless otherwise stated. A more detailed cost analysis on the basis of detailed process inventories and feedstock to technology matching will allow for a separate cost allocation to the pretreatment section in the next deliverables of WP3 (i.e., D3.5 and D3.6).

Table 1: TRL of the pretreatment technologies defined in D3.1.

Pretreatment Technology	**TRL** (E4tech et al., 2015, BIOCORE, 2014, RHC, 2014, Stafford et al., 2017)
Physical Methods	
Mechanical chipping, grinding or milling[1]	8 to 9
Pelletisation[2]	9
Torrefaction	8 to 9
Chemical Methods	
Dilute acid pretreatment	5 to 7
Concentrated acid hydrolysis	4 to 5
Organosolv	5 to 6
Alkaline pre-treatment	5 to 7
Physicochemical Methods	
Steam explosion	6 to 8
Liquid hot water	5 to 7
Ammonia Fibre Explosion	3 to 5
Biological Methods	
Microbial treatment	3 to 4

[1]Mechanical milling as lignocellulosic biomass pretreatment method for biofuels production in the context of the sugar platform, although presenting opportunities with respect to reduction of cellulose crystallinity and absence of inhibitors or residues production, is reported to have a TRL of 5-6 mainly due to high energy consumption and poor sugar yields (E4tech et al., 2015). Mitigation of these effects towards a further TRL development in this context includes process integration and combination with mild chemical treatments.

[2]Pelletisation as a lignocellulosic biomass pretreatment method used for heating and electricity production applications (e.g., steam turbines) is a commercially established technology (Stafford et al., 2017); the same TRL is considered also for pelletisation as pretreatment method for thermo-chemical conversion technologies.

3. KPIs for gasification pathways

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. In general, the gasification pathways to advanced fuels discussed in this report proceed through a syngas production step. The lignocellulosic feedstock is pretreated by drying and sizing (i.e., typically chipping, grinding, and milling but also torrefaction and flash pyrolysis in some cases) and then converted directly or indirectly to a raw Syngas type of mixture (i.e., CO and H_2), together with CH_4, tar and char components, at temperatures ranging from 800 °C to 1500 °C and pressures ranging from 1-30 bar. Depending on the technology and biomass used, impurities may include dust, ash, bed material, sulphur and chloride compounds (Reihnard et al., 2013), and the product gas may be rich in CO and N_2 (i.e., direct gasification using air as gasification agent) or have a higher content of H_2. Syngas yield can be maximised by steam reforming (i.e., when methane is not the target product), while the resulting CO_2 from the water/gas shift reaction can be removed, typically by physical or chemical liquid absorption processes. Syngas will then need to be compressed to the required downstream synthesis pressure (i.e., typically to 80-100 bar). It should be noted that if methane is the target fuel, low temperature, indirectly heated gasifier systems can be advantageous because of the higher content of methane already in the gasifier and the lower investment cost compared to directly operated gasifiers using oxygen (i.e., by avoiding the oxygen plant investment).

The reported overall efficiencies for the gasification pathways (i.e., from biomass as received prior to pretreatment up to the delivery product) range from 40% to 70%, on an energy basis (Low heating value). The higher values of this range refer to biomethane as well as special applications (e.g., gasification of black liquor in pulp mills), while integration of gasification plants with district heating or combined heat and power production can further increase the overall efficiency by 5% to 10%. On the other hand, the lower values in this range refer to production of Fischer Tropsch diesel and kerosene (Landälv et al., 2017).

The current **TRL of the gasification pathways to the defined ADVANCEFUEL products is considered to be between 5-8** (i.e., technology validated/demonstrated in industrially relevant environment to system prototype demonstration in operational environment or even complete and qualified), the lower TRL part of the range mainly referring to the gasification part (i.e., the Syngas based synthesis technologies to methanol, ethanol, and Fischer Tropsch liquids being already demonstrated at commercial scale). This is, for instance, the case in the following plants at various scales (Landälv et al., 2017):

- The Bioliq pilot plant at Karlsruhe Institute of Technology in Germany, including a fast pyrolysis reactor of slurry from lignocellulosic biomass (see also paragraph 3, "Technologies for pyrolysis pathways", where one option of valorization of pyrolysis oil to biofuels is via gasification), an entrained flow gasifier technology, and a DME/gasoline synthesis technology with 2000-3000 hours and a synthesis product capacity equivalent to 1600 tonnes/year.
- The BioDME plant in Sweden, applying the Chemrec black liquor gasification technology and the HaldorTopsoe syngas to methanol and DME technology, with more than 27000 hours of operation for the gasifier and approximately 11,000 hours for the methanol and DME synthesis technology and a product capacity equivalent to 1200-1300 tonnes/year.
- The GTI gasification based pilot plant in USA, applying the U-Gas based Carbona steam/oxygen gasification technology, the HaldorTopsoe catalytic syngas cleanup technology and the HaldorTopsoe Tigas process to produce gasoline from syngas, with 3000 hours of operation and a product capacity equivalent to 1000-1100 tonnes/year.
- the Enerkem's demonstration and commercial plants in Canada, converting waste wood and assorted solid municipal waste by applying bubbling fluidized bed operating at low pressure, wet scrubbing and absorber/desorber systems for gas cleaning, and a syngas to methanol and ethanol catalytic synthesis process developed by Enerkem, with approximately 13000 hours of operation at demonstration scale and 2600 hours of operation at commercial scale, and product capacities equivalent to approximately 4000 and more than 30000 tonnes/year, respectively.

Examples of CAPEX and OPEX for gasification pathways are those reported by E.ON (Möller et al., 2013), Chemrec (International Energy Agency, 2013, Landälv, 2016), and VTT (Hannula et al., 2013). Recently, a detailed analysis of technical performance, process inventories and lessons learned in the case of the GoBiGas plant in Sweden (fully operated plant with a capacity of 20 MW methane output from lignocellulosic residues) was presented by Alamia et al. (2017) and Thunman et al. (2018), followed by a detailed economic analysis for by Thunman et al. (2019). The estimated values for the economic KPIs on the basis of the aforementioned studies are summarized in Table 2 together with the relevant input and output parameters, namely feedstock and product type and their respective capacities. Unless otherwise stated, lignocellulosic biomass feedstock refers to forest residues with a moisture content of 45-50%, delivered to the plant as chips or pellets. It should also be noted that for the Fischer-Tropsch downstream processing, the data represent a mix of various technologies for gasification and upgrading (e.g., from 66% diesel yield and 34% naphtha yield to 48% yield of synthetic paraffinic kerosene, 28% yield of diesel and 24% yield of naphtha.

Table 2: CAPEX and OPEX reference values for technologies based on gasification pathways. The respective plants are indicative for the type of technologies, while the ranges for the economic KPIs are calculated on the basis of the assumptions listed below the table.

	E.ON Bio2G (Möller et al., 2013)	GoBiGas (Thunman et al., 2019)	Chemrec (IEA, 2013, Landälv, 2016)	VTT (Hannula et al., 2013)	Fischer-Tropsch (FT) (Landälv, 2016)
Input type	Lignocellulosic biomass	Lignocellulo-sic biomass	Black liquor from pulp mill	Lignocellu-losic bio-mass	Lignocellulo-sic biomass
Input capacity (MW)	325	155	145	335	20-2000
Output type	Methane	Methane	Methanol	Methanol	FT liquids
Output capacity (MW)	200	100	100	200	100-300
CAPEX(1) (€/kW-product)	1850-2050	3100-3260 2240-2400(2)	3400-3500 2800(2)	1700-1750	2000-4000
Share of CAPEX in production cost(3) (€/MWh-product)	**26-38**	**42-63 31-46(2)**	**45-68 18-27(2)**	**23-34**	**39-59**
Share of Biomass OPEX in production cost(4) (€/MWh-product)	33	26	29	30	36-50
Share of other OPEX (material and energy utilities, maintenance, etc.) in production cost(5) (€/MWh-product)	15-18 (6-24)	17-22 14-18(2) (8-29) (6-24)(2)	18-24 12-14(2) (8-32) (5-18)(2)	13-16 (6-21)	19-27 (8-36)
Total production cost(6) (€/MWh-product)	**73-89 (65-95)**	**84-111 70-89(2) (75-118) (62-95)(2)**	**92-121 82-105(2) (82-129) (73-112)(2)**	**66-80 (59-85)**	**95-136 (84-146)**

(1)An average of the respective CAPEX range is used to calculate the share of CAPEX in production cost. The E.ON Bio2G, GoBiGas and VTT CAPEX data include fuel handling (e.g., reception, preparation, storage) and drying and a steam cycle. The GoBiGas original report refers to cases of pellets (10% moisture), forest residues (45% moisture) and recovered wood (18% moisture) as ingoing feedstock at different prices (i.e., thus the CAPEx for pelletisation is only reflected in these prices and not included in CAPEX data). The VTT case study refers to forest residue chips (50% moisture content) produced from the residue formed during harvesting of industrial wood (i.e., including needles and having a higher proportion of bark than chips made out of whole trees). The CAPEX for FT liquids result from a variety of studies reported by Landälv et al., (2016) without specific reference of the boundaries for the CAPEX calculation. In this report, it is assumed that they refer to the same boundaries used in the E.ON Bio2G, GoBiGas and VTT studies. The overall CAPEX range for FT-liquid studies provided by Landälv et al., (2016) is somewhat wider than the one presented in Table 2 (i.e., 1500-6000 €/kW-product), the vast majority of the values being however between the 2000 and 4000 €/kW-product with an average of 3000 Euros/kW-product for a plant with product capacity of approximately 200 MW (the respective overall capacity range with respect to the output of the plant being between 20 and 1000 MW).

(2)If the capacity of the GoBiGas plant is scaled up to 200 MW, the corresponding CAPEX is expected to be reduced to 2240-2400 €/kW (Thunman et al., 2019). Similarly, if the Chemrec plant is scaled to the size of the larger plants (i.e., 200 MW output) CAPEX is expected to decrease to about 2800 €/kW.

(3)To calculate the share of CAPEX in production costs, the concept of annuity is used with economic lifetime of the plant equal to 15 years, an average operating time of 8000 hours/year and 10% annual interest rate. These values refer to typical settings proposed in the report of Landälv et al., (2017) and are also used as a common reference values for the other pathways in this report. However, these should not be interpreted as commonly accepted values in the respective literature on which this report is based. For the case of the GoBiGas, the respective values used in the report of Thunman et al. (2019) for the conclusive estimated production costs are 20 years for the economic lifetime of the plant and 5% annual interest rate. This results in a share of CAPEX in production costs of 20-25 €/MWh-product for the 100 MW plant and 15-20 €/MWh-product for the 200 MW plant and is the main reason for the difference to the ranges presented in Table 2. In all cases, the provided range results from considering 20% uncertainty in these calculations, following the approach of Landälv et al. (2017). The respective equations are presented in Appendix 1.

(4)The share of biomass OPEX in production costs is calculated on the basis of 20 €/MWh for the price of biomass. It should be noted that this biomass price is not necessarily used in the calculations of the original studies (e.g., both the VTT and the GoBiGas studies use a biomass feedstock cost of 17 €/MWh). The range in the case of the FT-liquids refers to the respective efficiency range as a result of the multiple studies on which the respective data is based.

(5)The share of other OPEX corresponds to an approximate percentage of 20% with respect to the total production cost. The values in parenthesis correspond to a range of 10-25% for the percentage of other OPEX with respect to production cost. This range is as wide as possible with respect to the aforementioned assumptions, in the sense that the lower values of the OPEX are combined with the lower values of the CAPEX and vice versa. Narrower ranges can result from combining the lower values of the OPEX with the higher values of the CAPEX and vice versa.

(6)The values reported in Table 2 are in agreement with the conclusive ranges reported by Landälv et al., (2017) for the total production costs, namely 71-91 €/MWh-product for methanol and bio-methane, and 91-139 €/MWh-product for FT-liquids. In the case of GoBiGas, the detailed economic assessment presented by Thunman et al. (2019) results in a total production cost of 72 €/MWh-product and 60 €/MWh-product for the 100 MW and 200 MW capacity plants, respectively. The relatively lower values compared to Table 2 are mainly due to the different assumptions for capital interest, economic life time of the plant and feedstock cost, as explained above. Hannula et al. (2013) estimate a production cost of 58-65 €/MWh-product for methanol synthesis (and 58-66 €/MWh-product for DME), which corresponds to the lower values of the ranges provided in this report. This is partly due to different assumptions for the feedstock price, the calculation of the annuities, and partly to the estimated operating costs as part of the production cost (i.e., the lower values of the reported ranges correspond to 10% of operating cost as part of the production cost and the higher values to 25%, respectively). A report from IEA and IRENA (International Energy Agency, 2013) estimates total production cost values of 72-90 €/MWh-product for plants of similar capacity to those mentioned in Table 2, but also wider ranges for the total production cost of methanol from wood 29.9-170 €/MWh-product) are mentioned, depending on feedstock prices and local conditions and other early or niche opportunities (e.g., integrated production with bio-ethanol from sugarcane, co-feeding with fossil fuels, and co-production of heat, electricity and other chemicals). It should be noted that production costs include crediting for the co-production of by-products, where these are explicitly quantified. For example, the E.ON Bio2G case refers to co-production of 50 MW of heating and 10 MW of electricity for internal use. The inventories of the GoBiGas case (Thunman et al., 2018) do not refer to any heating utilities consumption since the hot flue gas is used to cover the internal heat demand; moreover, no electricity demand is reported for a 20-MW reference plant. For the VTT case, flu gas is reported to cover the internal heat demand and 33.5 MW are provided to district heating. For the design case of this report, a net consumption of 8.6 MW electricity is reported (Hannula et al., 2013). The FT liquid studies are diverse with respect to the composition of the upgraded FT liquids after upgrading and the potential by-products. Reported ranges for maximum diesel yield refer to 66% diesel and 34% naphtha, while maximum kerosene yields refer to 48% kerosene, 28% diesel and 24% naphtha. Waxes (C_{21+}) are also valuable by-products that may be recovered or further converted to fuel-related products depending on the process design (not specifically quantified and thus not specifically credited in this report). For instance, Hannula et al. (2013) report inventories for a 170 MW FT liquids plant targeting at maximum diesel production (i.e., 66/34 w% diesel/naphtha production) co-producing 70 MW for district heating, a net consumption of 1.1 MW electricity and no waxes production.

Gasification pathways from municipal waste to methanol and ethanol have also been reported (e.g., the Enerkem plant in Edmonton). Although this type of feedstock does not lie within the scope of the ADVANCEFUEL project, the respective economic KPI values are presented here for comparison purposes. On the basis of ethanol as the product, estimated investment costs reported by Landälv et al., (2017) amount to 4700 €/kW-product and a respective share of CAPEX in production cost of 77 €/MWh-product (i.e., a respective range of 62-93 €/MWh-product). For the waste feedstock, a range of positive to zero prices or even credit associated with a tipping fee can be assumed. In the future, the trend on waste feedstock pricing is expected to be influenced by the respective dominating policies: focus on climate change policies will result in credits associated with the waste feedstock and thus negative pricing (e.g., similar to the Enerkem case where a credit of 12.5 €/MWh is assumed leading to a share of biomass OPEX in production cost of -25 €/MWh-product), while focus on waste recycling policies will result in costs associated with the feedstock (e.g., similar to the case of UK with a similar cost to the lignocellulosic biomass, namely of 20 €/MWh for the waste feedstock). Calculating the share of other OPEX in a similar way to the case of lignocellulosic biomass feedstock results in a range of 25-33 €/MWh-product (or a respective range of 11-44 €/MWh-product considering a variability of the other OPEX between 10-25% of the total production cost). This corresponds to ranges of 127-166 €/MWh-product, 87-126 €/MWh-product, and 62-101 €/MWh-product, for waste feedstock prices of 20, 0 and -12.5 €/MWh, respectively (i.e., the wider ranges considering the variability of the other OPEX are 113-177 €/MWh-product, 73-137 €/MWh-product, and 48-112 €/MWh-product, for waste feedstock prices of 20, 0 and -12.5 €/MWh, respectively). These ranges are in agreement with the conclusive values reported by Landälv et al., (2017) for the total production cost for methanol or ethanol production from waste (67-87 €/MWh-product) considering a credit of 25 €/MWh-product for the waste feedstock. Other reports (International Energy Agency, 2013) estimate that the total production cost of methanol from solid waste will amount to 36.1-90.5 €/MWh-product; significantly higher production costs are reported for the production of methanol from CO2 (92.3-162.3 €/MWh-product).

4. KPIs for pyrolysis pathways

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. As pointed out in D3.1, pyrolysis products include also unconverted biomass char and pyrolytic gases, which are typically used as fuels in CHP units. The yields of liquid, solid and gas fractions depend on many parameters, the pyrolysis oil yield ranging from 50-80 wt% of dry biomass basis, where the higher values of this range refer to very high heating rates (Amutio et al., 2012). Gas and bio-char yields amount to 13-25 wt% and 12-15 wt% of dry biomass feed basis, respectively. Maximising the yield of bio-oil via fast pyrolysis (e.g., typically in 0.5-10 seconds, involving high heating rates, typically 50-200 °C/s (Demirbas and Arin, 2002)) favors decentralized production (i.e., producing the pyrolysis oil locally and transporting and upgrading it in centralized larger plants (Landälv et al., 2017)). However, fast pyrolysis liquids are of lower quality, having a relatively higher content of water (e.g., approximately 25 %wt) and acid (3-4 %wt) and inherent instability.

Biomass pyrolysis reactors can be fixed bed, fluidised bed, heated kiln, rotating cone, screw feeder and vacuum pyrolysers (Bridgwater, 2000). From these reactor types, bubbling and circulating fluidised beds, heated kiln and rotating cone have been commercialised, while others remain at the demonstration or pilot stage. Typical capacities for commercial scale are in the range of 0.2-20 tonnes/hour, at feed moisture less than 10 wt%, and feed size of 0.2-50 mm and bio-oil yields of 70-75% wt%.

The biomass feedstock requires some form of pre-treatment before pyrolysis to enhance the pyrolytic efficiency. The pre-treatment methods can generally be those mentioned in paragraph 2 or a combination thereof. For instance, smaller particles (i.e., through milling or grinding of biomass) promote heat and mass transfer to form uniform temperatures within particles during pyrolysis and enhance bio-oil production by restraining the char formation and secondary cracking of vapours. On the other hand, extrusion of biomass under high pressure to produce pellets of large diameters increases the char and gas yields (Kan et al, 2016). Biomass drying prior to pyrolysis increases the energy efficiency of the pyrolysis process and improves the quality of the bio-oil product. Reducing the ash content through water or acid washing reduces the presence of inorganic minerals (e.g., alkali and alkaline-earth metal salts) which affect the mechanism of biomass pyrolysis leading to lower bio-oil yields.

In general there are two process concept for further upgrading of the bio-oil (e.g., through catalytic cracking, high-pressure hydroprocessing) prior to practical application in engines (Ballat, 2011): integrated into the pyrolysis plant (i.e., centralized production concept) or off-site either in co-processing with fossil-fuels in oil refineries or via steam reforming and gasification to Syngas, (Xiu et al., 2012) for biofuel production (i.e., following the gasification pathways described in paragraph 2).

The **biomass pyrolysis for bio-oil production has reached TRL 6 or higher,** as it is the case, for instance, in the following plants at various scales:

- The Bioliq plant at Karlsruhe Institute of Technology in Germany, where pyrolysis is used as pre-treatment prior to gasification (see also paragraph 2, "Technologies for gasification pathways").

- The Fortum plant in Finland, where the produced pyrolysis oil (30 MW capacity) is used for replacing the heavy fuel oil in boilers of various sizes, and the char and uncondensed gases are also used as fuels in the plant boiler.
- The Empyro plant in the Netherlands, utilizing a BTG-BTL technology with more than 3500 hours operation including a rotating cone reactor integrated in a circulating sand system, where char is burned to provide the heat required in pyrolysis, and producing pyrolysis oil as the main product with an equivalent capacity of more than 25000 tonnes/year, while uncondensed gases are combusted to produce heat and power.
- The ENSYN plant in Canada, where a Rapid Thermal Processing technology is used (fast pyrolysis) to convert biomass from forest and agricultural sectors to pyrolysis liquid with a product capacity of more than 20000 tonnes/year, which is used as petroleum replacement for heating purposes.

However, it is also clear that in these technologies, with the exception of pyrolysis liquids being used for gasification or co-gasification biorefinery concepts (Zetterholm et al., 2018), pyrolysis oil is mostly used directly as a fuel for heating purposes rather than upgrading it to liquid fuels as it is the scope of the ADVANCEFUEL project. **The technologies of upgrading pyrolysis oil to advanced liquid fuels**, both in a fully integrated plant or by co-processing with fossil fuels, are mainly focusing on catalyst development and **are typically validated at lab scale, reaching TRL 4 to 6** (Stafford et al., 2017, Landälv et al., 2017).
Examples of CAPEX and OPEX for pyrolysis pathways are those reported for the Fortum project (Landälv et al., 2017), the Empyro project (Muggen, 2015), a Swedish study of Gasefuels AB for the Swedish Energy Agency (Benjaminson et al., 2013), and a study by the Pacific Northwest National Laboratory in USA (Jones et al., 2013, 2017). The estimated values for the economic KPIs on the basis of the aforementioned studies are summarized in Table 3 together with the relevant input and output parameters (e.g., feedstock and product type and respective capacities).

Table 3: CAPEX and OPEX reference values for technologies based on pyrolysis pathways. The respective plants are indicative for the type of technologies, while the ranges for the economic KPIs are calculated on the basis of the assumptions listed below the table.

	Fortum	Empyro	Gasefuels AB study (stand-alone plant)	Gasefuels AB study (integrated plant)	Pacific Northwest National Laboratory study

Input type	Side stream from biomass fuelled boiler	Clean wood residues	Lignocellulosic biomass	Lignocellulosic biomass	Lignocellulosic biomass
Input capacity[(1)] (MW)	50	25	25	58	485
Output type	Pyrolysis oil	Pyrolysis oil	Pyrolysis oil	Pyrolysis oil	Gasoline, Diesel
Output capacity (MW)	30	15	15	30[(2)] (60)[(3)]	272
CAPEX[(4)] (€/kW-product)	1000-1450	1250-1350	1400-1600	1100-1800[(2)] (1100-1500)[(3)]	2300-2380
Share of CAPEX in production cost[(5)] (€/MWh-product)	**16-24**	**17-26**	**20-30**	**19-29[(2)] (17-26)[(3)]**	**31-46**
Share of Biomass OPEX in production cost[(6)] (€/MWh-product)	33	33	33	39	36
Share of other OPEX (material and energy utilities, maintenance, etc.) in production cost[(7)] (€/MWh-product)	5-6 (0-10)	6-7 (0-10)	6-7 (0-11)	6-7[(2)] 6-7[(3)] (0-12)[(2)] (0-11)[(3)]	17-20 (7-27)
Total production cost[(8)] (€/MWh-product)	**55-63 (49-76)**	**56-66 (50-79)**	**59-70 (53-84)**	**64-75[(2)] 62-71[(3)] (58-90)[(2)] (56-86)[(3)]**	**83-102 (74-109)**

[(1)]The biomass feedstock in the Empyro plant is woody residues dried to a moisture content of 5%. The biomass feedstock in the Gasefuels AB report is wood residue (hog fuel) with a moisture content of 55% reduced to 6% after drying. The biomass feedstock in the Pacific Northwest National Laboratory report is blended woody biomass (i.e., 30% pulp, 35% logging residues, 10% switchgrass, and 25% construction and demolition waste) with 30% moisture content dried to a moisture content of 10%. The dry biomass feedstock capacities in the original reports of the Gasefuels AB and Pacific Northwest National Laboratory (i.e., 10 tonnes/hour and 2000 tonnes/day, respectively) are converted to the respective energy input considering an LHV of 19 MJ/kg.

[(2)]According to the study of Gasefuels AB for the Swedish Energy Agency this capacity refers to collocation and integration of the pyrolysis oil plant to a CHP plant.

[(3)]According to the study of Gasefuels AB for the Swedish Energy Agency this capacity refers to collocation and integration of the pyrolysis oil plant to a pulp mill. The respective input capacity is proportional to the case of integration to the CHP plant (i.e., 10 tonnes/hour corresponding to 116 MW of dry biomass feedstock).

[(4)]An average of the respective CAPEX range is used to calculate the share of CAPEX in production cost. The Empyro CAPEX data include the biomass feedstock handling and drying. No specific information is provided for additional mechanical treatment (e.g., grinding, pelletisation). THE CAPEX in the Gasefuels AB report include biomass milling and drying to a moisture content of 5%. The CAPEX data in the Pacific Northwest National Laboratory report include the biomass feedstock handling, drying to a moisture content of 10%, and grinding.

[(5)]To calculate the share of CAPEX in production costs, the concept of annuity is used with economic lifetime of the plant equal to 15 years, an average operating time of 8000 hours/year and 10% annual interest rate. In all cases, the provided range results from considering 20% uncertainty in these calculations, following the same approach as in the gasification CAPEX (see paragraph 3). The respective equations are presented in Appendix 1. It should be noted that these assumptions may vary from those in the original reports (e.g., in the study of the GaseFuels AB a discount rate of 6% is considered and an operating time of 7800 hours/year, resulting in shares of CAPEX ranging from 14-19 €/MWh-product, instead of 17-30 €/MWh-product for the various cases presented in Table 3).

[(6)]The share of biomass OPEX in production costs is calculated on the basis of 20 €/MWh for the price of biomass. It should be noted that this biomass price is not necessarily used in the calculations of the original studies.

[(7)]The share of other OPEX corresponds to an approximate percentage of 10% and 20% with respect to the total production cost for the case of pyrolysis oil production and upgraded liquid fuel production (e.g., gasoline, diesel), respectively. The values in parenthesis correspond to a range of 0-15% and 10-25% for the percentage of other OPEX with respect to production cost for the case of pyrolysis oil production and upgraded liquid fuel production, respectively. These ranges are generally as wide as possible with respect to the aforementioned assumptions, in the sense that the lower values of the OPEX are combined with the lower values of the CAPEX and vice versa. Narrower ranges can result from combining the lower values of the OPEX with the higher values of the CAPEX and vice versa. It should be noted that the case of 0% for other OPEX considers revenues from co-products in pyrolysis plants (i.e., heat, power, and bio-char) that balance the other OPEX. It should also be noted that in the case of the upgraded fuel production, the original reports by Jones et al. (2013, 2016) refer to a range of 29-59 €/MWh-product, 73% of which is related to the pyrolysis oil upgrading process (i.e., the pyrolysis oil production costs range from 8-16 €/MWh-product and the pyrolysis oil upgrading costs range from 21-43 €/MWh-product). The lower value of the range refers to projections for 2017 and corresponds to 25-30% of other OPEX as part of the total production cos, while the upper value of the range corresponds to 40% of other OPEX as part of the total production cost. These can be considered as reference values for stand-alone integrated pyrolysis plants with pyrolysis oil upgrading.

(8)The values reported in Table 3 are generally in agreement with the conclusive ranges reported by Landälv et al., (2017) for the total production costs, namely 83-118 €/MWh-product for stand-alone pyrolysis plants with pyrolysis oil upgrading. The total production costs in the original report of the Gasefuels AB (Benjaminsson et al., 2013) are 60 €/MWh-product for the stand-alone pyrolysis plant (i.e., without pyrolysis oil upgrading), 48-64 €/MWh-product for the pyrolysis plant integrated to a CHP plant, and 42-46 €/MWh-product for the pyrolysis plant integrated to a pulp mill. The main reason for these values being lower compared to those of Table 3 lies in the different assumptions for the economic factors defining the share of CAPEX as part of the production cost (i.e., lower discount rates assumed in the study of Benjaminsson et al. (2013)).

It should be noted that production costs include crediting for the co-production of by-products, where these are explicitly quantified. For the Empyro case, 1.5 to 2 MW of produced steam are used for biomass drying purposes while 6 MW of steam are sent to a nearby AkzoNobel plant; similarly 0.3 MW electricity are used for internal process demand and 0.4 MW electricity are sent to the grid. The Fortum plant does not report any by-products besides char and uncondensed gases used to cover internal heat demand. The Gasefuels AB report refers to co-production of char, steam, electricity and uncondensed gases for the stand alone and the integrated cases which after balancing with process demands result in a cost contribution 7 €/MWh-product (stand-alone case) to 4-9 €/MWh-product for the case of integration to the CHP plant and 1-3 €/MWh-product for the case of integration to the pulp mill. The Pacific Northwest National Laboratory reports a production of approximately 53-55% diesel and 45-47% gasoline in terms of thermal content with no by-products for the downstream pyrolysis oil upgrading process.

There are also more studies estimating techno-economics of pyrolysis of forest residues for advanced bio-fuel production; however most of them are heavily based on process simulator models couples with very early stage laboratory experiments and thus they are not expected to be more accurate than the values presented in this report. As an example, a recent study by Carrasco et al., (2017) investigated the design and economics of a stand-alone pyrolysis plant of wood residue (hog fuel) to gasoline and diesel, for a capacity of 421 MW input biomass and 168 MW output fuel. The plant contains a significant level of integration where pyrolysis char and gases are used as sources of thermal energy and hydrogen. The conclusive CAPEX and annual OPEX values are 427 million US$ and 154 million US$, respectively. Converting these values with the assumptions of the present report for the economic lifetime of the plant and the interest rate and also assuming 1 US$=0.9€, results in shares of CAPEX and CAPEX in the production cost of 30-45 €/MWh-product and 102 €/MWh-product, respectively, and thus a total production cost in the range of 132-147 €/MWh-product. These values are similar to those of the Pacific Northwest National Laboratory study (Jones et al., 2013, 2017) in Table 3 for the higher other OPEX share of 59 €/MWh-product (i.e., note (7) of Table 3).

Finally, the total production cost of fuels from pyrolysis oil based on the concept of co-processing in oil refineries is estimated by Landälv et al., (2017) to lie within the range 59-104 €/MWh-product. The range in the total production cost results from the respective ranges of the share of CAPEX in the production cost (19-30 €/MWh-product) and the share of biomass OPEX in the production cost (34-68 €/MWh-product), while the share of other OPEX of the pyrolysis plant in the production cost is set to a net of 0 (i.e., balanced by the co/production of heat and electricity), and the share of CAPEX in the production cost due to refinery modifications and the share of the refinery related OPEX due to modifications are set to 1 €/MWh-product and 5 €/MWh-product, respectively, for rough order of magnitude calculations.

5. KPIs for biochemical pathways

The biochemical pathways in the ADVANCEFUEL project focus on the production of ethanol and higher alcohols (i.e., mainly butanol) from lignocellulosic biomass including the following typical process sequence: drying, grinding, slurry preparation and treatment, hydrolysis (i.e., saccharification) and fermentation. Lignin is separated either before or after fermentation and typically used for heat and power generation. Detoxification may be required before and/or after hydrolysis; hydrolysis and saccharification may be performed separately (SHF) or simultaneously (SSF).

Lignocellulosic biomass as a feedstock for ethanol production has numerous advantages (e.g., availability, price, non-competitiveness with food, waste material) but often requires extensive pre-treatment to yield fermentable sugars because of the recalcitrant structure of the material (Morales et al., 2017). Moreover, it contains a relatively low concentration of monosaccharides in the medium that does not allow to achieve ethanol concentrations comparable with those obtained using first generation feedstocks. An increase in fermentable solids in batch reactors results in technical problems associated with high viscosity, a low amount of free water due to its absorption in the biomass, a high content of inhibitors, nutrient levels and heat and mass transport (Modenbach and Nokes, 2013). These low concentrations typically require a high amount of energy for downstream separations and ethanol purification (Landälv, 2017). The upgrading of ethanol from lower concentrations for application as biofuel requires a series of evaporations (45 wt%), rectification (96 vol%) and dehydration (99.5 vol%) for blending into gasoline. The latter can be performed using zeolite adsorbents in a vacuum swing adsorption process.

Annual production of ethanol in 2nd generation cellulosic plants ranges today from 5400 to 75000 m^3. It has been estimated that bioethanol from lignocellulosic biomass can become economically attractive at reactor concentrations exceeding 40 g/l (Uppugundla et al., 2014). For instance, ethanol concentrations for 2nd generation ethanol production around 100 g/l will be required to be compared with 1st generation performance (Chen and Fu, 2016).

Butanol as a biofuel presents some significant advantages because of its energy content, lower vapor pressure and flammability, hydroscopic nature, and supply in existing gasoline channels and pipelines (Qureshi and Ezeji, 2008) to use in a gasoline blend (i.e., 85% butanol/gasoline blends can be used in unmodified gasoline engines). In general, the same types of process parameters affecting ethanol production are also significant for butanol production. Butanol tolerance of microorganisms is lower, and this results in lower titer levels and lower productivity, and additional purification issues with respect to energy consumption (Nanda et al., 2014). In various efforts butanol yielded concentrations of 5-20 g/l and butanol productivities of 0.05-0.15 g/l/h (Cao et al., 2016). To overcome the problem of butanol toxicity, recovery technologies such as liquid-liquid extraction, pervaporation, gas stripping, and adsorption have been proposed as alternatives that can be integrated with the conventional fermentation process (Jang and Choi, 2018). It is also acknowledged that another big challenge for industrialization of the butanol fermentation is the fermentation of acetone and ethanol as byproducts.

A number of pilot, demonstration and commercial plants around the globe indicate that the **2nd generation ethanol production technologies have reached TRL 6 or higher,** while the **butanol production technologies are marginally reaching the pilot scale (TRL 5)**, as it is the case, for instance, in the following plants at various scales (Landälv et al., 2017):

- The Abengoa plant in USA, based on acidic steam explosion pretreatment, followed by enzymatic hydrolysis and fermentation of C5 and C6 sugars to ethanol at a production capacity of 95 million liters/year and co-production of 18 MW_{el}.
- The Biochemtex plant in Italy, where the PROESA technology is used to produce cellulosic ethanol by a variety of feedstocks, pretreated thermally followed by enzymatic hydrolysis, fermentation and ethanol recovery at a production capacity of 25000-40000 tonnes/year.
- The DuPont's plant in USA, where cellulosic ethanol is produced by corn stover through mild alkaline pretreatment, biocatalytic saccharification, fermentation of C5 and C6 sugars and ethanol recovery at a production capacity of 90000 tonnes/year.
- The GranBio Bioflex plant in Brazil, which also utilizes the PROESA technology (i.e., as the Biochemtex plant in Italy), enzymes from Novozymes and yeast from DSM, at a production capacity of

65000 tonnes/year and co-production of heat and power as the plant is collocated with a 1st generation ethanol plant, sharing a CHP unit using both sugarcane bagasse and lignin.
- The Raizen IOGEN plant in Brazil, collocated with a 1st generation sugarcane ethanol plant, where lignocellulosic biomass is pretreated by acidic steam explosion followed by enzymatic hydrolysis, fermentation and ethanol recovery at a production capacity of 32000 tonnes/year and co-production of heat and power.
- The POET-DSM plant in USA, collocated with a 1st generation grain based ethanol plant, where corn stover is pretreated by acidic steam explosion followed by enzymatic hydrolysis and fermentation of C5 and C6 sugars to ethanol at a production capacity of 60000 tonnes/year and co-production of heat and biogas by anaerobic digestion of mixed lignin and organic waste streams.
- The SEKAB plant in Sweden, with an operation of more than 50000 hours, where soft wood is thermally pretreated in alkaline or acidic conditions followed by steam explosion, enzymatic hydrolysis including detoxification, fermentation under SHF or SSF conditions, recovery of ethanol via distillation at a production capacity of 3.5 MWh/day (i.e., approximately 170 tonnes/year) and co-production of lignin and biogas (4 MWh/day and 1 MWh/day, respectively).
- The Butamax plant in UK, where isobutanol is produced as the single product at a capacity of 18-23 tonnes/year.
- The Inbicon plant in Denmark, where straw is converted to ethanol in two operation modes, including mechanical conditioning and hydrothermal pretreatment followed by pre-enzymatic hydrolysis and C6 or C5/C6 fermentation with an operation of 15000 hours and 5000 hours respectively, production capacities of 4300 and 1500 tonnes/year respectively, and co-production of lignin and molasses to be used as fuel in a nearby CHP plant.
- The Borregard plant in Norway, with an operation of more than 23000 hours, where spruce is undergoing a sulfite based cooking pretreatment followed by enzymatic hydrolysis and fermentation of the sugars to ethanol at a predicted full scale production capacity of 82000 tonnes/year and co-production of 138000 tonnes/year lignin chemicals and 80000 tonnes/year CO_2.
- The IFP Futurol plant in France, where lignocellulosic biomass is hydrothermally pretreated followed by C5/C6 SSF to produce ethanol at a capacity of 0.25 tonnes/day and 2000 hours annual operation.
- The Clariant plant in Germany, with an operation of 30000 hours, where agricultural waste is thermally pretreated in the absence of chemicals, followed by enzymatic hydrolysis, solid/liquid separation processes, fermentation of C5/C6 sugars to ethanol and ethanol recovery at a capacity of 1000 tonnes/year and co-production of 1500 tonnes/year lignin.
- The Cellunolix plant in Finland, where sawdust is pretreated in acidic environment followed by hydrolysis, fermentation (mainly C6 sugars), lignin separation, and ethanol recovery at a production capacity of 90000 tonnes/year and co-production of burnable byproducts.

Examples of CAPEX and OPEX for biochemical pathways are those reported by Landälv et al. (2017) on the basis of a study by Lux Research Inc. The estimated values for the economic KPIs on the basis of this study are summarized in Table 4, adjusted for the same economic parameters (i.e., biomass feedstock price, economic lifetime of the plant, annual interest rate) as used for the gasification and pyrolysis pathways. Generic technology parameters (i.e., production capacity of 90000 m^3/year and 30-40% conversion efficiency from biomass feedstock to ethanol) are the same as those used in the study of Landälv et al. (2017).

Table 4: CAPEX and OPEX reference values for technologies based on biochemical pathways for ethanol production. The respective plants are indicative for the type of technologies, while the ranges for the economic KPIs are calculated on the basis of the assumptions listed below the table.

	Low CAPEX case	Medium CAPEX case	High CAPEX case	Medium CAPEX and biomass feedstock price case (Landälv et al., 2017)	High CAPEX and biomass feedstock price case (Landälv et al., 2017)
Input type	Lignocellulosic biomass	Lignocellulo-sic biomass	Lignocellulo-sic biomass	Lignocellulo-sic biomass	Lignocellulo-sic biomass
Input capacity (MW)	175-235(1)	175-235(1)	175-235(1)	175	175
Output type	Ethanol	Ethanol	Ethanol	Ethanol	Ethanol
Output capacity(2) (MW)	70	70	70	70	70
CAPEX(3) (€/kW-product)	2380	3650	6700	2570	3650
Share of CAPEX in production cost(4) (€/MWh-product)	**31-47**	**48-72**	**88-132**	**42**	**60**
Share of Biomass OPEX in production cost(5) (€/MWh-product)	57	57	57	33	50
Share of other OPEX (material utilities, in-cluding enzyme, energy	22-26 (10-35)	26-32 (12-43)	36-47 (16-61)	28	48

utilities, maintenance, etc.) in production cost(6) (€/MWh-product)					
Total production cost (€/MWh-product)(7)	**111-130 (98-139)**	**131-161 (117-172)**	**182-237 (161-252)**	**103**	**158**

(1)The input capacity ranges refer to the respective conversion efficiency ranges; in these cases an average value of 35% is used (i.e., corresponding to 200 MW input capacity).

(2)The reference production capacity in the report of Landälv et al. (2017) is 90000 m^3/year and is converted here to energy basis (MW) considering an LHV of 22.8 MJ/l for ethanol.

(3)Lux Research used an average CAPEX of 3300 €/kW-product for several of the aforementioned demonstration and commercial plants; however, the actual investment intensity for these plants varies from 2380 €/kW-product to 6700 €/kW-product. Landälv et al., (2017) used as reference CAPEX values 2570 €/kW-product and 3650 €/kW-product from a Bloomberg study in 2013 (high CAPEX value) projected to 2016 (low CAPEX value).

(4)To calculate the share of CAPEX in production costs, the concept of annuity is used with economic lifetime of the plant equal to 15 years, an average operating time of 8000 hours/year and 10% annual interest rate. In all cases, the provided range results from considering 20% uncertainty in these calculations, following the same approach as in the gasification CAPEX (see paragraph 3). The respective equations are presented in Appendix 1.

(5)The share of biomass OPEX in production costs is calculated on the basis of 20 €/MWh for the price of biomass, except for the “medium” case of Landälv et al. (2017) where a price of 13 €/MWh is used.

(6)The share of other OPEX corresponds to an approximate percentage of 10% and 25% with respect to the total production cost, including the cost of enzymes. These ranges are generally as wide as possible with respect to the aforementioned assumptions, in the sense that the lower values of the OPEX are combined with the lower values of the CAPEX and vice versa. Narrower ranges can result from combining the lower values of the OPEX with the higher values of the CAPEX and vice versa. It should be noted that in the two cases of Landälv et al. (2017), the enzyme cost is considered separately ranging from 15.5 €/MWh-product (“medium” case) to 31 €/MWh-product (“high” case). These values are added to the other OPEX and presented as total share of other OPEX in Table 4.

(7)As commented by Clariant in the report of Landälv et al. (2017), the lignin utilisation for energy production or additional revenue is not explicitly included in the respective calculations. Despite this fact, the general comment of Clariant was that they were aligned with the ranges reported in the report of Landälv et al. (2017).

6 Conclusions

This document contains information for the present status of technology readiness level (TRL), operating (OPEX) and capital investment (CAPEX) expenditures of conversion technologies in the context of the ADVANCEFUEL project. The data cover the gasification, pyrolysis and biochemical conversion technologies reported in D3.1, targeting at methanol, ethanol, butanol, dimethylether, FT products (gasoline, diesel, kerosene) and methane as potential biofuels for road, aviation and maritime transport. The cost data represent a top-down perspective being derived from reported overall efficiencies of biomass conversion to ADVANCEFUEL relevant end-products, ranges of CAPEX and OPEX from operating processing plants and/or relevant engineering studies, and typical percentages of OPEX breakdown to biomass feedstock costs and other material and energy utilities and maintenance related costs.

With respect to TRL, the least marginal case is the second generation ethanol production technologies. However, the respective ranges for the cost of production are relatively wide (i.e., 103-158 €/MWh-product according to Landälv et al. (2017) and 102-228 €/MWh-product considering the assumptions of the present report) and subject to many non-technological factors, such as the type and cost of feedstock, the on- or off-site enzyme production, and the lignin and other by-products utilization.

The gasification based pathways for the defined ADVANCEFUEL products are well established (i.e., demonstrated at commercial scale) with respect to the Syngas based synthesis technologies; what lowers the overall TRL of this pathway is the gasification part, with only very few demonstration plants reaching an adequate operational performance with scale-up perspectives. However, the economic KPIs for methane and methanol production lie within narrower range (i.e., total production cost of 73-89 €/MWh-product) compared to FT liquids (i.e., total production cost of 95-136 €/MWh-product).

With respect to TRL, the most marginal case is the pyrolysis oil upgrading technologies; this makes the reported CAPEX and OPEX ranges for the production of advanced biofuels by this pathway to resemble rough order of magnitude estimates and are thus the most uncertain from those presented in this report (i.e., total production cost of 83-102 €/MWh-product). However, the ranges presented for the pyrolysis oil production part (55-75 €/MWh-product) are of similar accuracy with those presented for the biochemical and gasification based pathways.

The presented TRL, CAPEX and OPEX data will be used in the rest of the deliverables of WP3 (more specifically in D3.5 and D3.6) as reference points for the relevant key performance indicators (KPIs) regarding the conversion technologies as defined in D1.2, namely "well-to-wheel" system efficiency and the potential for increase due to innovative processes, the CAPEX needed to increase the TRL of selected technologies, and the CAPEX and OPEX reduction due to opportunities for greening the fossil fuel infrastructure (i.e., comparing the total costs of an integrated system to a stand-alone system).

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List of Abbreviations

Table 5: List of abbreviations

CAPEX	Capital Expenditure
CHP	Combined Heat and Power
DME	Dimethyl Ether
FT	Fischer-Tropsch
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
KPI	Key Performance Indicator
LHV	Low Heating Value
LNG	Liquefied Natural Gas
OPEX	Operating Expenditure
SHF	Separate Hydrolysis and Fermentation
SSF	Simultaneous Saccharification and Fermentation
TRL	Technology Readiness Level
WP	Work package

Appendix

1 Background calculations for CAPEX and OPEX data

The annual share of CAPEX (*a_CAPEX*, €/MWh-product) in the production cost is calculated on the basis of annuities according to eq. (1):

$$a\_CAPEX = r \cdot CAPEX / AOT \qquad (1)$$

where *r* is the annuity (or capital recovery) factor calculated according to eq. (2), *CAPEX* is the specific fixed investment costs (€/MW-product), and *AOT* is the annual operating time of the plant (i.e., 8000 hours per year in this report).

$$r = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \qquad (2)$$

where *i* is an annual interest rate (i.e., 10% in this report) and *n* is the economic lifetime of the plant (i.e., 15 years in this report).

The share of other OPEX (*Other_OPEX*, €/MWh-product) in the production cost (i.e., OPEX other than the biomass feedstock, e.g., including energy, chemical auxiliaries, maintenance, etc.) is calculated on the basis of estimated percentages according to eq. (3):

$$Other\_OPEX = \frac{p}{1-p} \cdot (a\_CAPEX + Feed\_OPEX) \quad (3)$$

where p is the estimated percentage of *Other_OPEX* in the total production cost (i.e., ranging from 10-25% in this report), and *Feed_OPEX* is the share of the biomass feedstock in the total production cost (€/MWh-product).