European Commission

Sub Group on Advanced Biofuels

Sustainable Transport Forum

Building up the future

Cost of Biofuel

12 February 2017

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Date: 12 February 2017

SGAB Cost of Biofuels

Abbreviations

Abbr.	Full name	Abbr.	Full name
2G	second generation	MSW	Municipal Solid Waste
ASJ	Alcohols to Synthetic Jet	mt	Metric ton
ATJ	Alcohol to Jet	MtG	Methanol to Gasoline
BA	British Airways	Mtoe	Million tons of oil equivalent
BLG	Black Liquor Gasification	NGOs	Non-Government Organizations
bpd	Barrels per day	NREL	National Renewable Energy Laboratory (USA)
Btu	British Thermal Unit	NOAK	N^{th}-of-a-kind
CAPEX	Capital Expenditure	OPEX	Operating Expenses
CCU	Carbon Capture and Utilization	O&M	Operations and Maintenance
CHP	Combined Heat and Power	PO	Pyrolysis Oils
CFB	Circulating Fludized Bed	R&D	Research & Development
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation	RFS2	2nd Renewable Fuel Standard program (USA)
DM	Dry Matter	SGAB	Sub-group on Advanced biofuel
DME	Dimethyl Ether	SIP	Synthetic Iso-Paraffins
DSHC	Direct Sugar to Hydrocarbons	SPK/A	Synthetic Paraffinic Kerosene Aromatics
EBA	European Biogas Association	SPK	Synthetic Paraffinic Kerosene
e-fuels	fuels based on the use of renewable electricity	STF	Sustainable Transport Forum
EGFTF	Expert Group on Future Transport Fuels	TRL	Technology Readiness Level
ETS	Emission Trading Scheme	UN	United Nations
EtOH	Ethanol	VGO	Vacuum Gas Oil
FAME	Fatty Acids Methyl Esters	WACC	Weighted Average Cost of Capital
FCC	Fluid Catalytic Crackin		
FOAK	First of a Kind		
FT	Fischer-Tropsch		
ge	gasoline equivalent		
HEFA	Hydrogenated Ether and Fatty Acids		
HDCJ	Hydrotreated Depolymerized Cellulosic Jet		
HDO-SK	Hydro-Deoxygenated Synthesized Kerosene		
HDO-SAK	Hydro-Deoxygenated Synthesized Aromatic Kerosene		
HTL	Hydrothermal Liquefaction		
HVO	Hydrotreated Vegetable Oil		
ICAO	International Civil Aviation Organization		
IRENA	International Renewable Energy Agency		
LCO	Light Cycle Oil		
LCFF	Low Carbon Fossil Fuel		
LHV	Lower Heating Value		
LPG	Liquefied Petroleum Gas		
MCAD	million Canadian Dollars		
MESP	Minimum cellulosic Ethanol Selling Price		
MSEK	million Swedish Crowns		

Conversion Factors and Units

The conversion numbers used throughout this document are:

The unit ton or tons, unless noted otherwise refers to metric tons, also sometimes abbreviated as mt.

1 MMBtu	=	0.293 MWh
1 barrel (bbl)	=	0.159 liter
1 US galon (gal)	=	3, 785 liter
1 ton US gasoline(LHV)	≈	12.1 MWh
USD/bbl gasoline equivalent and day	=	USD/bpd ge
1 EUR	=	1.12 USD
1 USD/bpd g.e.	=	0.01485 EUR/kW (base: 32,67 MJ/liter EU petrol)
1 PJ	=	0.278 TWh
1 EJ	=	278 TWh
1 TWh	=	10^6 MWh
1 MWh/ton	=	3.6 MJ/kg

In some cases, the suffices *th* or *e* are used in inconjuction with an energy unit, e.g. MWh_{th} to indicate that the energy is in the form of thermal or MWh_{el} to indicate that the energy is in the form of electric energy.

SGAB Renewable Fuel Targets; biofuel quantities and relation to the EU use of energy for transports

Take Away Messages

Biofuels will remain more expensive than fossil fuels (with rare exceptions) unless the costs of mitigating climate change are going to be factored in the cost of fossil fuels.

- The cost of biofuels is mainly governed by the cost of the resource (feedstock) and cost of capital (the investment) and only value chains based on waste streams with zero or negative cost offer possibilities for competitive cost production at present.

Fuels for aviation

- Aviation fuel is one product or side product in processes that generate drop-in fuels (diesel, gasoline, kerosene) in varying proportions, such that production cost is related to the product slate and value of all products
- Aviation Hydrogenated Ether and Fatty Acids (HEFA) can be produced at a cost of 80-90 EUR/MWh
- Aviation via Fischer-Tropsch (FT) synthesis or through sugar pathway can be produced at a cost of 110-140 EUR/MWh

Commercially available biofuels

- Biomethane produced from waste streams and via biogas (anaerobic digestion) has at present the lowest cost at about 40-50 EUR/MWh. In certain niche markets it can be competitive to fossil fuels.
- Hydrotreated Vegetable Oils (HVO) has a production cost in the range of 50-90 EUR/MWh subject to the cost of the feedstock.

Cellulosic ethanol at the stage of early commercialisation

- The production cost of cellulosic ethanol is estimated in the range of 90-110 EUR/MWh subject to the feedstock cost.

Biofuels in the stage of First of a Kind (FOAK)

- Biomethane, methanol, ethanol and DME from waste and biomass via gasification have a production cost of 60-80 EUR/MWh.
- Transport fuels via the FT process have a production cost of 90-140 EUR/MWh subject to the feedstock cost and comparably high investment intensity.

The key *Take Away* messages are based on work carried out by the SGAB group. Production cost data are summarized the Table 1. They are a summary of information provided in Figure 1 and from data taken from the memo.

Table 1. Summary of Biofuels Production Costs

Biofuel type production costs	Feedstock price EUR/MWh	Production cost range EUR/MWh	Production cost range EUR/GJ
Aviation HEFA	40-60	80-90	22-25
Aviation sugar fermentation or FT synthesis	Sugar: 65-85 FT: 10-20	110-140	31-39
HVO liquids	40	50-70	14-19
	60	70-90	19-25
Biomethane from biogas	0-80	40-120	11-34
Cellulosic ethanol	13	103	29
	10	85	24
Biomethane & ethanol from waste	([1])	67-87	19-24
FT liquids from wood	20	105-139	29-35
	10-15	90-105	25-29
Biomethane, methanol or (DME (Dimethyl Ether) from wood	20	71-91	20-25
	10-15	56-75	16-21
Pyrolysis bio-oil co-processing	10-20	58-104	14-27
Pyrolysis bio-oil stand alone	10-20	83-118	23-33

([1]) Base: Net tipping fee of 55 EUR/ton, energy content of 4.4 MWh/ton, Conversion efficiency of 50%

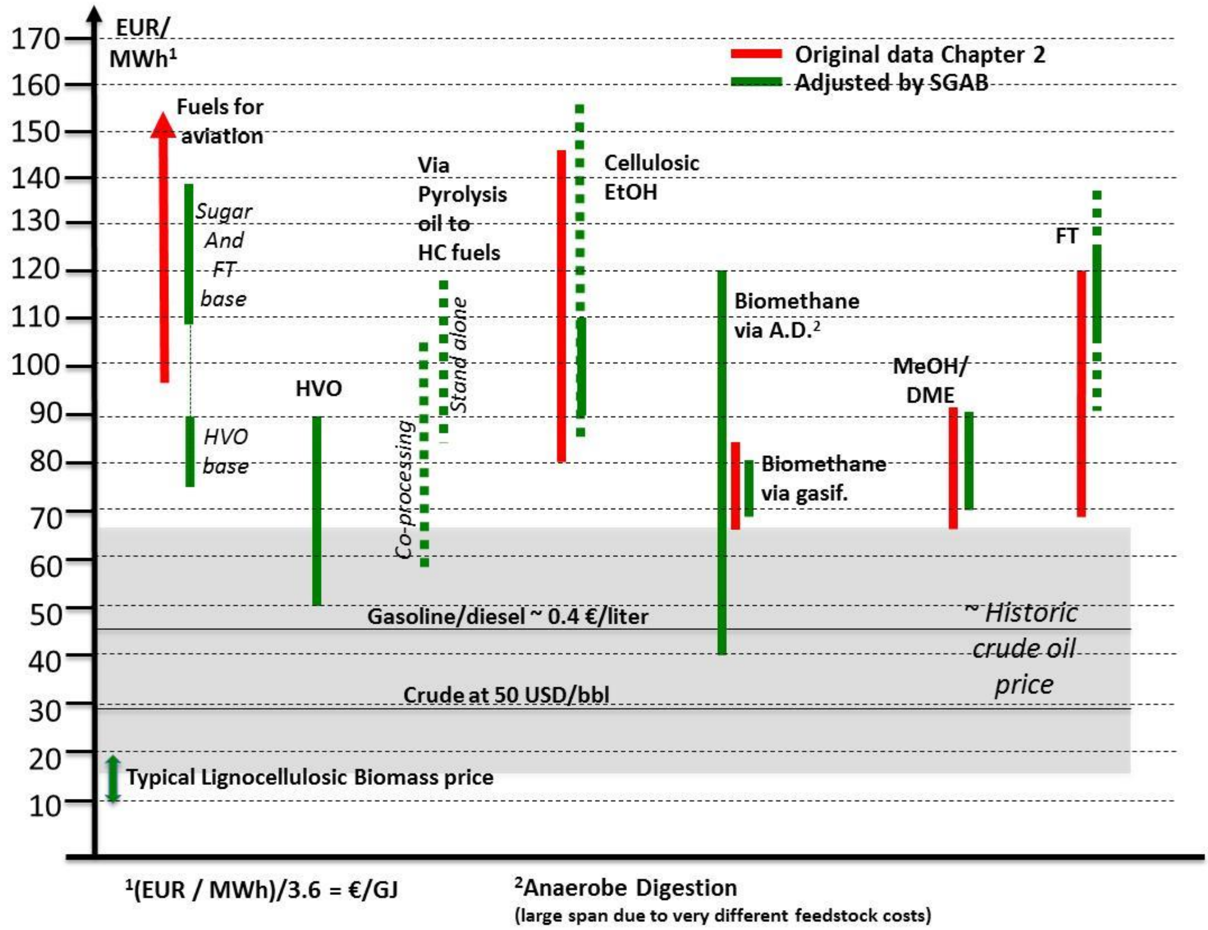

Figure 1. Summary of production cost

1 Background and purpose of this memo

The Sub-group on Advanced biofuels (SGAB), to the Sustainable Transport Forum (STF), is chaired by the EC and has some thirty members that represent biofuel, fuel, vehicle and transport industries, while other stakeholders such as national authorities, Non-Government Organizations (NGOs) and others are welcomed as observers. SGAB, which had its first meeting in December 2015 and the end meeting in October 2016, had a main defined deliverable to give a recommendation on targets for advanced biofuels in 2030. Furthermore, SGAB was invited to propose suitable policy measures to facilitate the establishment of flagship, First-of-a-kind (FOAK) plants, and stimulate further duplication and deployment of such technologies to arrive at fully commercial so-called Nth-of-a-kind (NOAK) plants. Such policy measures include, but is not limited to, various means of economically supporting innovation and technical developments to go from pilot plants to prototypes and later more widely adopted for industrial deployment.

The advanced renewable fuel technologies under discussion span over a wide range of technical readiness. Some fuels, like e.g. hydrogenated lipids (often referred to as HVO) is already a commercial technology with a global capacity approaching 4 Million tons of oil equivalent (Mtoe) per year, other technologies have industrial prototype installations in early operation whereas yet other technologies are partly demonstrated or have only yet reached further than to a conceptual stage. This has an impact on the judgment of the economic performance while moving through the development stages to the FOAK stage. This is illustrated in Figure 2Figure 1. Increased insight in the overall process is often accompanied by a cost increase as more detailed designs involves additions to the core process concept to have an operable industrial unit, while societal aspects also influence the design in terms of e.g. environmental performance and other factors not readily available in the Research & Development (R&D) phase. Once a FOAK plant comes into operation and is replicated towards the NOAK stage, costs are reduced as learning and innovation are added to the next design, and risk allowances can be reduced.

For this reason, reference should be made to the separate SGAB memo, *Technology status and reliability of the value chains*. Since there is a scarcity of quality data for technologies that have yet not reached Technology Readiness Level (TRL) of 7-9, i.e. FOAK development stage the technologies considered in this memo are:

- oxygenates and hydrocarbons from thermochemical processing of lignocellulosic biomass or waste streams,
- drop-in hydrocarbon fuels from hydrogenation of waste lipids (HVO),
- oxygenates and hydrocarbons from biochemical processing of lignocellulosic biomass or waste streams and,
- bio-methane from anaerobic digestion or from gasification of lignocellulosic materials or waste streams

Technologies that are being pursued and where SGAB has considered these possible to be introduced and used in 2030, but still to some extent covered in this memo are the upgrading of Pyrolysis Oils (PO) to hydrocarbon drop-in fuels and so-called Low Carbon Fossil Fuel (LCFF) fuels. In the case of pyrolysis oils, the FOAK stage for the intermediate pyrolysis oil has been reached in Canada, USA, Finland and the Netherlands. However, the upgrading has this far been tested at R&D scale and in a few small pilot tests with largely unpublished data. The extent of such processing is still under development and the associated cost uncertain.

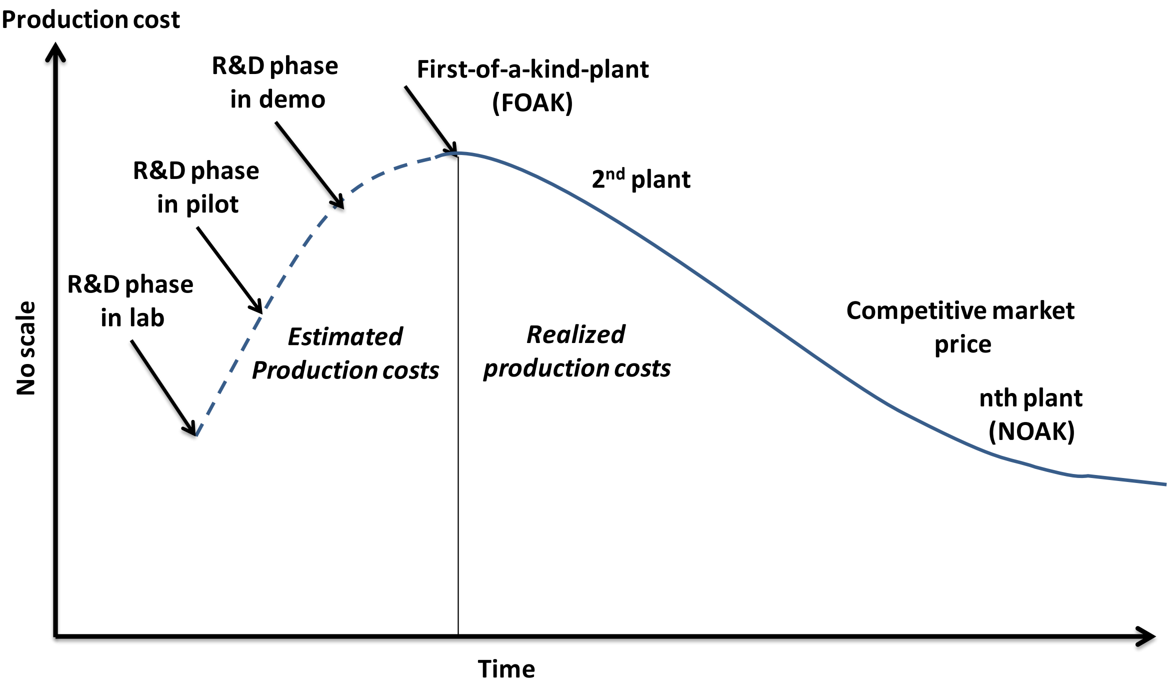

Figure 2. Illustration of the “learning effect” from innovation to industrialization

So called Carbon Capture and Utilization (CCU) and fuels based on the use of renewable electricity (e-fuels) and Fatty Acids Methyl Esters (FAME) are not included in this memo. FAME bio-diesel is a mature technology where the main cost contribution is from the feedstock.

There have been a large number of publications made in the past year on the cost of biofuels. The purpose of the present memo is to provide an overview of such cost data. The objective is to give some insight into the build-up of such cost data and costs associated with a development pathway. The support by data and comments of industrial stakeholders has been an important part of the input to this work. Nevertheless, the cost estimates presented below are based on different technologies, and within each such technologies different designs and processes are available with slightly different development status and costs. Hence it has been decided to give data in the form of ranges as projects will represent different locations and designs. The use of ranges also is relevant, as there is no single biofuel technology that is outperforming all other technologies under all conditions.

1.1 Technology Status

This report has the ambition to present overall economics for production of various advanced biofuels. With a few exceptions, this industry is just starting its path to commercialization and data based on years of operating experiences and construction of a series of plants therefore do not exist for most of the fuels covered by this report.

- Lignocellulosic or second generation (2G) Ethanol (EtOH) is on the verge of being commercial with several industrial scale FOAK plants using a variety of integrated technologies in early operation. The technology developers are competing in licensing their technology to locations with strong support policies. All of them are based on agricultural residues while technologies based on forestry residues still have to reach the level of industrial scale demonstration.
- Gasification technologies lag relative to 2G EtOH, with a small number of plants in early operation and in pilots. Technically it could provide quantities in 2030 if the move to scale can be accomplished during the coming years. Due to high investment intensity for demo scale plants, larger scale installed plant capacities are in focus which makes it more complex to realize the FOAK industrial scale plant even though their total fuel production costs are comparably attractive.

  Another hampering circumstance is that gasification based production utilizes a number of processes in combination. Successful gasification technology development needs to be combined with synthesis gas conditioning and cleaning and with synthesis technology to generate the desired product from the syngas. Investors tend to demand wraparound guarantee from one single company for the whole plant to feel comfortable to get involved. This can cause difficulties especially for FOAK plant for which commercial performance is jet not demonstrated.
- Two relatively small trials of co-processing PO in refineries in Brazil and the USA are known to have taken place. Upgrading capacity for pyrolysis oil will at first instance largely use existing refinery infrastructure.

Exceptions where industry is already commercial today relates to two conversion routes, HVO production from a variety of feedstocks and biomethane through anaerobic digestion of biological material.

- Hydrogenated Vegetable Oil (HVO) production is today at a scale of millions of tons produced from large plants integrated into the existing oil industry. The EU oil industry is retrofitting existing refineries to produce HVO. Future production capacity growth is limited by availability of sustainable oils but could double. However, when used oils and process residues from industrial operations are taken into consideration on a global scale the capacity can increase significantly. The expansion can be based on proprietary technologies from several licensors representing both own-operate entities but also at least two world-scale contractors that can provide technology to any third party.
- Biomethane through anaerobic digestion is already commercially available for use as transport fuel in captive fleets or injecting in the natural gas grid. The further development with respect to the scale that bio-based methane is used in transport depends on the competitive demand for biomethane for use in Combined Heat and Power (CHP)-plants.

This report does not have the ambition to draw “the final conclusion” of all good work generated in the field of advanced biofuels during the last couple of years. It will however claim to draw well based conclusions on the topic “Cost of Advanced Biofuels”. Chapter 2 describes how information has been gathered and reviewed. Results of this work are compared with other relevant work in the field of advanced biofuels. This is done on a fuel by fuel basis in the chapters thereafter.

The overall results are presented in the Summary chapter. Production cost of biofuels are there presented as cost of energy and data are presented as a span. It will give a well-founded base for how much production cost of advanced biofuels differs from cost of today's main fuels, gasoline and diesel and can therefore be used when investigating what level of incentives would be needed in order to introduce advanced biofuels into the market.

Even commercially mature technologies for advanced biofuels need some kind of economic incentive to bring its products to the market. The level of incentive varies depending on cost of feedstock, production pathway and maturity of technology.

2 Methodology and Data used

2.1 Gathering of information

Members of SGAB have been asked to comment a base document sent by the SGAB core team (from vice chair Ingvar Landälv). The objective was presented as follows:

> *As we have seen from investigations within the SGAB group and from what we heard today (June 9, 2016) from the presentation by the Commission there is a strong consensus regarding the fact that biofuels cannot compete head to head with fossil fuels on a cost per energy basis. We often come back to the issue of the lack of long term support schemes to enable the introduction of advanced biofuels. We often get the question*
>
> - *How much support?*
> - *For how long time?*
> - *What is needed to bridge the difference?*
> - *Etc.*
>
> *We believe that well based information regarding these matters will add value to the final work delivered from SGAB to the Sustainable Transport Forum.*

Due to limitations in time and resources, it was not considered possible to produce a new and comprehensive report on the Cost of Biofuels topic covering all pathways. Instead, the approach selected was to present a base of estimated production cost ranges for most of the different pathways to the group, and to which members were invited to comment.

With a very active and knowledgeable group of stakeholders including active developers and producers, as is the case in the SGAB group, it can be expected that the participants who would not agree to what is presented would comment and give corrections. The invitation to respond to the cost has been brought forth in all meetings except for the very first one. In addition, this invitation has also gone out three times via email. The outcome has been that information and comments have indeed been received from the stakeholders.

To get industry and developers to react to compiled data from other recent sources means to get the first-hand views of the active stakeholder on the economic situation of their respective pathways at a generic level.

The "Cost of Biofuels" discussion was triggered by Figure 3 which was developed firstly to put in comparison some current published data on production costs of a number of the biofuels, secondly to show them in relation to cost of crude oil based fuels and finally to illustrate the often referred need for “long term stable legislation” required to launch advanced biofuels into the market.

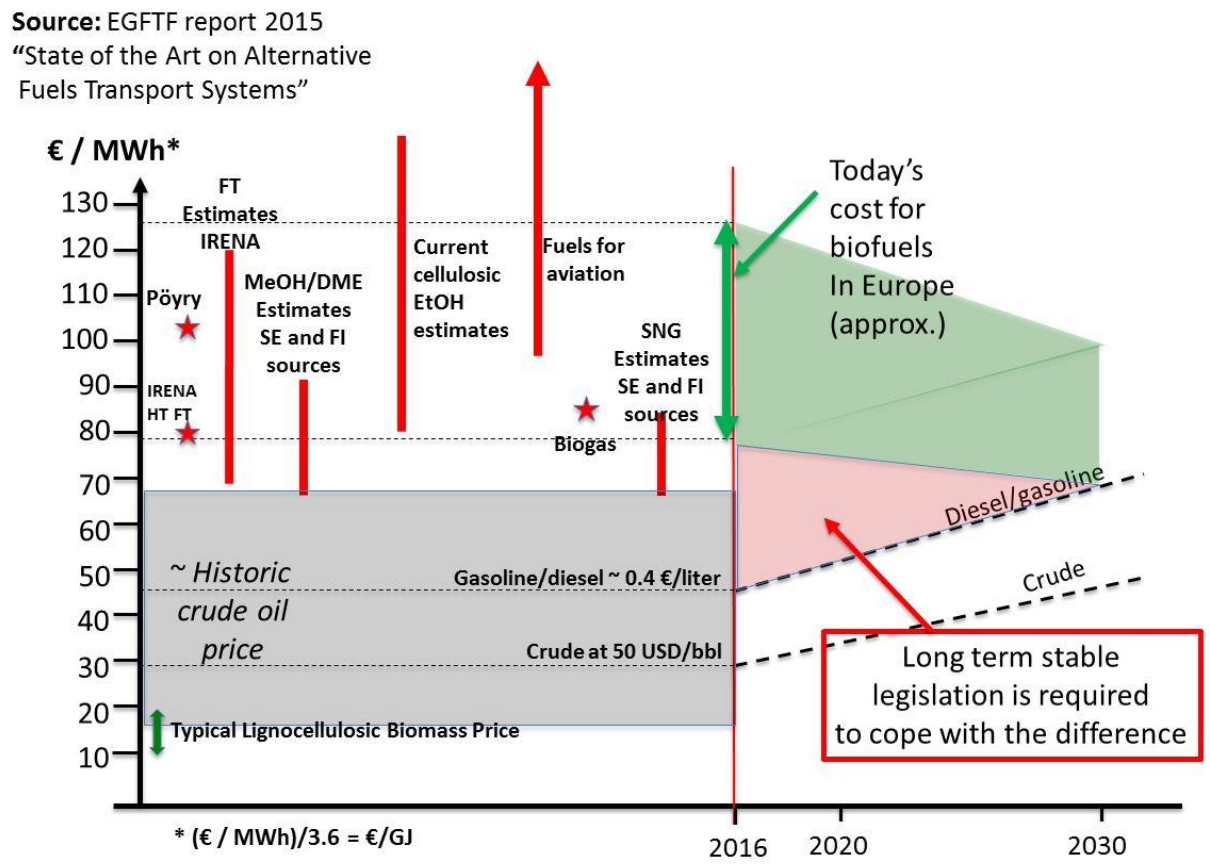

Figure 3. Cost of some selected biofuels compared to the historic crude oil price

The figure intended to convey the following messages and initiate discussion and input from the SGAB members.

- Production cost of various types of advanced biofuels varies substantially
- Current production cost of biofuels lies in the interval of 80-120 EUR/MWh. There are some lower data points but to initiate construction of first of kind plants the quoted interval is realistic.
- Current lowest production cost of advanced biofuels is at least 50-100% higher than their crude oil based alternatives (70-90 EUR/MWh compared to about 45 EUR/MWh)
- Typical biomass price in Europe: 10-20 EUR/MWh
- In a 15-year period production cost of biofuels can be expected to be lowered due to increased experience. This however implies that construction of full sized plants is initiated without further delay. The green area indicates a cost reduction of about 15 %.
- A crude oil price increase during the coming 15-year period is given as an illustration. The dotted line shows 90 USD/bbl in 2030. A corresponding increase in gasoline and diesel process are also shown.
- The red area is an indicator of minimum difference in assumed production cost of biofuels and the (assumed) price of fossil fuels.

An investor who plans to start a project in 2017 with a three-year building time and a 10-year payback period needs to have a firm knowledge of what selling price that can be counted with for the coming 13-year period. The difference between the required selling price and the actual prevailing cost of fuel in the market may shrink (lower subsidy required over time) or increase. A necessary support mechanism should preferably account for this.

Based on provided information the SGAB members were specifically asked to revert with comments and input relating to the following

1. Comment to the overall task and to the presented cost data. Is it an effort worthwhile doing? Can this work add substantial value to the discussion regarding the role of biofuels in the transport sector?
2. Insert other sources of information with respect to production cost of advanced biofuels, your own data and/or data from reports you find well based.
3. Cost of fuel e.g. as EUR/MWh or EUR/GJ (lower heating value)
4. Cost of Capital. One source specifies capital cost as 10 % Weighted Average Cost of Capital (WACC) while another source presents it as “Capital cost” and ROI without giving any specifics.
5. Cost of Feedstock. To be presented as cost per ton of material with the water content specified. Cost per ton on a dry basis is preferred.

13 members of SGAB have come back with either identified reports they recognize as good sources of information or with own comments to the material. Stakeholder input is reflected in the chapters covering the various biofuels as well as in the Summary chapter.

2.2 Data

The cost data regarding Capital Expenditure (CAPEX) have, with the exception of data directly received from SGAB stakeholders, been found in publicly available documents, and have been cited when possible. Further sources are compilations and analyses of such data, made and analyzed by others. This category consists both of information published in publicly available reports and non-published material available to the authors of this memo, and here the full background cannot be disclosed.

Regarding Operating Expenses (OPEX), there is less specific information available in public or shared by the stakeholders. In most cases OPEX has been specified as a yearly cost related to a percentage of the plant investment. See the various biofuels for further information.

Performance i.e. the relation between the feedstock input and the product output has been based on a similar set of sources as for the CAPEX.

The cost of feedstock used in the estimates have been based on the values of traded feedstocks whenever possible, complemented by estimates from other sources or cost related to alternative processing cost, this latter is in particular applicable to wastes.

2.3 Methodology

The methodology is based on a simplified methodology by estimating the production cost from a capital cost contribution, an OPEX contribution and the feedstock contribution. The CAPEX data have been collected from projects that have been or is in construction whenever possible, otherwise the cost is based on the cost estimates representing cost estimates for projects close to an investment decision that was not, or still is not reached. CAPEX has been converted to an investment intensity, expressed as medium value with a +/- and has been expressed as EUR/kW (some places complemented with USD/bpd ge or other units due to source of information) to allow comparison of capital expenditure for various biofuels and with other technologies also outside the biofuel area. Typical plants size varies considerably between small biogas plants to large plants for HVO production. Investment intensity (EUR/kW) should be studied having this in mind.

CAPEX is seen as equal to the overnight investment cost for building the plant and no cost for interest during construction or working capital has been added. The capital recovery charge is composed of an annual cost estimated as an annuity based on the CAPEX using a real interest of 10 % for 15 years, i.e. a factor of 13.3 % per year. Elements of a fully elaborated project economic model such as level of grant support, debt-to-equity ratio, loan repayment grace and amortization periods, etc. have been ignored.

OPEX, less feedstock, as used, have been expressed as an annual percentage of CAPEX or as a percentage of the production cost. The percentage includes co-feeds, labor, feedstock associated costs on the site, maintenance, by-product disposal etc. When available, relevant data from project estimates have been the basis for the percentage or other figures used.

Feedstock cost contribution is estimated from the performance data and feedstock cost.

The production cost estimated as the sum of the capital recovery charge, OPEX and feedstock procurement costs on an annual basis divided by the production output.

3 Thermochemical conversion (incl. HVO routes)

This chapter covers various thermochemical routes and is divided into (1) gasification to synthesis gas (syngas) to synthetic fuels, (2) pyrolysis oil routes and (3) various routes for generation of HVOs. Production cost is covering cost at plant gate and disregarding distribution, storage and final use by the customer.

Pyrolysis oil may be a pretreatment step to gasification and for this application it is part of the first mentioned section. Pyrolysis oil for further processing into final or semi-final products is described in section (2).

3.1 Synthetic fuels via gasification

Biofuel products via gasification covered in this section can be divided as follows:

- Synthetic long chain hydrocarbons in the form of diesel (so called FT diesel), gasoline and kerosene
- Oxygenates such as methanol, ethanol and DME
- Bio-methane

Other product routes not mentioned but of often listed together with the above are hydrogen and (mix of) higher alcohols.

It should be noted that using the gasification route to utilize a certain feedstock (biomass, waste, black liquor in pulp mills etc.) generates a syngas which can be synthesized to any of the mentioned syngas derived products as well as other products produced via syngas.

From production point of view the production pathway is very similar in terms of its main process steps. The fuel is pre-treated by drying and sizing to suit the gasification technology used before being fed to the gasifier. In the gasification step (most likely being at elevated pressure and utilizing pure oxygen and steam as oxidant) the fuel is converted to a raw syngas is then followed by gas conditioning and purification where impurities and carbon dioxide is removed and finally, the clean synthesis gas is fed to a synthesis unit where it is reacted to desired product, which is upgraded to the marketable quality. Especially for the bio-methane route a low temperature, indirectly heated gasifier system can be advantageous because it generates considerable amount of methane already in the gasifier and the oxygen plant investment can be avoided.

The overall conversion efficiency is in principle the product of the individual conversion efficiencies of the four mentioned main process steps. Even if there may be other, exothermic conversion steps in the chain overall these have lower impact. Overall conversion, i.e. from fuel as received, up to ready for delivery product, ends up in the interval 40-65% (Low Heating value - LHV) on an energy basis. There are some special applications such as gasification of black liquor in pulp mills where the overall conversion can reach around 70% and even higher. Utilization on of the by-products like steam/heat can increase the overall energy efficiency of the plant up to 5-10%, when integrated to district heating or combined heat and power production.

Another general observation is that long chain hydrocarbons are more energy consuming products. FT diesel and kerosene have the lowest yield from feedstock to product, and at the same time the highest investment. Production of biomethane (and also hydrogen), on the other hand, have high overall conversion efficiency and relatively low investment. The difference between these two extremes is quite significant.

3.1.1 Capital Expenditure (CAPEX)

Methane and methanol production

Capital cost has been evaluated in quite some detail by stakeholders and institutions involved in advanced technology development such as e.on (200 MW output biomethane plant[2]), Chemrec (100

[2] Bio2G - A Full-Scale Reference Plant for Production of Bio-Sng (Biomethane) Based on Thermal Gasification of Biomass In Sweden. Björn Fredriksson Möller *et al*. 21st European Biomass Conference & Exhibition Copenhagen, Denmark, 3-7 June 2013.

MW output methanol plant[3]) and VTT (200 MW output methanol plant[4]). When these plants are compared investment intensity are calculated to be 1,850 to 2,050 EUR/kW for the two larger plants and 3,450 EUR/kW for the smaller plant. If the latter plant is scaled to the size of the larger plant the investment will decrease to about 2,800 EUR/kW. The remaining difference is mainly due to a high level of reliability measures of redundancy in order to reach the demand for very high availability set by the commercially operated host pulp mill in this black liquor gasification case. The referred black liquor case (Chemrec) will in its commercial application be credited for avoiding the investment in the alternative technology; the today used recovery boiler technology. This leads to that the net investment is brought down to approximately half or 1,300-1,400 EUR/kWh.

A specific investment of 2,000 EUR/kW, 8,000 hours per year operation and a capital cost corresponding to 15 years and 10% results in a cost of capital in the product cost of 33 EUR/MWh. Deviation ±20% corresponds to a span of 26-40 EUR/kWh.

The company Enerkem has constructed a waste to methanol / ethanol plant in Edmonton, Canada (output ethanol approx. 22 MW). It is a first of a kind plant construction which can be expected to carry a higher investment than investments which will follows in its footsteps. Although the investment costs have not been disclosed by Enerkem, it has been publicly quoted by a non-Enerkem source to amount to 120 MCAD[5] while the waste separation and RDF fuel preparation plant cost 40 MCAD[6] , i.e the total investment amounts to 160 MCAD, corresponding to approximately 105 MEUR. This gives an investment intensity of about and 4,700 EUR/kW and a capital-related cost of production of 77 EUR/MWh. For the Enerkem part the capital-related cost of production would amount to 57 EUR/MWh based on an investment intensity of 3,480 EUR/kW (investment of 120 MCAD). This concept uses assorted wastes as a feedstock, and economics are to an extent compensated due to zero to negative feedstock cost.

Production of FT products

For the FT production data[7] the information was based on a large number of studies and the estimates used are summarized in Figure 4. The spread of data is considerable and no clear trend in terms of economy of scale can be seen. In the figure, there is an indication of an FT product capacity of 200 MW. This number is chosen as being an average sized production for the data included in the diagram. “FT product” includes here all sellable products (see below). The selected plant size corresponds approximately to an investment intensity of 3,000 EUR/kW. With the same capital charge as for the methane/methanol cases, the capital cost contribution to the production cost is 49 EUR/MWh. A spread of ±750 EUR/kW (±50,000 USD/bpd ge) corresponds to a span of 37 -61 EUR / MWh.

[3] Chemrec
[4] Ilkka Hannula and Esa Kurkela “Liquid transportation fuels via large-scale fluidised-bed gasification of lignocellulosic biomass”. VTT TECHNOLOGY 91. VTT Technical Research Centre of Finland. 2013
[5] http://www.saanichnews.com/opinion/letters/395732921.html
[6] http://www.biofuelsdigest.com/bdigest/2014/10/22/enerkem-albertas-municipal-waste-to-fuels-juggernaut-in-pictures/ and https://www.edmonton.ca/programs_services/documents/PDF/Fact_Sheet_June_2014.pdf
[7] Waldheim Consulting unpublished work.

3.1.2 Operating Expenditure (OPEX)

Methane and methanol production

Conversion efficiency for biomass to methane and methanol is in the range of 60 to 70%. Biomass to methanol is typically around 60% and methane some percentage points higher while conversion to methanol in pulp mills around 70%.

With these conversion efficiencies and a feedstock price of 20 EUR/MWh this part of the production cost will contribute with 29-33 EUR/MWh for biomass to product.

Other operating costs (covering staff, maintenance, utility costs including electric power as well as catalyst replacements and chemicals consumed etc.) typically contributes about 20% (range 10-25%) to the total cost of production. This corresponds to an annual cost relative to the investment of 5-6%.

In the case of waste, the feedstock could be free, or even be associated with a "tipping fee". The range varies between different countries from 0 up to e.g. 20 EUR/MWh (in the UK). This would result that the feedstock cost in Table 2 (showing normal feedstock process) would change sign, which has a dramatic impact on the production cost picture. The following calculation case should be seen as an example:

- 50% energy conversion efficiency from feedstock (MSW) to product
- (Ref to Rosemount article[8]): "1 solid ton of feed generates 100 gal of EtOH"
- 100 gal of ethanol contain 2.2 MWh.
- "a solid ton" contain 4.4 MWh (10% inorganics
- Assume a credit of 55 EUR/ton of feed leads to a credit of feed energy of 12.5 EUR/MWh (=55/ 4.4)

Therefore, to produce 1 MWh of ethanol there is a need for 2 MWh of waste energy with a credit to the plant of 2 x 12.5 = 25 EUR/MWh of product. This corresponds to a credit of 177 EUR/ton of ethanol or 147 EUR/m3 of ethanol.

O&M costs for an Enerkem plant can be approximately determined via relating the yearly cost of O&M to plant investment. 6% of investment as yearly O&M would give 35 EUR/MWh of product (based on full investment 105 MEUR).

FT liquids production

The overall conversion efficiency from biomass to FT products is in the order of 40-55%, depending on the feedstock, the gasification technology, the FT technology and product slate optimization, plant capacity, etc. As the large span indicates conversion efficiency cannot be defined in detail. The product slate between the liquid product fractions naphtha (gasoline), kerosene and diesel is defined by the raw FT liquid ("FT crude") upgrading process design severity which can to some degree be optimized for specific market demands to generate either diesel and gasoline only or also have a significant fraction of Synthetic Paraffinic Kerosene (SPK) bio-kerosene to be used as aviation fuel.

[8] http://www.cantechletter.com/2016/10/enerkem-proposes-construction-200-million-minnesota-biofuel-facility/

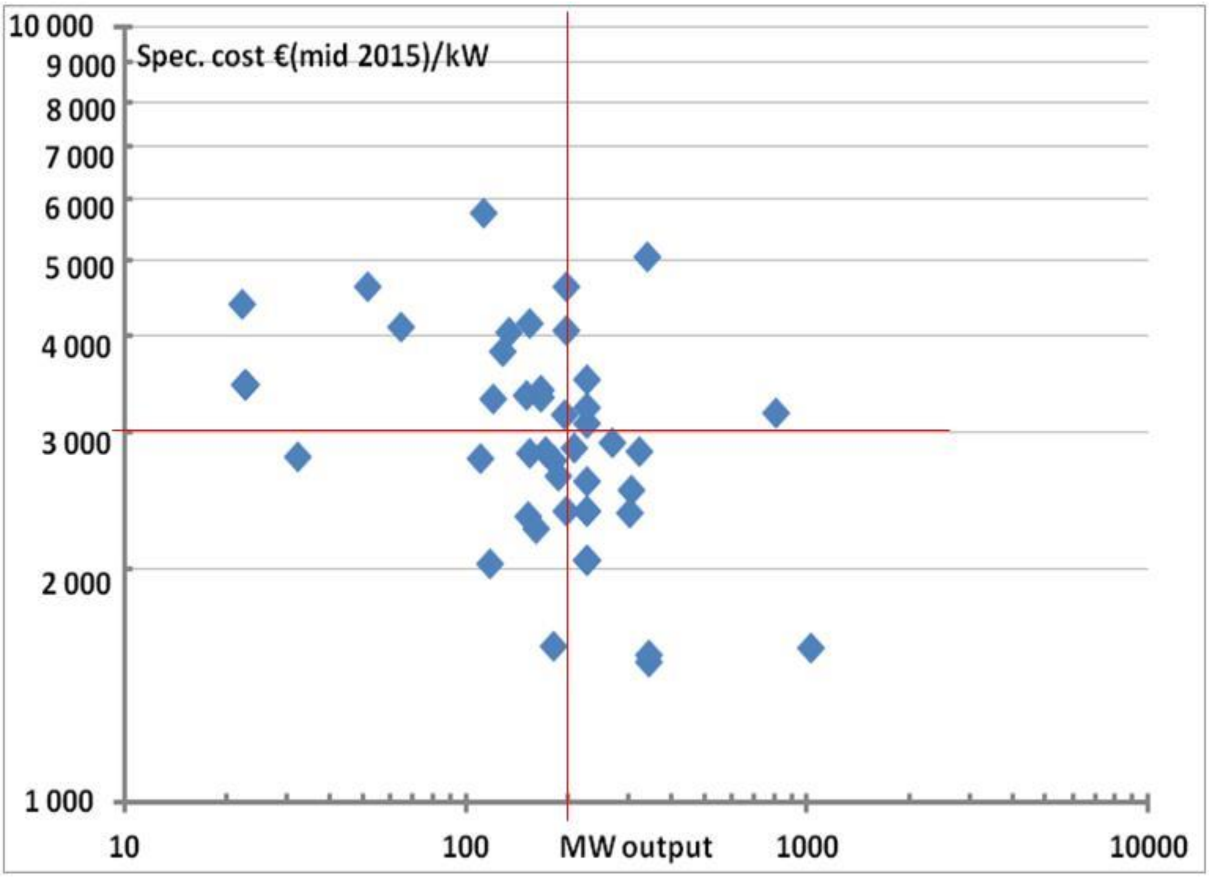

Figure 4. Compilation of Biomass to Liquid (BtL) data

Table 3**Error! Reference source not found.** gives an indicative example of the magnitude of how different severities in the upgrading process changes the product slate from a diesel only case to a high yield of kerosene case (SPK bio-jet)). It should also be noted that the C_{21+} waxes produced are important industrial products with a commercial value, such that also other combinations can be obtained.

Table 2. Production cost of biomethane, methanol and FT products

Component	Methanol and biomethane		FT Products	
	Low (EUR/MWh)	High (EUR/MWh)	Low (EUR/MWh)	High (EUR/MWh)
Capital	26	40	37	61
Feedstock	31	33	36	50
Other O&M	13	18	18	28
Total	71	91	91	139

In any case the FT process is not a single product process. All products are present in significant quantities regardless which way the upgrading is designed.

With a background in how different the various technologies for the gasification and the upgrading steps can be, a large span with respect to conversion efficiency is obtained. A feedstock price of 20 EUR/MWh will thus contribute with 36 – 50 EUR/MWh to the production cost of FT products.

Other operating costs contribute to about 15-25% to the total cost of production. Another way to determine these costs is to estimate them as annual cost relative to the investment. Typical number used is 5-10%.

Table 3. The different severities in the upgrading process changes

Products % wt.	FT total output before upgrading	FT liquid output before upgrading	FT total output after upgrading	Liq. product treated and split to max. diesel yield	Liquid product treated and split to max. jet fuel (SPK) yield
C_1 (methane)	5		6		
C_2-C_4 (LPG)	5		6		
C_5-C_{11} (gasoline)	25	28	30	Naphtha 34	Naphtha 24
C_{12}-C_{20} (diesel and kerosene)	25	28	58	Diesel 66	SPK 48, Diesel 28
C_{21+} (heavy oil, waxes)	40	44	0	0	

3.1.3 Cost of production

In general, in reports in this field, two cost elements dominate the cost of production. It is the cost of capital and the cost of feedstock. These two contribute to 75 to 90% of the total cost of production (and with typically a 50/50 split) the rest being other variable and fixed operating cost. Production of methanol and production of biomethane are handled together because the differences in production cost are too small to distinguish in this type of overview. If separated, biomethane would come out with a somewhat lower production cost than methanol.

Overall cost of production of methane / methanol alternatively FT liquids are shown in Table 2. The range is between71 and 91 EUR/MWh for methanol/methane and 91 and 139 EUR/MWh for FT products. Compared to production cost as proposed when initiating the cost survey (as per Figure 3) the methane/methanol cost level is very close to the same but the FT cost level has moved upwards about 20 EUR/MWh.

Enerkem data given earlier in this chapter are summarized in Table 4. Although constructed in comparably small scale and therefore carrying a higher relative investment than larger plants the overall production cost comes out very favorable due to credit received when gasifying a feedstock which otherwise would be carrying a tipping fee. The calculation is of course very sensitive to comparably small changes in tipping fee credits. It is on the other hand likely that an investment decision would be taken together with a long-term supply agreement with a supplier which would offset such risk. Enerkem has provided investment costs for next generation plants (after Edmonton) which results in a capital cost element lower than what is shown in Table 4. This would bring down the total cost of production further, towards the level of fossil based fuels.

For methanol production via Black Liquor Gasification (BLG) in an average sized pulp mill (2,500 tons black liquor solids per day) the corresponding figures are 21 EUR/MWh for capital, 35 EUR/MWh for feedstock and auxiliary power and 13 EUR/MWh other Operations and Maintenance (O&M), in total 69 EUR/MWh.

Table 4. Production cost for ethanol or methanol from waste

Component	EUR/MWh
Capital	57-77
Feedstock	-25
Other O&M	35
Total	67-87

3.1.4 Feedback from SGAB members

- European Biogas Association (EBA)

EBA has provided a diagram which combines biomethane from fermentation (see section 4.3) and via gasification. Figure 5 shows a development of gasification based biomethane concepts from 2006 and onwards with a reduction in cost of production from around 200 EUR/MWh to approximately 90 EUR/MWh in concepts realized in the 2020 timeframe.

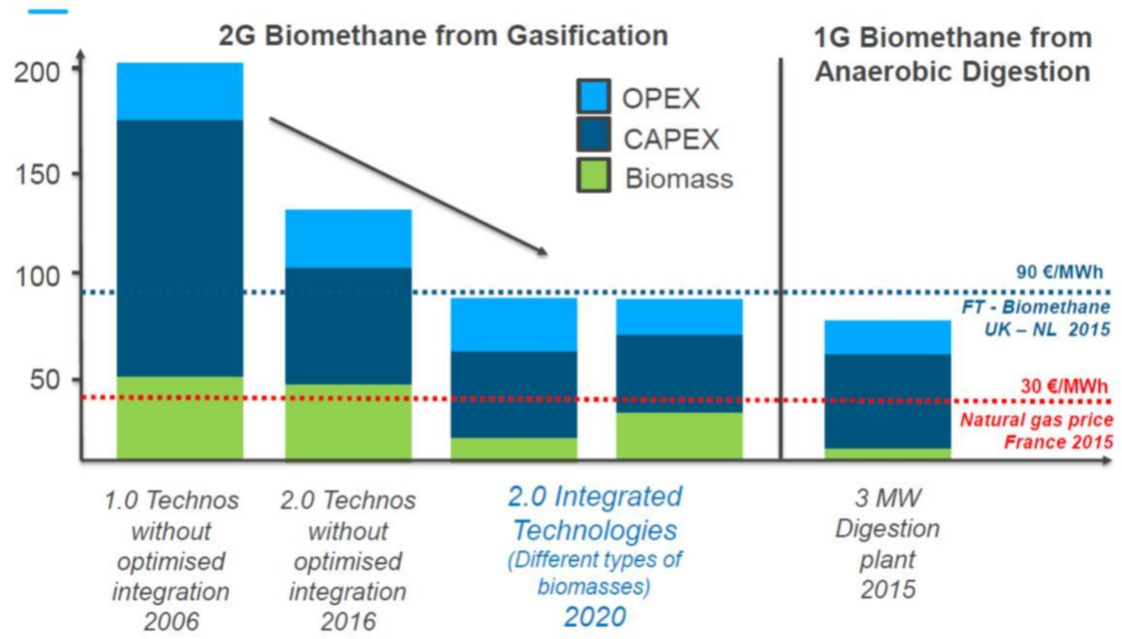

Figure 5. Production cost for biomethane via gasification and via anaerobic digestion[9]

[9] Source: Engie and EBA

3.2 Pyrolysis oil upgrading

The technology for generating pyrolysis oil includes the pretreatment (drying to low moisture content, milling to particle size of a few mm), the reactor where the pyrolysis occurs at approx. 500°C and the recovery of the pyrolysis oil. In the pyrolysis process, combustible gases and unconverted biomass char are by-products, which are typically used in a CHP unit. The bio-char can also be sold as a product in its own right.

The pyrolysis oil produced is a high oxygen, moderate water content and acidic solution that can be used as a combustion fuel. It is not miscible with fossil oils and cannot be used for engines without upgrading to a fuel with similar properties as more conventional liquid fuels. Two direct routes have been pursued for the upgrading, either as an integrated part of the pyrolysis plants facility, or off-site and then preferably in co-processing with fossil fuels in a fossil refinery. In addition, an indirect route is also being developed, whereby the pyrolysis oil (and excess char) is gasified to synthesis gas that is used for biofuel production by the routes described in Section 3.1. The potential for refinery upgrading will possibly require e.g. some initial deoxygenation and be limited to the refineries with suitable technologies (Fuel Catalytic Cracking (FCC), hydrotreatment etc.). The blend-in rate of into the fossil streams in such refineries is therefore in practice limited to a magnitude of 2-10%, depending on the pre-processing of the PO intermediate[10, 11] (deoxygenation etc.).

Both routes have significant technical challenges, and the integrated route has only been pursued at laboratory scale this far, i.e. below TRL5. The co-processing route has been explored in pilot tests in a refinery in Brazil with, and will be tested also by Valero in California, in both cases using PO from Ensyn Corp., Canada. The figures given below then give very indicative production costs for co-processing and for a dedicated upgrading.

3.2.1 Cost of Production

The cost of producing biofuels for transport via pyrolysis and co-processing in a refinery has an efficiency of below 30 %, but also has a low estimated cost 52-98 EUR/MWh, but the share of OPEX for the refinery processing stage is not included in this figure due to a lack of a basis for allocating such a cost. There is also a limitation to 1-2 million tons of drop-in based on the available FCC capacity in Europe.

For a large, fully integrated plant with an output of 272 MW, the production cost was estimated to 83-118 EUR/MWh, using data from the most recent study. No adjustments for investment cost differences between USA and the EU have been made, and one substantial cost item is natural gas for which no price correction has been done.

[10] A perspective on oxygenated species in the refinery integration of pyrolysis oil. M. Talmadge et al. Green Chem., 2014, 16, 407.
[11] The Potential and Challenges of Drop-in Biofuels. Sergios Karatzos, James D. McMillan, Jack N. Saddler IEA Bioenergy Task 39. Report T39-T1 July 2014

3.2.2 Capital Expenditure (CAPEX)

For pyrolysis plants without integrated upgrading there are a few FOAK plants and planned projects. The Empyro project is reported to have an investment of 19 MEUR for a 25 MWth wood input/ 15 MW bio-oil output plant[12,13]. This gives a specific investment of 1,300EUR/kW. The oil is used as a fuel substituting natural gas in an industrial boiler.

The Joensuu project in Finland for 50,000 tons of bio oil (210 GWh per year, 30 MW) was reported to have a total cost 30 million EUR according to the Fortum press release[14]. The main use of the PO is as a replacement of heavy fuel oil. The announced plants[15],[16] 40,000 tons in Latvia and 50,000 tons in Estonia which have received NER 300 support are stated to cost 35[17] MEUR and 30 MEUR, respectively. The specific investment is 1,000-1,100 EUR/kW. As the pyrolysis unit in this concept is a "bolt-on" to existing Combined Fuel Boilers (CFB) boilers already equipped with a CHP unit, the specific investment is typically lower than for a stand-alone pyrolysis plant where also such ancillary equipment needs to be installed. In addition, there are also synergies regarding handling of char and gases as well as for the efficient use of heat that can reduce the net operational costs.

A Swedish study[18] indicates investment costs of 211 million Swedish Crowns (MSEK) (23 MEUR) for a stand-alone 15 MW bio-oil products, 281-504 MSEK (31-56 MEUR) for a 30 MW oil output unit co-located with a CHP plant, and 607-810 MSEK (67-90 MEUR) for a 60 MW bio-oil product unit co-located with a pulp mill. The data is based on supplier information (average numbers have been used), and there are synergies in the use of power and heat. This translates to 1,500 EUR/kW, 1,100-1,800 EUR/kW and 1,100- 1,500 EUR/kW, the span being dependent how the CHP potential would be fitted into the existing boiler and turbine facilities of the mill.

The investments for upgrading at the refinery end could constitute tanks, pumps and other conventional equipment. This is site specific but not expected to involve any major sums.

For a complete stand-alone plant with integrated with upgrading, a techno-economic analysis made in the USA is more or less the only source. This plant[19] is based on 2,000 dry metric ton per day fed to two lines of pyrolyzers (i.e. significantly larger than any pyrolysis reactor built this far). The bio-oil is then treated in two steps before gasoline and diesel is obtained in almost equal shares (48/52 %). The total output is 272 MW. To provide the hydrogen for the processing, the plant uses 47 MW of natural gas. Figure 6 gives some details of the mains flows.

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[12] Empyro BV Press Release February 8 2014

[13] Looking back at the first half year of commercial scale pyrolysis oil production at Empyro. Gerhard Muggen tcbiomass Chicago November 4th 2015.

[14] Fortum press release March 7, 2012.

[15] Fortum's CHP-integrated pyrolysis oil production, Fortum presentation, October 2013.

[16] http://www.investinestonia.com/en/about-estonia/news/article/921-fortum-planning-eur-30-mln-bio-oil-plant-in-estonia-s-paernu

[17] Biomass CHP in Latvia: Now and in the Future. G. Cimdiņa, Nordic Baltic Bioenergy 2015 Riga, April 14th - 16th, 2015

[18] Decentraliserad produktion av pyrolysolja för transport till storskaliga kraftvärmeverk och förgasningsanläggningar. Gasefuels AB för Energimyndigheten. Februari 2013

[19] Fast Pyrolysis and Hydrotreating: 2015 State of Technology R&D and Projections to 2017. S Jones et al. Prepared for the U.S. Department of Contract DE-AC05-76RL01830. Pacific Northwest National Laboratory , March 2016

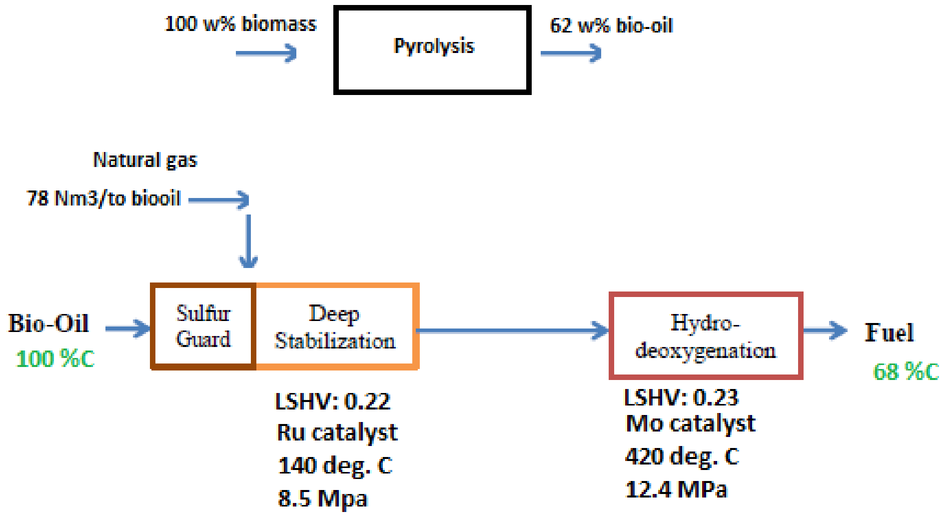

Figure 6. Overview of streams in the stand-alone pyrolysis to drop-in hydrocarbon plant (Adapted from[19])

The cost for this system was estimated to 700 million USD in 2013 in a previous design study report[20], i.e. a specific investment of 2 340 EUR/kW.

3.2.3 Operating Expenditure (OPEX)

For pyrolysis plants producing bio-oil as their main product, the typical O&M costs are of the order of 4-7% of the investment per year for maintenance, staffing and normal utilities. However, as these typically product heat and power (and possibly bio-char), revenues from these balances the O&M costs, such that including these by-products the net is here taken as zero. For the OPEX for the upgrading stage by co-processing in a refinery, the first assumption is that there is capacity available in the FCC unit, so the economic impact of displacement of fossil products have not been considered. The OPEX related to the bio-oil fraction in co-processing is not readily available for estimation at present. This relates to a general lack of process data and that the refineries will differ. However, contacts with experts in the field gave some basic numbers that was used to arrive at a Rough Order of Magnitude (ROM) figure.

For the larger integrated installation with integrated product upgrading, the non-feedstock OPEX is given as 59 EUR/MWh product for the state-of-the-art 2015 plant, the contribution to this figure being 73% being related to the upgrading step. This includes natural gas but also catalyst replacement of 82 million USD per year, or 34 EUR/MWh. Projections for 2017 reduce the OPEX to 29 EUR/MWh.

The pyrolysis unit in itself typically has a conversion efficiency from (dry) biomass, as fed to the reactor, to pyrolysis oil of 65-70% on a mass basis. The lower number is used.

[20] Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast Pyrolysis and Hydrotreating Bio-oil Pathway. S. Jones *et al* Report PNNL-23053 NREL/TP-5100-61178 (November 2013).

An article[21] describing the tests with 5-10% of bio-oil in Vacuum Gas Oil (VGO) in the Brazilian refinery had as one of its main results that some 30% of the biogenic carbon in the bio-oil ended up in the liquid products during co-processing with fossil fuels. So, as a simple estimate, biomass hold 48 % carbon as did the bio-oil in the tests. Then the product (as CH_2) per weight of dry biomass can be calculated to 109 kg/ton dry biomass, and using an energy content of 11.9 MWh/ton for fuel fractions and 4.5 MWh per ton for wet biomass, the energy efficiency is 29 %. The cited article does not indicate the split between the raw gasoline and Light Cycle Oil (LCO) (diesel precursor) fractions for the bio-oil, but the overall split was 2/3 gasoline and 1/3 LCO (, the output stream that can be upgraded to diesel and kerosene).

For the case with the integrated fuel production facility, the carbon efficiency from bio-oil to fuel was given as 68%. Doing the same estimate as above, the yield would be 248 ton/ton or 66% on an energy basis from the as-received biomass.

The feedstock commonly used in this memo has a cost of 10-20 EUR/MWh. The production costs are shown in Table 5 and Table 6.

Table 5. Cost of production, co-processing

	LOW **Low inv. (1,000 EUR/kW)** **No refinery costs included** **Capital 15y/10%** **Feed at 10 EUR/MWh** **EUR/MWh**	**HIGH** **High inv. (1,800 EUR/kW)** **No refinery costs included** **Capital 15y/10%** **Feed at 20 EUR/MWh** **EUR/MWh**
Capital cost pyr. plant	19	30
Capital cost refinery	**~ 1***	**~ 1***
Feedstock cost	34	68
Other O&M, Pyr. Plant	~ net 0	~ net 0
Other O&M refinery	**~ 5***	**~ 5***
Total	59	104

**These figures are based on ROM calculations. Data is generally not available and refineries are different in terms of their investment needs and processing capabilities such that a generic figure cannot be estimated.*

However, according to a graph in the 2015 Refinery BREF[22], the total FCC capacity in Europe is approx. 2,500,000 bpd or 100 million tons per year, split on 56 different refineries. Replacing 5-10% of the VGO with bio-oil, and use the same arithmetic's as above for the bio-oil only, this would result in a maximum yield of 0.16 tons hydrocarbons/ton of bio-oil which would give 0.8-1.6 million tons of bio-based drop-in fuels.

[21] Fast pyrolysis oil from pinewood chips co-processing with vacuum gas oil in an FCC unit for second generation fuel production. Andrea de Rezende Pinho *et al*. Fuel 188 (2017) 462–473.

[22] Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas. Industrial Emissions Directive 2010/75/EU Integrated Pollution Prevention and control. Pascal Barthe *et al.* JRC 2015 EUR 27140 EN

3.3 Wastes lipids to Hydrotreated Vegetable Oils (HVO)

The HVO process converts any fatty acid containing raw materials such as such as free fatty acids or triglycerides (three fatty acid chains with up to 24 carbons joined together with a glycerol unit) with hydrogen using catalysts under high pressure at temperatures in the range of 300-400°C. Hydrotreatment accomplishes deoxygenation and saturation of double bonds. The process consists of pretreatment, hydrotreatment and isomerization steps. The main product is in the diesel range but also kerosene and gasoline is obtained in the process to some varying degree, depending on the process severity and also to some degree on the feedstock composition. By-products are propane from the hydrogenation of the glycerol and light gases, as well as water and CO_2. The hydrogen can either be derived from the propane or be produced from natural gas, in which case the propane can be sold as a renewable LPG.

The scale of HVO units range from 0.05 to 1 million (metric) tons output, and the world annual production is around 4 million tons, and growing. There are stand-alone plants built specifically for the purpose of HVO, revamps of existing refineries to produce HVO and revamps to allow co-processing of HVO with fossil streams in existing refineries.

Table 6. Cost of production, stand-alone integrated pant

	LOW **Low inv. (2,340 EUR/kW)** **Capital 15y/10%** **Feed at 10 EUR/MWh** **EUR/MWh**	**HIGH** **High inv. (2,340 EUR/kW)** **Capital 15y/10%** **Feed at 20 EUR/MWh** **EUR/MWh**
Capital cost	39	39
Feedstock cost	15	30
Other O&M cost	29	59
Total	83	118

3.3.1 Production cost

Based on the data below, the cost of production falls in the range 600- 1,100 EUR/ton, or approx. 50-90 EUR/MWh. The dominating cost, 60-80 %, is the contribution of the feedstock cost.

3.3.2 Capital Expenditure (CAPEX)

The CAPEX figures are based on publicly available data[23] and data available from stakeholders.

Currently, the majority of HVO production facilities are stand-alone plants. CAPEX for stand-alone plants, reflecting a span from 0.1 to 1Mton per year capacity can range from 300-1,000 EUR/kW product (500 – 1,500 EUR/ yearly ton or 23,000 to 70,000 USD/bpd gasoline equivalent (ge) for 2,500 -25,000 bpd ge capacity).

[23] http://www.biodieselmagazine.com/articles/677239/totalundefineds-la-mede-conversion-the-unabridged-version

Another option is to perform a conversion of traditional oil refineries to HVO production or co-production. Based on published figures, such installations with capacities between 0.2 and 0.5 Mtons per year have a CAPEX of 200-250 EUR/kW product (300-400 EUR/ton per year or 15,000- 20,000 USD/bpd ge for capacity is 5,000- 15,000 bpd ge). Both stand-alone plants as well as refinery conversions produce 100 % HVO fuels.

In addition to the 100% HVO production, biofuels can be produced through co-processing. In co-processing, biomaterial is fed into refinery units together with fossil feeds typically in low (<5-10%) blends although there is at least one unit going up to 30%.

3.3.3 Operating Expenditure (OPEX)

The process cost or OPEX less feedstock is mainly reflecting the use of hydrogen for the process (if sourced externally) plus the normal costs for utilities, catalysts maintenance and staff.

As a typical OPEX value, 100-200 USD/ton can be used for HVO production. The exact value is depending on the type of feedstocks and associated upstream purification requirement, the process design and catalysts used, the market price for natural gas which is used for hydrogen production and the capacity and the location of the plant.

The yield of hydrocarbon liquid primarily as diesel (liquid fuel product / feed lipids) is typically 80-85% on a mass basis, and close to 100% on an energy basis, as most energy used in the process is derived from the hydrogen consumed. Hydrogen is added to the lipids and at the same time oxygen is removed which increases the energy content of the product over the feed. Hydrogen consumption is 3-4% on a mass basis or 10% on a direct energy basis relative to the feedstock. Most of the hydrogen is consumed for removing oxygen from the triglyceride as water but also to hydrogenate the glycerol part to propane and hydrogenate unsaturated fatty acids.

If the process is configured to maximize the yield of HEFA aviation fuels, the increased severity in the processing reduces the liquid yields by 5-10%. There will also be some diesel formed so the overall yield reduction can be minimized. In addition to HEFA aviation fuel, also HEFA+ aviation fuels can be produced. HEFA+ are renewable aviation fuels which can be used in lower blends than HEFA aviation fuels[24] .

3.3.4 Feedstock

For advanced biofuels, the feedstock for the HVO process is lipid residues from forest and other industries and waste and residue materials such as UCO, tallow. The feedstocks can be any fatty acid containing materials: As an example, Neste uses animal fats, waste fish fats, fatty acid distillates and acid oils from vegetable oil refining and food processing, technical corn oil, sludge oils, etc. UPM and PREEM, on the other hand uses tall oil by-products from pulp mills. These waste and processing residue streams origin from the oleochemical, biodiesel, vegetable oil refining, food processing and animal fat rendering industries.

[24] Neste publications: https://www.neste.com/en/revolution-plane-sight and http://www.itakamadrid2016.eu/assets/images/workshop/VirpiKroger_Session5.pdf

Based on public sources[25, 26, 27, 28] the cost of such materials is in the range of 400-600 €/ton (assumed to have 10 MWh/ton).

Table 7. Cost of production, HVO

	LOW Low inv. (200 EUR/kW) Capital 15y/10% Feed at 40 EUR/MWh EUR/MWh	MEDIUM Medium inv. (600 EUR/kW) Capital 15y/10% Feed at 60 EUR/MWh EUR/MWh	HIGH High inv. (1,000 EUR/kW) Capital 15y/10% Feed at 60 EUR/MWh EUR/MWh
Capital	3	6	15
Feedstock	40	60	60
Other O&M	8	12	16
Total	51	78	91

3.3.5 Stakeholder feedback

Neste: Neste have provided data for the document and also have reviewed and commented on the document.

4 Biochemical Conversion-methane

4.1 Ethanol from lignocellulosic sugar via fermentation

4.1.1 Production cost

Ethanol being one of the advanced biofuels which has entered the commercialization phase there is a lot of material available through reports and other well recognized sources of information. The material presented to the group originated from two different sources and gave a converging story. The data still shows a wide range with respect to cost of production and this is not surprising as such. Cost of feedstock plays a comparably big role in the production cost with a conversion efficiency of typically 30-40% on energy basis. This leads to large handling and processing of feedstock material which is reflected in investment intensity for these types of plants. Figure 7 shows projected production costs for cellulosic ethanol.

It should specifically be noted that the plants shown in Figure 7 are first of a kind (FOAK) plants and built with different type of technologies in very different geographical locations and with different start-up years. They also differ in size and also have quite different scope, e.g. with and without own utility units producing power and steam.

[25] Trends in the UCO market - Input to DRAFT PIR – .G. Toop, S. Alberici, M. Spoettle, H. van Steen. BIOUK10553. Ecofys November 2013 for UK Department for Transport (DfT).
[26] Used Cooking Oil collection: a market worth 470 million euros, with France representing only 5%. GREENEA, September 2014
[27] Grease Lightning pays price as oil cools. G. Meyer. Financial Times February 22, 2016.
[28] BIODIESEL DEMAND FOR ANIMAL F AT S AND TALLOW GENERATES AN ADDITIONAL REVENUE STREAM FOR THE LIVESTOCK INDUSTRY. Centrec Consulting Group, LLC for the National Biodiesel Board, September 2014

Figure 7 illustrates the following:

- For cellulosic ethanol plants cash cost contributes with a large portion to the overall production cost and with cost of feedstock often being the biggest single element (strongly dependent on cost of feedstock and ethanol yield)
- Based on the reported cellulosic ethanol plant data for feedstock, O&M and capital costs one of the plants reaches a total ethanol production cost below 85 EUR/MWh, four in the interval 105 to 130 EUR/MWh and one more than 180 EUR/MWh.

Another source of information comes from survey carried out by Bloomberg in 2013 named CELLULOSIC ETHANOL COSTS: SURVEYING AN INDUSTRY (March 18, 2013). The result is shown in Figure 8

4.1.2 Capital Expenditure (CAPEX)

The producer of the data for Figure 7, Lux Research, Inc. used by PennEnergy to make the illustration was contacted to comment cost of capital. They informed the following:

"Our capital-related assumptions are as follows: straight-line capital depreciation over 15 years at a loan rate of 8% with an investor return on investment of 20% the capital cost, and other operations cost calculated as 4% of investment per year. This result in the proportional observation you made for most of the cases, given that the investment cost for these projects were all very similar (approximately 10 USD/installed gallon per year) except for Hugoton Plant and DuPont."

Lux Research has thus used the same investment intensity for all plants i.e. investment directly proportional to the plant capacity. 10 USD/installed gallon of ethanol per year corresponds to 3,600 USD/kW or about 3,300 €/kW (calculated for 8,000 hours of operation per year). If using officially available investment numbers for the various plants, investment intensity varies considerably, from 160,000 to about 450,000 USD/bpd ge This corresponds to 2,380 to over 6,700 EUR/kW of ethanol production capacity.

Investment relating to Figure 8 (Source: Bloomberg) was for 2013 estimated to 270 MUSD for a plant producing 90,000 m^3 of ethanol (66 MW of ethanol for 8,000h). This corresponds well with plant data presented in Figure 7. The investment was calculated to fall from 270 MUSD to 190 MUSD in 2016 which equals a decrease in investment intensity from 3,650 to 2,570 EUR/kW.

2,570 EUR/kW and a capital cost corresponding to 15 years and 10% results in a cost of capital in the product cost of 42 EUR/MWh. Corresponding number for 3,650 EUR/MWh is 60 EUR/MWh.

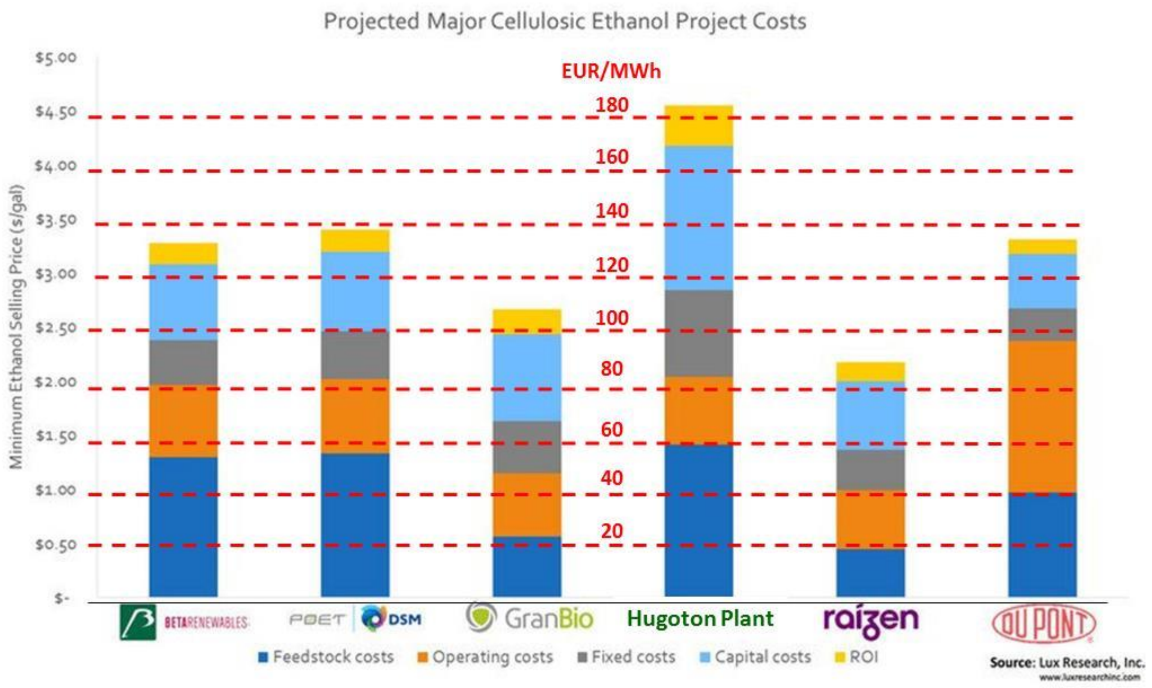

Figure 7. Projected production costs for major first of a kind Cellulosic ethanol projects[29]

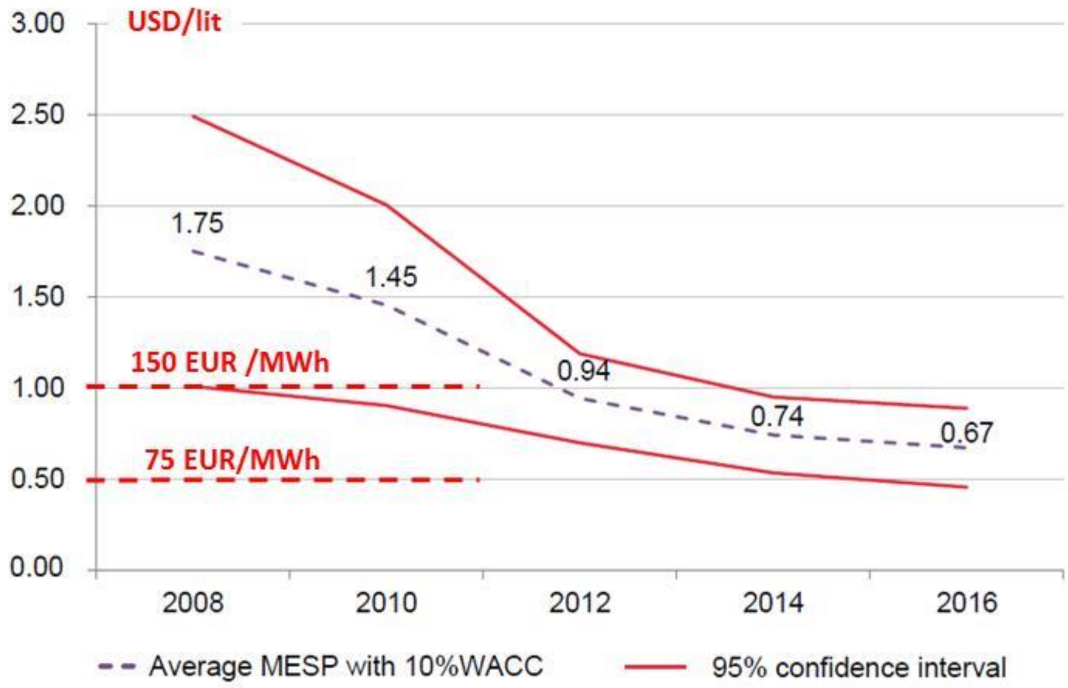

Figure 8. Minimum cellulosic ethanol selling price (MESP) in USD/liter, 2008 – 2016[30]**.**

[29] http://www.luxresearchinc.com/news-and-events/press-releases/read/raizen-has-lowest-price-cellulosic-ethanol-hinges-feedstock-cost and contacts with LUX Research Inc.

[30] Used with permission from Bloomberg New Energy Finance

4.1.3 Operation Expenditure (OPEX)

Feedstock costs in the Bloomberg report was put at 13 EUR/MWh. With 40% conversion efficiency from biomass feedstock to ethanol it results in a feedstock cost in cost of production of 33 EUR/MWh. If feedstock price is at 20 EUR/MWh corresponding number is 50 EUR/MWh. This latter cost of feedstock coincides approximately with three of the cases in Figure 7.

Table 8. Production cost of lignocellulosic ethanol

	LOW	MEDIUM	HIGH
	Low (2570 EUR/kW) Capital 20y/8% Feed at 10 EUR/MWh EUR/MWh	**Low (2570 EUR/kW) Capital 15y/10% Feed at 13 EUR/MWh EUR/MWh**	**High (3650 EUR/kW) Capital 15y/10% Feed at 20 EUR/MWh EUR/MWh**
Capital	32	42	60
Feedstock	25	33	50
Enzymes	15	15	30
Other O&M	13	13	18
Total	85	103	158

Besides cost of feedstock cost of enzymes is an important part of MESP. The enzyme supplier Novozymes has provided the following information together with an illustrative graph showing how cost of enzymes relating to MESP has developed during the last 15 years.

The following information has been received from Novozymes:

> *"Enzymes are an important technology component. The required enzyme dosing depends on the choice of pre-treatment technology. While for example a more capital-intensive acid pre-treatment setup requires a lower enzyme dosing, a less capital intensive steam-explosion pre-treatment requires a higher dose. Today's first-of-its-kind commercial facilities see an enzyme cost in the range of 0.1-0.2 USD per litre."*
>
> Figure 9 illustrate how Novozymes' enzyme development has been a major driver to make cellulosic ethanol production economically viable. Novozymes has been able to bring down the enzyme costs for one litre of cellulosic ethanol from more than 1.3 USD per litre in 2000 to as low as 0.1-0.2 USD today (15.5 – 31 EUR/MWh or 4.3 – 8.6 EUR/GJ). Since the introduction of Novozymes' first commercially available Cellic® CTec product in 2009, Novozymes was able to more than double the efficiency of its cellulosic enzymes. In 2015, Novozymes launched its latest generation of Cellic® enzymes which are customized to match the specific process and feedstock of its different partners.

The following information has been received from DuPont with respect to enzyme costs. Figure 10 illustrates how they have reduced enzyme costs when calculated for the same ethanol yield with 75% during the period 2008 to 2012[31].

[31] DuPont information shared with SGAB

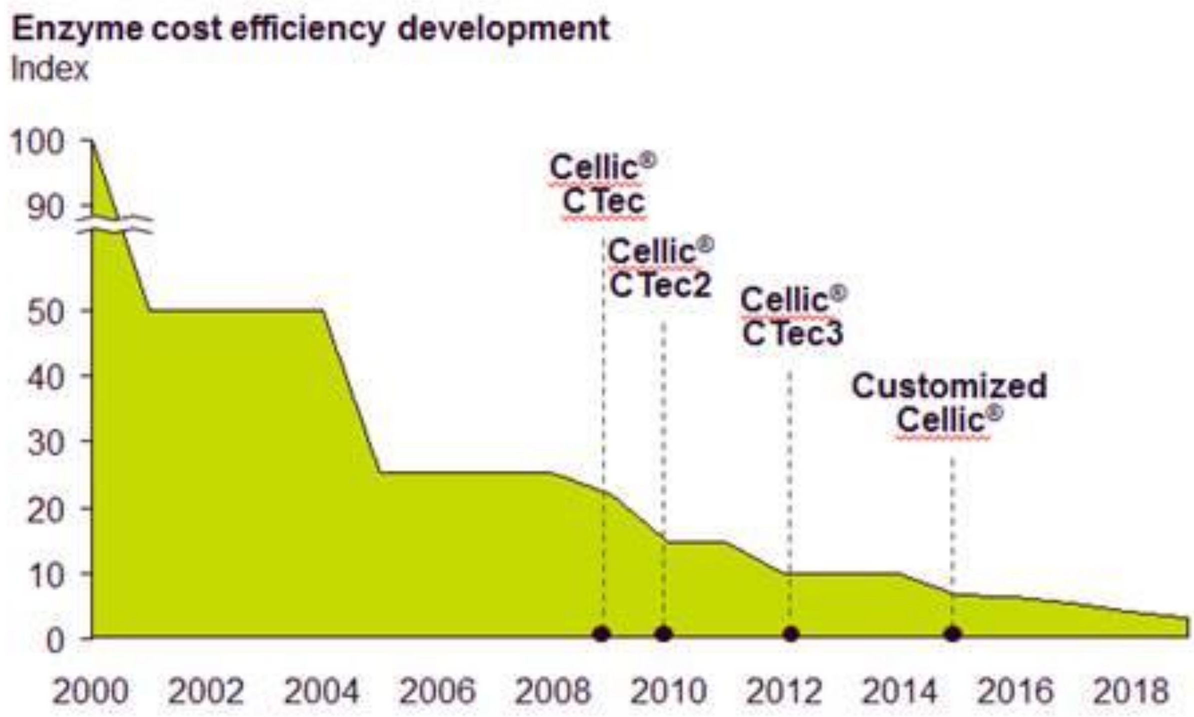

Figure 9. Enzyme efficiency improvements of Novozymes' enzyme development since 2000[32]

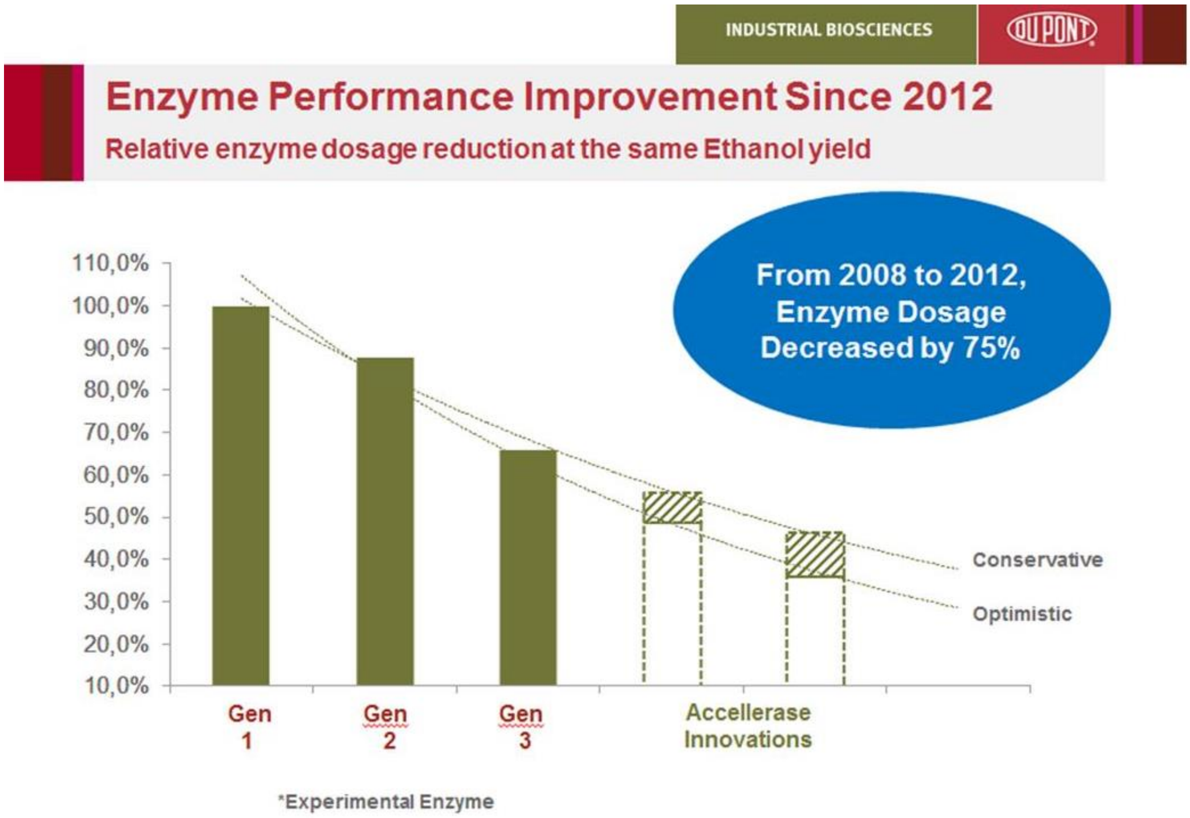

Figure 10. Reduction of relative enzyme dozing 2008-2012[33]

[32] Novozymes material shared with SGAB
[33] Source: DuPont

The company Clariant is also developing technology for the lignocellulosic ethanol conversion route. They highlight another important aspect of the technology, namely how the overall cost of enzymes is influenced by where and how they are produced.[34] Figure 11 illustrates savings made by production place (enzymes produced at another location, at the plant site or completely integrated into the process) for the enzymes as well as which sugar type is used for their production (glucose or from sugar actually being part of the plant process).

The cost of cellulase has been one of the deterrents in the profitable business case of a commercial scale cellulosic ethanol plant. The integrated enzyme production substantially lowers this cost as depicted in Figure 11 and makes the business case profitable for commercial scale production reaching cost savings of more than -50% compared to on-site enzyme production and of more than -70% compared to off-site enzyme production. The total OPEX is also reduced due to the benefits that are offered by the development of process specific enzymes integrated in the production itself.

Other OPEX costs besides feedstock and enzymes are by Bloomberg estimated to be a yearly cost of 4 % of plant investment. For the 90,000 m^3 per year plant referred to in their survey this would add 18 EUR/MWh for the year 2013 estimate and 13 EUR/MWh for the 2016-year estimate.

4.1.4 Performance

Today, the typical ethanol yield ranges between 250-350 liter per dry tone of feedstock.

In addition, the lignin solid residue is used within the plant in a co-generation unit to generate thermal heat and power. Depending on the individual process, the location and support to RE power, it may also be advantageous to export RE power from the plant. Alternatively, and where it makes economic sense, the lignin can be further processed to chemicals or biokerosene[35].

4.1.5 Feedback from SGAB members

- DuPont

Agree with the ranges of production costs shown in the background material (as per chapter 2), that it corresponds to where the industry is at this stage.

Similarly, the cost of capital (WACC[36]) likely differs by project depending on debt / equity ratio as well as by region and is likely to be higher than normal due to the risk component of these projects at this early stage. Suspect that WACC is likely between 10-13% but can be substantially higher when going outside of the Euro region.

Judge cost of feedstock to be at 50 EUR/ton +/-20 EUR (dry) corresponding to 10 +/- 4 EUR/MWh

- St1

St1 has different ethanol production costs in their different production units with different feedstocks and technologies. St1 cannot go into details of price structure of ethanol produced from different

[34] Clariant information shared with SGAB

[35] Biochemtex is coordinating the project "BIOREFLY" to produce bio-kerosene from the lignin residue of their Cresentino plant.

[36] Weighted Average Cost of Capital

waste and residue feedstocks. However, they can confirm that our cost level ranges from the bottom line (80 EUR/MWh) to 75%-percentile (140EUR/MWh).

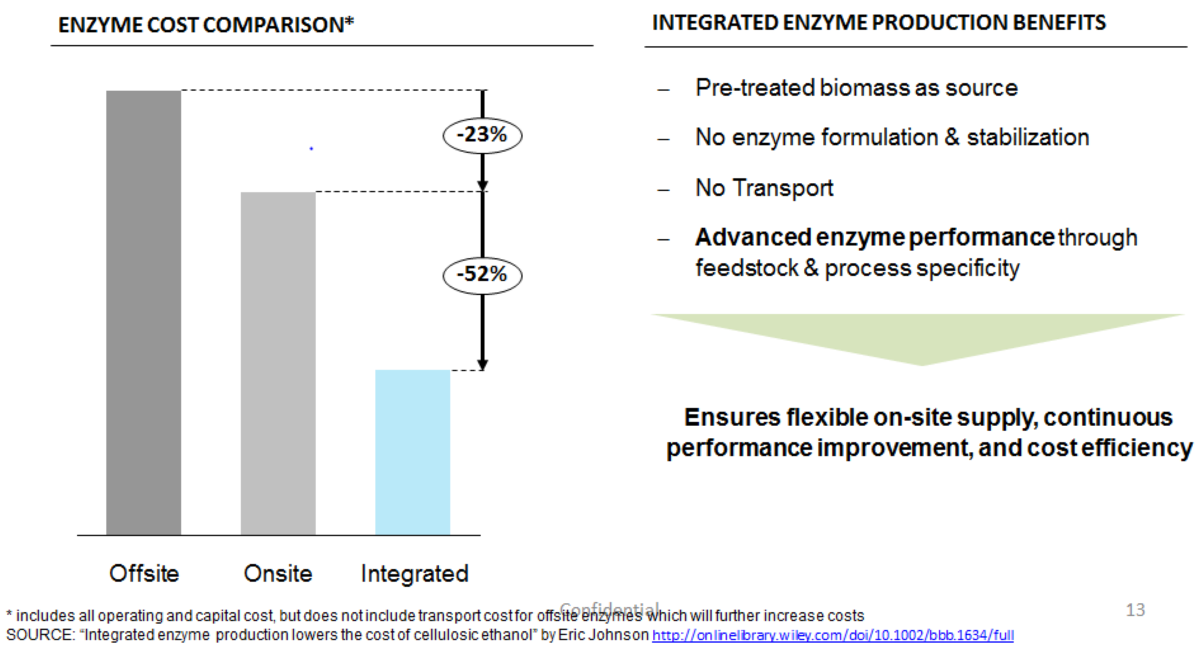

Figure 11. Enzyme cost as function of place of production and sugar source[37]

- Abengoa

<u>Comments to the cellulosic ethanol concept</u>

An updated base case from Abengoa coincides well with presented data in Figure 7. Cost are revised to 2,61 USD/US gallon which is in line with cash cost in the referred figure. If one applies a standard feedstock cost to the four non-Brazilian plants in the figure then, visually, cash costs (no capital cost) even up considerably between technologies.

The plant having the lowest production cost in the quoted figure is around 80 EUR/MWh. To lower that 10-15% over time due to various improvements sounds like a reasonable target within the short to medium term. For cereal residues, 80 EUR/MWh is a long-term goal. For the US, it seems feasible. For the EU, the problem will be competing demand for the biomass and the insecurity of supply.

Technically, energy crops have more cost-saving potential than agricultural residues, but it will also have the problem with competing demand of the biomass.

<u>Data regarding a Municipal Solid Waste (MSW) to ethanol concept</u>

Abengoa has spent considerable time and effort in their pilot plant in Salamanca, Spain to test sorted MSW feedstock as feedstock to their biochemical ethanol process. Based on operation experiences from the pilot plant and market investigations with respect to MSW quality and availability in Europe (and World-wide) Abengoa has developed a MSW to ethanol concept. Their provided data is brought into the same type of overall economic figures as other production concepts in this report.

[37] Source: Clariant

The presented case is based on a tipping fee of 70 EUR/ton MSW and a size of the operation of 500,000 t/y MSW (both data given "as received" basis). The income from the "tipping fee" is thus 35 MEUR/year. The investment is a MSW to ethanol plant is divided into two parts where the first part handles the pretreatment of the raw feedstock into recycling, RDF residual, landfilling streams and to a suitable organic waste stream fed to the second part. The second part converts the organic feedstock (bio-waste) to ethanol. Abengoa calculates that investment in the pretreatment can be carried by part of the "tipping fee" and the net credit from selling or disposing of the various recycle and waste streams from the pretreatment part of the business. The credit carried through to the organic feedstock stream of the ethanol plant (the bio-waste) corresponds to 27.6 MEUR/year or 180 EUR/ton organic waste.

The Bio-waste to ethanol plant produces 14,100 t/y of ethanol (98.7%) corresponding to 89,500 MWh/y and carries an investment of 127 MEUR. Assuming 8000 hours of operation per year the investment intensity becomes 11,350 EUR/kW. Capital element in the production cost is calculated as for other concepts in this report (annuity factor of 0.133) and becomes 189 EUR/MWh of ethanol. Enzymes are calculated to a cost corresponding to 42 EUR/MWh. Other O&M costs are specified to 15.2 MEUR corresponding to 170 EUR/MWh and finally the credit for the feedstock is a credit to the calculation corresponding to 308 EUR/MWh. The data are compiled in Table 10. The table includes two different cases where cost of capital has been varied in same way as for the cellulosic ethanol presented earlier in this chapter (see Table 8).

Table 9. Production cost for MSW based ethanol (biochemical pathway)

	Capital 15y/10%	Capital 20y/8%
	EUR/MWh	EUR/MWh
Capital	189	145
Feedstock	-308	-308
Enzymes	42	42
Other O&M	170	170
Total	93	49

<u>Comments from the authors:</u>
The calculations in Table 9 are sensitive to small variations in the main cost elements as the result is a difference between comparably large numbers.

The Abengoa calculation also includes quite large deviations from key numbers coming out from similar technologies e.g. investment intensities for the FOAK lignocellulosic plants presented in chapter 4.1.1, as is the cost of enzymes and O&M.

The effective feedstock credit for the organic waste as fed to the conversion plant is also considerably higher compared to other MSW- or RDF-based concepts presented in this report. However, this cost difference arises in the MSW separation plant and its mass balance and economics rather than in the downstream conversion plant. It is therefore recommended to develop all the MSW to ethanol concepts being part of this report further, with the attempt to bring all concepts to a level playing field. This is outside of the scope of this work and also need involvement of specialists in the waste management field.

- Clariant

We are aligned on the general range of the production cost depicted in Figure 7. This corresponds with our base case although we are of the opinion that this figure is misleading. The major difference between the listed companies as depicted is stemming from the cost of feedstock not from the technology. Although this is mentioned in the text it is not a fair reflection of the available technologies. Also, this does not take into account two things:

1. Differences in feedstock cost per quantity of ethanol produced may result from either yield (a technical reason) or feedstock purchase cost (a non-technical reason).
2. Neither the figure nor the text take into account that the byproduct lignin can be used for energy generation or used to add additional income and thus bring down operating costs.

We suggest to either take feedstock costs out of the graph completely or at least move it to the top to be better able to compare differences in production costs by technology.

Production costs do differ by technology. For example, enzyme production has a strong impact on overall production costs being one of the major cost drives. See Figure 11, A recent study analysed and compared three production methods (off-site, on-site and integrated) and their effect on overall cellulosic ethanol production costs, coming to the following conclusions:

- The cost of enzyme is one of the most significant cost factors in cellulosic ethanol production
- Integrated enzyme production is the most cost efficient way
- The cost of enzyme production is the most variable single input item by production approach

Breaking down the enzyme production costs, it is shown, that by changing from off-site to on-site to integrated enzyme production, the cost for enzymes can be lowered by 23% and 52% respectively, and thus enzyme production is the most variable of cost factors. This quite dramatic decrease is mainly attributed to the difference in feedstock for enzyme production and the huge price difference between biomass for integrated production versus sugars in the off-site and on-site case. Hence, it is not surprising, that a reduction in enzyme costs has a significant impact on overall cellulosic ethanol costs. The study looked at the annual cash costs, which showed a reduction of 8% and 20%, respectively, by shifting from off-site to on-site to integrated production, and at annual full costs (including capital costs), with a reduction of 7% and 19% respectively. Overall cellulosic ethanol production costs were calculated to decrease from 2.78 USD/gallon to 2.61 USD/gallon to 2.36 USD/gallon, with enzyme costs making up 0.78 USD/gallon, 0.58 USD/gallon and 0.23 USD/gallon respectively.

The overall predicted production costs for cellulosic ethanol from both sources correspond with our data as mentioned above. We agree that a 10-15% decrease over time due to the learning curve is reasonable.

Each company has their internal guidance on discounting factors (e.g. WACC), also dependent on the country and location, so these are likely to vary by project.

4.2 Biomethane via anaerobic digestion

Anaerobic digestion technologies use a substrate which is most commonly wet. However, dry substrates (in the range of 30-35% dry matter content) are also increasingly used in the so called solid state fermentation, especially for waste fractions. The substrate is processed in a digester under anaerobic conditions at atmospheric pressure and temperatures slightly above ambient, in the range between 35°C and 60°C

The process of hydrolyzing the substrate and generate methane takes one to fifty days, depending on the substrate and temperature used. The product, so-called biogas, mainly contains methane up to 50-70% vol., CO_2 and some minor constituents/contaminants. To use the biogas as a transport fuel it is upgraded by removal of the contaminants and the CO_2 to reach 97% vol. methane or more. There are a variety of proven technologies for this purpose.

The technologies used for the biogas generation and for the upgrading are well-known, there are over 17,000 biogas plants in Europe mainly used for CHP applications, but already over 350 units have an integrated upgrading technology to biomethane. Therefore, the technology is at the right-hand side of the learning curve, Figure 2, such that the improvements over time have a slower pace than for other, less well-established technologies.

However, compared to other biofuel technologies the processing via anaerobic digestion is done at smaller capacity, typical state-of-the-art installations in the upper end of the capacity scale are below 20 MW product output, i.e. approximately 2,000 Nm^3/hr, corresponding to 350 bpd. There are smaller capacity biogas installations available, well below 1 MW units, but in such small installations the upgrading of the biogas is rarely motivated. The focus has therefore been on the larger scale more relevant for vehicle fuel (or for injection into gas grid).

4.2.1 Production cost

The production cost of biomethane, based on estimates from different sources[38, 39, 40,] is given in Figure 12 and Figure 13. Figure 12shows the impact of scale and upgrading technology. Figure 13, which is based on Swedish conditions and a scale[41] of 50-100 GWh per year (600-1,200 Nm^3/hr) shows the impact of different substrates.

Based on a 10 kWh/Nm^3, the total costs fall within 40-120 EUR/MWh or 4-12 EUR/Nm^3. The range relates to the cost of the substrate where wastes of different kinds can have negative or zero cost, while other materials comes with a cost, e.g. grass at approximately 86 EUR/ton Dry Matter (DM) (18-19 EUR/MWH) on the average in Germany. The second factor is the economy of scale, indicated by Figure 12.

[38] Data obtained from EBA (European Biogas Association)
[39] Biosurf project. D3.4 | Technical-economic analysis for determining the feasibility threshold for tradable biomethane certificates. B Stürmer et al. June 24 2016. http://www.biosurf.eu
[40] Publically available data for individual projects from press releases etc.
[41] Personal communication, B. Fredriksson-Möller, EON Sverige.

4.2.2 Capital Expenditure (CAPEX)

Information from the cited sources and for real projects in Sweden and Germany for the upper capacity range indicate that the investment cost is of the order of corresponds to around 1,500-2,000 EUR/kW or 15,000- 20,000 EUR/Nm^3. (or in the region of 100,000-130,000 USD/bpd gasoline equivalents). There is also a fairly large scale factor disfavoring smaller plant, the specific investment cost goes up by 50-100% when going significantly below 5 MW output, but such smaller installations have not been considered further.

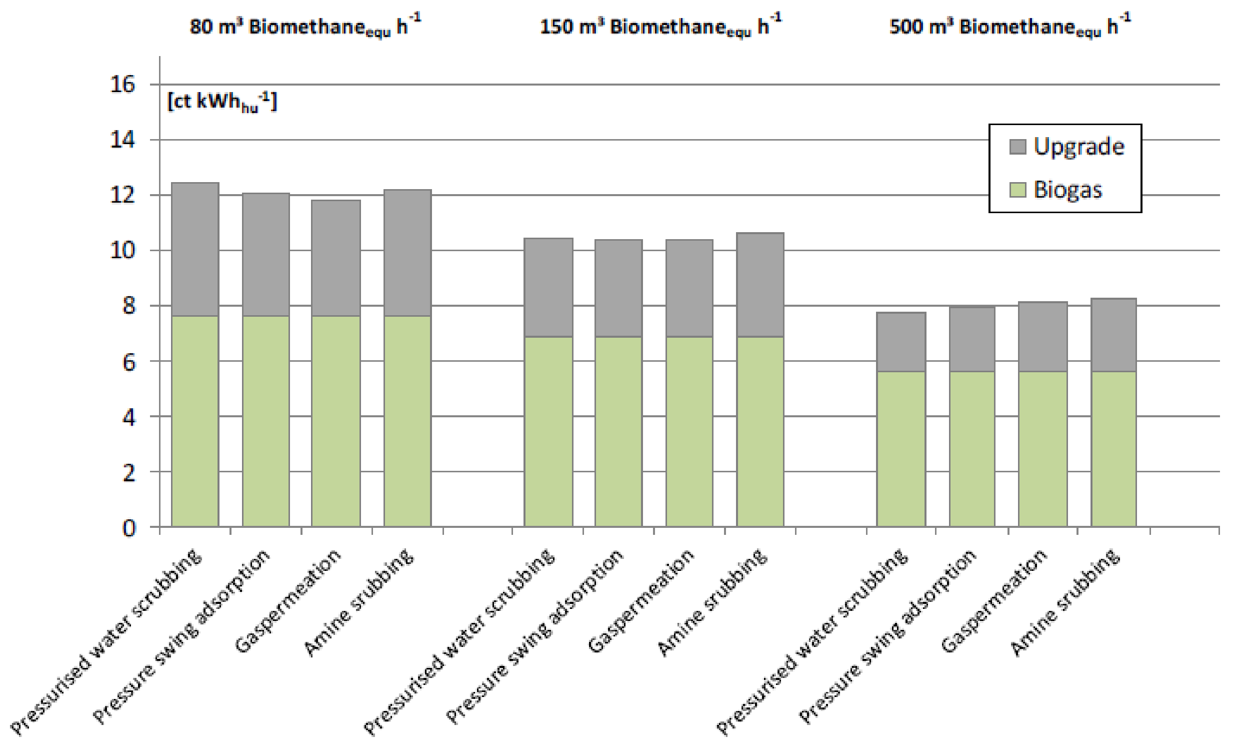

Figure 12. Cost of production of biomethane at different scales and upgrading systems (Substrate not known)[39]

4.2.3 Operational Expenditure (OPEX)

The magnitude of the operating cost, other than for the substrate feedstock, is similar to the capital cost, e.g. in the range of 10-15% of the investment per year. The main cost drivers are the heat required for the process and the electricity used both in the biogas plant and in the upgrading and compression part. Also, regarding the OPEX, there are considerable scale effects as the staffing requirements are more or less independent of the capacity, and can then become the dominant cost at smaller capacities.

4.2.4 Feedstock and performance

There is a large variety of substrates available for biogas plants, organic waste fractions, farm-yard manure, sludge from sewage treatment, food and meat processing industrial wastes but also energy crops and straw, alone or in combinations. The feedstock cost could therefore range from negative up to the cost of straw, e.g. up to 100 EUR/ton.

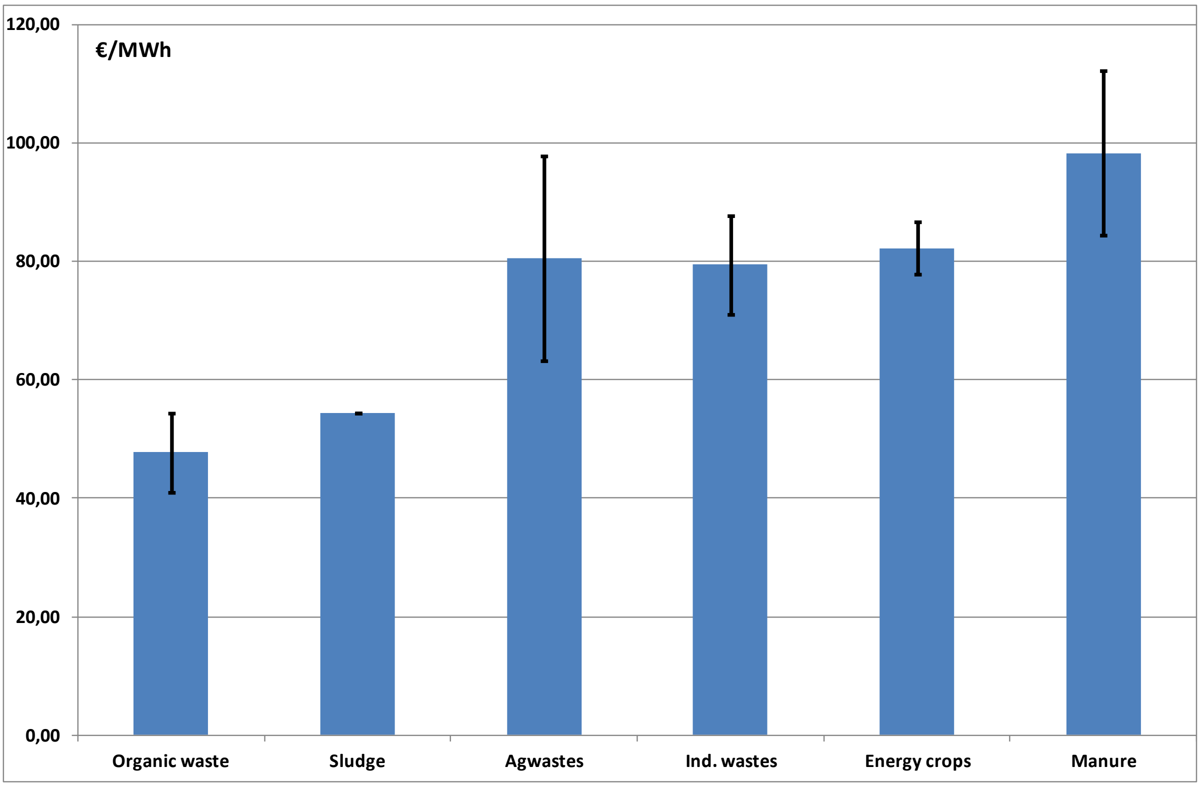

Figure 13. Cost of production of biomethane from different substrates (Adapted from graph in[42])

In addition, the choice of feedstock also affects the value or cost of disposal of the digestate. Furthermore, the gas yield from the variety of substrates may in practice range from 150 to 600 Nm^3/ton dry substance, and where manures are both low in the theoretical yield and in the conversion efficiency in the digester[43]. For these reasons the feedstock component of the production cost is a complex matter beyond the scope of this memo, and the reader is referred to more specialized literature on this subject.

A survey[39] made among biogas plant operators in the EU gave a range of feedstock cost, expressed as feedstock contributions to the biogas production cost ranging from 3-60 EUR/MWh.

4.2.5 Feedback from stakeholders

- EBA

EBA have provided information e.g. the cost reduction estimates in Figure 5 and have made comments on the drafts.

[42] Kostnadsbild för produktion och distribution av fordonsgas (Cost benchmarking of the production and distribution of biomethane/CNG in Sweden). Johan Vestman, Stefan Liljemark, Mattias Svensson. SGC Rapport 2014:296. Svenskt Gastekniskt Center AB
[43] Styrmedel för biogasproduction. U2014-02. Avfall Sverige. (In Swedish)

4.3 Hydrocarbons and alcohols from waste gaseous material via gas fermentation

Gas fermentation utilizes gas streams with a range of CO and H_2 compositions to produce fuels and chemicals such as e.g. ethanol and 2,3-butanediol at high selectivity and yields. Microorganisms developed for this type of feedstocks are also able to consume H_2-free, CO-only gas streams, due to the operation of a highly efficient biological water gas shift reaction occurring within the microbe which enables the release of H_2 from water using the energy in CO.

This pathway offers a differentiated technology with feedstock and product flexibility. Gas fermenting microbes are claimed to be more tolerant to high levels of gas contaminants than synthesis catalysts with sulphur as a key example, thereby avoiding expensive conditioning. Large-scale applications require the provision of insoluble gases into the growth medium; this challenge has been overcome through developments in gas delivery technology.

However, when the feedstock is an off gas from a steel mill the feedstock is not qualified as renewable under the Renewable Energy Directive and it falls under a feedstock category named LCFF.

Feedback from SGAB members

- LanzaTech

Information was provided in the form of Table 10.

Table 10. Lanzatech: Basic Cost data for an 32 000 m3 per year ethanol plant

Item	Steel Mill Off-Gas	Biomass	MSW
Feedstock Cost	5$/GJ	20$/mt	50$/mt
Feed Rate (mtpd)	650-700	300-320	650-700
LanzaTech ISBL ($mm)	30-35	35-40	35-40
Gasification ISBL ($mm)	N/A	50-60	80-100
Cash Cost of Productio ($/mt)	400-500	500-550	150-200

The table was complemented with the following information:

- Feed rate on dry basis
- Waste biomass price at 20 USD/mt (3.5 EUR/MWh) is available (18 GJ/mt, dry)
- MSW, 45% organics. 18 GJ/mt for organic fraction which means 8.1 GJ/mt (dry) as received
- Tipping fee for MSW at 50 USD/ton which gives a credit to the feedstock corresponding to 20 EUR/MWh.
- Steel mill off-gas at 5.4 GJ/mt and at cost of 16 EUR/MWh (5 USD/GJ)
- Cash cost includes fixed and variable operating expenses as are typical, but does not include repayment of capital.
- Commercial plant sizes in multiples of 300 mt/d(ay) for feedstocks like waste biomass and MSW.

- Typical gasification energy conversion efficiency is 65-75%.
- Cash cost of production includes fixed and variable operating expenses as are typical

The following can be concluded from supplied data.

- The 32,000 t/year ethanol plants have a capacity of 23.4 MW ethanol during 8,000 h/y operation.
- 675 t/d of steel waste gas corresponds to 42 MW of gas
- 310 t/d of dry biomass corresponds to 64 MW which can be converted to 45 MW of (raw) syngas with 70% cold gas efficiency.
- Conversion from feed gas/syngas to ethanol has an energy conversion efficiency of 52-56% (to be compared with theoretical value of 73 % and 86 % from reaction of 6 moles of CO or 6 H2, respectively, to form 1 mole ethanol)
- Including the gasifier conversion, the energy yield is 35-40 % from fuel to ethanol
- 675 t/d MSW with energy content of 8.1 GJ/mt corresponds to 63 MW which can be converted to 44 MW of (raw) syngas with 70% cold gas efficiency.

CAPEX for the proposed process is 1,260 EUR/kW for the steel mill gas case, 3,590 EUR/kW for the biomass case and 4,950 EUR/kW for the MSW case. With a 15 year/10% annuity factor of 0.1315 this give a capital cost for element in the fuel production cost of 21, 59 and 81 EUR/MWh respectively.

Feedstock cost in the ethanol production cost for the cases are for steel gas 29 EUR/MWh, for biomass 10 EUR/MWh and for MSW a credit of 54 EUR/MWh.

Cash costs element are said to have average values of 450, 525 and 175 USD/mt for the steel gas, biomass and MSW cases which can be recalculated to 54, 63 and 21 EUR/MWh for the respective cases.

O&M costs excluding feedstock can thus be calculated to be 25, 53 and 75 EUR/MWh for the steel gas, biomass and MSW cases.

Table 11 summarizes the cost elements and gives total ethanol production cost.

Table 11. Production cost of ethanol through gas fermentation

Type of plant		**Steel mill off-gas**	**Biomass waste**	**MSW**
Cash cost	**USD/mt**	450	525	175
	EUR/MWh	54	63	21
Feedstock cost	**EUR/MWh**	29	10	-54
O&M w/o feedstock	**EUR/MWh**	25	53	75
CAPEX	**EUR/MWh**	21	59	81
Total production cost	**EUR/MWh**	75	122	102

5 Aviation fuels

The global jet fuel market is above 300 million m^3 per year[44]. For aviation fuels, only drop-in hydrocarbon fuels can be accepted, i.e. bio-kerosene, and the properties and conditions for these fuels are defined by an ASTM standard[45]. The blended Fuel (i.e. fossil + abio-jet) fuels must also meet the regular fuel standard[46]. The production of aviation fuels does not imply any specific technology in itself; several of the technology developments discussed in this report and in the Technology Status Report are capable of providing bio-jet with more or less processing of the primary biofuel product. Irrespective of the processing route, all such processes, and in addition to the bio-kerosene product, also yield other hydrocarbon fractions as by-products that are suitable for ground transport fuels, or for the fraction below C_5, use as energy carriers.

5.1 Alternative production routes

At present, there are five fully accepted forms of bio-kerosene as defined by annexes to the cited standard

- FT-SPK (Synthetic Paraffinic Kerosene) from different forms and product streams of the FT process, blend ratio (bio-jet/total jet fuel) 50%
- FT-Synthetic Paraffinic Kerosene Aromatics (SPK/A) from different forms and product streams of the Fischer Tropsch (FT) process, blend ratio 50%
- HEFA-SPK from the HVO process, blend ratio 50%
- Synthetic Iso-Paraffins (SIP), derived from sugar-based organics, notably farnesene produced by Amyris, blend ratio 10% and finally
- Alcohol to Jet (ATJ)-SPK , made from iso-butanol obtained via fermentation of sugars, blend ratio 30% (approved early 2016).

In practice, the actual tank blend level will be lower than the cap in the ASTM specification since an operational aircraft normally has a significant part of the fuel left in the tanks from the previous flight as a safety precaution when refueling.

Several other annexes are in preparation such as Alcohol to Jet Synthezised Kerosene with ATJ-SKA (Synthezised Kerosene with Aromatics), HFP-HEFA (*fka* HEFA+), Hydrotreated Depolymerized Cellulosic Jet (HDCJ), Hydro-Deoxygenated Synthesized Kerosene (HDO-SK), Hydro-Deoxygenated Synthesized Aromatic Kerosene (HDO-SAK), CH Catalytic Hydrothermolysis etc. The HFP-HEFA annex would be a relaxation of the already approved HEFA annex such that only after blending, all the properties of the jet fuel are met. This would mean that HVO diesel could be used more or less as-is but in a more limited blend ratio of the same order of magnitude as for SIP. If accepted in 2017, the availability of bio-kerosene would improve significantly based on already operating HVO plants. In the event of such an approval, it is not unlikely that also other pathways will try the same thing to obtain e.g. SPK+ or ASJ+. As far as their respective blend-walls are far away e.g. 10% in a large quantity of biofuel used in a major airport, this could increase the market (Stockholm Arlanda Airport consumes

[44] The Flight Paths for Biojet Fuel. T. Radich. U.S. Energy Information Administration. October 9, 2015

[45] ASTM D7566 Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons

[46] ASTM D1655 Standard Specification for Aviation Turbine Fuels

some 0.7 million m^3 per year, Schiphol around 4.4 million m^3). FT-SPK/A, ATJ-SKA and HDO-SAK are of some additional interest in addition to the fuel value, as these fuels are higher in aromatics than the SPK, SIP and SK fuels, and since after blending a minimum requirement for aromatics of 8 % must be retained to meet specifications. However, since the aromatics are also increasing soot particle emissions, fossil jet typically is not overshooting this specification such that the aromatics can be a limiting factor for the blending.

HEFA has been the predominant fuels for test flights and more extended tests. None of the HVO plants that were in operation before 2016 produce a dedicated stream of bio-jet, they are all mainly focusing on renewable diesel. The 100,000 ton per year Altair plant in California, USA, that came on stream in 2016, is the first plant that produces a combination of a dedicated stream of HEFA bio-jet and HVO bio-diesel.

With regard to SIP, this is a product developed by Amyris, and it is demonstrated in a plant in Brazil with a capacity of 0.05 million m^3 per year. The original product farnesene is hydrogenated to farnesane and used as the bio-jet component[47]. Since farnesene is also used for lubricants, bio-polymers and –resins, the actual production of bio-jet is not known.

At present., there is no biomass FT plant in operation and hence no SPK bio-jet is produced. There are several plans for such installations, mainly in the USA (Red Rock Biofuels, 0.05 million m^3 per year off which 40 % aviation fuel, Fulcrum Sierra Biofuels, 0.04 million m^3 per year). In the EU some project with NER300 contracts[48] were planned to produce FT liquids. FT-SPK/A relates to the use of the high temperature FT process used by Sasol.

ATJ-SPK covers synthetic kerosene produced from C2-C5 alcohols. Currently the only qualified pathway starts with iso-butanol, a technology developed by Butamax and Gevo, where the initial production of the butanol is still in the pilot/demonstration phase. Since at present both SIP and ATJ-SPK are produced from crop-based sugars, they are not advanced biofuels according to the SGAB definitions. However, other ATJ technologies exist and are currently in review by ASTM, including one developed by LanzaTech to convert ethanol to SPK. LanzaTech's technology is in particular said to allow the use of ethanol from any source, including cellulosic and industrial waste gas feedstocks, for conversion to drop-in jet fuel blendstocks.

There are also various technologies in various stages of developments below an actual demonstration such as pyrolysis oil upgrading, sugar chemical conversion to hydrocarbons and conversion of ethanol to hydrocarbons. Recently an FP7 project presented a review of the status of ASTM approval and of the pathways mentioned above, and also listed over a dozen pathways in the pipeline to initiate qualification[49].

[47] http://www.greenaironline.com/news.php?viewStory=1955

[48] See SGAB memo " NER 300 Initiative and Status of Bioenergy Projects"

[49] Final Report on Technical Compatibility, Certification and Deployment. Work Package 5, D5.2. A. Quignard CORE-JetFuel. 07.09.2016.

5.2 Market conditions and available incentives

Despite of the more restrictive quality demands for aviation fuel relative to road transport fuels, the price of kerosene does not significantly deviate from the price of diesel, Figure 14, and sometimes even fall below this price.

For this reason, aviation biofuel does not in itself have a sufficient additional value, relative to drop-in HVO diesel or some other advanced biofuel, to give an incentive to focus on this product, in particular as in most cases a focus aviation fuels causes a slight overall loss in yield of liquid products relative to producing ground transport fuels.

Another observation is that many of the feedstocks used for production of biofuels and bio-jet are also part of the commodity markets such that synergistic effects have an impact on the market price. When fossil fuel prices increase, there is tendency that the price of alcohols, vegetable oils, that are both to considerable extent used for transport fuels, follows. Therefore, the gap between the costlier biofuels and the fossil fuels is not necessarily reduced to the same extent that could be expected if there were no such synergies.

Furthermore, for ground transport there are various support mechanisms in place in the EU (targets in ground transport etc.) and in the USA (RFS2) to bridge the price difference between biofuels and fossil fuels, and where aviation fuels can be included on the same terms as other biofuels. The RFS 2 covers jet fuel, and language has been proposed to modify California's Low Carbon Fuels Standard (LCFS) to also cover bio-jet fuel, which could provide significant incentives for alternative jet fuel production. Cellulosic jet fuels would benefit from cellulosic and LCFS credits; approximately 60-70 USD/MWh and 15-20 USD/MWh, respectively, but so would also ground transport biofuels. The Flightpath EU 2020 cooperation involving various stakeholders, has formulated a non-binding target of 2 million tons of bio-jet in 2020, and without any economic incentives than what the member states have for the implementation of the RED. So, in general, no additional mechanisms to the benefits for biofuels in general are in place for aviation biofuels fuels to compensate for the additional cost burdens and to stimulate producers to go beyond the ground transport biofuels to this more demanding market.

In the US, initiatives and support has largely been channeled through the Department of Defense for support and procurement of biofuel batches. The airline industry in the EU has also opted in into the third phase of the ETS cap-and trade system covering flights within the EU, and the EC the ambition to also include non-EU airlines flying to and from the EU in the fourth phase. However, these airlines protested directly, and also via diplomatic channels, and the proposal was not pursued, as it would then have disadvantaged EU carriers. The complexity of trying to regulate an industry where both the fuel used and the activities have such an international dimension was described in a presentation by BA[50]. Nevertheless, the participation in the ETS system could indirectly have economically promoted bio-jet, had not the price of emission allowances gone down to a level where it has an insignificant impact on the market. The ETS system is intended not only to limit the emissions, but has an annual decrease of the allowed cap intended to achieve a reduction of the emissions over time.

[50] Global Policy: Market Based Mechanism and Sustainable Fuels and the Role of Regional Policy. Presentation by L. Hudson, BA, at SGAB meeting April 22, 2016.

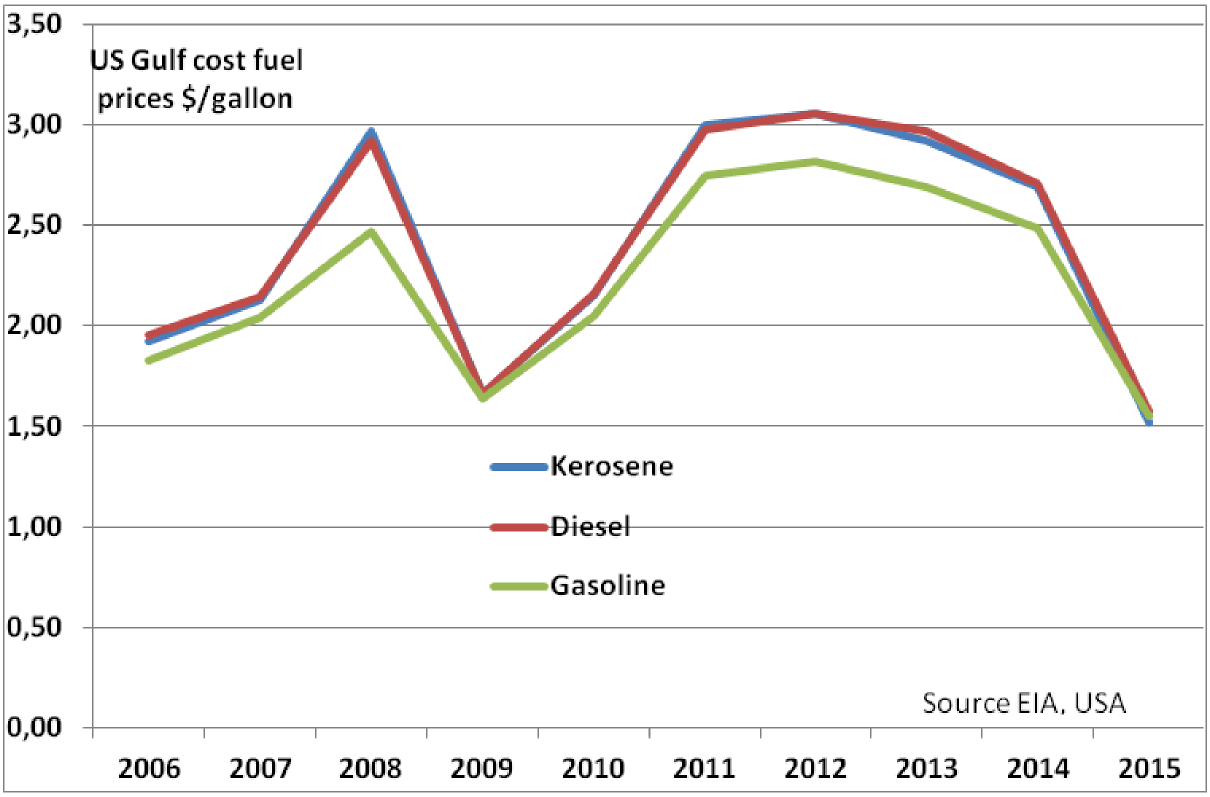

Figure 14. Historical price relations between gasoline, diesel and kerosene

Instead, the airlines directly, or in cooperation with their corporate customers, have themselves started activities for the purpose of procuring bio-jet fuel at prices above the fossil fuel prices to foster the industry[51]. In addition, In the Netherlands, aviation bio-jet is also eligible for so-called "bio-tickets", tradable certificates used in the transport sector[52] that have a value of approx. 7 EUR/GJ or 25 EUR/MWh. Such trading schemes are also being considered for other EU member states and could also be used there[53].

Example of airline engagement in the biofuel industry is e.g. off-take agreements[54] by Fed EX and Southwest Airlines with Red Rock Biofuels for 3 million gallons per year each (approximately 11,000 m^3 each), thereby buying all aviation fuel produced in this 15 million gallon per year plant and by United Airlines off-take agreement[55] from Altair for 5 million gallons per year, or some 15 % of the output. Also, the US Navy has a take-off agreement for 78 million gallons of diesel at 2 USD/gallon[56]. Fulcrum Sierra Biofuels has a combination of stakeholder and off-take agreements with Cathay Pacific

[51] Business models for introduction of biofuels in aviation. SkyNRG memo for SGAB, January 2016.
[52] Voluntary RED opt-in in The Netherlands: HBEs (bio-tickets) generation with the supply of biokerosene to the national transport market. SkyNRG memo for SGAB, February 2016.
[53] High level implementation guide line for voluntary RED opt-in, per selected Member State, based on the existing system and Dutch blue print. E. Schapers, SkyNRG. Deliverable 3.14, ITAKA project. October 28, 2016.
[54] http://www.biofuelsdigest.com/bdigest/2015/07/21/fedex-southwest-airlines-combine-to-buy-entire-jet-fuel-output-of-red-rock-biorefinery-through-2024/
[55] Biofuels in Defense, Aviation, and Marine. Bioenergy Technologies Office Peer Review. Zia Haq. U.S. Department of Energy March 24, 2015.
[56] http://www.aiche.org/chenected/2016/01/us-navy-green-fleet-makes-biofuels-new-normal

(investment not known, 375 million gallons over 10 years), United Airlines[57] (30 million USD, 90 million gallons per year) and very recently also BP[58] (30 million USD, 50 million gallons per year). These volumes are based on that the Sierra Biofuels plant should be replicated in 5-8 other locations. The price in the take-off agreements is not known, but a 1 USD/gallon production cost have been stated, as the plants will be using wastes with zero cost at the gate.

Within the UN air transport industry umbrella organization ICAO, the participating states have also recently agreed on the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA)[59] as a complement to other measures in international aviation. Implementation of the CORSIA will begin with states signing up for a voluntary pilot phase from 2021 through 2023, followed by an, again voluntary, first phase, from 2024 through 2026. The third phase from 2027 to 2035 would see all states on board, with some exemptions. The average level of CO_2 emissions from international aviation covered by the scheme between 2019 and 2020 represents the baseline for carbon neutral growth from 2020. If emissions any year thereafter exceed this baseline, the difference becomes the off-setting requirement for that year i.e. CORSIA stabilizes the emissions but does not necessarily decrease the emissions, as the EU ETS system intends. The emissions can increase by the growth of the industry and hence an increased use of fuel and decrease by more efficient aircrafts, operational improvements and use of less emitting fuels, e.g. bio-jet. Initially, up to 2029, this off-set will be managed of the sector as a collective, whereas thereafter individual carriers will be responsible for 20 % of their own growth of emissions, this share to be increased to 70 % in 2035. The off-setting of any difference in emissions is planned to be performed via a market based mechanism whereby eligible emission rights in acknowledged, already operative carbon trading systems are acquired and redeemed or by carbon off-setting projects.

5.3 Bio-kerosene fuel production cost

The actual data for bio-jet production cost are scarce. For the drop-in fuels already discussed in this report, i.e. HVO installations, HEFA and gasification based FT plants (SPK), the higher requirements on a plant that has a dedicated bio-aviation fuel output is associated with an overall marginally higher investment and a loss of yield. In all cases, also such plants produce diesel and gasoline by-products in significant quantities, such that the aviation fuel cost can be expected to be in the higher part of the interval given in Section 3.1 and Section 3.3, respectively. This would imply 70-90 EUR/MWh for HEFA and 110-140 EUR/MWh for SPK. If, and when, a HFP-HEFA annex is adopted, more or less regular HVO diesel could be used and production cost would drop down into the lower part of the interval, i.e. 55-65 EUR/MWh. For the SIP pathway, starting with crop-based sugars, data from one of the co-developers[60] gives the price as 8 USD/liter (750 EUR/MWh) in 2010, 2 USD/liter (185 EUR/MWh) today with a target of 1 USD/liter (93 EUR/MWh) in the coming decade.

[57] http://www.biofuelsdigest.com/bdigest/2015/06/30/united-airlines-invests-30m-in-fulcrum-bioenergy-inks-1-5b-in-aviation-biofuels-contracts/
[58] http://www.biofuelsdigest.com/bdigest/2016/11/07/air-bp-and-bp-ventures-invest-30m-in-biojet-producer-fulcrum-bioenergy-ink-500m-gallon-10-year-offtake-deal/
[59] http://www.icao.int/environmental-protection/Pages/A39_CORSIA_FAQ2.aspx
[60] Sugar to biofuels: the roadmap, presentation slide provided for SGAB by Total

There have been many attempts to estimate the cost of bio-jet production, both regarding individual technology pathways and to compare different pathways. These also involve the less developed pathways.

One such recent attempt done by US National Renewable Energy Laboratory (NREL) is summarized in **Error! Reference source not found.**. ((For details, further data and references see the original report[61]. These authors have tried to collect data for different pathways from the feed (for vegetable oils the starting points is the seed and the oil is the intermediate))

However, this compilation based on numerous references is not very conclusive. The span in yield of bio-jet is often quite large. For HEFA and HDO, the feed is on one hand based on seeds with a convertible oil content of 30-50%, on the other hand it is based on algae biomass, dairy wastes and cooking oil with higher lipid content than the seeds. The ATJ and the SPK has a factor of 10 and 4, respectively, in the yield which is difficult to explain. The cost data does not reflect this span. Cost of production is however in line with other calculations done for the FT route. In the case of pyrolysis oil, the almost lowest yield of bio-jet product (an energy efficiency of around 15 %) gives one of the lowest product cost. The authors of this report also conclude that data is often lacking.

Another recent attempt[62] to estimate the costs used a consistent modeling approach to estimate the cost for both the FOAK and the NOAK cases, Figure 15. However, basic data on yield and investments etc. to use as inputs are based on more or less the same published data as in the previous report.

Again, pyrolysis oil but also Hydrothermal Liquefaction (HTL) come out as the low-cost alternatives together with HEFA. One reason for these surprisingly low costs are that the energy efficiency figures are very high for these pathways, 80 % and 60 % from fuel to jet for HTL and pyrolysis oil, respectively, while the specific investment cost is only some 2/3 of the FT plants. HTL is a technology at lower TRL that pyrolysis oil and FT, so the results seem speculative, and again reference should be made to the Mountain of Death graph, Figure 2.

5.4 Comments to production cost data for aviation fuels

Comment 1: ATJ via Ethanol

The market value of ethanol already lies at 70-100 EUR/MWh depending on the location, and from chapter 4.1, it is clear that cellulosic ethanol still has some ground to cover to reach such cost levels. Under such circumstances, it is not self-evident that post-processing to ATJ, at an even higher cost of production per unit of energy is motivated. This increases the gap to the competing commodity even more, and is not a strengthening of the business case. The maximum value in Table 12. Estimated yields and costs for bio-jet from a variety of feedstocks and processing routes. (Adapted from)which is 3 MWh of fuel per ton corresponds to 60% energy efficiency from biomass to aviation fuels which is theoretically not possible when proceeding via ethanol. Establishing the right incentive framework which properly rewards the investment needed to produce alternative jet fuels would correct this imbalance.

Comment 2: HDO technology from oil seeds to aviation fuels

Cost of product is considerable lower than the indicated cost of the intermediate, due to that table entries have not reported both, such that these does not reflect the evolution of cost from feed over intermediate to product

Table 12. Estimated yields and costs for bio-jet from a variety of feedstocks and processing routes. (Adapted from[61])

Category	Technology	Biomass	Intermediate Yield	Intermediate Cost	Jet Fuel Yield		Jet Fuel Cost	Notes
			l/tonne dry	€/MWh	l/tonne dry	MWh/tonne dry	€/MWh	
Alcohol to Jet (ATJ)	Ethanol to Jet (e.g. ATJ)	Corn, Corn Stover, Wood, Straw, Sugarcane, Switchgrass	Ethanol 67-442	51-173	46-330	0.4-3.0	103-362	1
	N-butanol to Jet	Corn, Corn Stover, Wheat Straw, Wood	N-butanol 129-238	94-135	96-179	0.9-1.6	103-189	
	I-butanol to Jet (e.g. ASJ)	Corn Stover, Wood Chips	I-butanol 230	121	171-200	1.6-1.8	130-162	
Oil to Jet	Hydrotreated Renewable Jet (e.g. HEFA)	Soyabean, Algae, Pongamia, palm Seed, Rapeseed, Jatropha Seed, Camelina Seed, Salicornia, Cooking Oil	Vegetable or Algae Oil 209-589	26-604	117-363	1.0-3.6	65-863	
	Catalytic Hydrothermolysis (e.g. HDO-SAK)	Algae Biomass, Siybean, Jatropha Seed, Tung Seed, Dairy Waste	Vegetable or Algae Oil 209-426	130-208	33-509	0.3-4.8	89-121	2
	Pyrolysis/ Hydropyrolysis (e.g. HDCJ)	Corn Stover, Wood	Pyrolysis Oil 209-639	22-100	79	0.7	97	3
Gas to Jet	FT (e.g. SPK)	Corn Stover, Wood	FT-Crude 184-463	84-168	38-158	0.3-1.4	156	
	Gas Fermentation	Wood, Yard, Vegetative & Household Waste	Ethanol 275-321	40	184-217	1.7-2.0	Not Available	
Sugar to jet	Catalytic APR	Corn Stover, Wood	Sugars	111-262	58-104	0.6-0.9	Not Available	
	Catalytic HMF & DMF	Fructose (to HMF and DMF)	HMF, or DMF	192-318	217-259	0.6-2.4	Not Available	
	Sugar Fermentation (e.g. SIP)	Corn Stover, Sugarcane, wood, Wheat Straw	Sugars	183	100-179	0.9-1.7	10-620	

Comment 3: Aviation fuel via pyrolysis of cellulosic materials

Biomass conversion to pyrolysis oil can be carried out with an energy efficiency of 65-70%, and the complete conversion can, based on the material discussed in Section 3.2, have an overall energy efficiency (hydrocarbons/ wood at plant gate) from 30% in co-processing to around 60 % for a stand-alone integrated plant, in the latter case not including the natural gas used for hydrogen production. Technology development status regarding this upgrading are on low TRL levels. It is therefore premature to conclude that the pyrolysis route can lead to efficient and very low cost production of aviation fuels, as proposed in **Error! Reference source not found.** and also in **Error! Reference source not found.**.

[61] Review of Biojet Fuel Conversion Technologies. Wei-Cheng Wang *et* al. Technical Report REL/TP-5100-66291 July 2016

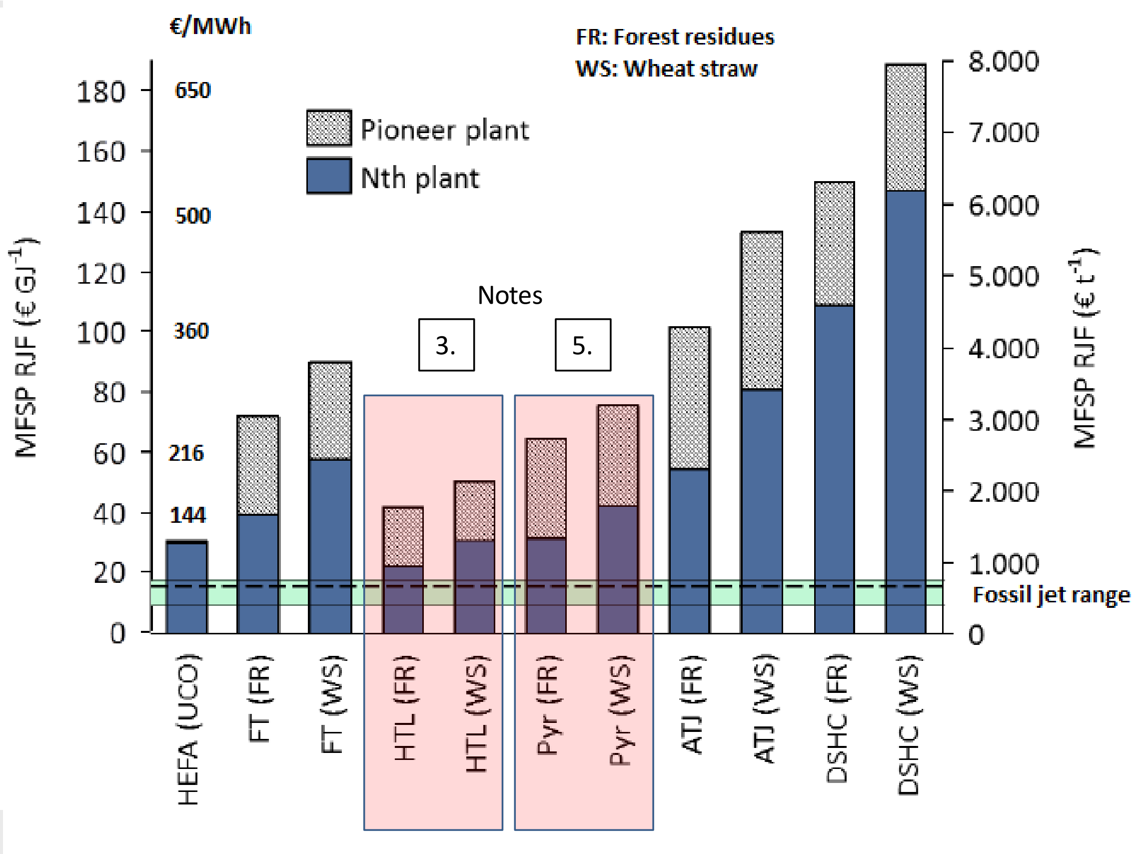

Figure 15. Estimate FOAK and NOAK minimum selling price for bio-jet (Adapted from[62]).

The table also shows a comparably low yield (0.7 MWh per dry ton of biomass which equals about 15% energy conversion efficiency) which does not support a low production cost. In this case the yield is the only number reported from seven studies, while the cost comes from other studies where cost, but not yields were reported). With a feedstock price of 10-20 EUR/MWh just the cost of feedstock in the product would account for a large fraction in the product cost bars. The estimates made in Section 3.2 also indicate that co-processing is indeed low cost at the level indicated in the blue bar, 60 EUR/MWh. However, this comes with the limitation that the FCC unit capacity would only allow production at this cost level of some 0.3-0.6 million tons maximum. To apply a stand-alone integrated plant technology to reach higher production volumes would shift the production cost to a higher value.

Comment 4 SIP from sugars

The cited authors[62] also notes that farnesene in itself has a value of over 5,000 EUR/ton as a chemical intermediate in its own right. The potential markets for farnesene are discussed in a recent report[63], where it is concluded that the opportunities in high price niche markets (e.g. squalene at 30 USD/liter) may be more attractive than in commodity fuels markets.

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62 The feasibility of short-term production strategies for renewable jet fuels – A comprehensive techno-economic comparison. De Jong et al. Biofuel, Bioprod. Bioref. 9:778–800 (2015)

63 From the Sugar Platform to biofuels and biochemicals Final report for the European Commission Directorate-General Energy N° ENER/C2/423-2012/SI2.673791. April 2015. E4TECH, RE-CORD and WUR

Comment 5 Forest biomass and straw to aviation fuels via HTL

HTL based technology is at a very early stage of development and it is questionable if a conversion route at this very early stage should be shown in the same picture as conversion pathways where technology is available although at cost and efficiency levels which seems to be less attractive than the HTL based (or pyrolysis oil based) route. According to the authors of this report data cannot be directly compared.

Comment 6 Aviation fuels from FT

The cost of aviation fuels from FT in **Error! Reference source not found.** deviates from our estimates by being significantly higher than what presented in section 3.1. This probably relates to that in the cited paper the conversion factor in the cited paper from wood to fuel seem to be lower than what we have used.

6 Comparison of the results and discussion

To assist the reader of the report to link resources, conversion pathways or technologies, their readiness in view of market deployment and the possible products for use in the market, the SGAB has developed the Table 13"*Classification of BIO, Low Carbon Fossil Fuels, e- & Hydrogen Transport Fuels*". The SGAB does not claim that this table covers all resources, all conversion pathways or technologies and all possible fuels, or that the technology readiness is accurately representing all possible variations. However, the SGAB is of the opinion that the table is a good reference for discussion amongst all stakeholders.

6.1 Production Cost Summary

Data released to the SGAB groups in documentation as described in Chapter 2 has been investigated and commented by the authors and by SGAB members. The resulting set of data has been compared with relevant data recently released in a report by IRENA (International Renewable Energy Agency) named *INNOVATION OUTLOOK, Advanced Liquid Biofuels*[64] and are summarized in Figure 16. The result is shown as follows:

- Original data from Chapter 2 in red,
- Adjusted data from the authors and the SGAB group in green

Data from the referred UN International Renewable Energy Agency (IRENA) report in blue.

[64] http://www.irena.org/DocumentDownloads/Publications/IRENA_Innovation_Outlook_Advanced_Liquid_Biofuels_2016.pdf

Table 13. Classification of BIO, LCFF, e- & Hydrogen Transport Fuels

Classification of BIO, LCFF, e- & Hydrogen transport Fuels					
	Raw Material	**Technology**	**Type of Biofuel**	**Status TRL[1]**	**Application**
Conventional	Sugar*	Fermentation	Ethanol	Commercial	Gasoline blend, E10, E85, ED95[£], upgrade to biokerosene
	Starch*				
	Vegetable oils*	Esterification or Transesterification	FAME/Biodiesel		Diesel blend, B7, B10, B30, 100%
	Fats				
	Food Crops	Biogas Production & Removal of CO2	Biomethane		100% heavy duty transport, Flexy Fuel Vehicles, captive fleets, injected in the gas grid
Advanced	Waste streams of oils & fats	Esterification or Transesterification	FAME/Biodiesel	Commercial	Diesel blend, B7, B10, B30, 100%
	MSW[2], sewage sludge, animal manures, agricultural residues, energy crops	Biogas or Landfill production & removal of CO_2	Biomethane		100%in heavy duty transport, flex fuel vehicles, captive fleets, injected in the gas grid.
	Vegetable oils*, fats, Used Cooking Oils, Liquid waste streams & effluents[7]	Hydrotreatment	Hydrogenated		Diesel drop in or 100%, bio-kerosene[$]
	Lignocellulosics	Enzymatic hydrolysis + Fermentation	Ethanol	TRL 8-9	Gasoline blend, E10, E85, ED95, upgrade to biokerosene
			Other Alcohols	TRL 6-7	
	MSW, solid industrial waste streams/residues[3]	Gasification + Fermentation	Ethanol	TRL 6-7	
	Lignocellulosics, MSW, Liquid Industrial Waste streams & effluents[5] or Intermediate Energy Carriers[6]	Gasification + Catalytic Synthesis	Synthetic[4]	TRL 6-8	Depends on fuel type; can be used for blends or drop-in with diesel, gasoline, kerosene, bunker fuel or as pure biofuel e.g. BioSNG, DME, MD95
	Algal Oils[8] and other non-food oils	Hydrotreatment	Hydrogenated	TRL 4-5	Diesel drop-in or 100%, bio-kerosene
		Esterification	FAME/Biodiesel	TRL 5-6	Diesel blend, B7, B10, B30, 100%.
	Pyrolysis Oils from lignocellulosics, MSW, waste streams	Hydrotreatment	Hydrotreated	TRL 5-6	Diesel drop-in or 100%
		Co-processing in existing petroleum refineries[9]	Petrol, Diesel, Kerosene	TRL 5-6	All of the above
	Non-lignocellulosic biomass (algae, non-food biomass)[10]	Various as above	Petrol, Diesel. Methane, Hydrogenated	TRL 4-5	Various as above
	Sugars [11](cellulosic, non-food)	Microbial	Petrol, Diesel, Kerosene	TRL 4-6	Diesel drop-in or 100%, bio-kerosene
	Supply of waste/byproducts gases	**Technology**	**Type of Biofuel**	**Status**	**Application**
Low Carbon Fossil Fuels	Steel & Chemical Industry	Fermentation	Ethanol	TRL 6-7	Gasoline blend, E10, E85, E95
		Upgrading & Catalytic Synthesis	Methanol	TRL 5-6	Shipping, Blends with gasoline, M95, M100
			Methane	TRL 5-6	100% in heavy duty transport, Flex Fuel Vehicles, captive fleets injected in the gas grid.
	Waste Polymers, Plastics, non-biodegradable fraction of MSW	Gasification + Catalytic Synthesis	Synthetic[4]	TRL 6-8	Depends on fuel type; can be used for blends with diesel, gasoline, kerosene, drop-in
	Supply of H_2	**Technology**	**Type of Biofuel**	**Status**	**Application**
e-Fuels	RES electricity	Catalysis	Methanol	TRL 5-6	Shipping, blends with gasoline, M95, M100
			Methane		100% in heavy duty transport, Flex Fuel Vehicles, Captive Fleets, injected in the gas grid
			Synthetic[2]		Depends on fuel type; can be used for blends with diesel, gasoline, kerosene, drop-in

*Capped by ILUC

[£] ED95: 95% hydrous ethanol + additives for medium & heavy duty transport

[$] There is always also a smaller fraction of gasoline (nafta) from Hydrotreatment processes.

[1]Technology Readiness Level, http://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf, as of medio 2016. Needs dedicated financial mechanisms: Note: Value chains at low TRL need financial support for longer duration while value chains at high TRL need financial support for relative shorter period, however, the financial support for high TRL technologies is by order of magnitude higher than that of low TRL per project. This is due to the high investment costs for the hardware or "steel in the ground".

[2]Municipal Solid Waste biodegradable fraction

[3]Waste fibres

[4]Synthetic biofuels are produced from the catalytic synthesis of CO+H2 and can be:
Liquid: ethanol, methanol, Fischer Tropsch (diesel replacement), dimethyl ether (LPG replacement or 100% in vapour phase),
Gas: biomethane,

[5]E.g. tall oil, black liquor

[6]Pyrolysis oils

[7]Waste streams from food industry, or pulp & paper (tall Oil)
[8]Oils extracted from algae
[9]In co-processing the bio component ends up in all output streams of the refinery
[10]Algae: they can be used as biomass in gasification processes or anaerobic digestion or extract algal oils and therefore can produce all types of biofuels
[11]Produced from lignocellulosic biomass, MSW and other waste streams
[12]The ethanol, methanol or methane have to be bio- or RES-

A summary of each type of fuel follows after a summary chapter covering the investment intensity of various production pathways.

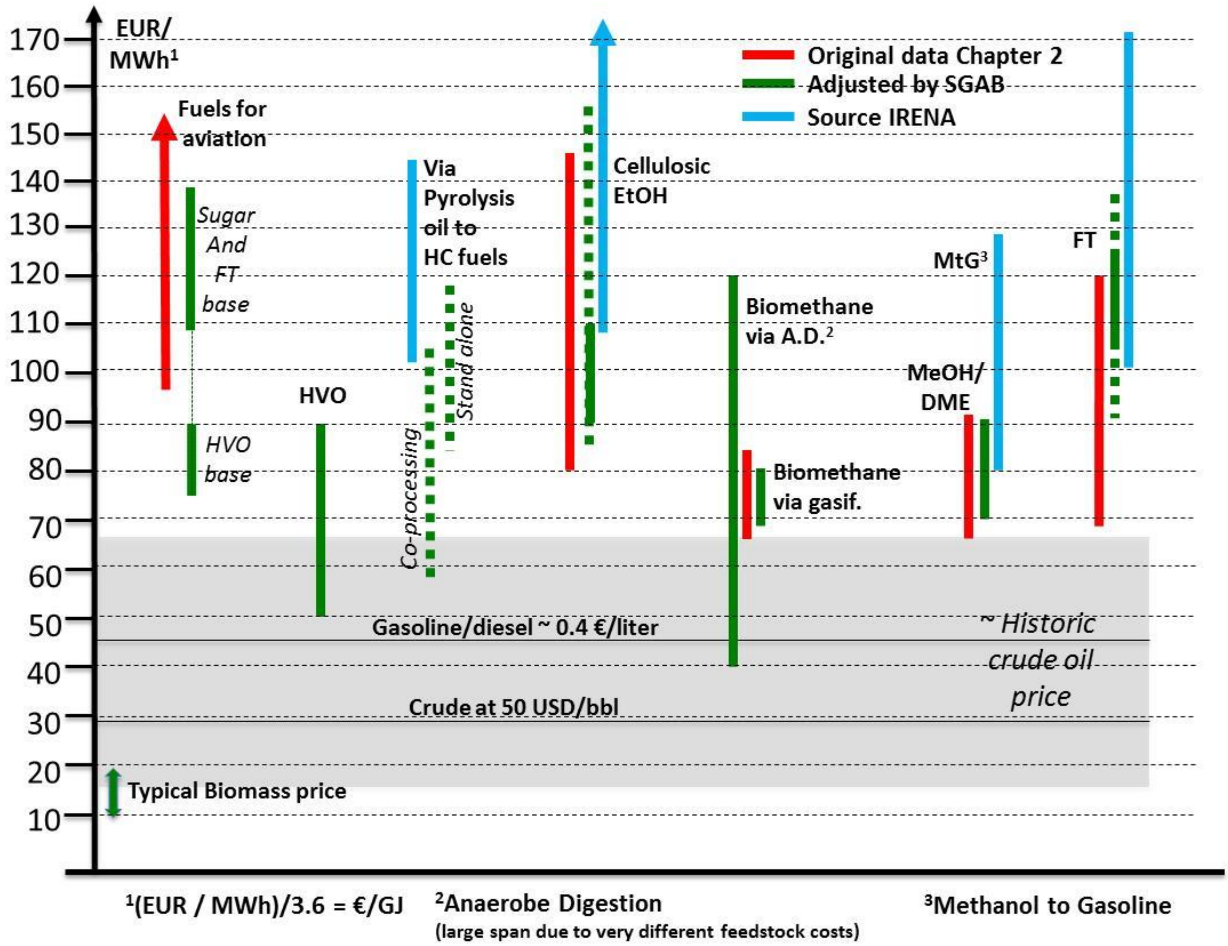

Figure 16. Summary of production cost data

6.2 Plant investment

Plant investment plays a major role when building up the overall production cost of a certain biofuel. Different conversion routes show large variations with respect to capital burden and this is most easily seen by comparing investment intensity, here defined as investment per produced kW of fuel energy. Low investment intensity combined with high conversion efficiency (minimizing effect of increased feedstock prices) leads with few exceptions to low overall production costs.

Thermochemical conversion plants need to build larger in capacity to benefit of economy of scale. These plants have however comparably high conversion efficiencies meaning that the upstream end of the plant handles comparable low volumes of feedstock. A plant producing 200 MW of product with 65% energy efficiency consumes about 300 MW of feedstock. An ethanol plant producing 80 MW of product with 40% efficiency consumes 200 MW of feedstock, 2/3 of the flow consumed by the plant producing more than double the amount of product at high conversion efficiency. Figure 17 shows investment intensity for different biofuels production processes.

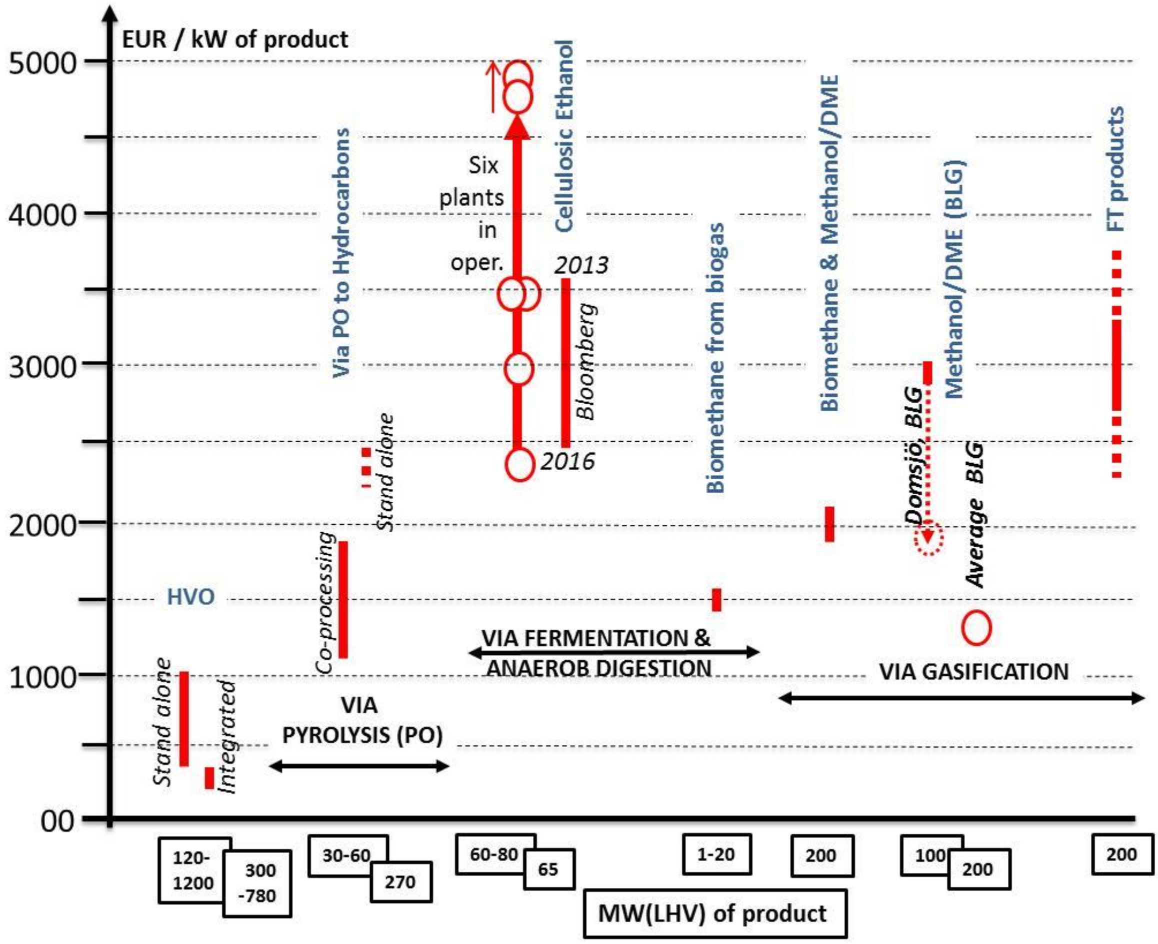

Figure 17. Investment intensity for different conversion routes (EUR per kW of product)

Plant capacities in MW are shown at the bottom of the figure. HVO plants are comparably large installation with production capacities over 1000 MW. Cellulosic ethanol plants are typically in the 60-80 MW range (65,000 to 85,000 t/year ethanol production) while gasification based technologies often are planned in sizes around 200 MW (100 – 300 MW). Bio-methane via anaerobic digestion, on the other hand are smaller, typically below 20 MW product.

The capital intensity for 2G ethanol plants and gasification based plants producing FT products are of similar magnitude in relative terms, so in this sense gasification is not a more expensive technology. However, in absolute terms the investment differs. As an example: A 65 MW (70,000 t/y) ethanol plant costs 65 x 3,000,000 resulting in 195 MEUR if the investment intensity is 3,000 EUR/kW. For comparison, an FT plant of 200 MW FT plant, i.e. of three times the output capacity, is estimated to have approximately the same investment intensity and would therefore cost 600 MEUR., The total investment in absolute numbers is considerably higher, and this may also influence the perceived risk of making such an investment. Biomethane (via gasification) and methanol plants on the other hand are estimated to have investment intensity at a level of 2/3 of the two these two production routes just mentioned and a 200 MW biomethane plant would thus only cost 400 MEUR.

6.3 Synthetic long chain hydrocarbons via the FT route

The result from the review shows a trend towards higher production cost than originally proposed. The lower end of the original interval (70-80 EUR/MWh) is very difficult to support. The total interval identified (91-139 EUR/MWh) is on the other hand very wide and there are logic reasons to claim that the extreme data are less probable (a product cost estimate combing the highest values in the interval of investment, OPEX and fuel cost contribution). As examples (see data in Table 13**Error! Reference source not found.**): In a high-level investment scenario it is likely that conversion efficiency to sellable products is high and therefore high investment numbers should be combined with lower feedstock costs. Other O&M costs are proportional to investment which will keep that part of the cost high, but a high investment could mean that the ASU is within battery limits, and lower OPEX than if oxygen is bought over the fence. In a corresponding way if investment is kept low the conversion efficiency is low (feedstock costs high) and other O&M is low following the investment. Average numbers for investment and feedstock costs are also a logic scenario. These three alternatives identify the interval 105-120 EUR/MWh of product and are shown as a solid bar in Figure 16. There can be specialty solutions where special products from the FT synthesis can generate a credit for the overall production cost level but such solutions can only affect the overall result marginally.

The single most important independent variable which would influence the overall production cost is feedstock price. This report has mostly used 20 EUR/MWh as delivered price at plant gate. A 10 or 15 EUR/MWh price would lower cost of feedstock in the final product cost from the interval 36-50 EUR/MWh to 18-25 EUR/MWh or 27-38 EUR/MWh respectively. As an average impact, it could lower the total production cost to 90-105 EUR/MWh.

The quoted IRENA report presents a higher and very wide production cost interval with its lower part being in line with the identified range above, 105-120 EUR/MWh.

FT liquids Production costs
Feedstock price at 20 EUR/MWh.
Production cost range: 105-125 EUR/MWh or 29-35 EUR/GJ

Feedstock price at 10-15 EUR/MWh
Production cost range: 90-105 EUR/MWh or 25-29 EUR/GJ

6.4 Oxygenates such as methanol and DME and biomethane

Result from this review shows good agreement with the original proposed production cost range. The identified production cost interval is between 71 and 91 EUR/MWh.

The single most important independent variable which would influence the overall production cost is feedstock price. This report has mostly used 20 EUR/MWh as delivered price at plant gate. A 10 or 15 EUR/MWh price would lower cost of feedstock in the final product cost from the interval 31-33 EUR/MWh to 16-17 EUR/MWh or 23-25 EUR/MWh respectively. As an average impact, it could lower the total production cost to 56-75 EUR/MWh.

Production cost of methanol through Black Liquor Gasification (BLG) in pulp mills can due to low investment intensity and high energy conversion efficiency be accomplished at 69 EUR/MWh and somewhat lower at lower feedstock prices as per previous paragraph.

The IRENA reference indicates higher production cost (80-130 EUR/MWh) but this is for production of synthetic gasoline via methanol (MtG) and DME routes. Elimination of the last stage (methanol/DME to gasoline) will lead to substantial decrease of the investment as well as increased yield and would thus lower the indicated interval to harmonize with production cost level of the single molecule cases (methane, methanol and DME) or even below.

Waste gasification to methanol or ethanol has a potential for low or even very low production costs depending on what net tipping fee the plant can credit to its cost of production. With a conversion efficiency of 50% waste to product and a net tipping fee of 12.5 EUR/MWh (55 EUR/ton and energy content of 4.4 MWh/ton) of feedstock the overall production cost is estimated to be 82 EUR/MWh. Lower energy content per ton (but with same 55 EUR/ton credit) will increase credit to the production cost and so would of course higher net tipping fee. Also, lower conversion efficiency (using more tons of credited feedstock per product MWh of product) would also decrease the total cost of production. These variables are company secrets and this report does not expect to get these numbers published. Smaller deviation in positive direction of one or more of the mentioned variables would easily move the total cost of production 10-20 EUR/MWh lower.

Biomethane, methanol and DME production costs (from biomass)
Feedstock price at 20 EUR/MWh.
Production cost range: 71-91 EUR/MWh or 20-25 EUR/GJ

Feedstock price at 10-15 EUR/MWh
Production cost range: 56-83 EUR/MWh or 16-21 EUR/GJ

Methanol and Ethanol production costs (from waste)
Base: Net tipping fee of55 EUR/ton, energy content of 4.4 MWh/ton,
Conversion efficiency of 50%
Production cost: 67-87 EUR/MWh or 19-24 EUR/GJ

6.5 Upgrading of pyrolysis oil

In the originally proposed graph, Figure 4, there was no data for pyrolysis upgrading.

The technology for generating pyrolysis oil is being demonstrated at present I Finland, the Netherlands and Canada at the scale of 20,000- 50,000 tons of bio-oil, i.e. below 50 MW.

Two routes have been pursued for the upgrading, either as a stand-alone plant, i.e. the upgrading is fully integrated with the pyrolysis plant, or off-site and then preferably in co-processing with fossil fuels in a fossil refinery. The potential for refinery upgrading is limited to the refineries with suitable technologies (FCC, hydrocracking etc.). The blend-in rate of into the fossil streams in such refineries is therefore in practice limited to a magnitude of 2-10%. The availability of FCC units also imposes a limit for the volume that can be expected from the co-processing route to 1-2 million tons in the North and West Europe, including the EU.

Both routes have significant technical challenges, and the stand-alone, integrated route has only been pursued at laboratory scale this far, i.e. below TRL 5. The co-processing route has been explored in pilot tests in a refinery in Brazil, and will be tested also by Valero in California. The figures given below then give very indicative production costs for co-processing and for the integrated stand-alone facility.

The cost of producing biofuels for transport via pyrolysis and co-processing in a refinery has an efficiency of below 30%, but also has a low estimated cost 58-104 EUR/MWh. There is also a limitation to 1-2 million tons of drop-in based on the available FCC capacity in Europe.

For a large, fully integrated stand-alone plant with an output of 272 MW, the production cost was 83-118 EUR/MWh. No adjustments for investment cost differences between USA and the EU has been made, and one substantial cost item is natural gas for which no price correction have been done.

Pyrolysis bio-oil upgrading
Co-processing
Feedstock price at 10-20 EUR/MWh.
Production cost range: 58-104 EUR/MWh or 14-27 EUR/GJ

Stand-alone
Feedstock price at 10-20 EUR/MWh
Production cost range: 83-118 EUR/MWh or 23-33 EUR/GJ

6.6 Hydrotreated Vegetable Oils (HVO)

The originally proposed graph, Figure 4, did not include any data for HVO production cost. HVO plants are commercially available at 0.05 to 1 million (metric) tons per year output. There are stand-alone plants built specifically for the purpose of HVO, revamps of existing refineries to produce HVO and revamps to allow co-processing of HVO with fossil streams in existing refineries. The nature of the plant and its capacity has a high impact on the investment cost. Nevertheless, the dominating cost, 65-80 %, is the contribution of the feedstock cost.

The estimated cost of production falls in the range 600- 1,100 EUR/ton, or approx. 50-90 EUR/MWh. Feedstocks such as UCO, yellow grease etc. have a cost of 400- 600 EUR/ton according to the sources reviewed but the cost of other potential feeds like tall oil is less readily available.

HVO liquids Production costs
Feedstock price at 40 EUR/MWh.
Production cost range: 50-70 EUR/MWh or 14-19 EUR/GJ

Feedstock price at 60 EUR/MWh
Production cost range: 70-90 EUR/MWh or 19-25 EUR/GJ

6.7 Ethanol from lignocellulosic sugar via fermentation

The result from the review shows a positive learning curve where more recent sources indicates production cost at the lower end of the originally presented interval corresponding to 85-110 EUR/MWh of ethanol. The review shows clearly that overall investment via the cost of capital and the cost of feedstock influences the production cost most. The full interval identified (85-158 EUR/MWh) is very wide and the three mentioned components are the ones to focus in order to keep production cost down.

As examples (see data in Table 8): With investment at the lower end of identified data and with a lower payback demand on investment, the cost of capital element in the production cost is reduced from 60 to 32 EUR/MWh. Due to comparably low conversion efficiency of the technology (40% used in these calculations, already in the higher end of the state-of-the-art) cost of feedstock has a major impact and reducing cost from 20 to 10 EUR/MWh lower the feedstock element in the production cost with 25 EUR/MWh.

The IRENA reference indicates a higher cost of production then has been identified from the work with this report.

Cellulosic ethanol production costs
Feedstock price at 13 EUR/MWh and investment at low end of estimates
Production cost: 103 EUR/MWh or 29 EUR/GJ

Feedstock price at 10 EUR/MWh, investment low combined with decreased payback pace
Production cost: 85 EUR/MWh or 24 EUR/GJ

6.8 Biomethane via anaerobic digestion

In the original graph, Figure 4, biomethane via fermentation was only added as a point at 85 EUR/MWh. In the present analysis of the production costs falls within 40-120 EUR/MWh but this is explainable. There is a large variety of substrates available for biogas plants, waste or energy crops and straw, alone or in combinations. The feedstock cost could therefore range from negative up to the cost of straw, e.g. up to 100 EUR/ton. The specific investment cost is of the order of corresponds to around 1,500-2,000 EUR/kW, i.e. between HVO and the 2G technologies. Anaerobic digestion technologies for upgrading to bio-methane are in general in the range of 1-20 MW output. There are considerable scale effects on the cost, and for these relatively small plants scale effects also influences the OPEX more than for larger plants.

Bio-methane production cost
Substrate cost at 0-80 EUR/ton.
Production cost range: 40-120 EUR/MWh or 11-34 EUR/GJ

For a feedstock associated with cost, also the methane potential affects the cost, such that no simplified estimate can be given.

6.9 Aviation fuels

With the exception of HEFA and the SIP process starting from sugars, and to some extent the better-known FT process, cost and performance data for other technology pathways to bio-jet are so uncertain and the global processing pathway not sufficiently developed to really assess their potential. It seems highly unlikely that the HTL and pyrolysis processes, including the upgrading of the intermediate products really has the economic benefits that results from studies pretend.

Cost of Aviation Fuels Production

<u>Via HEFA</u>

80-90 EUR/MWh (potentially lower if HEFA+ annex is approved)

<u>For SIP (sugar fermentation) and SPK (via FT synthesis)</u>

110-140 EUR/MWh