Advanced drop-in biofuels

UK production capacity outlook to 2030

Final Report

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E4tech (UK) Ltd for Department for Transport

in partnership with TRL, Temple and Scarlett Research

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List of acronyms

1G	First generation, conventional food crop-based biofuels
2G	Second generation, waste & residue-based biofuels
ABDC	Advanced Biofuel Demonstration Competition
ABE	Acetone, butanol, ethanol
AD	Anaerobic digestion
APP	Advanced Plasma Power
APR	Aqueous phase reforming
ATD	Alcohol-to-diesel
ATJ	Alcohol-to-jet
BEIS	Department for Business, Energy & Industrial Strategy
BMW	Biodegradable municipal waste
BTL	Biomass to liquids
CCC	Committee on Climate Change
CO	Carbon monoxide
CO_2	Carbon dioxide
DECC	Department for Energy & Climate Change (now part of BEIS)
DfT	Department for Transport
DME	Dimethyl ether
EBRD	European Bank for Reconstruction & Development
EBRI	European Bioenergy Research Institute
EfW	Energy from waste
EPSRC	Engineering and Physical Sciences Research Council
ERDF	European Regional Development Fund
ETBE	Ethyl tert-butyl ether
ETD	Ethanol-to-diesel
ETI	Energy Technologies Institute
EU	European Union
EWP	Essex Waste Partnership
FCC	Fluid catalytic cracker
FQD	Fuel Quality Directive
FT	Fischer-Tropsch
GB	Great Britain
GHG	Greenhouse gas
GM	Genetically modified
GMWDA	Greater Manchester Waste Disposal Authority
H_2	Hydrogen
HDO	Hydrodeoxygenation
HGV	Heavy goods vehicle
HTL	Hydrothermal liquefaction
HVO	Hydrotreated vegetable oil
ICAO	International Civil Aviation Organization
IEA	International Energy Agency
ILUC	Indirect land use change
IP	Intellectual property
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre (European Commission)
LC	Lignocellulosic
LHV	Lower Heating Value
LPG	Liquefied petroleum gas
LWP	Lancashire Waste Partnership
MBT	Mechanical biological treatment
MRWA	Merseyside Recycling and Waste Authority
MS	Member State (EU)
MSW	Municipal solid waste
MTBE	Methyl tert-butyl ether
MTG	Methanol-to-gasoline
NASA	National Aeronautics and Space Administration
NL	The Netherlands
NPIF	National Productivity Investment Fund
NREL	National Renewable Energy Laboratory

NRMM	Non-road mobile machinery
odt	Oven dry tonnes
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
RFNBO	Renewable fuel of non-biological origin
RDF	Refuse derived fuel
RED	Renewable Energy Directive
RFS	Renewable Fuel Standard (USA)
RHI	Renewable Heat Incentive
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RTFC	Renewable Transport Fuels Certificate
RTFO	Renewable Transport Fuel Obligation
SOM	Stabilised organic material
SRF	Solid recovered fuel
TRL	Technology Readiness Level
(TRL	Transport Research Laboratory)
TUHH	Technical University of Hamburg
UCO	Used cooking oil
UK	United Kingdom
USA	United States of America
VGO	Vacuum gas oil
WLWA	West London Waste Authority
WWT	Waste water treatment

List of units

Unit	*Definition*
GJ	Gigajoule
ktpa	Kilo tonnes per annum
MJ/kg	Megajoule per kilogram
ML(/yr)	Million litres (per year)
Mtoe(/yr)	Million tonnes of oil equivalent (per year)
Mtpa	Million tonnes per annum
p/l	Pence per litre
PJ	Petajoule
$/bbl	US Dollar per barrel

Glossary of terms

Acidity	The amount of acid present in a solution, often expressed in terms of pH
Alcohol to jet	A conversion process in which alcohols undergo dehydration, oligomerisation and hydrogenation in order to produce a replacement paraffinic jet fuel
Biomass	Material that is biological in origin, being derived from living, or recently living organisms
Capital costs	A fixed, one-off expense incurred to acquire, develop or construct a fixed asset (such as a conversion plant). Often referred to as capex
Dehydration	The loss of water as a result of a chemical reaction. Reverse reaction to hydrolysis
Distillation	A process used to separate a (pure) component substance from a liquid mixture by selective evaporation and condensation
Efficiency (conversion)	The ratio between fuel produced (output) and feedstock (input), in LHV energy terms
Feedstock	Renewable matter of biological origin that may be directly combusted as a fuel, or converted to a fuel product
Fermentation	A metabolic process that converts carbohydrates (starch, sugar) to acid, gas or alcohol using yeasts and/or bacteria
Gasification	A thermochemical process that converts carbon-containing materials to syngas at high temperature and pressure and with a controlled amount of oxygen and/or steam
Hydrocracking	A catalytic process used in refineries to convert or upgrade heavy oil fractions to high quality gasoline, diesel and jet fuel, with the addition of hydrogen gas
Hydrotreating	A process used in refineries to reduce or remove contaminants (such as sulphur, nitrogen and aromatics) to prepare the fuel for further processing or blending
Hydrolysis	A chemical reaction which breaks the bond in a molecule by the addition of water, to decompose the original molecule into smaller chemical units
Lignin	A complex organic polymer found in the cells and cell walls of vascular plants. It binds cellulose fibres, and contributes to the structure of the plant
Lignocellulose	A major structural component of woody and non-woody plants, consisting of carbohydrate polymers (cellulose and hemicellulose) and lignin
Oligomerisation	A chemical process that convert a monomer or monomer mixture to an oligomer through polymerisation
Operational and maintenance costs	The expenses incurred for any operational or maintenance activity (in a plant). Often referred to as opex
Polymerisation	An addition reaction in which two or more molecules join together to produce a single product (polymer)
Pyrolysis	The controlled decomposition of organic material at high temperatures in the absence of oxygen, to produce oil, syngas and charcoal
Syngas	Gas produced from the gasification of biomass, composed mainly of hydrogen and carbon monoxide, along with carbon dioxide and other impurities
Viscosity	A fluid property which indicates the degree of resistance to gradual deformation by shear stress or tensile stress (i.e. resistance to flow)
Yield (conversion)	The amount of product produced per amount of feedstock. It is most commonly given as the volume of product specific production per kg of feedstock supplied to the system

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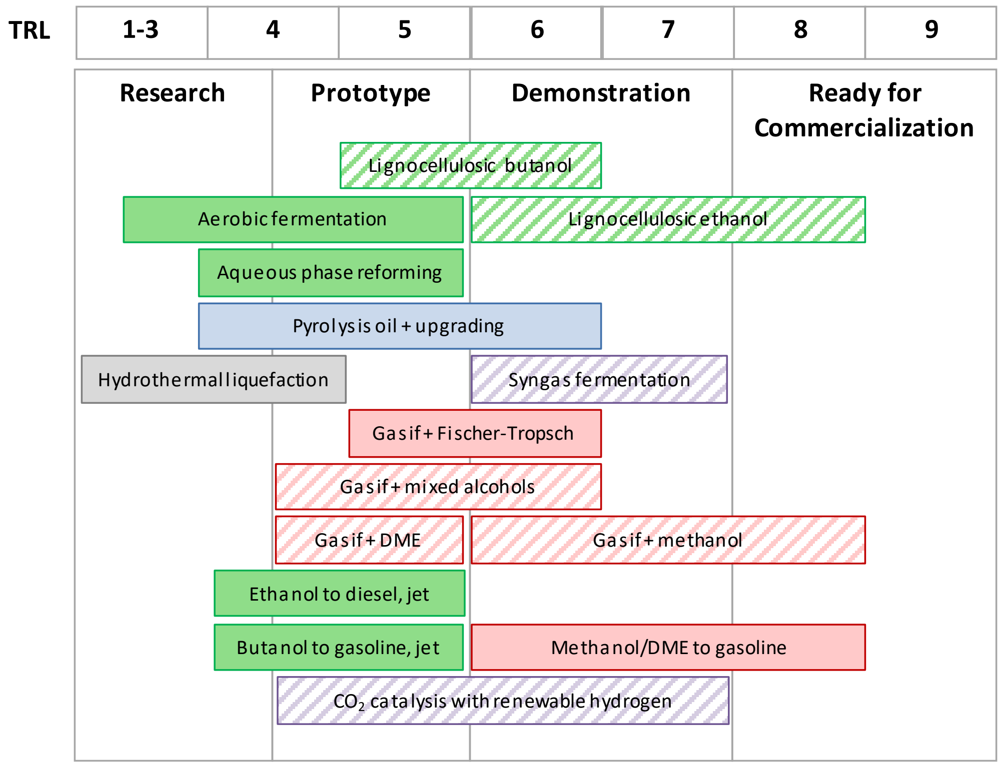
Executive Summary

Under the Climate Change Act 2008, the UK has ambitious decarbonisation targets, which aim to reduce greenhouse gas emissions by 57% (from 1990 levels) by 2030 and by at least 80% by 2050. Decarbonisation across all transport segments and modes will be vital in order to meet these targets, and it is likely that advanced biofuels will form a key part of transport decarbonisation. Advanced drop-in biofuels, defined here as long chain hydrocarbons derived from biomass wastes and residues, which are able to substitute diesel, gasoline and jet fuel without infrastructure or vehicle changes are particularly attractive to segments of the transport sector which are difficult to decarbonise via electrification, such as shipping, aviation and heavy duty road vehicles.

Technology

There are multiple technology platforms potentially suited to the conversion of waste and residue feedstocks (or the intermediates derived from these feedstocks) into long-chain, drop-in hydrocarbon fuels, such as diesel, gasoline and jet. However, in general, these technologies are at an earlier development stage than other advanced biofuels, such as lignocellulosic ethanol, and there are only a handful of developers active within each technology.



Technology Readiness Level (TRL) of different advanced biofuel technologies

Technology global commercialisation estimates, leading developers and key challenges

Technology	TRL (with 2G feedstocks)	Possible date for 1st commercial-scale plant	Leading developers	Key technical challenges
Gasification + FT synthesis	TRL 5-6	2020-2021	Kaidi, Joule, Fulcrum, Velocys	Consistent syngas quality, plant thermal integration
Fast pyrolysis + upgrading	TRL 5-6	2020-2022	Envergent, BTG, Cool Planet, CRI	Catalyst deactivation and coking, low carbon conversion
Catalytic conversion of 2G alcohols	TRL 5	2022-2023	Swedish Biofuels, Gevo, Sundrop	Reactor thermal control, catalyst deactivation and recycling to improve yields
Aerobic fermentation of 2G sugars + upgrading	TRL 5	2022-2024	Amyris, Global Bioenergies	Microbe adaptation to 2G sugars, low yields
Aqueous phase reforming of 2G sugars + upgrading	TRL 4-5	2023-2024	Virent/Tesoro	Catalyst selectivity, co-refining unproven
Hydrothermal liquefaction + upgrading	TRL 4	2024-2026	Licella, SCF Technologies, Biochemtex	Waste water recycling, carbon losses, co-refining unproven

Feedstock

The assessment of UK waste and residue feedstock potential indicates that the greatest opportunities currently for locally available supplies are the biogenic fraction of household, commercial and industrial wastes; straw from cereal cropping; and the co-products and residues of the timber value chain. Due to a significant number of competing plants (such as EfW incinerators) which are anticipated to come online between now and 2020, it is anticipated that feedstock access will become increasingly challenging. So, while there should be sufficient feedstock available in the UK for early deployment of advanced biofuel plants, the potential is expected to become significantly more constrained in the period to 2030. Longer term deployment in the UK would therefore need to rely more on feedstock imports, or switching feedstock use from power to biofuel applications.

Summary of estimated UK feedstock availability (Mtpa, dry)

Feedstock	2015 production	2015 availability after competing uses	Change in availability (after competing uses) to 2030
Municipal solid waste (biogenic fraction)	25	7.3	↓↓ with recycling and EfW plants
Straw	9.9 – 10.4	3.4 – 5.1	↔ only modest new competition
Wet manures	3.3 – 4.2	>3.0	↔ some new AD plants
Forestry residues	1.35 – 2.1	~1.1	↑ (but may decline after 2030)
Wood waste	4.5 – 5.0	0.0 – 3.0	↓ with new competition
Other wastes and residues	0.25	~0	↔ still minimal
Imported forestry	~20 available	~13	↓ with new coal conversions
Imported agricultural residues	~25 available	~25	↔ few expected users

Key: Little change in availability ↔ Increased availability ↑ Decreased availability ↓

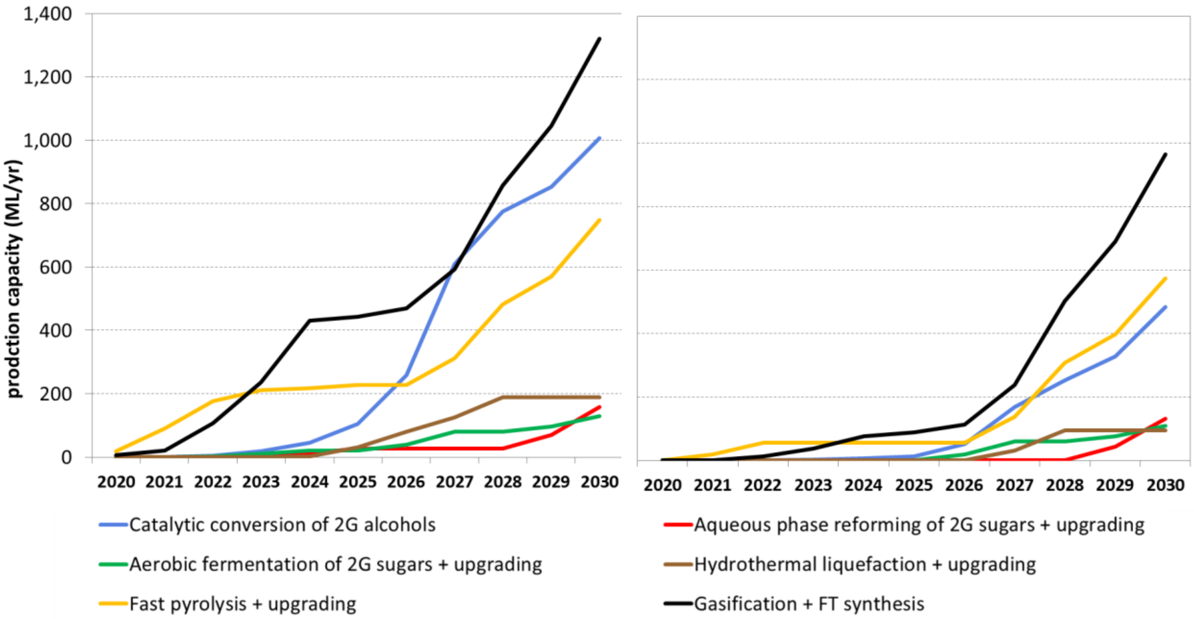
Non-technical barriers

Projects using the technologies and feedstocks discussed above face a number of non-technical barriers. The supply side barriers with the highest impact are related to **project finance**, particularly for advanced biofuels looking to transition from demonstration to first commercial plants. In general, the industry is considered to be a high risk investment, given past failures, high capital costs and reliance on policy support, whereas since 2008 lenders have been more risk-averse, and preferring shorter-term investments. Government support is necessary across the technology development levels, and is still needed at higher TRL levels to help mitigate the high risks to private investors because of the capital intensive nature of the sector.

On the demand side, there are a number of high impact barriers related to **policy and markets**. Most notably, the absence of clear, stable, long-term bankable policy frameworks will hinder the development of the advanced biofuels industry. There will also need to be a recognition that different transport segments such as aviation, marine and road face different challenges and the policy frameworks will need to account for these differences. Continued low oil prices since 2014 have led to the cancellation or suspension of several advanced biofuel projects, and some developers have shifted their focus towards higher value applications instead of biofuels.

Production capacity

A ‘realisable maximum’ or best case scenario broadly assumes an environment in which technology and feedstock development are supported by stable, long-term and sufficiently attractive policy support, plus widespread availability of finance. However, industry growth rates are still limited by the small number of technology developers in each route, as well as the time required to scale up and demonstrate reliable operation of each technology. Those technologies that achieve the greatest capacity globally by 2030 are those with the highest TRL (gasification + FT, pyrolysis + upgrading), or those able to be scaled up the fastest (catalytic conversion of 2G alcohols). Those technologies with the lowest total capacity by 2030 are those at the lowest current TRL, or with the fewest developers.



Projected global (left) and UK (right) capacity ramp-up to 2030 in a 'realisable maximum' scenario

To test what the maximum realisable potential could be in the UK, this study makes the hypothetical assumption that all suitable technology developers proceed with their current demonstration and commercial projects, but site their subsequent commercial plants in the UK. This would only occur if the UK offers an extremely attractive environment, better than that available elsewhere in the world in terms of financing, infrastructure and long-term policy support, and overcomes any cost disadvantages that the UK faces versus other world regions with cheaper feedstocks and labour (i.e. ensuring UK production and not just importing of biofuel). In this best case scenario, the UK could then possibly attract up to around 20 plants (some of these as refinery retrofits) by 2030, representing 65% of the total global capacity of advanced drop-in biofuels by 2030. This 1.9 Mtoe/yr is 3.5% of the 2014 UK transport fuel demand, and would require in the order of 9.0 million dry tonnes of biomass feedstock (depending on the conversion yields achieved), which is likely to require some level of feedstock imports by 2030.

Policy considerations

Current policy is unlikely to lead to investment in UK production for the advanced drop-in biofuel technologies within the scope of this study. With this in mind, and considering competing global policy mechanisms, a number of policy considerations, which focus in particular on the proposed RTFO development fuels sub-target, emerge:

- Competition from other higher TRL development fuels could be overwhelming, leaving no space in the mandate for advanced drop-in biofuels. Policy mechanisms would need to be designed so as to allow advanced drop-in biofuels to supply in line with their potential

- There needs to be greater clarity about how the policy framework will extend beyond 2030, including the fact that a fixed blending percentage will lead to declining fuel volumes and energy. This is particularly important as Renewable Transport Fuel Obligation (RTFO) targets do not currently appear to reflect CCC carbon budgets
- The development fuel buy-out needs to be set at an appropriately high value, and there should be clarity around the risks of changes to the sub-target, as this would affect the buy-out
- The use of advanced drop-in biofuels in aviation and marine sectors is likely to require an enhanced level of support or a separate obligation relative to road transport fuels
- Existing financial incentive schemes and infrastructure development initiatives should cover advanced drop-in biofuel projects, and this support made clear

The extension, adaptation or introduction of other complementary policies and mechanisms (such as the Motor Fuel greenhouse gas (GHG) reporting regulations, the waste hierarchy, and fiscal support measures) could provide additional incentives to increase the production and use of advanced drop-in biofuels within the UK.

1 Introduction and scope

Under the Climate Change Act 2008, the UK has ambitious decarbonisation targets, which aim to reduce greenhouse gas emissions by 57% (from 1990 levels) by 2030 and by at least 80% by 2050. The transport sector accounts for 29% of the UKs greenhouse gas emissions[1], and domestic transport[2] will need to reduce its emissions by 43% between 2015 and 2030 to meet the UK's fifth carbon budget[3]. Decarbonisation across all transport segments and modes will be vital in order to meet these targets, and the further emissions reductions required in the longer term. Advanced biofuels, produced from sustainable biogenic waste and residue feedstocks[4], are likely to form a key part of transport decarbonisation. Advanced drop-in biofuels which are able to substitute diesel, gasoline and jet fuel without infrastructure or vehicle changes, are particularly attractive to segments of the transport sector which are difficult to decarbonise via electrification, such as shipping, aviation and heavy duty road vehicles.

The development status of advanced drop-in biofuels is at a lower level than other advanced biofuels, such as lignocellulosic ethanol, and deployment globally is currently limited. Nevertheless, the strong sustainability and decarbonisation drivers provide impetus for continued development towards commercialisation and accelerated uptake.

The aim of this study is to evaluate the UK potential for production of advanced drop-in biofuels to 2030. This analysis is based on a wide base of evidence, which considers: technology development to date and the remaining technical barriers to commercialisation; other development influences such as the availability of finance, policy support and regulation; and likely commercialisation and scale-up timelines. The outcomes of this study will enable the UK Department for Transport to assess the impact of policy and incentives on commercialisation barriers and increased uptake, and to understand how policy post-2020 can best shaped to support continued development and investment in UK production plants. It is important to note that at the time of writing this report, the proposed RTFO "development fuels" sub-target was still under development.

The fuels which are considered in this study include drop-in, long-chain hydrocarbons, namely diesel, gasoline and kerosene type fuels[5]. Other advanced biofuels including ethanol, butanol, methanol and dimethyl ether (DME) are not explicitly considered within the scope of drop-in fuels, but are considered in their capacity as intermediates in conversion processes such as alcohol-to-jet, alcohol-to-diesel, and methanol-to-gasoline. The biomass feedstocks in scope are wastes and residues, primarily agricultural and forestry residues, and the organic fraction of municipal solid waste. Imported feedstocks meeting the same scope are also considered. Feedstocks which are not likely to be part of the Department for Transport's (DfT's) development fuel remit (such as food crops, non-

[1] DECC (2016) "Provisional estimates of UK Greenhouse Gas emissions for 2015, including quarterly emissions for 4th quarter 2015", Statistical release. Available at www.gov.uk/government/uploads/system/uploads/attachment_data/file/511684/20160331_2015_Provisional_Emissions_Statistics.pdf
[2] International aviation and shipping emissions are not included in the carbon budget, but do form part of the target for 2050
[3] Committee on Climate Change (2016) "Meeting Carbon Budgets – Implications of Brexit for UK climate policy", October 2016. Available at www.theccc.org.uk/wp-content/uploads/2016/10/Meeting-Carbon-Budgets-Implications-of-Brexit-for-UK-climate-policy-Committee-on-Climate-Change-October-2016.pdf
[4] The term "2G" is used as shorthand throughout this report for sustainable biogenic wastes and residues, i.e. 2G alcohols are those derived from these feedstocks. This term is preferable to "LC" or lignocellulosic, as lignocellulosic feedstocks are only a subset of 2G feedstocks.
[5] Acceptable diesel range is typically C9-C24; gasoline range is C4-C12; jet range is C6-16

food energy crops, used cooking oil and animal fats), as well as others with very limited availability in the UK are not included.

Based on the above, all conversion technologies which are able to produce diesel, gasoline and jet fuel from wastes, residues and 2G intermediates are included in scope. These routes are illustrated in Figure 1.1 below. Upstream technologies such as pre-processing, and intermediate conversion technologies (e.g. fermentation to ethanol/butanol, methanol synthesis etc.) are not covered.

The report begins with a technology assessment to briefly explain the technologies, establish their development status and highlight key technical challenges (Chapter 2). A feedstock availability assessment then examines national and regional availability, the logistical, infrastructure and other requirements of the supply chain, and the potential for locating a plant in the UK (Chapter 3). The non-technical demand and supply side barriers to technology development and deployment in the UK are then identified and discussed (Chapter 4). The results from modelling the ‘realisable maximum’ global and UK potential production capacity to 2030 are then presented and discussed (Chapter 5). The report concludes with a synthesis of the previous chapters, feeding into a review of existing policies and incentives, as well as those under consultation, to provide policy considerations for supporting advanced drop-in biofuel production in the UK (Chapter 6).

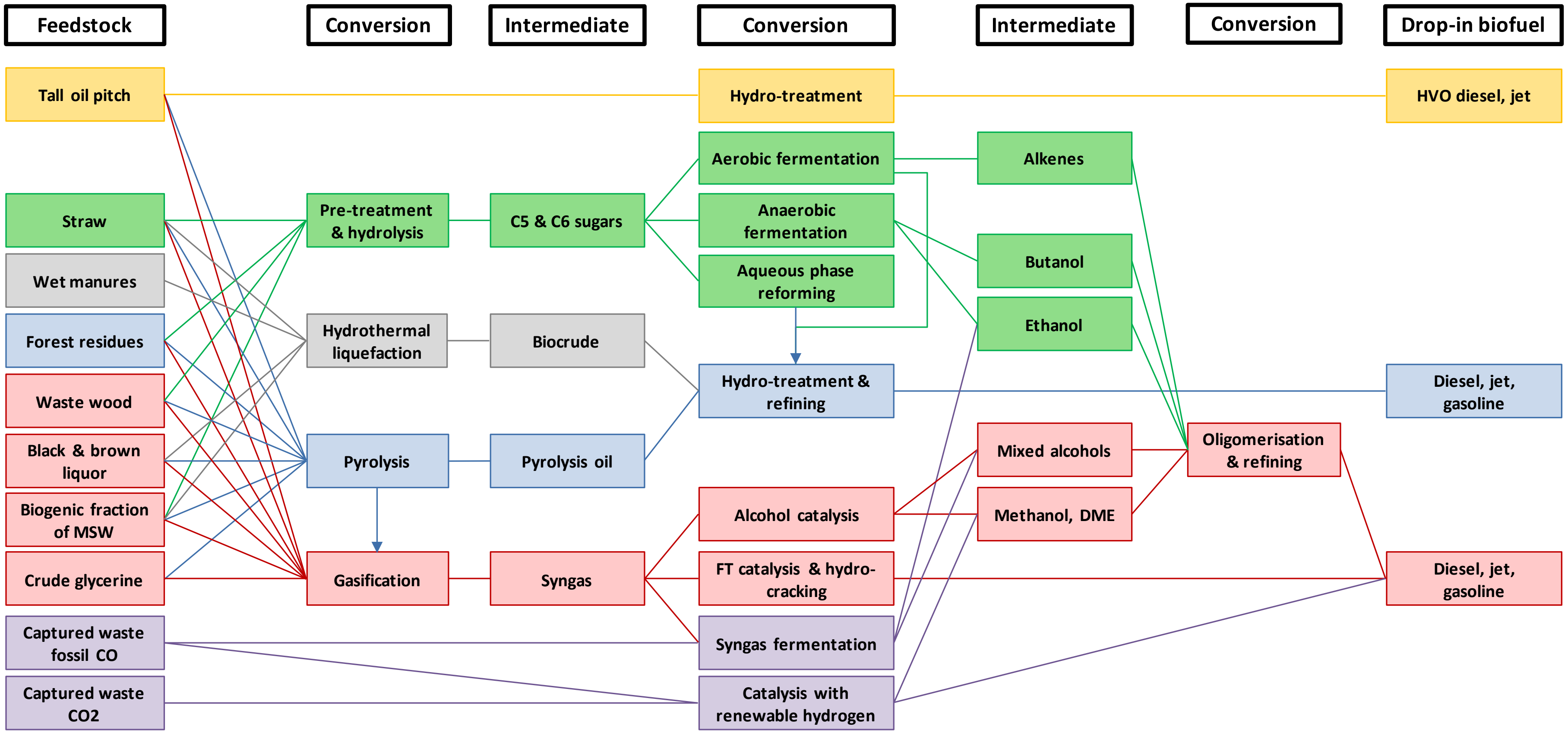


Figure 1.1: Overview of conversion routes from feedstocks to products in-scope[6]

[6] Colours represent the primary conversion process

2 Technology assessment

2.1 Introduction

The technology assessment reviews the status of technologies for the conversion of waste and residue feedstocks (or intermediates derived from these feedstocks) into long-chain, drop-in hydrocarbon fuels, such as diesel, gasoline and jet. It also summarises the technical barriers that need to be overcome to progress towards commercial deployment, together with the severity of these barriers (with key barriers highlighted in bold in the tables).

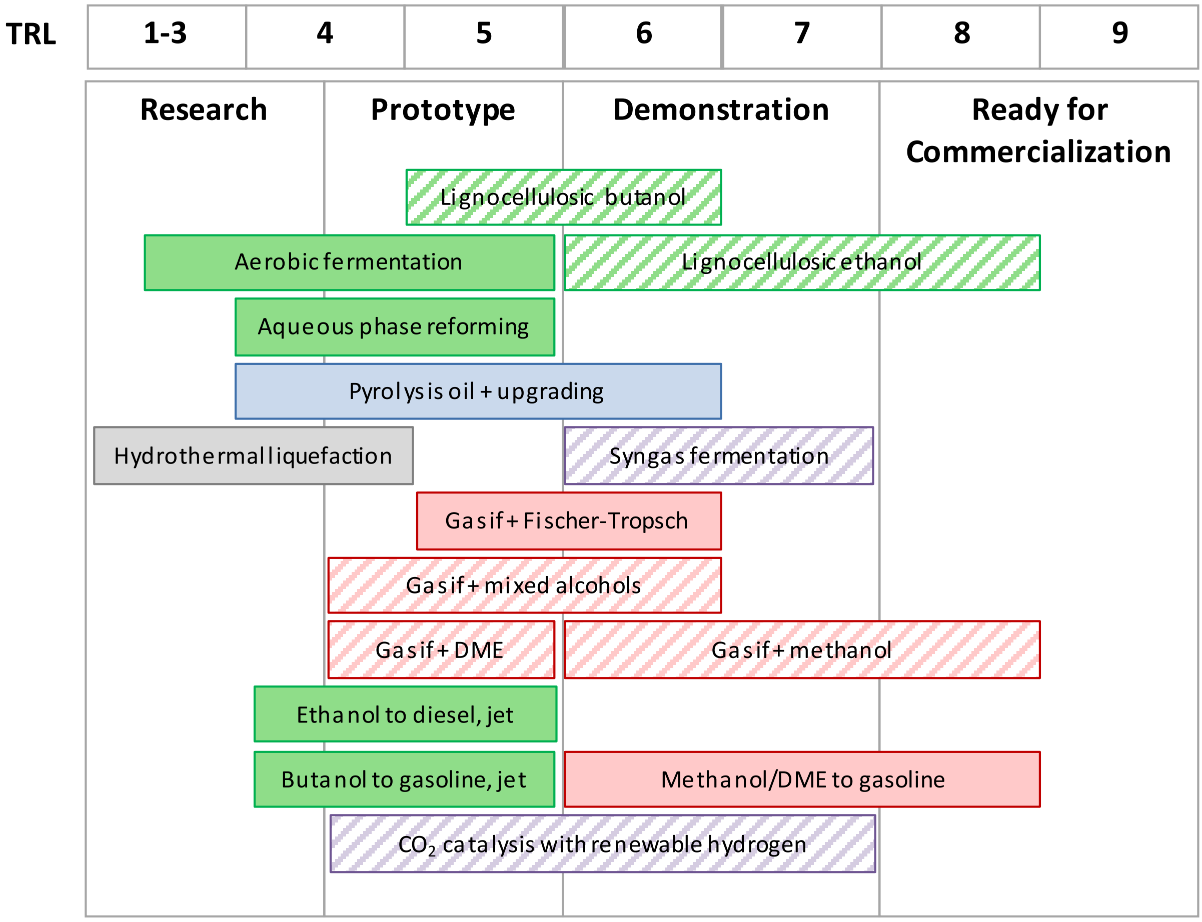
For the conversion of wastes and residues to advanced fuels, the key technology platforms which are most likely to reach commercial scale and be available in the UK by 2030 are illustrated in Figure 2.1. These include gasification with Fischer-Tropsch synthesis, fast pyrolysis and upgrading, hydrothermal liquefaction and upgrading, biological and chemical conversion of 2G sugars to hydrocarbons, and catalytic conversion of alcohols. Other conversion technologies outside of the direct scope of the study are also shown (as they produce relevant intermediates), including 2G ethanol and butanol, gasification with catalysis to alcohols, fermentation of fossil syngas (to ethanol), and CO_2 catalysis with renewable hydrogen (to methanol or methane).

The development status is expressed in terms of the technology readiness level (TRL). TRL was first introduced by NASA, and is a relative measure of the maturity of evolving technologies on a scale of 1 to 9. As shown in Table 2.1, TRL 1 represents basic research on a new invention, while TRL 9 demonstrates a fully commercialised technology.

TRL definitions are not necessarily inferred by a common plant capacity scale, because of the large potential difference in market sizes and minimum economic scales of the technologies. For example, at the same capacity a small demonstration plant using one technology could count as a first commercial plant for another technology route. Annual production or production capacity for a specific product is therefore only an indicator for the level of commercialisation.

Table 2.1: Technology Readiness Level definitions

TRL	Definition	Explanation
1	Basic research	Principles postulated & observed, no experimental proof available
2	Technology formulation	Concept and application have been formulated
3	Applied research	First laboratory tests completed; proof of concept
4	Small scale prototype	Built in a laboratory environment
5	Large scale prototype	Tested in intended environment
6	Prototype system	Tested in intended environment close to expected performance
7	Demonstration system	Operating in operational environment at pre-commercial scale
8	First-of-a-kind commercial system	Manufacturing issues solved
9	Full commercial application	Technology available for consumers



Colours represent the principle conversion process: fermentation (green), pyrolysis (blue), hydrothermal liquefaction (grey), gasification (red) and non-biogenic routes (purple). Hashed technologies are those not directly in scope of the study, but producing relevant intermediates

Figure 2.1: TRL status of different advanced biofuels

2.2 Gasification with Fischer-Tropsch synthesis

Brief description

Gasification converts (typically dry) biomass feedstocks into syngas under high temperature and pressure, in a limited oxygen environment. Syngas is a gas mixture comprised primarily of carbon monoxide and hydrogen. The syngas is then cleaned of tars and chemical contaminants, and then conditioned via a water-gas shift reaction to meet the catalyst specification, before carbon dioxide is removed. During Fischer-Tropsch (FT) synthesis, conditioned syngas is reacted over metallic catalysts to produce a mixture of long-chain hydrocarbons, which may then be upgraded via standard refinery processes (such as hydrocracking and distillation). As shown in Figure 2.2, the FT process produces high quality drop-in fuels for road transport and aviation, as well as co-products such as naphtha. Highly integrated gasification + FT plants can also generate excess electricity for sale to the grid.

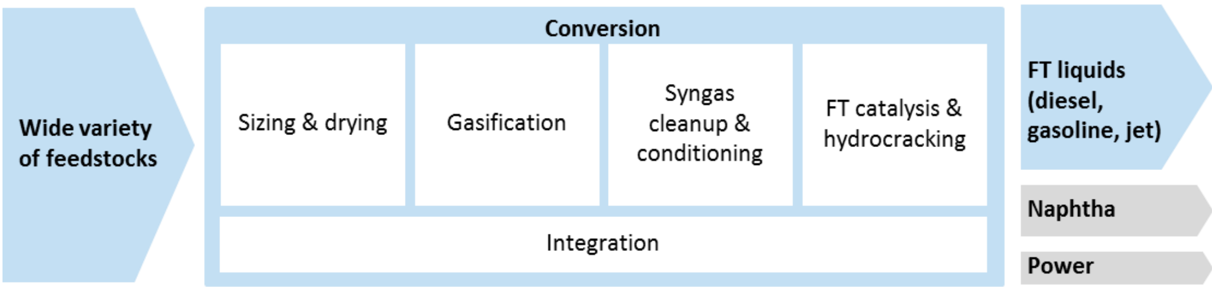


Figure 2.2: Generic process diagram for gasification + FT synthesis

The gasification process is suited to, and being developed for, multiple lignocellulosic and waste biomass feedstocks such as forestry and agricultural residues, industrial waste and municipal solid waste. The suitability of a feedstock is dependent on the specific reactor design, with some designs more suited to heterogeneous waste feedstocks. Feedstocks also impact the quality of the syngas and process efficiency – ideal feedstocks are volatile, with low levels of moisture and ash, such as dried forestry wood.

Development status

Both gasification and FT synthesis are well-established commercial processes when using fossil feedstocks. However, their use with biomass feedstocks and biomass-derived syngas is more limited, particularly when integrating all the plant components together. Biomass gasification and FT synthesis is therefore judged to be at **TRL 5-6** currently. The known gasification and FT synthesis projects at pilot scale and above, which are planned and underway worldwide, are shown in Table 2.2. This list includes only active and finished projects, and not those which have ceased due to project cancellation or plant/developer failure (such as CHOREN, UPM, Flambeau River, Rentech, Solena, NSE Biofuels).

Global production activity and key UK actors

The known gasification and FT synthesis projects at pilot scale and above, which are underway worldwide, are shown in Table 2.2. A number of first commercial plants are currently in the planning stage, with none yet under construction, and have been announced to start production from 2018 onwards.

Table 2.2: Current gasification + FT synthesis projects worldwide

Company & plant location	Feedstock	Product(s)	Scale	Status (Start date)	Production capacity (ML/yr)
Kaidi (Finland)	Forest residues	FT diesel, jet	First commercial	Planned (2020)	256
Joule Unlimited / Red Rock Biofuels (USA)	Wood wastes & residues	FT diesel, jet	First commercial	Planned (2018)	57
Fulcrum Biofuels (USA)	Prepared MSW	FT diesel, jet	First commercial	Planned (2019)	38
Haldor Topsoe & Gas Technology Institute (USA)	Wood pellets	FT gasoline	Pilot	Finished (2014)	1.3
Kaidi (China)	Biogenic waste	FT diesel	Pilot	Operational (2012)	0.52
Gridley Biofuels Project / Red Lion / Greyrock (USA)	Agricultural residues	FT diesel	Pilot	Finished (2014)	0.46
TÜBİTAK MRC - ENERGY INSTITUTE - TURKEY	Hazelnut shell, olive cake, wood chip & lignite	FT liquids	Pilot	Operational (2013)	0.32
BioTfuel - Uhde (France)	Torrefied wood	FT diesel, jet	Demo	Under construction (2017)	0.08 (slipstream)
NREL (USA)	Lignocellulosics	FT liquids	Pilot	Operational	0.06
BIOENERGY 2020+ (Austria)	Syngas slipstream from wood gasification	FT liquids	Pilot	Planned (~2018)	0.05
Frontline Bioenergy (USA)	Wood, sorted MSW	FT jet	Pilot	Planned	0.05
Velocys (Austria)	Syngas slipstream from wood gasification	FT diesel	Pilot	Finished (2011)	0.03
TRI (USA)	Wood waste & forest residues	FT liquids	Pilot	Operational (2010)	0.02
Southern Research Institute / TRI (USA)	Wood waste & forest residues	FT liquids, mixed alcohols, industrial sugars	Pilot	Operational (2007)	~0.00
Cutec (Germany)	Straw, wood, dried silage, organic residues	FT liquids	Pilot	Operational (1990)	~0.00

An important UK actor is Velocys, who are developing a technology combining bespoke catalysts with microchannel FT reactors to create a system suited to small-scale biomass-to-liquids (BTL) plants. This technology was piloted at a gasifier in Güssing, Austria, and is currently being deployed at scale in a (landfill and natural) Gas-To-Liquids plant in Oklahoma City, USA. Velocys are also licensing their technology to Red Rock Biofuels' Lakeview project.

Johnson Matthey, another UK actor, is also a globally recognised actor in the development of FT catalysts. The UK also has academic strengths on which industry can build, for example, Newcastle University are working on plasma promoted Fischer-Tropsch synthesis using a novel catalyst. Advanced Plasma Power (APP) operate a pilot plant in Swindon, UK, and have the potential to be an important player in the future of UK waste gasification. However, APP are currently focused on producing methane, for gas grid injection or truck fleets, and not using FT catalysis for distillates.

Technical challenges and needs

Gasification and FT synthesis has some significant remaining challenges where the syngas is produced from biomass residues and wastes. One such challenge is syngas quality, where developers need to demonstrate that their gasification technology can operate reliably and efficiently with industrially relevant biomass and waste feedstocks, and still always meet the FT catalyst specification, even with variable feedstock inputs. This is viewed by many technology developers as critical to their success, as achieving reliably high quality syngas negates the need for developing expensive custom FT catalysts (and adding technical risk). Efficient thermal integration of biomass handling, gasification, syngas clean-up and FT synthesis is also a key challenge, while FT catalyst performance and lifetimes are a less significant barrier – especially if integration, and syngas clean-up, is successful.

Existing commercial FT technology (developed for fossil feedstocks) typically operates at a very large scale not suited to biomass, thus requiring scaling down. This impacts the economics of the process significantly, and creates a need to modify the process and/or equipment to overcome this. Advanced reactor designs, such as modular micro-channel reactors, and improvements to existing slurry FT rectors are under development, together with solutions that combine synthesis and cracking (thereby reducing the need for additional reactor vessels). General technical challenges and the accompanying technical needs are described in Table 2.3. Material for this table has come from interviews with developers and previous studies, such as E4tech & TUHH (2016)[7].

[7] E4tech & TUHH (2016) "Innovation Outlook: Advanced Liquid Biofuels", International Renewable Energy Agency (IRENA). Available at www.irena.org/DocumentDownloads/Publications/IRENA_Innovation_Outlook_Advanced_Liquid_Biofuels_2016.pdf

Table 2.3: Technical challenges and development needs for gasification + FT synthesis

Technical challenges	Corresponding development needs
Commercialised gasification systems require high quality, homogeneous feedstocks to operate reliably and efficiently	Robust gasifier performance with on-spec feedstocks. Alternatively, use of gasifier designs (e.g. plasma) able to handle heterogeneous feedstocks
FT requires a high quality, very clean syngas, free of inert gases (which requires the use of oxygen or steam gasification)	Clean-up operating at high temperatures, or integrated processes optimised for energy efficiency. Develop efficient and flexible air separation unit technologies, or heat-recovery to raise steam
Some gasifiers produce higher levels of tars, which increase corrosion and erosion, opex and downtime	Robust performance of the integrated gasifier and gas cleaning within temperate windows
Fluidised bed gasifiers can produce relatively high levels of methane, which reduces conversion yields and increases size of downstream process units	Efficient production of high quality syngas through optimisation of the gasifier operating conditions
Clean-up using low temperature water scrubbing makes large volumes of contaminated waste water	Processes and design optimised to minimise impacts, or WWT plant installed, or use of high temperature clean-up to avoid water use
FT catalysts require tightly specified CO to H_2 ratio, often needing a significant water gas shift reaction. This adds costs and loses carbon	Gasifier optimisation, or matching of oxidant and gasifier reactor type to adjust syngas H_2:CO ratio. Alternatively, catalyst promoters may be added
FT catalysts are deactivated by sulphur, often found in biomass. Solutions are a cost trade-off between high clean-up costs or catalyst replacement rates	Robust operation of FT catalysts with biomass-derived syngas, minimising loss of activity and lifetime. Reduction in cost of sulphur removal technology
Selectivity to desired diesel, jet or gasoline fractions often limited to <40%. Significant amounts of olefins, alcohols, acids, ketones, water and CO_2 are also made	Higher selectivity catalysts and more efficient recycling of unreacted syngas. Alternatively, back-end upgrading steps can be used to improve selectivity
FT reactor design influences catalyst lifetime and deactivation, and rate of reaction. Reactor design also impacts heat and mass transfer limits	Improve all FT reactor types, and develop advanced catalyst and catalyst separation systems (high activity catalysts with efficient heat removal)
FT catalysts produce a range of hydrocarbons needing upgraded and fractionated to produce biofuels – but capital costs at small scales are significant	Upgrading processes that are economic at scales relevant to biomass gasification, or use of novel FT catalysts to reduce upgrading requirements
FT and syngas clean-up can generate large amounts of heat, whilst biomass drying and gasification can consume large amounts, leading to thermal losses	Optimised plant integration and heat flow (trade-off between opex and capex), on-site steam turbine(s) to generate power, and reduced temperature changes

2.3 Fast pyrolysis and upgrading

Brief description

Pyrolysis is the controlled thermal decomposition of (typically dry) biomass at moderate temperatures, in the absence of oxygen, to produce liquid oil, gas and charcoal (biochar), as shown in Figure 2.3. Catalytic fast pyrolysis maximises the production of the liquid pyrolysis oil fraction (instead of char), with the gas produced typically used to heat the system and dry the biomass.

Crude pyrolysis oil can be upgraded by directly blending with fossil vacuum gas oil at up to 10-20% within an existing refinery fluid catalytic cracker (FCC) unit. Alternatively, the crude pyrolysis oil can undergo hydro-deoxygenation (adding hydrogen at high pressure to remove oxygen and other trace elements) before hydrocracking[8]. Either upgrading process is usually done in a series of separate catalytic steps of increasing severity to reduce the oxygen content while minimising catalyst deactivation. Both upgrading options produce a combination of light, medium and heavy products, which can be distilled to produce diesel, jet and gasoline streams.

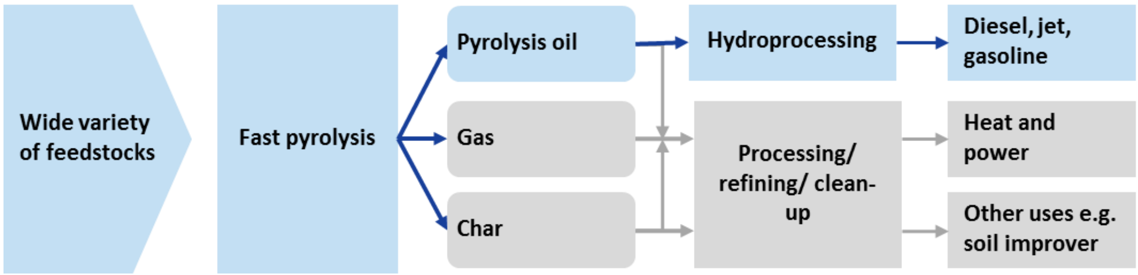


Figure 2.3: Generic process diagram for fast pyrolysis and upgrading

Pyrolysis is suitable for a range of lignocellulosic, cellulosic and waste feedstocks, and may tolerate slightly more heterogeneous feedstocks than some other conversion technologies – however, like gasification, ideal feedstocks are still volatile with low moisture and ash content (e.g. dry wood).

Crude pyrolysis oil is a complex mix of oxygenated compounds, such as carboxylic acids, phenols, sugars and water. It is an energy dense intermediate, which provides the potential for economic transportation of bioenergy to a much larger centralised refinery for upgrading. However, pyrolysis oil characteristics (such as high acidity, high viscosity and high water content) make it relatively difficult to store and handle, and stabilisation is needed for shipping and storage.

Development status

Conventional fast pyrolysis technologies for making food flavourings and bio-oil for heat and power applications have already been commercialised[8], so fast pyrolysis is currently at TRL 8. However, upgrading is less developed at around TRL 5-6, with 5-20% short blending campaigns conducted at demonstration scale with a few oil refinery actors, but no dedicated upgrading facilities operational globally. Hydro-deoxygenation of pyrolysis oil is at an earlier lab and pilot scale (TRL 4-5). Thus the overall process remains at **TRL 5-6**.

[8] Jones *et al.* (2016) "Fast Pyrolysis and Hydrotreating: 2015 State of Technology R&D and Projections to 2017", Pacific Northwest National Laboratory (PNNL). Available at www.pnnl.gov/main/publications/external/technical_reports/PNNL-25312.pdf

Global production activity and key UK actors

The known upgrading projects at pilot scale and above, which are underway worldwide, are shown in Table 2.4, along with those pyrolysis oil projects relevant to the transport fuels market (ignoring those plants and projects focusing heat, power and food applications). This list includes only active and finished projects, and not those which have ceased due to project cancellation or plant/developer failure (such as KiOR and Dynamotive).

Table 2.4: Current fast pyrolysis & upgrading projects worldwide

Company & plant location	Feedstock	Product(s)	Scale	Status (Start date)	Production capacity (ML/yr)
Envergent / Ensyn / UOP (Canada)	Forest residues & straw	Pyrolysis oil	First commercial	Under construction (2017)	40.0
Cool Planet (USA)	Wood residues & thinnings	Pyrolysis oil, Gasoline?	First commercial	Under construction (2018?)	3.8 initially, aim for 38.0
BTG (Netherlands)	Wood biomass and/or residues	Pyrolysis oil	First commercial	Operational (2015)	15.1
Ensyn (Canada)	Lignocellulosics	Pyrolysis oil	First commercial	Operational (2006), Improved (2014)	11.0
Iowa / NREL / ConocoPhilips (USA)	Pyrolysis oil	Gasoline, diesel, jet	Batch demo	Finished	4.0
Petrobras / Ensyn / NREL (Brazil)	Pyrolysis oil	Gasoline, diesel, jet	Batch demo	Finished (2015)	2.2
SynSel / CRI (Norway)	Forest residues	Gasoline, jet, diesel	Demo	Planned	2.1
Shell / CRI (India)	Straw, wood residues, wastes	Gasoline, jet, diesel	Demo	Planned	2.1
Bioliq / Karlsruhe Institute of Technology (Germany)	Wood, waste wood, straws, hay	Pyrolysis oil	Pilot	Operational (2007)	1.8
	Pyrolysis oil	DME, gasoline	Pilot	Operational (2015)	1.8
Petrobras / BTG (Brazil)	Pyrolysis oil	Gasoline, diesel, jet	Batch demo	Finished (2014)	1.7
UOP (USA)	Pyrolysis oil	Gasoline, diesel, jet	Pilot	Operational	0.20
Next BTL / Future Blends (UK)	Lignocellulosics	Upgraded pyrolysis oil	Pilot	Operational	0.03
Research Triangle Institute (USA)	Lignocellulosics	Bio-crude	Pilot	Operational	0.03
Gas Technology Institute / CRI (USA)	Residues, wood, stover, bagasse, algae	Gasoline, jet, diesel	Pilot	Operational (2012)	0.01
LignoCat / VTT Fortum / UPM / Valmet (Finland)	Pyrolysis oil	Upgraded pyrolysis oil	Pilot	Planned (likely at Joensuu plant within 5 years)	Not yet public

The UK has fair capabilities in pyrolysis generally; however the focus to date has been on producing pyrolysis oil for use in heat & power applications. Fuel-focused fast pyrolysis UK industrial actors include Future Blends (now bought by Next BTL LLC), who operate a pilot plant near Oxford using a modified fast pyrolysis platform, and Torftech Energy, who have multiple waste-to-energy plants and are researching biofuel production[9]. Cynar, who developed a pyrolysis plant in Avonmouth to convert waste fossil plastic to fuels, went into liquidation in January 2016[10]. A key UK strength in fast pyrolysis and upgrading is concentrated in robust academic activity at institutions including Aston University, Newcastle University, University College London, University of Cambridge, University of Leeds, and University of York.

Technical challenges and needs

Several early commercial plants producing pyrolysis oil for heat and power applications are in operation. There is some R&D ongoing to improve fast pyrolysis efficiency and product quality (such as Ensyn investing to optimise their Renfrew plant's oil for transport applications)[8], however the most significant technical challenges relate to the upgrading process. The use of hydrotreating to upgrade pyrolysis oil contributes significantly to fuel production costs. The main research areas for conventional fast pyrolysis oil upgrading are related to improving catalyst lifetimes[8], and there are opportunities for wider catalyst improvement to address performance challenges such as deactivation, stability, and cost. Full integration of fast pyrolysis with upgrading in a single facility has also not yet been demonstrated at scale, and presents a significant challenge (an aspect GTI's IH2 technology is attempting to address with on-site H_2 generation). General technical challenges and the accompanying technical needs are described in Table 2.5. Material for this table has come from interviews with developers and previous studies, such as E4tech & TUHH (2016)[7]**Error! Bookmark not defined.**.

Table 2.5: Technical challenges and development needs for fast pyrolysis & upgrading

Technical challenges	Corresponding development needs
Liquid pyrolysis oil yields could be further improved, but the presence of feedstock ash (alkali metals) can dramatically lower yields	Optimised reactors with high yields of pyrolysis oils, and recycling of gases for process energy needs Pre-washing of biomass to reduce alkali metals/ash
Pyrolysis oil is typically unstable and has high acidity, viscosity, water content, and a tendency to polymerise, making storage and upgrading challenging	Low cost stabilisation techniques, and demonstration of a consistent and stable intermediate oil suitable for downstream processes (long-term storage testing)
Catalysts used in upgrading are deactivated due to high water and oxygen content of the pyrolysis oil	Improve pyrolysis (e.g. with in-situ catalysts) to decrease oil water and oxygen content, or improve robustness of upgrading and catalyst regeneration
Crude pyrolysis oil can only currently be blended at up to ~20% in existing refinery FCC equipment, as coke formation can obstruct feed lines and risks kit damage	Further long-term testing in larger-scale refinery FCC equipment in real-world conditions (outside of the lab), and at higher blend %s
FCC carbon conversion of crude pyrolysis oil into liquid biofuels is only currently ~30%	Improve catalyst selectivity, and minimise pyrolysis oil oxygen content to reduce water, CO and CO_2 losses
Presence of alkali metals and water in the pyrolysis oil can damage hydro-deoxygenation catalysts and reduce HDO reactor run-lengths	Improved pyrolysis oil filtering, desalting and processing before HDO upgrading

[9] Bridgwater, T. & I. Watkinson (eds.) (2016) "Biomass and Waste Pyrolysis A Guide to UK Capabilities", Available at www.pyne.co.uk/Resources/user/UK%20Biomass%20and%20Waste%20Pyrolysis%20Guide%202015%20081015.pdf
[10] Brewster, S. (2016) "The eight steps in turning plastic back into oil", MRW. Available at www.mrw.co.uk/knowledge-centre/the-eight-steps-in-turning-plastic-back-into-oil/10012840.article

2.4 Hydrothermal liquefaction and upgrading

Brief description

Hydrothermal liquefaction (HTL) is a process where biomass (plus a large amount of water) is heated at very high pressures to convert it into an energy dense 'bio-crude'. The near- or super-critical water acts as a reactant and catalyst to depolymerise the biomass, although other catalysts can also be added. Although the HTL process is related to pyrolysis, HTL oils are notably different[11]. They typically have much lower water contents, higher energy contents (33-36 MJ/kg), lower oxygen contents (5-20%) and greater stability, hence are expected to require less extensive upgrading than pyrolysis oils. Their higher molecular weight distribution makes it more suitable for diesel production, but gasoline and jet are possible with more hydro-cracking. HTL is also well suited to process very wet biomass (sewage sludge, manure, micro-algae and macro-algae are commonly used), as well as some lignocellulosic feedstocks. The feedstock composition has a significant influence on the yield and quality of the oil (and the co-production of water-soluble organics, chars and gases).

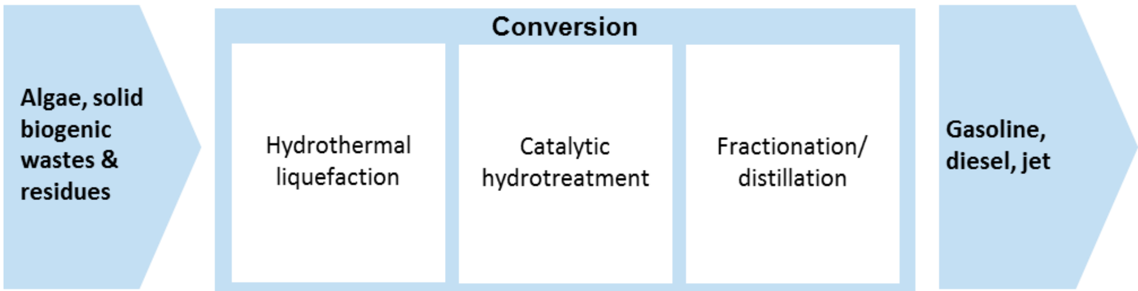


Figure 2.4: Generic process diagram for hydrothermal liquefaction and upgrading

Developers claim that with further optimisation, it will be possible for the upgrading step to use standard refining processes to produce gasoline, diesel and jet fuel (Figure 2.4). It is expected that HTL oils would already be able to be used at high blend % in refinery FCC units, and with mild hydro-deoxygenation, it might be possible to co-process the bio-crude with fossil crude oil in the front end of existing oil refineries. The high energy density of the intermediate bio-crude provides the potential for economic transportation to a much larger off-site refinery.

Development status

HTL technology for producing bio-crude is currently only at pilot scale (with continuous reactors), with a demo in commissioning (TRL 5-6), but experience of upgrading HTL oils is limited to lab-scale[12,13] batch reactors at TRL 3-4 (and no integrated plant or refinery testing experience). The overall technology route is therefore at **TRL 4**. Developers expect that HTL oil testing in refineries will

[11] Elliott *et al*. (2015) "Hydrothermal liquefaction of biomass: Developments from batch to continuous process", *Bioresource Technology*, vol. 178, no. 1, pp. 147-156

[12] Mullins, M. (2015) "Conversion of Biologically Derived Oils into Transportation Fuels", Michigan Tech. Available at www.svebio.se/sites/default/files/8.%20Michael%20Mullins%20-%20Conversion%20of%20Biologically%20Derived%20Oils%20into%20Transportation%20Fuels.pdf

[13] Lane, J. (2015) "Still algae, still fuels: The Digest's 2015 8-Slide Guide to Muradel", Biofuels Digest. Available at www.biofuelsdigest.com/bdigest/2015/11/10/still-algae-still-fuels-the-digests-2015-8-slide-guide-to-muradel/

be 5-10 years behind pyrolysis oils (as there are not sufficient volumes available yet to run testing campaigns), and hence the integrated technology may struggle to reach TRL 8 by 2030.

Global production activity and key UK actors

The known HTL projects at pilot scale and above, which are underway worldwide, are shown in Table 2.6. Note that there are currently no known upgrading projects operating, with oil characterisation discussions with refinery operators only recently started[14].

Table 2.6: Current hydrothermal liquefaction projects worldwide

Company & plant location	Feedstock	Product(s)	Scale	Status (Start date)	Production capacity (ML/yr)
Licella (Australia)	Wood, energy crops, algae	Bio-crude	First commercial	Planned (2019)	19.9
Altaca / SCF Technologies (Turkey)	Sewage sludge, food waste	Bio-crude	Demonstration	In commissioning	9.1
Licella (Australia)	Wood, energy crops, algae	Bio-crude	Demonstration	Operational (2012)	4.0
Biochemtex / ETH / KLM / RECORD (Italy)	Lignin	Jet	Demonstration	Planned (2018)	2.5
Next Fuels (Netherlands/SE Asia)	Palm waste	Bio-crude	Pilot	Planned	0.42
Licella (Australia)	Wood, energy crops, algae	Bio-crude	Pilot	Operational (2011)	0.40
Southern Oil Refining (Australia)	Bio-crude	Diesel, jet	Pilot	Planned (2017)	0.33
Genifuel / PNNL (USA)	Wastes, algae, wood, straws	Bio-crude	Pilot	Operating (2015)	0.32
Shell HTU (Netherlands)	Wastes, wood, residues	Bio-crude	Pilot	Finished (1999)	0.05
Licella / University of Sydney (Australia)	Wood, energy crops, algae	Bio-crude	Pilot	Operational (2008)	0.03
Research Triangle Institute (USA)	Lignocellulosics	Bio-crude	Pilot	Operational	0.03
Muradel (Australia)	Micro-algae	Bio-crude	Pilot	Operational (2014)	0.02
Steeper Energy /Aalborg Uni (Denmark)	DDGS, peat, wood, tall oil	Bio-crude	Pilot	Operational (2013)	0.02
Chemtex (USA)	Lignin	Bio-crude	Lab	Operational	~0.00
PNNL (USA)	Lignocellulosics, algae	Bio-crude	Pilot	Operational	~0.00
Chalmers University (Sweden)	Lignin	Bio-crude	Pilot	Operational	~0.00

HTL is still a relatively early stage technology, and there are no commercial UK actors. However, the Energy Research Institute, part of the School of Chemical and Process Engineering at the University of

[14] ARENA (2016) "First step towards an Australian green-fuel biorefinery". Available at http://arena.gov.au/media/first-step-towards-australian-green-fuel-biorefinery/

Leeds has active research and collaboration activities with leading global research actors such as the Pacific Northwest National Laboratory (PNNL) and Aalborg University.

Technical challenges and needs

Hydrothermal liquefaction plants face challenges related to catalyst performance and efficiency, product quality, and disposal/treatment of high volumes of waste water. Research is also underway to reduce capital costs by introducing a scalable continuous flow reactor configuration, instead of batch reactors. There are also technical challenges around moving and stirring large volumes of biomass slurry at high pressures. Due to the severe process conditions, it is often necessary to use expensive alloy materials for the process equipment to avoid corrosion, and the high pressures can be detrimental for the system components. By far the most serious of the technical barriers currently facing this route is the lack of upgrading demonstration activities, with refineries in the real-world. The key technical challenges and corresponding technical needs are noted in Table 2.7. Given the earlier stage of the technology, interviews were supplemented with several studies, such as E4tech & TUHH (2016)[7], Elliott *et al*. (2015)[11] and VTT (2015)[15].

Table 2.7: Technical challenges and development needs for hydrothermal liquefaction & upgrading

Technical challenges	Corresponding development needs
Limited commercial experience with slurry handling and oil extraction (e.g. pumping, stirring) at high temperatures and pressures, and under continuous operation conditions	Improved feedstock handling technologies, cross-over learning from paper & pulp industries, operation outside of batch reactors (where initial heat-up and cool-down phases not present)
Solid contents need maintained between 5-35% to ensure pumpability and that water carbon levels are sufficient for conversion	Monitoring of input biomass feedstocks, develop lower cost biomass grinding (to allow use of drier, larger particle feedstocks)
Product recovery step can be complex/expensive if oil and aqueous phases do not separate	Lower cost solvent extraction and evaporation methods, or HTL optimisation to better define separate oil and aqueous phases
Carbon losses to aqueous phase can still be significant, lowering output yields	Process condition optimisation to minimise losses
High processing or recycling costs of waste water, containing significant amount of organic material	Minimise loss of organic material to waste water, and improve waste-water treatment
High capital cost, given expensive alloys needed to avoid water corrosion, and survive high pressures	Development of scalable reactor configurations, and new metal alloys
Lower quality feedstocks can lead to more corrosive bio-crude, representing a challenge for downstream processing	Demonstration of a consistent and stable oil suitable for downstream processes; development of more robust downstream processes
Upgrading is almost completely unproven (only lab tests done), and ability to input bio-crude into front end of oil refinery still to be tested	Full characterisation of bio-crude, collaboration with oil refineries, provision of samples, subsequent optimisation of HTL process based on test results

[15] VTT (2015) "Hydrothermal refining of biomass - an overview and future perspectives". Available at www.vtt.fi/inf/julkaisut/muut/2015/OA-Hydrothermal_refining.pdf

2.5 Aerobic fermentation of 2G sugars to hydrocarbons

Brief description

Given the feedstocks in scope for UK development fuels, biomass pre-treatment technologies developed for lignocellulosic ethanol plants (such as steam explosion) will have to be used to extract fermentable sugars from the starting waste and residue feedstocks. These 2G sugars can then be biologically converted by aerobic fermentation (with air, at atmospheric pressure), to generate specific hydrocarbon precursors, before product recovery, purification and upgrading to diesel, gasoline and jet fuels. There are currently three main biological routes in development:

- Heterotrophic algae or yeast converting sugars into lipids within their cells, which can then be extracted by solvents rupturing the cells (making a co-product protein animal feed), cleaned and upgraded to a transport fuel using conventional HVO diesel technology; or
- Genetically modified (GM) yeast consuming sugars and excreting long-chain liquid alkenes (such as farnesene or isobutene), which needs recovery from the fermentation broth, purification and then hydrotreating to jet or diesel; or
- Genetically modified (GM) bacteria consuming sugars and venting short-chain gaseous alkenes (such as isobutene), which can then be oligomerised and hydrotreated to gasoline or jet.

The overall process for fermentation of sugars to hydrocarbons is shown in Figure 2.5.

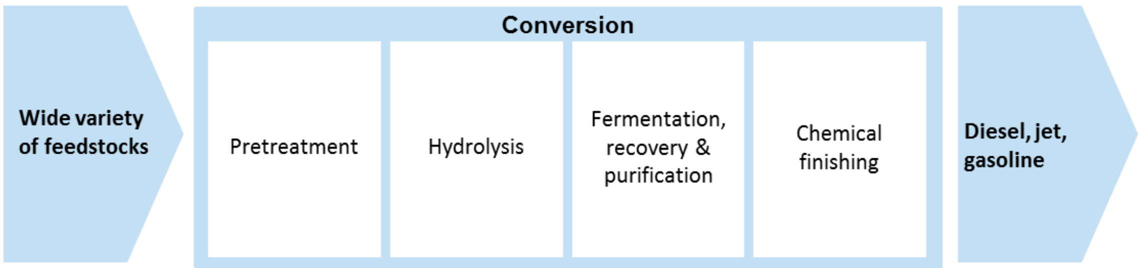


Figure 2.5: Generic process diagram for conversion of 2G sugars to hydrocarbons via fermentation

Development status

Current aerobic fermentation processes use 1G sugar feedstocks almost exclusively, such as those from sugarcane, sugarbeet and corn starch. The process is at TRL 7-8 on 1G feedstocks (with first commercial plants operational and ramping up), however the TRL is much lower for 2G feedstocks. Global Bioenergies have started LC sugar collaborations already, and Amyris have modified their microbes and conducted testing with NREL in the US, placing the technology with 2G sugars currently at **TRL 5**.

Global production activity and key UK actors

The known sugar to hydrocarbon projects at pilot scale and above, which are underway worldwide, are shown in Table 2.8 – noting that all of these projects are using, or primarily focused on, 1G feedstocks.

Table 2.8: Current aerobic fermentation projects worldwide

Company & plant location	Feedstock	Product(s)	Scale	Status (Start date)	Production capacity (ML/yr)
Global Bioenergies (France)	Sugar beet	Isobutene (gas)	First commercial	Planned (2018)	83
Amyris (Brazil)	Sugarcane	Farnesene	First commercial	Operational	Currently 5-8, ramping to 40
REG / LS9 (USA)	Corn starch	Long chain fatty alcohols	Demo	Operational	1.7
Amyris with Antibioticos (Spain) / Tate & Lyle (USA) / Biomin (Brazil)	Sugar beet, corn dextrose, sugarcane	Farnesene	Three separate toll demos	Stopped (2010-11)	~1.0 combined
Total (USA)	Farnesene	Jet	Pilot	Operational	~0.5, based on 10% fuel sales
Global Bioenergies (Germany)	Sugarcane, sugar beet, (LC sugars)	Isobutene (gas)	Demo	In commissioning	0.17
Amyris (USA)	Sugar crops, corn dextrose, (corn stover)	Farnesene	Pilot	Operational	~0.0
DSM / BP (USA)	Sugarcane	Lipids	Lab	Finished (2014)	~0.0

Isobutene is being upgraded to iso-octane at lab scale (with Fraunhofer and Audi). Upgrading of Amyris' farnesene to jet (for commercial flights) and diesel (for buses) has been happening at pilot scale with Total. However, Amyris have set a shift away from fuels as a 2016 key business objective, given current oil prices[16]. Similarly Solazyme, who developed and successfully demonstrated their sugar to lipid aerobic fermentation technology (using algae), has rebranded as TerraVia and shifted away from biofuels to focus on high-value food, nutrition and speciality ingredients[17]. Their fuel technology is now grouped under Solazyme Industrials, however no current information on the status of their plants, collaborations or fuel product sales could be found, and hence Solazyme have not been included in the table above.

There are no known UK industrial actors currently working on these aerobic fermentation technologies. BP were involved in the development of DSM's sugarcane to lipids technology from 2008, but exited in 2014[18], and DSM's US lab tests appear not to have progressed further.

Technical challenges and needs

Some developers see the adaption of microbes to use LC and other 2G sugars as relatively straight-forward, and stated that the ability to consume C5 and C6 sugars can be achieved in a few years. However, similar to the technical issues experienced by the first commercial LC ethanol plants, the primary challenges of using 2G sugars will be dealing with real-world feedstocks causing variability in

[16] Biofuels Digest (2016) "Revenues tripling: The Digest's 2016 Multi-Slide Guide to Amyris"., Available at www.biofuelsdigest.com/bdigest/2016/11/03/revenues-tripling-the-digests-2016-multi-slide-guide-to-amyris/3/
[17] Fehrenbacher, K. (2016) "Solazyme ditches biofuel (& name) in a world of cheap oil, Fortune. Available at http://fortune.com/2016/03/16/solazyme-terravia-ditches-biofuels/
[18] Biofuels Digest (2014) "BP to make major job cuts, sell assets as energy prices fall: lignocellulosic business goes on the block". Available at www.biofuelsdigest.com/bdigest/2014/12/08/bp-to-make-major-job-cuts-sell-assets-as-energy-prices-fall-lignocellulosic-business-goes-on-the-block/

the quality and composition of 2G sugar hydrolysates, plus the presence of new inhibitors from the integrated pre-treatment processes that can dramatically lower microbe yields[19].

All biological sugar to hydrocarbon routes have low maximum theoretical yields, as oxygen has to be removed entirely, and the microbes have to grow and live on a proportion of the sugars – this means process economics are highly sensitive to feedstock prices. Because oxygen is only sparingly soluble in aqueous broths, the need to maintain aerobic conditions via continuous aeration is also a key challenge in economically scaling up operations to larger vessel sizes[20]. The key technical challenges and corresponding technical needs are noted in Table 2.9. Information from interviews was supplemented with industry and academic literature, including Holladay *et al*. (2014)[19] and PNNL & NREL (2013)[20].

Table 2.9: Technical challenges and development needs for aerobic fermentation of 2G sugars

Technical challenges	Corresponding development needs
Microbes need significant adaption to lignocellulosic sugars, to achieve similar conversion yields to 1G feedstocks, and avoiding inhibition and contamination	GM of microbes to utilise new sugar metabolic pathways, and improve robustness to new inhibitors from pre-treatment steps, and extra contaminant/bugs introduced with the feedstock
Pre-treatment technologies are currently optimised for ethanol microbes operating in anaerobic conditions, and not integrated with aerobic conditions and new microbes	Piloting and demonstration of pre-treatment steps integration with fermentation, to optimise process conditions in both steps, and overall thermal integration (including lignin use)
Achieving sufficiently high yields to make the processes economic is challenging, as both the maximum theoretical mass yields are low (around 30%), and current performance vs. these maximum yields still needs significant improvement	Scale-up of plants to achieve higher yields, efficient translation of pilot results into larger scale reactors using industrial fermentation experience, minimise sugar consumption in microbes growth phases
GM is a double-edged sword, as might result in larger improvements, but will restrict the use of biomeal co-products in certain markets	Identifying new strains without GM
Contamination issues with real-world feedstocks resulting in microbial competition in the fermenters	Careful removal of contaminants and microbes found in the feedstock (via pre-treatment), and making desired microbes more robust
Energy use in extraction of products from within cells or fermentation broth is significant, and needs to be reduced	Novel membrane separation technologies, reduced solvent use, or production of gaseous hydrocarbons that do not require separation
Oxygen is only sparingly soluble in aqueous broths, so maintaining aerobic conditions is difficult in large scale vessels – continuous aeration requires significant electricity input for air compression, reactor bubbling and mixing	More efficient air compressors, and optimise reactor designs (e.g. through mixing, bubble sizing) to minimise air requirements and maximise gas-liquid mass transfer rates

[19] J. Holladay *et al.* (2014) "Renewable routes to jet fuel". Available at http://aviation.u-tokyo.ac.jp/eventcopy/ws2014/20141105_07DOE%EF%BC%BFHolladay.pdf
[20] PNNL & NREL (2013) "Biological Conversion of Sugars to Hydrocarbons Technology Pathway". Available at www.pnl.gov/main/publications/external/technical_reports/PNNL-22318.pdf

2.6 Aqueous phase reforming of 2G sugars to hydrocarbons

Brief description

In aqueous phase reforming (APR), an aqueous solution of sugars is converted by a high temperature reforming process using a chemical catalyst to produce a mixture of acids, ketones, aromatics and cyclic hydrocarbons, plus hydrogen and water. Further processing steps are then required to produce gasoline, diesel and jet fuel, as this requires a series of condensation reactions to lengthen the carbon chains in bio-crude, before hydrotreating and isomerisation.

Given the feedstocks in scope for UK development fuels, biomass pre-treatment technologies developed for lignocellulosic ethanol plants (such as steam explosion) will have to be used to extract fermentable sugars from the starting waste and residue feedstocks. The generic process is shown in Figure 2.6.

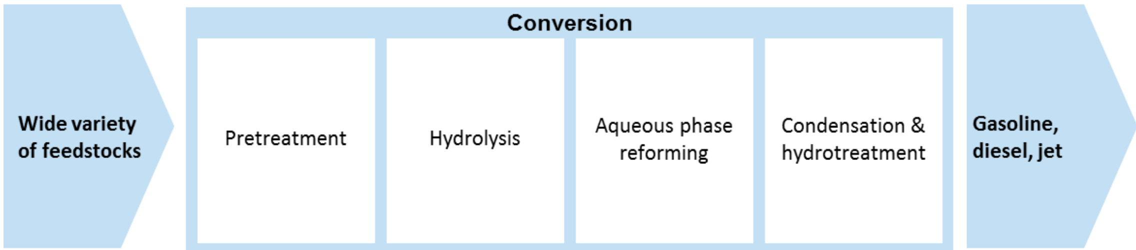


Figure 2.6: Generic process diagram for aqueous phase reforming to hydrocarbons

Development status

Virent's APR process is currently the most developed catalytic conversion route from sugars to longer-chain hydrocarbons (noting Virent were recently acquired by Tesoro). Much of the academic work ongoing in APR has been focused on the production of hydrogen rather than alkanes, and Virent have previously worked extensively with NREL, PNNL and Washington State University.

APR may use sugars isolated from a broad range of feedstocks, however current processes involve primarily 1G feedstocks (such as corn and sugarcane), although Virent/Tesoro have produced bio-crude using Virdia's lignocellulosic sugars, and upgraded this to bio-jet (at lab scale).

The overall process to produce drop-in hydrocarbon fuels via APR is at TRL 5-6 for 1G feedstocks, and at around **TRL 4-5** for 2G feedstocks (those in scope).

Global production activity and key UK actors

The known APR projects at pilot scale and above, which are underway worldwide, are shown in Table 2.10. There are no known UK activities or exclusively UK-based industrial actors currently working on APR technologies, although Shell (as a partially UK company) have been working closely with Virent, building a replica pilot plant in the US, and are continuing to assist with upgrading options[21]. Johnson

[21] Virent (2012) "Shell Using Technology Licensed From Virent", Available at: http://www.virent.com/news/shell-using-technology-licensed-from-virent/

Matthey (catalyst developers) have also just joined a consortium agreeing to work with Virent/Tesoro on scale-up of their technology (focusing mainly on para-xylene for plastics)[22].

Table 2.10: Current aqueous phase reforming projects worldwide

Company & plant location	Feedstock	Product(s)	Scale	Status	Production capacity (ML/yr)
Virent (USA)	1G & 2G sugars	Bio-crude (light fractions)	Pilot	Operational (2010)	0.04
Virent/Shell (USA)	1G & 2G sugars	Bio-crude (light fractions)	Pilot	Operational (2012)	0.04
Virent (USA)	1G & 2G sugars	Bio-crude (heavy fractions)	Pilot	Operational (2013)	0.02

Technical challenges and needs

The APR process is primarily used for the production of hydrogen, rather than liquid fuels. However the reaction conditions, catalyst composition and reactor design can be tailored to produce a higher selectivity of heavier alkanes, though not without challenges.

Catalyst challenges, shown in Table 2.11, are a key issue in commercialising aqueous phase reforming. The process makes use of commercially available catalysts, and faces similar catalyst challenges to pyrolysis oil upgrading, including deactivation and coking. While catalyst choice is very specific to the desired product (for example hydrogen versus alkanes) selectivity (especially to liquid hydrocarbons) is a challenge, together with catalyst tolerance and poisoning during liquid phase, and catalyst durability and lifetime. Catalyst innovation is required to address these challenges, as well as reduce costs for scale-up. Further challenges to scale-up include improved reactor design, and process integration issues. The key technical challenges and corresponding technical needs are given in Table 2.11. Interview information was supplemented with E4tech & TUHH (2016)[7].

Table 2.11: Technical challenges and development needs for aqueous phase reforming & upgrading

Technical challenges	Corresponding development needs
Low selectivity to liquid long-chain hydrocarbons – current production has large gaseous yields and wide range of aromatics	Increase selectivity to liquid hydrocarbons, through process condition optimisation or catalyst development
Catalyst lifetime is short due to deactivation and coking	New or optimised catalysts with higher lifetimes at given process conditions
Limited testing and low yields when using 2G sugars (C5), due to less homogeneous feedstock and impurities introduced from the pre-treatment steps	Adaptation of the catalysts to improve tolerance and conversion of C5 sugar structures
Upgrading is almost completely unproven (only lab tests done), and ability to input bio-crude into front end of oil refinery still to be tested	Full characterisation of bio-crude, collaboration with oil refineries, provision of samples, subsequent optimisation of APR process based on test results

[22] Virent (2016) "Strategic consortium announced to commercialize Virent's Bioforming technology for low carbon fuels and bio-paraxylene". Available at www.virent.com/news/strategic-consortium-announced-to-commercialize-virents-bioforming-technology-for-low-carbon-fuels-and-bio-paraxylene/

2.7 Catalytic conversion of 2G alcohols to hydrocarbons

Brief description

Short chain alcohols (such as ethanol, methanol, n-butanol and isobutanol) can be catalytically converted to longer-chain hydrocarbon fuels, including gasoline, diesel and jet fuel. The conversion of ethanol or butanol molecules typically involves a combination of dehydration (to ethene or butene), then oligomerisation reactions (combining molecules into longer-chains), followed by hydrogenation (adding hydrogen), isomerisation (branching to meet fuel specifications) and finally distillation into the required product streams (as shown in Figure 2.7).

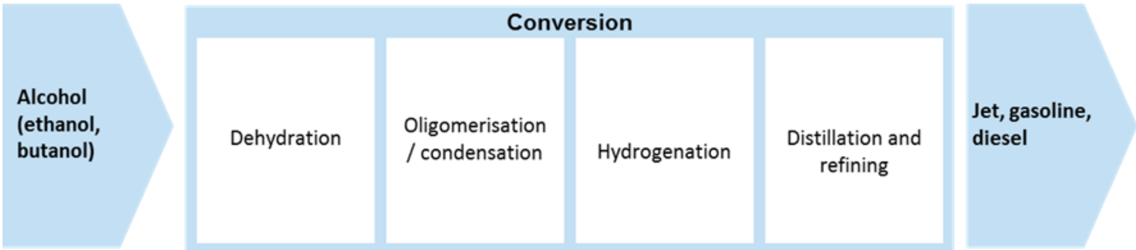


Figure 2.7: Generic process diagram for conversion of alcohols to hydrocarbons

The process for methanol to gasoline (MTG) follows a different conversion pathway (as shown in Figure 2.8), which includes dehydration of methanol over a catalyst to form dimethyl-ether (DME), followed by further catalytic dehydration and hydrogenation reactions via light olefins to gasoline. The main co-products are LPG and water.

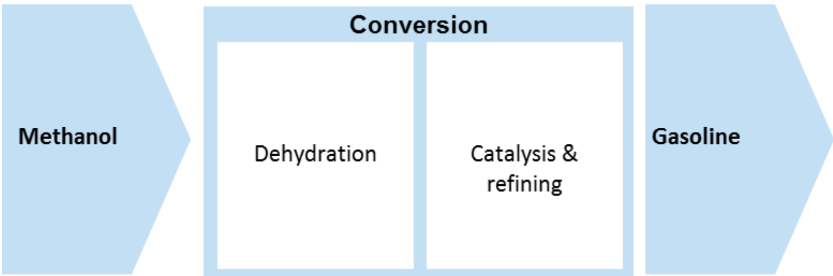


Figure 2.8: Generic process diagram for conversion of methanol to gasoline

Each catalysis step involves a relatively standard fossil fuel industry process; however the overall integrated plant can be relatively complex, adding capital costs and efficiency losses on top of the biomass to alcohols section of the fuel supply chain. Whilst most of the biomass-derived alcohols currently converted are based on 1G sugars, a small handful of developers (including Gevo and Biochemtex) have started looking at conversion of lignocellulosic alcohols.

Development status

Since 2G alcohols are (almost) chemically identical to their 1G alcohol or fossil alcohol counterparts, the TRL of catalytic conversion to drop-in hydrocarbons is largely unrelated to the origin of the alcohol. This allows licencing of commercialised fossil methanol/ DME to gasoline technology from

ExxonMobil, or commercial ethanol dehydration technology from Axens, Technip (via BP) or Chematur, or commercial oligomerisation technology from AkzoNobel, Albermarle or BASF (amongst others) – with a very wide range of commercialised hydrogenation options. There are fewer commercial offerings for (iso)butanol dehydration and (iso)butene oligomerisation than technologies based on ethanol or DME – although the principles are the same, different isomers introduce some challenges, and the longer four carbon chains mean product carbon distributions only fit multiples of four (C8, C12, C16). It is also possible for acetone, butanol, ethanol (ABE) mixtures to directly undergo condensation and oligomerisation reactions to form a distribution of ketones, which can then be hydrotreated to diesel, jet or gasoline, but this is still at lab scale.

Overall, technologies from 2G alcohols to hydrocarbon product are currently operating at **TRL 5**, but could progress quickly given decades of prior fossil or 1G biofuel experience.

Global production activity and key UK actors

The known biomass based alcohol to hydrocarbon projects at pilot scale and above, which are underway worldwide, are shown in Table 2.12. A key focus has been on jet fuel production to date.

Table 2.12: Current alcohol-to-hydrocarbon projects worldwide

Company & plant location	Feedstock	Product(s)	Scale	Status (Start date)	Production capacity (ML/yr)
Sundrop Fuels / ExxonMobil (USA)	Methanol *(from wood syngas + nat gas H_2)*	Gasoline	First commercial	Planned (2020)	183.0
Gevo (USA)	Isobutanol *(from corn)*	Jet fuel	First commercial	Planned (~2020)	34.0
Swedish Biofuels (Europe)	Ethanol *(from wood, wastes)*	Jet fuel	Demo	Planned (2018)	6.2
Gevo (USA)	Isobutanol *(from corn)*	Jet fuel	Pilot	Operational (2011)	0.28
PNNL / Imperium / Lanzatech (USA)	Ethanol *(from wood syngas)*	Jet fuel	Lab	Operational (2016)	~0.01
Swedish Biofuels / Lanzatech (USA)	Ethanol *(from steel mill syngas)*	Jet fuel	Lab	Finished (2012)	~0.01
Swedish Biofuels / KTH (Sweden)	Ethanol, butanol	Jet fuel	Lab	Operational (2011)	0.01
Byogy / Texas A&M University (USA)	Ethanol	Diesel	Lab	Operational (2008)	~0.0
Energy Biosciences Institute / BP (USA)	Acetone, butanol & ethanol *(from corn)*	Diesel	Lab	Operational	~0.0

There are no known UK industrial actors currently working on alcohol to hydrocarbon technologies. BP were working on an ethanol to diesel route, but sold the rights to their ethanol to ethylene technology to Technip. BP and DuPont’s JV, Butamax, has a UK pilot plant, but is primarily focused on isobutanol for gasoline blending, having reached an agreement with Gevo after many years of legal disputes (with Gevo leading on jet development), and hence is not considered further here[23].

Technical challenges and needs

The biggest remaining technical challenge to alcohol-to-hydrocarbon technology is optimisation of the process conditions towards greater throughput and reduced recovery losses, whilst minimising the risks of runaway reactions. This is all technically feasible, but a lack of a full-scale end-to-end pilot or demonstration plant operating globally for ethanol or butanol to diesel/jet means that project engineering and design will be slower (as no available directly applicable learnings to transfer).

Processing costs, particularly if including hydrogen to increase product yield, or using high pressure vessels, are also challenges to be addressed, although the economics of these plants is generally dominated by the starting alcohol price[24]. The key technical challenges and corresponding technical needs are noted in Table 2.13. These have been collected via developer interviews and literature sources such as E4tech & TUHH (2016)[7] and Karatzos *et al*. (2014)[24].

Table 2.13: Technical challenges and development needs for alcohols-to-hydrocarbon catalysis

	Technical challenges	Corresponding development needs
Alcohol to jet / diesel	Runaway risk since first dimerisation step proceeds very quickly/highly exothermic, can lead to reactor hot-spots and damage	Use of a solvent to dilute ethane/butene and manage thermal profile across reactor
	Trace levels of contaminants found in 2G alcohols compared to 1G or fossil alcohols may deactivate catalysts[25]	Further testing needed to assess species present and their impact
	Difficult to scale-up due to slurry reactors and heat exchanger installations	Simplify equipment setup, simulate different system configurations
	Single pass catalyst selectivity to desired product range is not always high, and in some systems light ends cannot be recycled leads to large losses	Choose catalysts to improve conversion yields using recycle loops, and reduce lights and heavies
Methanol to gasoline	Deactivation of zeolite catalysts for conversion of DME to gasoline by carbon deposition in fixed bed applications, need batch-wise regeneration of catalysts with oxygen, and a high number of maintenance intervals	Robust catalyst systems with greater availability
	MTG is conventionally a multi-step conversion process (methanol/DME/olefins/gasoline), with multiple steps which is complex and potentially costly	Demonstrate effective integration of the conversion processes to reduce process costs. If methanol generated from syngas, can instead go straight to DME

[23] Butamax (2015) "Butamax and Gevo Enter into Global Patent Cross-License and Settlement Agreements to Accelerate Development of Markets for Bio-based Isobutanol and End All Litigation". Available at: http://www.butamax.com/Portals/0/pdf/Butamax%20Gevo%20Press%20Release%2008-24-15.pdf

[24] Karatzos *et al*. (2014) "The Potential and Challenges of Drop-in Biofuels", IEA Bioenergy Task 39. Available at http://task39.sites.olt.ubc.ca/files/2014/01/Task-39-Drop-in-Biofuels-Report-FINAL-2-Oct-2014-ecopy.pdf

[25] Jernberg *et al*. (2015) "Ethanol dehydration to green ethylene". Available at www.chemeng.lth.se/ket050/Finalreport2015/COWIFinal.pdf

2.8 Commercialisation outlook

Based on the assessment of all the technologies currently under development, including their status and projects underway globally, and their remaining technical barriers, it is likely that only a small number will be available for production in the UK in the near-term. Given the current TRLs when using the feedstocks within the scope of this study, many routes will not commission their first commercial plant until after 2022, i.e. reach full operation until ~2025. The construction and operation of UK facilities will also be dependent on factors beyond just the technology status (such as feedstock availability, financing, long-term policy support etc.).

Nevertheless, Table 2.14 summarises the various technologies and their technology readiness levels, with a corresponding estimated date for commissioning of a first commercial plant (based on the TRL and current projects in planning). The development status of these technologies, and a pragmatic view of roll out and ramp-up rates (based on experience from other more advanced technologies such as LC ethanol) is anticipated to be a limiting factor for a UK advanced drop-in biofuel plant. This is modelled and discussed in more detail in Chapter 5.

Table 2.14: Technology status and global commercialisation estimates

Technology	Development status (with 2G feedstocks)	Earliest commissioning date of a 1st commercial-scale plant
Gasification + FT synthesis	TRL 5-6	2020-2021
Fast pyrolysis + upgrading	TRL 5-6	2020-2022
Catalytic conversion of 2G alcohols to hydrocarbons	TRL 5	2022-2023
Aerobic fermentation of 2G sugars to hydrocarbons + upgrading	TRL 5	2022-2024
Aqueous phase reforming of 2G sugars to hydrocarbons + upgrading	TRL 4-5	2023-2024
Hydrothermal liquefaction + upgrading	TRL 4	2023-2025

3 Feedstock availability assessment

3.1 Introduction

The potential production of advanced drop-in fuels in the UK depends on the availability of a range of biomass feedstocks that could be used in their production. This chapter analyses the overall potential feedstock availability, regional variations to establish potential suitable locations for production plants, and whether feedstock availability or access will be a constraint to advanced fuel production.

Although there are multiple ways of classifying a biofuel as "advanced"[26], one defining feature of advanced biofuels is their use of waste or residue feedstocks. This study therefore considers the following feedstocks for analysis:

- Municipal solid waste (MSW)
- Agricultural residues (straw and manure)
- Forest and forestry product residues
- Wood waste
- Industrial wastes and residues
- Imported feedstocks (wood pellets and potentially agricultural residue pellets)

Some waste biomass feedstocks such as tallow and used cooking oil (RED Annex IXb feedstocks) are outside of the scope of this report as production of biodiesel from these feedstocks is already well established, and they are unlikely to be eligible as a feedstock for development fuels[27,28]. Perennial energy crops, such as Miscanthus and short rotation forestry, are also outside the project scope. They are not anticipated to be a significant resource by 2030[29], though could complement other feedstocks to feed a plant. Micro-algae is also excluded, as the technology for commercial-scale algae cultivation and conversion is not anticipated to be available or economically viable by 2030[30].

For each feedstock the current UK production is presented, along with details of how this feedstock is used in the UK. The amount of feedstock that is not currently used, taking into account any additional sustainability or logistical constraints on feedstock access, is considered to be the amount available for biofuel production. An outlook of feedstock availability to 2030 is also given. A regional breakdown of the current feedstock availability assesses whether the volumes in a given area might be able to supply a commercial-scale conversion plant. Potential plant locations using the most accessible feedstocks are explored further in a set of short case studies, with a description of some of the challenges and opportunities particular UK locations may provide.

[26] Classification approaches may be based on feedstock, GHG emissions savings, technology maturity, and product type or quality. At present no standard definition has been agreed globally

[27] A 'development fuel' is a fuel made from a sustainable waste or residue (subject to waste hierarchy test and excluding UCO and tallow) or a non-biological renewable fuel. This is subject to an upcoming consultation of changes to the Renewable Energy Directive (RED).

[28] Hood, J. (2016), "Biomethane transport fuel", Department for Transport. Available at www.cngservices.co.uk/images/BiomethaneDay/2016/09Jonathan-Hood-DfT-Biomethane-Day-2016.pdf

[29] Uptake of perennial non-food energy crops has been limited due to lack of specialist planting and harvesting equipment, previously poor establishment and management practises, limited local supply infrastructure, high upfront establishment costs and low economic viability for farmers [NNFCC (2012) "Domestic Energy Crops; Potential and Constraints Review". Available at www.gov.uk/government/uploads/system/uploads/attachment_data/file/48342/5138-domestic-energy-crops-potential-and-constraints-r.PDF]

[30] E4tech & TUHH (2016) "Innovation Outlook: Advanced Liquid Biofuels", International Renewable Energy Agency (IRENA). Available at www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=2741

Data on feedstock availabilities is taken exclusively from publicly available literature. For current UK feedstock production and projections to 2030, data is taken from a study carried out by Ricardo for the Department of Business, Energy and Industrial Strategy[31]. This data has been compared to, and supplemented by, additional information on regional availability and existing uses of feedstocks from other publically available sources which are referenced throughout.

It should be noted that choice of feedstock may depend on or influence the conversion technology to be deployed. In general, fermentation yields are sensitive to variable feedstock composition due to the specialised nature of the microorganisms involved, while thermochemical processes are more able to treat contaminated or heterogeneous waste (such as MSW), but often with equipment maintenance and product clean-up issues. The use of different feedstocks with different technologies is illustrated by the list of current projects found in Chapter 2. It should also be noted that whilst a **first commercial-scale advanced drop-in biofuel plant is likely to need at least 200 – 500 ktpa of feedstock** (to produce ~35 – 130 million litres of fuel, depending on the technology), some of the technologies being investigated (such as pyrolysis or biological routes) could potentially operate commercially at smaller scales.

3.2 Municipal solid waste

Municipal solid waste (MSW) is likely to be an attractive feedstock for the UK advanced biofuel industry. Policy and regulation are encouraging the diversion of waste away from landfill and towards higher-value uses: higher landfill taxes have made MSW increasingly expensive to dispose of, so it is likely to be available to advanced biofuel producers at very competitive (negative) prices. In addition, MSW is available across the UK, is produced throughout the year, is not dependent on another industry (e.g. agriculture, forestry), and needs to be dealt with sustainably. The ambitious recycling targets and current legislative framework for waste in the UK originate mainly from European directives. Future legislation once the UK leaves the EU would need to consider the impact on the viability of the waste reprocessing industry, including any new advanced biofuel production capacity.

Resource availability across the UK

The biological fraction of waste produced by households and commercial and industrial (C&I) sources, commonly known as biodegradable municipal waste, is a valuable feedstock for the production of advanced biofuels. However, there are several existing uses of this biological fraction of waste, primarily in the paper industry, for composting, plus generating biogas in anaerobic digestion (AD) or heat & power from energy from waste (EfW) plants[32]. In the UK, the priority for use of waste is governed by the waste hierarchy, which prioritises prevention, reuse and recycling (Figure 3.1).

[31] Reference to be included upon publication. Referred to here as Ricardo (2015)
[32] Energy from waste refers to all forms of waste incineration with energy recovery. Some waste undergoes mechanical biological treatment (MBT) to produce a more readily-combustible fuel, but this is not an EfW technology in itself.

Figure 3.1: EU waste hierarchy from the EU Waste Framework Directive

The use of MSW for production of biofuels falls under the category of 'other recovery', which also encompasses AD and EfW. As the use of waste for biofuel production is thus preferable to other forms of disposal, such as landfill and incineration without energy recovery, the biological fraction of waste that is currently disposed of in these ways is considered to be available for advanced biofuel production, and forms what is defined here as the accessible feedstock.

The biogenic fraction of MSW is estimated by Ricardo (2015)[31]. In 2015, they estimate that the total arising of biological MSW from households and C&I sources is 40.2 Mtpa (wet). Of this, 28.4 Mtpa (wet) is currently used in alternative applications, comprising around 5.4 Mtpa (wet) used for energy, and the remainder used in recycling or composting. Therefore Ricardo calculate that the available biological MSW resource is currently 11.8 Mtpa (wet) – a figure that is slightly higher than the 8.6 Mtpa (wet) of biological MSW sent to landfill in 2014[33]. The accessible potential of biological MSW for energy uses out to 2030 is shown in Figure 3.2.

Tolvik (2016)[34] also suggest potentially comparable amounts of MSW used for energy generation, estimating that 4.39 Mtpa (wet) of biogenic MSW was consumed at EfW facilities in the UK in 2015 (based on a 51.8% biogenic content for the (wet) 8.48 Mtpa of residual waste and RDF consumed) – although this only considers EfW facilities, and not gasification/pyrolysis, cement kilns and AD treatment options which will add to the total consumption for energy. This Tolvik study also found that 17 of the 37 EfW plants are now accredited as energy recovery (rather than disposal) facilities under the Waste Framework Directive.

[33] Defra (2016) "Digest of Waste and Resource Statistics – 2016 Edition (revised)". Available at www.gov.uk/government/uploads/system/uploads/attachment_data/file/508787/Digest_of_Waste_and_Resource_Statistics_rev.pdf
[34] Tolvik (2016) "UK Energy from Waste Statistics – 2015". Available at www.tolvik.com/wp-content/uploads/UK-EfW-Sector-Report-2015-Final.pdf

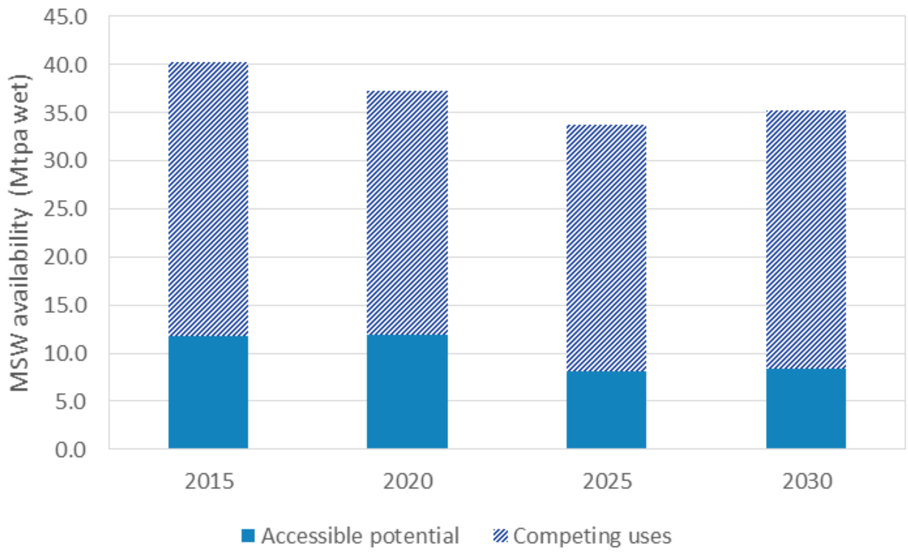


Figure 3.2: Biological MSW accessible for UK energy uses from 2015 to 2030[31]

Ricardo (2015) figures may present an optimistic picture of the future availability of biological MSW, due to assuming little growth in competing demands. Improving reuse rates decrease the overall volumes of wastes generated, but increasing recycling rates also decrease the accessible potential (although recycling rates have recently stalled below the 2020 target level). Furthermore, Eunomia (2015)[35] suggest that at the end of 2015, 14.9 Mtpa (wet) of waste treatment capacity had been granted planning consent, and consent was being sought for a further 1.8 Mtpa (wet) capacity (these are full capacities, not just biogenic fractions). Although not all of these EfW and AD plants will become operational, these figures suggest that the capacity for competing uses of biological MSW is likely to increase significantly into the future, therefore potentially substantially decreasing the amount of feedstock available to advanced biofuels. The amount of additional EfW capacity that actually becomes operational is likely to be heavily dependent on the landfill tax and gate fees going forwards, plus local competition effects.

Non-recyclable (residual) waste is made up of three main waste streams: untreated mixed waste; refuse derived fuel (RDF) and solid recovered fuel (SRF). The majority of this residual waste has traditionally gone to landfill (75% in 2012), followed EfW (19%) and export (3%), however this is changing rapidly, and by 2020 the UK is expected to see the majority going to EfW (56%) and increased levels of exports (9%)[36].

The lack of EfW capacity in the last few years has seen RDF exports from the UK increasing from 0.01 Mtpa in 2010 to ~3.3 Mtpa (wet) in 2015 (total waste tonnage, not just the biogenic fraction), with export predominantly to the Netherlands, plus Germany, Denmark, and to a lesser extent the rest of Scandinavia and the Baltics[33]. This ~1.6 Mtpa (wet) of exported biogenic RDF offers a potential feedstock for advanced biofuel production depending on export contracts - which are likely to be shorter in length than most residual waste contracts that local authorities in the UK have in place.

[35] Eunomia (2015) “Residual Waste Infrastructure Review, Issue 9”, December 2015. Available at www.eunomia.co.uk/reports-tools/residual-waste-infrastructure-review-9th-issue/

[36] UK Green Investment Bank (2014) “The UK residual waste market”. Available at www.greeninvestmentbank.com/media/25376/gib-residual-waste-report-july-2014-final.pdf

However, residual waste levels in the UK are projected to fall significantly to 2030 (with increased reuse and recycling), and a large number of new treatment facilities are due to be operational by 2020, i.e. waste gate fees are likely to fall as competition increases. The capacity gap for landfilled waste could therefore disappear by 2020, as shown in Figure 3.3 (note that this shows Mtpa of the total waste arising, not just the biogenic fraction). Although Eunomia forecast exports of RDF and SRF to remain high to 2030, these may fall over time with the residual waste trajectory (depending on contracts and pricing), and may no longer be an available feedstock in the UK after 2025, except in specific locations. Existing EfW plants will also retire slowly over time, unlocking some waste contracts for possible use in transport fuels, but the wider trend is a significant tightening of the market.

Given our current exports of waste, it is not impossible that the UK could in the future import wastes to meet UK demands, including as feedstock for advanced biofuel plants, but this would come with an added cost, and depend on the wider NW Europe waste treatment market, plus currency movements and any trade tariffs upon the UK's departure from the EU. However, the key message is that the very large volumes of very negative cost biogenic MSW that have previously been sent to landfill are likely become unavailable (or significantly higher price/less negative cost) in the near-term, certainly before any commercial scale advanced drop-in biofuel plant is built.

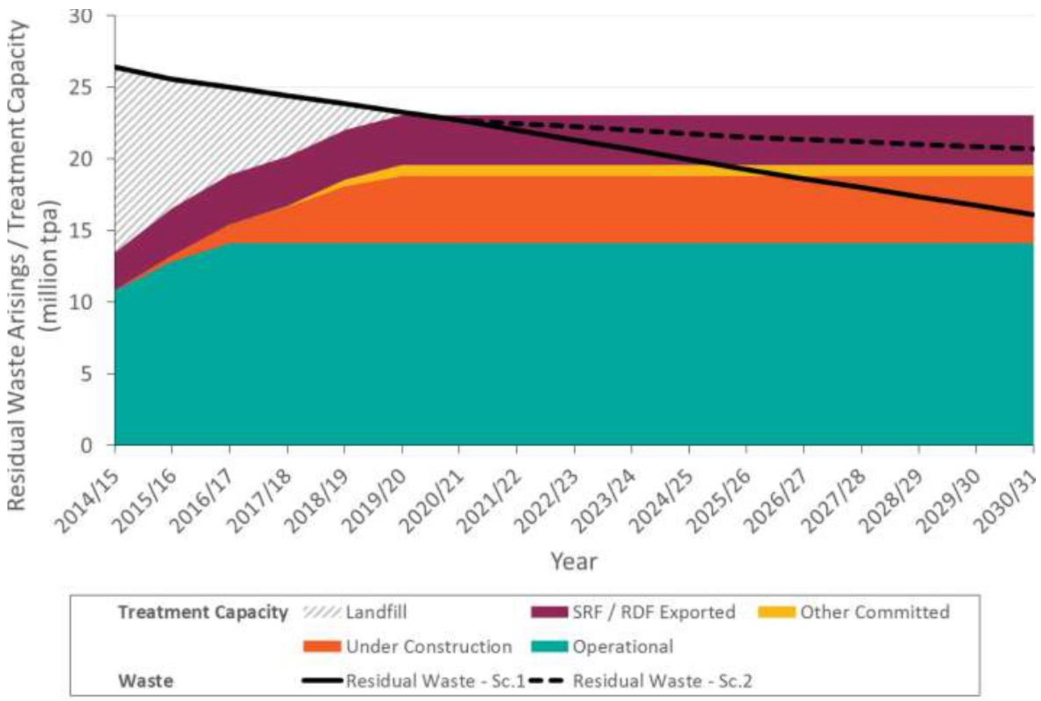


Figure 3.3: Potential future residual waste capacity gap in the UK[37] (wet tonnes, fossil and biogenic)

[37] Eunomia (2015) "Residual Waste Infrastructure Review Issue 9". Available at www.eunomia.co.uk/reports-tools/residual-waste-infrastructure-review-9th-issue/

Regional waste availability

The amount of MSW generated varies significantly according to location. In addition, the proportion of the total waste that is generated that is biological is likely to vary between regions, although this variation is anticipated to be smaller than the variations in total waste generated in each area.

The majority of waste generated in the UK is generated in England. A breakdown of local authority collected waste, which excludes recycled waste but includes waste directed to competing uses, is given in Figure 3.4 (note that this shows Mtpa of waste, not just the biogenic fraction). Bars show on the left hand axis the amount of local authority collected waste, excluding recycled waste, in the UK. Yellow points show the on right hand axis the percentage of local authority collected waste that is landfilled or incinerated without energy recovery.

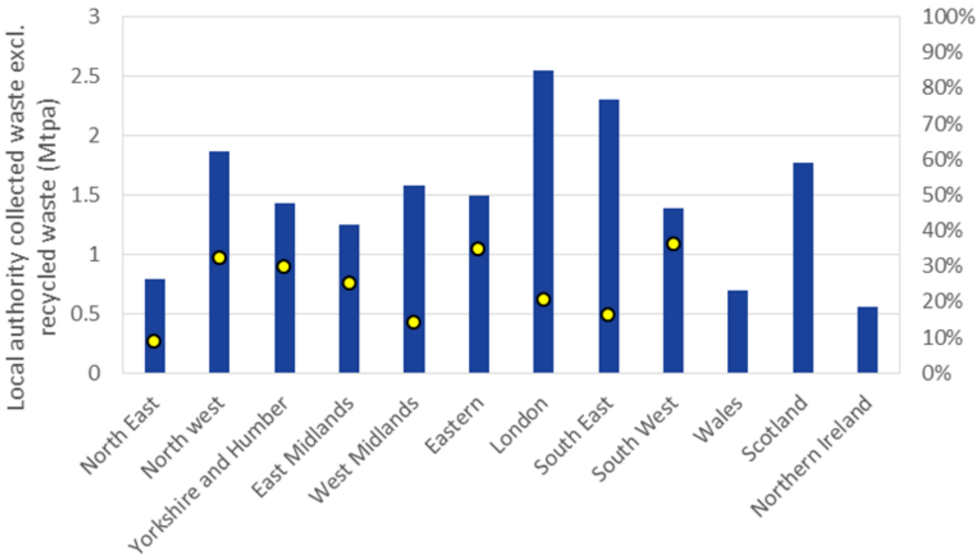


Figure 3.4: Regional availability of MSW (wet), excluding recycling, in 2014/15[38]

This chart shows that London, the South East and the North West of England generate the greatest amount of MSW. However, the current use of waste is not uniform across these regions. This means that a high volume of waste arising does not necessarily correlate with a large volume of currently underutilised biological waste in a region. Figure 3.4 indicates that although London and the South East produce high volumes of waste, a relatively high proportion of this currently undergoes recycling, composting or energy recovery. However, regions with relatively high waste production, and a high percentage currently going to landfill or incinerated without energy recovery, such as the North West, the East or the South West of England, could show potential for locating an advanced biofuel plant.

Logistical, infrastructure and other considerations

There is an existing infrastructure for waste collection and management, which could be capitalised on to create an economic feedstock supply chain. However, MSW is generally governed by long waste-collection contracts, which can last up to 20 years. It is unlikely that waste that is tied up in

[38] Due to the nature of the data, figures from Scotland may be slightly underestimated compared to other data points

contracts would therefore be available for advanced biofuel production until the contract has expired or it is purchased from the waste management contractor. In addition, transport of MSW can be expensive and energy intensive due to its low energy density and potentially hazardous nature. Therefore location of an advanced biofuel plant in an area with a high local availability of biological MSW would be a key economic consideration.

Potential plant locations in the UK

MSW appears to be an important potential feedstock for advanced biofuel production, however the location of such a plant is very dependent not only on regional availability but also accessibility in the face of long-term waste management contracts. The potential locations identified here (see Figure 3.5) have been selected based on the highest volumes of potentially available resource (MSW reported by local authorities as **currently** going to landfill or incinerated without energy recovery – not considering planned EfW plants), combined with the suitability and availability of existing infrastructure or industrial clusters and access to ports for potential import of feedstock or diversion of currently exported RDF.

A number of areas with both high population and waste generation, which would seem suitable locations, were excluded for reasons as follows:

- *Cornwall*: There is a contract in place until 2039 covering diversion of waste from landfill to EfW with Cornwall's last remaining landfill aiming to close in 2018
- *South Wales*: The level of available feedstock was considered too low as only 290 ktpa waste went to landfill or was incinerated without EfW throughout Wales in 2015/16. Some authorities export waste abroad but this is likely to be too small an amount to be a feasible feedstock source
- *West London*: Despite having the fifth largest amount of waste going to landfill or incineration without EfW the West London Waste Authority (WLWA) recently signed a 27 year contract for residual (non-recycled) EfW waste services, with EfW facilities already constructed, meaning 96% of WLWA waste will be diverted from landfill and unavailable as an advanced biodiesel feedstock
- *West Midlands*: Due to high levels of incineration with EfW the level of available feedstock was considered too low.
- *Merseyside*: Merseyside Recycling and Waste Authority (MRWA) currently has 320 ktpa MSW going to landfill or incinerated without EfW, but has contracts for recycling, and residual recovery by rail to Teesside. Although there are three landfill contracts, there are gasification and MBT plants under construction, with another EfW plant committed, hence there the amount of feedstock remaining is expected to be limited.

The areas in the section below currently have modest amounts of potentially available feedstock and benefit from established infrastructure and supply chains, however, as with the trend identified in Figure 3.3, none of these areas are immune from increasing competition. In general, the collection of MSW is carried out by or on behalf of the local authority with long term contracts for waste management in place. Discussion is made below of contractual issues and whether residual waste contracts are in place. It should be noted that these locations are not a firm recommendation for siting a plant, but rather an exploration of where in the UK might show potential in light of the factors described here.

1. Basildon, Essex

Essex County Council has ~ 333 ktpa MSW going to landfill or incinerated without EfW. Approximately 50% of this waste will be biological and available as a feedstock for advanced biofuel production.

MSW in the area is managed by the Essex Waste Partnership (EWP), which includes the 12 councils of Essex County Council and Southend-on-Sea Borough Council. In 2009 EWP signed a 25 year contract with Urbaser Balfour Beatty (UBB) to manage all local authority residual waste at a Mechanical and Biological Treatment (MBT) plant in Basildon. This 417 ktpa facility is currently operating, and it is expected that 50% of waste will be processed into SRF or stabilised organic material (SOM) - material potentially suitable for advanced biodiesel production but would need to be purchased from UBB.

Competing uses for the SRF and SOM would be EfW facilities locally or abroad. Basildon has the advantage of being situated near to Tilbury docks if imported material is needed. There is also an RDF facility, managed by Sita UK at Tilbury docks that currently exports RDF abroad, that could potentially be diverted to a UK plant.

2. Manchester, Lancashire

The Greater Manchester Waste Disposal Authority (GMWDA) has ~331 ktpa MSW going to landfill or incinerated without EfW, while Lancashire County Council has ~261 ktpa.

In 2009, GMWDA signed a 25 year recycling and waste management contract for the treatment of residual waste, which has involved the construction of five MBT and four AD plants. Non-recycled waste is processed into RDF for a combined heat and power generation facility and in-vessel composting recycles segregated garden waste. Unless the RDF could be diverted to advanced biofuel production or the contract could be bought out, very little of this additional material would be available before 2034. The Lancashire Waste Partnership (LWP) signed a 25 year contract with Lend Lease and Global Renewables Lancashire Limited in 2007 but LWP took over ownership of this contract in 2014 to allow a focus on waste reduction. Two MBT plants near Blackpool and Preston use residual non-recyclable organic waste to produce a high quality compost-like product, which is used for land restoration and tree planting across the county and so would be unavailable for advanced biofuel production. LWP have a target of 88% diversion of waste from landfill by 2020 so there will still be some feedstock available, although the biological content of this may be lower.

3. Scottish Lowlands

The Scottish Lowlands region, from Greenock in the West to Edinburgh in the East, currently sends ~ 580 ktpa MSW to landfill, with Glasgow City Council sending the most at ~ 162 ktpa (73% of MSW generated in Glasgow). Glasgow City Council is building a new recycling and renewable energy centre at Polmadie to handle 200 ktpa residual waste from Spring 2017, aiming to divert 80% of waste from landfill to EfW, which will absorb a significant proportion of the currently available waste. While recycling targets and circular economy practices are currently competing uses for MSW, advanced biofuel could have a significant role in Scotland as part of a future bio-economy.

Scotland has ambitious targets for recycling (70% rate by 2025, no more than 5% of waste to landfill), food waste reduction (33% reduction by 2025 and separate collection of food waste with no separately collected material going to landfill) and a strategy for a circular economy, which will put strong downwards pressure on the future availability of Scottish wastes. However, Scotland has also brought in separate household and commercial organic waste collection, which may benefit an advanced biofuel plant requiring this biogenic waste fraction only. Any advanced biofuel plant would need to integrate into this strategy, which includes Scotland's ambition to increase the proportion of biological wastes being used for production of high value materials and chemicals, followed by increased production of renewable fuels, heat, and fertiliser products. Scotland also has a Biorefinery Roadmap which aims to develop the conversion of sustainable feedstocks into renewable products such as biofuels.

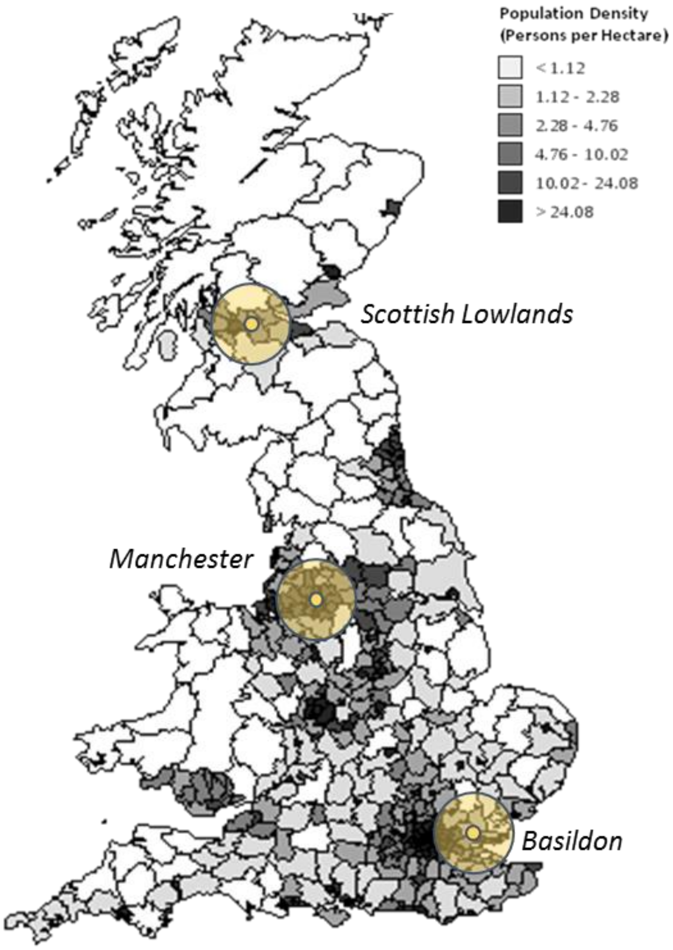


Figure 3.5: Potential locations for sourcing MSW feedstocks, on a GB population density background[39]

3.3 Straw

Straw may be an attractive feedstock for advanced biofuel production in the UK. It does not compete directly with food (other than barley and oat straw used for animal fodder), is not likely to be contaminated, and usually has fairly homogenous characteristics across different suppliers. Due to the composition of the straw – predominantly cellulose and hemicellulose - it is much easier to

[39] Vision of Britain (2010) "Population Density (persons per hectare) in 2001". Available at www.visionofbritain.org.uk/atlas/data_map_page.jsp?data_theme=T_POP&data_year=2001&u_type=MOD_DIST&u_id=&date_type=1Y&data_rate=R_POP_DENS_H

extract sugars from straw than from feedstocks such as wood or municipal solid waste, which contain a higher proportion of lignin or are more heterogeneous. However, the high ash, chlorine and alkali metal content of straw make its use in thermochemical routes more challenging.

Resource availability across the UK

Straw is a by-product of cereal crop cultivation, and in the UK is mainly derived from wheat, barley, oil seed rape and to a lesser extent oats[40]. Therefore the total amount of straw that is produced annually is determined by the areas of these crops that are grown, together with crop yields and straw to grain ratios achieved (straw availability can vary 30% between harvests).

Ricardo (2015)[31] estimate that of the 10 Mtpa (dry) of straw produced in the UK, 4.9 Mtpa is currently used, primarily in livestock bedding, leaving 5.1 Mtpa potentially accessible for advanced biofuel production. Other older references indicate similar total straw production figures to those given by Ricardo (Table 3.1) after adjusting for moisture contents – although this is slightly coincidental given Ricardo do not include oilseed rape straw production, but do include dry chicken litter. However, the low estimate of current competing uses given by Ricardo results in a slightly higher estimate of the straw that could be available to advanced biofuel production compared to the other two sources.

Table 3.1: Straw resource in the UK (Mtpa, dry)

	Total production	Currently used in energy	Currently used in other applications	Potentially available to adv. biofuel
Ricardo (2015)[31]	10.0	0.3	4.6	5.1
NNFCC (2014)[40]	9.9	Data not given	6.5	3.4
AHDB (based on data from 2012)[41]	10.4	0.3	5.4	4.8

The straw resource going to energy uses has increased significantly since 2014, with the start-up of the 250 ktpa (wet) Brigg Biomass Plant and the 240 ktpa (wet) Sleaford Plant, and another 250 ktpa (wet) plant currently under construction at Snetterton. This is in addition to the 210 ktpa (wet) plant at Ely which has been running since 2000. Therefore the straw potentially available to advanced biofuels may be anticipated to drop by up to 0.63 Mtpa (dry) from Table 3.1 figures once all three new plants are operational.

Some straw must be left on the field in order to replenish soil organic matter and improve the structure and nutrient status of the soil[40], but the percentage straw removal rate can vary significantly and there is considerable debate in the farming and scientific community about the removal % that can be achieved on different soils. The figures presented by Ricardo, NNFCC and AHDB suggest that all of the straw that is currently left on fields could be used for additional biofuel production, so these figures should be viewed as an upper limit for the accessible feedstock and agronomic conditions and practices considered carefully. For example, high straw recovery rates in

[40] NNFCC (2014) "LBNet Lignocellulosic feedstock in the UK". Available at http://lb-net.net/wp-content/uploads/2015/04/LBNet-Lignocellulosic-feedstock-in-the-UK.pdf
[41] AHDB (n.d.) "Straw". Available at www.ahdb.org.uk/projects/straw.aspx

livestock farming-orientated regions may not result in a soil nutrient or organic matter deficit because farmyard manures and animal slurries are returned to the land in the locality.

Ricardo (2015)[31] project that the amount of straw available to the UK advanced biofuel industry is not anticipated to change significantly to 2030, as both the total amount of straw produced and the amount used in competing industries is anticipated to remain constant (Figure 3.6). The total amount of straw produced is dependent on UK cereal crop production which is not anticipated to change significantly before 2030 (despite recent falls in oilseed rape areas), so the estimation of broadly constant total production to 2030 seems reasonable. However, the assumption by Ricardo that the competing feedstock use to 2030 will also remain constant is much less certain. Use of straw for heat and power is strongly influenced by government policy and subsidies, so changes to these could impact demand significantly. Nevertheless, with each straw-fired power station requiring around 0.21 Mtpa (dry) of feedstock, and a total accessible resource of 2.8 - 4.5 Mtpa (dry) after the three new straw plants come online, it is not likely that enough power plants will be built between today and 2030 to make feedstock availability a limiting factor in producing advanced biofuel from straw, although regional competing demands could be a factor.

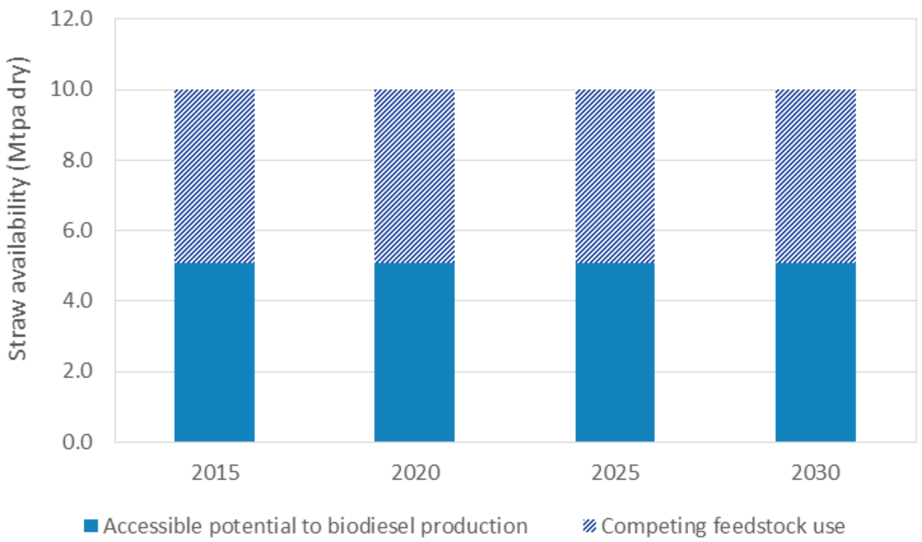


Figure 3.6: Current and projected straw resource[42] in the UK that could be accessible from 2015 to 2030[31]

Regional straw availability

Straw production in the UK varies widely by region (Figure 3.7), and availability of this feedstock is dependent upon:

- *Nature of agriculture in the locality*: Areas which are most suitable for livestock farming tend to have the least arable cropping, because land is devoted to grassland for the livestock. Therefore in these areas there is high demand for straw for livestock feed / bedding and low production, meaning that straw tends to be in deficit. Due to this deficit, a high rate of straw removal tends

[42] These are estimates of 'dry agricultural residues' made by Ricardo. These are predominantly straw, with some husks and chicken litter.

to be practiced in mixed agricultural areas, with soil quality maintained by ready availability of livestock manure as fertiliser.

- *Competing demands in the locality*: This is strongly influenced by the nature of agriculture in the locality. Where arable crop production occurs in / near to areas of significant livestock farming there is likely to be strong demand for the straw for feed and bedding. Existing straw-fired power stations also create competing demand. If straw is produced relatively far from existing demand centres, the high cost of transport may make its collection and sale uneconomic.

A quantitative analysis of potential straw availability and current usage on a regional basis suggests that Yorkshire, the East Midlands and Eastern England have the greatest unused resource, as shown in Figure 3.7. This concurs with a spatially explicit study of the European straw resource[43], which provided higher resolution data of the potential availability of straw for energy in the East of England (shown in Figure 3.8).

In the UK, arable crop production dominates in the East of England, while livestock farming broadly increases to the West. Therefore in the West of England and Wales, straw removal rates tend to be high, and there is likely to be a deficit of straw, while in the East a straw surplus is likely. This East/West availability is shown for illustrative purposes on Figure 3.9. Straw-deficit regions also exist in the North West of England, in Scotland and in Wales.

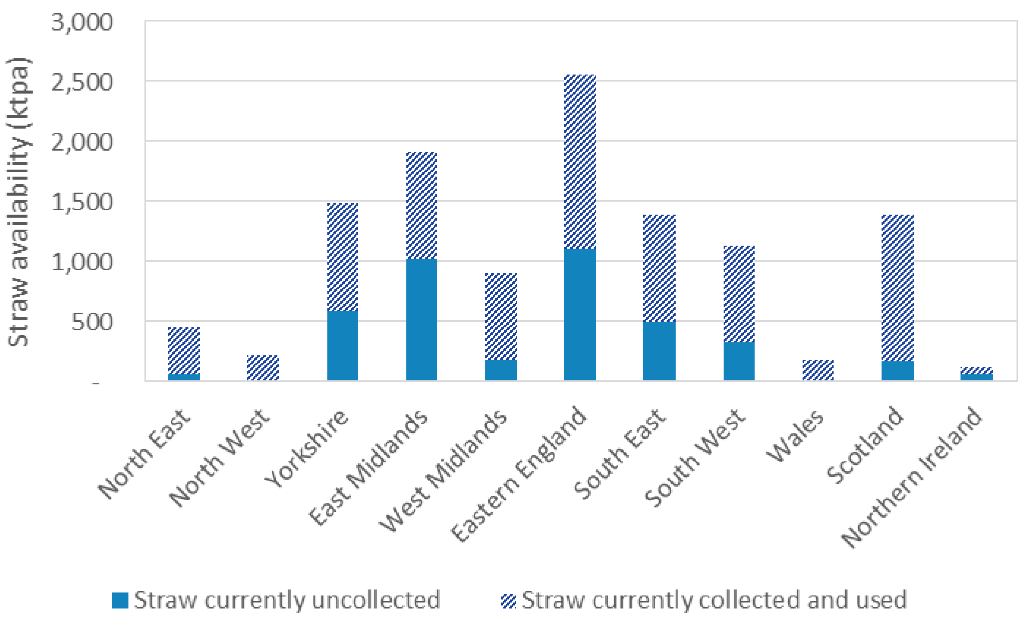


Figure 3.7: Regional straw production, showing current use and uncollected straw that may be available[40]

[43] JRC (2006) "GIS-Based Assessment of Cereal Straw Energy in the European Union", European Commission. Available at http://iet.jrc.ec.europa.eu/remea/sites/remea/files/files/documents/events/%3Cem%3EEdit%20Event%3C/em%3E%20Cereals%20Straw%20Resources%20for%20Bioenergy%20in%20the%20European%20Union/background_paper.pdf

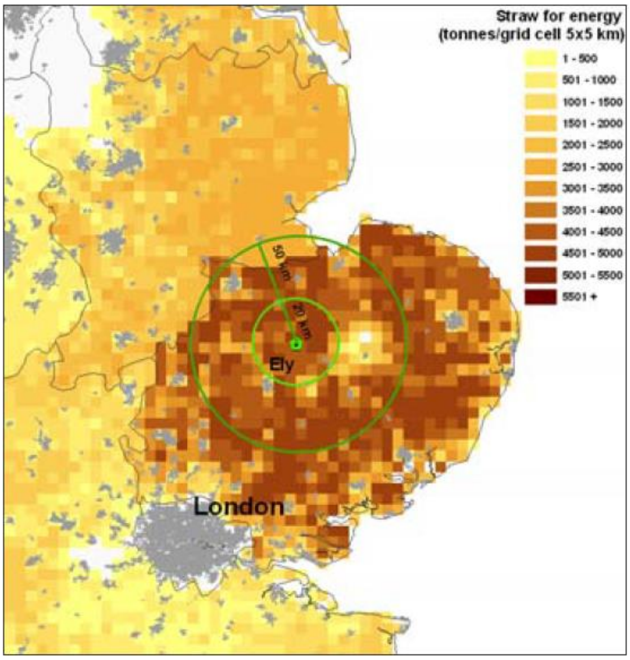


Figure 3.8: Density of straw availability for energy uses in the East of England[43]

Logistical, infrastructure and other considerations

There is a very narrow window of time after crop harvesting in which straw collection can occur, hence this resource is highly seasonal. Therefore, if a plant operates using straw throughout the year, there needs to be significant storage of straw, which can result in degradation and loss of dry matter (plus increased fire risks) if not stored within dedicated buildings or other similar secure and weatherproof facilities. Additionally, the potential timeliness of straw removal operations and the ever-present risk of weather-induced delays, which may restrict subsequent cultivations and the timely establishment of the following crop, are major factors in limiting the rate of straw recovery within regions of apparently significant straw availability.

There is a cost and energy penalty associated with the collection of straw. Straw has a low volumetric density, even when dried and baled making bulk transport expensive. As a result, most existing straw bioenergy plants take the resource from approximately a 30 mile radius around the plant. The distance varies according to regional straw availability, but as an indication, the Ely plant in Cambridgeshire receives its straw from within a 30 mile radius[43], the Snetterton plant (currently being commissioned), expect to bring material in from a maximum 30 – 40 mile radius, and the DuPont corn stover ethanol plant in the US also from within a 30 mile radius[44]. Plants must therefore be located in areas with a high geographic density of straw production.

Potential plant locations in the UK

Due to the high cost and energy associated with transporting low-density straw over long distances, there must be a high availability of straw in a given area for a commercial-scale biofuel plant to be

[44] DuPont (2016) "The DuPont Cellulosic Ethanol Facility in Nevada, Iowa: Leading the Way for Commercialization". Available at www.dupont.com/products-and-services/industrial-biotechnology/advanced-biofuels/cellulosic-ethanol/nevada-iowa-cellulosic-ethanol-plant.html

viable. While regional straw availability is discussed above, the following points should also be considered for siting a straw biofuel plant:

- A long-established industry already exists for baling, storing and transporting straw (for livestock feeding / bedding) from East to West and from Lincolnshire / Yorkshire to the North
- Straw from Essex, Kent, Sussex, Berkshire, Hampshire and Wiltshire is exported to France, Holland and Belgium. Straw from certain of these counties is also likely to go to the West (for example to Somerset, Dorset, Devon & Cornwall)
- Straw may be transported by road over the Dartford Bridge, but not through the Dartford Tunnel. This influences the economics of transporting straw from Kent or Surrey / Sussex North into Essex if, for example, an advanced biofuel plant were to be located in that region
- Competing demands for straw regionally and the agronomic and economic factors which influence current utilisation of the material in each locality could affect the ability of existing power stations to secure sufficient straw supplies. The potential siting of an advanced biofuel plant has to consider the proximity to existing straw-fired power stations.

Considering these issues, the regional nature of straw availability and the practical and logistical restrictions of straw transport, four potential areas for locating a straw biofuel plant have been identified. Each location has been selected primarily on the basis of potential feedstock availability in the locality, known competing demands, and the existence of suitable transport links to serve the location. The proposed sites are illustrated in Figure 3.9, along with existing straw-fired power plants (major competing users as red dots) and the location of the UK's most abundant straw resources (in shaded green). It should be noted that these locations refer to a general area rather than a specific location, and also that this is not a firm recommendation for siting a plant but rather an exploration of where might show potential in light of the factors described above.

1. Bury St Edmunds, Suffolk

There is significant straw production around Bury St Edmunds in Suffolk, North Essex and East Cambridgeshire, which may be able to provide sufficient feedstock for a commercial-scale advanced biofuel plant. There are excellent transport links to this proposed location via the A14, A11, M11 and A12; and an existing industrial cluster on the western fringe of the town, including for example a sugar beet factory. Although there is high straw production in this location, a new biofuel plant near Bury St Edmunds may experience competition for feedstock with existing straw-fired power stations at Ely and Snetterton, both of which are located approximately 25 miles away.

A plant at Bury St Edmunds would also be in close proximity to Thetford Forest, a potential source of forest residues. Depending on the technology deployed at the plant and the economics involved, it may be able to utilise both straw and forest residues to attenuate inevitable seasonality in straw supply.

2. Great Dunmow, Essex

An advanced biofuel plant in Great Dunmow would be sited near intensive cereal growing areas of East, Central and South Suffolk, North and Central Essex, North East Herts and South Cambridgeshire. With no competing straw-fired power stations in the locality, feedstock availability for an advanced biofuel plant would likely be significant and this location has good transport links via the A120, M11, A12 and A121.

3. Ipswich, Suffolk

The third potential plant location is near Ipswich in Suffolk. There are likely to be significant volumes of straw available to this plant, as it could source feedstock from the intensive cereal growing areas of East, Central and South Suffolk and North and Central Essex, and there are no existing straw-fired power plants in the locality. Ipswich has good transport links via the A14 and A12, and depending on the precise location of the plant, could be situated near existing industrial activity and the Port of Ipswich, which recently expanded its dry bulk capability. In addition, the large port at Felixstowe could allow additional feedstock to be imported.

4. South of Grantham, Lincolnshire

A plant sited South of Grantham in Lincolnshire would be able to source feedstock from the surrounding intensive cereal growing regions. However there may be competition for feedstock from Sleaford straw-fired power station. Also, this site may experience greater competition for feedstock supplies from the livestock bedding sector due to a greater proximity to areas of straw deficit than the other proposed locations (Figure 3.9). Grantham has good transport links via the A1 and the A52.

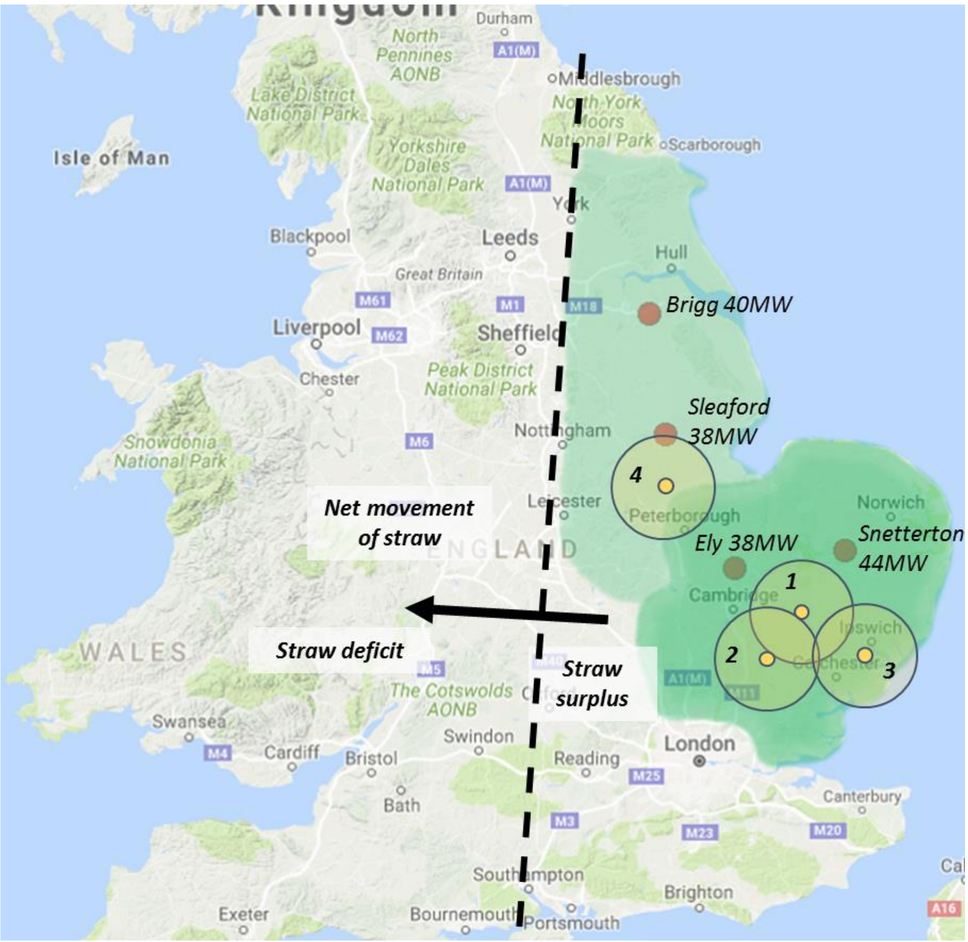


Figure 3.9: Potential plant locations using straw (yellow), with surplus regions (green) and competing plants (red)

3.4 Manure

Manure is an extremely wet source of biomass (can be up to 98% moisture) and consequently is most appropriate for local scale anaerobic digestion (AD), with minimal transport distances involved. The high moisture content is challenging to process for most advanced biofuel technologies, however would be suited to hydrothermal liquefaction.

Resource availability across the UK

Significant volumes of manure are produced across the UK in the agricultural sector each year. Estimates range from 68 Mtpa (wet)[45] to 83 Mtpa (wet)[46] when slurry and solids are included – which Ricardo (2015) equate to around 3.3 Mtpa (dry). Almost all of this manure is currently spread on the land, with a small proportion undergoing AD. The regions with the highest availability are those with the highest livestock numbers, particularly in the Western half of the UK.

As of March 2016, there are over 300 operational AD plants in the UK outside of the sewage treatment sector with a further 450 projects currently under development[47]. There are concerns that reduced government support could hamper the development of small-scale AD going forward[48], suggesting that the rapid increase in UK AD capacity seen in recent years could slow down.

It was estimated that in 2015 around 0.636 Mtpa (wet) of manure were treated through AD[48]. The amount of farm waste (which includes, though is not limited to, manure) that is used in AD plants is anticipated to increase from around 1.3 Mtpa (wet) in 2015 to around 2.5 Mtpa (wet) in 2019[49]. However it is clear that this would remain a very small proportion of the overall manure resource, and at least 65 Mtpa (wet) would still be available to advanced biofuel production if the HTL technology to utilise it were commercialised (which is likely to be in the late 2020s at the earliest).

Logistical, infrastructure and other considerations

Manure can undergo AD and then be returned to the field as fertiliser, therefore manure that is currently used as fertiliser should also be considered as available for AD. If manure were to be used in a production process that does not produce some form of nutrient-rich digestate then the alternative provision of nutrients to the soil should be considered.

The transport of wet feedstock is extremely expensive (on an energy basis) and thus not particularly economic – large conversion plants are highly unlikely to be viable, due to the collection radius. Therefore a high volume of manure in a concentrated area would be required to site an small HTL plant – for example, a concentration of large dairy or livestock farms that house their animals indoors during the winter (for easiest manure collection). Following the production of HTL bio-crude, this high energy dense product could more easily be transported to a centralised upgrading facility.

[45] E4tech (2014) “Advanced Biofuel Feedstocks – An Assessment of Sustainability”, Department for Transport, submitted by Arup URS Consortium. Available at www.gov.uk/government/uploads/system/uploads/attachment_data/file/277436/feedstock-sustainability.pdf
[46] Smith, K.A., Williams, A.G. (2016) “Production and management of cattle manure in the UK and implications for land application practice”, *Soil use and Management*, vol. 32, no. 1, pp. 73-82
[47] NNFCC (2016) “Anaerobic digestion deployment in the UK”. Available at www.nnfcc.co.uk/tools/nnfcc-report-anaerobic-digestion-deployment-in-the-uk
[48] REA (2015) “Evaluating cost-effective greenhouse gas abatement by small-scale anaerobic digestion”. Available at www.biogas.org.uk/images/upload/news_116_REABangorUnismallscaleADreportfinal.pdf
[49] ADBA (2016) “Anaerobic Digestion Market Report”. Available at www.ciwm-journal.co.uk/wordpress/wp-content/uploads/2016/07/marketreport2016-44a4_v1.pdf

3.5 Forestry residues

Forestry residues can include bark, tops, branches, and in some cases tree stumps that are normally left in the forest after felling[40]. The majority of suitable residues managed for commercial timber production originate from softwood (coniferous) forests, as opposed to deciduous plantations. This varied composition, and the absence of national statistics on forest harvesting residues , means there may be significant variation between estimates of the amount of resource available in the UK.

Resource availability across the UK

NNFCC (2014)[40] estimate that the current available forestry waste production in the UK is 1.35 Mtpa (dry), assuming only 80% of residues can be practically collected (for logistical reasons) and a further 50% can be removed sustainably (without affecting the soil). In contrast, Ricardo (2015)[31] estimate an unconstrained feedstock potential in 2015 of 2.1 Mtpa (dry), but it is not clear whether they have accounted for the same sustainability and logistical limitations as the NNFCC report.

Figure 3.10 shows that the majority of this resource lies in Scotland, where most of the UK's forestry industry is located. Based solely on these figures and without considering long-distance transport possibilities, the only location suitable for the establishment of a commercial-scale advanced biofuel plant using forestry product residues would appear to be Scotland. The largest regional source of sustainable and recoverable forest residues is almost certainly Scotland. However the Scottish forest area is quite distributed and transport links in certain areas are poor, which presents a challenge to the accessibility of feedstock. Northern Ireland data is not available, but would be very small.

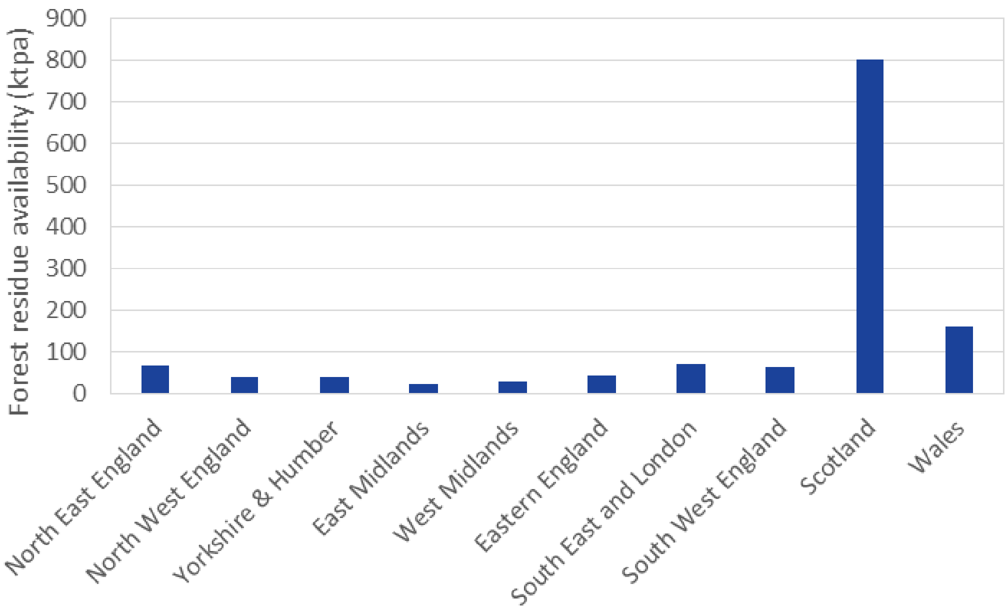


Figure 3.10: Regional GB current sustainable and recoverable forest waste arisings[40]

Forest residues can be used in heat and power, but they are currently not widely used in these applications[45]. Therefore the sustainable and practicable availability given in Figure 3.10 could potentially be used for advanced biofuel production.

Modelling by Ricardo (Figure 3.11) suggests that the available forest waste arisings in the UK are anticipated to increase slightly in the next 15 years and then decrease (not shown here), a trend which is also identified by the NNFCC (2014)[40] based on a 25 year projection of timber volumes produced in the UK by the Forestry Commission (2012)[50]. This projected decrease after 2030 may lead to some caution in establishing long-term plants.

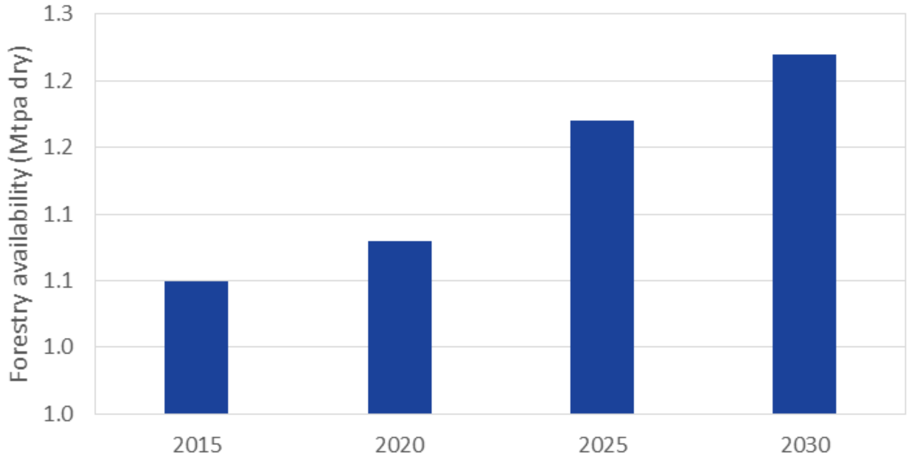


Figure 3.11: Current and projected available forest residues in the UK from 2015 to 2030[31]

Logistical, infrastructure and other considerations

Forest harvesting operations generally occur throughout the year, and residues are often left at point of harvest or at the roadside to dry. Therefore storage of the feedstock is not likely to present a problem to advanced biofuel developers.

However, transport of forest residues from remote locations can be uneconomical. Transport represents approximately 50% of the delivered cost of roundwood[40], and this figure can be even higher for harvest residues due to their lower density. The development of greater mechanisation and densification technologies such as baling or chipping at the point of harvest could make transport of forest residues more cost effective.

Forest areas in private ownership tend to be smaller and (generally) more distributed, whereas those in public ownership / management (e.g. Forestry Commission) tend to be managed as much larger units, particularly within England. The Forestry Commission (or similar bodies) currently manage 44% of English coniferous forests and 41% of those in Scotland.

Potential plant locations in the UK

Three potential locations have been identified for a plant utilising forest residues. Each location has been selected primarily on the basis of potential feedstock availability in the locality, known competing demands, and the existence of suitable transport links to serve the location. As with the straw biofuel plants, existing industrial infrastructure would be an additional advantage when siting a

[50] Forestry Commission (2012) "UK 25 – year forecast of softwood availability", NFI statistical analysis report. Available at www.forestry.gov.uk/pdf/NFI-Statistical-Analysis-Report_UK-25-Year-Forecast-Softwood-Availability.pdf/$FILE/NFI-Statistical-Analysis-Report_UK-25-Year-Forecast-Softwood-Availability.pdf

forest residue biofuel plant, but the rural nature of the feedstock means this is often difficult to accomplish in practice.

The largest softwood (coniferous) forests in public ownership in the UK are:

- Galloway Forest ~97000 ha - Dumfries & Galloway
- Kielder Forest ~65000 ha - Northumberland / Scottish Border
- Thetford Forest ~19000 ha - Norfolk / Suffolk Border

Other significant areas of forest exist in Scotland, particularly in Strathclyde and the Grampian / Highland regions, but they do not constitute a single, coherent forest area.

The identified locations are illustrated in Figure 3.12, along with major existing power stations that burn forestry and/or forestry residues (those > 10MW_e are given as red dots, with the largest plants labelled), and areas that are highly forested (shaded green areas). It should be noted that these locations refer to a general area rather than a specific location, and also that this is not a recommendation for siting a plant but rather an exploration of where might show potential in light of the factors described above.

1. Solway Firth

An advanced biofuel plant located near Carlisle on the Solway Firth could potentially source feedstock from both the Kielder and the Galloway forests. Given the significant size of these forests, which are the largest in England and the UK respectively, there is likely to be significant forest residue produced by them. Transport to a biofuel plant in Solway Firth from these forests would be ~30 mile distance, and good road links via the A75, the M6, the A69 and the A68 would facilitate feedstock transport. The main disadvantage of this site is its proximity to two large existing wood biomass power plants: Stevens Croft (50MW) and Iggesund (49MW) (Figure 3.12), which create a high competing demand for wood resources in this area.

2. Moray Firth

A plant sited on the Moray Firth near Inverness would be on the boundary between the Grampian & Highland forest regions. A large number of existing saw mills and timber product factories in the area suggest plentiful supplies of feedstock, but may also compete for access to that feedstock. The Moray Firth has good transport links via the A96, A9, A941 and A82.There is also some existing industrial activity in the area.

3. Northern Clyde side

A wood residues biofuel plant on the Clyde in the Dumbarton area would have proximity to the Strathclyde forest region albeit with possible extended travel distances due to the distributed nature of the forestry. However, there are good transport links via the A82, A814 and A811. In addition, a plant in this area would be near any existing industrial activity. There is however likely to be significant competing demand for forestry residues from other plants in the region including the Caledonian Paper Mill (26MW) and Cowie biomass facility (15MW), and depending on sourcing distance possibly Markinch (65MW).

Figure 3.12: Proposed plant locations for using forest residues (yellow), with major forest areas (green) and competing plants (red)

3.6 Wood waste

Wood waste is distinct from municipal solid waste as it arises predominantly from commercial and industrial users such as the construction, demolition and furniture industries. Even if separated at source, some grades of waste wood are still contaminated with chemicals such as paint or varnish, or physical items such as nails.

Resource availability across the UK

It is estimated that the UK production of waste wood is around 5 Mtpa (dry)[31]. Annual production is anticipated to remain constant to 2030. Currently around 1.1 Mtpa (dry) is estimated to be used for energy uses, and an additional 0.9 Mtpa (dry) for other uses[31] – predominantly panelboard manufacture and manufacture of agricultural and horticultural products. Other sources estimate that almost 2.8 Mtpa is recycled[51]. Current data suggests that the price of waste wood is currently negative[52], although this varies depending on quality and local demand for the feedstock.

[51] Health and Safety Executive (n.d.) "The wood recycling industry". Available at www.hse.gov.uk/woodworking/recycling.htm
[52] LetsRecycle (2016) "Price, Wood". Available at www.letsrecycle.com/prices/wood/

It should be noted that in a report by Wrap (2009)[53], a similar volume of waste wood production is calculated (4.5 Mtpa) but it is assumed that the whole volume is used: around 50% used by panel manufacturers, 25% used by dedicated biomass energy generators, 20% used in the manufacture of agricultural or horticulture products, and the rest used in pellet production or co-firing in coal power stations. As this source and underlying data from previous years is relatively old, it is possible that the figures have changed considerably (co-firing has disappeared in the UK, and panel manufacturers were severely affected by the financial crisis), but nevertheless this comparison does illustrate the challenges around calculation of the additional resource available for advanced biofuel production.

The production of advanced biofuels using waste wood feedstocks is subject to the Waste Hierarchy. For wood that is highly contaminated it is likely that reuse and recycling are not possible, so using this feedstock for biofuel production would comply with the waste hierarchy. On the other hand, much waste wood could be recycled, hence using it for biofuel production would not meet the waste hierarchy. Currently around 60% of waste wood is recycled[33], and it is anticipated that a significantly higher percentage could be recycled. Therefore of the resource that is identified in this chapter, only a limited proportion (that which is contaminated or unable to be recycled for other reasons) would be expected to comply with the waste hierarchy.

The availability waste wood to 2030[31] is shown in Figure 3.13. As highlighted above, the assessment of competing uses of waste wood seems fairly low from Ricardo (2015). The fact that demand for waste wood decreases further to 2020 suggests that this assessment may not include recent waste wood bioenergy plants such as Margam Green Energy Plant which is due to start in 2017 (using 250 ktpa waste wood), the Port Clarence Renewable Energy Plant due to start in 2018 (using 325 ktpa waste wood), the Northwest England biomass power plant (Widnes) due to start in 2017 (using 147 ktpa waste wood), and the Tansterne HRS biomass power plant due to start in 2017 (using 175 ktpa waste wood). LetsRecycle (2016)[54] suggest that there are at least 10 waste wood biomass plants set to come online in the UK between April 2016 and the end of 2017. If all these plants were scaled at ~200 ktpa, this is 2 Mtpa of additional competing demands for waste wood that would have to be considered, in addition to existing users – total demand could equal up to 4 Mtpa by 2018, leaving only 1 Mtpa for new projects.

[53] Wrap (2009) "Wood waste market in the UK". Available at www.wrap.org.uk/sites/files/wrap/Wood%20waste%20market%20in%20the%20UK.pdf

[54] LetsRecycle (2016) "Waste wood market 'less reliant on Sweden". Available at www.letsrecycle.com/news/latest-news/waste-wood-market-less-reliant-on-sweden/

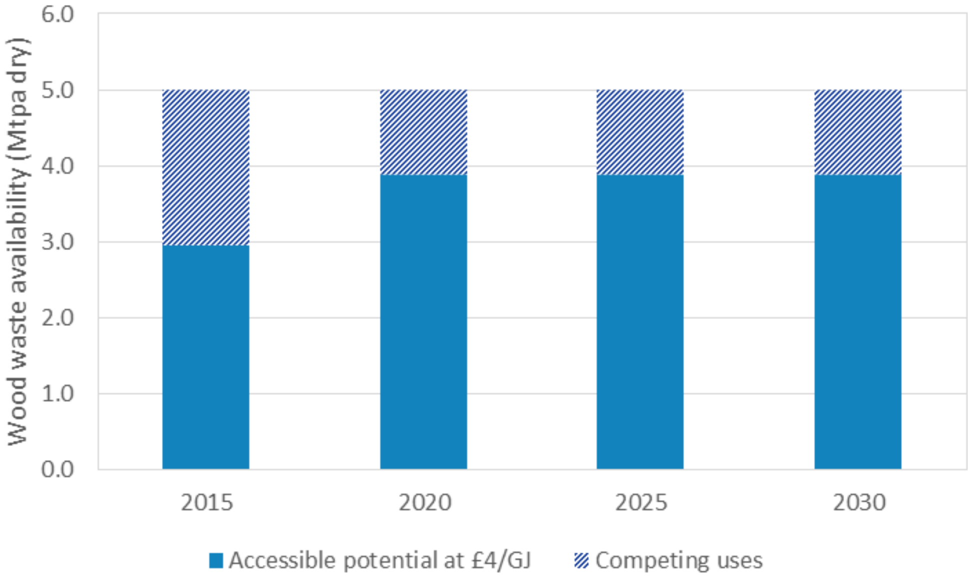


Figure 3.13: Current and projected UK waste wood that could be accessible from 2015 to 2030[31]

Data on regional availability of waste wood is fairly old (from WRAP, 2009), but suggests that the highest resource is found in areas of high population density alongside substantial construction and manufacturing activity such as London, the South East and the North West (Figure 3.14). Although it is produced in significant quantities in all regions of the UK, much of it is already used or planned to be used. A further regional analysis would be required to better understand availability after competing uses, particularly given waste wood power plants.

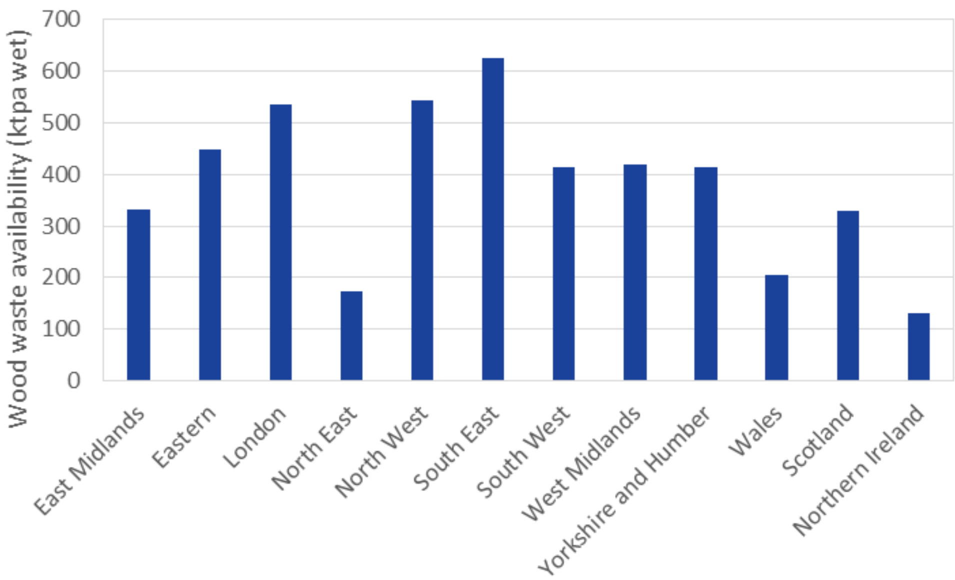


Figure 3.14: Regional production of waste wood[53]

Logistical, infrastructure and other considerations

Waste wood is likely to be produced by a large number of small producers spread over many construction and demolition sites, or other businesses. The price paid for the feedstock will have to overcome the cost of separation from other wastes produced on-site, as well the costs associated with transport and logistics when collecting from multiple, distributed sites.

Nevertheless, production of waste wood is likely to be fairly constant throughout the year, and due to its low moisture content, transport and storage are relatively low-cost (although new stack size guidelines are now in force).

Waste wood could be a problematic feedstock for some processes as cheaper, lower grades are highly likely to be contaminated with chemicals, plus additional erroneous objects (needing careful screening and handling). Thermochemical routes would likely have to consider Waste Incineration Directive legislation for any flue gases or venting, and the impact of contaminants on metal corrosion and catalyst poisoning (requiring wood pre-treatment or enhanced clean-up of intermediate syngas or bio-crudes). Biological routes would likely have to consider the impact of contaminants on microbial activity, and waste water treatment.

3.7 Other wastes and residues

Resource availability across the UK

A very small volume of other relevant industrial wastes and residues were produced in the UK in 2015, and they are not anticipated to provide significant resource into the future (Table 3.2). In addition, the current resource is already fully utilised in the UK, primarily for heat or power, so is not available for advanced biofuel production.

Table 3.2: Current availability of industrial residues in the UK[45]

Resource	Estimated current Mtpa (dry) produced
Black and brown liquor	0.21
Crude glycerine	0.033
Tall oil pitch	0.001

Logistical, infrastructure and other considerations

The industrial residues shown above are produced in a small number of locations in the UK. Given their minimal availability after considering competing uses, which is insufficient for a commercial-scale advanced biofuel plant, these feedstocks have not been disaggregated at a regional level, and are not considered further.

3.8 Imported feedstock

Resource availability across the UK

Foreign trade statistics[55] show that in 2015 the UK imported 6.5 Mtpa (as received) of wood pellets and 0.11 Mtpa of other wood including chips, sawdust and waste. Of these total imports, 1.9 Mtpa were from the EU and 4.7 Mtpa from outside the EU. The majority of these imports, particularly the wood pellets, are for heat and power use.

In their model, Ricardo (2015)[31] estimate the total surplus global supply of agricultural residues and woody biomass to 2030, which grows as supply chains are established. However, the model also assumes that the UK can access a certain percentage of this global surplus, which decreases from 10% in 2015 to 2% in 2050 (due to competing national demands), in order to determine the total amount of global resource which might be available to the UK. These forces largely counteract each other to 2030, as shown in Figure 3.15. Long-term to 2050, the decreasing % (i.e. increasing competition from other countries) wins over the increase in biomass suppliers, and import availabilities are expected to fall.

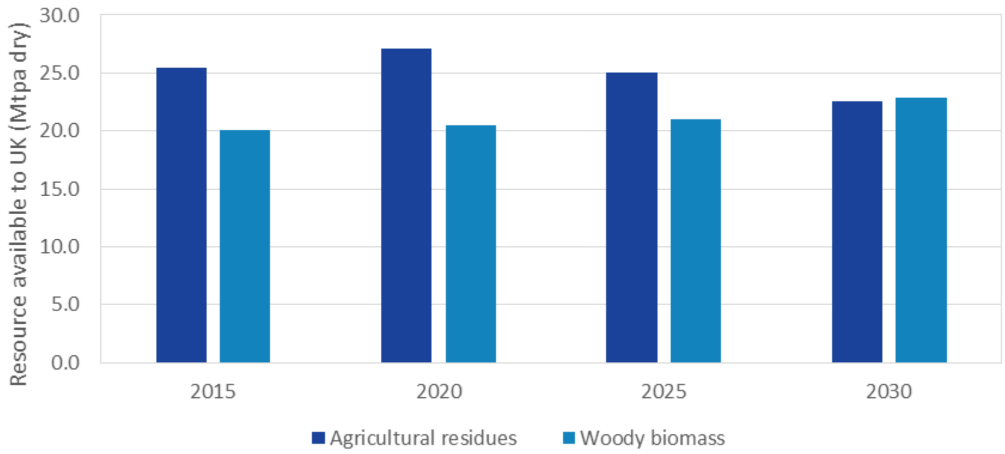


Figure 3.15: Global agricultural residues and woody biomass potentially available to UK[31]

This implies that the UK currently only imports ~30% of the global woody biomass that could be available to it in the Ricardo model. The amount of global woody biomass available to the UK is projected to remain broadly constant, suggesting that the UK could potentially import around three times more than it currently does by 2030. Based on a DECC (2016)[56] survey of large electricity generators, demand for imported biomass for heat and power is projected to increase significantly from around 5 Mtpa (dry) in 2014/15 to around 9 Mtpa (dry) in 2019/20 (Figure 3.16), with industry expecting less growth in heat and power in the 2020s. Nevertheless, the figures from Ricardo suggest that even with this additional demand from the power sector, the UK could still import more biomass feedstocks for advanced biofuel production.

[55] DUKES (2016) "DUKES G.6 Imports and exports of wood pellets and other wood". Available at www.gov.uk/government/statistics/dukes-foreign-trade-statistics
[56] DECC (2016) "Woodfuel disclosure survey 2015", Department for Energy and Climate Change. Available at www.gov.uk/government/publications/woodfuel-disclosure-survey

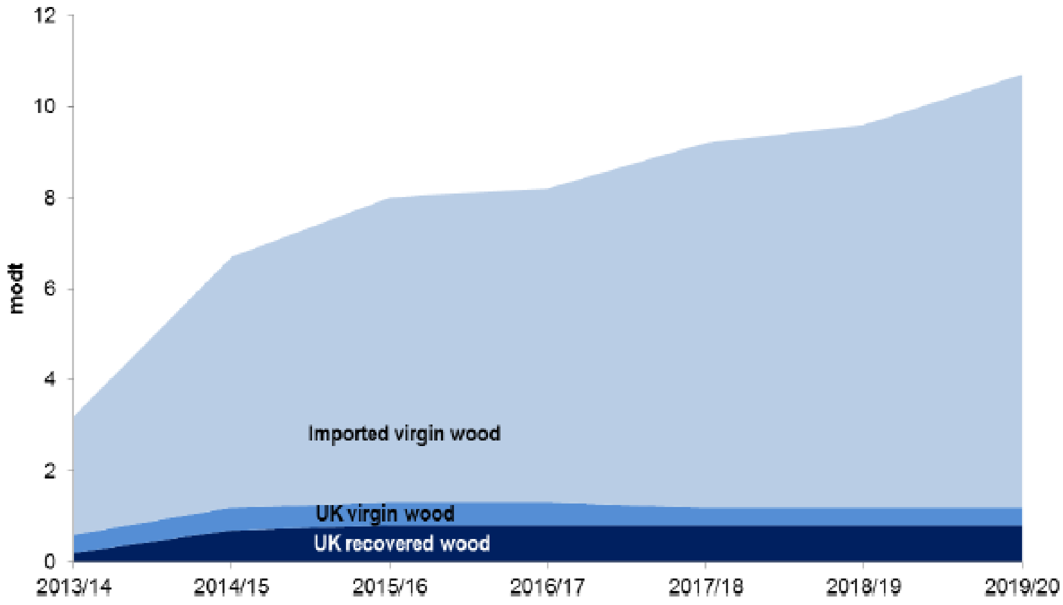


Figure 3.16: Anticipated increase in demand for imported wood from UK electricity generators[56]

The UK does not currently import significant volumes of agricultural residues, but the analysis by Ricardo suggests that these could be a significant source of feedstock for the UK, particularly in the short to medium term. However, due to the low density of agricultural residues, some form of pelletisation or densification would probably have to occur prior to long-distance transportation to the UK.

Logistical, infrastructure and other considerations

The example of Drax Power Station, which is located in North Yorkshire and imports wood pellets for power generation, is an example of the infrastructure adaption which could be replicated for advanced biofuel production. The ports at Port of Tyne, Immingham and Hull have been optimised for handling large quantities of biomass - Port of Tyne alone has a handling capacity of 2 Mtpa of pellets. Drax has also optimised its rail infrastructure to carry 50% more biomass from the ports to the power station compared to traditional freight trains[57]. Co-locating an advanced biofuel plant with Drax may also leverage an already existing supply chain and help to achieve economies of scale[58].

3.9 Infrastructure for imports and upgrading

When considering the potential for siting an advanced biofuel plant in the UK, it is important to take into account the infrastructure required for potentially importing biomass feedstock (including intermediate feedstocks such as liquid alcohols) as well as distributing and exporting finished fuel products. As illustrated in Figure 3.17, there are a number of major dry bulk ports located across the

[57] Drax (2013) "Biomass sourcing: capital markets day". Available at www.drax.com/media/13853/2_cmd_biomass_markets_final.pdf
[58] E4tech (2016) "An assessment of the potential for the establishment of lignocellulosic biorefineries in the UK". Available at www.e4tech.com/e4tech-evaluated-the-feasibility-of-lignocellulosic-biorefineries-in-the-uk/

UK, as given by DfT port statistics for 2015[59]. Locations nearby could be considered for conversion of biomass (likely wood pellets, or potentially RDF) into drop-in fuels.

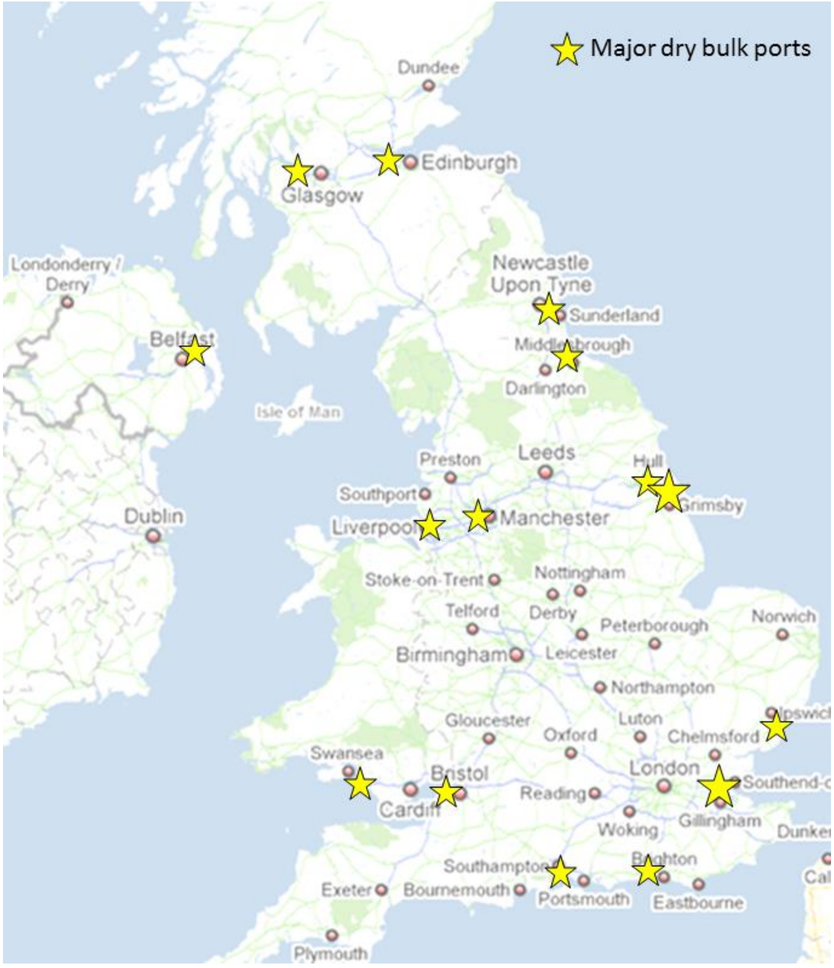


Figure 3.17: Major dry bulk ports in the UK

Major UK ports handling liquid bulk freight are Milford Haven, Forth, Southampton, Immingham and Hartlepool, along with London and Liverpool. Locations nearby could be considered for catalytic upgrading of 2G alcohols, were these to be imported in bulk for UK conversion.

Fuel infrastructure is an important consideration for the production of advanced drop-in biofuels where upgrading in a refinery is required – plus any distribution and storage of non-drop intermediates. The UK currently has 6 operating oil refineries (two have shut down in recent years) located at coastal or estuarial sites across the UK, as well as a number of fuel terminals and pipelines (Figure 3.18). The location and capacity of this infrastructure will be important to consider when planning an advanced drop-in biofuel plant. Recently closed sites at Milford Haven and Teesside could also be possibilities for siting a plant and retrofitting equipment – Greenergy already use the supply depot facilities at Teesside.

[59] DfT (2016) "UK ports and traffic (PORT01): Table PORT 0103: UK major ports, all freight traffic, by cargo type and direction". Available at www.gov.uk/government/statistical-data-sets/port01-uk-ports-and-traffic

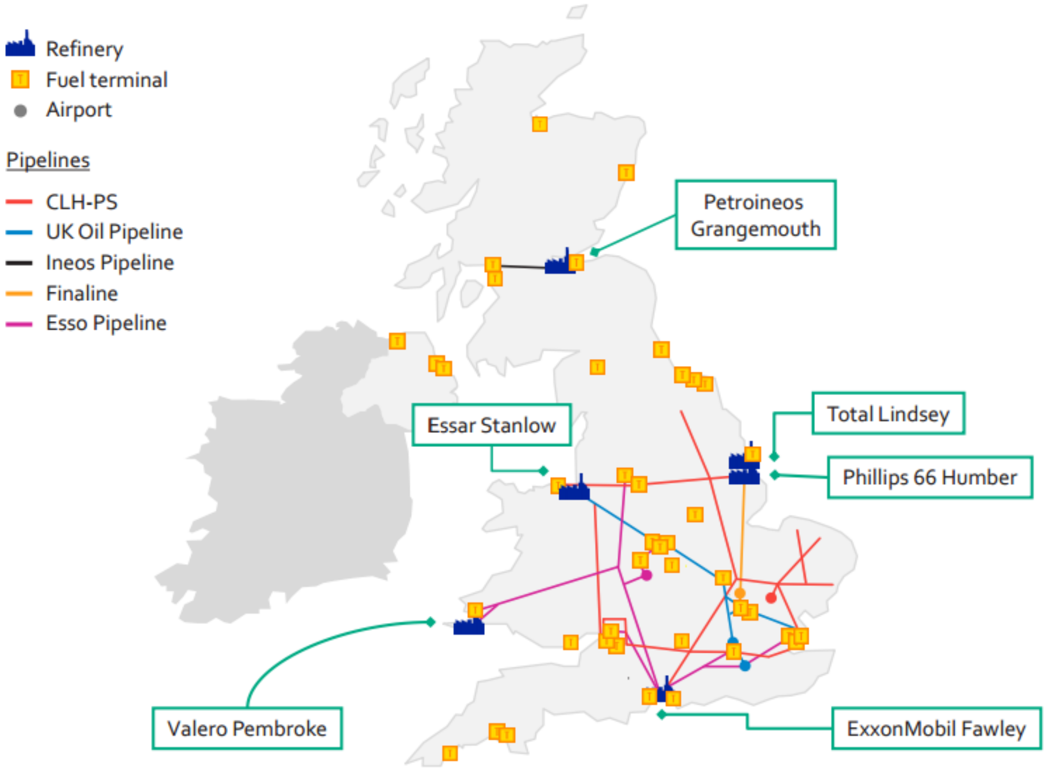


Figure 3.18: UK refineries and key product distribution terminals[60]

3.10 Implications for production outlook

Based on the feedstock availability assessment in this chapter, the three primary feedstocks best placed to serve an advanced drop-in biofuel plant in the UK are municipal solid waste (near cities), straw (particularly in the East of England), and forestry residues (in Scotland or via imports). Each, however, has its own complicating factors which may impact potential and viability of use in a plant.

For municipal solid waste, higher recycling targets, lock-in to current contracts and additional EfW capacity being built may present a challenge despite its current wide availability nationally. Availability of biogenic MSW is decreasing, although there may still be long-term contracts becoming available as landfills shut or older EfW plants close, or the opportunity to divert the significant flow of RDF exports currently leaving the UK.

For straw, transport costs dictate the need for a high density area to provide sufficient feedstock for fuel production, and the limited harvesting window leads to a requirement for storage with an additional impact on cost and losses. Straw is therefore attractive in the East of England, with only modest competition from new power plants, although soil protection factors have to be taken into account when determining the amount that can be removed from the field.

[60] UK Petroleum Industry Association (2016) "UK refining and product distribution terminals". Available at www.ukpia.com/docs/default-source/default-document-library/uk-map-of-refineries-and-terminalsc5c05c889f1367d7a07bff0000a71495.pdf?sfvrsn=0

For forestry, there appears to be a reasonable potential in Scotland, which currently does not seem to be under pressure from competing uses, but access to the resource at reasonable cost needs to be ascertained, given remote location of much of the resource.

The UK's waste wood resource is segregated by grades, but there is capacity coming online to use a significant amount of the remaining resource for power and heat applications, with the remaining resource likely to be too diffuse to be of interest for advanced biofuel plants. Manure may have a significant potential for energy use, but is likely to be exploited largely through AD, given very high transport costs and farmers wanting to return nutrients back to fields via the digestate.

A summary of UK feedstock availability is shown in Table 3.3, with all feedstock tonnages converted to oven dry tonnes (odt) for comparison purposes[61]. Despite the limitations and increasing competition, there is feedstock potential in the UK to support deployment of several advanced biofuels plants in the UK to 2030. The number of plants which could be supported by local feedstocks would be dependent on the conversion technology scale and efficiency, and requires further investigation to verify actual local accessibility. Nevertheless, this local availability, together with potential imports, is anticipated to be sufficient to supply the UK advanced biofuel deployment to 2030 modelled in Chapter 5. Post 2030, competition is likely to continue to increase, both for UK wastes and residues, and for imported feedstocks (with other countries increasing their bioenergy consumption). Perennial energy crops could offer additional long-term supplies globally, but only if suitable land is available – and micro-algae is unlikely to be an economic resource for bioenergy applications by 2030.

Table 3.3: Summary of estimated UK feedstock availability (Mtpa, dry)

Feedstock	2015 production	2015 availability after competing uses	Change in availability after competing uses to 2030
Municipal solid waste (biogenic fraction)	25	7.3	↓↓ with recycling and EfW plants
Straw	9.9 – 10.4	3.4 – 5.1	↔ only modest new competition
Wet manures	3.3 – 4.2	>3.0	↔ some new AD plants
Forestry residues	1.35 – 2.1	~1.1	↑ (but may decline after 2030)
Wood waste	4.5 – 5.0	0.0 – 3.0	↓ with new competition
Other wastes and residues	0.25	~0	↔ still minimal
Imported forestry	~20 available	~13	↓ with new coal conversions
Imported agricultural residues	~25 available	~25	↔ few expected users

Key: Little change in availability ↔ Increased availability ↑ Decreased availability ↓

[61] Assumptions are that biogenic MSW is 52% of total MSW and has a 38% moisture content, straw has 15% moisture, wet manures 95%, forestry residues 50%, wood waste 20%, imported pellets 10%. Note that these availabilities are based on competing uses in 2015, and not factoring in planned plants or plants currently under construction (which are considered in the "Change to 2030" column).

4 Evaluation of non-technical barriers

4.1 Introduction

The advanced drop-in biofuel pathways presented in Chapter 2 identified a number of the most significant technical barriers and development needs to progress the technologies towards commercialisation. These technologies, along with the waste and residue feedstocks covered in Chapter 3, also face a number of non-technical barriers to commercial development and deployment. These barriers include elements such as significant capital and production costs, policy longevity and stability, as well as upstream feedstock and downstream fuel specification aspects.

In this chapter, the non-technical barriers are broadly categorised into supply side and demand side barriers, and include a number of sub-categories:

- **Supply side**: Project finance, feedstock, infrastructure, environmental and social
- **Demand side**: Market, policy and regulation

Within each category the barrier is identified, and the significance explained together with a qualitative assessment of the impact (high, medium, low). In many cases the barrier is a global one, experienced across the world, however there are also those which are more specific to the UK – and this is also noted. Finally, where specific transport sectors (road, aviation, marine) or technology pathways are more affected by the barrier this is also noted.

4.2 Supply side barriers

The main non-technical supply side barriers to advanced drop-in biofuels, which impact technology deployment in the UK, are shown in Table 4.1. The barriers with the highest impact are related to project finance, and around the world there have been substantial financial barriers to the development and deployment of advanced biofuels (especially those looking to transition from demonstration to first commercial plant). In general the industry is considered to be a high risk investment. The scarcity of significant capital, together with a more risk-averse lending environment and preference for shorter-term investments, especially affects high capital advanced biofuel projects. The importance of public funding, to balance the risk, should not be underestimated and is necessary across the technology development levels. Feedstock supply barriers also play an important part in overall project success and the performance and profitability of a plant over time. Given that a technology is usually designed specifically for a certain feedstock (especially biological processes), addressing and mitigating feedstock barriers is critical.

Table 4.1: Non-technical supply side barriers

Barrier type	Barrier	Significance	Impact	Geographic specificity	Sectors / routes most affected
Project finance	High capital cost and capital risk	Especially impacts high capital pathways	High	Global	Thermochemical routes
	Shortage of long-term strategic investors	Limited pool of investors, even with multiple sources of capital being combined	High	Global	-
	Negative investor perception because of past failures	Deters investment	Medium	Global	Thermochemical routes
	Investors unwilling to scale-up technologies & simultaneously take on risks with new feedstocks and/or components	Switching to new feedstocks, e.g. 2G sugars or MSW, usually requires multiple development stages – which takes more time	Medium	Global	Sugar routes
	Low and volatile oil prices	If off-take agreement is based on oil price, it will affect plant profitability Reduced interest from investors & policy makers	Medium – *can be hedged over short-term*	Global	-
	Uncertainty caused by Brexit	Delay of investment until Brexit terms are clear Uncertainty around import and export tariffs	Low – *UK only supply chains* Medium – *if int'l exposure*	UK	-
	Currency risk	Impacts profitability if importing feedstock or exporting fuel, may impact equipment capital cost	Low - *can be hedged*	Global	-
Biomass feedstock	Variable feedstock quality (lack of specifications/standards)	May impact plant performance and guarantees Reduces amount of feedstock available and increases price	High - *particularly for MSW*	UK, or Global if exporting to UK	-
	Feedstock availability	Availability relates to the abundance of feedstock relative to project needs, and variation in production over time. These factors can increase project risk, and impact production security	Medium - *highly site & feedstock specific*	UK, or Global if exporting to UK	-

	Feedstock accessibility	The logistics and quality of feedstocks dictates infrastructure investment requirements	Medium - *highly site & feedstock specific*	UK, or Global if exporting to UK	-
	Feedstock competition	Increased feedstock competition may limit availability and increase feedstock price Severely limited access (e.g. supplies locked into 25 year waste contracts) could deter investment	Medium - *but increasing (especially where long-term waste contracts are in place)*	UK	MSW routes
	Cost variability	Feedstock cost forms a major part of production costs, and impacts price of end product Uncertain prices heavily impact profitability	Low - *unless outside of a supply contract*	UK	-
Infrastructure	Immature supply chain for feedstocks	Increases project risk as well as costs, potentially creating unfeasible project economics Impacts ability to procure sufficient feedstock volumes Supply logistics will become more important as development accelerates & feedstock competition increases	Medium	UK (e.g. not as good as Scandinavia)	Straw, manure, forest residues more affected than MSW (given established waste management chains)
	Immature supply chain for technology components	Increases project risk if large items of equipment are not available in time, need to be imported from abroad, or end up costing significantly more than first budgeted	Medium	Global	-
	Batch supply of intermediates from multiple locations could be problematic for refiners	Processing multiple batches together (to form a homogenous fuel product) requires additional time/cost for individual batch testing	Low	Global	Those relying on upgrading, e.g. pyrolysis and HTL oils
Environmental and social	Unclear sustainability characteristics of feedstock (e.g. soil quality, water, forestry carbon debt, biodiversity)	Some advanced biofuel feedstocks may not be sustainable in the long-term in certain regions. Policy makers may change categorisation/ accounting rules in future	Medium - *depending on feedstock*	UK	-

	Lack of factual knowledge about advanced biofuels (public awareness & perception)	Public opinion may change, or not realise the benefits compared to 1G biofuels. Policy may change categorisation/ accounting rules in future	Medium	Global	-
	Environmental sustainability policy implementation	Compliance with standards admin may increase operating costs; may be a barrier to entry to smaller players Inconsistent approaches globally may lead to inconsistent results & market fragmentation	Low	Global	-
	Site planning permission and building permits	Results in delays in project development	Low	UK	-

4.3 Demand side barriers

The main non-technical demand side barriers to advanced drop-in biofuels that impact the market in the UK are shown in Table 4.2. There are a number of high impact barriers related to policy and regulation. Most notably, the absence of clear, stable, long-term policy frameworks may greatly hinder the development of the advanced biofuels industry as it creates investment uncertainty and exacerbates perceived project risk. Continued low oil prices have left many projects on hold, or forced developers to shift their focus to non-biofuel applications. Within the industry, certain transport sectors may face greater barriers than others, for example requiring differentiated policy treatment of the fuels supplied and incentivised for aviation, marine and road sectors.

Table 4.2: Non-technical demand side barriers

Barrier	Barrier	Significance	Impact	Geographic specificity	Sectors / routes most affected
Market	Lack of understanding of market size and value as a result of policy mechanisms	Competitiveness compared to alternatives; how quickly market develops determines under/over supply; value implied by policy mechanisms	High	Global	-
	Shift to producing higher value products (e.g. bio-based chemicals) rather than fuels	Limits pool of developers interested in converting waste & residues to drop-in fuels Chemical outputs may also be a cash-flow positive in co-producing plants, helping with financing	Medium - *for some technology routes*	Global	Aerobic fermentation
	Nearer term, lower cost competing opportunities for growth (e.g. heat and power) rather than fuels	Limits pool of developers interested in converting waste & residues to drop-in fuels	Medium - *for some technology routes*	Global UK	Pyrolysis oil
	Fuel specifications either limit blending or are not yet approved	Mainly an issue for aviation, and early TRL fuel pathways that are not yet certified Takes a long time for new fuels & blends to be approved	Medium - *unapproved jet routes* Low - *non-jet*	Global	Aviation
	Unwillingness of oil refiners to take risks with new feedstocks (e.g. pyrolysis, HTL oils)	Takes a long time to carry out testing campaigns, & difficult to access large scale FCCs	Medium - *if not stand-alone supply chain*	Global - *especially EU and US*	Pyrolysis, HTL routes
Policy & regulation	Lack of clear, long-term policy signal	Discourages investment in new projects/plants Oil majors and refiners will not make significant investments	High	UK	-
	Uncertainty around policy attractiveness	Difficulty estimating economic value of multiple-counting and/or development fuels Level of policy support needs to be high enough to make sufficient volumes profitable	High	UK	-

	Lack of a decarbonisation driver for aviation & marine fuels	Slow-moving international agreements are driving support rather than national policies Sectors often outside of incentive schemes	High	Global - *but UK & NL including aviation*	Aviation, marine fuels
	Significant variation between national biofuel policies	Unclear how much fuel could be exported to other countries; and at what price Complicates replicability of project	Medium	Global, but RED II will help in EU	-
	Subsidies to support fossil fuel exploration, production and/or use	Creates additional price disparity Market signals can deter investors	Medium - *indirect impact, varies by country*	Global	-
	Government support scheme requirements incompatible with private investor financing terms	May deter investment Slows project development as additional alternative sources of funding become necessary	Low - *UK does not offer financing / loan guarantees to biofuel plants (yet)*	Global	-

5 'Realisable maximum' production estimate to 2030

5.1 Introduction

The aim of this chapter is to assess the maximum potential for UK production of advanced drop-in biofuels to 2030, in order to help understand the potential impact of policy support post-2020 on continued development and investment in UK production plants. This analysis is based on a wide base of evidence, which considers technology development to date and the likely commercialisation and scale-up timelines which have been typical of previous plants and other comparable technology developments.

The 'realisable maximum' production capacity estimate is a best case scenario, which in addition to the current and planned set of policies and funding mechanisms[62], also assumes that new strengthened policies and generous funding mechanisms are developed to incentivise UK production. Achieving maximum potential deployment also requires some bold assumptions that:

- Technology development within each of the six main technology groupings, and the corresponding developers, remains on track and all technical barriers are overcome
- All demonstration and first commercial plants globally are successful, and a supportive global policy environment provides long-term stability and decreases project risk
- Developers producing drop-in fuels currently using 1G sugars switch rapidly to 2G sugars as soon as is feasible
- There is sufficient supply of 2G ethanol, 2G butanol and 2G methanol products globally for this not to be a rate-limiting factor in the roll-out of 2G alcohol catalysis
- Catalytic routes from 2G alcohols to advanced drop-in biofuels (diesel, gasoline, jet) become commercially viable, i.e. drop-in biofuels price significantly above the starting 2G alcohols they are made from
- Developers continue to focus on fuels, and do not switch their business plans to producing chemicals, polymers or other higher-value products
- Mandates and generous market based mechanisms drive demand for advanced drop-in biofuels via a high product price (likely well in excess of $200/bbl), i.e. the sector is profitable
- UK demand incentives are higher than in any other market, providing a strong incentive for developers to focus on producing in, or supplying, the UK market (e.g. higher than incentives already offered in Italy and Denmark for advanced biofuels, or others that will arise from the EU RED II implementation)
- UK investment support for plants is more generous than in any other market, providing a strong incentive for developers to site plants in the UK (recognising policy competition between countries)
- Developers are educated and aware of UK policies, and drawn to the UK after their current demonstration or first commercial plants are constructed globally (i.e. current projects are not jeopardised), and achieve funding for UK plants and begin operations as soon as possible
- Where developers have a choice of fuel upgrading locations within Europe (e.g. for pyrolysis oil processing within a refinery), they choose the UK

[62] This includes initiatives which have been announced, are under consultation or are undergoing a feasibility analysis as of December 2016

In summary, the scenario therefore includes a number of assumptions across key areas such as production capacity, competitiveness and policy:

- *Production capacity*: Strong growth in capacity ramp-up, 100% success of projects. Developers choose to site first/next commercial plants in UK
- *Competitiveness*: High incentives make advanced drop-in biofuels competitive to produce in the UK, supporting investment & production
- *Policy*: Much higher targets introduced for 2020-2030, and extended to 2050, so that policy is not the rate-limiting factor to deployment

Based on evidence collected and interviews conducted during the study, the following timeline (Figure 5.1) is an example outlook for a first commercial-scale plant, which is used to develop the baseline capacities in the analysis. The initial stages of a project can take a number of years, as this includes engineering and design, gaining planning permission, permitting, signing feedstock and offtake contracts, and crucially, reaching financial close. The risk involved at this stage even with proven technologies is high, and is often the point at which projects fail. As seen with the first commercial plants built globally (e.g. LC ethanol, farnesene, waste gasification for power), the commissioning stage can also take several years, during which time product output will be well below nominal capacity, and is still an at-risk step without guaranteed success. We have therefore assumed first commercial plants take two years from the start of commissioning to operating at full capacity (during which time the capacity available is 17% then 50% of full capacity), whereas second/third plants might only take one year to commission and ramp-up.

Project development & financing	**Construction**	**Commissioning & ramp-up**	**Operation**
~3 years	~2-4 years	~1-2 years	Continuous

Figure 5.1: Example project development timeline for a first commercial-scale plant

Following a period of continuous operation, projects following the first commercial plant may experience an accelerated timeline, as technology learning takes place, equipment construction is replicated, markets are secured and projects are perceived as less risky by financers. Based on evidence collected during the study, funders will usually require at least 2-4 years of successful operational data before being willing to invest in a similar or somewhat larger scale plant. However, achieving a scale-up factor of more than 20 between plants is very rare in the industry, particularly if the project is handling feedstocks (not just a back-end, final upgrading step). Whilst a single technology can be licensed out to multiple project developers (provided they are sufficiently experienced), and multiple sites developed, this timing of when financers will be willing to invest in follow-on plants after the first commercial plant has been successfully brought into operation is the key rate-limiting step – as is the limited number of technology developers currently at the highest TRL for each technology.

5.2 Realisable maximum for global capacity

In terms of the global development picture under the 'Realistic maximum' scenario, the key findings are driven by the fact that the number of developers in each technology grouping is limited – typically 1 to 4 main players. These developers are currently strongly focused on trying to get their first demonstration and first commercial plants funded and built, and it is rare for developers to already publicly advertise that they have multiple or larger projects in the pipeline (and several do not have a pipeline). Developers are primarily located in the USA and Europe, with a few in Brazil and Australia.

Low oil prices and previous experience with 1G and 2G biofuel investments has led to the current risk appetite in the advanced biofuels space being low – the majority of the gasification + FT projects (including Joule, Fulcrum, Kaidi) are still effectively dormant and unable to attract sufficient commercial funding for their high capex first commercial plants, even with government support schemes available in the US and EU.

Developers in aerobic fermentation are mainly focused on 1G sugars, and developers have been backing out of biofuels to realign for higher value bio-based chemicals in the current oil price environment (Amyris are following Solazyme/ TerraVia). Although lab work and some limited pilot work has been done to test out microbe modifications to use 2G sugars (by both Amyris and Global Bioenergies), conversations to scale this up, and find the additional capital and partnerships required to develop plants using 2G feedstocks have only recently started. Similarly, the single developer in aqueous phase reforming (Virent/Tesoro) only has relatively early experience with 2G sugars and upgrading of the new bio-crude intermediate, and the lack of other players means scaling up the technology will be slow.

Conversations and longer testing campaigns are starting to happen for the upgrading of pyrolysis oil at existing refineries, and multiple pyrolysis oil projects are in the pipeline to make the intermediate bio-crude, with Envergent and BTG the key players. However, the upgrading of hydrothermal liquefaction oils is seen to be up to 5 years behind this pyrolysis oil testing and refinery campaign schedule, as a large amount of characterisation work on HTL oils is still to be done – Licella and Muradel are starting this in Australia. Hydrothermal liquefaction developers are currently mainly focused on micro-algae and sewage sludges, with one notable exception for lignin to jet (the BIOREFLY project).

Current global supply of 2G ethanol is modest (Biochemtex, Dupont, POET-DSM with first commercial plants), with a similar picture for 2G methanol (Enerkem and BioMCN), whereas 2G butanol supplies are minimal (Gevo, Lesaffre, Green Biologics). However, given alcohols to hydrocarbon technology is based on commercially available equipment, alcohol to hydrocarbon (including ETD, ATJ, MTG[63]) plants could be built relatively fast, and at a large scale. Sundrop Fuels are primarily interested in shale gas-derived methanol to gasoline (with an unspecified wood syngas input), Gevo are focused on isobutanol to jet, and Swedish Biofuels on ethanol to jet. These back-end catalytic technologies therefore have the steepest ramp-up globally in the charts shown, although there is currently no global incentive to invest in these plants, given the lack of a suitable premium for diesel, gasoline and jet compared to ethanol, methanol and butanol.

[63] ETD = ethanol-to-diesel; ATJ = alcohol-to-jet; MTG = methanol-to-gasoline

The resulting projections based on the above developers and assumptions leads to the global capacity roll-out in Figure 5.2, including the expected development timelines from Figure 5.1. As expected, those technologies that achieve the greatest capacity globally are those with the highest TRL (gasification + FT, pyrolysis + upgrading), or those able to be scaled up the fastest (catalytic conversion of 2G alcohols). Those with the lowest total capacity by 2030 are those at the lowest current TRL, or with the fewest developers.

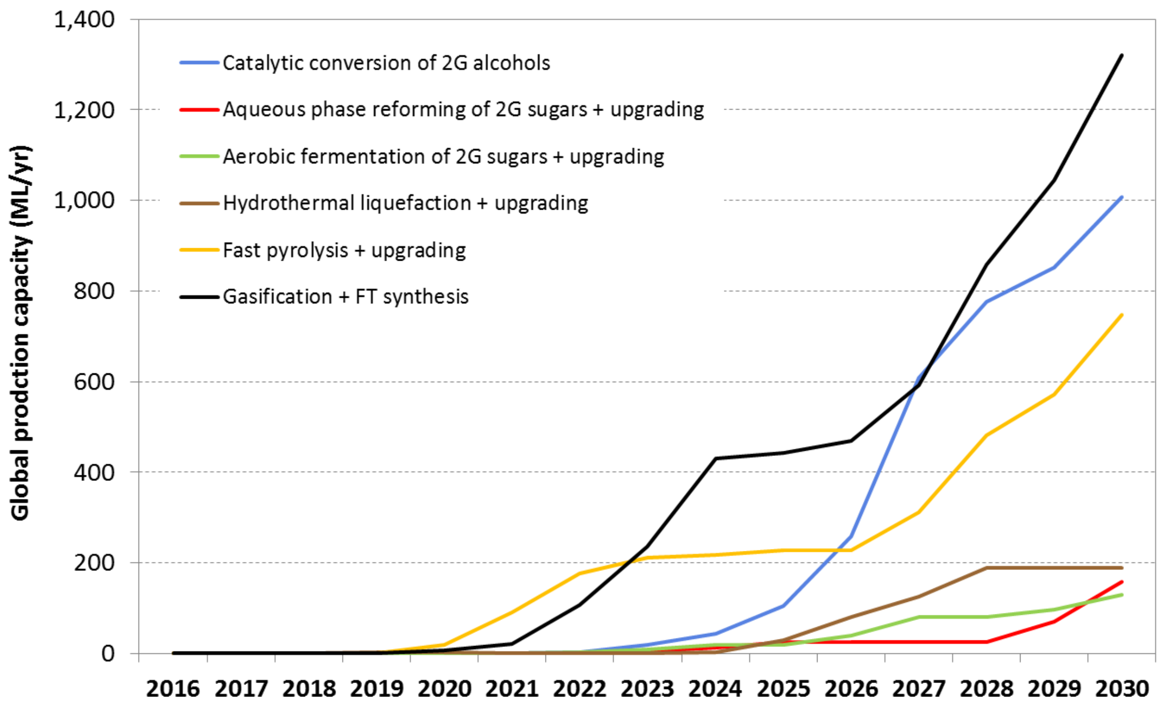


Figure 5.2: Projected global capacity ramp-up to 2030 in a 'realisable maximum' scenario

5.3 Realisable maximum for UK capacity

Next we considered how long it would take developers to come to the UK (or licence their technology to developers here in the UK), once they have successfully brought into operation their key project globally, provided the feedstocks are a good match. Given the absence of current UK projects and plants in scope, the main rate determining factor is how long it will take developers to commission their current project/plant elsewhere in the world, and then how long before the technology is seen as proven (via a few years of operational data) to allow new investment.

Although for the purposes of the realisable maximum projection we are assuming all suitable developers would come to the UK next, in reality other key factors will be the availability of attractively priced feedstocks, UK labour and construction costs, the competitiveness of the UK market and, critically, project support policies on offer (and how well publicised and stable these are), and therefore whether the UK is seen as sufficiently more attractive compared to policies and investment incentives on offer in the USA, Brazil, Australia, Scandinavia or other EU countries. Other world regions may have significantly cheaper feedstocks and overall production costs than the UK, and no matter how attractive the market support, if the UK does not just want to import the finished biofuels, the UK will have to put in place sufficient incentives to attract new projects that outweigh any cost disparity – particularly as the drop-in biofuels produced are so highly fungible and cheaply transported. This maximum scenario therefore assumes these UK incentives are put in place.

Taking into account the above developers and assumptions leads to the UK capacity roll-out as shown in Figure 5.3.

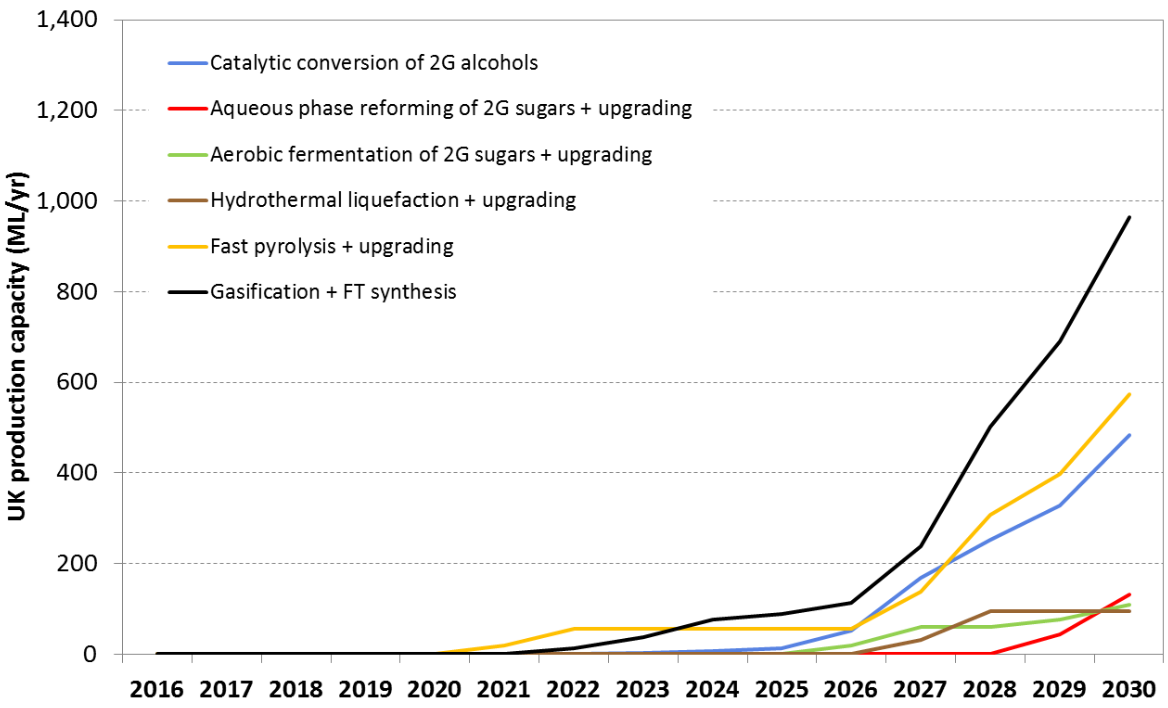


Figure 5.3: Projected UK capacity ramp-up to 2030 in a 'realisable maximum' scenario

This illustrates the dependency on global developments, as the UK projection in Figure 5.3 has a similar overall picture to Figure 5.2, although with several key differences. Firstly, the UK production capacities are lower and arrive later, due to global capacity mainly being built elsewhere first before coming to the UK.

This is particularly noticeable for Gasification + FT synthesis, where the length of time in construction and commissioning of other plants globally means UK capacity is unlikely to grow rapidly before 2027, at which point five larger commercial plants could potentially come online. As these large UK gasification + FT plants are "second-of-a-kind" commercial facilities, they are likely to be at the larger end of the first commercial projects currently planned, and might be scaled at 170 - 260 ML/yr each, consuming ~0.65 – 1.0 Mtpa of dry biomass each. Given the feedstock availability limitations by 2030 highlighted in Chapter 3.10, supplying this amount of UK biomass for a single plant location will be challenging, and either might rely on a mix of feedstocks (e.g. MSW and straw), and/or rely on imported feedstocks. Smaller plants are possible in the UK to better match local feedstocks, and two such facilities at under 80 ML/yr each are assumed to become operational in the mid-2020s as some of the first plants in the UK; however these would not benefit from capital cost savings at scale.

Pyrolysis oil upgrading could happen in the UK at a modest scale from the early 2020s if one or two UK refineries were involved in testing over the next 2 years, as changes at the refinery are relatively small. The intermediate pyrolysis plants could either be in the UK or abroad (with pyrolysis oil transported from plant to refinery), and could be developed quickly. This first period with proof of successful refinery integration would then kick-start larger investments in the late 2020s with more refineries investing, and/or higher blending %s.

Hydrothermal liquefaction follows approximately 5 years behind pyrolysis oil, so UK refiners will most likely not have the confidence to have invested heavily in upgrading of these oils by 2030, although some piggy-backing off the pyrolysis oil upgrading success could be possible (noting however that HTL oils are being targeted at blending with crude oil, whereas pyrolysis oils currently being targeted at blending in the FCC with VGO). Pyrolysis and HTL plant scales are less of a constraining factor for UK feedstock availability, and potentially better suited to use local supplies, given the downstream aggregation to a large-scale existing refinery.

Although the UK has no significant aerobic fermentation or APR experience with 2G sugars, the projection still assumes that the handful of developers globally would be attracted to the UK for their next plants. Hence the UK outlook is similar to the global outlook for these technologies.

Given the lack of 2G methanol, 2G ethanol or 2G butanol production capacity in the UK, there is unlikely to be an early ramp-up of 2G alcohol catalysis. However it is feasible that the catalysis plants are located in the UK, with the 2G alcohols imported from elsewhere. This led to the assumption that not every commercial plant will be located in the UK (due to staying near 2G alcohol production sites in the US, Brazil, EU), and UK production output (blue line in Figure 5.3) is not as high as the Gasification + FT projection (black line). These catalysis plants could easily be >100 ML/yr, as they are not tied to a particular feedstock supply region, and will want to minimise added costs by being as large and as efficient as possible.

The 'realisable maximum' scenario assumptions are very bullish for the UK competitiveness - they assume the UK could attract around two thirds of the total global capacity of advanced drop-in biofuels to be built in the UK by 2030 (between 50-85% depending on the technology grouping).

The total maximum UK capacity for 2030 is 2,360 ML/yr (which equates to 81 PJ/yr, or 1.9 Mtoe/yr). This is approximately 3.5% of the 2014 UK transport fuel demand (55 Mtoe/yr), and requires ~9.0 million oven dry tonnes/yr of biomass (slightly more than Drax currently import). Based on the conclusions from Chapter 3.10, many of these plants would likely either have to rely in part on imported biomass (given the decrease in MSW and waste wood availability, and difficulties in using wet manures), and/or rely on a mix of UK feedstocks (e.g. straw and MSW). Beyond 2030, further UK plants (particularly if they are larger) are likely to have to rely much more heavily on imported feedstocks, rather than UK resources.

6 Policy review and considerations

6.1 Introduction

DfT wish to ensure that current and future UK policies and funding mechanisms are appropriate and well designed to best support the decarbonisation of the transport sector, including the commercialisation of a UK advanced drop-in biofuel industry.

The aim of this chapter is therefore to review existing or planned policy and incentives and evaluate how these could help to overcome the key barriers identified in Chapters 2 and 4. Where appropriate, recommendations for how policies and incentives could be improved, and how these changes could impact deployment, are also discussed.

6.2 Current and proposed policies & funding mechanisms

There are a number of current and proposed policies and funding mechanisms which may help to address some of the non-technical barriers discussed in Chapter 4, and (either directly or indirectly) stimulate the development, production and/or use of advanced biofuels in the UK. These are set out in Table 6.1 below.

In particular, the Renewable Transport Fuel Obligation (RTFO) is, and will continue to be, influential on developments in advanced drop-in biofuels in the UK. Currently the RTFO includes a % volume mandate that incentivises all biofuels, and allows for double counting of those from wastes and residues. A number of proposed amendments to the RTFO have recently been under consultation, and are being considered by the Government. The most relevant of these to this study would be the introduction of a 'development fuels' sub-target, currently proposed at 0.05% by volume in 2017/18 rising to 1.2% in 2030 (2.4% with double-counting), along with a new development fuel category of Renewable Transport Fuels Certificates (RTFCs) allowing trading within the sub-target, and a separate buy out price. The overall RTFO is also likely to be extended to 2030, and allow aviation fuels and renewable fuels of non-biological origin, such as renewable hydrogen, to obtain support.

A separate GHG mechanism for FQD compliance will incentivise greater GHG savings in transport fuels, but only until 2020. The RED 2030 package may also include a 70% GHG savings threshold for new plants from 2021, further reductions in the crop cap, and advanced biofuel obligations upon EU fuel suppliers (in each year, rising from 2021 to 2030), which may or may not be transposed into UK law depending on Brexit negotiations and timescales.

Table 6.1: Current and proposed policies/funding mechanisms and non-technical barriers addressed

	Name	Type	End date	Barriers addressed
Current policies	RTFO (implementation of current EU RED)	Mandate, rules	2020, although ongoing after	Provides clear policy signal, making biofuels economically viable and allowing capital investment. Also supports move to more sustainable waste/residue feedstocks. Harmonisation with EU MSs.
	Motor Fuel GHG regulations	Rules, standards	2020	Fossil market transparency, single fuel market with reduced variation between MSs, and addresses a lack of fuel quality specifications
	4-5th Carbon Budgets	Framework	2032	Long-term high-level certainty of transport sector decarbonisation
	Corporation tax	Tax	Ongoing	Could encourage long-term strategic investors, by offering faster pay-backs
	UK guarantees scheme	Loan support	2021	Improves access to private finance, with lower risk profile/cost of capital, but may not apply to biofuels
	Fuel duty	Consumption tax	Ongoing	Helps overcome low and volatile oil prices, as duty is significant and can offer exemptions
	EU ETS	Carbon tax	2030	Driver for refinery decarbonisation. Internalisation of GHG costs in fossil fuels.
	UK carbon price floor	Carbon tax	2020+	Driver for refinery decarbonisation. Internalisation of GHG costs in fossil fuels.
	Landfill tax	Disposal tax	Ongoing	Makes MSW available and has developed mature supply chains, but also increases feedstock competition
(Potential) Future policies	RTFO consultation changes (implementing ILUC Directive)	Mandates, rules	2030, although ongoing after	As for the RTFO above Greater long-term clarity, incentives for aviation, renewable and advanced fuels will help build supply chains, although value implied by mechanisms still unclear
	GHG mechanism, implementing EU FQD 7a	Mandate, rules	2018-2020	Help overcome capital cost of GHG improvements, but does not address long-term move toward lower GHG fuels
	EU RED II	Mandates, rules	2030	As for the RTFO consultation above, but with further reduction in MS variability, inclusion of marine incentives and waste-based fossil fuels
	6-9th Carbon Budgets	Framework	2033-2052	Long-term high-level certainty of transport sector decarbonisation
Current funding mechanisms	DfT advanced biofuel demo competition	Matched-funded grants	2014-2018	Overcome high capital cost and technical risks at demonstration, and enable developers to prove waste & residue feasibility
	Innovate UK, EPSRC, other research councils	Grants	2017	R&D funding for researchers to improve technologies
	ETI Gasification Plant Design Competition	Match-funding	2017	Achieve high efficiency gasification of wastes and reduce technical risks at demonstration (focused on power although learning applicable to fuels)

	Name	Type	End date	Barriers addressed
	EU Horizon 2020 / BESTF3	Grants	2020	R&D funding for researchers to improve technologies
	EU NER300, Bio-Based Industries Joint Undertaking (BBI)	Match-funded grants	2020	Overcome high capital cost and technical risks at first commercial plant scale, enable developers to build supply chains
	National Infrastructure Commission, Green Investment Bank, European Regional Development Fund	Investor	Ongoing	Could act as a long-term strategic investor in conversion plants or UK feedstock infrastructure
(Potential) Future funding mechanisms	DfT advanced renewable fuels demo competition (II)	Direct	2017-2022?	Overcome high capital cost and technical risks at demonstration, and enable proof of feasibility of higher cost development fuel routes
	National Productivity Investment Fund (NPIF)	Grants	2020	R&D funding for researchers through Innovate UK

Despite the number of current and planned set of policies and funding mechanisms listed above, these are **unlikely to result in any investment in UK production for the technologies within the scope of this study.** This is due to the following reasons:

Support is not yet tailored to £ billion investments

- The UK does not have obvious capital grant support, equity support, loans or loan guarantees available for Government to mitigate first commercial plant risks. It is uncertain if the UK's infrastructure loan guarantee program is available for biofuel projects, and furthermore, it is unlikely that post-Brexit funding from EU sources such as the New Entrants Reserve (NER300, NER400) and the BioBased Industries Joint Undertaking (BBI) will be available. This situation contrasts with the US DoE loan guarantee program which has already supported a significant number of advanced biofuel projects to date.
- Whilst the DfT's advanced biofuel demonstration competition was well timed for the applicants, and gathered interest, the quanta of the investment required for a first commercial plant could be several hundred million pounds (or low billions), and not low tens of millions of pounds. Furthermore, the UK developers awarded Advanced Biofuel Demonstration Competition (ABDC) grant funding are focusing on producing fuels not directly relevant for the scope of this study.

Although a development fuel buy-out is yet to be set, currently available support is unlikely to make advanced drop-in biofuels profitable

- The cost of producing drop-in biomass-based diesel, gasoline or jet is high, particularly for the first commercial plants. Future plants could help reduce production costs through scaling up and the start of volume equipment manufacturing, plus via innovation, higher efficiencies and optimisation.

- When including feedstock prices, materials, maintenance, labour, co-product revenues, capital and financing costs, plus a profit margin, the required sale price range for the routes in scope is likely to be $140 – 920/bbl (70 - 430 p/litre) for the first commercial plants.
- However, a current base diesel price of ~$71/bbl + 2 RTFCs (at an assumed representative price of ~12p/litre) is only worth ~$119/bbl (60 p/litre), which would not support investment in any plants. Previous crude oil prices of ~$110/bbl (seen during 2010-2013) would have supported a double counting biofuel price of ~$175/bbl (88 p/litre). This might have just been enough to bridge the gap to the very lowest cost routes using negative cost wastes, although capital investment was highly constrained at this time.
- Although the buy-out price for the development fuels is not yet set (and has been proposed to be within the range 30-60p/litre), if it were only set at the current RTFC buy-out price (30p/litre), and the market were always short (the buy-out was being paid in full), then the current base diesel + 2 buy-outs would be worth $190/bbl (96 p/litre). This could just be enough to allow a few of the cheapest routes to be profitable if using low or negative cost feedstocks, although would not provide sufficient support to the majority of routes (particularly those involving 2G sugars or 2G alcohols, or imported biomass feedstocks). However, there is no certainty of the currently proposed development fuel mandate being short, as explained below.

Competition from other development fuels could be overwhelming, leaving no sub-target left to supply (or at the least leaving development fuel RTFC prices well below the buy-out)

- AD biomethane is a relatively cheap, near-term/fully commercial route when using waste feedstocks, and the UK grid injection market supported via the RHI has been growing strongly. Manure resources are also much more suitable for use at local scales in AD (and with a desire to return digestate to farmers' fields), rather than incurring the transport costs for aggregation at a larger centralised facility (and thermochemical routes only produce ash or char, not digestate).
- MSW gasification to biomethane, which is simpler and cheaper (and viable at smaller scales) compared to gasification + FT synthesis. Accessible AD feedstock supplies might be limited in the longer-term, although by this point, biomass synthetic natural gas (bioSNG) plants could then be deployed at large scale to supplement AD biomethane use in HGVs.
- Renewable hydrogen from wind or solar PV, which could be ramped up very quickly, and although expensive would attract 9.16 RTFCs per kg of hydrogen.
- Butanol made from food waste, brewery/distillery waste, and lignocellulosic feedstocks. Given that the UK has a volume based mechanism, there is no incentive to convert 2G butanol into diesel/jet and pay for the added costs (and loss in yield), if the butanol also counts as a development fuel. Furthermore, the inclusion of 2G butanol is most likely to displace or complement ethanol in gasoline (e.g. 16% by volume compared to 10% ethanol by volume) which could be decarbonised via EVs instead – and this will therefore constrain 2G butanol availability for use in HGVs, shipping and (via alcohol to jet routes) in aviation, which are options that are only starting to be discussed.
- HVO using virgin vegetable oils, UCO or animal fats are not eligible, but HVO produced from brown grease (removed from wastewater sewers) and tall oil pitch HVO would appear to be eligible. The proposed RED II to 2030 also now includes tall oil in Annex IXa, which if transposed into UK legislation, and if meeting the waste hierarchy, would also enable tall oil HVO to meet the development fuel sub-target.

- Bio-MTBE based on 2G methanol and bio-ETBE based on 2G ethanol could also be supplied as partially renewable gasoline blends under the sub-target, depending on the minimum blending levels set. These fuels would be immediately available at low cost and in high volumes.

The alternative fuel routes listed above have the potential to either be much cheaper or be deployed more quickly than the advanced drop-in biofuels in this study. It is therefore unlikely that the currently proposed development fuels market will be heavily undersupplied (developers get paid the buy-out). The opposite would be more likely – i.e. no space for expensive drop-in biofuels due to the sub-target (0.05-1.2% without double counting) being filled by the above fuels. Both suggest a lower traded 'development fuel' RTFC price than the buy-out, unless the scope of 'development fuels' is restricted to focus more on those routes and fuel types within the scope of this study.

Long lead times and the level of scale-up required from current TRLs require long-term policy support

- Although the RTFO levels as currently proposed do explicitly extend beyond 2030, the percentage by volume blending mandate levels post 2030 are expected to remain flat in the absence of future policy changes (the legislative nature of the RTFO prevents an automatic cliff-edge to zero). However, a fixed blending percentage post 2030 will be applied to a likely decreasing fuel market for road and NRMM sectors (due to improving engine efficiencies and a growing electric vehicle fleet)[64], and hence the volume of fuel required under the sub-target will decrease post 2030. A decrease in absolute volumes could even happen by the mid- to late-2020s, even as the % sub-target for development fuels is still slowly increasing, if the roll out of EVs is particularly rapid. It is very unlikely that new investment in development fuel production will be made in a declining market (or once this declining market becomes apparent), and the future fixing of a blending percentage is not sufficient reassurance that a plant operating for 20-30 years can still sell its output.
- The FQD and Motor Fuel GHG reporting regulations are also currently proposed to finish in 2020, and so there is unlikely to be an additional GHG driver for the low GHG emissions that some of these advanced drop-in biofuels are able to achieve.
- Given the capital intensity of most of the routes, first commercial plants typically require 6-8 years of successful operation (and fuel sales) to pay back their project debt, in a project developer / licencing model (not off balance sheet). However, the currently proposed policy changes have limited UK support after 2030 (and no investment guarantees), and given the required sale price of these fuels being well above the base fossil price (and lack of profitability without support), it is unlikely that investors would be willing to risk policy stagnation from 2030, with a decreasing liquid fuel market for their new plants, without the capital being paid back first.
- With construction timelines of 2-4 years for these large plants, and even with only 1 year of rapid commissioning, this would mean that investors are unlikely to fund UK projects after 2021 if policy support does not extend beyond planned levels after 2030. Since investors typically need to see 2-4 years of successful operations data at a plant (e.g. to go from demo to first commercial, or first commercial to a larger fully commercial plant), this means smaller projects need to be operational by 2013-2019 (at the very latest). Given that the UK does not have any announced live projects in scope, nor commercial developers leading projects in scope, and the

[64] Note that the expected future growth in aviation and marine fuel demand will not impact the RTFO mandates

known demonstration or first commercial projects globally are not going to be operating until 2020-2024, a modest ramp-up to 2030 and then a fixed blending percentage already potentially limits, or indeed closes the window, on likely investment in UK plants.

- Interviewees also stated that the oil majors (plus those that fund off-balance sheet) are unlikely to join the sector until they see the first developers succeeding, and there is more certainty about the long-term profits that can be made.
- There are no UK developers currently at demonstration scale or above in any of the routes in scope, although Velocys are an active participant in a landfill gas to FT plant (under commissioning in the USA), and are also involved in a MSW to FT project (pre-construction in the USA). Only a handful of UK commercial organisations are likely to be involved in UK production sites – for example, APP or Velocys if for gasification + FT synthesis routes; BP/Butamax, British Airways or Virgin if they invested in 2G alcohols to jet/diesel routes; and potentially Shell or Johnson Matthey in APR routes.

6.3 Policy considerations

The policy considerations below address some of the current policy issues in relation to advanced drop-in biofuel technologies, and build upon the barriers identified in Chapter 4, plus technology and feedstock elements from Chapters 2 and 3.

Policy mechanisms would need to be designed so to allow advanced drop-in biofuels to supply in line with their potential

There is a significant risk that including fuels with very different TRLs within the same mandate will mean that only the highest TRL and cheapest fuels will be supported. There are a number of options that could be considered[65] to focus the development fuels more tightly on drop-in biofuels that could be used in HGVs and aviation[66]:

1. Only award development RTFCs if the fuel is used in HGVs or aviation (without blending), or blended with fossil diesel or kerosene at above a minimum threshold.
2. Split out the biomethane, HVO, MTBE, ETBE, butanol and hydrogen as a separate alternative fuels category with its own new mandate, since these are higher TRL fuels that have the potential to be supplied relatively quickly, in large volumes and at reasonable cost. This would leave those fuels within the scope of this study (at TRL 4-6) within the scope of the development fuels mandate, along with diesel and jet fuels made from renewable electricity (a sub-set of RFNBOs). This option does add some additional complexity into the RTFO by introducing another mandated fuel category; however, it may also be able to improve industry investment by having more focused and clear support that aligns with policy priorities.
3. Maintain all the fuel types within the development fuels mandate, but provide (further) multiple-counting to drop-in diesel and jet biofuels. This would effectively be introducing banding within

[65] The Cost-Benefit Analysis to the RTFO Consultation only considered two options for the development fuels mandate – either as consulted (with the specific fuel types), or without specifying the fuel types (i.e. any biofuel from Annex IXa wastes & residues, or RFNBO). There was not an evaluation of restricting the scope of the fuels further to only diesel and kerosene (or the options above), which will need to conducted for the final policy decision.

[66] There are some industry concerns that the currently proposed development fuel mandate is too confusing, given the combinations of different feedstocks, technologies, fuel types and end-use sectors that are trying to be supported (and those it might expand to in the future). DfT should consider providing a clearer prioritisation as to the policy intent, and ensure the eligibility criteria match this intent – for example, if the intent is to decarbonise only HGV and aviation sectors, or decarbonise certain fuel types that could be used across transport, or commercialise earlier stage technologies using wastes/residues?

the development fuels, but previous consultation responses have highlighted that multiple-counting reduces the total volume of biofuel supplied (and GHG savings) and amplifies uncertainty in certificate values. Using bands can also be short lived and introduce policy and hence investment uncertainty (e.g. as with the Renewables Obligation adjustments to co-firing and energy crops bands).

4. Maintain all the fuel types within the development fuels mandate, but publically state that the mandates will be increased if biomethane, HVO, MTBE, ETBE, biobutanol and hydrogen over-supply the mandate. However, annual or sporadic increases to the mandate based on the short term evolution of supply may not provide the level of foresight necessary to invest in the more expensive/more risky options that have long development and construction timeframes. Increases to the development fuel sub-target would also have to be accompanied by an increase in the overall RTFO mandates if DfT wish to avoid impacting the market for the other fuels within the RTFO.

The availability of support post-2030 should be more clearly communicated to avoid a cliff-edge effect

Given the years required from financial close to construction, commissioning, ramp-up and pay back of debt during operation, investors are unlikely to fund large scale plants after 2016-2021 (at the very latest) if the years after 2030 do not have clear policy support or face declining market volumes.

DfT have confirmed that there is already continued policy support post 2030, which will maintain the overall RTFO and development fuel sub-target percentage mandates unchanged from their 2030 values until either the RTFO legislation is amended (or removed). However, much clearer communication of this policy permanence post 2030 would be beneficial, as currently the proposed RTFO policy appears to stop in 2030 (i.e. fall to zero afterwards).

This 'grandfathering' approach currently applies in the USA with the Renewable Fuel Standard (RFS) – after the final year in 2022, the 2022 standards continue indefinitely. This is also similar to the approach that has been used in the UK's Renewables Obligation for power, which shuts to new entrants in 2017, but with the obligations maintained to 2027, at which point remaining projects still claiming ROCs will be provided a fixed ROC price until 2037 when the RO policy ends – i.e. 20 years of certainty from the closure of the scheme to new generation.

However, as discussed earlier, fixed percentages do not allow any further growth or building of businesses post-2030. Fixed volume percentages (off road and NRMM fuels) also do not provide developers with comfort that the fuels they plan to produce for 20-30 years will still hold their value after 2030 because of the expected declining market volumes (and hence declining RTFC prices), which will put pressure on highest marginal cost producers to curtail output or shut down (likely to be the advanced drop-in biofuel technologies in this study).

Alternative policy options, which may address some of the shortcomings of a fixed volume percentage blending mandate post 2030 include:

1. The policy could be structured as a 'travelling window' of increasing support with explicit percentages, in order to match the latest UK carbon budget periods. This would mean immediately extending the proposed support to 2032, and then communicate that the support will be extended to 2037 by the year 2021 (at the latest), and extended to 2042 by the year 2026,

etc. This has the advantage of matching the carbon budgets and increasing the mandates over time through insights gained from the CCC's detailed carbon budget analysis every 5 years, but has the down-side that the time horizon might not be quite long enough, particularly in years just before the next carbon budget is set (e.g. in 2020, the policy would still only to explicitly set out to 2032). This has some risk of stop-start investment cycles for those technologies with the very longest construction and commissioning times, as they may not be able to be built and pay back within 12 years, although in some years the window will be 16 years. The CCC's advice to the Government in 2015 is worth bearing in mind, which recommended at least a 10 year horizon of transparent funding for the Levy Control Framework – however, this advice aimed at renewable power plants, many of which can be built and finish commissioning within one year of financial close, not the 3-6 years typically required for the advanced drop-in biofuel plants considered in this study.

2. The policy horizon could be immediately extended to 2050, with an increasing trajectory. Setting sensible %s to meet the Climate Change Act and intermediate carbon budgets should be possible based on DfT Transport Energy Modelling or CCC analysis (detailed recommendations already exist to 2030). This option would give the most certainty to industry that there is a large prize to be won, businesses built and jobs to be created, and that investing in cost saving and emissions reduction innovations will be important to stay competitive over time – i.e. that there will be more than just one round of first commercial plants built. The downside is the risk that DfT might wish to revise this trajectory downwards if alternative options (e.g. much greater electrification) progress much faster and are much cheaper than expected, or if new sustainability risks arise. However, the alternative options for haulage and aviation decarbonisation are limited, and hence the mandates could be designed around supplying these sectors by 2050. If looking to 2050, it will be even more important to highlight that the % mandates will be applied to a declining road transport fuel market.
3. More radical proposals could include the use of a Contracts-for-Difference (CfD) scheme, using auctions and/or bilateral investment decisions by a contracting authority. This would guarantee the fuel sale price from an advanced drop-in biofuel plant over a set period of time (e.g. 15, 20 years), and remove exposure to fossil oil price and RTFC price movements. However, CfDs were mentioned as a theoretical policy option in DfT's 2013/2014 call for evidence[67], but there was no real interest in the industry in pursuing this idea (a mandated sub-target for advanced fuels was much more popular). Introducing CfDs would also be a very significant policy change that would take several years to implement via primary legislation, and would introduce further uncertainty to the remaining RTFO.

RTFO targets should reflect UK carbon budgets

There are concerns within the industry that the proposed overall RTFO trajectory (holding at 9.75% by volume between 2020 and 2030) will be significantly under the CCC's recommendations to meet the UK's carbon budgets, putting these budgets at risk in the absence of other policies to fill this gap. DfT expect biofuels in all transport to only achieve 5-6% by energy in 2020 compared to a recommended 8% from the CCC[68]. Under current proposals, this % achieved is then likely fall to 2030,

[67] DfT (2014) "Advanced Fuels: Call for Evidence". Available at www.gov.uk/government/consultations/advanced-fuels-call-for-evidence
[68] DfT (2016) "The Renewable Transport Fuel Obligations Order: Proposed amendments". Available at www.gov.uk/government/uploads/system/uploads/attachment_data/file/572971/rtfo-consultation-document-2016.pdf

instead of being maintained at 8% as the CCC recommend, because road transport fuel volumes are projected to fall (whilst other non-mandated sectors like aviation increase their fuel demand), and as double-counting development fuels take up more of the overall RTFO mandate.

Further justification could therefore be given to industry, investors and the public as to the reasons why the CCC's recommendations are not being followed for biofuels, and/or as the additional policies that will be implemented to fill the resulting emissions gap. Alternatively, DfT should consider increasing the blending mandates to 2020 to meet the CCC's recommendations, and further raising them to 2030 to offset the decline in road transport fuel demand and the supply of more double counting development fuels (in order that the total energy supplied stays flat).

Clarity is required over which circumstances could lead to changes in the mandates, and hence how likely it is that buy-out prices will be seen

We have anecdotal evidence that heavy discounts are often applied to subsidy/certificate values when potential investors assess biofuel plants, i.e. some investors are unwilling to proceed unless the plant can be shown to be profitable without support. However, for the vast majority of advanced drop-in biofuel routes this likely to be impossible, given the additional capital costs and lower conversion yields arising from producing higher quality biofuels than exist in the market today (particularly jet fuel). Only a few routes using negative cost waste feedstocks may have the potential to achieve sufficient profits without support, but only if crude oil prices were above $150/bbl.

For investors to have more confidence that the value of the subsidy/certificates will be maintained (and hence are bankable), it needs to be clear when DfT would consider reducing (or increasing) the value of this support, so that investors can better assess these risks (or upside), and plan or hedge accordingly. As well as providing up-to-date information (or even projections) regarding the likely over/under supply of the development fuel mandate, this relies on DfT being transparent about the circumstances under which the development fuel mandate %s are allowed to be reduced or increased, or circumstances when the buy-out price can be revised, how much notice needs to be given before these changes come into force, and how to avoid retroactive changes impacting development fuel investments.

We have seen in the USA that the slow commercialisation of cellulosic biofuels has led to several annual revisions to the cellulosic biofuel standard for that year, undermining confidence in cellulosic RINs, and has reduced the clarity about the intended future trajectory for the sector (i.e. whether there is still political appetite to meet the 2022 targets). Although the US DOE have continued to provide good data about the current and expected under-supply of the cellulosic standard, the wider revisions to the RFS have also introduced policy uncertainty. DfT should therefore avoid a situation whereby if the development fuel mandate is under-supplied in a year, the mandate is reduced for that year with only a few months' notice in order to avoid the buy-out being incurred – DfT should be very clear if they expect the buy-out to be paid if the mandate is under-supplied. Particularly important is to avoid lowering the whole future trajectory based on a few consecutive years of under-supply, as this will reduce confidence – plus the scale of the UK market and relatively modest development fuel trajectory means that construction of just one large-scale advanced drop-in biofuel plant could enable supply to catch-up to the mandated level (whether this plant is built in the UK, or abroad and exporting its biofuel to the UK).

Development fuel buy-out needs to be set at an appropriately high value

Although there might be downwards pressure to set a development RTFC buy-out price low to protect consumers, this buy-out price cannot just match the production costs of the lowest cost developer, as this does not allow any profit/incentive to invest, nor does it allow other actors to enter the market and provide competition. The buy-out needs to be set at a level likely to provide adequate investment returns to a range of different technology routes – and then provided there is sufficient eligible production capacity (in the UK, or globally, if importing the fuel), the development RTFCs will trade at below the buy-out price, offering support to those lowest cost producers.

For example, RTFC prices have historically traded between 5-24p/litre, and were most recently known to be in the range 10-15p/litre, well below the 30p/litre buy-out[69]. This is partially to do with a lack of increasing mandates in the UK and across the EU in recent years, and double-counting impacts, rather than being fully reflective of the profitable level for new investment in biofuels.

The USA's cellulosic waiver credit (effectively, the buy-out price for the cellulosic biofuel standard) has been set at $1.33/gallon in 2016[70], although this changes inversely with the fossil gasoline price each year (the data sources and methodology used are highly transparent). This currently equates to 28p/litre, however, LC ethanol is the main fuel within the standard, which is a significantly more mature and lower cost biofuel than the advanced drop-in biofuels in scope.

Based on the information provided in Chapter 6.2, and using the upper bound of the RTFO Consultation range, setting a development fuel buy-out at 60p/litre that gets double-counted (to 120p/litre) and is available over the full plant lifetime, and assuming a current oil price of $54/bbl (equating to 36 p/litre of diesel), would provide plants with a maximum revenue of $309/bbl (156 p/litre) if the mandate was continuously under-supplied. As illustrated in Figure 6.1, this might be enough to incentivise investment in some BTL, HTL and pyrolysis oil routes, particularly those based on negative cost wastes or with lower capital cost requirements, although is unlikely to be sufficient to incentivise investment in lower efficiency 2G sugar routes to hydrocarbons (aerobic fermentation and aqueous phase reforming). Although the production costs of 2G alcohol catalysis routes can be estimated and some of the routes look likely to fall below the maximum buy-out level, their profitability still cannot be accurately modelled at present, as this depends on the future traded price for 2G alcohols once various future national mandates have been met, and the difference in incentives offered for 2G alcohols vs. drop-in long-chain hydrocarbons.

Each route will experience cost reductions over time as plants get larger and more efficient; in some cases production costs could fall as much as 30% by 2030 from today, although other routes will have more modest reductions. The entry of new competing routes and developers into the market will likely put downward pressure on the traded development RTFC price – although increased demand for biomass, wastes and residues by 2030 (across heat, power and transport fuels) may lead to feedstock price increases that offset some (or all) of these production cost improvements.

We assume that any development fuel buy-out funds will return to DfT or Treasury, as recycling these funds to those developers that were able to supply development fuels would constitute State

[69] DfT (2013) "Renewable Transport Fuel Obligation: Post-Implementation Review". Available at www.gov.uk/government/uploads/system/uploads/attachment_data/file/307437/impact-assessment-pir.pdf
[70] EPA (2016) "Cellulosic Waiver Credits Purchased Annually". Available at www.epa.gov/fuels-registration-reporting-and-compliance-help/cellulosic-waiver-credits-purchased-annually

Aid (although post-Brexit rules might be different). Although the buy-out fund could be sizeable in some years, any recycling to developers is highly unlikely to be bankable (and would therefore only contribute to rents), whereas these funds could be used by Government to support the industry and address remaining commercialisation barriers.

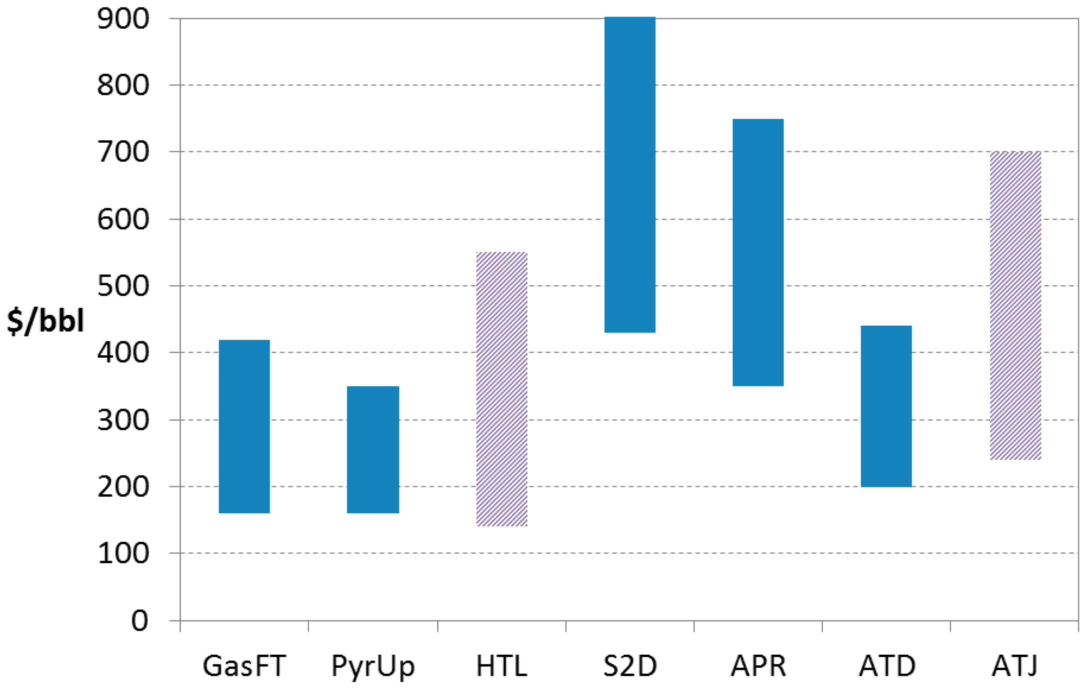


Figure 6.1: Estimated ex-plant production costs for first-of-a-kind commercial advanced drop-in biofuel plants[71]
(E4tech internal modelling)

An enhanced level of support or obligation is likely to be needed for use of advanced drop-in biofuels in the aviation and marine sectors compared to road transport

The price gap between advanced biofuel production costs and the end user willingness to pay for the fuel is higher for jet fuel than for diesel, and so an enhanced level of support would be needed if the DfT wanted to encourage use in aviation. Currently, airlines are generally unwilling to pay more for aviation biofuels than for fossil jet, as a result of unwillingness to pass on higher fuel costs to passengers.

Although publicly available production cost data is scarce, the additional processing means that dedicated bio-jet production should be associated with slightly higher investment costs and slightly lower overall yields, than similar bio-based diesel and gasoline production routes. Although many facilities will produce several products (e.g. diesel, gasoline, jet), and hence the jet costs will be part of the overall production costs, bio-jet cost estimates are typically towards the upper end of ranges given for drop-in biofuels.

[71] Gas+FT = Gasification + FT synthesis; Pyr+Up = Fast pyrolysis + upgrading; AF+Up = Aerobic fermentation of 2G sugars + upgrading; APR = Aqueous phase reforming of 2G sugars + upgrading; ATD = alcohol-to-diesel (Catalytic conversion of 2G alcohols); ATJ = alcohol-to-jet (Catalytic conversion of 2G alcohols)

DfT are extending the RTFO to allow sustainable biojet suppliers to claim RTFCs, however, this is unlikely to fully bridge the gap between fossil jet prices and biojet prices. Economics alone are therefore unlikely to bring forward large volumes of biojet, since developers with flexibility to produce diesel or jet are currently more likely to focus on producing road transport fuels, although some airlines could be active in taking a long-term strategic view and be willing to offer attractive offtake terms (also as a result of the recent ICAO global market based mechanism to reduce GHG emissions in aviation). However, it is likely that additional support for biojet would be needed, through a sub-target, credit or multiplier.

The EU's RED II proposal for 2030 includes a multiplier of 1.2 for counting sustainable biofuels used in aviation and maritime sectors[72]. However, use of a multiplier would have to be accompanied by a corresponding increase in the development fuel mandate in order to avoid a decrease in fuel volumes and GHG savings.

The lower quality of fuels used in the marine sector is likely to mean that production costs for marine biofuels are similar or below those of similar bio-based diesel production routes, as less upgrading/refining is typically needed. However, marine fossil fuels are significantly cheaper than fossil diesel, and the shipping industry is also currently generally unwilling to pay more for biofuels. So, in this case a multiplier could similarly be helpful in bridging the higher price gap, though the price gap will need to be considered in relation to potential additional costs the industry will face because of regulation relating to emissions affecting air quality, which requires fuel switching or introduction of after-treatment technologies.

Investments of several £100 million in large-scale UK plants would benefit from inclusion in existing financial incentive schemes and infrastructure development initiatives

Mandates create the market for advanced drop-in biofuels to be sold in the UK, but it is only support for investment in UK conversion facilities and feedstock supply chain infrastructure that can encourage UK production instead of other cheaper world regions that have larger volumes of feedstock – this is particularly true given the drop-in nature of the fuels in scope, and hence the ability to ship them around the world at low cost. Providing an attractive sub-target for development fuels on is therefore its own unlikely to be sufficient to encourage investment in UK production.

Government investment support is available in the form of loan guarantees (provided on a commercial basis), under the UK Guarantee Scheme[73], recently extended to March 2021. Whilst there are a significant proportion of pre-qualified energy projects, these mostly cover power and gas projects, and advanced drop-in biofuel plants are yet to be supported. Signed guarantees to date have ranged from £9m to £750m, having gone through a rigorous assessment and due diligence process. However, the underlying Infrastructure (Financial Assistance) Act 2012 does not make it clear if advanced drop-in biofuel plants would be eligible for loan guarantees, since the definition of infrastructure includes *"(a) water, electricity, gas, telecommunications, sewerage or other services, (b) railway facilities (including rolling stock), roads or other transport facilities*". DfT should look into

[72] European Commission (2016) "Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the promotion of the use of energy from renewable sources (recast)". Available at http://ec.europa.eu/energy/sites/ener/files/documents/1_en_act_part1_v7_1.pdf
[73] Gov.uk (2016) "UK Guarantees scheme key documents". Available at www.gov.uk/government/publications/uk-guarantees-scheme-key-documents

clarifying if "other services" or "other transport facilities" would cover advanced drop-in biofuel plants, or if an amendment to the Act would be required.

Government loan guarantees are most appropriate for large-scale demonstration or first commercial plants at TRL 7-8, and have been used in the USA[74] to support the first fleet of commercial LC ethanol plants, as well as building a number of other large-scale advanced biofuel facilities (although not all of these were technically successful). These loan guarantees were particularly successful as they were put in place at the same time as a $25m/yr Biomass Crop Assistance Program (providing establishment grants, maintenance payments and biomass residue collection payments), which helped farmers, foresters and landowners develop new biomass supply chains for these first large-scale plants[75].

Therefore, properly vetted, loan guarantees for the conversion plant combined with assistance in developing UK biomass supply chains will be vital to bridge the gap between pilot grants or small-scale demonstration match-funding that already exists in the UK (covering TRL 5-6), and the RTFO mandates that focus on the market demand aspects.

Whilst the Green Investment Bank has been active in supporting many biomass & waste power and AD projects[76], it is yet to invest in biofuel facilities – but could be an important source of financing alongside other commercial lenders. However, the bank's imminent sale may change their risk appetite, the key focus areas, attractiveness of the terms offered and the investment quanta available – if DfT still has an opportunity to do so, it could ensure that the bank remain opens to considering advanced drop-in biofuel plants.

The National Infrastructure Commission recently conducted a Call for Evidence and a National Infrastructure Assessment to help determine its priority areas for investment[77] – DfT could input to this process, making the case for advanced drop-in biofuel plants (and upstream biomass supply chains) to be within the NIC's remit to receive future loan support.

Other considerations

DfT would need to plan for failure, since large-scale demonstrations and first commercial plants still have several risks, and outside of a hypothetical 'maximum scenario', it cannot be assumed that all these facilities will be successfully constructed and commissioned, nor successfully operated at high availabilities every year. The US and EU experience is that a significant proportion of advanced biofuel projects fail (e.g. KiOR, Range Fuels, Coskata, Ineos Bio, Abengoa, Choren), and those that do succeed can still take several years to successfully commission and ramp-up production.

The waste hierarchy is not completely rigid, as derogations can be made to the ordering on the basis of improved environmental performance (e.g. PAS certified AD can count as a recycling activity, not energy recovery). Therefore, DfT could explore providing preference to the use of waste for advanced drop-in transport fuels by giving a hierarchy derogation based on environmental benefits versus EfW plants, particularly as the grid decarbonises. This would encourage Local Authorities to

[74] USDA (2016) "USDA - Biorefinery Assistance Program". Available at https://energy.gov/savings/usda-biorefinery-assistance-program
[75] USDA (2016) "Biomass Crop Assistance Program". Available at www.fsa.usda.gov/programs-and-services/energy-programs/BCAP/index
[76] Green Investment Bank (2016) "Investments: Waste and Bioenergy". Available at www.greeninvestmentbank.com/our-investments/all-investments/?sector=waste-and-bioenergy#main
[77] Gov.uk (2016) "National Infrastructure Commission". Available at www.gov.uk/government/organisations/national-infrastructure-commission

explore new waste-based transport fuel plants (producing partially renewable biofuels) before considering new EfW power plants.

The Fuel Quality Directive (through the GHG mechanism) will only currently apply until 2020, and will therefore not contribute to the value of any advanced drop-in biofuel. If this scheme were extended to 2030 or beyond, the low GHG intensity of several routes could contribute to the fuel value.

Treasury could consider further fiscal support measures for advanced drop-in biofuels, such as fuel duty exemptions, corporate tax reductions or enhanced capital allowances.