Programme Area: Bioenergy

Project: Biomass Value Chain Modelling

Title: Technology Landscaping Report

Abstract:

Work Package 3 in the Biomass Value Chain Model (BVCM) project had two objectives: firstly, to carry out a landscape review of the technologies used to transform raw biomass feedstocks into useable final products; and secondly, to develop a technology database, which could be used as an input to the value chain optimisation model developed in Work Package 2. This technology landscaping report was also the starting point of the technology roadmap exercise carried out in Work Package 4 for those technologies identified as having significant deployment potential by the value chain optimisation.

Context:

The development of the BVCM model has been ongoing since the project first started in 2011. The documents published here relate to the intial phases of model development. They do not included later developments and are therefore not representative of the current BVCM model, or in some cases, its findings. For a more recent overview of BVCM and the findings derived from it, readers are encouraged to look at the insights and reports published by the ETI, here: http://www.eti.co.uk/insights and here: http://www.eti.co.uk/library/overview-of-the-etis-bioenergy-value-chain-model-bvcm-capabilities

BVCM is now managed by the Energy Systems Catapult (ESC). Any questions about the ESC should be directed to them at: info@es.catapult.org.uk

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Technology Landscaping Report

Version 3.0

The BVCM Consortium

For the Energy Technologies Institute
2 November 2011

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Extended Executive Summary

1 Introduction and objectives

There are two objectives of Work Package (WP) 3 in the Biomass Value Chain Model (BVCM) project: firstly, to carry out a review (landscape) of the technologies used to transform raw biomass feedstocks into useable final products; and secondly, to develop a technology database, which can be used as an input to the value chain optimisation model under development in WP2.

1.1 Overview of WP3 process, its relation to WP4, and deliverable dependencies

The overarching objective of WP3 is to develop a technology parametrisation building block for the value chain optimisation model. To this end, an initial biomass technology landscaping exercise is needed – inter alia – to make sure that all relevant, up-to-date information on the technologies included in the Project are considered. Also, importantly, the technology landscaping will be the starting point of the technology roadmap exercise that will be carried out in WP4b for those technologies identified as having significant deployment potential by the value chain optimisation.

Building on the knowledge arising from the technology landscaping, as well as the background knowledge and data available to Black and Veatch, E4tech and Imperial, we will then develop a set of parameterised equations for each technology selected for inclusion in the modelling (the technology database). These parameterised equations will be integrated in the value chain optimization framework developed in WP2 and in the optimisation runs in WP4a. The development of the technology database will be an iterative process, in which the learning from the first optimisation runs will be used for any further model refinements (e.g. considering technology at different scale, applying different build rates, etc).

In WP4b we will identify promising technologies (and technology chains) based on the outputs of the spatial and energy system analyses carried out in the case studies, and based on a number of criteria such as technology readiness level, development needs, attractiveness of end use, cost potential, specific GHG savings, and other sustainability considerations. The following roadmapping exercise will focus on the technologies identified for acceleration. It will build on the technology status and barrier analyses carried out in WP3 and will outline what is required to overcome the innovation and commercialisation challenges, and when. In other words, the roadmap will provide actions required and indicators to track progress against the optimized biomass value chains for the UK as found by the model. For example, for selected technologies or technology chains, the roadmap will detail:

- possible development, demonstration and deployment sequence(s) from current status to 2050, and the associated investment needs (e.g. number of plants and capital expenditure);
- cost, efficiency, and GHG emissions targets;
- technical innovations required to overcome existing barriers and ensure that targets are met;

- type and level of support needed, as any successful implementation of a bioenergy technology roadmap is only likely to be possible if a supportive policy framework is in place.

After the roadmapping, we will quantify the benefits to the ETI of accelerating selected biomass technology options.

An overview of the overall WP3 process, of its relation to WP4, and of deliverable dependencies is given in Figure 1-1.

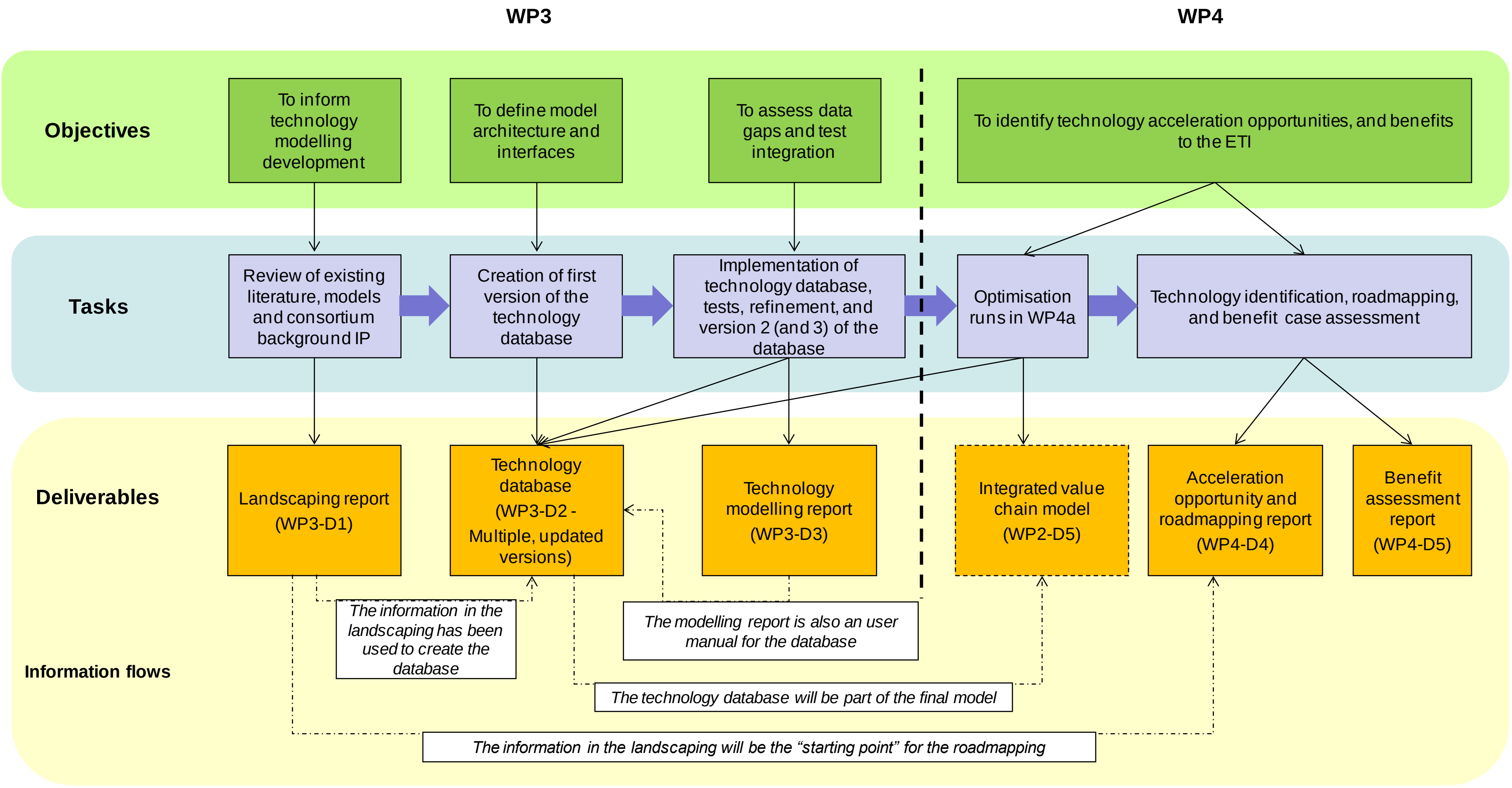

Figure 1-1 Development status of the main technologies to produce gaseous and liquid fuels from biomass

1.2 This document

This document reports on the landscaping activity in WP3, and covers all those technologies identified in the Technology Contract. As such, this report should be considered as providing the groundwork for the subsequent technology database development, by identifying key factors, metrics, and issues for parameterisation, and by informing the scope for commercialisation and technology acceleration opportunity to be assessed in WP4.

We have used a common landscaping framework to assess all technologies covered in this report. For each technology we have described the working principle, feedstock requirements, technical and environmental characteristics (size, efficiency, greenhouse gas emissions), costs, deployment and development status, barriers to development and deployment, and UK industry and R&D capabilities.

We have covered 33 different technologies, the details of which are presented in separate chapters, one for each technology. This executive summary provides a description of the methodology used to carry out the landscaping, a brief summary of the key points of each technology, as well as a comparison of the technologies based on their technology readiness level and UK capabilities.

2 Technology landscaping

2.1 Bioenergy chains and technologies

A bioenergy route or chain consists of a series of technology or conversion steps applied to transform a raw (i.e. as harvested) biomass feedstock into a useable final product, in the form of power, heat, fuel, or chemical. Due to the large variety of physical and chemical characteristics of biomass feedstocks and final products, a large number of conversion technologies exist, which result in different chains.

Different classifications exist for bioenergy technologies, depending on their products, the type of conversion occurring (e.g. thermochemical, chemical, physical, etc), the product application, etc. Each classification presents advantages and disadvantages. Here, we have classified technologies into the following categories:

- pre-treatment and densification technologies, which include:
  - chipping
  - pelletising
  - torrefaction
  - oil extraction
  - pyrolysis[1]
- technologies for gaseous fuel production, which include:
  - anaerobic digestion
  - landfill gas
  - biogas upgrading
  - gasification
  - gasification with catalytic methane synthesis
  - gasification with catalytic dimethyl ether synthesis
  - gasification with hydrogen production
- technologies for liquid fuel production, which include:
  - first generation ethanol
  - first generation biodiesel
  - first generation butanol
  - lignocellulosic ethanol
  - lignocellulosic butanol
  - gasification with catalytic Fischer-Tropsch synthesis
  - gasification with catalytic methanol synthesis
  - gasification with catalytic mixed alcohol synthesis
  - gasification with syngas fermentation
  - pyrolysis oil upgrading
  - hydrotreatment[2]

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[1] In principle, pyrolysis oil could be also used for heat, power and combined heat and power generation

[2] For the production of Hydrotreated Vegetable Oil (HVO) and Hydrotreated Renewable Jet (HRJ).

- technologies for heat, power, and combined heat and power generation, which include:
    - boiler combustion (for heat application)
    - dedicated biomass steam cycle
    - biomass co-fired steam cycle
    - Stirling engine
    - organic Rankine cycle
    - internal combustion engine
    - close-coupled gasification
    - biomass co-fired integrated gasification combined cycle
    - dedicated biomass integrated gasification combined cycle
    - gasification with internal combustion engine or gas turbine

This classification is proposed only for the sake of helping the reader navigating through the document. Indeed there is some overlap, as some technologies could be considered to belong to more than one category.

2.2 Brief technology description

2.2.1 Pre-treatment and densification technologies

Biomass typically has a much lower density (up to five times lower in volumetric density) than refined oil products, and it is more variable in its chemical-physical properties. The lower density and the chemical-physical variability make handling, transporting, and storing biomass more challenging, and ultimately more expensive, than for fossil fuels. In addition, technologies that convert biomass into intermediate and final products often require the biomass feedstock to be within certain ranges of moisture content and composition for correct or optimal working conditions, which may require additional drying or processing steps.

For the reasons outlined above, pre-treatment and densification technologies are used to make raw biomass into a denser, more homogeneous and easier to handle material, with the objective of increasing the efficiency and the reliability of the technologies along the chain, and ultimately of reducing the final product cost.

The key characteristics of pre-treatment and densification technologies covered in this report are outlined below.

Chipping

Chippers are used to reduce the size of biomass feedstock for ease of material handling and to comply with the requirements of downstream processes, e.g. boiler technology. There are broadly three basic types of chipper mechanisms available: disc chippers, drum chippers, and screw chippers. There are also other comminution technologies such as shredders and hammer mills but these are primarily used for volume reduction in the waste industry or as pre-treatment of biomass prior to pelletising.

The most common type in the UK is the disc chipper, followed by drum chippers with chip size influenced by several factors such as feed rate, number of blades, speed of rotation and angle of in-feed. The primary feedstocks for chipping are virgin and forestry timber, dedicated energy crops such as willow, co-products from primary timber processing and reclaimed clean timber material from the waste stream. The supply of woodchip is governed by European standards.

Chipping is a mature technology (TRL 9). There are various suppliers for wood chipping machines in the UK, however, most wood chipping machines are imported from markets with mature woodfuel and forestry supply chains e.g. Germany, Austria and Scandinavia. As of July 2011, there are over 100 suppliers of woodchips across the UK, with chipping facilities processing thousands of tonnes of wood per annum.

Pelletising

Biomass pellets are a processed biomass fuel that is typically manufactured from compacted sawdust or other biomass feedstock that has been milled prior to pelletising. In the UK, pellets are generally produced using material from primary processing activities within the timber sector. Equally, pellets may be manufactured from a variety of fuels including straw, miscanthus, agricultural residues such as corn stover etc though these are less common in the UK.

The benefit pellets have over raw unprocessed biomass is that the resulting fuel is homogeneous and has a moisture content of less than 10% w/w. This means that they are a high density energy fuel that can be easily transported and can deliver good combustion performance. However, depending upon the source of the feedstock, the biomass pellet can have quite different ash content levels and differing ash chemistry which will influence the combustion and grate choice.

The manufacture of pellets involves the milling / grinding of the biomass feedstock into a fine grade, passing the finely milled biomass material (typically sawdust in the UK) through a drier, mixing the biomass with a binding agent (and other substances if appropriate e.g. lime for miscanthus) and conditioning with steam before the material is extruded through a pellet die. Thereafter the pellets are left to cool before being screened and stored.

In the case of timber derived pellets, their manufacture is governed by a European standard which states that wood pellet production may only be derived from forest by-products, virgin wood, by-products from primary timber processing, and chemically untreated used wood.

Pelletising is an established technology used for various pressing applications in process industries (TRL 9), with established markets in North America and mainland Europe. In the case of wood derived pellet manufacture, as of July 2011, there were 15 wood pellet production facilities in the UK with the largest, Balcas, producing 100,000 tonnes from its plant in Scotland. However, the majority of pelletising equipments in the UK is imported from mainland Europe.

In the case of pellet manufacture using alternative feedstocks other than woody biomass, there are no commercial plants in the UK. However the process remains the same for differing feedstock alternatives and so the process is considered to be TRL 9, however varying moisture contents will require greater or lesser degrees of drying.

Torrefaction

Torrefaction is a thermal process in which biomass material is exposed to high temperature, in the absence of oxygen, and so without the oxidation that typically occurs during combustion.

In principle, all biomass feedstock could be treated via torrefaction. In practice, work so far has focused on woody biomass, wood pellets, bagasse, and straw pellets. Torrefaction is intended to improve some properties of the raw biomass feedstock, and therefore it is considered a pre-treatment technology. When compared to the untreated material, torrefied biomass tends to show an increase in hydrophobicity, grindability, and (for certain biomass feedstocks) energy density. Typical efficiency of torrefaction (expressed as energy in the torrefied biomass over total energy inputs to torrefaction) is 80% or less (depending on the feedstock), even though some developers (e.g. the ECN in the Netherlands) claim efficiencies in excess of 90%. Torrefied biomass has been proposed as a suitable feedstock for coal co-firing, gasification and Fischer-Tropsch process (see later).

In general torrefaction technology is at early demonstration/pre-commercial status (TRL 5-7), with first demo units being developed and commissioned. Beside numerous laboratory and bench scale testing units, existing or soon to be commissioned plants are at a scale of up to 60,000 ton/yr of torrefied biomass of output. In general the torrefaction technology development in Europe is led by Dutch companies and Dutch and Swedish research centres, with several demonstration plants under construction or being planned. However, some relevant industrial and academic capability exists in the UK as well.

Oil extraction

Oil extraction technologies involve the extraction of oil and fats from vegetable sources. The process typically consists of a mechanical (pressing step) yielding oil and pressed material (cake), and a solvent extraction step for extracting further oil from the cake. Steps for preparing the biomass prior to extraction and refining the extracted oil usually apply.

In principle, all fruits, seeds and nuts that contain oil and fats can undergo the process of oil extraction. In the bioenergy sector, these include *inter alia* oilseed rape, soybean, palm kernel, sunflower seed, coconuts, and jatropha seed. The efficiency of the oil extraction process, expressed in terms of extracted crude oil per unit of input feedstock, varies depending on the feedstock. Typical values for oilseed rape and sunflower seeds are 40% and 43% respectively.

As vegetable oil and fats have been used for a long time in various sectors such as food production, oil extraction is widely adopted at commercial and large scale plants and involves well-established, mature technologies (TRL 9). The scale of crushing equipment and facilities can range from farm scale to large commercial plant. The UK has some of the largest oilseed rape crushers in Europe, with a capacity of up to 1 million tonnes of seed per annum.

Pyrolysis

Pyrolysis is the controlled thermal decomposition of biomass in the absence of oxygen to produce a liquid bio-oil, a mixture of gases and charcoal (biochar). There are two main types of pyrolysis process, depending on the residence times in the pyrolysis reactor: fast and slow. Fast pyrolysis maximises the production of bio-oil, which can be used for power, heating or upgrading to transport fuels. Slow pyrolysis favours the production of bio-char. Conditions for slow pyrolysis are broadly similar to those for 'torrefaction', which are considered in a separate chapter. Here we will focus on fast pyrolysis only.

In principle, any dry lignocellulosic biomass feedstock can be used as an input for pyrolysis, including dedicated energy crops, agricultural residues and wood residues. The output of fast pyrolysis is a dark brown viscous liquid, also called 'bio-oil', which contains a complex mixture of oxygenated hydrocarbons with water, and potentially also solid char particles. Typically, the yield on a mass basis from dry wood is 75% liquid, the rest being gas and char. Typical energy efficiencies of bio-oil generation by pyrolysis (in terms of energy output over energy input) range from 50 to 75%, depending on feedstock and technology. Pyrolysis oil can be used with care in some applications directly, such as for heat or power generation using burner/furnace systems and burner/boiler systems (e.g. by using stainless burner tips), potentially in diesel engines, and as feedstock for gasification. However, due to its high acidity, high viscosity, presence of char, lack of miscibility with hydrocarbons, poor stability, and potential presence of contaminants, upgrading is needed for advanced applications, including advanced boiler systems, industrial gas turbines, and for transport fuels.

Pyrolysis technology is at the initial deployment stage, with several companies outside the UK having early commercial pyrolysis technologies (TRL 7-8) for use in heat, power, and food industry applications. Pyrolysis could be applied at small scale near to the feedstock source, as a pretreatment and densification option, followed by pyrolysis oil transport to a central plant for upgrading or use. Alternatively, pyrolysis could be deployed at a larger scale at a centralised location. Current plants are at a maximum of 200 ton/day dry biomass input. The UK has world-class capabilities in pyrolysis, particularly in academia, with several world class groups undertaking research into pyrolysis of certain types of feedstocks or focusing on reactor design or catalysts.

2.2.2 Technologies for gaseous fuel production

These technologies are associated with the production of gaseous fuels for transport applications as well as for heat, power and combined heat and power generation. Technologies include biological routes that use living micro-organisms to degrade the feedstock and produce gaseous fuels (e.g. anaerobic digestion), as well as thermochemical routes based on gasification, for the production of syngas and syngas-derived gaseous fuels.

The key characteristics of technologies for gaseous fuel production covered in this report are outlined below.

Anaerobic digestion

Anaerobic digestion (AD) is the decomposition of biological feedstocks by micro-organisms, usually in the absence of air (oxygen). The decomposition of the feedstock produces a gas comprising mostly methane and carbon dioxide. All AD systems use the same basic principle although actual plant design may differ slightly The process can be under “dry” or “wet” conditions, and occur at high temperatures (thermophilic) or medium-low temperatures (mesophilic).

AD consists of four stages; hydrolysis, acidogenesis, acetogenesis and finally methanogenesis. During hydrolysis feedstock is broken down into soluble monomers; during acidogenesis acids are formed from the products of the hydrolysis; acids are then fermented during acetogenesis yielding acetic acid, hydrogen, and carbon dioxide as main products; last, in methanogenesis the acids, the hydrogen, and carbon dioxide are converted into methane. AD efficiency can be measured by the volatile solids destruction in the digesters, measuring the percentage reduction of the volatile solids level going in to the plant and out. It varies significantly depending on the feedstock and the performance of the plant, and can range from c. 61 to 97%[3]

AD technology is well developed and mature technology (TRL 9), with approximately 5,000 plants in operation in Europe. However, the vast majority of them use waste (e.g. food) as feedstock or an amalgamation of waste and bioenergy crops such as straw rather than dedicated bioenergy crops alone.

Landfill gas

A landfill site works like a bio-reactor in which landfill gas is produced in a biochemical process from the decomposition of organic matter. Landfill gas is a mixture composed primarily of methane, carbon dioxide and nitrogen. The collection of the gas is achieved using gas vents from the landfill bed to the well head from where the gas is collected. The gas is subjected to filtration to remove solids and is measured and monitored to chart the composition of the gas. The volume of methane generated per tonne of carbon in the feedstock ranges from 180 to 310 m^3. Thereafter the direct use of collected raw landfill gas is impaired by gas contaminants such as hydrogen sulphide, siloxanes, moisture etc. Consequently, landfill gas needs to be upgraded (see later) before it can be used further.

At the end of 2009 in England and Wales there were 497 operational permitted landfills and 71 authorised landfill sites in Scotland. Waste to landfill has decreased in recent years, having fallen by 18% between 2008 and 2009. Moreover waste to landfill volumes have fallen nearly 45% since 2000 due to the Landfill Directive and whilst landfill will continue to

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[3] As evidenced by a survey of 41 full scale energy crop digestion plants in Austria (IEA, 2009).

contribute to renewable electricity generation, it will do so with declining gas volumes. Indeed, it is expected that there will be little or no future increase in capacity.

Landfill gas production is a well established technology (TRL 9). In the UK mature supply chain providing gas collection and other ancillary equipments exists, along with hundreds of operational permitted landfills sites.

Biogas upgrading

Biogas (primarily a mixture of methane and carbon dioxide) can be generated using a variety of feedstocks from organic wastes to animal residues or crops. The composition of the biogas depends upon the production route, the composition of the organic matter load and the feeding rate of the digester. Contaminants such as hydrogen sulphide (H_2S), oxygen, nitrogen and siloxanes could be present and could have an impact on the gas grid network, engines and appliances and need to be removed.

Several technologies are available for removing such contaminants from biogas and the levels of treatment required depend on the end use of the biogas. Technologies for removal of contaminants are well developed and established (TRL 9) and include: pressure swing adsorption, water scrubbing, chemical absorption and membrane separation. Despite the continuous improvements to these established technologies, such as the development of new washing agents and improvements on membrane selectivity, new processes are also being developed: cryogenic upgrading (TRL 8) and in-situ methane enrichment (TRL 3).

Although biogas upgrading is commonly used in Europe, in the UK there are only two projects under operation, Didcot Sewage Works and Albury Lanfill gas site; and two projects under development: Davyhulme waste water treatment works and Adnams Brewery.

Gasification

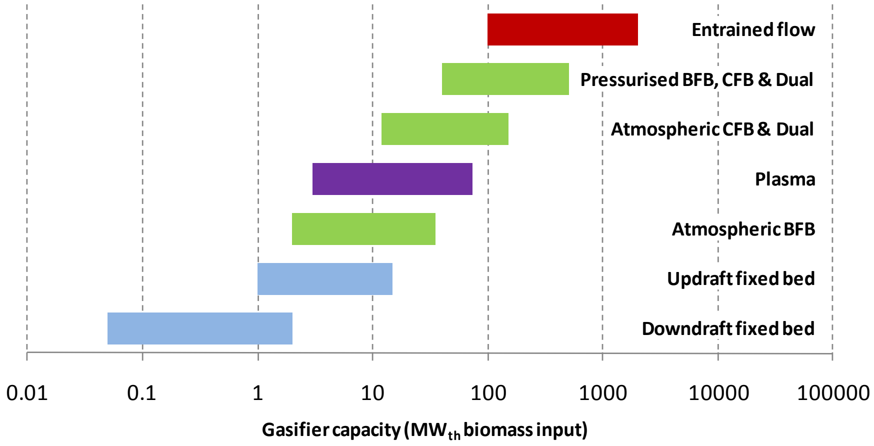
Gasification is a process in which a solid material containing carbon, such as biomass, is converted into a gas. It is a thermo-chemical process, meaning that the feedstock is heated to high temperatures, producing gases which undergo chemical reactions to form a synthesis gas. This ‘syngas’ mainly contains hydrogen and carbon monoxide, along with varying amounts of carbon dioxide, methane, tars and other impurities. After cleanup and conditioning, syngas can be used to produce heat, electrical power and/or a range of chemicals, including liquid and gaseous fuels.

There are several different generic types of biomass gasification technology that have been demonstrated or developed for conversion of biomass feedstocks – these are:

- Downdraft fixed bed
- Updraft fixed bed
- Bubbling fluidised bed
- Plasma

- Dual fluidised bed
- Circulating fluidised bed
- Entrained flow

These gasifier types, as well as the resulting syngas compositions, vary according to the temperature and pressure at which gasification takes place, how the biomass is fed into the gasifier, the oxidant used (oxygen, air or steam), and whether the gasifier is directly heated (through partial combustion of the biomass feedstock), or indirectly heated using an external source. The gasifier types are also applicable at different scales (see figure below).



There are a large number of different biomass feedstock types for use in a gasifier, each with different characteristics, including size, shape, bulk density, moisture content, energy content, chemical composition, ash fusion characteristics, and homogeneity of all these properties. Some form of sizing and drying is usually required before gasification, depending on the gasifier type. Entrained flow gasifiers require finely ground dry powder, whereas fixed bed and fluidised bed gasifiers can take chipped material (with less uniform moisture contents), with plasma gasifiers able to take any input (including heterogeneous wastes).

In general, most biomass gasifiers were initially developed for the production of syngas for heat and power generation, either as modifications from biomass combustion boilers, or fossil fuel gasifiers. However, numerous different developers now focus on different processes and products all based on syngas from gasification. Description of the integrated technology routes involving gasification are covered separately (see later). The gasification routes covered are:

- Technologies for gaseous fuel production:
  - gasification with catalytic methane synthesis
  - gasification with catalytic dimethyl ether synthesis
  - gasification with hydrogen production
- Technologies for liquid fuel production:
  - gasification with catalytic Fischer-Tropsch synthesis
  - gasification with catalytic methanol synthesis

  - gasification with catalytic mixed alcohol synthesis
  - gasification with syngas fermentation
- Technologies for heat, power, and combined heat and power generation:
  - close-coupled gasification
  - biomass co-fired integrated Gasification Combined Cycle
  - dedicated biomass integrated Gasification Combined Cycle
  - gasification with internal combustion engine or gas turbine

Gasification with catalytic methane synthesis

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into methane (biomass-derived synthetic natural gas, bioSNG). After any pre-treatment, sizing and/or drying, indirectly heated gasification with steam is used to thermo-chemically convert the feedstock into syngas[4]. Gas cleanup and conditioning is used to remove particulates, tars, sulphur compounds and other impurities, before a water-gas shift reaction adjusts the ratio of H_2/CO. The syngas is then catalytically converted into methane, before separation from unreated syngas, CO_2 removal and compression. Due to the high temperature processes, plants usually are highly integrated with several recycling loops, heat recovery, and steam and power generation.

BioSNG can be used as a direct replacement for fossil natural gas – i.e. if meeting certain specifications, it can be injected into the gas grid for heat, power and industry use, or it can also be used in compressed natural gas vehicles. Overall process efficiencies to bioSNG are between 65% - 70%. However, capital costs are high, and the technology is only at the pilot stage (TRL 5); whilst several components are commercially mature, their integration is not. There are only 3 known developers, with ~10 projects, all based in Europe.

BioSNG plants are expected to be commercial deployed at between 30 - 300 MW_{th} biomass input. The UK has particular expertise in the area of catalysis. However, there are no plant developers, planned projects, or firms with a suitable gasifier technology in the UK.

Gasification with catalytic dimethyl ether synthesis

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into dimethyl ether (DME). After any pre-treatment, sizing and/or drying, gasification with pressurised oxygen or steam is used to thermo-chemically convert the feedstock into syngas. Gas cleanup and conditioning is used to remove particulates, tars, inert gases, sulphur compounds and other impurities, before a water-gas shift reaction adjusts the ratio of H_2/CO. The syngas is then catalytically converted into DME (either directly or via methanol), before product separation from unreacted syngas. Due to the high temperature

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[4] In principle, also directly heated gasifiers can be used for bioSNG production. However, for BioSNG production, indirectly heated gasifiers offer higher efficiencies than directly heated ones, and for this reason they are chosen by most developers.

processes, plants usually are highly integrated with several recycling loops, heat recovery, and steam and power generation.

Overall process efficiencies to DME are between 66% - 69%. However, capital costs are high, and the technology is only at the pilot stage (TRL 5); whilst several components are commercially mature, their integration is not. There are only 2 known developers, both in Europe, working on black liquor and pyrolysis oil feedstocks. Importantly, DME is a gas at atmospheric conditions, and needs to be pressurised for use as transport fuel e.g. in diesel engines. This requires engine and fuel system modifications to be made.

The current minimum economic scale for DME synthesis is expected to be 100 MW_{th} biomass input, however, this could fall to ~20 MW_{th} in the future if process intensification technology is successfully developed, e.g. via micro-channel reactors. The UK has particular expertise in the area of catalysis and micro-channel reactors. However, there are no plant developers, planned projects, or firms with a suitable large-scale gasifier technology in the UK.

Gasification with hydrogen production

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into hydrogen. After any pre-treatment, sizing and/or drying, gasification with pressurised oxygen or steam is used to thermo-chemically convert the feedstock into syngas. Gas cleanup is used to remove particulates, tars and sulphur compounds, before steam methane reforming converts any methane into H_2, followed by substantial water-gas shift reactions to maximise H_2 production from H_2O and CO. Hydrogen is then separated from the cooled syngas by pressure-swing absorption or membranes, and compressed for use. Plants can use the heat recovered from syngas cooling for steam and power generation, or alternatively, combust some of the syngas.

The largest current uses of H_2 are in the chemical industry, for the production of ammonia, methanol, and fossil fuel refining. H_2 could also be used for power and heat generation (in gas turbines, combined cycle plants with CCS, or fuel cells), or as a transport fuel in fuel cell vehicles. The scale of hydrogen production from biomass gasification is expected to be determined by the scale of the gasifier, i.e. 3-150 MW_{th} biomass input for atmospheric systems, or 40-2,000 MW_{th} biomass input for pressurised systems.

Despite H_2 production being one of the cheapest biomass gasification routes, there are currently no developers working on biomass to hydrogen routes, and only a few who have mentioned future possibilities. The majority of the plant components are commercially mature, however, they have not yet been integrated into a pilot plant. The TRL is therefore currently only 4, although could accelerate rapidly in the future. Overall process efficiencies could reach 58% to 68%, although are likely to start nearer 50%.

Two of the major industrial gas companies with hydrogen handling and separation capabilities have a strong UK presence; however, there are no plant developers, planned projects, or firms with a suitable large-scale gasifier technology in the UK.

2.2.3 Technologies for liquid fuel production

These technologies are associated with the production of what are generally called biofuels, i.e. (high density) liquid fuels for transport applications. Biofuels, and the technologies to produce them, are typically grouped into generations, depending on their development and the feedstock they use (IEA, 2009). First generation biofuels include mature technologies for the production of ethanol from sugar and starch crops, diesel from oil crops (as well as animal fats). Second generation biofuels are novel biofuels or biofuels based on novel feedstocks. They generally use biochemical and thermochemical routes that convert lignocellulosic biomass to biofuels. Third generation biofuels generally include biofuels production routes which are at the early stage of research and development or are significantly further from commercialisation. In this report only first and second generation biofuel technologies will be covered.

The key characteristics of technologies for liquid fuel production covered in this report are outlined below.

First generation ethanol

Currently, ethanol is produced using crops such as corn in North America, wheat and sugar beet in Europe, and sugar cane in Brazil. The processing of such feedstocks for the production of ethanol is termed “first generation” or conventional technology, and it is based on the fermentation of sugars using yeast and enzymes.

The process normally consists of 7 key steps – milling of the feedstock; liquefaction & saccharification - where the feedstock is mixed with water, with heat, chemicals and enzymes added thereafter; fermentation of the mix with yeast; distillation of the ethanol; decantation where the insoluble solids are separated from the soluble material; evaporation of any moisture from the decanted stillage and finally drying of the concentrated stillage to produce DDGS which may be pelletised for animal feed. Process efficiency, expressed in yield of ethanol per feedstock input depends on the feedstock. Typical yields are 0.25 and 0.32 tonnes of ethanol per tonne of sugar beet and wheat respectively.

The production of conventional ethanol is a mature and well understood technology (TRL 9), with the USA being the major producer of conventional ethanol. In the UK, conventional ethanol production is relatively new, with only two plants currently operational.

First generation biodiesel

The most common path to produce first generation biodiesel (as fatty acid methyl ester – FAME) is through transesterification of vegetable oils extracted from seeds rich in oil (e.g. rapeseed, soyabean, palm kernel), animal fats and used cooking oil. This process is based on the reaction of oil with an alcohol (methanol or ethanol) in the presence of a catalyst. The products of this reaction are esters – biodiesel and glycerine. The process involves the following steps: transesterification which is the reaction of vegetable oil with excess methanol, in the presence of a catalyst; acid esterification of free fatty acids (FFA) to biodiesel and glycerine; separation of the glycerine and subsequent purification; and finally biodiesel drying and methanol recovery. Biodiesel produced from used cooking oil, requires additional processing to reduce its higher FFA content. Typical yields are 0.99 tonnes of biodiesel per tonne of refined oil input.

The production of biodiesel from vegetable oils and waste vegetable oils is a mature technology (TRL 9), with some technologies in potential areas of improvements e.g. in more efficient catalyst recovery, improved purification of the glycerine, enhanced feedstock flexibility; and better utilisation of co-products at earlier stage of development (TRL 3)

First generation butanol

Butanol (n-butanol or 1-butanol, C_4H_9OH) is a chemical used in the production of paints, polymers and plastics, and it can be also used as liquid fuel. Compared to ethanol, butanol has superior properties that make its use easier in that it is less hygroscopic than ethanol; has higher energy density, and has the potential to be blended into diesel.

Biobutanol can be generated from starch or sugars via a process known as ABE fermentation, named after its products: acetone, butanol and ethanol. The ABE process consists of: the pretreatment of the feedstock involving either milling or pressing; fermentation wherein the first stage hydrogen, acetic and butyric acids are generated and acetone, butanol, ethanol and carbon dioxide are produced in the second stage; product recovery using distillations and finally by product recovery where carbon dioxide, hydrogen and distillers dried grains with soluble are recovered.

Biobutanol can be produced from the same feedstock as conventional ethanol, such as sugars (molasses) and starch rich biomass, including potato, wheat, rye and cassava. However, one of the main limitations of the ABE fermentation is the low yield, e.g. the typical yield of butanol from corn is below 0.21 tonnes per tonne of corn.

Biobutanol production is an established technology (TRL 9) that was developed in the early 1900’s. However, in the mid 1950’s the process was unable to compete with petroleum derived butanol and so most of the biobutanol production declined. Since the beginning of the 21st century the production of biobutanol has experienced a revival due to its potential as a biofuel and high oil prices, although its production remains concentrated in China. Good industrial and academic capabilities exists in the UK, with a couple of companies leading the way for the commercialisation of biobutanol, and researchers working on improving yields.

Lignocellulosic ethanol

This route involves converting any lignocellulosic feedstocks, such as energy crops, into ethanol. Pretreatment and hydrolysis are used to break down and convert the feedstock to produce sugars first, which are then fermented to produce ethanol. Different process options for conversion of lignocellulosic materials to ethanol exist depending on the level of process integration, with a technology trend towards simultaneous pretreatment, enzyme production, hydrolysis and fermentation in the same reactor. The typical expected overall efficiency is around 300 litres ethanol per tonne of feedstock.

Lignocellulosic ethanol conversion plants as a whole are at the early demonstration to full demonstration stage (TRL 5-7), with total worldwide installed capacity of around 20 Ml per year in 2010. A handful of UK companies are working on lignocellulosic ethanol technology and/or component technology. The UK has around 20 academic groups working on a range of relevant technologies.

Lignocellulosic butanol

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into butanol. Pretreatment and hydrolysis are used to break down and convert the feedstock to produce sugars, which are then fermented to produce butanol. The steps first steps are the same as for the process for lignocellulosic ethanol production for conversion to sugars. The remaining steps are similar to the processes for butanol production from sugars, derived from sugar or starch crops. However, there is research on consolidated routes to butanol that combine hydrolysis and fermentation in a single step, as for lignocellulosic ethanol. The typical expected overall efficiency is around 200 litres ethanol per tonne of feedstock, along with ethanol and acetone if the ABE process is used, or higher if alternative butanol only routes are used.

Lignocellulosic butanol plants as a whole are at the early demonstration to full demonstration stage (TRL 5-7). Most developers are currently focusing on demonstrating butanol production based on sugar and starch feedstocks, with an aim to move to lignocellulosic feedstocks in the longer term. Globally, there are not yet any demonstration scale lignocellulosic butanol plants operational, with one pilot using lignocellulosic feedstock. UK capabilities from lignocellulosic ethanol production, and from first generation butanol are relevant to lignocellulosic butanol production. UK butanol developers are interested in lignocellulosic butanol production in the longer term, once their technology has been further demonstrated on other feedstocks. There is also an UK academic research on lignocellulosic butanol specifically.

Gasification with catalytic Fischer-Tropsch synthesis

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into petrol, diesel or jet fuel. After any pre-treatment, sizing and/or drying, gasification with pressurised oxygen or steam is used to thermo-chemically convert the feedstock into syngas. Gas cleanup and conditioning is used to remove particulates, tars, inert gases, sulphur compounds and other impurities, before a water-gas shift reaction adjusts the ratio of H_2/CO. The syngas is then catalytically converted into Fischer-Tropsch (FT) liquids, before product separation from unreacted syngas and undesired outputs for recycling. The FT liquids are finally upgraded to petrol, diesel or jet. Naphtha and power are also commonly produced as valuable by-products. Due to the high temperature processes, plants usually are highly integrated with several recycling loops, heat recovery and steam generation.

Unlike many of the other routes, the final FT petrol, diesel or jet fuels are direct fossil fuel replacements – i.e. drop-in fuels, with no blending, infrastructure or engine changes required. Overall process efficiencies are between 47% and 57%. However, capital costs are high, and the technology is only at the pilot and demonstration stage (TRL 5 and 6); whilst several components are commercially mature, their integration is not. There are around 11 developers working on ~30 projects globally, with 1 plant planned in the UK to date.

The current minimum economic scale for FT synthesis is expected to be 320 MW_{th} biomass input, however, this could fall to ~60MW_{th} in the future if process intensification technology is successfully developed, e.g. via micro-channel FT reactors. The UK has particular expertise in the area of FT catalysis and micro-channel reactors, however, there are no plant developers, planned projects, or firms with a suitable large-scale gasifier technology in the UK.

Gasification with catalytic methanol synthesis

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into methanol. After any pre-treatment, sizing and/or drying, gasification with pressurised oxygen or steam is used to thermo-chemically convert the feedstock into syngas. Gas cleanup and conditioning is used to remove particulates, tars, inert gases, sulphur compounds and other impurities, before a water-gas shift reaction adjusts the ratio of H_2, CO and CO_2. The syngas is then catalytically converted into methanol, before product separation from unreacted syngas. Note that methanol-to-gasoline (MTG) is not currently seen as a viable downstream upgrading option. Due to the high temperature processes, plants usually are highly integrated with several recycling loops, heat recovery and steam & power generation – some of the syngas can also be used to generate power, instead of producing methanol.

Overall process efficiencies to methanol are between 54% - 57%, or slightly lower if also exporting significant amounts of power. However, capital costs are high, and the technology is only at the pilot and demonstration stage (TRL 5 and 6); whilst several components are commercially mature, their integration is not. There are only 3 developers, with methanol only one product of interest alongside bioDME or ethanol production. Methanol also faces several barriers to its use as a fuel, including low energy density, poor cold start properties in engines, high toxicity, water solubility, and corrosivity. However, biogenic methanol could also be used in chemical applications, or as input to transesterification (thus contributing to lower the life-cycle GHG emissions of biodiesel).

The current minimum economic scale for methanol synthesis is expected to be 120 MW_{th} biomass input, however, this could fall to ~24 MW_{th} in the future if process intensification technology is successfully developed, e.g. micro-channel reactors. The UK has particular expertise in this area, however, there are no plant developers, planned projects, or firms with a suitable large-scale gasifier technology in the UK.

Gasification with catalytic mixed alcohol synthesis

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into a range of alcohols (methanol, ethanol and higher alcohols). After any pre-treatment, sizing and/or drying, gasification with pressurised oxygen or steam is used to thermo-chemically convert the feedstock into syngas. Gas cleanup and conditioning is used to remove particulates, tars, inert gases, sulphur compounds and other impurities, before a water-gas shift reaction adjusts the ratio of H_2/CO. The syngas is then catalytically converted into alcohols (using a modified FT or methanol catalyst), before product separation from unreacted syngas and undesired outputs (mainly methanol) for recycling. Due to the high temperature processes, plants usually are highly integrated with several recycling loops, heat recovery and steam & power generation.

As for butanol, the mix of higher alcohols means that the product has superior properties compared to ethanol alone, with higher blends possible. Overall process efficiencies are between 38% - 46% for mixed alcohols, and lower for ethanol only. However, capital costs are high, and the technology is only at the pilot and demonstration stage (TRL 5 and 6); whilst several components are commercially mature, their integration is not. There are around 9 developers working on ~12 projects, all based in North America.

The current minimum economic scale for mixed alcohol synthesis is expected to be 200 MW_{th} biomass input, however, this could fall to ~40MW_{th} in the future if process intensification technology is successfully developed, e.g. micro-channel reactors. The UK has particular expertise in this area, however, there are no UK plant developers, planned projects in the UK, or firms with a suitable large-scale gasifier technology.

Gasification with syngas fermentation

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into ethanol. Other alcohols or organic acids could also be produced (e.g. butanol, acetate), although most developers are focused on producing only ethanol.

After any pre-treatment, sizing and/or drying, gasification is used to thermo-chemically convert the feedstock into syngas. Gas cleanup and conditioning requirements are much less strict than for catalytic fuel synthesis routes. The syngas is then biologically fermented into ethanol by a set of living micro-organisms, at low temperatures and pressures. Liquid-gas mass transfer rates are low, so syngas recycling is common. Downstream, ethanol is separated out by distillation or membranes. Plants can use the heat recovered from syngas cooling for steam & power generation, or alternatively, combust the off-gases (i.e. no syngas recycling).

The minimum economic scale for syngas fermentation is expected to be 60 MW_{th} biomass input, i.e. around 40 Ml per year ethanol output. Overall process efficiencies to ethanol are currently between 34% - 39%, although developers quote 43% - 46%. Capital costs are high, and the technology is only at the pilot stage (TRL 5); whilst several components are commercially mature, their integration is not. There are only 3 developers (one of which has a strong UK presence), working on ~10 projects, with 1 project in the UK.

Pyrolysis oil upgrading

Crude pyrolysis oil, also called 'bio-oil', is a dark brown viscous liquid. It contains a complex mixture of oxygenated hydrocarbons, water, and potentially solid char particles. The crude oil can be used in some applications without further treatment. However, for others, including advanced boiler systems, industrial gas turbines, or combined cycle systems and for transport fuels, further processing is needed. Primary objectives of the upgrading processes are to remove the oxygen present in the oil and to crack and isomerize the longer hydrocarbon chains to yield the required fuel characteristics. Upgrading can be divided into three main routes: gasification, hydrotreating, and zeolite cracking.

If the oil is gasified, the resulting syngas can serve as a feedstock to the synthesis processes described elsewhere in this report. Under zeolite cracking, oxygen is removed through cracking in either liquid or vapor phase. Unfortunately, pyrolysis oils tend to coke easily in this process. Much of the work on upgrading of pyrolysis oils is therefore focused on hydrotreating where the oil is exposed to hydrogen and a catalyst under high temperature and pressure. The upgrading process yields different products depending on the system configuration, e.g. an equal share of diesel and naphtha. The mass conversion yields from pyrolysis oil (containing 10-20% water) to upgraded fuel vary from 22%–39%. This equates to an energy efficiency range from pyrolysis oil to upgraded fuel of 56%–75% (with the energy input of any natural gas or hydrogen also accounted for).

This upgrading process is still in development (TRL 4) with significant problems with catalyst life being reported. The UK has world-class capabilities in pyrolysis, particularly in academia. There are a few UK companies active in pyrolysis oil upgrading, although none of the main technology developers with demonstration plants are based in the UK.

Hydrotreatment

Hydrotreatment of vegetable oils involves the conversion of vegetable oils into automotive diesel and jet fuel, referred to as hydrogenated vegetable oil (HVO) and hydrotreated renewable jet (HRJ) respectively. The process of hydrotreatment consists of a thermal decomposition process, a hydrogenation and isomerisation reaction to produce HVO, and an additional selective cracking process to produce HRJ. As all fossil diesel specification are met or exceeded by HVO (e.g. HVO has a much higher cetane number than fossil diesel), it could be potentially used without blending with fossil diesel. Conversely, HRJ can be blended with fossil jet fuel up to a 50% blend, based on latest standards on aviation fuels.

The main advantage of both HVO and HRJ is that they can be used in current diesel or aviation supply chains (drop-in fuels).

The scale of currently operating or planned hydrotreatment plants ranges from 190,000 to 800,000 t/a. Depending on the plant configuration, it can be a dedicated HVO plant or a co-production plant with different shares of HRJ and HVO as products. The plant can either be a separate unit at an existing oil refinery (which would allow for co-usage of hydrogen) or be built as a dedicated standalone plant.

The TRL of hydrotreatment to HVO is 8, as the technology is operating successfully in various commercial plants. The current TRL for HRJ production is slightly lower (TRL 7) as only one commercial plant is in operation. UK refineries are expert in hydrotreating; however capabilities in hydrotreatment of vegerable oils are limited, with only an engineering design centre of one of the leading technology developers.

2.2.4 Technologies for heat, power, and combined heat and power generation

Biomass feedstock can be used to produce heat (typically in the in the form of radiative energy, hot water and steam) and electrical power via thermodynamic cycles. As the production of power is always associated with the generation of heat, biomass is also used in combined heat and power generation.

The key characteristics of technologies for heat, power, and combined heat and power generation covered in this report are outlined below.

Biomass boiler (for heat application)

In a biomass boiler, the biomass fuel is burned to produce heat or steam that can be used for either process or space heating (as well as cooling via absorption chillers). A typical biomass heat system comprises: biomass reception, storage and fuel extraction - where the fuel is discharged by delivery vehicle and held in storage until it is extracted to the boiler; energy conversion – where the conversion of the biomass in a boiler into heat or steam takes place; and heat distribution – where heat is delivered from the boiler to the point of use.

Biomass fired boilers for the provision of heat are a mature technology with markets well established in mainland Europe and North America (TRL-9). In the UK, the principal biomass materials used for heat only applications are wood pellets and woodchip whilst logs are used significantly in the domestic market.

Biomass boilers for heating application are available in a range of configurations with selection dependent upon the scale of application and the characteristic of the intended biomass fuel, with plant sizes concentrated at the sub 10MWth scale. Typical boiler efficiency for boiler combustion units firing biomass is c.70 to 75 % (on GCV basis).

There is very little indigenous capacity for the manufacture and assembly of biomass plant in the UK. Those that are active tend to address small scale batch boilers (<300kW) or target waste combustion applications, with the majority of UK suppliers importing commercially proven EU technology from mature markets such as Austria, Germany and Scandinavia.

Dedicated biomass steam cycle

A dedicated biomass steam cycle power plant is an integrated power system that comprises three main components:, biomass reception and feedstock preparation, energy conversion in the boiler and power and heat production.

The biomass fuel is burned in a biomass boiler to produce high-pressure steam that is used to drive a steam turbine-driven power generator. In many applications, steam is extracted from the turbine at medium pressures and temperatures and is used for combined heat and power generation (for process/space heating as well as cooling). A modern steam cycle power plant using biomass will have a gross overall electrical generation efficiency in the range of 20 to 35% (GCV basis) depending upon scale, although efficiencies seldom exceed 30%. In CHP applications, the electrical efficiency may drop to 15% depending on the heat to power production.

There are 36 projects in development in the UK where the total projected capacity is 3764MWe and most of the projects are in the range 100MW to 350MW. These larger projects are located adjacent to dockland and assume significant import of biomass materials. The minimum economic capacity for biomass with a steam turbine for CHP would be c. 2 to 5 MWe but this largely depends upon specific site conditions where much of the heat generated can be used in order for it to achieve financial viability. The bias toward a larger scale of generation is a consequence of the much higher revenue streams that can be secured for electricity generation as compared with heat and therefore development has tended towards the larger scale of installation where economies of scale are greater and thereby, profit margins are more attractive. The largest dedicated biomass CHP plant in the UK is the 50MWe plant at Markinch, Fife.

Dedicated biomass steam cycles for both CHP and electricity generation are considered to be mature technologies with thousands of successful operating hours globally (TRL 9). The whole UK power equipment and services sector is relatively large, however when compared with fossil fuel plant there have been relatively few biomass power stations constructed over the past 20 years (305MWe capacity in total as at October 2010). Indeed compared to Europe, there has been a lack of development in this field by conventional UK power sector players. As a result, the UK-based supply chain for biomass power generation plant has been eroded quite considerably and UK sector players have formed strategic alliances with European based companies who have established a position in biomass markets with the UK companies providing ancillary plant. Technology providers tend to be located in Northern Europe/Scandinavia and North America, where the new generation of biomass fuels are expected to be sourced.

Biomass co-fired steam cycle

Biomass co-fired steam cycle involve power and combined heat and power generation using fossil fuels co-fired with biomass The great majority of biomass co-firing projects worldwide have involved the utilisation of solid biomass materials and have been as retrofits to existing pulverised coal-fired power stations. In most cases, co-firing of biomass up to 10% by heat input is technically possible, but the normal co-firing ratio is less than this (typically 5%) to ensure operating efficiency is not compromised.

The use of co-firing does not require significant changes to the boiler over and above burner modifications or additions to introduce biomass material to supplement fossil fuel burning. Typical modifications in an existing coal boiler include changes or additions to fuel handling, processing, storage, and feed systems. Slight modifications to existing operational procedures, such as combustion air supply might also be necessary, as well as increasing fuel feeder rates to compensate for the lower density and heating value of biomass.

Biomass co-firing is a mature technology application (TRL 9) with thousands of operating hours worldwide. However, no retrofit for co-firing application was carried out in the UK prior to 2002. In the UK most of the large biomass plants have carried out trials burning biomass with coal at levels ranging from 2 to 10%.

Stirling engine

Stirling engines are indirectly fired gas engines, i.e. an engine where the working fluid (or process medium) is a gas, which is used in a closed cycle**,** the heat is transferred to the working fluid indirectly from an external heat source. Both these features are different than for the internal combustion engine (ICE), which works in an open cycle, and heat is generated within the engine in the combustion chamber. The thermodynamic cycle of a Stirling engine consists of a compression of the working gas in a cold cylinder volume, supply of heat to the gas, an expansion of the gas in a hot cylinder volume, and cooling of the gas before the cycles starts again. During the expansion, force is transmitted to a crankshaft which can then be used for electrical power generation**.**

As Stirling engines require an external heat source, often Stirling engines are designed, produced and installed together with the heat source. This often ensures, amongst other things, better heat integration and the combined production of heat and power. Biomass fuelled heat source include biomass furnaces, biogas or landfill gas combustion chambers, bio-oil and pyrolysis oil burners. Stirling engines are suited for small scale application in power generation and combine heat and power (CHP) generation, in the scale from 1kWe up to slightly more than 100 kWe. The electrical efficiency of existing Stirling units is in the range of 10 to 15%, depending on the heat output.

Stirling engines are at the market introduction stage (TRL 7). They are not yet widely deployed worldwide, although some commercial units are in operations at the moment and more are being developed.

Organic Rankine cycle

The Organic Rankine Cycle is a thermodynamic cycle to produce power and combined heat (as hot water) and power. It is similar to the conventional Rankine cycle used in water steam cycles to generate power, with the difference that instead of water it uses an organic liquid, with lower boiling temperature than water, as process medium. There are some advantages of using an organic liquid over water, the most important being the possibility of using low temperature heat source (from 70 to 300°C).

An ORC plant can be divided into two main components: the heat source, which is typically a furnace with a boiler (see Section on boiler for details on it), and the ORC turbogenerator, where the Rankine cycle takes place. The heat source and the ORC turbogenerator are always integrated in one single unit, due to heat integration reasons. Typical sizes for ORC generators range from 400 kWe to 2MWe. Typical ORC technology electrical efficiencies are around 15%, less if in co-generation of hot water.

ORC can be considered a market-proven technology unit (Obernberger, 2010), at 7 TRL, with more than hundred plants already operating worldwide.

Internal combustion engine

Biomass-derived gas can be used as a substitute for natural gas for the production of power and CHP in internal combustion engines (ICE). Gas-powered internal combustion engines are modified versions of medium- and high-speed engines powered by liquid fossil fuels. The ICE is connected to a generator to produce power, and the excess heat in the engine cooling system and the exhausts can be used to produce heat by using heat exchangers. To ensure efficient operation and engine components life, the gas must be cleaned to meet certain requirements (e.g. sulphur levels). In addition to gas, other biomass-derived liquid fuels can be used in ICE for power and CHP production. However, due to their higher energy density, liquid fuels are more typically used for transport applications.

Reciprocating (natural gas or biomass derived gas) engines are used for a variety of stationary power generation applications, with typical sizes of a single ICE ranging from 100kWe up to 5 MWe. Internal combustion engines are relatively efficient at converting biogas into electricity, achieving efficiencies in the range of 25 to 36%. Over the forementioned range based on GCV, it would be expected that the conversion efficiency for syngas and natural gas would be similar.

ICE technology for both power and CHP application is a mature technology in the successful operations stage of a technology lifecycle (TRL 9). In the UK, gas CHP and electricity generation has been applied extensively and therefore there are many manufacturers providing biomass-derived gas to electricity generators.

However, it should be noted that whilst ICE are frequently used for some bio-energy chains (AD / landfill gas) the use of biomass derived gas from woody sources is not extensively applied and there remain some fundamental operational issues when using biomass derived gas. For this reason the TRL within a woody biomass application would be 7-8.

Close-coupled gasification

In close-coupled gasification, syngas is generated by the gasifier and then it is either combusted directly (without syngas cleanup) in the gasifier itself, or downstream in an adjacent boiler. The systems typically produce space heat, and / or process heat or steam and can also be combined with downstream equipment such as steam turbines and absorption chillers to produce electricity and cooling respectively

Suitable feedstocks depend on the type and scale of the gasifiers, and include woody, agricultural residues, animal and municipal waste or industrial or commercial wastes. Typical thermal input (for biomass) to thermal output efficiencies for close-coupled gasifiers range from 65% to 88%.

Close-coupled gasifiers are commercially available (TRL 8), with hundreds of units installed. Some industrial capability exists in the UK, with some technology developers focusing on technologies for waste feedstocks.

Biomass co-fired Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) with biomass co-firing combine coal gasification technology with combined-cycle generation technology. The gasifier converts coal and co-fired biomass into syngas, which is cleaned and then combusted in a gas turbine to generate power. The hot flue gases from the gas turbine are used to supply heat to a steam cycle, thus increasing the overall efficiency of the electricity production.

The main advantage of IGCC over coal combustion is the higher efficiencies due to the combined gas and steam cycle. The efficiency of existing IGCC plants (without CO_2 capture) currently varies between 38 to 45%. As a further advantage, IGCC plants are potentially very attractive for pre-combustion CO_2 capture as the syngas is produced at high pressures and can be shifted to enrich the CO_2 concentration. The main disadvantages of IGCC biomass co-firing is the current limit of 10% co-firing due to economic considerations and the higher capex and complexity of the plants. For co-firing shares above 10%, separate suitable mills and burners for coal and biomass are necessary which significantly increase capital costs.

The likely scale for fully commercial coal IGCC plants is thought to be between 250 and 1200 MWe. Given the current 10% co-firing limits, the biomass co-firing of IGCC plants would be in the range of 25-120MW. The co-firing of biomass at IGCC plants is at TRL 7, as a couple of large scale demonstration projects exist. Currently, there are no IGCC plants in the UK, however at least one co-fired IGCC (with carbon capture) plant is being planned

Dedicated biomass Integrated Gasification Combined Cycle

The working principle of a dedicated biomass integrated gasification combined cycle (BIGCC) is similar to that of fossil fuelled or co-fired integrated gasification combined cycle (IGCC): the syngas produced in a gasifier is combusted in a gas turbine to drive a generator, with exhaust heat recovery raising steam to drive a further steam turbine and generator. BIGCC plants offer the same advantages of (co-fired) IGCC plants in terms of carbon capture.

BIGCC technology is at the early demonstration stage (TRL 6). Globally, only a few early BIGCC demonstration plants have been realized so far, in the range of 6-32MWe output, although none are still operational. Current projects under construction in the US are in the range of 20-55MWe and planned projects slightly above 100MWe. Early commercial availability is expected for 2020. Currently, there are no BIGCC plants in the UK, with the ARBRE plant closing in 2002 shortly after construction. However, some relevant industrial capabilities in some BIGCC components exist.

Gasification with internal combustion engine, or gas turbine

The syngas from a gasification process can be used as a fuel for a prime mover such as an internal combustion engine (ICE) or an open cycle gas turbine, generating electricity and heat.

Given the large range of possible gasification approaches, suitable feedstocks include woody, agricultural residues, animal and municipal waste or industrial or commercial wastes. Depending on the scale of the plant, typical electrical efficiencies are in the range of 30–40% for gasifier plus ICE systems, and 35-45% for gasifier plus open cycle gas turbine systems, whilst CHP efficiencies can be up to about 60–80%.

At small scales, fixed bed gasifiers and ICEs are typically used. The syngas from these gasifiers requires cleaning before it can be used in an ICE to avoid fouling, erosion and corrosion, with more extensive cleaning required before use in a gas turbine. Small scale systems are still largely at an early commercial stage (TRL 7), with each developer only installing single digit numbers of units to date — and are therefore not yet considered fully commercially available.

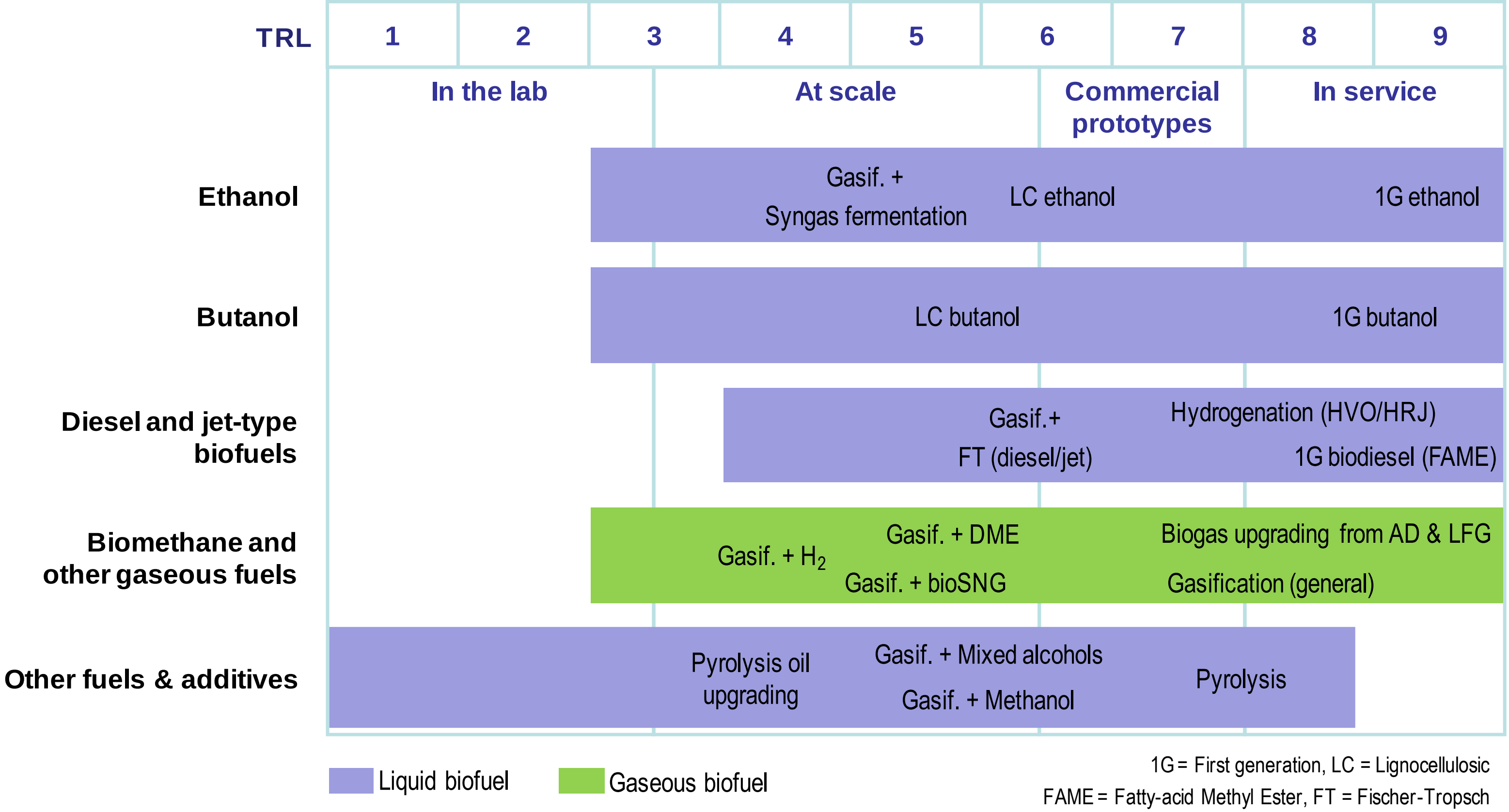
At large scales, gasification technologies generating electricity from MSW and other wastes are commercially available, with numerous plasma and BFB plants built to date (TRL 8-9). However, plasma gasification experience with other feedstocks is limited. Gasification for power or CHP generation not using wastes is at the demonstration / pre-commercial stage, with developers only currently having single figures of units installed globally (TRL 5-7).

2.3 Summary of technology development status

Development status, expressed in Technology Readiness Level (TRL) for all technologies covered in this report is summarised in the following sections.

2.3.1 Technologies for gaseous and liquid fuels

The development status of the technologies to produce gaseous and liquid fuels from biomass is summarised in Figure 2-1.



1G = First generation, LC = Lignocellulosic
FAME = Fatty-acid Methyl Ester, FT = Fischer-Tropsch
HVO = Hydrogenated Vegetable Oil, HRJ = Hydro-treated Renewable Jet
DME = Dimethyl Ether, SNG = Synthetic Natural Gas, AD = Anaerobic digestion

Figure 2-1 Development status of the main technologies to produce gaseous and liquid fuels from biomass

2.3.2 Pre-treatment and densification technologies, and technologies for heat, power, and combined heat and power generation

The development status of the biomass pre-treatment technologies and technologies to produce for heat, power, and combined heat and power generation from biomass covered is given in Figure 2-2.

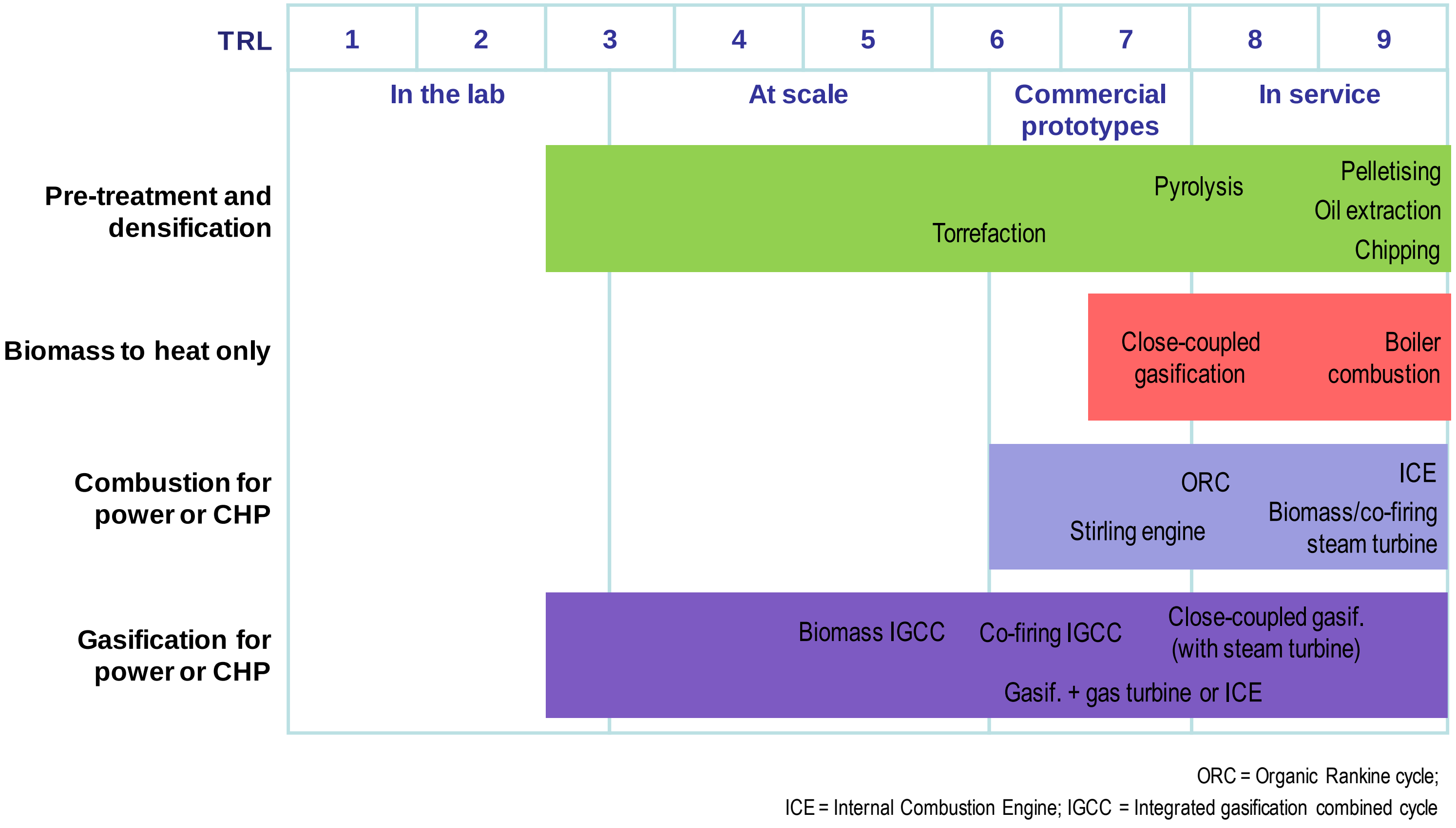


Figure 2-2 Development status of main biomass pre-treatment technologies and technologies to produce for heat, power, and combined heat and power generation from biomass

2.4 Summary of UK capabilities

A summary of UK academic and industrial capabilities[5], as compared to those of other countries, for all technologies covered in this report is summarised in the following sections. This summary is based on the information included in this report and complemented with the work for the Technology Innovation Needs Assessments (TINA) in bioenergy carried out by E4tech for the Carbon Trust and the Department of Energy and Climate Change (E4tech, 2011).

2.4.1 Pre-treatment and densification technologies

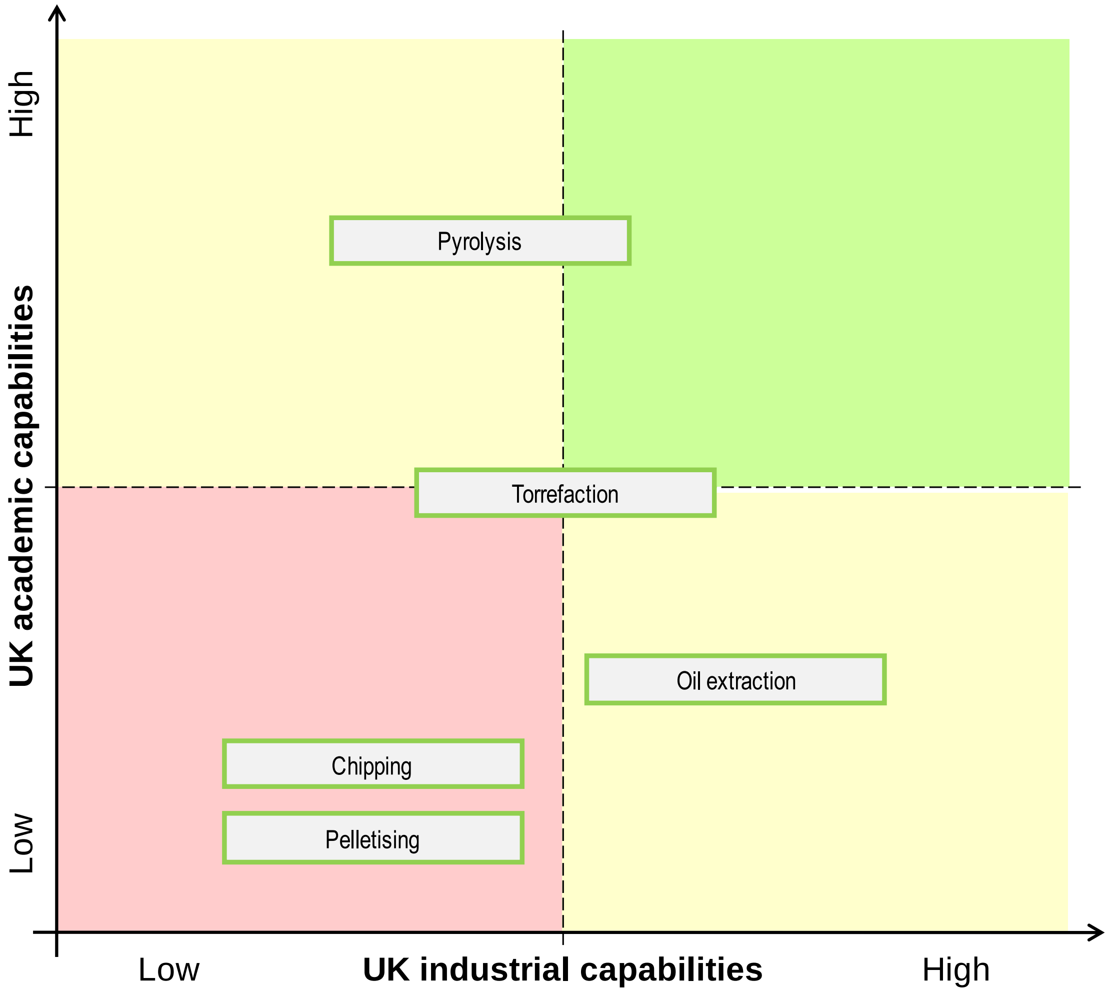


Figure 2-3 UK academic and industrial capabilities in pre-treatment and densification technologies

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[5] By industrial capability we intend capability in technology and equipment research, development, testing, design and manufacturing. As such, capabilities in project developments are excluded in this analysis.

2.4.2 Technologies for gaseous and liquid fuel technologies

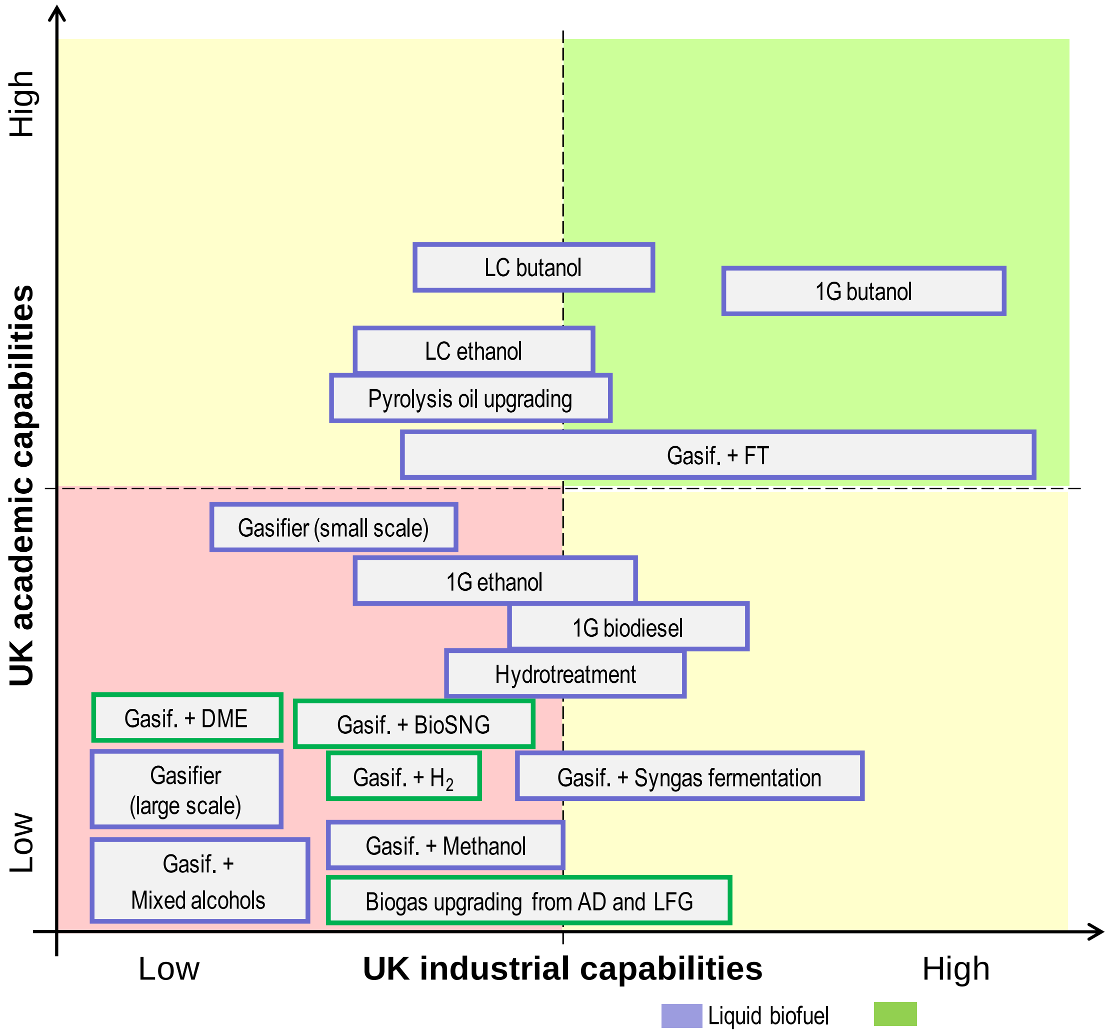

Figure 2-4 UK academic and industrial capabilities in gaseous (in green) and liquid (in purple) fuels from biomass

2.4.3 Technologies for heat, power, and combined heat and power generation

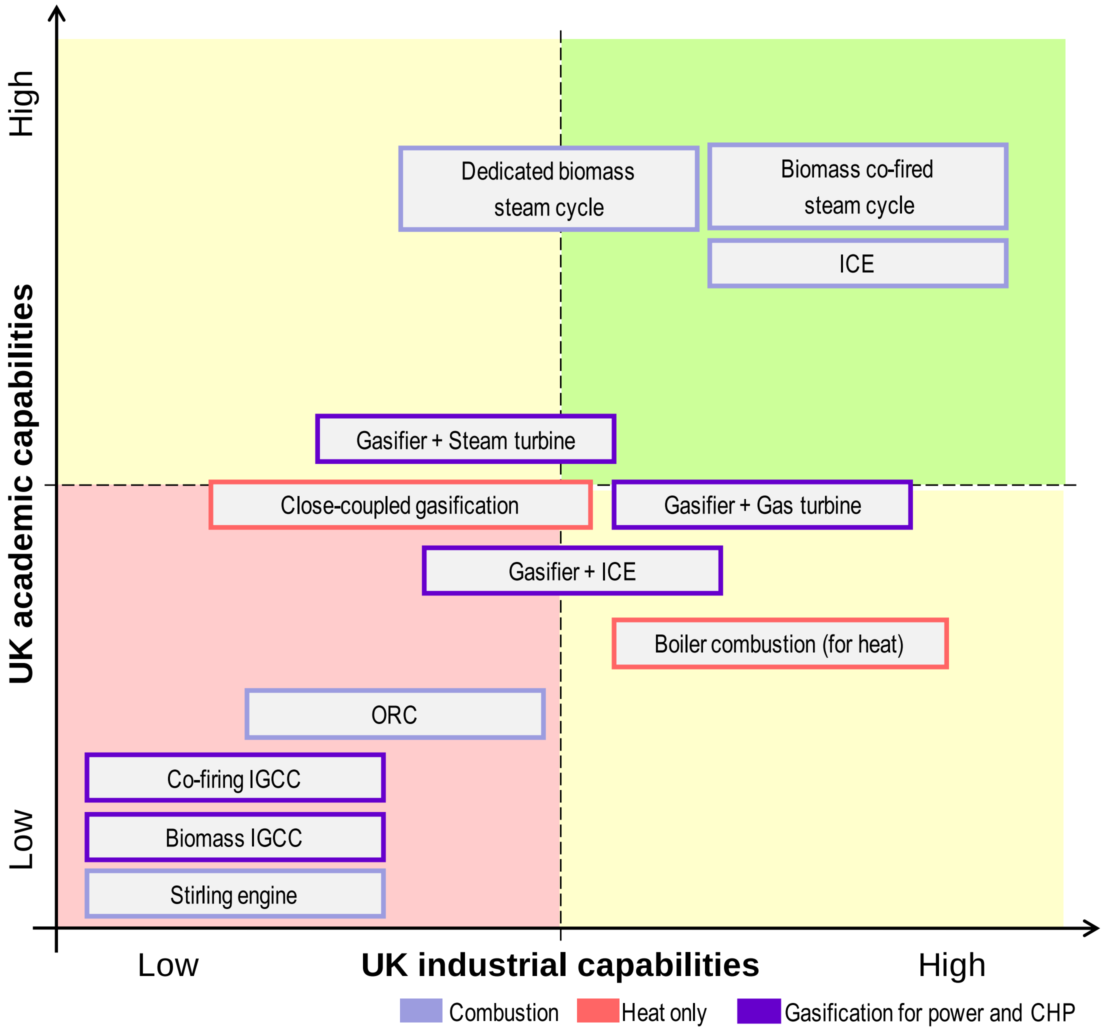

Figure 2-5 UK academic and industrial capabilities in technologies for heat, power, and combined heat and power generation

3 Next steps

The landscaping work carried out for this report, together with the references and the technology data gathered so far, constitutes the groundwork of the following technology parameterisation task in WP3.

By the time of the submission of this report, WP3 parties E4tech and Black&Veatch, together with Imperial College, have already developed the structure of the technology parameterisation database (in MS Excel). Such database has been already piloted with a handful of technologies, and is ready to be prototyped by Imperial College

The next steps to be carried out in WP3 will be:

- E4tech and Black&Veatch to populate the database with data for most technologies by end of August 2011 and deliver it to Imperial College (WP3-D2 – internal deliverable) for first value chain prototype. Data gaps in the database will be reported and explaine in the technology modelling report (WP3-D3)
- Imperial College to develop a tool to extract data from the technology database in automatic fashion, to allow for quick and multiple data extraction under different scenarios
- Imperial College to run simulations with the prototype model in September/October 2010 and feedback to E4tech and Black&Veatch for any technology model refinement need. More refinement can include for example: modelling of a technology at different scales, update of future technology data, etc.
- E4tech and Black&Veatch to produce a report on the technology modelling (WP3-D3), as fully annotated and commented MS Word version of the MS Excel technology database
- Case study definition by the whole consortium together with the ETI and any stakeholders by end of October, to define scenarios for technology modelling.

Part 1: Introduction

4 How to read this document

4.1 Document structure

For the sake of improving readability, this document is divided into five parts:

- Part 1 – “Introduction”. It describes the document structure and the framework used for the technology landscaping
- Part 2 – “Pre-treatment and densification technologies”. This part covers:
    - chipping
    - pelletising
    - torrefaction
    - oil extraction
    - pyrolysis
- Part 3 – “Technologies for gaseous fuel production”. This part covers:
    - anaerobic digestion
    - landfill gas
    - biogas upgrading
    - gasification
    - gasification with catalytic methane synthesis
    - gasification with catalytic dimethyl ether synthesis
    - gasification with hydrogen production
- Part 4 – “Technologies for liquid fuel production”. This part covers:
    - first generation ethanol
    - first generation biodiesel
    - first generation butanol
    - lignocellulosic ethanol
    - lignocellulosic butanol
    - gasification with catalytic Fischer-Tropsch synthesis
    - gasification with catalytic methanol synthesis
    - gasification with catalytic mixed alcohol synthesis
    - gasification with syngas fermentation
    - pyrolysis oil upgrading
    - hydrogenation
- Part 5 – “Technologies for heat, power, and combined heat and power generation”. This part covers:
    - boiler combustion (for heat application)
    - dedicated biomass steam cycle
    - biomass co-fired steam cycle
    - Stirling engine
    - organic Rankine cycle
    - internal combustion engine

  - close-coupled gasification
  - integrated Gasification Combined Cycle
  - dedicated biomass integrated Gasification Combined Cycle
  - gasification with internal combustion engine or gas turbine

4.2 Landscaping framework

This report covers each technology within a common landscaping framework. This framework is illustrated into the document structure below.

4.2.1 Technology description

This section provides a description of the technology, with particular emphasis on those cases where different technological options exist and on how differing options compare with each other.

We will attempt at answering the following questions:

- What does the technology do?
- What are its main stages (with options and descriptions on what they are and what they do)?
- Are different technology options under investigation?
- What are the technical barriers to development and deployment?

4.2.2 Feedstock

This section provides a description of feedstocks the technology can work with (including comments on constraints on minor constituents).

We will attempt at answering the following questions:

- What feedstock properties are of interest / problematic?
- What feedstocks are suitable?
- What feedstocks have been tested?
- How different feedstock / feedstock characteristics affect the technology?

4.2.3 Technical and environmental characteristics

This section provides a description of the main technical and environmental characteristics, including scale, efficiency and GHG emissions.

This section attempts at answering the following questions:

- At which scale the technology is (expected to be) deployed? What are the implications on feedstock requirements?
- What is the energy efficiency? What factors may affect it?
- What are the sources of emissions? What ranges does the literature provide for emissions savings resulting from the deployment of the technology? What are typical emission values in the literature for different configurations?

It is important to stress the fact this section, as all other sections, provides a review of the literature and of the state of the art for a given technology. It follows that data and information on scale, efficiency and GHG emissions are as found in the original references. Detailed modelling (including unit conversion, currency conversion, component breakdown, GHG emissions factors and assumptions, etc) will be done in the following WP3 task on technology parameterisation. Technology model data on – inter alia - scale, efficiency and GHG emissions (and their projected change till 2050) will be reported in the next WP3 deliverable (Technology Modelling report - WP3-D3).

4.2.4 Costs

This section provides a qualitative discussion of costs.

This section attempts at answering the following questions:

- What are the main cost components?
- What are typical production costs in the literature?
- What is the split between capex and opex?
- What cost reductions are expected with deployment?

When referring to capital costs, unless otherwise specified, we will refer to installed capital costs. These costs typically cover items such as engineering and supervision, construction expenses, legal and contractor’s fees, besides the costs of purchased equipments.

Unless otherwise specified, operating costs include items such as utilities, personnel and overheads, and chemicals. In general, feedstock costs are not included in the operating cost value (this is because in the value chain model feedstock costs are assessed in a different Work Package).

Similarly to what said above for scale, efficiency, and GHG emissions, detailed explanation, breakdown (where applicable), currency conversion and annualisation, etc. of capital and operating costs (and their projected change) will be given in the Technology Modelling report (WP3-D3).

4.2.5 Requirements of the upstream/downstream process and system considerations

This section provides a qualitative discussion of requirements of the processes upstream and downstream of the technology under scrutiny.

This section attempts at answering the following questions:

- What are the requirements upstream and downstream of possible configurations and fuel chains for deployment?

4.2.6 Deployment and development status

This section provides a commentary on the status of the technology in terms of:

- technology maturity; Technology maturity will be express in terms of Technology Readiness Levels (TRLs)

- number of applications. Primary focus is on the be UK but, where possible, major activities worldwide are included
- typical size ranges
- recent R&D trends and progresses

This section attempts at answering the following questions:

- What is the technology readiness level(s)
- What is the deployment status (pilot plants, demo plants, commercial plants)

The definition given by the US Department of Energy is used for the TRL, as in Table 4-1. TRLs are also grouped into the following categories, in line with ETI vision (ETI, 2011):

  - TRL 1 to 3: ‘in the lab’ research and feasibility.
  - TRL 3 to 6: “at scale” technological development.
  - TRL 6 to 7: technology is demonstrated with commercial prototypes.
  - TRL 8 to 9: describes technology once it is ‘in service.'

Relative Level of Technology Development	**Technology Readiness Level**	**TRL Definition**
System Operations	TRL 9	Actual system operated over the full range of expected conditions.
System Commissioning	TRL 8	Actual system completed and qualified through test and demonstration
	TRL 7	Full-scale, similar (prototypical) system demonstrated in relevant environment
Technology Demonstration	TRL 6	Engineering/pilot scale, similar (prototypical) system validation in relevant environment
Technology Development	TRL 5	Laboratory scale, similar system validation in relevant environment
	TRL 4	Component and/or system validation in laboratory environment
Research to Prove Feasibility	TRL 3	Analytical and experimental critical function and/or characteristic proof of concept
Basic Technology Research	TRL 2	Technology concept and/or application formulated
	TRL 1	Basic principles observed and reported

Table 4-1 Technology Readiness Level scale (DOE, 2009)

4.2.7 Barriers to development and deployment

This section provides description of barriers at market, company, policy and regulatory levels.

This section attempts at answering the following questions:

- What are the non-technical barriers to development and deployment?

4.2.8 UK Capabilities

This section provides commentry on UK capabilities in terms of R&D, engineering, deployment, and commercialisation of the technologies.

This section attempts at answering the following questions:

- Who is doing research on key aspects of the technology in the UK?
- Who has experience in deploying the technology in the UK?
- Does the UK have particular competitive strengths in the technology in relation to research and deployment?

4.2.9 References

References are provided for each technology at the end of the related chapter.

4.3 A note on gasification sections

Many of the routes covered in the technology landscaping task include a gasification step. Due to benefits arising from system integration, in the vast majority of cases the gasification step and the downstream process steps to produce power, heat, and/or gaseous or liquid fuels are heavily integrated into a single plant. Typically the main driver for integration is heat integration, i.e. the possibility of using part of the excess heat from a typically exothermic downstream process for the gasification step, which is endothermic. Also, the majority of the information in the literature and from technology developers is only available at an integrated plant level.

For the reasons above, we have decided to cover routes involving gasification by providing:

- a general chapter on gasification, to give an introduction to the gasification principles and technology, including a description of different gasifier types, their range of scales, and the downstream applications of the syngas production. This introductory chapter is also intended to lay out the common ground regarding feedstocks, upstream requirements, UK R&D activities and capabilities in gasification, as well as the barriers facing all the routes involving gasification. Therefore it acts as a reference for each of the separate chapters on gasification routes (below)
- a separate chapter on each integrated technology route involving gasification, e.g. gasification with catalytic Fischer-Tropsch synthesis. These chapters cover in the details the characteristic of the gasification together with the downstream process steps, according to the common landscaping framework used throughout the report.

The chapters on the integrated technology routes cover:

- Technologies for gaseous fuel production:
    - gasification with catalytic methane synthesis
    - gasification with catalytic dimethyl ether synthesis

  - gasification with hydrogen production
- Technologies for liquid fuel production:
  - gasification with catalytic Fischer-Tropsch synthesis
  - gasification with catalytic methanol synthesis
  - gasification with catalytic mixed alcohol synthesis
  - gasification with syngas fermentation
- Technologies for heat, power, and combined heat and power generation:
  - close-coupled gasification
  - biomass co-fired integrated Gasification Combined Cycle
  - dedicated biomass integrated Gasification Combined Cycle
  - gasification with internal combustion engine or gas turbine

4.3.1 Implications for the technology modelling parameterisation

Due to the system integration issues described above, in the next WP3 technology parameterisation task, the gasification step will be in general modelled together with the downstream process, similarly to what was done for the technology landscaping. This means that the gasification step and the downstream technology will be in general modelled as a single technology module for the model optimisation.

However, we do recognise the interest of the ETI to ensuring that technology modules are developed at the appropriate level and scale, to allow for assessing e.g. decentralised value chains options.

To this end, for the technology parameterisation task we propose a hybrid approach, where:

- technology modules will be provided for all of the gasification routes, in line with the gasification routes covered in the landscaping report. Each of these technology modules will represent an integrated route including a gasification step and a downstream process
- a generic gasifier technology module (at different scale, where applicable) will also be provided. By supplying a generic gasifier model, we intend to achieve two objectives:
  - First, the optimisation model will be able to cover decentralised value chain options, such as gasifiers networked to a pipeline feeding into a large scale power plant with carbon capture (the technology data for the plant with carbon capture should be supplied by other ETI projects)
  - The optimisation model will maintain its flexibility insofar as any new technology based on a gasification route (both centralised and decentralised) can be plugged in by new users in the future.

4.4 References

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Part 2: Pre-treatment and densification technologies

5 Chipping

The increasing importance of woodfuel in the UK, in terms of stated renewable energy policy and sustainable forest management, has highlighted the need for an indigenous woodfuel supply industry and feedstock chipping is a critical element within this supply chain.

Woodfuel is currently the main form of feedstock for automated wood-fuel heating boilers as well as some CHP and some electricity only generating plant. This demand is set to rise considerably given the challenging targets for renewable energy generation under the UK Renewable Energy Strategy.

5.1 Technology description

In its primary form, woody feedstock can be supplied in a number of ways such as:

- Short diameter roundwood from conventional forestry operations;
- Coppice bundles;
- Slabwood from primary timber milling processes;
- Offcuts and lengths from segregated waste operators.

Chippers are used to reduce the size of woody feedstock for ease of material handling and to accord with the requirements of boiler technology. There are broadly three basic types of chipper mechanisms available:

- Disc chippers;
- Drum chippers;
- Screw chippers.

Other technologies are also available such as shredders but these are primarily employed in the waste industry and are therefore excluded here.

5.1.1 Disc chippers

The most common type of chipper mechanism is based on a spinning disc. The disc chipper consists of a heavy rotating disc with usually 2, 3 or 4 blades mounted on the face of the disc. Material to be chipped is fed towards the blades. The rotating knives cut woody material into chips as they pass an anvil or fixed knife. Blower paddles on the back of the disc accelerate the chips up to a spout where they are discharged.

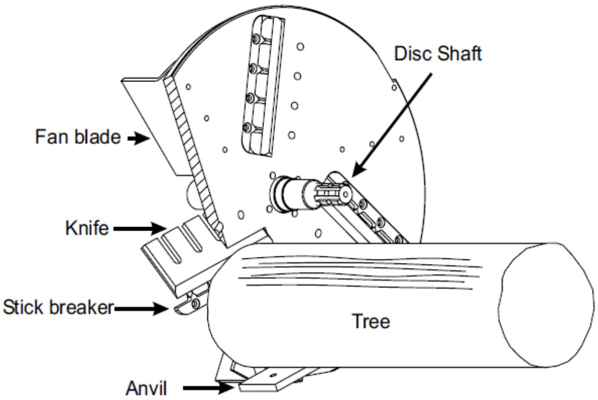

Figure 5-1 Disc chippers (CBT, 1999)

Chip size can be influenced by several factors:

- The faster the infeed, the larger the average chip, while a slower infeed may produce a smaller, more consistent chip;
- The number of blades also has an effect, with fewer blades producing larger chips;
- The speed of disc rotation may be varied, although there will be a minimum speed required to achieve sufficient air movement for chip outflow; and
- The angle of infeed may be varied from the perpendicular to reduce machine stress and produce shorter chips.

5.1.2 Drum chippers

The drum chipper has a rotating drum with 2-4 knives inserted on its circumference. Wood to be chipped is fed in and cut against an anvil, chip size can be adjusted. Separate blowing provision is required.

As with disc machines, chip size is influenced by infeed speed, blade frequency and adjustment, and drum rotation speed. Additionally, timber diameter affects the angle at which the cut is made and influences chip size and consistency.

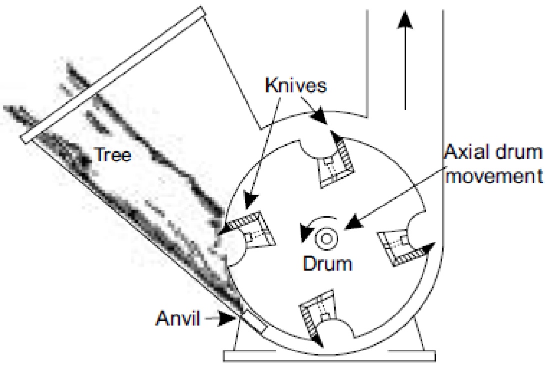

Figure 5-2 Drum chipper (CBT, 1999)

5.1.3 Screw Chippers

This type of chipper is not as common in the UK as the other two types. The screw cone chipper consists of a conical screw with a sharp edge. When rotated, the screw pulls the tree into the chipper and cuts it into large chips or chunks, though it is unsuitable for twiggy material.

To chip for fuel use it is essential to have a consistent particle size, therefore these chippers are available with a special grading device to restrict chips to a suitable size at a small extra cost.

Figure 5-3 Screw chipper (Chipper-Knife)

5.2 Feedstock

The main sources for woodchip in the UK are:

- Forestry - small round wood, whole trees, logging residues, thinning, tree surgery;
- Wood processing - slabwood from primary processing, other sawmill residue, joinery residues;
- Dedicated energy crops – primarily willow coppice;
- Reclamation - recycled untreated timber, pallets and construction industry clean wood waste.

5.3 Technical and environmental characteristics

5.3.1 Scale

According to the required power, chippers can be classified into three categories (Woodfuel handbook, 2009) as bulleted below with their capacity tabulated thereafter:

- Small power - usually installed on the rear three point hitch of a tractor or on a trailer. These chippers are powered by the tractor power take off or by an independent engine (~50 kWe). Typically they are hand fed which also limits the throughput. They can only process small diameters (20 cm max) and can produce no more than 20 t/day;
- Medium power - trailer-mounted, usually with independent engine (50-110 kWe) and can be fed by hand or preferably by grabber to place multiple logs on the feed bed. They can chip diameters up to 30 cm and produce up to 50 t/day; and

- High power - installed on trailers or on trucks, these chippers are sometimes activated by the truck's engine, but normally they are provided with an autonomous engine (>130 kWe). They can chip larger diameter roundwood etc (>30 cm) with material being placed onto the feed bed by a grabber allowing the chipper to easily produce more than 100 t/day.

Chipper Type	Diameter of input material	Output
Small Power	<20cm	<20t/day
Medium Power	<30cm	<50t/day
High Power	>30cm	>60t/day

Table 5-1 Chipper Capacity (Woodfuel handbook, 2009)

5.3.2 Efficiency

The production rates for the different scales of chippers are discussed in Section 6.3.1 above.

The quality of woodchip is crucial for reliable operation of a woodchip boiler. The key parameters are:

- **Material**: Forestry chips from air dried roundwood are ideal. Tops and brash may also be suitable although high bark content can cause problems with ash formation. Sawmill co-product such as slabwood is also suitable. Reclaimed timber from pallets and construction can be used, but requires close attention to ensure there is minimal contamination from metals and plastics.
- **Chip size**: Consistency of chip size is critical for the reliable operation of a small boiler fuel feed system. Fuel blockages are often the main cause of system shut down on many small systems, primarily due to poor fuel quality. For small systems, chips should be no larger than 50mm whilst the fines fraction (< 2mm) should not be more than 15%. Optimum size is generally 8 to 30 mm.
- **Moisture content**: The moisture content of the fuel has a considerable effect on its useful heat yield as higher water content means more energy is consumed to evaporate the moisture. This often affects optimum combustion conditions leading to higher emissions and losses. All boilers have an operating range of acceptable moisture content, depending largely on the combustion system. Larger boilers (1MW +) with moving grates will tolerate wetter fuel (up to 60%MC) whilst smaller systems with stationary grate combustion chambers require fuel with an MC below 40%. Freshly felled timber is 40% - 60 % moisture, therefore for smaller applications, there is a requirement to air-dry the material prior to chipping.

The specification required will depend on the boiler, although in general larger systems are more tolerant of variable quality. There are three grades defined by the range of chip sizes:

- **Super Grade Wood Chip**: (2 - 25 mm) - This is a very tightly defined wood chip, with a total absence of larger material to avoid blockages in fuel feeding systems. Specialised chipping and screening facilities will be required for its production.

- **Fine Grade Wood Chip**: (2 - 50 mm) - This is the most widely used retail chip grade, being suitable for the majority of small-medium scale heating applications (100kW-1MWth). This grade is achievable with selected chippers and/or basic screening.
- **Coarse Grade Wood Chip**: (2 - 100 mm) - Larger scale plant (1MWth and CHP above 1MWe) will operate acceptably on this grade, however occasional blockages can be expected. The lower price of this readily produced fuel will compensate for the extra intervention required. A wide range of chipping equipment including many mobile chippers can produce fuel to this grade without screening.

The European standard EN 14961-4: 2011, was published in June 2011 and allows all relevant properties of the fuel to be described, and includes both normative information that must be provided about the fuel, and informative information that can be included but is not required. The standards determine the fuel quality classes and specifications for non-industrial wood chips. The standard covers wood chip produced from the following raw materials:

- Forest, plantation and other virgin wood;
- By-products and residues from wood processing industries; and
- Used wood.

5.3.3 GHG emissions

The GHG emissions from the use of woodchip encompass the emissions from the non-renewable energy that is consumed along the chain: extraction, processing, storage, fuel energetic conversion, including the energy cost of the machinery and tools used. The CO_2 emissions relating to the production of woodchips are shown in Table 5-2. The emissions relate to the use of diesel oil, for chainsaws and harvesting machinery, transportation and the powering of PTO's for chipping equipment.

Heating system	kgCO_2eq/MWh
Forestry wood chips (50 kW)	26.04
Forestry wood chips (1 MW)	23.95
Wood chips poplar SRC (50 kW)	40.16

Table 5-2 CO_2eq emissions from use of woodchips (Woodfuel handbook, 2009)

5.4 Costs

5.4.1 Capital cost

The capital cost of chippers varies depending on the type and maximum diameter they can process. Typical cost ranges for different sizes are below:

- For maximum diameters up to 20 cm: £5,000 - £12,000
- For diameter range 20-30cm: £8,000 – £50,000
- For diameters greater that 30cm: £50,000 – 250,000

5.4.2 Operating cost

The operating cost for chipping ranges from £8-44/tonne of produced woodchip depending on chipper type and size with, the larger systems able to meet very low production costs by ensuring high throughput levels. This covers fuel cost, repair, maintenance and labour costs (Sarajevs, V. 2008). The reason for the very broad range relates to the lower productivity of the smaller systems whereby manual labour is used to load the material onto the feed bed prior to chipping the biomass feedstock. At the larger scale of operation (and hence the lower cost), costs are reduced by using mechanical grabbers to load several logs at a time on to the feed bad for onward chipping. The use of mechanical handling significantly increases productivity and thereby reduces costs substantially within a high throughput operation.

5.5 Requirements of the upstream/downstream process and system considerations

Material may be either chipped at roadside, in the forest, or at a dedicated treatment / storage depot.

If chipped in the forest, the material can be chipped fresh at 50-60% moisture content and chipped directly into trailers for transport directly to the energy facility. Alternatively, it may be air dried by stacking the material at roadside prior to chipping to reduce the moisture content to c.40%, prior to chipping into a trailer for transport to the energy facility. Where the material is delivered at 50-60% moisture content, these applications tend to be the larger energy facilities (1MW +) where the boiler is more tolerant of both the grade and moisture content of the material.

Conversely, given the rising demand for woodfuel, the sector is seeing the proliferation of storage facilities where material is delivered in the round (either slab wood or small diameter roundwood), then stacked for air drying prior to chipping into a large storage barn for onward delivery to an energy facility. These facilities tend to service the heating market with typical applications tending to be 100kW – 1MW each where the grade and moisture content of the woodchip is more critical.

5.6 Deployment and development status

The demand for UK sourced wood fuel of all types has been rising rapidly in recent years. UK sourced wood fuel is being used successfully for generating heat and electricity using wood fuelled boilers.

There has been a change in the balance between potential availability and demand in the last few years, mainly due to the significant increase in the demand for wood fuel for generating energy, indeed this is set to expand further given the recent announcement of the Renewable Heat Incentive which will be the primary mechanism to drive renewable heating with biomass fuelled sourcing projected to be a third of the overall supply.

At the end of 2010 there was 2.5 GW of biomass electricity capacity operating in the UK, accounting for 11.9 TWh of generation which includes 0.4 GW of co-firing capacity. Much of this material will have undergone some form of communition with the exception of fuel imports which are delivered in usable form. In the case of heat, in 2010 the UK generated 12.4 TWh of renewable heat from biomass, 12.1 TWh of this from biomass boilers which would have required chipping whilst the balance is from energy from waste (DECC, 2011).

The provision of machinery for chipping is a mature market (TRL 9), particularly on the continent though its deployment in the UK has been limited by a lower level of demand due to the incentive regime governing biomass use in the UK.

Nevertheless, as a consequence of existing demand and the significant growth predictions for woody biomass, an emerging supply chain with chipping capacity is coming on stream both at the local level for regionalised heating markets and for significant woodchip users using large scale chipping contractors. As of July 2011, there are over 100 suppliers of woodchip across the country (Biomass Energy Centre). Typically, these contractors have diversified into this field from previous forestry processing and logistic operations. Consequently the larger contractors (c.24 in total) operate national logistic fleet with significant chipping facilities processing 1000’s tonnes per annum,.

5.7 Barriers to development and deployment

- Wood supply chains are relatively small and fragmented in the UK which makes it more difficult to provide secure long term “bankable” supply contracts for new ‘greenfield’ projects, particularly if the projects are of a large size. The supply contracts potentially available tend to favour the smaller developments, ones that can use a mix of wood sources.
- The absence of large long term wood fuel supply contracts for wood sourced in the UK has resulted in a number of companies looking for them overseas which has led the UK to import significant quantities of wood chips and pellets on a regular basis and this is expected to rise rapidly.
- As biomass is a natural product there can be considerable variation both in quality (e.g. moisture content or level of contamination) and quantity (e.g. yield variations for energy crops). This has been a problem in recent years but is largely being overcome as the market and supply chain matures. Similarly the widespread application of a CEN standard in relation to woodchip supply is also facilitating the appropriate specification and delivery of woodchip within a contractual framework.
- Wood fuels usually have alternative uses (e.g. in the paper or furniture industry) and therefore the supply of woodchip to the bio-energy market is subject to the financial conditions of competing markets (e.g. paper and pulp). Should the buying price of biomass rise in these markets, then there is a risk concerning long term fuel availability for indigenous sources.
- For small scale heating markets (<1MW) where fuel chip grade is more critical, there has been an issue with regional chipping capacity and this remains in some regional pockets. This is because fuel suppliers / brokers need to secure a significant volume of chip sales per annum before being able to justify the investment in chipping plant (c.3,000 tonnes / annum). Consequently, for capacity to grow in the UK, it is dependent upon the growth of woodfuel heating at the small – medium scale (<3MW) to allow investment to be made in chipping capacity.

5.8 UK Capabilities

There are various suppliers for wood chipping machines in the UK. Most wood chipping machines are imported from markets with mature woodfuel and forestry supply chains e.g. Germany, Austria, and Scandinavia.

It is likely that machinery will continue to be imported but the existing forestry supply chain is responding to the demands of the market and is capable of providing chipping facilities and capacity. The main issues lie in the availability of the wood fuel supply as a rising demand will lead to the UK resource being supplemented with imported woodchips.

5.9 References

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6 Pelletising

Global pellet production in in 2008 was estimated to be c. 10 million tons with the primary feedstock sourced from sawdust and shavings from primary timber processing. However due to rising demand, interest in alternative feedstock sources is widespread with a focus on feedstocks such as agricultural residues (e.g. wheat straw, barley, strawn, swtchgrass etc).

Woodpellets have a moisture content of less than 10% w/w and this, combined with their homogeneity, mean that they are a high energy density fuel that can be easily transported and can deliver good combustion performance.

6.1 Technology Description

Pelletising is an established technology used for various pressing applications in process industries. There are several pieces of equipment that are used in the commercial wood pellet manufacturing process. These include hammer mills, dryers, pelletisers, coolers, baggers etc..

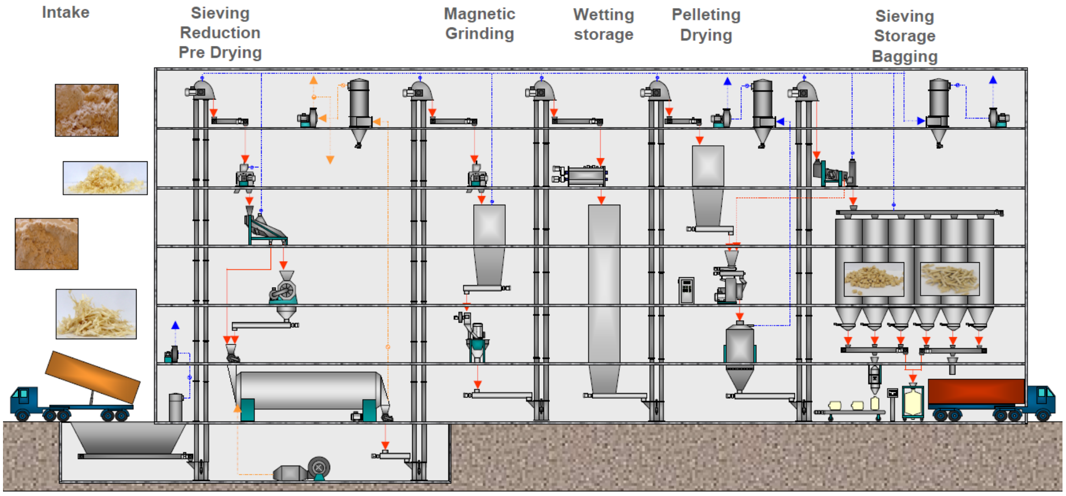

Figure 6-1 Wood pellet production (Buhler, 2006)

The various steps involved in the production of wood pellets are detailed in Figure 6-1 above with further explanation below:

- **Grinding**: The size of the input raw material is reduced by crushing into appropriate particles. Depending on the characteristics of the raw material, this can be achieved by a hammer mill, chipper or shredder.
- **Drying:** The size-reduced material is dried to meet the required moisture content. Typically, the material is placed on a belt dryer on in a drum dryer as the moisture content in the pellet directly affects the pellet quality and burning efficiency.
- **Mixing**: The dried material is mixed with binder and lubricant to help the lignin laced material bind and compress into pellets.
- **Conditioning**: Adding dry steam into the mixed material heats and softens the lignin. This facilitates the compression into pellets and maintains consistent pellet quality.

- **Pelletising**: The material is then fed into a pelletising machine where it is compressed under pressure and extruded through a die. During this process the lignin, naturally contained in the biomass, melts and acts as a further 'binder' stitching together the fibres to form an extruded pellet section and helping to keep the shape of the pellets as they dry. The lignin also gives rise to the 'glaze' found on the exterior of the pellets.
- **Cooling**: The fresh final pellets are produced at a high temperature with extra moisture which needs to be released. A counter-flow cooler is usually adopted for the cooling process.
- **Screening**: This step is used to remove fines, dust particles and broken pellets. A vibrating screen is usually used for the screening process before it is finally bagged or discharged into delivery blower vehicles.

6.2 Feedstock

Primarily the international pellet market and indeed that of the UK and Europe is based on the manufacture of high quality pellets using woody based feedstock. Based on the European Standards EN 14961-2: 2011 the following wood types are permitted to be used for wood pellet production:

- Forest plantation and other virgin wood:
- By-products and residues from wood processing industry; and
- Chemically untreated used wood.

Additives used to improve fuel quality, to decrease emissions or to boost burning efficiency are allowed to make up a maximum 2% of the total mass. Only primary farming and foresting products which were not chemically altered can be used as pressing agents or additives to improve efficiency during production and delivery (EPC, 2011).

However, Europe is currently a net importer of wood pellets and therefore with a possible shortage of woody raw materials for pellet production in countries such as Sweden and Denmark, and considering the low forestry residue potential in southern European countries, agricultural residues are being widely considered for for fuel pellets manufacturing in the future.

However, the diverse composition of alternative fuel pellets can trigger problems at the manufacture and utilisation stage.

In terms of production, straws and grasses can be pelletised without major difficulty. The energy requirement for pelleting straw or other residue can be lower as generally straw is delivered at a moisture content (<20%) that allows by-passing the drying stage. However, straw would present a higher abrasive power (in relation with its silica content), possibly inducing an increased wear of the die and rolls if the latter are made of the same steel as for wood residues.

Aside from this, the homogeneity of pellets regarding size, water content and particle density (all parameters of great relevance to achieve fully automatic operation and complete combustion) appear to be a controllable factor within the pelleting process for any residue. However the main differences relate to the higher friability and the slightly lower energy content of agripellet alternatives. The table below gives a brief comparison of

Feedstock	Bulk density (kg/m^3)	Energy content (MJ kg^{-1})	Ash content (%)
Sawdust	606	20.1	0.45
Bark	676	20.1	3.7
Logging residues	552	20.8	2.6
Switchgrass	445	19.2	4.5
Wheat straw	475	16	6.7
Barley straw	430	17.6	4.9

Table 6-1 Characteristics of Woody and Agripellets (European Pellet Centre)

Agri-pellets combustion triggers several major obstacles regarding emissions (dust, gas and aerosols), deposit formation (slagging, fouling) , corrosion and ash as typically agri residues have higher ash contents than woody biomass.

These issues derive from the chemical composition of the feedstock and as a consequence will impact the design of the combustion equipment and the way it is operated. A typical feature of agricultural residues in comparison with wood residues is their higher content in nitrogen (N), sulphur (S), chlorine (Cl) and potassium (K), much of which is caused by the increased use of fertilisers and pesticides/herbicides in agriculture.

The presence of these elements leads to relatively higher emissions of NOx, SOx, and HCl compared to wood pellets. In addition, the higher prevalence of potassium (K) also influences particulates emissions and slagging (by lowering the softening temperature of the fuel) of of the ash which also has a higher content compared with woody biomass, (5% for straw – 0.5% for sawdust).

Finally, a high chlorine (Cl) content result both in corrosion problem on boiler's surfaces and in formation of dioxins. Those problems can be partly overcome by a range of techniques, ranging from agricultural practices (leaching of the straw in the field) to combustion processes (airstaging) and flue gas cleaning. Possible improvements could come from the fuel preparation stage, with the addition of some specific anti-slagging agents (e.g. kaolin) or the mixing with sawdust to present final characteristic more convenient with regard to combustion and ash issues.

For these reasons it is expected that most agri-pellets will be used in large scale combustion facilities with grate combustion or fluidised bed systems. Cofiring of agricultural residues with fossil fuels also presents a viable market alternative, both technically and economically.

However the use of agripellets with higher ashcontents and varying chemical compositions to that of woody biomass pellets will present problems for in the small scale market where devices for their combustion is very limited.

As a conclusion, the environmental impact as well as current state-of-the-art of combustion technologies indicate that pellets made from agricultural residues (and in general other ash-, N-, Kand Cl-rich fuels) should be used primarily in large scale combustion plants equipped with sophisticated combustion control systems and flue gas cleaning systems, whereas wood pellets should be preferred for residential and commercial heating applications. This may change as the market for technology evolves (European Pellet Centre).

6.3 Technical and environmental characteristics

6.3.1 Scale

Wood pellet mills typically have a throughput of c. 0.5t/h to 6t/h with multiple lines used for higher production capacity.

6.3.2 Efficiency

The efficiency of pellet production process can be depicted by the energy consumption of the process. Table 6-2 shows the average energy consumption of the different steps.

Process Step	Energy Consumption (kWh/t)
Transport	5
Grinding	15
Pelletising	60
Cooling	2.5
Other	2.5
Total	**+/- 85**

Table 6-2 Average energy consumption (CPM, 2011)

Energy demand for wood pelleting (including all stages from reception of raw material to packing) is generally comprised in the range of 80 - 150 kWh/t for electricity and around 950 kWh of heat per ton of water to be vaporised. Thus, the exact energy demand depends on the production requirements which depend upon the initial particle size, the delivered moisture content of the feedstock, the technology used (e.g. hammer mill) and plant scale.

Average energy consumption for pellet production is estimated to be 1140kWh/tonne of pellets produced.

6.3.2.1 Quality Consideration

A number of European Pellet Standards exist. In order to develop a common standard a new European standard CEN/TC 335 for biomass has been developed. The European standard EN 14961-2: 2011 determines the fuel quality classes and specifications for non-industrial wood pellets. The standard covers wood pellet produced from the following raw materials:

- Forest, plantation and other virgin wood;
- By-products and residues from wood processing industries; and
- Used wood.

There are no standards for the production of agri-pellets at the present time. High fuel quality which is necessary for the combustion of densified biomass fuels in automatic small-scale furnaces is not necessary if these fuels are used in larger industrial furnaces. This is because the larger facilities are equipped with more sophisticated flue gas cleaning, combustion and process control systems. This situation will change if more flexible combustion units become available at the small scale.

6.3.3 GHG emissions

The GHG emissions from the use of wood pellets encompass the emissions from the non-renewable energy that is consumed along the chain: extraction, processing, storage, fuel energetic conversion, including the energy cost of the machinery and tools.

The life-cycle CO_2 emission for production of wood pellets is quoted to be c. 184 $kgCO_2e/t$ or 0.3895 $kgCO_2e/kWh$ (net CV basis) (DECC, 2010).

However the exact footprint will depend upon the feedstock input. Energy demand for wood pelleting (including all stages from reception of raw material to packing) is generally comprised in the range of 80 - 150 kWh/t for electricity and around 950 kWh of heat per ton of water to be vaporised.

6.4 Costs

6.4.1 Capital cost

The capital cost shown in Figure 6-2 is the total equipment cost associated with the following processes of a pelletising plant:

- Grinding;
- Conditioning;
- Feeding & mixing;
- Pelletising;
- Cooling;
- Sifting.

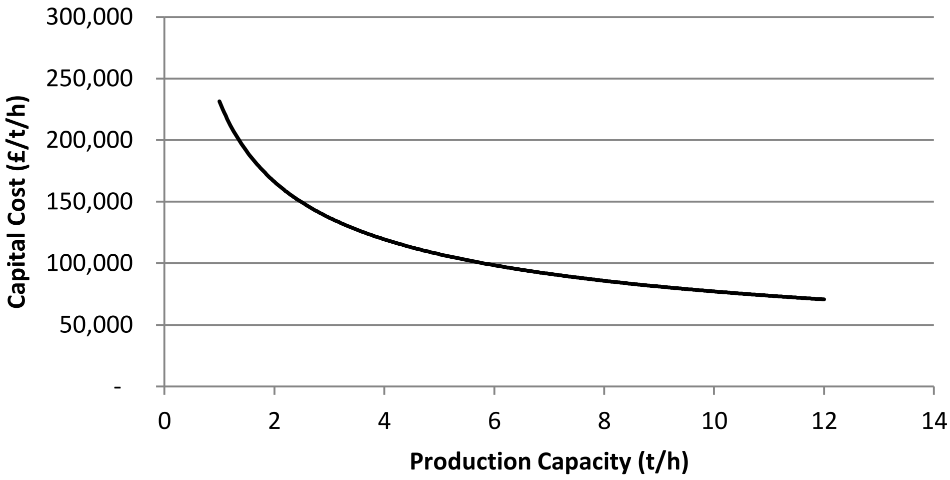

Figure 6-2 Capital cost for pelletising plant (CPM, 2011)

Pelletising appliance costs are likely to come down naturally as demand grows for pellet systems, and more of a mass market develops.

6.4.2 Operating cost

The operating costs for a pelletising plant are provided in Figure 6-3. These include:

- Labour costs;
- Consumables and maintenance; and
- Energy costs.

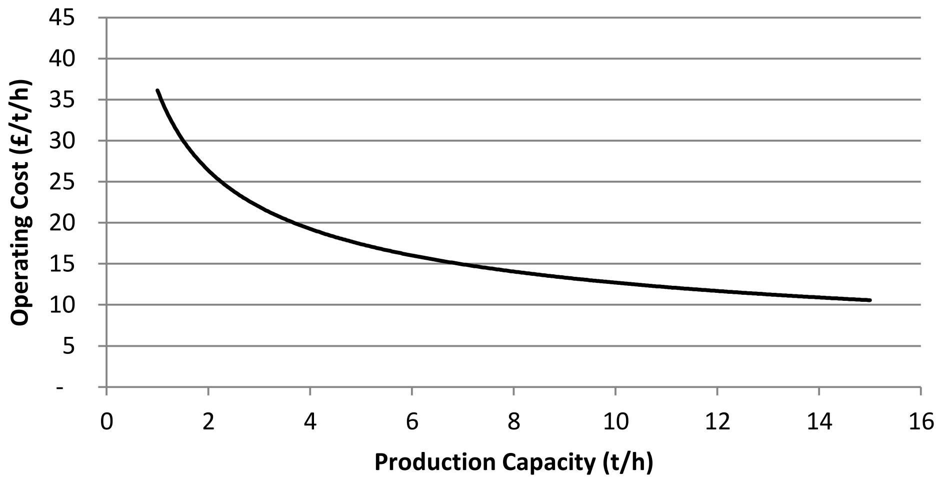

Figure 6-3 Operating cost for a pelletising plant (CPM, 2011)

6.5 Requirements of the upstream/downstream process and system considerations

Pre-processing of wood for conversion to wood fuel has been discussed in Chapter 5.

When the thickness of raw wood material is >10mm, the material needs to be chipped into small pieces and crushed into wood powder with a diameter of <3mm using a hammer mill crusher.

Post pelletising and cooling, the wood pellets need to be kept dry and are packaged either in sealed bags or are discharged to a tanker for onward delivery.

6.6 Deployment and development status

In the late 1990s, a number of initiatives were developed, primarily using EU funded assistance, to introduce wood pellets into the UK and to encourage the adoption of pellet burning wood boilers to heat small commercial and industrial buildings.

Pellet production is well established technology (TRL 9). Pellets are now produced and supplied by a number of companies in the UK with a number of production facilities and storage depots to facilitate national delivery. With growing demand across the heat and power sector, there is still a demand for imported material with wood pellets being imported from Scandinavia, North America and Eastern Europe. As of June 2011, there were 15 wood pellet mills in the UK with the largest, Balcas, producing 100,000 tonnes from its plant in Scotland and 55,000 tonnes output from Northern Ireland in 2009 (REA, 2011).

However, as of July 2011, there are c. 100 suppliers for wood pellets in the UK (Biomass Energy Centre) though many of these are either importing pellets or are second tier suppliers from the main manufacturers such as Balcas.

Currently there are no clear statistics reporting the volume of pellets used in the UK as the figures report biomass as a whole.

Going forward, it is predicted (DECC 2011) that the majority of wood pellet consumption will be concentrated at the sub 200kW scale including domestic stoves.

At the present time there are no manufacturing facilities in the UK using alternative crop feedstocks; however there have been a number of projects within research facilities exploring the technical characteristics of alternative feedstock pellet manufacture.

The global amount of pellet production in 2008 was estimated up to 10 million tonnes with this figure expected to double by 2012/13. Europe is actually considered to be the principal market for pellets, though North American continues to expand in market size consequently import growth will cause the biomass flow reduction from North America to Europe, which will prompt European pellet customers to look for alternative raw stuff sources in Asia, Latin America, Africa and Russia.

The sawdust and shavings from the sawmilling industry is a principal traditional raw stuff, applied for pellet production. Though, due to this supply source run down, the industry there is growing interest in alternative feedstocks for pellet manufacture. With this said, there is no discernable difference in the production of pellets using alternative feedstocka and therefore the TRL remains at 9 for agripellet production. However a key barrier to use will be the flexibility of systems to accommodate the chemical composition of the feedstock at the smaller scale.

6.7 Barriers to development and deployment

The barriers for the availability of wood fuel have been discussed in Chapter 5.

Barriers to the development of UK pellet market are:

- Increased fuel costs for wood pellets compared with their woodchip counterpart which means that they tend to be used in the smaller heating applications or where space is a premium;
- Absence of an organised pellet fuel distribution network;
- Lack of storage space for pellets in the urban / domestic environment where wood pellet adoption is projected to be strongest;
- Resistance to community district heating schemes due to the capital cost of the required infrastructure.

6.8 UK Capabilities

The majority of pelletising production plant is imported from mainland Europe. There are various agents and suppliers for pelletising equipments in the UK but there are no indigenous manufacturers of pelletising production plant. Examples of imported systems are below:

- Andritz (Austria);
- Buhler (Germany); and
- CPM (USA).

Pellet equipment sales in the UK are increasing and reflect the growing demand for wood pellets for heating, with this demand set to rise substantially with the advent of the renewable heat incentive.

There is now an emerging wood pellet fuel industry in parts of the UK-focussed around pellet production using imported equipment. There are a growing number of medium and small size plants now starting production.

There are no facilities producing agripellets in the UK as current demand for these exists at teh large utility scale biomass facilities which are using primarily imported material.

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7 Torrefaction

7.1 Technology description

Similarly to gasification and pyrolysis, torrefaction is a thermal processing of biomass feedstock consisting in exposing the material to high temperature in an oxygen-constrained environment, without the oxidation that typically occurs during combustion. In particular, torrefaction is carried out at or close atmospheric pressure, in the absence of oxygen, at temperatures from 200 up to 280-300°C, and for a duration of one hour or less. Torrefaction is intended to improve some properties of the raw biomass feedstock, and therefore it is considered as a pre-treatment technology.

7.1.1 Physical process

The three main structures of woody and herbaceous biomass (cellulose, hemicellulose, and lignin) all participate in the torrefaction process, with the thermal activation and depolymerisation of hemicelluloses being the dominating reactions. Figure 7-1 from Bergman et al (2005) shows the main phenomena occurring during torrefaction as a function of the temperature regimes.

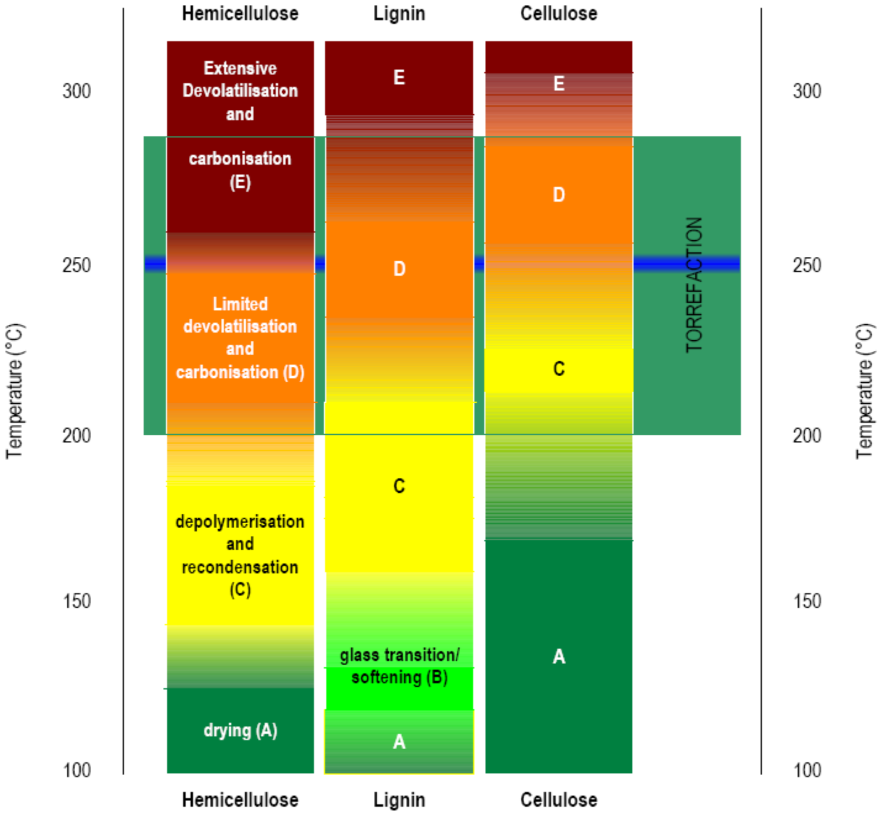

Figure 7-1 Main reactions occurring during torrefaction for hemicelluloses, lignin and cellulose, from Bergman et al. (2005)

Numerous reactions occur during torrefaction, yielding a wide range of products in solid, liquid, and gaseous phases. The products split into 70-90% solids, 6-35% liquid, and 1-10%-gas (on a mass basis) depending on feedstock and operating conditions, with the solid being the quantity of interest. The solid fraction of torrefied biomass is made up by unreacted cellulose and lignin, and non-volatile products of the hemicellulose degradation. The liquid fraction (condensed gases after torrefaction) consists primarily of water, acids (e.g. acetic acids), methanol, furfural, hydroxyacetone and phenol. The gaseous fraction contains mostly CO_2 and CO.

7.1.2 Torrefaction equipment

Torrefaction is typically accomplished by supplying heat (convectively) to a sealed chamber filled with inert gas (operating conditions in absence of oxygen requires air-tight systems). Screw reactors and tray ovens have also been proposed. Equipments for both batch and continuous processes have been investigating so far.

Heat is typically supplied convectively by using steam as a medium, with hot combustion gases (e.g. from a gas turbine) also considered as an alternative medium (dry roasting).

So far, only units from laboratory scale to demonstration scale have been fully investigated, and it remains unclear how scale related effects associated with larger, commercial size equipments may drive changes in current equipment design. In terms of prospects, microwave radiation has been suggested as a way of achieving torrefaction at large scale (Budarin et al, 2009), by allowing the uniform processing of larger and wet feedstock chunks (wet processing). Also, operating under high pressure conditions has been proposed for torrefaction of wet biomass (Yan et al, 2010).

7.1.3 Fuel properties

Typical calorific value of torrefied biomass is about 19.9 MJ/kg, much higher e.g. of that of woodchips (10.5 MJ/kg, as received) (NNFCC, 2008). Elemental analysis of feedstock and torrefied biomass shows that more oxygen and hydrogen are lost during torrefaction than carbon, which increases the calorific value of the biomass. This phenomenon is independent of the type of biomass. Figure 7-2 shows the H/C and O/C ratio for various energy materials, including dry wood, torrefied wood (label as “TW” in the Figure) under different temperature conditions, coal, charcoal, and peat. The elemental composition of torrefied biomass is similar to that of peat.

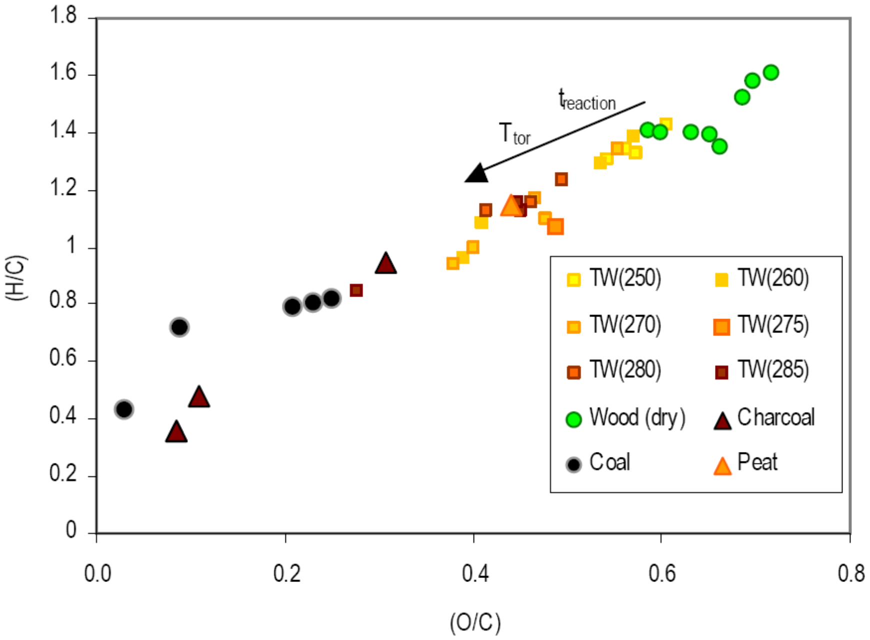

Figure 7-2 Van Krevelen diagram for different energy vectors from Bergman et al. (2005).

Torrefied biomass tends to maintain the appearance of the original feedstock, except for a change in colour, which ranges from brown to black, and a more rounded shape. Biomass immediately after torrefaction is completely dry and shows a significant increase in hydrophobicity. This is typically due to a combination of factors, including the removal of the OH groups from the hemicellulose and the generation of non-polar molecules that results from the breakdown of the hemicellulose. Due to the increased hydrophobic properties, the moisture uptake is limited after torrefaction, ranging from 1 to 6% (Bergman et al., 2005). Even though it is claimed that torrefied biomass cannot undergo any form of rotting, hydrophobic properties, especially under conditions of repetitive and extended exposure to water and humidity, still need to be fully qualified (Cielkosz and Wallace, 2011).

Torrefied biomass also shows an increase in grindability, which makes it very attractive for application like coal co-firing. The energy requirement for grinding torrefied biomass is reported to be from 10 to 20% less than that of raw feedstock (Cielkosz and Wallace, 2011). A literature review by Cielkosz and Wallace (2011) on typical yield of various biomass samples undergoing torrefaction at different temperature shows that the energy retained in the torrefied biomass range from 80% to 97.5% depending on the material.

The ideal torrefied biomass would feature improved energy density and grindabilty, both achieved with minimal energy loss compared to the original feedstock. In general, conditions to improve energy density and minimise energy loss are antagonist, so trade-off and optimisation are required. No conclusive study exists on optimal torrefied conditions, and more pilot and full-scale projects may be needed to provide insights into this.

As regards uses of torrefied biomass, it has been proposed as a suitable feedstock for coal co-firing, gasification and Fischer-Tropsch processes, or even for some bio-chemical routes.

7.1.4 Integrated torrefaction and pelleting process

The Dutch Energy Research Centre of the Netherlands (ECN) is developing an integrated torrefaction and pelletisation technology called BO_2. This technology is based on a system with high heat integration, in which torrefaction gases are used (directly or combusted) to supply heat for pre-treatment (drying) and for torrefaction itself (Figure 7-3). The BO_2 technology uses conventional drying and pelletisation and a compact dedicated moving bed reactor technology with direct heating. Calorific value of torrefied pellets is slightly higher than that of torrefied biomass and can be up to 21.9 MJ/kg (NNFCC, 2008).

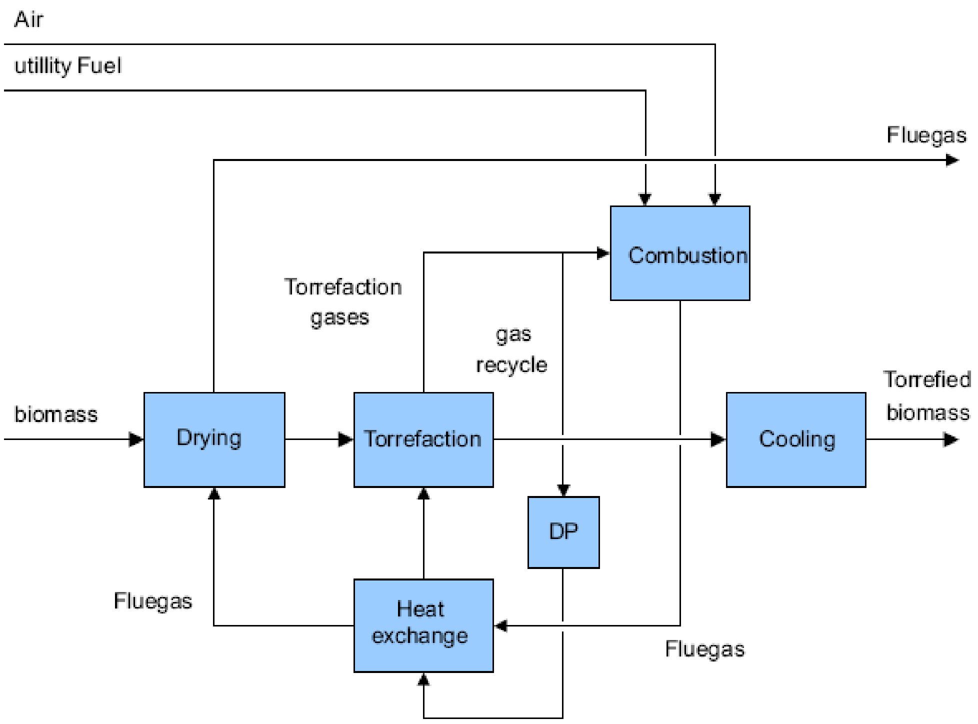

Figure 7-3 General flow diagram of the ECN BO2 torrefaction technology (pelletising step of torrefied biomass not shown) from (Uslu et al. 2008). DP is pressure drop recovery.

7.2 Feedstock

In principle, all biomass feedstocks could be treated via torrefaction. In practice, tests and research so far have focused on woody biomass (pine, birch, salix, Miscanthus), wood pellets, bagasse, and straw pellets (Zanzi et al. 2004, Ciolkosz and Wallace R. 2011).

Feedstock for torrefaction usually needs grinding (by grinder and/or hammermill). This is to reduce the feedstock to particle sizes which are compatible with the heat rate and the residence time within the torrefaction chamber. Feedstock also needs to be dried prior to entering the torrefaction reactor. Most studies use feedstock with less than 10% moisture content, as the torrefaction of higher moisture content biomass has been found to achieve lower mass yield (and hence efficiency) (Cielkosz and Wallace, 2011).

7.3 Technical and environmental characteristics

7.3.1 Size

Beside numerous laboratory and bench scale testing units, existing or next to commission plants are at a scale between 5,000 to 60,000 ton/yr of torrefied biomass output (Kleinschmidt, 2011). As these plants are already a significant step in terms of scaling up (and associated efforts) from existing testing units, it is reasonable to expect that torrefaction plants in the near future will not exceed 100,000 ton/yr.

7.3.2 Efficiency

The efficiency of torrefaction is usually reported in different ways in the literature. Here we use the most common one, which considers the net thermal process efficiency – the ratio between the energy in the torrefied biomass and the total energy input to torrefaction (energy in the feedstock plus any other energy input). Energy input to torrefaction can be classified into energy for feedstock pre-treatment, process energy, and parasitic loads.

Energy inputs for feedstock pre-treatment consists of electricity (for chipping and/or grinding) and fossil fuels (for drying), if needed. Process energy consists of the thermal energy needed to sustain the torrefaction conditions. Such thermal energy can be either supplied externally, via fossil fuels or any other suitable heat source, or in total or partially from the combustion of the torrefaction gases. Parasitic loads are electric loads associated to the operation of the torrefaction equipments (e.g. fans, pumps, etc.).

At present, actual energy balances and efficiencies from existing torrefaction equipments are not available and efficiency values in the literature are typically based on either models or small scale experiments. Net thermal process efficiency in excess of 90% is suggested in some cases in the literature. However, it is reasonable to expect that such efficiency can be achieved only for dry feedstock with relatively low or no pre-processing requirements. Efficiencies around 80% or lower are likely to be more realistic in the short-medium term. In terms of prospects in efficiency improvements, they all lie around process integration and optimisation. First, gaseous and liquid products of torrefaction, which typically contain from 10 to 30% of the energy content of the feedstock, can be used to provide the process energy and/or to dry the feedstock. Second, torrefaction conditions (mainly temperature, residence time, and heat rate) can be optimised based on the feedstock. Last, careful integration and design can make a contribution in reducing the often neglected parasitic losses, which are typical a large portion of the total energy requirement for torrefaction.

7.3.3 GHG emissions

GHG emissions for torrefaction are associated to electricity (for pre-treatment and parasitic losses) and fossil fuels (for drying and process energy, if needed).

7.4 Costs

By improving biomass properties (mainly higher energy density and improved hydrophobicity), torrefaction can reduce the costs in the downstream steps of the value chain (transport, storage, final use). On the other side, torrefaction implies added costs, due to the torrefaction itself, and the pre-treatment requirements. Whole chain models and assessments are needed to understand whether or not torrefaction provides net benefits for a given fuel type and application.

Uslu et al (2008) carried out a techno-economic assessment of torrefaction based on the combined torrefaction and pelletisation BO2 technology developed at ECN, based on a single torrefaction process line of 50-60kton/year. Uslu et al. reported capital investment cost at 5.2 to 7.5M€ for that process line, of which 39% and 31% are for installation costs and equipment costs respectively. Uslu et al. concluded that, for imported biomass from South America to Europe, torrefaction combined with pelletisation provides a fuel for power generation which is from 4 to 16% less expensive than pelletisation alone.

7.5 Requirements of the upstream/downstream process and system considerations

Requirement upstream of torrefaction are associated with the pre-treatment of feedstock, which has been covered in Section 7.2. Post-treatment of torrefied biomass may include cooling and densification (typically pelletising). Densification is used to improve handling and transport properties of torrefied biomass. Also, aerial dispersion of biomass material is much more accentuated after torrefaction, which may pose health and safety risks (e.g. respiration, combustion hazards). Such risks are eliminated or drastically reduced by pelletisation.

Energy requirements for pelletisation of torrefied biomass can be as lower as 50% than those for raw biomass pelletisation. The low energy requirements are explained by the loss of structural strength arising from hemicelluloses breakdown occurring during torrefaction.

7.6 Deployment and development status

In general torrefaction technology is at early demonstration/pre-commercial status (TRL 5 to 7), with first demo units being developed and commissioned. There is a relatively large number of technology developers in Europe, due to a strong market pull. However, some developers have been adapting pre-existing reactor concepts originally developed for other thermochemical processes (typically pyrolysis), which resulted in some limitation in efficiency, feedstock flexibility, process control and scaling up.

A first demonstration unit has been operated by Pechiney SA (aluminium conglomerate based in France) since 1987 with a capacity of 12,000 ton/yr of torrefied biomass. Scaling up to this size showed issues with high moisture feedstock and feedstock uniformity. The ECN was one of the first actors in Europe to recognise the potential role and scaling-up opportunities for torrefaction. Since 2003 the ECN has been conducting tests and developing laboratory scale plants, which resulted in a pilot plant (50 to 100 kg/h of input) for the proprietary BO_2 technology.

In general torrefaction technology development is lead by Dutch companies and research centres, with several technology developers (Stamproy Green, Torrcoal, Topell,, ECN, Foxcoal) with demonstration plants under construction or being planned. Some research activities in also on-going in other European countries such as Sweden (e.g. Umeå University, Bio Energy Development North) As of 2011, several demonstration and pilot initiative were on going in Europe, with scales ranging from 5,000 to 60,000 ton/yr of torrefied biomass (Kleinschmidt, 2011).

In 2011 the ECN and the utility Vattenfall entered into a partnership for upscaling and demonstrating the ECN's BO_2 technology, with a demonstration unit scheduled for the end of 2011 (Kiel 2011). Outside Europe, torrefaction developers exist in the US (New Earth, Agri-Tech, Idaho National Lab).

7.7 Barriers to development and deployment

- The main barrier is associated with financing. Most torrefaction developers are small companies with a limited financial base, which face the challenge of convincing investors to finance the necessary R&D and up-scaling
- The lack of a product standardisation may delay the maturity of the market.
- There is a variety of torrefaction concepts and a dominant one is likely to emerge. This may impose R&D and scaling up risks onto those companies whose torrefaction concept is significantly different than the dominant one
- Current technologies work with a narrow range of particle sizes. Increasing this range (and proving technology for other feedstock such as agricultural residues) is a challenge.
- First commercial demonstration plants may find difficult access to feedstock

7.8 UK Capabilities

The only UK developer currently active in torrefaction technologies is the Torftech group. Torftech (based in Thatcham, UK) has developed and currently licenses and provides the TORBED technology, based on a proprietary patented process reactor, which can be used for torrefaction, inter alia.

Two types of reactors are offered by Torftech, both based on toroidal bed circulation pattern (Figure 7-4). The first one is the Torbed Compact Bed Reactor, in which process gases flow through fixed blades thus driving the motion of the biomass feedstock. The second is the Torbed Expanded Bed Reactor, which is similar in concept to a circulating fluidised bed reactor, but with different particle motion patterns and speed (The Torftech Group 2011).

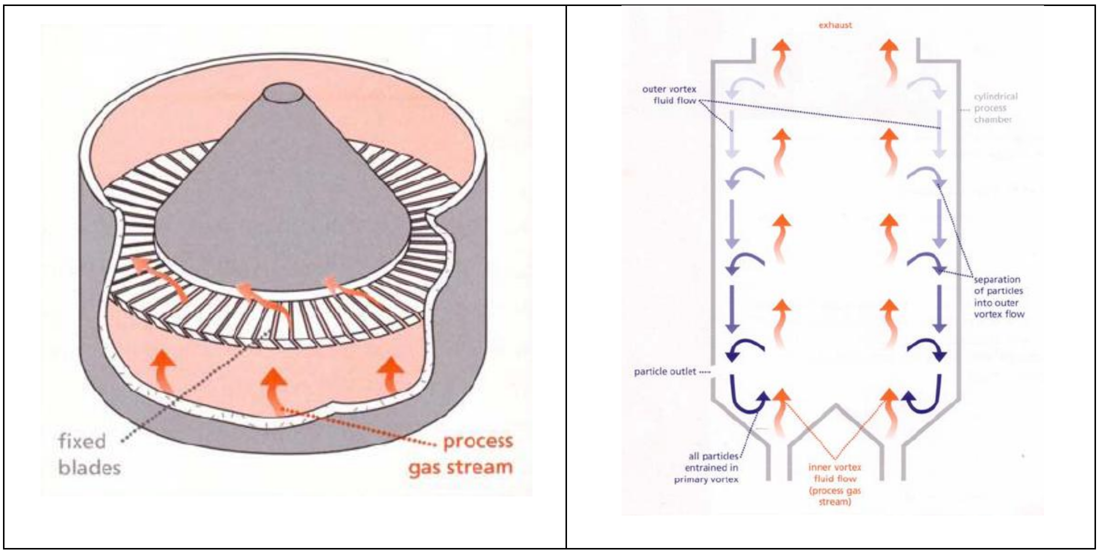

Figure 7-4 Torbed reactor technologies by Torftech. Compact Bed reactor (left), Expanded Bed Reactor (right). (The Torftech Group, 2011)

At the end of 2010, Torftech supplied Topell Energy in the Netherlands with a 60,000 ton/yr TORBED reactor (Kleinschmidt, 2011)

In terms of academic research landscape, there is limited UK activity overall:

- Prof Jones from University of Leeds is working on an EPSRC funded project (partnering with Alstom, Drax Power and RWE nPower) on the design of safe, environmentally-friendly large scale torrefiers by developing, inter alia, a torrefier design tool
- Prof Mitchell of Aberdeen University is working on business cases and techno-economic assessment of pellets from torrefied biomass, in collaboration with ECN, ITI energy and Doosan Babcock
- In slow pyrolysis, there is research underway at Aberystwyth University, Cranfield University, Swansea University, University of Edinburgh, University of Sheffield, often focusing on production and use of biochar.

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8 Oil extraction

8.1 Technology description

This section covers the technologies for the extraction of oil and fats from vegetable sources. Oil and fats can be extracted from a large variety of fruits, seeds and nuts. The whole oil extraction process involves typically six steps:

- Preparation. The preparation of the raw material depends on the material itself, and it generally involves cleaning, and in some cases drying, dehulling, husking, and flaking.
- Pressing. Pressing may take place in one to three steps (e.g. pre-pressing, finish pressing, cold pressing), depending on the material, resulting in crude pressed oil and cake (pressed material). After pressing the crude oil is often filtered. Some feedstocks with low oil content (e.g. beans) are not pressed but go directly from preparation to solvent extraction (next step)
- Solvent Extraction. In order to improve the overall oil recovery yield, the extraction of further oil left in the cake is carried out using a solvent, typically in a counter-flow system. The most common solvent is hexane, which is a petroleum-derived product. As the solvent passes though the cake, it results into two streams: an oil/solvent mixture (called “miscella”) that is sent to distillation and a cake containing hexane, which is sent to further conditioning
- Distillation. The miscella is distilled to recover the hexane, which can then be reused in the extraction step. A make-up of the hexane losses in the process is needed. The hot hexane-free crude oil is cooled before is sent to the next step
- Conditioning and refining of the crude oil. The crude oil from the press and that from the distillation are recombined for further conditioning and refining. These include processes such as degumming, neutralization, bleaching, deodorization, and any further refining depending on the final use
- Conditioning of the cake. Further hexane is recovered from the remaining cake via a stripping process (cake desolventising), using steam. Beside the recovery of the hexane, this step is needed e.g. if the cake is to be used as animal feed. This process also contributes to the reduction of the micro-organism and enzymes activity in the cake. The cake (which now is also called “meal”) is then dried and cooled by air and it can be stored and transported.

An overview of the overall process is given in Figure 8-1.

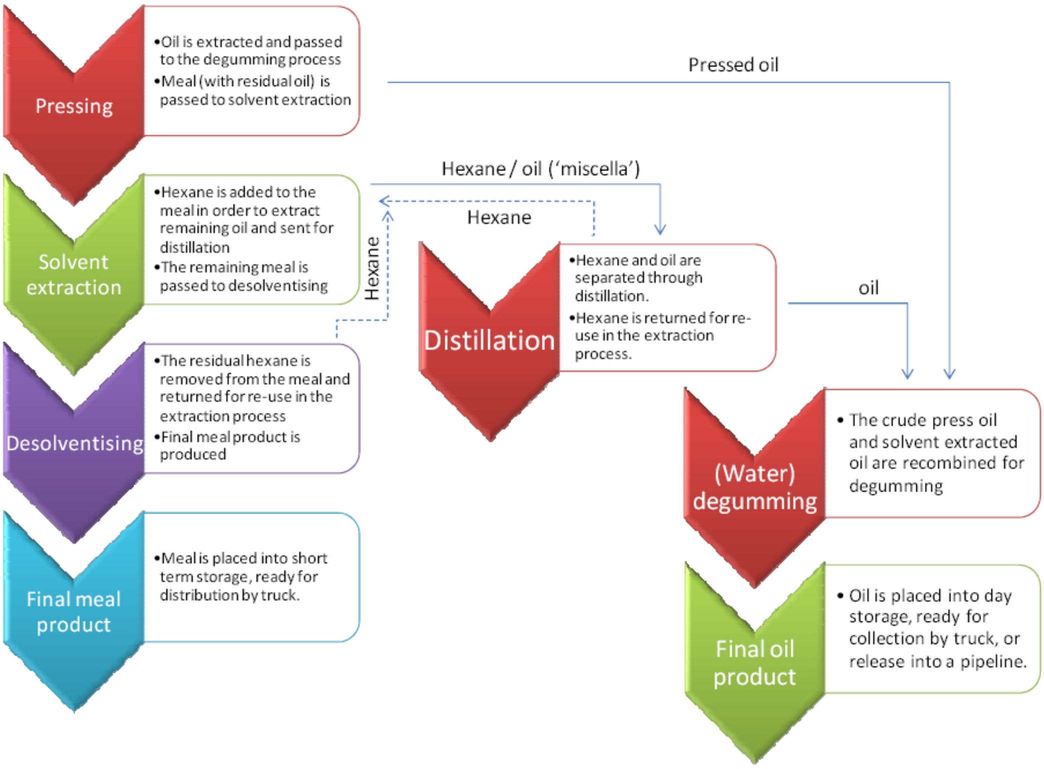

Figure 8-1 Schematic of oil extraction from Axion Consulting (2011). Preparation step not shown.

Oil extraction via solvent is widely adopted for commercial and large scale plants, as it allows for high yields. However, other solvent-free oil extraction methods are still used, which involve only mechanical extraction. However, these methods are typically confined to small scale food production. Some of these involve screw press, ram press, or expeller press.

Oil extraction is a processing step that also applies to novel bioenergy feedstocks such as micro-algae. In the case of algae, oil extraction would consist of two steps (Benemann, et al., 1982):

- Algae cell disruption. The cell walls must be broken to allow the oil to be recovered. This could be carried out by a variety of processes, including sonication (i.e. treatment with ultrasounds), chemical treatments, and homogenization.
- Emulsification. The broken algal cells are homogenized, heated, and emulsified with algal oil recovered and recycled in the process
- Centrifugation to separate the oil from the residual biomass, using a three-phase centrifuge. The centrifuge produces three streams: algae lipids (algal oil), a liquid waste fraction, and an algal residue. The liquid waste fraction is recycled to the ponds where the algae are grown for fertiliser recycling, with the residue used for animal feed or anaerobic digestion.

8.2 Feedstock

In principle, all fruits, seeds and nuts that contain oil and fats can undergo the process of oil extraction. In the bioenergy domain, these include rapeseed, sunflower seed, coconuts, and jatropha seed, inter alia.

8.3 Technical and environmental characteristics

8.3.1 Scale

Scale for crushing equipments and facilities can range from farm scale to large commercial plant. The three largest oilseed rape crushers in the UK are in Liverpool (Cargill), Erith (ADM), and Hull (Cargill), have a capacity of 1, 1 and 0.25 million ton/yr of seed respectively, and are amongst the largest in Europe. A general trend toward larger plants exists.

8.3.2 Efficiency

The efficiency of the oil extraction process is typically expressed in terms of extracted crude oil per unit of input feedstock (at given moisture content). The extraction efficiency varies significantly depending on the feedstock. For example, the default efficiency values in the Carbon Calculator for the UK Renewable Transport Fuel Obligation are 43% for sunflower seeds, 40% per rapeseed oil, and 24% for jatropha seeds.

8.3.3 GHG emissions

GHG emissions arise from the following input to the oil extraction process:

- electricity for operation (e.g. pressing). In some cases, some of the electricity may be produced on site by combustion of the oil itself or of other process residues
- natural gas. This is used in boilers to raise steam for e.g. miscella distillation and cake desolventising
- hexane solvent. This is a petroleum-derived product, which comes with an emission factor
- Fuller’s earth. This is a chemical which is used in the crude oil refining to remove water from oil.

An important co-product of the oil extraction process is the meal, which can be used e.g. for animal feed. GHG emissions for the whole oil extraction process have to be then allocated to the oil and the meal on an adequate basis. Depending on the final use and carbon accounting regulations, both allocations by energy content and by market value are typically considered.

Amounts and emission factors for the process inputs above can be found in the Carbon Calculator for the UK Renewable Transport Fuel Obligation for all biofuels currently in use in Europe.

8.4 Costs

The business plan for a regional oilseed rape oil extraction (crusher) facility in North East England (Axion consulting, 2010), commissioned by the North East Process Industry Cluster

(NEPIC) provides detailed up to date capital and operating costs for a large scale (500,000 tons of seed input/yr) commercial plant.

The capital cost for the prospective NEPIC facility is 47.5 M£ (91 £/ton of seed input), and has been based on the input of two European technology providers (Europa Crown and DeSmet Ballestra).

Operating costs (net of energy and feedstock costs) are estimated to be 7.8 M£ per annum (15.6 £/ton of input seed), for a plant operating 24 hours per day, 365 days a year.

8.5 Requirements of the upstream/downstream process and system considerations

Certain feedstocks such as oilseed rape need to be kept dry when stored before undergoing oil extraction. For oilseed rape, the maximum moisture content is 10% (w/w), as oil acidity increases with moisture content and it may cause problems downstream.

8.6 Deployment and development status

As vegetable oil and fats have been used since a long time in various sectors such as food production, as well as animal feed and medicine production, the vast majority of extraction methods involve well-established, mature technologies, implemented in sites worldwide with no 'step-change' developments anticipated. As such, TRL conventional oil extraction technologies are at TRL 9. Novel extraction technologies, e.g. for algal oil extraction, are in earlier stage of development, at TRL 1-3.

8.7 Barriers to development and deployment

Due to the maturity of the technology, there is no major technical barrier affecting the deployment of oil extraction facilities. Assuming it is well designed and implemented, there is minimal technical risk in implementing a large scale crushing facility.

Some barriers to the deployment may exist in relation to planning permitting, though. This is because large scale facility may require high volume of truck movement (unless input is delivered via a jettison on water, and pipeline is used for the oil product, which is not typical). Also, regulations on emission limits (e.g. for particulate matter, volatile organic compounds, solvents, liquid effluents, etc) may apply.

8.8 UK Capabilities

Beside some small seed crusher developers, no oil extraction technology provider exists in the UK. Capabilities though existing in operation, as some of the largest oil extraction facilities in Europe are located in the UK.

R&D capability around algae biofuel (including oil extraction) where developed in the UK under the Carbon Trust Algae Biofuel Challenge (ABC). However, as of early 2011, the ABC has been halted due to funding cuts.

8.9 References

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9 Pyrolysis

9.1 Technology description

Pyrolysis is the controlled thermal decomposition of biomass to produce a liquid bio-oil, a mixture of gases (syngas) and charcoal (biochar). Pyrolysis occurs at around 500°C in the absence of oxygen. There are two main types of pyrolysis processes: fast and slow. These are characterised by different residence times in the pyrolysis reactor, and lead to different proportions of the liquid, gas, and solid fractions.

- **Fast pyrolysis** maximises the production of bio-oil, which can be used for power, heating or upgraded to transport fuels. The remainder of this chapter will focus on fast pyrolysis.
- **Slow pyrolysis** favours the production of bio-char, which can be substituted in applications using solid biomass or coal. One type of slow pyrolysis 'torrefaction' is considered in Chapter 0.

9.1.1 Fast pyrolysis reactors

After feedstock reception, storage and handling, drying and grinding, the feedstock is transferred to a pyrolysis reactor. Several types of reactor have been studied and developed. The main types that have been demonstrated at the largest scales and are still being considered for development (Bridgwater, 2011) are:

- Bubbling fluidised bed – biomass is fed into a bed of hot particles agitated by a fluidising gas This technology has consistent performance with high liquid yields of 70-75 wt.% from wood on a dry-feed basis. Small biomass particle sizes of less than 2-3mm are needed to achieve the high biomass heating rates required. Char is typically ~15 wt.% of the products but about 25% of the energy of the biomass feed. Char can be used to provide process heat or can be separated and exported.
- Circulating fluidised bed – this is a circulating system, where heat is provided to the reactor generally by recirculation of sand heated in secondary char combustor. As a result, all char is used to provide heat. This system may be more suitable for scale up to large scales, given existing uses in the petrochemical industry.
- Rotating cone reactor – hot sand and biomass are rotated in a heated cone, from which the pyrolysis vapours are collected. The char is used to heat the sand, which is re-circulated. It offers liquid yields of 60-70 wt% on dry feed.

9.1.2 Pyrolysis oil

The gases produced by fast pyrolysis are condensed to form pyrolysis oil. Crude pyrolysis oil, also called 'bio-oil', is a dark brown viscous liquid. It contains a complex mixture of oxygenated hydrocarbons with water, and potentially also solid char particles. The yield of organic compounds depends on the temperature of the pyrolysis reaction, and on the feedstock used. Pyrolysis oil has a heating value of ~17 MJ/kg and it is produced with around 25 wt.% water that cannot readily be separated (Bridgwater, 2011).

Pyrolysis oil can be used in some applications directly, such as heat or power generation using burner/furnace systems and burner/boiler systems, in diesel engines and in modified industrial gas turbines, with tests also done on Stirling engines (see Czernik and Bridgwater, 2004). However, upgrading is needed for advanced applications, including advanced boiler systems, industrial gas turbines, or combined cycle systems and for transport fuels (Stevens, 2009).

The properties of pyrolysis oil that result in the need for upgrading include:

- high acidity - causing corrosion
- high and increasing viscosity – causing high pumping costs
- high density - which has implications for design of pumps
- presence of char – causing blocking of filters and catalysts
- lack of miscibility with hydrocarbons - making refinery integration difficult
- poor stability and potential for phase separation
- potential presence of contaminants such as sulphur – which would cause catalyst poisoning

Pyrolysis oil can also be used as a feedstock for gasification. As pyrolysis leads to the alkali metals from biomass being retained in the char, rather than the oil, this reduces problems in gasification and gas cleaning (Bridgwater, 2009). Other benefits include easier feeding to the gasifier, and reduced tars.

9.2 Feedstock

In principle, any dry lignocellulosic biomass feedstock can be used as an input, including dedicated energy crops, agricultural residues, wood residues, and wastes. The biomass is ground before use for most reactor types, to achieve the high rates of heat transfer needed in pyrolysis, although some reactors can use larger forms, which reduces the energy requirements. The whole of the feedstock can be converted, and mixed and variable feedstocks can be used. The composition of the feedstock affects the yield and composition of the pyrolysis oil (see also Table 9-1 below).

9.3 Technical and environmental characteristics

9.3.1 Scale

Pyrolysis could be applied at small scale near to the feedstock source, as a pretreatment and densification option, followed by pyrolysis oil transport to a central plant for upgrading or use. Alternatively, pyrolysis could be deployed at a larger scale at a centralised location. Current plants are at a maximum of 200 t/day dry biomass input (Dynamotive), with plans for plants at 400 t/day (Ensyn), although much larger plants are envisaged, at up to 1000t/day (Bridgwater, 2011).

9.3.2 Efficiency

Typically, the yield on a mass basis from dry wood is 75% liquid, 13% gas, 12% char (Bridgwater, 2011). However, the yields of these products vary according to the composition of the feedstock used, the temperature, and the system chosen. The composition and so energy content of the pyrolysis oil also varies with feedstock type, as shown in Table 9-1. Typical energy efficiencies of bio-oil generation by pyrolysis (in terms of energy output over energy input) range from 50 to 75%, depending on feedstock and technology.

Feedstock	Yield of oil (wt%)	Gross Caloric Value of oil (MJ/kg)
Hardwood	70-75	17.2 - 19.1
Softwood	70-80	17.0 - 18.6
Hardwood Bark	60-65	16.7 - 20.2
Softwood Bark	55-65	16.7 - 19.8
Corn Fibre	65-75	17.6 - 20.2
Bagasse	70-75	18.9 - 19.1
Waste Paper	60-80	17.0 - 17.2

Table 9-1 Pyrolysis oil yields and energy content from lignocellulosic feedstocks (Envergent, 2011)

9.3.3 GHG emissions

The pyrolysis process is often assumed to have no inputs other than the biomass feedstock, with char and some of the gases being used to provide heat and electricity to the system (NNFCC, 2010). In this case, there would be very low greenhouse gas emissions from the conversion, often assumed to be zero. In other analyses, electricity import e.g. for grinding is assumed, as well as natural gas for start up leading to GHG emissions (e.g. Jiqing Fan et al. 2010), and/or char is exported, giving a GHG credit (e.g. Mortimer, 2009). Jiquing Fan et al (2011) give GHG emissions from the pyrolysis step of 8.6 gCO_2e/MJ of pyrolysis oil produced, resulting in emissions of 8.6 to 14.5 gCO_2e/MJ of pyrolysis oil including feedstock sourcing and transport. These emissions are primarily due to the use of electricity from the US grid.

9.4 Costs

A number of different studies have analysed the techno-economics of fast pyrolysis bio-oil production. The studies examined in this chapter all consider pyrolysis and upgrading to fuel, and are the same studies as used in the pyrolysis oil upgrading chapter (Chapter 26). Here, only the costs for pyrolysis oil production are covered

The production economics for pyrolysis oil are strongly influenced by biomass price, moisture content, plant scale, capacity factor and capital costs.

In their modelling, Wright et al. (2010) give capital costs of $\$_{2007}$ 181-197m for a 2,000 odt/day biomass input plant, which equates to $£_{2011}$ 106-115m. This plant also has an O&M cost of £8.4-8.6m/yr, and revenues of £1.3m/yr from the sale of excess char. The cost of the bio-oil, without including feedstock costs, is therefore estimated to be $0.33/gallon (£2.4/GJ). Including a feedstock cost of $83/odt, and an energy efficiency of 68% from biomass to bio-oil, this gives a final bio-oil production cost of approximately $0.86/gallon (£6.2/GJ). These costs are for an "nth" plant – a pioneer cost analysis gives significantly higher production costs (although not available split into pyrolysis and upgrading as for the nth plant)

Jones et al. (2009) also model a 2,000 odt/day biomass input plant, giving capital costs of $\$_{2007}$ 106m, which equates to £$_{2011}$ 62m. Operating costs are given at £10.9m/yr, with no revenues. The cost of the bio-oil, without including feedstock costs, is therefore estimated to be $0.26/gallon (£1.9/GJ). Including a feedstock cost of $51/odt, and an energy efficiency of 80% from biomass to bio-oil, this gives a final bio-oil production cost of approximately $0.53/gallon (£3.9/GJ).

Wright et al. (2010) also show the results from 7 other past studies, mainly at smaller scales (200 – 1,000 odt/day biomass input), which have bio-oil production costs, including feedstock costs, ranging from $0.55-2.1/gallon (£4.0-15.3/GJ).

For a 50kt/yr output plant, with a 72% mass yield of bio-oil from dry biomass (i.e. ~211 odt/day), Nexant (2008) give bio-oil production costs of £280/t (£15.6/GJ) using feedstock at 45% moisture content, and £140/t (£7.8/GJ) at 10% moisture content. For a larger plant at 250kt/yr output plant (1,057 odt/day input), Nexant (2008) give bio-oil production costs of £215/t (£11.9/GJ) using feedstock at 45% moisture content, and £100/t (£5.6/GJ) at 10% moisture content. These costs therefore align with the range given in Wright et al. (2010), and show the effect of using drier feedstock (with less energy required for drying), and plants at larger scales.

Pyrolysis oil production costs are summarised in Table 9-2.

Reference	Scale (odt/day biomass input)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
Wright et al. (2010), nth plant	2,000	181 – 197	8.4 – 8.6, less 1.3 revenues	nth plant 2.4 without feedstock, 6.2 with feedstock
Jones et al. (2009)	2,000	106	10.9	1.9 without feedstock 3.9 with feedstock
Wright et al. (2010) meta-review	5 – 1,000			4.0 – 15.3 with feedstock
Nexant (2008)	211 – 1,057			11.9 - 15.6, with 45% moisture content feedstock 5.6 – 7.8, with10% moisture content feedstock

Table 9-2: Range of pyrolysis economic data

9.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the process are feedstock sourcing and transport, and sizing if necessary, such as a chipping step, before further grinding at the plant.

Downstream of the process, there are several options for use of the solid, liquid and gaseous products, as shown in Figure 9-1.

Bio-oil would generally need to be upgraded for use in fuels. As explained above, the char may be used to provide heat to the process, and so may not be available for export.

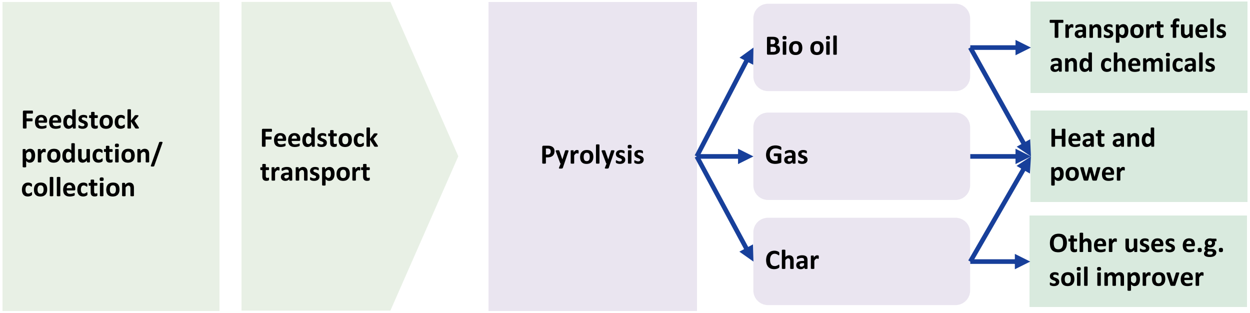

Figure 9-1 Process schematic for pyrolysis

Bio-oil has a higher energy density (per unit volume) than raw biomass, pellets or torrefied biomass, and so would have reduced transport costs, and also lower handling costs than solid biomass. As a result, pyrolysis has been proposed as a distributed pre-treatment option for thermochemical conversion processes. However, the economic and environmental benefits of this option need to be considered carefully, as several studies have shown higher costs and emissions of this option, particularly in the UK, where transport distances are short (see e.g. Bridgwater, 2009, Mortimer et al, 2009).

9.6 Deployment and development status

Pyrolysis technology is at the initial deployment stage, with several companies outside the UK having constructed their first plants in the 1990s, for use in heat, power, and food industry applications.

Several companies have early commercial pyrolysis technologies (TRL 7-8):

- Dynamotive (Canada) has built 4 plants in Canada, operating at up to at 200 odt/day biomass input
- Ensyn (Canada) has built seven plants using circulating fluidised bed reactors in the US and Canada, including plants used to produce food flavourings, and for pyrolysis oil sales from their site in Renfrew, Ontario which can use up to 100dry t/day biomass input. Envergent Technologies, Ensyn’s joint venture with UOP, plans to produce bio-oil for heat, power and transport fuel applications. Current planned projects are a 150 t/day plant in Italy using pine forest residues and wood industry by-products with use of pyrolysis oil in a stationary diesel engine, a 400odt/day input plant in Malaysia using palm residues and a 400 t/day in Alberta, Canada using wood residues (Ensyn, 2011).
- BTG Bioliquids BV have a 250 kg biomass/h unit operational (6 t/day), a 50 t/day plant commissioned in Malaysia in 2005, and a 120 t/day plant planned (as of 2010).

In terms of technology development, there is further scope for improvement which includes:

- Further scale-up
- Reactor design which addresses issues such as heat transfer and reaction rates and the removal of impurities
- Improving oil quality – developments which reduce suspended chars, alkali metals, water and viscosity of the oil, increasing the pH of the oil and improving the yield of pyrolysis oil over gas and char. This could be done through new pyrolysis processes (e.g. microwave

pyrolysis) and through optimising the combination of feedstock composition and pyrolysis process.
- Use of catalysts (e.g. zeolites) in the pyrolysis reaction to help optimise the reaction and oil quality and potentially yield other useful products, such as aromatics.

Production of better quality oils could reduce the requirements for upgrading.

9.7 Barriers to development and deployment

The principal barriers to further development and deployment for pyrolysis are (Pyne, 2011, Stevens, 2009):

- Uncertainty over potential pyrolysis oil markets, given the early stage of upgrading technology, and relatively limited experience in use of pyrolysis oil in heat and power. As a result, many companies are planning the whole system to heat, power or fuels, rather than intending to focus on oil sales.
- Uncertainty over value of char, including the potential benefits as a soil improver and for carbon storage.
- Limited supplies of pyrolysis oil are available for testing and development of applications
- There is a lack of standards for use and distribution of bio-oil and inconsistent quality inhibits wider usage; considerable work is required to characterise and standardise these liquids and develop a wider range of energy applications
- Environment health and safety issues in handling, transport and usage

9.8 UK Capabilities

The UK has world-class capabilities in pyrolysis, particularly in academia. A comprehensive view of UK activities in pyrolysis was published this year (Bridgwater and Watkinson, 2011), highlighting UK activity and links with work underway internationally.

There are several world class academic groups undertaking research into pyrolysis in the UK. These focus on particular aspects of the process, such as pyrolysis of certain types of feedstocks or focusing on reactor design or catalysts. Main examples are Aston University (fast pyrolysis), University of Leeds (pyrolysis of wastes and wet feedstocks) and University of York (microwave pyrolysis).

There are a few UK companies active in pyrolysis, together with others with skills in process design and evaluation, although none of the main technology developers with demonstration plants is based in the UK. In particular:

- Biomass Engineering Ltd are planning a 250kg/h fast pyrolysis plant using sawdust, to be operational by end 2011/early 2012.
- 2G BioPOWER plans to develop fast pyrolysis projects using Envergent and UOP technology to produce pyrolysis oil for CHP
- Future Blends, a company set up by the UK's Carbon Trust, focuses on the upgrading of pyrolysis oils to transport fuels.

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Part 3: Technologies for gaseous fuel production

10 Anaerobic Digestion

10.1Technology description

All anaerobic digestion (AD) systems use the same basic principle although actual plant design may differ slightly. Figure 10-1 shows a block diagram of the typical steps in an AD plant.

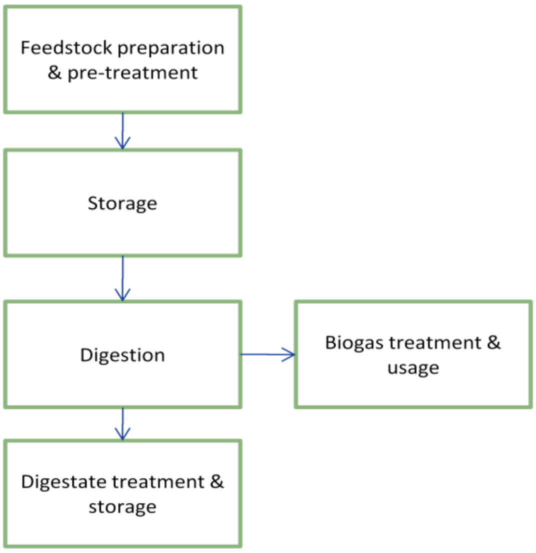

Figure 10-1 Anaerobic digestion process steps

AD is defined as the decomposition of biological feedstocks by micro-organisms in the absence of air (oxygen). The decomposition of the feedstock produces a gas comprising mostly methane and carbon dioxide. This process can take place under wet or dry conditions and can occur at high temperatures (thermophilic) or medium-low temperatures (mesophilic). A simplified process flow diagram of AD is shown in Figure 10-2 and the critical design parameters required for the success of the digestion process are explained in the following sections.

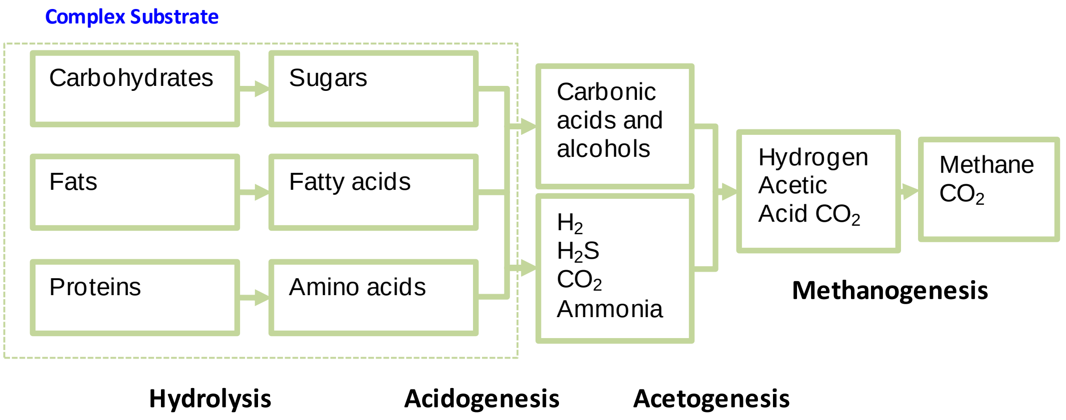

Figure 10-2 Biochemical processes during the digestion phase

In the first stage of AD, complex organic materials are broken down into their constituent parts in a process known as hydrolysis. The result is soluble monomers:

- Proteins are converted to amino acids;
- Fats are converted to fatty acids, glycerol and triglycerides;
- Complex carbohydrates such as polysaccharides, cellulose, starch and fibre are converted to simple sugars, such as glucose.

Hydrolysis is immediately followed by the acid-forming phase of acidogenesis. In this process, acidogenic bacteria turn the products of hydrolysis into simple organic compounds, mostly short chain volatile acids (e.g., formic, acetic, propionic, formic, lactic or butyric), ketones (e.g., glycerol and acetone) and alcohols.

The next stage of acetogenesis is often considered with acidogenesis to be part of a single acid forming stage. Acetogenesis occurs through carbohydrate fermentation, through which acetic acid, hydrogen and carbon dioxide are the main products produced.

Finally, in methanogenesis or methane fermentation, methanogenic anaerobic bacteria convert the soluble matter and CO_2 and H_2 into methane. About two thirds of methane is derived from acetic acid conversion with one third the result of carbon dioxide reduction by hydrogen.

10.1.1 Dry vs. Wet Digestion

The main difference between a dry digestion and a wet digestion process is the level of solids in the digesters and the corresponding means of mixing. Typically:

- Dry digestion refers to feedstock containing more than 15% dry solids (DS);
- Wet digestion refers to feedstock containing 5 to 15% dry solids.

Dry or wet digestion is selected depending on the dry solids level of the feedstock mix. Energy crops tend to be high in dry solids, varying from 22 to 42% DS. Animal slurry, depending on the collection method, may have dry solids content ranging from 5-20% DS (dry solids) to as low as 2% DS.

Wet or dry digestion is selected based on the overall DS of the mixture of feedstock. Digestion of energy crops in a wet system requires dilution to achieve the desired level of dry solids at c. 15%DS. Recycling liquor and brown water may be used for dilution. For harvested crops which are suited to AD conversion (such as energy crops), it is likely that a wet AD process would be used.

10.1.1.1 Wet Digestion

Wet digestion involves digestion with either an overall dry solids of 2-8%DS in the digesters or what is also known as effluent liquid digestion with dry solids less than 0.1%DS. Depending on the feedstock being treated, the influent dry solids can be higher, up to 12% DS in which case for wet digestion, the feedstock would then need to be mixed with water to achieve lower solids content (whilst the addition of water improves the conversion efficiency, it also increases water consumption costs within the project as well as environmental issues including higher levels of digestate treatment and utilisation).

Wet digestion plants comprise either a single-stage process or a multiple stage process.

- Single stage reactors use one reactor for the acetogenic phase as well as the methanogenic phase of AD;
- A multiple stage process uses one reactor for the acid phase which is composed of the hydrolysis, acidogenesis and acetogenesis phases as shown in Figure 10-2 and one reactor for the methane forming stage called the methanogenesis.

10.1.1.2 Dry Digestion

A high (15–40% DS) solids content of feedstocks can cause transport and handling issues and therefore such a system often requires robust and expensive conveyor belts, screws and high power pumps designed for high viscosity streams.

Prior to digestion, the pre-treatment stage is simpler than for low solids processes as the system has a greater tolerance for impurities such as stones, glass and wood. Only coarser (>40mm) impurities need to be removed before pre-digestion.

Due to the high feedstock viscosity, plug-flow reactors are used to digest the feedstock with baffles providing minimal mixing. These digesters can operate at a mesophilic or thermophilic temperature (as defined below) and have the advantage of being technically simple, with no need for any mechanical devices inside the reactor. Limited mixing occurs in the digester, so feedstock must be mixed with digestate to inoculate the feedstock with the required bacteria. The reactor may also be smaller as no water is added and the smaller reactor volume means that less heat is required to maintain the digester temperature. .

10.2 Feedstock

A number of feedstocks are suitable for anaerobic digestion, however, all wastes (animal slurries and food wastes etc) have been excluded for the purposes of this study. Consequently, the analysis focuses on harvestable biomass feedstocks such as energy crops, many of which have been tested for their potential biogas yields.

Energy crops suitable for AD include grass and maize silage, rye, whole crop wheat, triticale, miscanthus, sorghum, clover, corn silage, and sugar/fodder beet, and have the potential for high biogas yields. The most common energy crops used in anaerobic digestion are grass, maize and grass silage, and whole crop wheat.

Typically, energy crops are high in dry solids and are rarely digested as a lone feedstock with animal slurry often being added to assist with the digestion process. This is because, the high cellulosic and lignin content in energy crops does not biodegrade as easily as food waste or manure. The IEA comment that 83% of the new German agricultural plants are operated with a mixture of energy crops and manure, 15% use only energy crops and 2% were operated with manure only (IEA, 2009). Also, energy crops may have a volatile solids range between 60% and 90%. Digestion of energy crops in a wet system requires dilution to achieve the desired level of dry solids at c. 15%DS. Recycling liquor and brown water may be used for dilution.

Additional physical/chemical pre-treatment prior to digestion of energy crops enhances its biodegradability and the quality of digestate. Typically, shredding and macerating are required to reduce the particle size and this enhances biogas yields. Pre-treatment may be required for some energy crops if the contamination level, of sand and stones, is high.

10.3 Technical and environmental characteristics

10.3.1 Scale

In 2009 Germany had 4,300 agricultural plants (Weiland, 2010) generating biogas mainly from energy crops (maize being the most commonly used crop) with an aggregate installed electric capacity of 1,650MW$_e$ (Wiedman, 2010). The most typical size of plant is in the range of 350 to 400kWe.

In Austria, out of the 41 energy crop plants analysed by the IEA, the median plant capacity is recorded to be 13.2 tonnes per day and a maximum of 58.9 tonnes per day (IEA, 2009).

The scale of the plant depends on the substrate available, as well as a trade-off between the economies of scale, revenues from biogas, electricity and the feedstock cost. The NNFCC report on Farm-scale Anaerobic Digestion Plant Efficiency showed that small and medium scale returns are very low or even negative (NNFCC, 2011). Therefore, unlike in Austria and Germany, the development of small scale farm AD plants in the UK is unlikely.

10.3.2 Efficiency

Anaerobic digestion efficiency is typically measured by its biogas yield per tonne of feedstock, as well as the volatile solids destruction in the digesters.

A large range of energy crops have been analysed for their biogas potential. The methane yield per tonne of volatile solids fed is shown in Table 10-1. The specific methane yields for grass and maize are in the range of 298 to 467 m^3 per tonne of volatile solids (VS) fed and 205 to 450 m^3 per tonne of VS fed respectively.

From the International Energy Agency (IEA) analysis of the 41 energy crop plants in Austria, the median biogas yield observed is 673 m^3 per tonne of VS and a maximum of 1,018 m^3 per tonne VS (IEA, 2009).

The degradation of VS can range from 61.5 to 96.8% (IEA, 2009).

Feedstock	Methane (m^3 /t VS)	CV (MJ /t VS)	Feedstock	Methane (m^3 /t VS)	CV (MJ /t VS)
maize (whole crop)	205 – 450	7,339 - 16,110	**Barley**	353 – 658	12,637 - 23,556
Wheat (grain)	384 – 426	13,747 - 15,251	**Triticale**	337 – 555	12,065 - 19,869
oats (grain)	250 – 295	8,950 - 10,561	**Sorghum**	295 – 372	10,561 - 13,318

Feedstock	Methane (m^3 /t VS)	CV (MJ /t VS)	Feedstock	Methane (m^3 /t VS)	CV (MJ /t VS)
Rye (grain)	283 – 492	10,131 - 17,614	**Alfalfa**	340 – 500	12,172 - 17,900
Grass	298 – 467	10,668 - 16,719	**Sudan grass**	213 – 303	7,625 - 10,847
Clover grass	290 – 390	10,382 - 13,962	**Reed Canary Grass**	340 – 430	12,172 - 15,394
Red clover	300 – 350	10,740 - 12,530	**Ryegrass**	390 – 410	13,962 - 14,678
Clover	345 – 350	12,351 - 12,530	**Nettle**	120 – 420	4,296 - 15,036
hemp	355 – 409	12,709 - 14,642	**Miscanthus**	179 – 218	6,408 - 7,804
flax	212	7,590	**Rhubarb**	320 – 490	11,456 - 17,542
sunflower	154 – 400	5,513 - 14,320	**Turnip**	314	11,241
oilseed rape	240 – 340	8,592 - 12,172	**Kale**	240 – 334	8,592 - 11,957
Jerusalem artichoke	300 – 370	10,740 - 13,246	**Chaff**	270 – 316	9,666 - 11,313
Peas	390	13,962	**Straw**	242 – 324	8,664 - 11,599
Potatoes	276 – 400	9,881 - 14,320	**Leaves**	417 – 453	14,929 - 16,217
sugar beet	236 – 381	8,449 - 13,640	**Fodder beet**	420 – 500	15,036 - 17,900

Table 10-1 Potential methane yield of energy crops (IEA, 2009)

10.3.3 GHG emissions

Energy crop AD plants consume electricity operating the mechanical equipment of the plant, as well as heat to maintain the required digestion temperatures.

The AD process is often assumed to have no inputs other than the biomass feedstock, with biogas being used to provide heat and electricity to the system. However, when AD is considered separately from the energy conversion process downstream, it is necessary to allow for parasitic heat and electricity loads.

Generally, biogas is burnt in a CHP engine which provides electricity and heat to operate the plant and export for external uses. If the resulting biogas was used for alternative uses (e.g. grid injection), then brown electricity may be required to operate the plant in which case the GHG footprint of the system would be substantially impacted.

The electricity requirement for the plant's operation varies from 10 to 15% of the electricity generated by a CHP engine. The electricity required by an AD plant may vary from 0.22 to 0.35kWh_e per m^3 of biogas produced.

The heat requirement for the digestion process varies from 20 to 40% of the waste heat recovered from a CHP unit, which is approximately 0.33 to 0.66 kWh_{th} per m^3 of biogas produced.

Electricity or gas exported to the grid, if any, is a direct displacement of fossil fuel. Presently the above metrics do not take account of any GHG emissions resulting from the cultivation and harvesting of the energy crops.

Finally, it is common within this sector for an AD system to experience methane leaks. Typically, these range between 5% to 10% (Cenex, 2009).

10.4 Costs

10.4.1 Capital Cost

The capital cost for an energy crop AD plant can be significant andmay vary considerably depending on the plant scale and the complexity of the plant.

It is reported that typical capital investment for AD systems range from £2,500 to £6,000 per kW_e averaging £4,000 per kW_e (The Andersons Centre, 2010). Assuming a biogas conversion factor of 2.5kW_e per m^3/hour of biogas produced, the average capital cost is £1,600 per m^3/hour of biogas produced.

10.4.2 Operational Cost

The IEA (IEA, 2009) states that for an energy crops feedstock cost of £26.5 per tonne, £3,50 per kW_e of investment cost will provide a breakeven point, equivalent to £1,600 per m^3/hour of biogas produced.

Aside from feedstock costs, other operational costs will include (The Andersons Centre, 2010):

- Insurance – set at 1% of the capital investment;
- Maintenance and repair – set at 2% of the capital investment;
- Labour - The labour requirement is dependent on the type of plant, the feedstock, the level of automation, the plant's scale and the feedstock pre-treatment requirements. Approximately, 2 operators are required for every 15,000 tonnes per year of waste treated. (The Andersons Centre, 2010)

Total operating costs for a on farm facility will vary between £115/kWe and £215/kWe.

10.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the pre-treatment process are feedstock harvesting, transportation, silage preparation, storage and recovery where necessary.

Requirements **downstream** of the AD plant, is the digestate preparation, such as de-watering if necessary, digestate storage, transportation and also spreading management.

10.6 Deployment and development status

AD for energy crops is proven at a commercial scale especially in other EU countries such as Germany where the market for such technology is more mature (e.g. c. 4,300 agricultural plants are operational).

According to the Biogas Barometer published by the Le Journal des Énergies Renouvelables, the primary energy production from biogas in Europe during 2007 was approximately 6 Mtoe, an increase of 20.5% in comparison with 2006. The source of biogas may be broken down as follows: 49.2% of the energy was generated from landfill gas, 15% from the treatment of sewage sludge and 35.7% from other sources, mainly agricultural plants (EuroObserv'ER, 2008).

Germany is the largest biogas producer in Europe (c.2,400 ktoe in 2007) and 71.2% of this biogas was generated through AD plants using agricultural feedstock. In 2009 Germany had 4,300 agricultural plants (Weiland, 2010) generating biogas mainly from energy crops (maize being the most commonly used crop) with an aggregate installed capacity of 1,650MW$_e$ (Wiedmann, 2010).

By 2010, 700-800 new systems were expected to be installed in Germany alone (Wiedmann, 2010) with the majority of the biogas used for heat generation or CHP plants.

To date, the majority of existing UK AD plants use the biogas for electricity generation as there has been little incentive for heat only capacity. This will change with the introduction of the renewable heat incentive (RHI), however, AD plants operating mainly on energy crops, especially if grown specifically for the AD plant, will not be eligible for RHI payment and therefore a proliferation of small scale heat only plant in the UK is unlikely because of this.

Currently in the UK there are c. 33 off farm plants and 30 on farm plants, generating c. 21,700kWe and 18,900 KWe respectively (Anaerobic Digestion, 2011).

10.7 Barriers to development and deployment

The potential UK market for AD is significant, but the UK has seen a slow development in the use of non-landfill based AD for energy generation compared with other European countries. The following distinct factors have been identified as main barriers to the development of this sector in the UK.

10.7.1 Economics

AD plants tend to require a significant capital investment but deliver a poor return on investment without significant financial incentives provided by Government schemes. Consequently AD projects have failed to attract private investment this situation is likely to reverse in eth coming years with a more positive incentive structure, however as mentioned above schemes which secure energy crops as their sole feedstock will not be eligible for RHI payment. Therefore development will focus on schemes with alternative feedstocks, or projects at a larger scale focusing upon CHP or electricity only which are able to secure ROC payments for the electricity generated.

10.7.2 Feedstock and Digestate Management

In the UK, silage for biogas generation has not been widely used as the investment climate has been poor for small farm based systems. Similarly there have been feedstock and digestate management issues:

- Until 2010, digestate from AD in the UK was generally considered a waste product although it can be used as a fertiliser. Only a limited number of farmers accepted the use of non-certified waste by-products for spreading on their land. Consequently this was a significant barrier as the resultant digestate either incurred a cost for disposal or was used on some farms at zero cost. In 2010, Publicly Available Specification (PAS) 110 has been issued as a BSI standard certifying the digestate as a product rather than a waste. Consequently, this will increase farmers' confidence in its use as a fertiliser and make the digestate more attractive as well as securing a shadow cost in the form of displaced expenditure on fertiliser.
- The supply chain links (feedstock and digestate) is, at this stage, undeveloped (The Andersons Centre, 2010) and is an area for development.
- Land cost adds a burden to the project's economics. In some cases, land is available but in very rural areas, thus the transportation cost of feedstock and digestate becomes significantly high.

10.7.3 Permitting and Planning

Permitting and planning can be a complicated and time-consuming process for plants processing feedstock from third parties, particularly for the larger scale of plant using energy crops that are likely to proliferate.

The process for on-farm plants using residues from farm activities can be relatively simple. However, given the exclusion of energy crops within RHI eligibility, this scale of plant using energy crops is less likely to materialise in significant numbers.

Finally, it has been apparent that a lack of public awareness of the biogas sector can lead to negative perceptions causing subjective objections to biogas projects. There have been many reasons for projects being rejected and these include: the potential adverse local environmental impact such as odour, traffic generation, noise, landscape impact, etc.

10.8 UK Capabilities

With the recent and ongoing increase in European suppliers covering the UK market, technology transfer should not pose a barrier to AD development in the UK. Presently, most of the equipment suppliers in the UK are European with few indigenous manufacturers and few UK AD providers implementing their own in-house design.

Technology development in AD is focusing upon newer reactor designs which could lower the capital costs by reducing the hydraulic retention time or operating at lower temperatures. Work carried out at laboratory scale showed that it is feasible to work at ambient temperatures, or as low as 15ºC, with the consequent energy savings and reduction in operation costs. However, this research will need to be proven at operational scale before it can be implemented.

The thermal and enzymatic pre-treatment of the waste has proven advantageous for the digestion process. It also provides a boost in the biogas yields

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11 Landfill gas

11.1Technology description

A landfill site works like a bio-reactor in which landfill gas is produced in a biochemical process from the decomposition of organic matter. Landfill gas is a mixture composed primarily of methane, carbon dioxide and nitrogen.

A gas extraction system from a landfill consists of the following elements:

- Gas vents from the landfill bed (vertical wells and horizontal pipes);
- Header pipes discharging gas to the collection point (collection station);
- Collection station consisting of demoisturisers, blowers, and measuring and monitoring equipment.

11.1.1 Elements of installation for gas extraction

Vertical gas extraction system - wells

Newly constructed landfills may have their extraction wells built on a layer of soil placed directly on a geo-membrane, which serves as an additional landfill lining. This way the stress of the well on a geo-membrane is reduced and the landfill lining is not damaged.

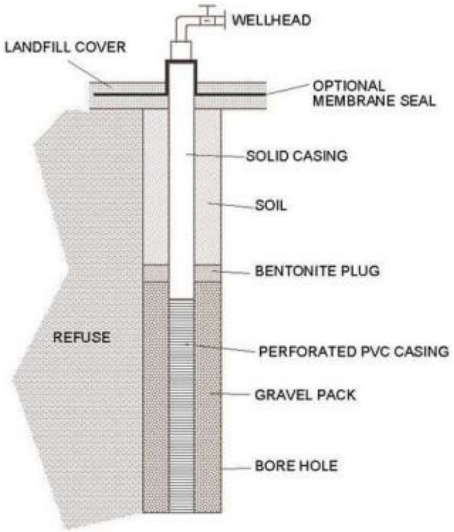

Figure 11-1 Vertical gas extraction well (EPA, 2006)

The solid wastes are deposited and compacted around wells, which are spaced every 30 – 50 m apart. At the lower sections of the well a filter is mounted. A horizontal header pipe running from the filter discharges leachate to the collection well.

A gas extraction well filter consists of a slotted 100 - 200 mm diameter pipe. The space between the filter and well cover is filled with gravel and covered with a sealing ring. The well cover is gradually extended and the extra space is made up with gravel as the void is filled. The upper part of the well is made from a non-perforated pipe. A header equipped with a gas valve is connected to the non-perforated pipe. The outlet port of the valve is connected with a compensation hose to the header pipe (Figure 11-1).

On existing landfills, the gas extraction wells are driven into the ground using a drilling rig (Figure 11-2). Bore-holes of 400 – 460 mm diameter go down to the solid waste base. Perforated pipes are installed in bore holes and the space between the pipe and bore-hole is filled with gravel. The upper part of the bore-hole is sealed with clay, while space next to the bore–hole is covered with the geomembrane. Sealing the well protects against infiltration of atmospheric air into the solid waste bed and fugitive emissions of landfill gas. Extracted LFG is piped to the collection station, which is an important part of the gas utilisation system.

Figure 11-2 Drilling of gas extraction wells

Horizontal gas extraction system – horizontal pipes

Another way of gas extraction from landfill is a horizontal well system (Figure 11-3). The total landfill surface area is divided into cells of approximately 1 ha each. In each cell, collection pipes are installed at a permeable layer of inert material (thickness app. 200 mm), within a waste bed. Pipes from each cell are arranged at a sufficient slope so as to remove condensate allowing the transport of gas to the collection station.

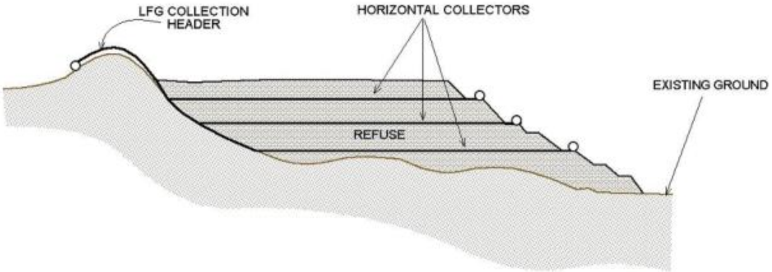

Figure 11-3 Horizontal gas extraction system (EPA, 2006)

Vertical-horizontal collection system

Some landfills use installations consisting of both vertical gas wells and perforated horizontal pipes. This collection method is often used at landfills with a thick layer of solid waste. The horizontal pipes are connected with vertical wells at numerous levels to facilitate the gas discharge to the header. This option has the economic advantage of a reduced number of wells.

11.1.2 Connection of elements of a landfill gas extraction installation

Gas extraction wells and horizontal pipes can be connected in one of two ways.

Individual headers

Individual headers require that there is a single pipe running directly from each well (or a horizontal header) to the gas collection station. The basic advantage of a direct connection between gas extraction wells and the collection station is a possibility of regulation of all wells at a single point. The most popular pipes are 50 - 63 mm in diameter. The drawbacks of this solution include possible siphoning and potential problems with gas flow. Operational problems may be experienced when pipes have not been placed properly.

Collective headers

In collective headers, individual wells and horizontal headers are connected to the main headers, which supply gas to the collection station. Gas extraction wells are linked to several collective headers (called bulkheads) of 100 – 160 mm diameter. This system may be used at landfills with large surface areas. The main advantage of such construction is the easy removal of condensate due to large bore pipes, however regulation of gas extraction from the landfill may be more troublesome as the adjustment valves are installed at the heads of wells located all over the landfill area.

11.1.2.1 Gas Collection Station

The gas collection station comprises the following units:

- Central collectors connected to pipelines to transmit the gas off the landfill;
- Blowers to extract gas from the landfill;
- Filters to remove solids;
- Knock-out pots where condensate is removed from the gas;
- Instruments for control of gas extraction and transport; and
- Measuring & control equipment.

A diagram of a typical gas collection station is presented in Figure 11-4.

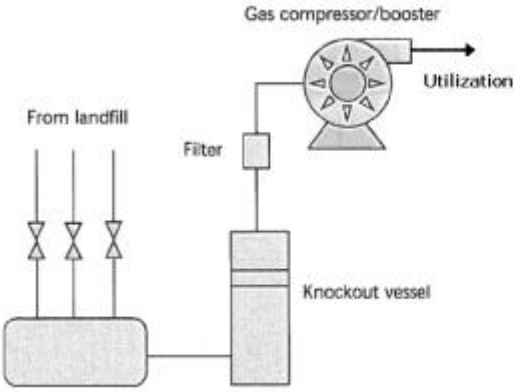

Figure 11-4 Gas collection station (SEPA, 2004)

11.2 Feedstock

The implementation of the Landfill Directive introduced many new requirements in 2002. Under the Directive, landfill sites were classified into three main types:

- Hazardous waste;
- Non hazardous waste; and
- Inert waste.

Some non-hazardous waste landfills can also have a separate hazardous waste cells for Stable Non Reactive Hazardous Wastes (SNRHW), e.g. asbestos and gypsum. This cell is usually a very small part of the overall site.

There are also detailed restrictions on the waste (i.e. Waste Acceptance Criteria) that each class of landfill can take.

In 2009, 75% of waste was landfilled at sites accepting non-hazardous biodegradable waste. 18% went to inert only sites, with 6% to restricted user sites (consisting of mainly ashes and slags from metal manufacture and power stations) and 1% to hazardous merchant landfills (EA, 2011).

During 2009, regulated facilities in England and Wales managed a total of around 134 million tonnes of waste. Of this 46.5 million tonnes were landfilled (EA, 2011);

At the end of 2009 there were:

- 614 million cubic metres of available landfill capacity, with 68% of this available at merchant non-hazardous sites;
- 18 million cubic metres available at hazardous waste only sites;
- nearly eight years of landfill life left at sites for non-hazardous wastes in England and Wales, at 2009 input rates (EA, 2011).

Operators are seeing a declining gas resource mainly due to biodegradable municipal waste (BMW) and other organic waste being diverted from landfill to other uses, for example, composting and anaerobic digestion. This trend is likely to continue in the future due to increasing landfill tax charges and local authority targets for reducing the quantity of BMW going to landfill.

11.3 Technical and environmental characteristics

11.3.1 Scale

The quantity of landfill gas extracted from a landfill varies with time and between sites for the same reasons that account for compositional differences. Typically, extraction rates may vary from 25 to 100 m^3/h for small sites of 100,000 m^3 waste capacity up to 250 to10,000 m^3/h or more for large sites with waste capacities of 1–10 million m^3.

11.3.2 Efficiency

The theoretical volume of methane generated per tonne of carbon, assuming 100% of the carbon is converted to methane (50%) and carbon dioxide (50%), is 443 Sm^3. This is the total volume of methane generated over time if all of the carbon is converted. In practice, 100% carbon conversion is not achieved and various factors are required to allow for actual site conditions.

The percentage of actual energy that is accessible ranges from 40-70% (177 - 310 Sm^3) of the theoretical energy.

11.3.3 GHG emissions

GHG emissions from landfill dominate waste sector emissions in the UK contributing about 89% of the total waste sector emissions. CH_4 is the dominant GHG emitted. CH_4 from landfill is produced as organic wastes decay in the oxygen deficient lower layers of the landfills.

Landfill gas emissions in the UK may be estimated using a first order decay methodology based on estimates and historical data on waste quantities, composition and disposal practices over several decades. First-order decay is simply the assumption that biodegradable carbon in the material decays to CH_4 with a reaction rate that is proportional to the amount of carbon remaining in the material (DECC, 2010). The rate of decay is a function of a whole range of factors that are normally taken into consideration when modelling but in particular, the type of material, the moisture content, the age of the material strongly influence the rate that may be assumed for the Technology Modelling Report.

The GHG emissions per tonne of land filled waste for 2008 are estimated to be 0.298 tCO_2 (DECC 2010). As the organic content of waste sent to landfill is decreasing year on year through the Landfill Directive, the GHG emission per tonne of landfilled waste will reduce accordingly. However, we recommend that the 2008 number be used in the Technology Modelling Report in order to make due allowance for the landfilling of the organic material in question.

GHG emissions from waste contributed about 4% of the total UK GHG emissions in 2008. Emissions from the waste sector have decreased by 57% since 1990. This is mostly due to the implementation of LFG recovery systems at UK landfill sites. In the future, emissions from landfill are expected to continue the current declining trend. Historic and projected emissions from waste are shown in Figure 11-5.

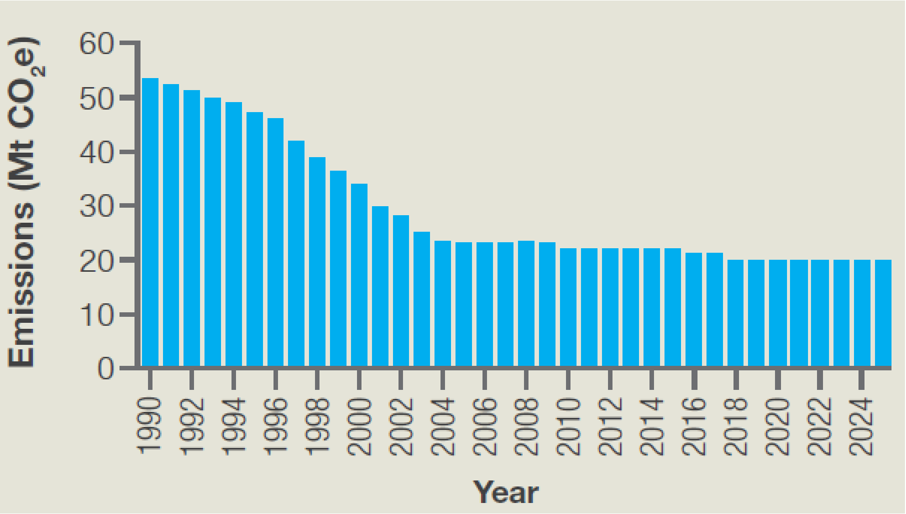

Figure 11-5 Historic and projected emissions from waste in the UK (DECC, 2010)

11.4 Costs

11.4.1 Capital cost

The capital cost estimates detailed below are the costs that could be expected for an average site development. These include the following scope:

- Gas collection and booster fan;
- Civil engineering and building works;
- Other miscellaneous items.

The average cost of drilling wells (including gas collection, pipeline, booster fan, civils, etc.) is £4,000/well. The gas flow rate per well may be anywhere in the range of 10-50 Sm^3/h. The gives a cost range of £80-£400 per Sm^3/h flow of landfill gas (based on Black&Veatch experience).

11.4.2 Operating cost

Operation and maintenance costs for landfill gas utilisation typically comprise:

- General site overheads;
- Insurance;
- Input electricity;
- Maintenance materials;
- Other materials;
- Operating labour;
- Decommissioning.

The average O&M costs have been estimated to be £6/MWh (based on Black&Veatch experience).

11.5 Requirements of the upstream/downstream process and system considerations

In addition to upgrading, there are various other end-uses for the landfill gas. These are mainly for electricity generation or heating. Figure 11-6 provides a summary of the various processes that can be considered for different uses. Electricity generation and combined heat and power options are discussed in detail in Chapter 33.

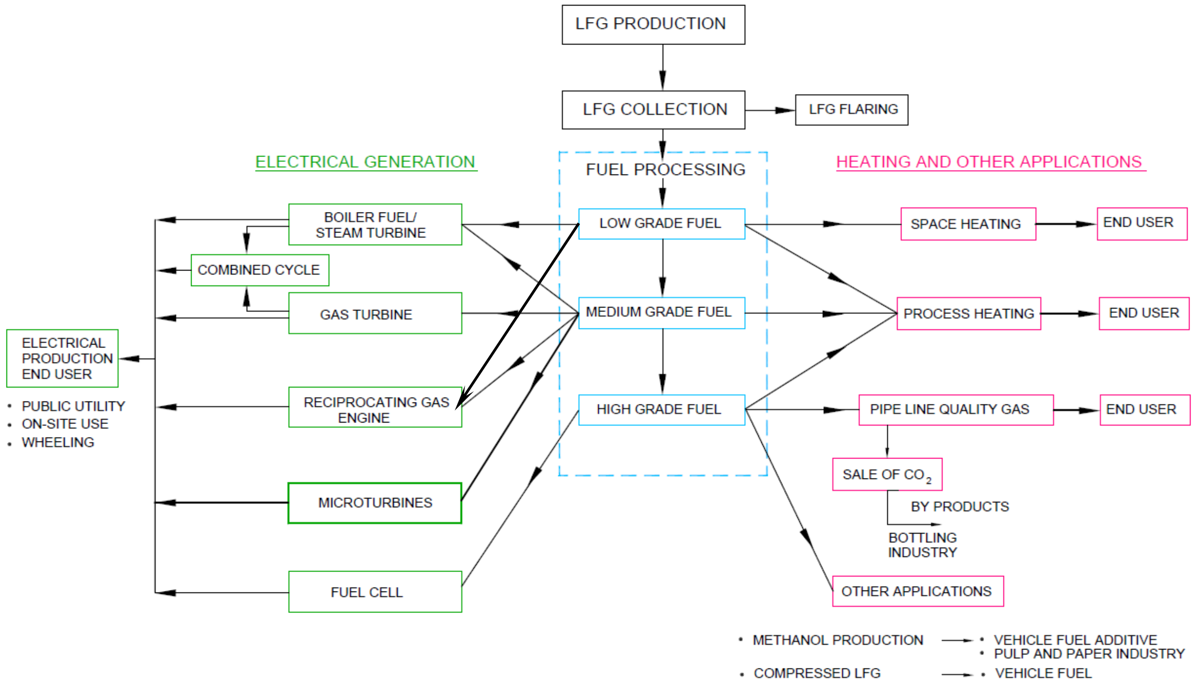

Figure 11-6 Landfill gas utilisation options (World Bank, 2006)

11.6 Deployment and development status

At the end of 2009 in England and Wales there were 497 operational permitted landfills, and there were 71 authorised landfill sites in Scotland (SEPA, 2004).

Waste to landfill has decreased in recent years, having fallen by 18% between 2008 and 2009. Moreover waste to landfill volumes have fallen nearly 45% since 2000. One of the principal reasons is the implementation of the Landfill Directive. Many older landfill sites that did not meet the stringent requirements of the Directive had to close by July 2009 at the latest. Between 2008 and 2009 there was also a fall in economic activity with an associated reduction in waste generated.

Remaining capacity at landfill sites fell by over 5% during 2009 and overall, since 2000, landfill capacity has decreased by 19%.

Inputs through permitted transfer facilities decreased by 10% between 2008 and 2009. (EA, 2011)

The planning guidance supports the development of power generation from landfill gas. In addition to this, landfill gas utilisation is also a mature market that remains unconstrained by any lack of technical innovation, (DECC, 2010).

Landfill will continue to contribute to renewable electricity generation but with declining gas volumes, it is expected that there will be little or no future increase in capacity.

England and Wales are mature markets, which will see generator sets relocated to exploit the gas potential in other geographic areas. Northern Ireland may see some activity but, with few sites operational, any development would not have a significant impact on the overall technology band. (DECC, 2010).

The amount of landfill gas used to generate electricity and heat in the UK in 2009 was 1,637,850 toe (DECC, 2010a).

11.7 Barriers to development and deployment

Barriers to the development of landfill gas production in the UK include:

- **Waste to landfill** volumes: as discussed above.
- **Gas/electrical grid connection costs**: The issues around landfill gas development are well understood but the connection costs still remain a constraint for sites of smaller capacity in areas where the infrastructure must be reinforced to accept the output. These connection costs can often make a small project financially unviable.
- **Maturity of gas reserve**: The largest determining factor on the future of landfill gas energy generation is the maturity of the gas reserve - how quickly it will deplete and the continuation of gas with a calorific value that can be utilised by the available technology at an attractive commercial rate.

Scotland has very few sites remaining to be exploited and proposed changes to the rateable value of LFG generation may further constrain or reduce the contribution.

11.8 UK Capabilities

The technology risks and resource requirements for effective commercial exploitation of LFG are well established and there are no constraints to development. LFG production in the UK is well established (TRL 9) with the associated mature supply chain providing gas collection and other ancillary equipment.

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12 Biogas upgrading

Upgraded biogas may be used for vehicle use or for grid injection subject to the requisite cleaning to ensure it is compliant with current regulation.

12.1 Technology Description

Biogas is primarily a mixture of methane (CH_4) and carbon dioxide (CO_2) and can be produced using a variety of feedstocks from organic waste to animal residues or indeed crops. The composition of biogas will depend upon the production route, the composition of the organic matter load and the feeding rate of the digester. Biogas generated from:

- Farm residues typically contains ammonia and will have higher concentrations of hydrogen sulphide (H_2S) when compared to biogas obtained from the digestion of sewage sludge;
- Energy crops also contains H_2S, O_2, N_2, and organohalogens;
- Sewage sludge gas will contain higher levels of siloxanes, terpenes and aldehydes and low levels of particulates and metals;
- Landfill gas is dependent on source of waste, but commonly contains H_2S and siloxanes becoming more apparent;
- MSW typically contains terpenes and carbonyls, whereas gas from commercial and industrial (C&I) waste will typically contains higher levels of arsenic (GL Industrial Services, 2010).

The contaminants mentioned above could have an impact on the gas grid network, engines, and appliances and therefore need to be removed. For example carbon monoxide, carbon dioxide and H_2S in the presence of water can cause different types of corrosion; siloxanes can harm the gas distributing system and engines and gas appliances due to silica deposition. The removal of impurities is also a pre requisite to comply with the concentration levels required by Gas Safety (Management) Regulations (GS(M)R).

Several technologies are available for removing such contaminants from biogas and the levels of treatment required depend on the end use of the biogas as shown in Table 12-1.

Biogas Use	Components to Removed
Heat	Liquid water, sulphur (H_2S)
Electricity/Cogeneration	Liquid water, sulphur (H_2S), organo-halogens, siloxanes
Fuel	Liquid water, sulphur (H_2S), organo-halogens, carbon (CO_2), siloxanes
Gas Grid	Liquid water, sulphur (H_2S), organo-halogens, carbon (CO_2), oxygen (O_2), metals, siloxanes

Table 12-1 Summary of required treatments for different biogas end use (Trendsetter, 2003)

The methane in biogas after upgrading has similar properties and constituents to the properties of natural gas. This section describes the different technologies currently available for the removal of the different contaminants from the raw biogas to upgrade the biogas to biomethane.

12.1.1 Removal of hydrogen sulphide (H_2S)

H_2S is formed during microbiological reduction of sulphur containing compounds (sulphates, peptides, amino acids). The concentrations of H_2S in the biogas can be decreased either by precipitation in the digester liquid or by treating the gas either in a stand-alone vessel or while removing CO_2. For the removal of H_2S from biogas, several technologies have been developed (IEA Bioenergy, 2009):

- Precipitation;
- Adsorption on activated carbon;
- Chemical absorption; and
- Biological treatment.

12.1.2 Removal of oxygen and nitrogen

Current theoretical understanding of anaerobic digestion suggests that oxygen should not be present in biogas as any free oxygen in the feed to the digesters should be scavenged by aerobic bacteria. However if it does remain, the oxygen and nitrogen gases can be removed by adsorption with activated carbon, molecular sieves or membranes (IEA Bioenergy, 2009). They can also be removed by catalytic oxidation. The level of oxygen and nitrogen gases may be reduced in desulphurisation processes or in some of the biogas upgrading processes.

Both oxygen and nitrogen are expensive to remove; hence their presence should be avoided when the biogas is to be upgraded to biomethane.

12.1.3 Removal of ammonia

The amounts of ammonia present in the gas are dependent upon the pH in the digester and substrate composition. It is formed during the degradation of proteins. A separate cleaning step is usually not necessary as it is usually separated when the gas is dried or when it is upgraded.

12.1.4 Removal of water

Biogas is effectively 100 % saturated with water vapour when it leaves the digester. The water can condense in gas pipelines and, together with sulphur oxides, cause corrosion. Water can be condensed from the biogas by decreasing the temperature or increasing the pressure and can thereby be removed. Moisture in the biogas can be controlled by a combination of the following:

- Use of condensate trap;
- Dehumidification;
- Cyclones for large water droplets; and
- Coalescers for fine water droplets.

Water can also be removed by adsorption using silica, activated charcoal or molecular sieves (IEA Bioenergy, 2009). Absorption in glycol solutions, or the use of hygroscopic salts, are some other technologies for water removal.

12.1.5 Removal of particulates

Particulates present in biogas can cause mechanical wear in gas engines and gas turbines. These can be separated by mechanical filters.

12.1.6 Removal of carbon dioxide (CO_2)

There are four different methods that are well developed and established for the removal of carbon dioxide: pressure swing adsorption (PSA), water scrubbing, chemical absorption and permeation. In addition, two less advanced processes exist: cryogenic upgrading and in situ methane enrichment. Table 12-2 is a summary of the advantages and disadvantages of the different carbon dioxide removal technologies.

Technology	Advantages	Disadvantages
Pressure Swing Adsorption (TRL 9)	• More than 96% CH_4 enrichment; • Low emissions of waste gas • Partial reduction of O_2 and N_2 levels • Established technology	• Upstream H_2S removal stage necessary for high concentration • The presence of water destroys the structure of the material • Additional siloxane removal step • Relatively high levels of CH_4 in waste gas • Consumption of activated carbon depends on H_2S level in raw biogas
Water Scrubbing (TRL 9)	• Simple and mature technology with no special chemicals or equipment requirement • Relatively low levels of CH_4 in waste gas • More tolerant to high H_2S levels in biogas to plant • Simple design and construction	• High operating costs in most cases, due to high water demand even with the regenerative process • Potential for bacterial contamination of packing media (pall rings) • H_2S and methane emissions to atmosphere
Chemical Absorption Scrubbers (TRL 9)	• Almost complete H_2S removal and therefore very low H_2S emissions to atmosphere	• High process heat requirement • Potential corrosion issues • Expensive catalyst • Relatively complex operational control
Membrane Separation (TRL 9)	• Compact and light weight • Simple process • Oxygen reduction from the raw biogas	• Multiple stages and additional process equipment required • High feed pressure required (dry membrane), higher power consumption • Gas pre-treatment needed, otherwise membrane quickly contaminates and fails • Membranes must be replaced periodically under normal operation • Limit on input O_2 levels • Low methane levels recovered (c. 81%) • Operational complexity

Technology	Advantages	Disadvantages
Cryogenic Upgrading (TRL 8)	• Can produce large quantities with high purity • No chemicals used in the process	• High capital cost • Complex technology not established at small scale • High operating costs in comparison to other technologies
In-situ methane enrichment (TRL 3)	• Technology is relatively simple • No need for much of auxiliary equipment, such as pressurised tanks	• Technology limited to smaller plants • Limited to sludge that is easy to pump • Concentrations of N_2 might increase due to air bubbles attaching to the material when it is circulated through the desorption column • Demonstration scale

Table 12-2 Summary of carbon dioxide removal technologies

12.2 Feedstock

The feedstock to a biogas upgrading plant is raw biogas from anaerobic digestion or from landfill gas.

As discussed in Section 12.1, the composition of the biogas will vary depending on the feedstock used to generate the gas. Biogas generated from the anaerobic digestion of energy crops typically has a lower concentration of carbon dioxide and no siloxane. Siloxane is typically found in either landfill gas or biogas from sewage sludge. The digestion of food waste and/or the organic fraction of MSW will typically generate high levels of H_2S. Ammonia and H_2S levels may be higher for digester gas in comparison to landfill gas. Due to the presence of several contaminants (including organo-halides, pharmaceuticals and microorganisms) landfill gas can be more difficult to upgrade (GL Industrial Services, 2010).

12.3 Technical and environmental characteristics

12.3.1 Scale

Biogas upgrading technology suppliers have specified in their website the scale at which they operate as shown in Table 12-3. Most of the suppliers offer modular designs allowing the plant capacity to be increased upwards as required. However, this will be dependent on costs and also on the capacity to store and distribute the biomethane generated.

Technology Provider	Scale (Biogas raw flow - Nm^3/h)	Technology
Carbotech	Up to 3,000	PSA / Chemical absorption / Membrane
Cirmac	50 – 5,000	PSA / Chemical absorption
Chesterfield Biogas	40 – 2,000	Water scrubbing
Gasrec UK	>1,500	PSA / Membranes

Technology Provider	Scale (Biogas raw flow - Nm^3/h)	Technology
Malmberg	150 – 2,400	Water scrubbing
Purac	150 – 4,000	Chemical absorption
Xebec	150 – 5,000	PSA
Guild Associates	170 – 1,200	PSA

Table 12-3 Scale of operation

12.3.2 Efficiency

Different biogas upgrading technologies provide different methane recovery efficiencies. Table 12-4 summarises the methane recovery efficiency for the different potential technologies.

	Pressure Swing Adsorption (PSA) (Carbotech, 2011)	Water Scrubbing (Malmberg, 2011)	Chemical Absorption (Amine) (Purac, 2011)
Methane recovery (% v/v)	High (96-98%)	High (>97- 98%)	Very high (99%)
O_2 removal	Partial	None (2nd stage PSA available)	None, oxygen tends to breakdown certain amines
H_2S & CO_2 removal	Yes – separate stage	Yes - simultaneously	Yes – separate stage
Siloxane removal	Yes, but will reduce the efficiency of H_2S removal	Partial	Partial
H_2S & Siloxane (if any) pre-treatment advisable	Yes	No	Yes
Waste gas issues	Yes – CH_4	Yes – H_2S & CH_4	None
Activated carbon required	Yes	None	None
Approx electricity requirements (kWh/Nm^3 pa raw biogas) – for a flow of 500Nm^3/h	0.24	0.3	0.1
Approx heat requirements (kWhth/Nm^3 pa raw biogas) – for a flow of 500Nm^3/h	None	None	0.8 (heat recovery possible)

Table 12-4 Comparison of common parameters for different technologies

12.3.3 GHG emissions

GHG emissions from the process of upgrading biogas to biomethane typically include the emissions due to electricity and heat consumption and methane losses in the waste stream.

Typical electricity and heat requirements for the different process are listed in Table 12-4. GHG emissions can be calculated directly from these consumption figures. Some technology providers such as Purac and Malmberg offer energy integration with biogas production plants, where heat recovered from the biogas upgrading plant is used to pre-heat the digesters, therefore lowering the process GHG emissions.

Waste gases are primarily composed of CO_2, CH_4, O_2, H_2S, N_2, water and siloxanes compounds. The highest impact to the environment is considered to be generated by emissions of methane and carbon dioxide to the atmosphere. Depending on the technology, the composition of the waste gas varies. The highest methane recovery, and therefore the lowest methane slippage, is achieved by chemical absorption (1%).

As an example a typical PSA composition of waste gas is shown in Table 12-5 (Carbotech, 2011).

Component	Level
Methane (CH_4)	<4%
Carbon dioxide (CO_2)	>93.5%
Nitrogen (N_2)	>1%
Oxygen (O_2)	>0.2%
Hydrogen sulphide (H_2S)	<3 ppm
Water	<5 mg/Sm^3
Siloxanes	<1.5%

Table 12-5 Typical waste gas composition using PSA technology

Methane emissions can be mitigated by oxidizing the methane to carbon dioxide, either by using direct combustion or regenerative thermal oxidation (RTO).

- Direct combustion:
    - Diverting the waste gas to the biogas boiler assuming that the diluted gas is combustible; or
    - Flaring the waste gas with biogas or a supplementary gas.
- Treating the waste gas using RTO. Low concentrations of methane (4%) can be oxidised in a burner at temperatures between 850 – 1,000°C. After treatment, the methane concentration in the waste gas would have been reduced to <0.1% (Carbotech, 2011). A typical RTO application has a preheating chamber that uses electric heating rods (c. 30kWe – a completely cold chamber needs to be pre-heated for 6 to 8 hours), that are used only when the unit has been out of operation for a long time. During normal operation the heat transfer from combustion is sufficient to maintain the process, with an electric requirement for the system of c. 15kWe for a biogas flow rate of 400m^3/h.

As well as a greenhouse gas, carbon dioxide is also a raw material for various industrial processes. Carbon dioxide removed by the upgrading process is usually emitted to the atmosphere as waste stream. Currently, cryogenic liquefaction is the only upgrading technology that results in the recovery of CO_2.

12.4 Costs

12.4.1 Capital costs

B&V has developed a cost curve for the supply of biogas upgrading plants. The cost (£/Nm^3/h) is for a turnkey delivery and does not include integration costs. Integration cost could be 2 to 3 times the supplier's cost, depending on the application. The capital cost of upgrading technologies is dependent on the plant size (see Figure 12-1).

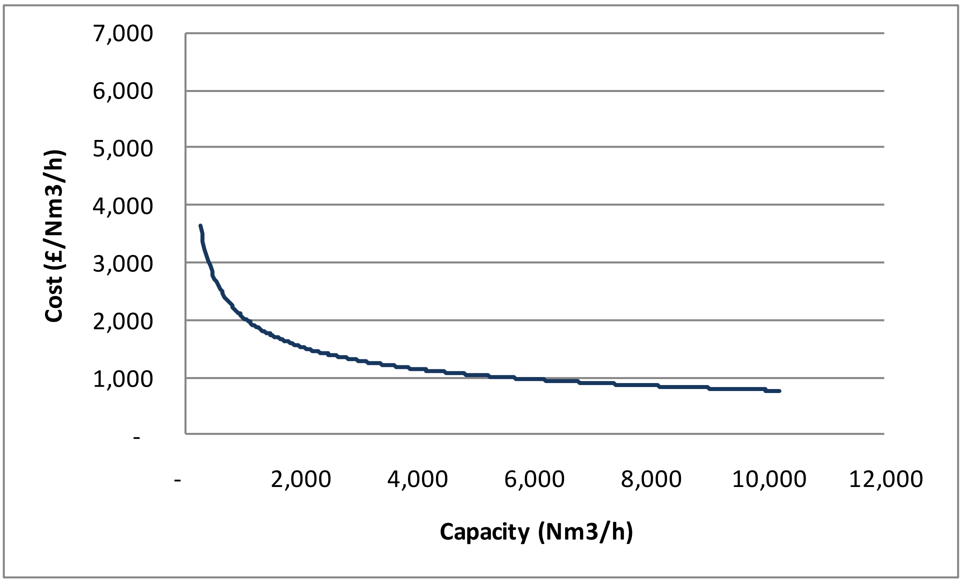

Figure 12-1 Suppliers capital cost – biogas upgrading

The development of standardised modular designs has led to cheaper and more efficient plants. Technology developments, such as the development of new amines and increase in membrane selectivity, and the increase demand for more upgrading plants is likely to generate further cost reduction. For example, Germany alone has set a target to substitute 6 billion m^3 of natural gas with biomethane in its network by 2020, and as a result it is expected that 1,000 biogas upgrading plants will be constructed in Germany within the next 10 years (Weiland, 2009).

12.4.2 Operating cost

Opex for biogas upgrading to biomethane includes:

- Electricity requirements;
- Heat requirements;
- Consumables – water, activated carbon and amine, anti-foam agent and other depending on the technology selected.

Carbotech, a technology provider has estimated the operational cost for different technologies, including PSA, water scrubbing, physical scrubbing and amine scrubbing. This cost includes power, heat and consumables requirements. Amine scrubbing has the highest operating cost, between £360 and £460/Nm^3/year of raw biogas capacity (see Figure 12-2).

The lowest operating costs were estimated for PSA, between £270 and £300/Nm^3/year of raw biogas capacity.

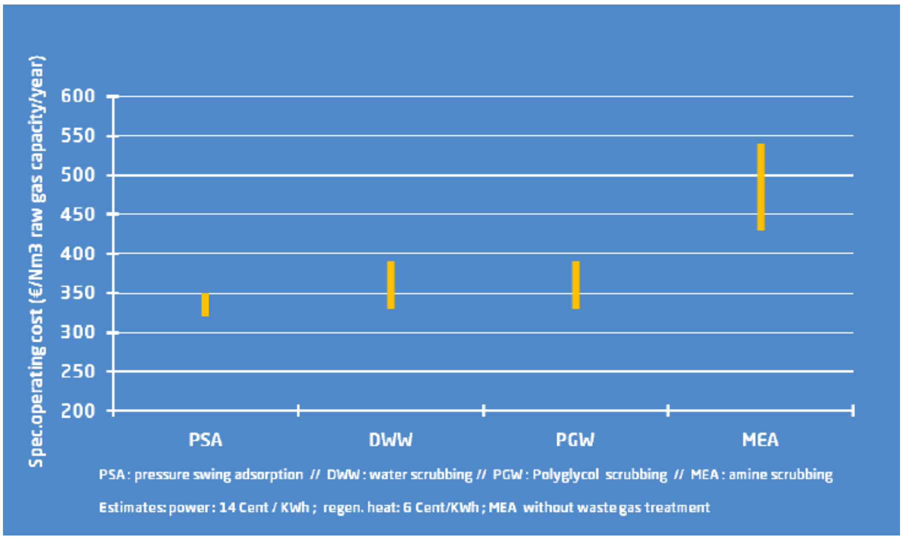

Figure 12-2 Operating cost biogas upgrading (Carbotech, 2010)

12.5 Requirements of the upstream/downstream process and system considerations

Requirements upstream of the upgrading process depend on the concentration of contaminants on the biogas. It is advisable that biogas with high concentrations of H_2S and siloxanes should be pre-treated in order to extend media life.

Downstream requirements are dependent on the biomethane usage. If biomethane if to be injected into the gas grid, a biomethane to grid (BtG) plant, which monitors and enhances the biomethane quality prior to grid injection, is required. In addition biomethane will need to comply with the GS(M)R and Gas Distribution Network Operator (GGNO) requirements. If biomethane is to be used as vehicle fuel, storage and compression capacity is required in addition to re-fuelling facilities.

12.6 Deployment and development status

Globally there are numerous biogas upgrading plants: approximately 134 operational plants of which 54 are in Europe (IEA Bioenergy, 2009). Most biogas cleaning and upgrading technologies, such as pressure swing adsorption (PSA), water scrubbing, chemical absorption, and activated carbon adsorption have been widely used in other sectors and thus are well developed (TRL 9). Biogas upgrading technology has been present since 1981 with plant sizes varying from 10Nm^3/h to 13,000Nm^3/h (IEA, Bioenergy, 2009). The applications are predominant in Germany and Sweden. Most of the applications in Germany are used for biomethane for grid injection, while in Sweden, most of the applications are for the use of biomethane as vehicle fuel.

An illustration of the commonly used technologies in Europe, with the number of plants, is shown in Figure 12-3. The most commonly used technologies for biogas upgrading in Europe are PSA and water scrubbing.

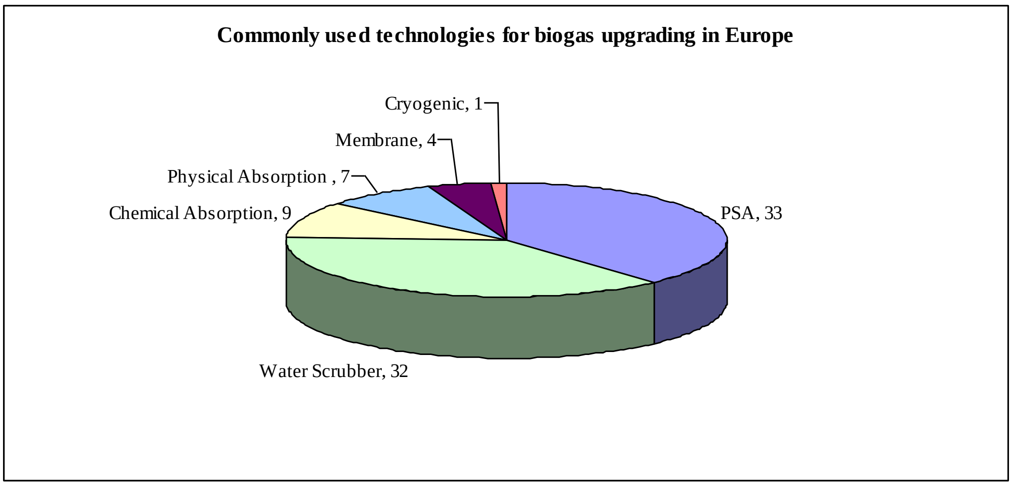

Figure 12-3 Commonly used technologies for biogas upgrading in Europe (IEA Bioenergy, 2009)

Currently in the UK there are three projects in operation or under development using upgrading facilities for grid injection.

- **Didcot Sewage Works** - injecting biomethane from sewage sludge digestion into the grid. This is a partnership between Centrica, Scotia Gas Networks and Thames Water, to process the biogas generated at Didcot Sewage Works. The plant started in October 2010 and it is designed to treat 100 m3/hr of biogas and produce c. 60 m3/hr of biomethane for injecting into the grid. The biogas is upgraded by using water scrubbing technology provided by Chesterfield Biogas. Thames Water is using this is a trial project and hopes to replicate this type of process on other sites where biogas is produced. Thames Water has also looked at the potential of compressing the biomethane to use as vehicle fuel.
- **Davyhulme** - The Davyhulme waste water treatment works project proposes a small scale biomethane injection facility. Approximately 230 Nm3/h of the biogas produced at Davyhulme will be diverted into the biogas upgrading facility. Of the resulting biomethane gas:

    - Approximately 100 Nm3/h will be used to fuel up to ten sludge transport vehicles via a dispensing / fuelling system.
    - A minimum of 20 Nm3/h will be supplied to National Grid, who will construct an adjacent facility to condition the biomethane (consisting of propane enrichment and odourisation) and a new offsite gas pipeline to enable export of the conditioned biomethane to the gas grid. Should the project proceed, it is planned to be operational by the end 2012.

- **Adnams Brewery** - The Adnams brewery received a £1.18 million grant from the European Regional Development Fund (ERDF) for the construction of the plant to produce biomethane for grid injection. The plant will generate biogas which is upgraded to biomethane using cryogenic technologies. The biomethane flow rate is reported to be in the order of 80m3/h. Part of the biomethane will be injected into the grid and part used for vehicle fuel. It is understood that Adnams are to use the CO2 by-product in the main site process.

There is one site in the UK upgrading biogas for vehicle fuel: the facility at Albury in Surrey is generating liquefied biomethane from landfill gas for commercial vehicles operating in the haulage and waste management sector.

Table 12-6 is a summary of the operational, and close to operation, biomethane projects in the UK.

Plant	Biogas source	Utilisation	Technology	Status
Albury	LFG	Vehicle	PSA/Membrane	In operation since 2008
Didcot	Sewage sludge	Grid	Water Scrubbing	In operation since 2010
Davyhulme	Sewage sludge	Grid/Vehicle	To be defined	Planned 2012
Adnams	Brewery & food waste	Grid/Vehicle	Cryogenic	2011

Table 12-6 Summary of UK biomethane plants

12.7 Barriers to development and deployment

For biogas injection into the UK gas grid, the main barrier is the GS(M)R requirements and the cost of the BtG system for small scale projects. Biomethane entering the network must comply with the gas quality requirements set out in the GS(M)R listed in table below.

Content or Characteristic	Value
Hydrogen sulphide content	≤ 5 mg/Sm^3 (UK standard conditions are 15°C and 1,013.25 mbar for both combustion and metering)
Total sulphur content (Inc. H_2S)	≤ 50 mg/Sm^3
Hydrogen content	≤ 0.1 % molar
Oxygen content	≤ 0.2 % molar
Impurities	The gas shall not contain solid or liquid material which may interfere with the integrity or operation of pipes or any gas appliance which a consumer could reasonably be expected to operate.
Hydrocarbon dewpoint and water dewpoint	Shall be at such levels that they do not with interfere the integrity or operation of the pipes or any gas appliance which a consumer could reasonably be expected to operate.
Wobbe Number (WN)	≥ 47.20 MJ/ Sm^3 to ≤ 51.41 MJ/Sm^3
Incomplete Combustion Factor (ICF)	≤ 0.48
Soot Index (SI)	≤ 60
Odour	Gas below 7 barg will have a stenching agent added to give a distinctive odour.

Table 12-7 Gas quality requirements (HSE, 1996)

One of the main barriers for injecting the biomethane to the grid is the gas quality required. Oxygen limitation in the UK 0.2% molar as specified in the GS(M)R is considered too low by the industry. Other countries in Europe allow higher oxygen content, for example 3% for dry gas grid and 0.5% for wet gas grid in Germany. The options for oxygen reduction are listed in section 12.1.2. At this stage, the treatment options are either at R&D stage or commercially available for large scale (used in coal-mine methane applications). Application of this technology to small scale would require significant investment and may impact the methane level recovered. The development of small scale oxygen removal technologies is required to meet the UK standard.

The Health & Safety Executive (HSE) is studying the impacts of the introduction of contaminants to the network. The studies may lead to potential relaxation in the biomethane quality requirements, subject to the outcome of the studies and the relative risks. Relaxation in the requirements may lead to an acceleration of the biogas upgrading sector in the UK. The HSE has identified three areas of concern:

- Corrosion of distribution pipework: Corrosion from chloride and carbon monoxide can be intensified by the presence of oxygen in the biomethane;
- Siloxane contamination and any other trace elements;
- Masking of mercaptan odourant by contaminants from biomethane.

Another barrier is the required minimum Wobbe Number of 42.7 SMJ/m^3 as defined in the GS(M)R. Depending on the quality of the gas, it may be necessary to add propane to increase the calorific value.

12.8 UK capabilities

There are more than sixteen technology providers providing biogas upgrading technologies in Europe and in USA, of which, two are based in the UK.

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13 Gasification

13.1 Introduction

The aim of this chapter is to provide an introduction to the gasification principles and technology, including a description of different gasifier types, their range of scales, and the downstream applications of the syngas production.

Given that many of the routes considered in this technology landscaping task include a gasification step, this chapter also lays out the common ground regarding feedstocks, upstream requirements, UK R&D activities and capabilities in gasification, as well as the barriers facing all the routes involving gasification. This chapter therefore acts as a reference, for each of the separate chapters in this document that include a gasification step, within a heat, power, or biofuels conversion route. These chapters, later on in the document, cover:

- Technologies for gaseous fuel production:
    - gasification with catalytic methane synthesis (Chapter 14)
    - gasification with catalytic dimethyl ether synthesis (Chapter 15)
    - gasification with hydrogen production (Chapter 16)
- Technologies for liquid fuel production:
    - gasification with catalytic Fischer-Tropsch synthesis (Chapter 22)
    - gasification with catalytic methanol synthesis (Chapter 23)
    - gasification with catalytic mixed alcohol synthesis (Chapter 24)
    - gasification with syngas fermentation (Chapter 25)
- Technologies for heat, power, and combined heat and power generation:
    - close-coupled gasification (Chapter 34)
    - biomass co-fired integrated Gasification Combined Cycle (Chapter 35)
    - dedicated biomass integrated Gasification Combined Cycle (Chapter 36)
    - gasification with internal combustion engine or gas turbine (Chapter 37)

The rationale for covering each technology bundle involving a gasification step in a single chapter is that in the vast majority of cases, such technologies are heavily integrated into a single plant, and most information are available and are better interpreted only at system level.

13.2 Gasification working principle

Gasification is a process in which a material containing carbon, such as biomass or coal, is converted into a gas inside a reactor vessel. It is a thermo-chemical process, meaning that the feedstock is heated to high temperatures, producing gases which can undergo chemical reactions to form a synthesis gas. This ‘syngas’ mainly contains hydrogen and carbon monoxide, usually with smaller amounts of nitrogen, carbon dioxide, methane, other hydrocarbons and tars, organic compounds and metallic contaminants. The proportions of these species vary according to the feedstock composition and gasification conditions. After any required cleaning and conditioning steps, syngas can then be used to produce heat, electrical power and/or a range of chemicals, including liquid and gaseous fuels.

Gasification is typically carried out with solid feedstocks, such as biomass or coal. In these cases, the inorganic proportion of the feedstock is not converted into syngas, and remains as solid (or molten) ash. However, low water content liquid feedstocks, such as pyrolysis oil, can also be gasified. Liquid feedstocks with higher water contents, such as black liquor or agricultural manures, will generally produce a gasification slurry by-product (e.g. green liquor), and hence require specialised reactor designs.

13.3 Gasifier types

There are several different generic types of gasification technology that have been demonstrated or developed for conversion of biomass feedstocks. This range of gasifier types has arisen for various reasons – adaptation from other thermo-chemical technologies (e.g. combustion boilers), adaptation to biomass or biomass co-firing from other feedstocks (e.g. coal), different required product outputs and scalability, enhanced syngas quality, and/or being able to use difficult feedstocks (e.g. MSW). In general, most of the gasifier types were initially developed for the production of heat and power from syngas.

The principal types are shown in Table 13-1. The types vary according to the temperature and pressure at which gasification takes place, how the biomass is fed into and moved around the gasifier, the oxidant used (oxygen, air or steam), and whether the gasifier is directly heated (through partial combustion of the biomass feedstock), or indirectly heated using an external source (E4tech, 2009).

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Updraft fixed bed (UD)

- The biomass is fed in at the top of the gasifier, and the air, oxygen or steam intake is at the bottom, hence the biomass and gases move in opposite directions
- Some of the resulting char falls from the middle 600-950°C gasification zone and combusts to provide heat at >1,300°C at the bottom of the gasifier. Exiting gas at the top is <200°C
- The methane and tar-rich gas leaves at the top of the gasifier, and the ash falls from the grate for collection at the bottom of the gasifier

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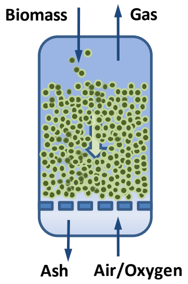

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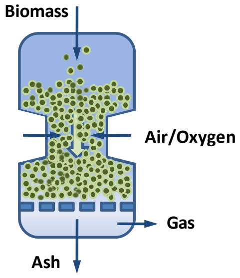
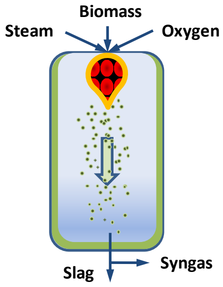
Downdraft fixed bed (DD)

- The biomass is fed in at the top of the gasifier and the air, oxygen or steam intake is also at the top or from the sides, hence the biomass and gases move in the same direction
- Some of the biomass is burnt at >1,300°C, falling through the gasifier throat to form a zone of hot charcoal which the gases have to pass through (a 600-950°C reaction zone)
- This ensures a fairly low tar syngas, which leaves at the base of the gasifier, with ash collected under the grate



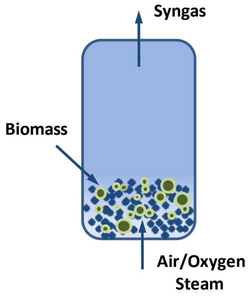
Entrained flow (EF)

- Powdered or liquid biomass is fed into a gasifier with pressurised oxygen and/or steam
- A turbulent flame at the top of the gasifier burns some of the biomass, providing large amounts of heat, at high temperature (1200-1500°C), for fast conversion of biomass into very high quality syngas
- The ash melts onto the gasifier walls, and is discharged as molten slag



Bubbling fluidised bed (BFB)

- A bed of fine inert material sits at the gasifier bottom, with air, oxygen or steam being blown upwards through the bed just fast enough (1-3 m/s) to agitate the material
- Biomass is fed in from the side, mixes, and combusts (to provide heat) or reacts to form syngas, which exits at the top
- Usually operates at temperatures below 900°C to avoid ash melting and sticking. Can be pressurised



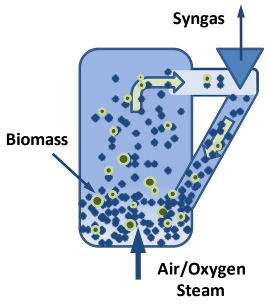
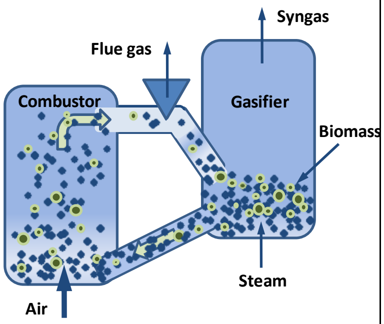
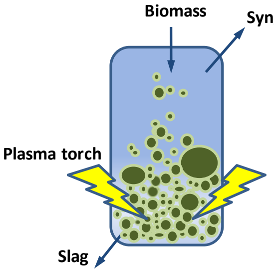
Circulating fluidised bed (CFB) • A bed of fine inert material has air, oxygen or steam blown upwards through it fast enough (5-10 m/s) to suspend material throughout the gasifier • Biomass is fed in from the side, is suspended, and combusts providing heat, or reacts to form syngas • The mixture of syngas and particles are separated using a cyclone, with material returned into the base of the gasifier • Operates at temperatures below 900°C to avoid ash melting and sticking. Can be pressurised	
Dual fluidised bed (Dual) • This system has two chambers – a gasifier and a combustor • Biomass is fed into the CFB / BFB gasification chamber, and converted to nitrogen-free syngas and char using steam • The char is burnt in air in the CFB / BFB combustion chamber, heating the accompanying bed particles • This hot bed material is then fed back into the gasification chamber, providing the indirect reaction heat • Cyclones remove any CFB chamber syngas or flue gas • Operates at temperatures below 900°C to avoid ash melting and sticking. Could be pressurised	
Plasma • Untreated biomass is dropped into the gasifier, coming into contact with an electrically generated plasma, usually at atmospheric pressure and temperatures of 1,500-5,000°C • Organic matter is converted into very high quality syngas, and inorganic matter is vitrified into inert slag • Note that plasma gasification uses plasma torches. It is also possible to use plasma arcs in a subsequent process step for syngas clean-up	

Table 13-1: Gasifier types. Note that biomass particles are shown in green, and bed material in blue

13.4 Gasifier scales

Figure 13-1 shows the likely scale of operation of different gasifier types – these ranges have increased slowly over the years as designs have become more efficient, and technical issues overcome, and may continue to do so. The minimum economic scale for fluidised bed and plasma gasifiers is around 2 MW$_{th}$ feedstock input, and can be scaled up to around 150 MW$_{th}$ for a single atmospheric unit, or around 500 MW$_{th}$ for pressurised systems. Larger gasification plants can be built using modular systems, although currently only plasma gasifier developers are looking at modular power systems.

gasifier developers are looking at modular power systems.

The majority of manufacturers of updraft and down-draft gasifiers that use wood as a feedstock offer systems that are at sizes of less than 2 MW$_{th}$ input. However, systems exist in the range of 40 kW$_{th}$ to 15 MW$_{th}$. Systems fired on MSW, RDF or other wastes run to larger sizes spanning from low MWs up to ~100 MW$_{th}$, or even higher when co-fired with coal.

Current gasifier heat and power plants are typically in the range 4 – 30 MW$_{th}$, with larger gasifier systems, often found co-located at existing combustion power stations, still rare. Many of the plasma gasifiers built are small (around 2MW$_{th}$) as they are primarily focused on waste treatment from a particular site, and not energy production. For high efficiency power applications, gas turbines and combined cycle systems are typically available at scales of 50MW$_{e}$ and above – this corresponds to a minimum gasifier size of around 100MW$_{th}$.

Currently, catalytic fuel synthesis is economically viable above 100,000t/yr of fuel output, i.e. 320 MW$_{th}$ biomass input (Choren 2009), hence only pressurised fluidised bed and entrained flow systems would be appropriate. Future developments could reduce this to 20,000t/yr (60 MW$_{th}$ biomass input) (Velocys, 2009), also estimated as the minimum economic scale for syngas fermentation (Ineos Bio 2009). This minimum economic scale determines which types of gasifier might be the most suitable for liquid fuels production, and so excludes fixed bed systems.

This scale is either as a single gasifier, or combining a small number of gasifier modules. Modular systems may not have the same economies of scale as single systems, but could have benefits in terms of use of different feedstocks, and of availability. The largest biomass gasification to liquids plant (via Fischer-Tropsch synthesis) currently operating is Choren's Beta demonstration plant in Freiburg, Germany at 45 MW$_{th}$, and the largest commercial plants currently planned are at ~625 MW$_{th}$ biomass input scale (Choren, 2009) (Biofuels Digest, 2011).

BioSNG plants are only currently at a pilot scale of 1.4 MW$_{th}$ biomass input. The minimum economic scale for a commercial bioSNG plant is considered by industry to be around 20-30MW$_{th}$ biomass input (E4tech, 2010b). Larger projects using imported biomass are also envisaged at scales of >290 MW$_{th}$, but those currently planned are only up to 145 MW$_{th}$. Dual gasifiers are most likely to be used, since steam gasification promotes hydrogen and methane production in the syngas, and avoids nitrogen dilution.

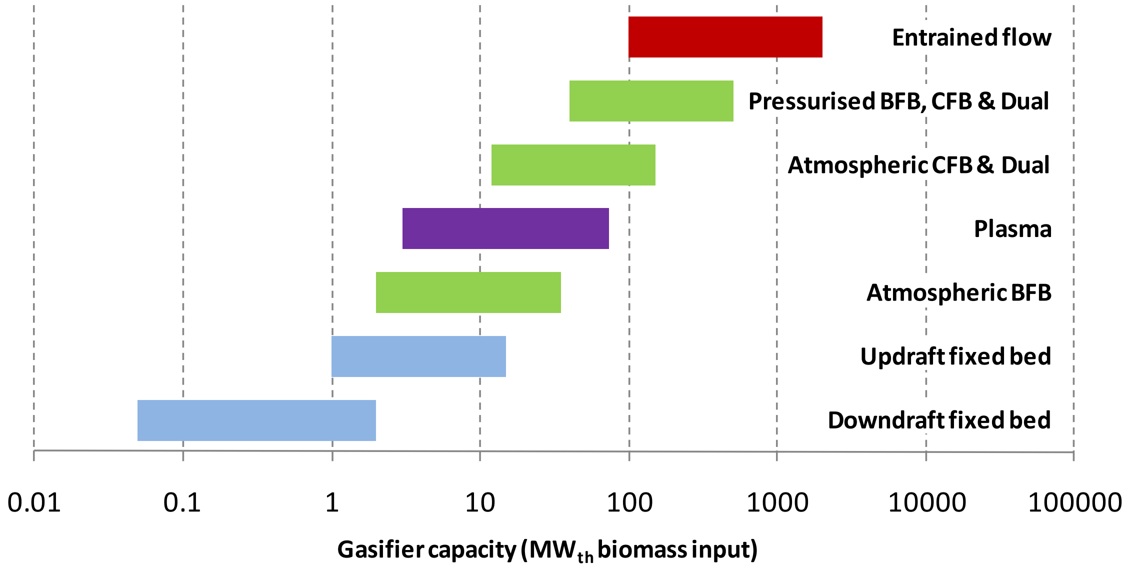


Figure 13-1: Gasifier capacities (MW$_{th}$ biomass input). Adapted from Rensfelt et al (2005), Babu (2005), and Westinghouse Plasma Corp (2009)

13.5 Syngas applications

Syngas is a highly versatile intermediate product, and can be used in numerous different end-use applications (Rhodes & Keith, 2005). Downstream of the gasifier, the specific syngas cleanup and conditioning step requirements are determined by the energy conversion process and end product – these are discussed in the relevant Chapters, as explained in Section 13.1. In summary, going down the list below, the uses for syngas increase in terms of the value of the product, but also increase in syngas cleanup requirements (Valler et al. 2009, World of Renewables 2010):

- Combustion of the syngas directly after gasification for space, water and industrial process heating applications. No syngas cleanup required, since the gasifier and combustor are ‘**close-coupled**’. Air is primarily used as the gasification oxidant (since oxygen separation is too expensive at small-scales)
- Combustion of the syngas in a **boiler** to raise steam for a steam turbine, driving a generator. Overall electrical efficiency of 20-30%, with minimal gas cleanup required
- Combustion of the syngas in a gas **internal combustion engine** (ICE), driving a generator. Overall electrical efficiency of 25-30%. Clean up is conducted mainly to protect from abrasion, alkali metal corrosion, and tar deposition
- Combustion of the syngas in an **open cycle gas turbine**, driving a generator. Overall electrical efficiency of 30-40%. Significantly more cleanup required than for a gas ICE
- Combustion of the syngas in a gas turbine to drive a generator, with exhaust heat recovery raising steam to drive a further steam turbine and generator. Overall electrical efficiency of this biomass integrated gasification combined cycle (**BIGCC**) plant is 40-50%
- Biological fuel synthesis via **syngas fermentation** to directly produce ethanol (or other possible fuels). Less syngas cleanup required than for catalytic fuel synthesis routes

- **Catalytic fuel synthesis** to produce FT petrol, FT diesel, FT jet, ethanol, mixed alcohols, methanol, bioDME, bioSNG, or hydrogen. Extensive gas cleanup and conditioning is required, as discussed in the individual chapters.

Differences between the gasifier types, along with the composition of the biomass feedstock, all have a marked impact on the produced gas composition and its calorific value, which can vary between 4-18 MJ/Nm^3 (Pang and Li 2006). No gasifier directly produces a gas clean enough for high-efficiency power generation, biofuel or bioSNG applications – these applications all require several gas clean up and conditioning steps. However, some gasifier types produce higher quality syngas than others, or promote the generation of particular gases, hence certain gasifier types are less or more suitable for particular gasification routes, due to their range of economic scales, feedstock requirements and syngas characteristics (Table 13-2).

High quality syngas contains few particulates, hydrocarbons or tars. The order of gasification temperatures dictate that Plasma gasifiers produce the best quality syngas, followed by EF, Downdraft, then Dual, CFB and BFB gasifiers, with Updraft gasifiers last. Avoiding nitrogen dilution is another important consideration for most of the biofuels applications, which is automatically achieved in an EF, Plasma or Dual fluidised bed gasifier, but only occurs in a CFB or BFB gasifier if oxygen or steam is used as the gasification oxidant. Steam gasification gives higher hydrogen syngas levels, but also higher levels of methane (an advantage for bioSNG production, but disadvantage for biofuels catalysis). Particulates are an issue for CFB, BFB and Dual technologies, whereas impurities coming from the feedstock are an issue for all technologies.

Gasifier type	Close-coupled heat or boiler for steam turbine	ICE	Open cycle gas turbine or BIGCC	BioSNG or H_2 synthesis	Other catalytic fuels synthesis, fuel cell power	Syngas fermentation
Updraft fixed bed	🟩 Suitable for range of scales	🟩 Suitable for range of scales, tar issues	🟧 Feasible at medium scale, although dirty syngas	🟥 Not feasible at large scale	🟥 Not feasible at large scale	🟥 Not feasible at large scale
Downdraft fixed bed	🟩 Suitable at small and medium scales	🟩 Highly suitable at small scales, good quality syngas	🟥 Not feasible at medium or large scale	🟥 Not feasible at medium or large scale	🟥 Not feasible at medium or large scale	🟥 Not feasible at medium or large scale
Plasma	🟧 Suitable for larger applications only	🟩 Highly suitable, good quality syngas, able to take mixed wastes	🟩 Highly suitable, good quality syngas, able to take mixed wastes	🟥 Clean syngas, but low methane and H_2 content	🟧 Suitable with modular systems, high quality syngas	🟩 Suitable at medium scales
Bubbling fluidised bed	🟧 Suitable for larger applications only	🟩 Suitable at larger scales, flexible to feedstock size	🟧 Suitable if pressurised steam or O_2-blown, turbine modifications needed if air-blown	🟧 Only if steam-blown, otherwise methane and H_2 too low	🟧 Suitable if steam or O_2-blown, large scale possible if pressurised	🟩 Suitable at medium scales
Circulating fluidised bed	🟧 Only suitable for very large applications	🟩 Suitable at larger scales, flexible to feedstock size	🟧 Suitable if pressurised steam or O_2-blown, turbine modifications needed if air-blown	🟧 Only if steam-blown, otherwise methane and H_2 too low	🟧 Suitable if steam or O_2-blown, large scale possible if pressurised	🟩 Suitable at medium scales
Dual fluidised bed	🟥 Not economic at small scales, no benefit from N_2 avoidance	🟩 Suitable at larger scales, flexible to feedstock size	🟩 Suitable given N_2 avoidance, flexible to feedstock size	🟩 Highly suitable, due to high methane & H_2 syngas	🟧 Suitable, large scale possible	🟧 Methane content not required, although avoided N_2 useful
Entrained Flow	🟥 Not economic at small or medium scales, no benefit from N_2 avoidance	🟥 Not economic at small or medium scales	🟩 Highly suitable, clean syngas	🟧 Syngas very clean, methane too low unless steam-blown	🟩 Highly suitable, very large scale, high quality syngas	🟧 Likely to be too big for syngas fermentation

Key	🟥 Unsuitable	🟧 Suitable in some situations	🟩 Highly suitable

Table 13-2: Suitability of different biomass gasifier types for different applications

13.6 Feedstock and upstream requirements

There are a large number of different biomass feedstock types for use in a gasifier, each with different characteristics, including size, shape, bulk density, moisture content, energy content, chemical composition, ash fusion characteristics, and homogeneity of all these properties.

Feedstock moisture contents above 30% result in a lower gasification thermal efficiency, as energy is needed to evaporate the water, with the resulting steam also affecting the gas composition. Higher moisture contents also reduce the temperatures achieved, increasing the proportion of syngas tars in the syngas due to incomplete cracking (Williams et al. 2007). However, drying feedstocks to less than 10% requires ever increasing energy inputs, and hence a moisture contents in the 10-20% range are preferable (Hamelinck 2004).

Ash is the inorganic material (or mineral content) in biomass which cannot be gasified. It ranges from less than 1% (on a dry mass basis) in wood to above 20% in some animal manures and herbaceous crops (e.g. rice straw) (ECN, 2011). Low-ash content feedstocks (<5%) are usually preferable to minimise disposal issues. Ash composition is also important, since feedstocks with low ash melting points can be difficult to gasify in some reactors. This is particularly true for fluidised beds, since melting ash can make bed particles adhere (agglomerate), causing the bed to 'freeze' – requiring a shut-down and clean-out or major overhaul. Catalytic bed additives, such as olivine or dolomite, can be used to prevent sand bed agglomeration, but this is an additional expense (Zevenhoven-Onderwater et al. 2001). Whilst woody biomass feedstocks usually meet the ash requirements, crop residues (such as straw and husks) may have to be first screened for their ash melting characteristics.

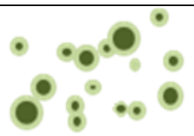
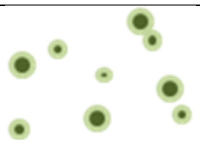
Besides feedstock moisture and ash properties, the size of the biomass fed into the gasifier can have a large influence on the gasification reaction – the required sizing is mainly a function of feeding rate, residence time, tar production, temperature and gasifier efficiency, which need evaluation for each individual gasifier and feedstock. Detailed testing information is scarce; however, in general, it is desirable to use a feedstock that is fairly uniform in size, shape and density (Ramos Casado & Esteban Pascual 2008). Loose crop residues should usually be compacted to provide the desirable bulk density to facilitate solids flow into the gasifier, and avoid feeding problems. Many plant stoppages are due to clogging of feeding mechanisms, either due to inhomogeneous feedstock or foreign objects. Blockages are particularly problematic for pressurised systems, which use a pressurised biomass feeding system – this is a technology area where additional development is needed to improve reliability and reduce costs (Wilen and Rautalin 1993, Lau et al. 2003).

Preparation of biomass, such as drying and/or sizing is needed to some extent for most combinations of feedstock and gasifier type. Some gasifier type and feedstock combinations require more pre-treatment, such as pelletising, torrefaction or pyrolysis, to make the biomass suitable for use. This approach is being also considered in order to use a diverse and variable range of feedstocks, reduce transport, storage and handling costs, and to mitigate feedstock supply and price risks. Plant economics can be greatly improved through the use of lower cost feedstock, and in addition to this, achieving the potential bioenergy deployment cited in many studies will require use of a wide range of feedstocks, not all of which will be the most suitable feedstocks for gasification. Pre-treatment does, however, add to costs and energy requirements, which must be compared with those of using alternative feedstocks.

General requirements upstream of the pre-treatment process are feedstock sourcing and transport. The principal feedstock preparation steps for biomass gasification include:

- **Sizing:** smaller particles have a larger surface area to volume ratio, and the gasification reaction occurs faster when there is a larger biomass surface area. Smaller particles can also be suspended in gas flows more readily, and if very small, the particles may act like a fluid. Achieving the correct feedstock sizing for the gasifier is important. Crude sizing operations include chipping, cutting and chopping, but in order to get very small ground particles, energy intensive pulverising milling equipment. A screening process is often also used to ensure any remaining larger particles and extraneous materials are removed
- **Drying**: the removal of moisture contained within the biomass by evaporation, typically using temperatures between 100°C and 120°C. Drying requires a significant amount of energy in order to evaporate the large mass of water. This heat can be provided externally, or extracted from the gasifier syngas or other plant process steps. Gasification efficiency increases with drier biomass, but drying costs increase quickly below 10% moisture
- Other more novel options include **torrefaction** (producing friable pellets) or **pyrolysis** (producing a liquid oil) – these particular options are discussed in their own separate Chapters

In summary, the requirements for feedstock particle size, moisture content and ash content are determined by the gasifier type. These requirements vary considerably: from EF gasifiers requiring small particle sizes, optimal moisture content and consistent composition over time, to plasma gasification which can accept nearly all biomass and waste feedstocks with minimal or no pre-treatment. CFB, BFB, and Dual systems are able to accept larger particle sizes and a wider range of moisture contents than EF, but also require care over the use of feedstocks with low ash melting temperatures, such as agricultural residues. The feedstock requirements for each gasifier type are summarised below in Table 13-3.

Gasifier	Size	Moisture	Composition
EF	 <1mm	<15%, tightly controlled	Should not change over time. Limits on high-ash agricultural residues due to corrosion. Torrefaction or pyrolysis preferred to reduce milling energy needs
BFB **Dual with BFB gasifier**	 <50-150mm	Below 30% preferred, although up to 50% is acceptable	Flexible to variations over time Care needed with some agricultural residues, ash melting temperature should be >950°C to avoid bed agglomeration
CFB **Dual with CFB gasifier**	 <20mm	Below 30% preferred, although up to 60% is acceptable	

Gasifier	Size	Moisture	Composition
Plasma	 Not important	Not important	Not important, can change over time. Higher energy content feedstocks preferred. Primarily used for a variety of different wastes, gate fees common
Downdraft **Updraft**	 30-60mm	Below 30% preferred, although up to 60% is acceptable	Need chipped or shredded material, although pellets and briquettes are also suitable. Ash contents below 10% preferred

Table 13-3: Summary of feedstock requirements (E4tech, 2009)

13.7 Efficiency, GHG emissions, and costs

Due to the highly integrated nature of many of biorefinery and power plant concepts involving gasification, the efficiency and GHG emissions of gasification itself are rarely defined – rather the overall plant efficiencies and GHG emissions from feedstock to final product is usually given. These overall plant efficiencies and GHG emissions are discussed in each of the relevant Chapters.

Due to large number of different system concepts, scales, levels of development, gasifier types, feedstock and syngas cleanup requirements, the costs attributed to only gasification can vary widely. The high levels of process integration also mean that individual component costs are difficult to separate out in a meaningful fashion. Costs are much more reliable at the overall plant level, as discussed in the relevant Chapters.

13.8 Deployment and development status

Due to the differing numbers of developers involved in each gasification route, the different scales, plant configurations and maturity of different plant components, and integrated nature of many of biorefinery and power plant concepts involving gasification, the overall deployment and development status of each route is discussed in its relevant Chapter

In this section we review the potential market, economic and regulatory barriers to deployment of the gasification–based routes considered. For each of the barriers identified, mitigation measures are proposed.

13.8.1 Market barriers

- Feedstock supply security and costs are uncertain.
- Securing a long-term, reliable supply of low cost feedstock is crucial for any plant using biomass, and should be considered from the outset, irrespective of technology or scale. The early stage of the biomass feedstock market, increasing competition with other plants and industry sectors, and current lack of liquidity, implies supply and price risks.
- Market based support for many of the products are in development, with future changes likely.
- All of the gasification routes are at different stages of development, with none of them currently being competitive with incumbent technologies. As a result, policy support is being developed, although the status and level of this support varies according to the

end-use market. Gasification to power routes are already supported under the banded Renewables Obligation, with gasification to heat and bioSNG routes only very recently supported via the Renewable Heat Incentive. The use of biofuels is incentivised under the Renewable Transport Fuels Obligation, with the EU's Renewable Energy Directive requiring an increasingly strict GHG savings threshold to be met, and double credit for wastes and advanced biofuel routes. However, proposed and future changes to these policies led to investor uncertainty – for example, the recent Electricity Market Reform, fast-track review of feed-in tariffs for small-scale power, and ongoing discussions at the EU level regarding the Indirect Land Use Change impact of biofuels.

- Access to heat markets is limited in the UK.
- The economic viability of large plants with co-produced heat such as bioSNG plants is partly dependent on access to markets for the heat, such as local industrial users.

13.8.2 Economic barriers

Access to project finance for large plants is difficult, particularly in the current investment climate This is a barrier to large scale gasification based technologies, as a result of the lack of investors with both the willingness to accept technology, supply chain and price risks and the ability to invest in capital intensive projects, given the opportunity cost of investing in other more mature, less risky technologies. Investment costs for small plants are high

Gasification systems have high specific capital costs, and higher operating costs than equivalent biomass combustion systems, which presents a barrier to installation for many users.

13.8.3 Regulatory barriers

- Planning timelines are lengthy
- Whilst there are no inherent barriers to planning associated with gasification-based routes compared with any other biomass technologies, it is important to note that renewable energy projects in the UK can often take longer to be granted planning permission, or face constraints, compared with other EU countries.
- Waste policy is leading to lower available supplies
- There are several aspects of waste policy which provide a barrier to deployment of gasification technologies using biomass wastes in the UK. Specifically, gasification energy recovery from wastes is lower on the waste hierarchy than recycling or composting, proving the renewable fraction of wastes is currently an onerous requirement for plant developers, and large waste streams are already being tied up in long-term contracts (using other technologies) due to landfill diversion targets and increasing landfill taxes.
- Feedstock sustainability requirements are tightening
- Large plants using biomass feedstocks will need to meet lifecycle greenhouse gas savings targets, and wider sustainability criteria including avoidance of use of high carbon stock or biodiverse land, along with potential reporting requirements. These sustainability criteria are laid out in the EU Renewable Energy Directive. Whilst understanding these requirements and sourcing suitable feedstocks will add an administrative burden to developers and their supply chain, these are unlikely to provide a significant barrier to

development of gasification based routes. Plants using wastes will have fewer criteria to meet, and small plants would be exempt.

13.8.4 Summary of barriers and mitigation options

Type	Barrier	Mitigation
Market	Feedstock supply security for large plants	• Will largely be resolved as the experience of plant developers and project financiers with bioenergy plants in general grows, and contracting structures and vertical integration progress
	Price and price variability	• Price ultimately depends on supply: maximising UK and global resources through energy crop, forestry and waste policy
	Policy uncertainty	• Many of the risks result from policies still in development. These will mostly be resolved as policy is finalised, although it is not yet known whether the levels of support provided will be sufficient to support deployment, and whether they will be maintained.
	Access to heat markets	• May be improved by further pressure for companies to reduce emissions e.g. CRC, and could be supported by heat demand mapping, facilitating planning in these locations etc.
Economic	Access to project finance for large plants	• There is the potential for government intervention such as through loan guarantees, capital allowances or grants
	Investment cost barrier for small plants	• There is the potential for government intervention such as through loan guarantees, capital allowances or grants
Regulatory	Planning	• Local government support for bioenergy and in particular waste to energy could help e.g. the Mayor of London's Municipal Waste Management strategy
	Waste policy	• Further harmonisation of waste and energy policy for power, heat and transport fuels is needed at a European level, ensuring that this is correctly interpreted locally
	Feedstock sustainability policy	• This is likely to be overcome by developers as policies develop

13.9 UK Capabilities

In this section, we set out the UK's capabilities in areas relevant to the development and deployment of biomass gasifiers. This includes gasification R&D as well as gasification developers, but does not consider the whole route from feedstock through to end product, as specific UK capabilities in each of these overall routes and their unique components will be considered in the relevant Chapters.

13.9.1 R&D

The main research programme on gasification in the UK is through the Supergen Bioenergy programme (Supergen, 2011), which covers biomass feedstocks, conversion technologies, and systems analysis. Research has included the interaction between feedstocks and gasification, co-gasification with coal, and hydrocarbon synthesis from syngas. However, few of the research groups involved have biomass gasification as their main focus, with most being more active in pyrolysis, combustion, or co-firing with fossil fuels.

The groups (outside Supergen) with more of a focus on gasification technology development, and current projects, are gasifier development at Newcastle University and the University of Ulster, and syngas cleaning at the University of Nottingham. There are also other groups modelling fluidised bed gasification, often building on their experience with coal.

All of the groups are shown in Table 13-4, with their current research activity. This table focuses on gasification and gas clean up technologies, rather than downstream uses of syngas such as engines and turbines, or chemical synthesis.

All of the groups are shown in Table 13-4, with their current research activity. This table focuses on gasification and gas clean up technologies, rather than downstream uses of syngas such as engines and turbines, or chemical synthesis.

Organisation	Main researchers	Topic
Aston University Bioenergy Research Group (BERG)[6]	Tony Bridgwater, Andreas Hornung	• Current projects focus on pyrolysis, and systems analysis involving thermal routes, but has expertise in gasification, with student working on fixed bed gasifier modelling
Cranfield University Energy Technology Centre[7]	Nigel Simms	• Leading gasification work in Supergen Bioenergy Phase II • Predominantly interested in materials impacts of biomass use in current and new power systems
Imperial College London Energy Engineering Group[8]	Klaus Hellgardt, Nigel Brandon	• Gasification of coal and biomass – simulation of large scale reactors at bench scale. Techno-economic analysis of waste gasification • Use of biomass syngas in SOFC
Newcastle University Process intensification and miniaturisation[9]	Galip Akay	• Has a pilot gasifier, and spun out ITI energy, who have a gasifier at 1.5MW$_e$. Now working on equipment for syngas cleaning, high-temperature H_2 separation, and fuel synthesis
Sheffield University SUWIC[10]	Jim Swithenbank	• Mostly focused on waste combustion and pyrolysis • Various projects on modelling of lab scale systems, molten metal biomass gasification, ammonia synthesis gas production, two stage small scale gasification with a gas clean up system using biomass char, and hot gas cleaning for coal gasification
UCL[11] Chem. Eng	Stefano Brandani Paola Lettieri	• Modelling fluidised bed gasification of waste and biomass

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[6] Bioenergy Research Group at Aston http://www1.aston.ac.uk/eas/research/groups/berg/
[7] Nigel Simms profile http://www.cranfield.ac.uk/sas/aboutus/staff/simmsn.jsp
[8] Imperial College London http://www3.imperial.ac.uk/chemicalengineering/research/researchthemes/researchfocusareas/enge
[9] Newcastle University http://research.ncl.ac.uk/pim/index.htm
[10] SUWIC group http://www.suwic.group.shef.ac.uk/
[11] UCL http://www.ucl.ac.uk/chemeng/staff/brandani

Organisation	Main researchers	Topic
University of Cambridge[12] Chem.Eng. and Biotechnology	John Dennis	- Modelling and control of fluidised bed gasifiers, physics of fluidisation, emissions control
University of Leeds Energy and Resources Research Institute[13]	Jenny Jones, Paul Williams	- Mostly interested in biomass behaviour in combustion and pyrolysis processes, in pyrolysis of wastes and biomass - Work on hydrothermal gasification
University of Nottingham[14] Institute of Sustainable Energy Technology	Hao Liu	- Syngas cleaning technologies (mop fan and electrofilter, and a combined system) - Process simulation of biomass CFB gasification/combustion and work on other biomass and coal combustion systems
University of Ulster Centre for Sustainable Technologies[15]	Dr McIlveen-Wright	- Testing of downdraft gasification (3 systems), biomass CFB gasification and comparison with co-gasification, and use of syngas on power generation

Table 13-4: UK academic research in gasification technologies

13.9.2 Gasifier developers

There are several relatively early stage developers of down-draft and up-draft wood gasifiers for heat and power applications in the UK, and companies proposing larger waste to energy systems fuelled by MSW. However, many of these have faced difficulties during the 2008-2009 financial recession, with few projects going ahead, and those developers still remaining still face an uncertain future.

Furthermore, the UK does not have any developers with large-scale (CFB, BFB, Dual or EF) biomass gasifier technology – an important shortcoming compared to e.g. the US, Canada, Japan, Sweden, Finland, Germany, Austria and the Netherlands, who each have several large-scale gasifier developers, The main focus is currently on higher value biofuel applications, although there are bioSNG and BIGCC demonstrations going ahead.

The UK does not have any particularly distinctive capabilities in woody biomass processing or pre-treatment, and globally, numerous large engineering firms supply sizing and drying equipment; e.g. Andritz, Foster Wheeler, Siemens.

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[12] University of Cambridge http://www.ceb.cam.ac.uk/people.php?action=view&id=9
[13] University of Leeds http://www.engineering.leeds.ac.uk/erri/research/renewable.shtml
[14] University of Nottingham http://www.nottingham.ac.uk/Engineering/People/liu.hao
[15] University of Ulster http://www.cst.ulster.ac.uk/index.php and http://www.openlivinglabs.eu/pdfs/cst.pdf

Company	Focus	Details
Innovation Technologies (Ireland) Ltd	Downdraft +ICE	• Small engineering company making specialist equipment including research/ demonstrator downdraft gasifier systems at 10-70 kWe
Biomass CHP Ltd	Downdraft +ICE	• Demonstration plant in Northern Ireland based on wood at 200kWe, 300kWe plant being built • Formerly Exus Energy, formerly B9
Envirothermal	Multi-directional fixed bed	• Currently undergoing university testing, small demonstration prototype to be built in Poole, Dorset • Part of the Aerothermal Group
Rural Generation	Downdraft for heat and CHP	• Biomass heating company with a downdraft moving bed gasifier technology
Graveson Energy Management	"Thermal cracking" to CHP-ICE	• Original 1997 UK test facility in Port Talbot, South Wales re-built, 1 further plant built in US in 2007 • Describe their process as pyrolysis but produces syngas at 850°C
ITI Energy	Downdraft gasifier CHP-ICE	• Spun out of Newcastle University • 1 plant installed since 2006, 2 permitted, 2 under development, using RDF at 33–55odt/day
Energos	Updraft fluidised bed + ICE	• 7 units in operation operating since 1997 on MSW, at 30–240 odt/day. 3 planned plants in Norway, Germany and the UK
Ethos Energy	Pyrolysis with gasification of char, to heat	• 1 unit since 2001, 2 units scheduled for 2009, 4 mobile units planned for 2010, running on MSW at 2–300odt/day
Wellman Process Engineering		• Previous experience with MSW gasifiers– currently active in waste separation and treatment technology but not apparent gasification activity
JND Ltd		• Thermal technologies supplier, including an indirectly heated rotary kiln gasifier for wastes
Conversion & Resource Evaluation Ltd (CARE)		• Provides technical and economic services in thermal biomass conversion, including gasification.

Table 13-5: UK gasification developers

13.10 References

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14 Gasification with catalytic methane synthesis

14.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into methane. Gasification is used to thermo-chemically convert the feedstock into syngas, which is then catalytically converted into methane, before compression for gas grid injection or use in natural gas vehicles, as shown in Figure 14-1. Heat and power are also commonly produced as valuable by-products. E4tech (2010) give a good overview of the whole route.

'bioSNG' simply denotes that the methane is biomass-derived. Note that bioSNG is a **gas** at room temperature and pressure, not a liquid.

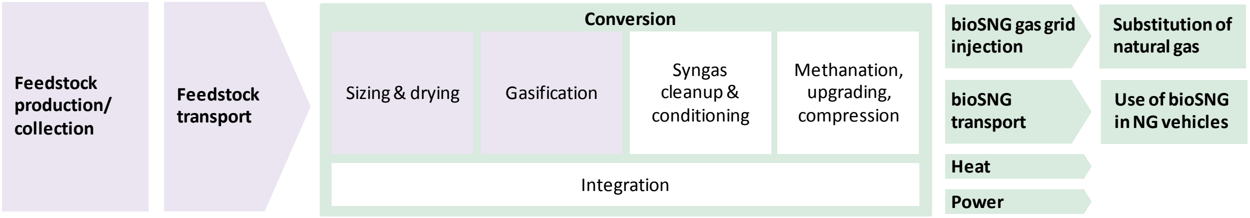

Figure 14-1 Process schematic for production of bioSNG

The bioSNG route shares many similarities with that of biomass to FT liquids, including suitable gasifier types and syngas quality requirements, and only differs significantly in the final synthesis step (and hence the resulting end products). E4tech (2010) give a good overview of the whole route. Each of the main process steps is described below.

14.1.1 Sizing & drying and Gasification

Given the downstream demands for methanation synthesis, and multiple gas cleanup steps, the avoidance of nitrogen is required. Although several gasification technologies exist (E4tech, 2009), only one type, the indirectly-heated dual fluidised bed gasifier, has been so far considered for integration with a downstream methanation process. This specific technology is particularly suited for the production of bioSNG, since its syngas has a high percentage of methane, a high H_2/CO ratio and no nitrogen dilution – favourable characteristics for subsequent methanation in comparison with other gasifier types.

Although there is no inherent reason why other gasifier types (such as entrained flow or oxygen-blown circulating fluidised bed gasifiers) could not be used for bioSNG production, these gasifiers have lower theoretical biomass-to-bioSNG efficiencies compared to an indirectly heated dual fluidised bed gasifier (van der Meijden, 2009). The indirectly heated Dual fluidised bed gasifier is described in more detail in the separate Gasification chapter, along with the feedstock sizing and drying requirements.

14.1.2 Syngas cleanup and conditioning

Gas cleaning and conditioning for methanation requires similar equipment to that for FT synthesis, although the FT process in general has tighter specifications for removal of nitrogen compounds, alkaline metals, tars and particulates. The discussion below only highlights those points where the processes steps and equipment differ significantly. For the rest of the cleaning steps not mentioned here, please refer to the FT synthesis chapter, or see Kopyscinski et al. (2010).

Water-gas-shift (WGS) reaction:

In the methanation reaction, three molecules of H_2 are consumed for each CO molecule. Although methanation catalysts exhibit some water gas-shift activity that will produce H_2 in-situ, the gas exiting a dual gasifier is usually only at a H_2/CO ratio of between 1 and 2. As a result, developers prefer to add an additional water-gas shift step upstream of the methanation reactor, in the gas cleaning stage. This water-shift reaction also has the added benefit of preventing downstream soot formation by lowering the gas H/C ratio (ECN, 2010).

Methane reforming:

Methane reforming is not used, since methane is the desired end product.

Removal of inert gas fractions – mainly CO_2:

Given that large amounts of CO_2 are produced during methanation, this step is usually only carried out after methanation (as upgrading), and not before.

Compression:

Depending on the operating pressure of the gasifier and cleanup equipment, (further) gas compression may be required to meet the specifications of the downstream catalytic synthesis.

14.1.3 Methanation, upgrading

Synthesis:

In the methanation process, the pressurised syngas is processed together with steam and a catalyst within a methanation reactor. This can be done at pressures typically ranging from 5 to 60 bar, and at a moderate temperature (<400°C). During the process, most of the hydrogen, carbon monoxide, and ethylene in the syngas is converted into methane and carbon dioxide.

The overall process is highly exothermic, and so large amounts of heat are also generated (more than in, for example, FT synthesis). Thermodynamically, low temperatures and high pressures are the preferred conditions for methanation. However, achieving low, constant reactor temperatures by the controlled removal of heat is difficult, due to the heat transfer and catalyst properties. Furthermore, low temperatures and high pressures increase the risk of carbon formation, leading to catalyst deactivation by deposition – although the introduction of steam can reduce this risk (Deurwaarder , 2005).

Upgrading:

The gas mixture exiting the methanation reactor is cooled down to around 30°C, which allows for condensed water to be separated from the gases. If the methanation process is operated at high pressures, this water will still contain dissolved methane; this can be extracted, and then either burnt in the gasifier combustion zone, or be pressurized and recycled in the methanation process. The dried gas is now mainly composed of CO_2 and CH_4 in similar proportions.

In order to be injected in the natural gas network, the methane-rich dry gas mixture must be purified to obtain bioSNG, i.e. as much CO_2 as possible must be extracted with minimal CH_4 losses and minimal energy consumption. Various techniques are commercially available for CO_2 separation in a methanation plant, such as physical absorption in a solvent, pressure swing adsorption, or removal using dedicated membranes.

14.1.4 Integration

BioSNG plants tend to be heavily integrated, since the catalytic methanation reaction occurs at high pressures, and is highly exothermic. This waste heat can be recovered by the generation of steam, to either input into the gasifier (indirect heating), used for biomass drying or the methanation reactor. However, there will normally be excess heat remaining, as well as heat from the syngas cleaning and purification steps. Because there is an onsite demand for power, planned projects include combined cycle turbines and other equipment to recover waste heat from these conversion steps, and generate electricity. How much heat is available, and power is generated, depends on the overall system integration.

14.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Dual fluidised bed gasifiers. In summary, given the limited number of developers, it is very likely that clean wood (forestry residues, short rotation coppice, etc.) will be the only feedstocks used for commercial bioSNG production out to 2020. Alternative feedstocks (e.g. municipal solid waste, miscanthus) may be used in the longer term if the technology proves robust enough to these more difficult feedstock types.

14.3 Technical and environmental characteristics

14.3.1 Scale

Unlike FT and other catalytic liquid fuels synthesis processes, methanation is commercially viable at much smaller scales, i.e. the synthesis step does not impose a strict minimum economic scale for the plant. Future developments such as process intensification could also be applicable to bioSNG production, i.e. allow even smaller plants (Velocys, 2011).

The size of the first commercial plants will be about 20 MW_{bioSNG}, although future plants are expected to fall in the range 30-100 MW_{bioSNG}, with plants up to 200 MW_{bioSNG} even envisaged. These scales are primarily as a result of constraints on the size of the dual gasifiers currently used, although switching to other high pressure gasifier types could allow larger plant scales. It may be difficult to use modular gasifier systems for bioSNG, as a result of the existing complexity of process integration. IEA (2010) model a small-scale plant at 23 MW_{bioSNG}, and a large-scale plant at 170 MW_{bioSNG}.

14.3.2 Efficiency

As mentioned above, the amount of heat recovered, the degree of biomass drying, and amount of steam and electricity generated depends on the design configuration of the bioSNG plant, as well as the operating conditions. These factors also have a large impact on the efficiency of conversion of biomass to bioSNG, potential energy exports, and on the plant economics.

The different technology developers and projects are considering different plant configurations, listed below. It is important to note when considering the efficiency of bioSNG production that these are generally based on lower heating value (LHV), and so vary depending on the moisture content of the feedstock used: the LHV efficiency increases when wetter feedstocks are used. ECN's commercial scale plants are expected to use an efficient steam cycle, importing no power, and exporting no heat. This would mean minimal co-product output, and a biomass to bioSNG efficiency of up to 70% (using 25% moisture content feedstock)

- The Gazobois project modelled a $30MW_{bioSNG}$ output, with $2MW_{th}$ heat and $0.7MW_e$ power also available for export. In this base case, the raw biomass-to-bioSNG efficiency is 74% (using 50% moisture content feedstock), and overall process efficiency 80%, although different efficiencies can be achieved in other configurations
- The GoBiGas project plans to operate at a biomass-to-bioSNG efficiency of 65-70%, using pellets at 10% moisture content; however, this does not include $2.5MW_e$ of imported electrical power alongside the $32MW_{th}$ biomass fuel input. They quote an overall efficiency of above 90% for the conversion of input biomass & power into output bioSNG & heat, since most of the waste heat will be recovered for use in a neighbouring co-generation plant and district heating scheme (Burman, 2010).

In general, a self-sufficient bioSNG plant can be configured to maximise bioSNG output to around 70% efficiency (with feedstocks at around 25% moisture content), with minimal co-products. This is significantly higher than FT synthesis plants, since the raw syngas already contains a proportion of methane, and because methanation is highly energy efficient (around 85% from input syngas to output methane) compared to FT and alcohol synthesis reactions (typically nearer 60% syngas to desired liquids) (E4tech, 2007) (E4tech, 2009).

14.3.3 GHG emissions

Most emissions within the bioSNG route are as a result of the upstream feedstock cultivation, use of fertiliser, harvesting and transport stages (using fossil fuel inputs). There are some emissions within the conversion plant itself, including the release of methane and other off-gases from the gas cleaning steps, or use of fossil fuel backup (Jungbluth et al. 2007).

However, in general, emissions of the conversion process for bioSNG from lignocellulosic feedstocks are relatively low, as a result of the excess heat from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. The net surplus of electricity and heat exported from the plant can also be given a credit for displacement of other electricity generation.

In the context of the EC RED methodology, net GHG emissions savings versus domestic or commercial fuel oil or natural gas heating are always less that 100%, as reference systems are excluded. Even so, analysis by North Energy (2010) shows that net GHG emissions savings for all woody biomass feedstocks are higher than 84%, apart from wood pellets from

UK arboricultural arisings, and some imported forest residues and clean wood processing wastes. UK miscanthus chips and bales, switchgrass bales and straw bales generate net GHG emissions savings higher than 74%. Alternatively, when comparing the net GHG emissions savings of using bioSNG for transport versus diesel or petrol, GHG savings range from 71% to 94% dependent on the feedstocks used, with most values gathered around 85% - 90% (North Energy, 2010).

Overall, bioSNG routes are estimated to have GHG savings of 35-90% compared with natural gas (IEA, 2011), depending on the feedstock and process use, and excluding any indirect land use change impacts. This is based on a UNEP and IEA review of 60 LCA “Well-To-Wheel” studies.

DBFZ (2011) give a range of 17 – 38.8 gCO_2e/MJ fuel currently (which equates to 73% - 37% saving), reducing to 10-23 gCO_2e/MJ (84%-63%) in 2030, and 10-20 gCO_2e/MJ (84%-68%) in 2050. These compare to a natural gas baseline of 62.0 gCO_2e/MJ (AEA, 2009).

Reference	**GHG emissions (gCO_2e/MJ fuel)**	**GHG savings (% vs. natural gas baseline)**
North Energy (2010)		Most feedstocks 84% - 90%, some >71%
IEA (2011)		35% - 90%
DBFZ (2011)	17 – 39 today 10 – 23 in 2030 10 – 20 in 2050	73% - 37% today 84% - 63% in 2030 84% - 68% in 2050
Fossil natural gas baseline (AEA, 2009)	*62.0*	

Table 14-1: Range of GHG emission savings from bioSNG compared to natural gas

14.4 Costs

There are no commercial bioSNG plant designs currently in existence that can serve as a replicable model for the economic analysis in this study. To date, the most advanced process design is that of the 1 MW_{bioSNG} demonstration plant in Güssing (Austria). This is the design that was used as the basis for the Gazobois feasibility study (E4tech, 2007), on which we based our economic analysis in E4tech (2010).

The capital costs for a 30 and a 100 MW_{bioSNG} plant built in the UK in 2018 are estimated to be £53.9m and £117.9m (in 2011 £), respectively, for a first-of-a-kind plant. This corresponds to specific cost of £1.8 and £1.2 million per MW_{bioSNG} of capacity, which shows that economies of scale have a significant impact on the capital intensity. The plant capex is primarily dominated by the gasifier and methanation reactor that, together, account for about three quarters of the investment costs.

As there are no commercial bioSNG projects, very little data exists in the public domain for comparison. The one commercial data point available is the quoted €170m total investment cost for the GoBiGas project (Nordic Energy Solutions, 2009), equivalent to £148m. Running our economic analysis for first-of-a-kind plants at the same scale (20 + 80 MW_{bioSNG}) gives very similar costs, of £144m. Zwart et al (2006) estimated that a 100 MW_{th} plant, producing

68 MW_{bioSNG}, would cost €85m. Converting this to UK (2011) prices, with the corresponding index increases in engineering project costs, gives a plant cost of £94m, again, similar to our costs (£91m) for a first-of-a-kind plant at this scale.

The annual operating cost, excluding feedstock, for a 30 or 100 MW_{bioSNG} plant is estimated to be £2.5m/yr and £4.7m/yr respectively, which represents 5.5% and 4.7% of the capital cost. Current bioSNG production costs are therefore estimated at £15.9/GJ for a 30MW_{bioSNG} plant, and at £14.2/GJ for a 100MW_{bioSNG} plant. Large plants taking more imports only have slightly lower production costs than small plants only taking local UK feedstocks, as economies of scale were modelled to be partially offset by an increased average feedstock cost. These costs are very similar to the current bioSNG cost estimates given by IEA (2011).

Costs are projected to decrease considerably in the future, both as a result of scale up and learning of plant, and from innovation, particularly through synthesis process intensification, novel gas cleanup, and experience with efficient plant integration. IEA (2011) projects production cost reductions from the current $0.9/lge (£15.8/GJ) to $0.84-0.95/lge in 2020 (£14.6-16.5/GJ), and $0.68-0.81/lge in 2050 (£11.8-14.1/GJ).

Reference	Scale (MW_{bioSNG} output)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
E4tech (2010)	30 100 20 + 80 68	54 118 144 91	2.5 4.7	14.5 13.3
Nordic Energy Solutions (2009)	20 + 80	148 total		
ECN (2006)	68	94		
IEA (2011)				~15.8 today 14.6 – 16.5 in 2020 11.8 – 14.1 in 2050

Table 14-2: Range of bioSNG economic data

14.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

For **downstream** vehicle applications, requirements are the same as set by natural gas vehicles - i.e. specific vehicle engines, fuel storage, refuelling and delivery infrastructure are required. For downstream injection into the UK gas network, bioSNG must comply with a range of specific thermodynamic and chemical properties, including those set out in the Gas Safety (Management) Regulations 1996 (GS(M)R), plus any other specific requirements set by the local Gas Transporter. The GS(M)R parameters, shown in Table 14-3, are very similar to the harmonised values across the rest of Europe (EASEE-gas, 2010).

Criterion	Requirement	Comments
Hydrogen Sulphide	< 5mg/m^3	
Total Sulphur	< 50mg/m^3	
Hydrogen	< 0.1% (molar)	Original syngas is H_2-rich, any left over after the methanation process is recycled. Danish Gas Technology Centre is investigating transmission of high H_2 blends
Oxygen	< 0.2% (molar)	National Grid and Ofgem discussing changes to relax limit to 1% to support biomethane injection. Sweden allows 1%, Germany 3%
Hydrocarbon Dewpoint	< -2°C at any pressure	
Water Dewpoint	< -10°C at 85 bar	
Wobbe Number[16]	47.20 to 51.41 MJ/m^3 (real gross dry)	Important range, to meet gas-air burning safety requirements for UK appliances
Incomplete Combustion Factor	< 0.48	
Soot Index	< 0.60	
Gross Calorific Value	36.9 to 42.3 MJ/m^3 (real gross dry)	Subject to location and volumes, injectors might be set a target within this range. BioSNG can have a lower CV, which may need to be corrected for by adding propane, or through future smart metering/billing
Carbon Dioxide	< 2.5% (molar)	Gas after methanation is mostly methane and CO_2, majority of the CO_2 must be removed
Contaminants	No liquids or solids	
Organo Halides	< 1.5 mg/m^3	
Radioactivity	< 5 Becquerels/g	
Odour	Must have a distinctive and characteristic odour at <7bar	
Pressure	> back pressure at Delivery Point, < maximum operating pressure	
Temperature	1 to 38°C	

Table 14-3: Gas quality requirements for injection into the UK gas grid (National Grid, 2008) (Airtricity, 2008)

14.6 Deployment and development status

Both gasification and methanation processes involve mature technologies, already used at large scale for fossil fuel feedstocks. Methanation has been intensively investigated in the past, in particular methane production from coal, although this was not followed by commercial developments (with the exception of Sasol in South Africa) due to the lack of market incentives in the 1990s. Many of the other plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, syngas cleanup.

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[16] Defined as the ratio between the lower heating value of the gas mixture and the square root of its specific density, i.e. the calorific value of the quantity of gas that will flow through a hole of a given size in a given amount of time. The Wobbe number is an indicator of the interchangeability of fuel gases, since appliances and boilers are designed to have particular gas nozzle combustion properties, and hence can only safely operate within a Wobbe number range

However, biomass gasification using a Dual gasifier is only at the demonstration and early commercial stage (TRL 6-7), with a handful of power plants built in Europe and the US, and there is limited experience in integrating biomass gasification with downstream processes, either for the production of liquid fuels via a Fischer-Tropsch process or gaseous fuels via methanation. Further work is needed to determine and optimize plant configurations that will be technically and economically viable. Other components and future alternatives are only at pilot scale, such as novel hot gas cleanup, and micro-channel fuel synthesis reactors. Plant integration experience is in line with the overall route, i.e. TRL 5.

To date, only two designs of Dual gasifier technologies have been developed in combination with downstream methanation: a large Austro-Swiss consortium led by REPOTEC and CTU, and ECN. These developers have each been working on bioSNG for about eight years, along with other projects. Other developers could enter the market, and may have shorter development timescales if they had existing capabilities in gasification or downstream technologies.

The Fast Internally Circulating Fluidised Bed (FICFB) gasifier technology developed by REPOTEC and CTU is at the pilot stage (TRL 5):

- 1MW$_{\text{bioSNG}}$ pilot plant operating since 2009 in Güssing, Austria (Novatlantis, 2010) as part of the EU 'bio-SNG' project
- First commercial-scale plant 'GoBiGas' in Göteborg, Sweden is expected to come online at 20 MW$_{\text{bioSNG}}$ in 2013, with a second 80 MW$_{\text{bioSNG}}$ phase in 2015/2016 (Göteborg Energi, 2009). Göteborg Energi working with Metso and E.ON
- ~12 MW$_{\text{bioSNG}}$ GAYA EU demonstration project, with GDF Suez and 11 other partners, operational by 2014 (Mambré, 2010)
- Possible ~20MW$_{\text{bioSNG}}$ Gazobois plant in Eclépens, Switzerland (E4tech, 2007)
- E.ON are also planning a 200 MW$_{\text{bioSNG}}$ plant (Bio2G) for 2015, along with future aspirations for a 300 MW$_{\text{bioSNG}}$ plant and two 600 MW$_{\text{bioSNG}}$ plants by 2020 (Jönsson, 2010) depending on the success of GoBiGas and Bio2G

The "MILENA" gasifier developed by the Energy Research Centre of the Netherlands (ECN, 2010) (van der Meijden, 2009) is currently at a lab scale (TRL 4):

- Lab-scale test rig operating since 2004, and current pilot plant is only producing syngas for CHP applications
- Future plans to work with HVC in the Netherlands to build a 10 MW$_{\text{th}}$ CHP demonstration by 2012, and then a 50 MW$_{\text{bioSNG}}$ integrated demonstration in 2015

There is also small-scale reforming heat-pipe work ongoing at the Technical University of Munich, which has been spun-out into a company, Agnion. They are targeting bioSNG, CHP and hydrogen applications at the ~1MW scale, but currently only have one CHP pilot plant (Agnion, 2011), and biomass to syngas efficiencies appear low (~70%), i.e. biomass to bioSNG efficiencies might only reach 60% at these small scales.

14.7 Barriers to development and deployment

Barriers generic to all biomass gasification routes are given in the Gasification chapter. The technical feasibility of bioSNG production appears to have been proven for the REPOTEC-

CTU technology. According to ECN, the main technical challenges for bioSNG remaining lie in (Zwart, 2009):

- the scale-up to commercial size, especially gasification and tar removal
- demonstrating and optimising the critical gas cleaning steps for removing unsaturated hydrocarbons, tars and organic sulphur found in real gases, i.e. beyond the existing limited testing at lab and pilot scale
- optimising methanation catalysts to handle specific contaminants (sulphur, unsaturated and saturated hydrocarbons), and conducting long-term testing for increased bioSNG efficiency
- the optimisation of plant configurations / the overall system to ensure each plant will be technically and economically viable

There are several barriers to bioSNG plant deployment in the UK that are not present for biomass to power or most fuels routes, because bioSNG technology is further from commercial development. These are the implementation of stable long-term policy support, accessing sizable heat markets for the co-generated heat, and the need to test proposed grid access arrangements (e.g. license exemptions, CV adjustments, relaxed oxygen specifications). Given that these barriers are currently being addressed, they may not exist by the time a bioSNG plant might be built in the UK. The other potential barriers are common to other large bioenergy plants: access to reliable, low cost supplies of sustainable feedstocks, project finance, plant siting, and markets for co-produced heat. Several of these may decrease in importance as other bioenergy technologies are deployed in the UK over the next few years, as feedstock supply markets build up, confidence is gained in assessing project finance risks, sustainability criteria and policy are developed and implemented, and familiarity with siting issues increases. However, they are likely to remain to a certain extent, as a bioSNG will be a new type of plant with its own particular risk profile, feedstock needs, and siting requirements.

14.8 UK Capabilities

Given the similarities between FT synthesis and bioSNG routes, the FT synthesis chapter already covers the discussion of UK capabilities in sizing, drying, gasification and syngas cleanup and conditioning steps.

Commercial methanation catalysts are available from companies such as Johnson Matthey, Sud-Chemie and Haldor Topsøe. The UK is considered a key player in catalysts and novel intensification technologies (with Johnson Matthey and Oxford Catalysts' Velocys), although is mainly focused on FT catalysis, not methanation.

Integration is typically carried out by technology developers/consortia, and EPC contractors conduct FEED studies and installation. Although there are no existing UK plants or projects in planning, there has been a recent increase in UK interest in bioSNG, and more generally, biomethane injection. Several organisations and projects have contributed to the debate surrounding new policy developments, technologies, costs and resource potentials. These interested stakeholders are listed in Table 14-4 below.

Although some of these organisations have links with existing projects elsewhere in Europe, the location and association of these stakeholders are unlikely to mean that one bioSNG technology type is more likely to be used in the UK than any others.

Organisation or Project	**Type**	**Location**	**Interest**
National Grid	UK gas network operator	UK	Understanding impact that a bioSNG plant would have on the gas grid, ensuring gas quality requirements met. Produced UK Renewable Gas potential report (National Grid, 2009)
Integrated Biomass to Syngas Project	Project	North East England, Teeside	Looking to establish a commercial supply chain & make 1m tonnes of synthetic biofuel products and chemicals by 2020, starting in stages from 2012. First step will be a 50MW_{th} CHP demo, with development options (North Energy, 2009)
Renewable Energy Association	Industry representative	Members UK wide	Originally suggested RHI principle of equivalence, but now favour a fixed biomethane injection tariff mechanism. Also run industry stakeholder workshops
E.ON	Utility	European	Have anaerobic digestion biomethane injection projects in Europe. 20% stakeholder in the GoBiGas project (Waldheim, 2009), also looking to build their own larger plants

Table 14-4: UK capabilities, projects and stakeholders

There are also general UK capabilities relevant to bioenergy projects that could support the development of a UK bioSNG plant, and may influence the likely location of early plants. Whilst plant engineering and design, component manufacture is likely to be led by the technology developers themselves, together with existing (non-UK) partners for early plants, UK companies could be involved in installation, e.g. site development, and in some aspects of operation e.g. feedstock transport and handling. It may be beneficial to site plants near existing capabilities in engineering and utilities, such as the chemical industry clusters in Teesside, the Humber, Runcorn and Grangemouth. All of these areas have planned biomass power plants, waste to energy plants, or feedstock supply chains in place.

14.9 References

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15 Gasification with catalytic dimethyl ether synthesis

15.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into dimethyl ether (DME). Gasification is used to thermo-chemically convert the feedstock into syngas, which is then catalytically converted into DME, as shown in Figure 15-1 below. ‘bioDME’ simply denotes that the DME is biomass-derived.

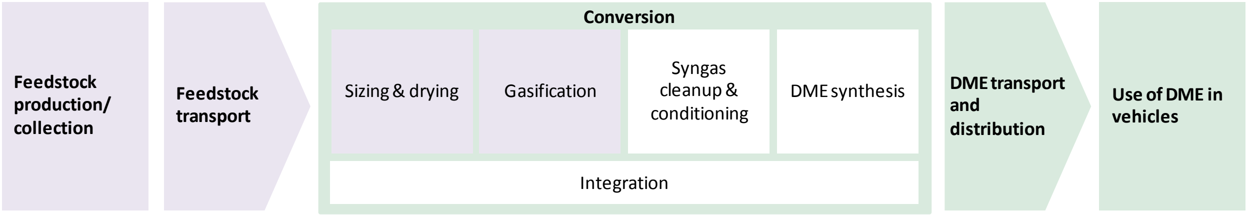

Figure 15-1 Process schematic for biomass gasification + DME production

Dimethyl ether (CH_3OCH_3) is a colourless **gas** at room temperature and pressure. The largest current use of DME is as a substitute for propane in LPG (liquefied petroleum gas), which is used as fuel in households and industry, for example in China (IDA, 2010). DME has two other primary applications: as a propellant in aerosol canisters, and as a precursor to dimethyl sulphate (a chemical used for the methylation of phenols). DME can also be used as a diesel engine fuel, and as an alternative starting chemical in the methanol-to-gasoline (MTG) process.

The biomass to DME route is almost identical to that of biomass to methanol synthesis, and shares many similarities with that of biomass to FT liquids, including suitable gasifier types and syngas quality requirements, and only differs significantly in the final synthesis step (and hence the resulting end products). A good description of the overall route is provided by Ekbom et al. (2005). Each of the main process steps is described below.

15.1.1 Sizing & drying and Gasification

Given the downstream demands for DME synthesis, minimum economic scales, and multiple gas cleanup steps, the avoidance of nitrogen is required, and operating at elevated pressures is also advantageous. The gasifiers chosen are therefore most likely to be oxygen or steam blown, pressurised fluidised bed gasifiers (i.e. Bubbling, Circulating and Dual fluidised bed gasifiers), or Entrained flow gasifiers. These have the ability to achieve very large scales, and meet the minimum economic scale for methanol synthesis.

The suitable gasifier types are described in more detail in the separate Gasification chapter, along with their sizing and drying requirements.

15.1.2 Syngas cleanup and conditioning

The optimum H_2/CO ratio for DME synthesis is lower than that for methanol synthesis and ideally should be around one. Except for this point, gas cleaning and conditioning for DME synthesis is identical to that of methanol synthesis - please refer to the methanol synthesis chapter.

15.1.3 DME synthesis, upgrading

Synthesis:

Commercial production of DME originated as a by-product of high-pressure methanol production. DME was originally formed in a two-step process (using two separate reactors), where first methanol is synthesised at high temperatures (220-275°C) and pressures (50-100bar), then dehydrated over an acid catalyst such as γ-alumina at the same methanol synthesis conditions. The DME reaction scheme only uses a few simple reactions:

Methanol synthesis:	$CO + 2\ H_2 \rightarrow CH_3OH$
Methanol dehydration:	$2\ CH_3OH \rightarrow CH_3OCH_3 + H_2O$
Water gas shift:	$H_2O + CO \rightarrow H_2 + CO_2$

Note that one product in each reaction is consumed by another reaction. These three reactions therefore combine to form a net reaction of:

$$3\ H_2 + 3\ CO \rightarrow CH_3OCH_3 + CO_2$$

Improvements to the DME synthesis process in the late 1990's involved the development of bi-functional catalysts to produce DME in a single gas phase step (i.e. one reactor) and the use of a slurry reactor for liquid phase DME synthesis – i.e. DME can now be produced directly from syngas, without the intermediate methanol step.

Because of the synergy between the DME synthesis reactions, syngas conversion to DME occurs at a significantly higher conversion rate than methanol synthesis – per pass DME conversion rates of 50%-60% can be achieved (compared to 14%-40% for methanol under the same process conditions). This leads to a smaller volume of unreacted syngas for recycling, and hence a more compact plant design (Ohno et al. 2001).

Depending on the process conditions, reactor type, and input syngas composition, total syngas to DME conversion rates can exceed 95% with only modest recycling. As with methanol synthesis, catalyst selectivity is very high (>99.5%), i.e. very few by-products are synthesised.

Upgrading:

At pressures above ~5bar, DME is a liquid, hence under the DME synthesis conditions described above, DME is produced in liquid form. Therefore, the product upgrading of the obtained alcohol and liquid DME mixture consists typically of de-gassing, drying and separation into 2 streams: DME and alcohols (for recycling). However, this separation step is very simple in comparison to FT or mixed alcohol routes, since after degassing, a reduction in pressure leads to DME becoming a gas again, whilst any alcohols remain as liquid.

15.1.4 Integration

DME plants tend to be heavily integrated, since the catalytic DME synthesis occurs at high temperature and pressure, and is highly exothermic. This waste heat can be recovered by the generation of steam, to either input into the gasifier, use for biomass drying, district heating or additional power generation using a steam turbine. Gasification is an endothermic reaction, hence heat need to be supplied (either from the biomass, or externally).

As well as the heat flows and integration in the plant, there are also several loops and components that need careful integration – e.g. example DME reactor recycle loops, and the gasifier air separation unit heating and cooling requirements.

15.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Entrained flow, Bubbling, Circulating and Dual fluidised bed gasifiers.

15.3 Technical and environmental characteristics

15.3.1 Scale

Due to the very similar requirements in syngas clean up, recycling and exothermic heat management, the minimum economic scale for DME synthesis is expected to be similar to that of methanol synthesis (Haldor Topsøe, 2009), corresponding to 100kt/yr DME output, i.e. ~100 MW_{th} biomass input.

Future developments such as process intensification (as for FT) could reduce this to 20kt/yr output or ~20 MW_{th} biomass input (Velocys, 2011). This minimum economic scale determines which types of gasifier might be the most suitable for liquid fuels production – i.e. oxygen or steam blown, pressurised fluidised beds, or entrained flow gasifiers. This scale is either as a single gasifier, or combining a small number of gasifier modules. Modular systems may not have the same economies of scale as single systems, but could have benefits in terms of use of different feedstocks, and of availability.

The largest bioDME plants currently planned are at the demonstration scale of 95kt/yr output (Chemrec, 2011), although currently the largest plant operating is Chemrec's 1.8kt/yr pilot in Pitea, Sweden.

15.3.2 Efficiency

Biomass to DME efficiencies vary according to the gasifier, synthesis reactor, product recycling and feedstock types, and particularly the amount of co-products generated (heat and power). Overall plant efficiencies are expected to be higher than methanol synthesis, and significantly higher than for FT synthesis. Available efficiency values from the literature are summarised in Table 15-1, and discussed below.

Chemrec (2011) have stated that their process is able to achieve overall LHV efficiencies of 69% from black liquor to DME (with no power export), although this is with a very high level of steam and power integration with an adjacent pulp mill. This same plant concept and efficiency was also included in the RENEW modelling studies (Seyfried et al. 2008) (RENEW, 2007).

Ekbom et al. (2005) models the addition of a DME plant to an existing pulp mill, which requires the input of 408MW_{th} of additional biomass, and outputs 275MW of DME. This equates to a biomass to DME efficiency of 67%.

By comparison, Stark (2010) gives a range of 51% to 58% for overall biomass to DME efficiencies, assuming a biomass gasification efficiency of 80%, or alternatively a range of 66% to 69% if assuming a gasification efficiency of 90%.

Larson et al. (2007) consider three different black liquor pulp mill configurations with between 514MW$_{th}$ and 636MW$_{th}$ fuel input. Overall efficiency to DME, exported electricity and process steam is ~71% in all three concepts; however, the individual output efficiencies vary from 14%- 34% DME, 0%-18% net electricity and 31%-39% process steam.

Reference	LHV % efficiency
Chemrec (2011), Seyfried et al. (2008), RENEW (2007)	69%
Ekbom et al. (2005)	67%
Stark (2010)	51-58% or 66-69% depending on gasifier efficiency
Larson et al. (2007)	71% in total, but only 14-34% for DME, rest steam and power

Table 15-1: Range of LHV efficiencies from biomass to DME

15.3.3 GHG emissions

Most emissions within the biomass to DME route are as a result of the upstream feedstock cultivation, use of fertiliser, harvesting and transport stages (using fossil fuel inputs). There are some emissions within the conversion plant itself, including the release of off-gases from the gas cleaning steps, or use of fossil fuel backup (Jungbluth et al. 2007). However, black liquor (a by-product from paper production) counts as having zero life-cycle GHG emissions under the EU's RED, up to the process of collection as a feedstock for DME production. Using black liquor feedstocks is therefore likely to decrease the emissions of the DME route, due to the avoidance of upstream cultivation and harvesting emissions of woody biomass.

However, whether using woody or black liquor feedstocks, emissions of the DME conversion process are low, as a result of the high conversion efficiency, the excess heat from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. Any net surplus of electricity or process steam exported from the plant can also be given a credit for displacement of other power or heat generation.

CONCAWE, EUCAR & JRC (2006) give well-to-wheel GHG emissions of -1 to 4 gCO$_2$e/MJ of DME for black liquor, and 2 to 5 gCO$_2$e/MJ for farmed wood. The average values of 1.9 and 3.7 gCO$_2$e/MJ correspond to GHG savings versus fossil diesel of 98% and 96%, respectively.

Kittelson et al. (2010) and Chemrec (2011) state that DME from black liquor has the highest well-to-wheel energy efficiency and the lowest GHG emissions of any biomass-based fuel, quoting GHG emission savings of 95% versus fossil diesel.

15.4 Costs

There have only been a few techno-economic estimates of the cost of DME production from biomass, and most consider integrated DME plants using black liquor feedstocks, not standalone woody biomass to DME plants. Available costs from the literature are summarised in Table 15-2, and discussed below.

RENEW (2007) models a 500MW$_{th}$ biomass input DME plant alongside a pulp mill. This plant is estimated to have a total investment cost of £$_{2011}$ 463m, annual operating costs of £$_{2011}$ 52m/yr, and a DME production cost of £$_{2011}$ 14.5/GJ.

For a 286kt/yr output (275MW) DME plant added to an existing pulp mill, Ekbom et al. (2005) give a DME production cost of 10.6 €$_{2005}$/GJ (12.8 £$_{2011}$/GJ), assuming a biomass price of 3.5 €$_{2005}$/GJ, a total investment cost of €$_{2005}$ 360m (£$_{2011}$ 434m), and operating costs of €$_{2005}$ 35m/yr (£$_{2011}$ 42m/yr).

Larson et al. (2007) consider three different black liquor pulp mill configurations with between 514MW$_{th}$ and 636MW$_{th}$ fuel input. These costs have been subsequently used by Antares Group (2010). Total investment costs vary from £$_{2011}$ 252m to £$_{2011}$ 416m, with annual non-fuel O&M costs varying from £$_{2011}$ 10 – 16.6k/yr. The resulting production costs are £$_{2011}$ 9.8 – 16.6/GJ. The lowest costs are realised for a 518MW$_{th}$ input plant which only gasifies black liquor, burning the small amount of input woody biomass for process heat. This concept also optimises DME production, and produces no net electricity, since only a steam turbine is used instead of a more efficient, but more expensive, combined cycle unit. These costs are based on mature "Nth" plant estimates, have an error of ±30%, and have been converted using 1 US\$$_{2005}$ = 1 GB£$_{2011}$.

Scaling from the cost of production from natural gas, and using a feedstock cost of \$$_{2007}$ 2/GJ, Stark (2010) estimates a bioDME production cost of \$$_{2007}$ 14.6/GJ (£$_{2011}$ 8.6/GJ).

As for FT synthesis and lignocellulosic ethanol plants, current DME costs are likely decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through DME catalyst development, synthesis reactor process intensification, novel gas cleanup, and experience with efficient plant integration. Production costs could fall at a similar rate to those given in the FT synthesis chapter, although no studies have yet modelled this in detail.

Reference	Scale (MW$_{th}$ biomass input)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
Ekbom et al. (2005)	408	434	42	12.8
Larson et al. (2007)	518, no power out 636, power out 514, less DME out	251 416 324	10.1 16.6 13.0	9.8 12.8 16.6
RENEW (2007)	500	463	52	14.5
Stark (2010)				8.6

Table 15-2: Range of biomass gasification + DME economic data

15.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

Downstream of the process steps described, the DME needs to be compressed to around 5 bar to maintain it in a liquid form, and diesel engines require some modification to accept this pressurised fuel input.

15.6 Deployment and development status

The overall biomass to DME route is currently at the pilot stage (TRL 5). The majority of the plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, syngas cleanup and DME synthesis. However, some processes are only currently at pilot scale, such as pressurised O_2-blown biomass gasification, novel hot gas cleanup, and micro-channel fuel synthesis reactors. Plant integration experience is in line with the overall route, i.e. TRL 5.

There are only 2 known developers working on biomass to DME routes, with only 3 active projects, based in Europe (Bacovsky et al, 2010), (E4tech, 2010) (Biofuels Digest, 2011)

- Chemrec (Sweden): uses black liquor feedstocks from adjacent paper mills. 1.8kt/yr output Piteå pilot plant opened in 2010 (part of the EU project 'bioDME'), and 95kt/yr (40Mgy) output demonstration plant in Örnsköldsvik due to open in 2013 producing both methanol and bioDME
- bioliq (Germany): 0.4kt/yr output pilot plant at KIT starting in 2013, although some of the upstream plant steps are larger. Has been built in several stages, with $2MW_{th}$ fast pyrolysis followed by $5MW_{th}$ gasification and $2MW_{th}$ hot gas cleanup already installed, with downstream DME synthesis still to be added

15.7 Barriers to development and deployment

Barriers generic to all biomass gasification routes are given in the Gasification chapter.

DME can be used as a diesel replacement because it has a high cetane number. However, DME is a gas at atmospheric conditions, and needs to be pressurised for use in diesel engines. This requires engine and fuel system modifications to be made; this is the main disadvantage for DME use as a transport fuel, and the reason why initial testing in Sweden has focused on captive truck fleets (with Volvo). DME also cannot be blended with petroleum-based fuel.

Interestingly, NREL chose not to consider DME routes for further study within a biomass-to-liquids techno-economic analysis (Swanson et al., 2010), because of limited commercial scale experience and incompatibility with present fuel infrastructure.

DME also faces a lack of public and political awareness, or policy recognition. Using DME as a propane replacement faces a poor definition of typical propane appliance performance, and uncertainty about suitable DME/propane blend ratios. Since DME is not a 'drop-in fuel', there is also a problem of having to develop the required infrastructure and vehicle changes simultaneously: DME use cannot occur without production, but similarly, DME production is unlikely to occur without an end use and available fuel infrastructure.

15.8 UK Capabilities

Given the similarities between DME, methanol and FT synthesis routes, the FT synthesis chapter already covers the discussion of UK capabilities in sizing, drying, gasification and syngas cleanup and conditioning steps.

DME synthesis from fossil-derived syngas is a mature and well-developed process and many large industrial plants are under operation. The two-step process is offered by companies such as Haldor Topsøe, Lurgi, Mitsubishi Gas Chemicals, Toyo Engineering Corp and Uhde. The one-step direct process is offered by Haldor Topsøe, JFE and Kogas, and the liquid phase process is offered by Air Products. Although the UK is considered a key player in catalysts and novel intensification technologies (with Johnson Matthey and Oxford Catalysts' Velocys), the UK is mainly focused on FT catalysis, although has some methanol capabilities which could be adapted to DME in the future.

Other players with micro-channel reactor offerings could enter the market in the future, for example, KIT are conducting research specifically on methanol micro-channel reactors (Bakhtiary-Davijany et al. 2011) which could be adapted for DME production.

As for FT synthesis, integration is typically carried out by technology developers/consortia, and EPC contractors conduct FEED studies and installation. The UK does not have any existing or planned biomass to DME projects.

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16 Gasification with hydrogen production

16.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into hydrogen. Gasification is used to thermo-chemically convert the feedstock into syngas, which is then catalytically shifted and/or reformed into hydrogen, before compression for numerous potential downstream uses, as shown in Figure 16-1. Heat and power are also commonly produced as valuable by-products.

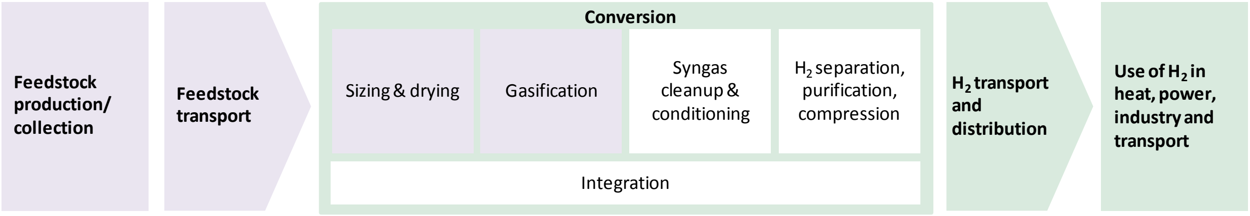

Figure 16-1 Process schematic for biomass gasification + hydrogen production

Hydrogen is a colourless gas with a boiling point of -253°C. Commercial bulk hydrogen is usually produced by the steam reforming of natural gas. Large quantities of H_2 are needed in the petroleum and chemical industries, with the largest current uses of H_2 being for the production of ammonia, fossil fuel refining and in the production of methanol.

The route shares many similarities with that of biomass to FT liquids, including suitable gasifier types and syngas cleanup, and only differs significantly by not having a final fuel synthesis step – instead H_2 is produced as a result of the syngas conditioning. Spath et al. (2005) give a good overview of the whole route. Each of the main process steps is described below.

16.1.1 Sizing & drying and Gasification

Given the multiple gas cleanup steps, the avoidance of nitrogen is required, and operating at elevated pressures is also advantageous. A high H_2/CO syngas ratio is also required in order to minimise downstream requirements.

The gasifiers designs chosen are most likely to be oxygen- or steam-blown pressurised fluidised bed gasifiers (i.e. Bubbling, Circulating and Dual fluidised bed gasifiers), Plasma gasifiers or Entrained flow gasifiers. These gasifier types are described in more detail in the separate Gasification chapter, along with their feedstock sizing and drying requirements.

16.1.2 Syngas cleanup and conditioning

Gas clean up and conditioning consists of using a tar reformer followed by syngas cooling, compression, sulphur removal, steam methane reforming (SMR), and high and low temperature water-gas shift (WGS) conversion. As there are many similarities with the process steps detailed in the FT synthesis chapter, the discussion below only highlights those points where the two processes differ significantly.

The syngas is cooled through heat exchange with the steam cycle and additional cooling via water scrubbing. The scrubber also removes impurities such as particulates and ammonia along with any residual tars. The excess scrubber water is sent off site to a waste-water treatment facility. Depending on the gasification pressure, and purification system used, the syngas can then be compressed using a multi-stage compressor with inter-stage cooling.

Prior to the PSA unit, any entrained water and condensed hydrocarbons must be removed, otherwise they will permanently damage the adsorbent. Cooling the product and installing a knock out drum with a mist eliminator prior to the PSA unit is usually sufficient – this is achieved using the syngas cooling and water scrubber mentioned above.

Steam methane reforming (SMR):

The syngas can contain a considerable amount of methane and other light hydrocarbons, representing a significant part of the heating value of the gas. Steam reforming (SMR) converts these compounds to CO and H_2, driven by the addition of steam over a nickel catalyst. The reformer is usually fuelled by the PSA off-gas, with a small amount of natural gas added for burner control. Upstream sulphur removal is essential to avoid catalyst poisoning.

Water gas shift (WGS) reaction:

Unlike liquid fuel catalysis routes (e.g. FT synthesis) which use WGS to control the CO / H_2 ratio to a desired value, the primary objective of the WGS within a hydrogen production route is simply to maximise the amount of H_2 produced. HTS and LTS reactors convert water (H_2O) and the majority of the remaining CO in the syngas into CO_2 and H_2, via the following reaction:

$$CO_2 + H_2O \rightarrow H_2 + CO$$

The equilibrium constant for the WGS increases as temperature decreases. Hence, to increase the production to H_2 from CO, it is desirable to conduct the reaction at lower temperatures, which is also preferred in view of steam economy. However, to achieve the necessary reaction kinetics, higher temperatures are required – this optimisation means that several WGS step designs are possible.

As mentioned below, ceramic membranes do not need a preceding WGS step, because the membrane surface is expected to have shifting capabilities.

16.1.3 H_2 separation/purification, compression

H_2 separation/purification, i.e. removal of inert gases

Pressure-swing absorption (PSA) is most commonly used to separate the hydrogen from the other components in the shifted gas stream, mainly CO_2, and unreacted CO, methane, and other hydrocarbons. PSA is based on the difference in adsorption behaviour between different molecules, separating components of a gas stream by selective adsorption to a solid at high pressure, and subsequent desorption at low pressure. This adsorption/desorption is in fact a batch process, but by placing two beds (usually activated carbon and a zeolite molecular sieve) in parallel, it operates nearly continuously.

The hydrogen purity achieved from a PSA unit can be greater than 99.99+%. However, the shifted gas stream must contain at least 70% hydrogen before it can be economically purified via PSA, since purification of streams more dilute than this decreases the product purity and recovery of hydrogen. This 70% limit will often require the recycling of some of the PSA product H_2 back into the input gas stream (with re-compression and cooling), leading to typical hydrogen recovery rates of 85% (Spath et al. 2005).

The minimum pressure ratio between the feed and purge gas of the PSA unit is about 4:1. The absolute pressures of the feed and purge gas are also important in regard to hydrogen recovery, since higher exit pressures lead to lower hydrogen recovery rates. The PSA efficiency is also affected by adsorption temperature. Fewer unwanted species are adsorbed at higher temperatures, because the equilibrium capacity of the molecular sieves decreases with increasing temperature. Therefore, integrated steam, air and water heat exchangers are used to cool the gas down to temperatures of around 40°C, to ensure that high absorption rates are achieved.

An alternative technology in development is the use of ceramic membranes for H_2 separation. These are potentially a very cheap and simple method of H_2 separation, with the added benefits of high temperature operation (efficiency synergies with hot gas cleanup), and possible in-situ WGS reactions (driving a chemical potential difference across the membrane and saving on upstream WGS costs). However, membrane temperature stability and current selectivity to which gases are able to permeate through the membrane is relatively poor, i.e. a pure H_2 product is not obtained (Hamelinck & Faaij, 2002).

Compression:

Depending on the end use for the H_2, and any intermediate transport and storage required (e.g. pipeline distribution), further compression may be required before the H_2 leaves the production plant, imposing another energy penalty.

16.1.4 Integration

Biomass to hydrogen plants tend to be heavily integrated, since the gas cleanup steps (reforming and WGS) occur at high temperature and pressures. This waste heat can be recovered by the generation of steam, to either input into the gasifier and reformer, use for biomass drying, district heating or additional power generation using a steam turbine. Gasification is an endothermic reaction, hence heat need to be supplied (either from the biomass, or externally).

In some plant concepts, syngas can also be diverted to generate power in a combined cycle gas turbine (although at greater capital cost) – this will likely significantly reduce the amount of hydrogen produced, but lead to a substantial export of by-product electricity.

16.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Entrained flow, Bubbling, Circulating and Dual fluidised bed gasifiers.

16.3 Technical and environmental characteristics

16.3.1 Scale

Due to the lack of downstream fuel synthesis step, the minimum economic scale for hydrogen synthesis is expected to be solely determined by the scale of the gasifier, and available biomass supply. Suitable gasifier types include pressurised fluidised bed, plasma or entrained flow gasifiers. These have a range of operation from between 3 and 150 MW_{th} biomass input for atmospheric pressure systems, or 40 to 2,000 MW_{th} biomass input for the pressurised systems.

Hamelinck & Faaij (2002) model various plant concepts, with pressurised oxygen-blown or indirectly heated steam gasification, hot or wet gas cleanup, with/without SMR, one or two step WGS, PSA or membrane H_2 separation, and steam or combined cycle power generation. The scale of the input biomass is 380 MW_{th} LHV in the base case analysis, with sensitivity values ranging from 71 to 1,767 MW_{th} biomass input.

Lau et al. (2002) model a range of plant scales from 83 MW_{th} to 367 MW_{th} biomass input, using bagasse, switchgrass or nutshell feedstocks. Plant concepts of 833 MW_{th} biomass input are also mentioned, but not modelled in detail.

Spath et al. (2005) model a plant at 417 MW_{th} biomass input, which is the same basis as used for the update by Kinchin & Bain (2009). All three literature plant scales lie well within the suitable gasifier range presented above, for pressurised single gasifier systems.

16.3.2 Efficiency

Biomass to hydrogen efficiencies vary according to the gasifier, gas cleanup, WGS reactor type, H_2 separation technique, feedstock types, and the amount of co-products generated (heat and power). It is worth noting that all the efficiencies discussed below, and summarised in Table 16-1, are only theoretical.

Three of the plant concepts given in Hamelinck & Faaij (2002) produce a significant amount of power (using a combined cycle), and hence whilst hydrogen production is only between 127-151 MW_{th}, there is also 72-84 MW_e exported electricity. LHV efficiencies to hydrogen are therefore only 33%-40%, but efficiencies to power are 19%-22% (hence overall efficiencies from biomass to useful outputs of 52%-62%). The other two plant concepts actually consume a small amount of net power (-1 and -22 MW_e), but have much higher hydrogen outputs of 221 and 259 MW_{th}. LHV efficiencies to hydrogen are therefore 58% and 68%, but efficiencies to power are 0% and -6% (overall efficiencies from biomass to useful outputs of 58% and 62%). The plants in Lau et al. (2002) give a similar range of LHV efficiencies between 60-61% for hydrogen production from biomass, with no power or heat export.

The most detailed of the techno-economic studies was conducted by Spath et al. (2005). This plant concept has minimal electricity and natural gas imports (an efficiency penalty of around 2%-points), and LHV efficiencies from biomass to hydrogen ranging from 48% to 50%. Updated results by Kinchin & Bain (2009) have an H_2 efficiency of 49%. These efficiencies are significantly lower than the ranges presented by other literature sources above, which may be due to using wetter feedstock (50% moisture compared to 10-20%

above), lower gasifier efficiency, lower PSA recovery, and consideration of the full syngas cleanup and conditioning processes and losses in greater detail than in other sources.

Reference	**LHV % efficiency**
Hamelinck & Faaij (2002)	33-40% to H_2, 19-22% to power 58 and 68% to H_2, 0% and -6% to power
Lau et al. (2002)	60-61% to H_2
Kinchin & Bain (2009), based on update to Spath et al. (2005)	48-50% to H_2, with around -2% to power

Table 16-1 Range of biomass gasification + hydrogen economic data

16.3.3 GHG emissions

Most emissions within the biomass to hydrogen route are as a result of the upstream feedstock cultivation, use of fertiliser, harvesting and transport stages (using fossil fuel inputs). There are some emissions within the conversion plant itself, including the release of methane and other off-gases from the gas cleaning steps, or use of fossil fuel backup (Jungbluth et al. 2007).

However, in general, emissions of the hydrogen production process from lignocellulosic feedstocks are relatively low, as a result of the excess heat or off-gases from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. Any net surplus of electricity exported from the plant can also be given a credit for displacement of other electricity generation.

Based on the techno-economic literature available, using some of the studies already mentioned above, HyWays-IPHE (2009) derives net well-to-tank GHG emissions of 1.7 – 2.4 kgCO_2e/kg of H_2, i.e. 14 – 20 gCO_2e/MJ of H_2. By comparison, Williams et al. (2007) give GHG emissions from the conversion plant of 1.02 – 1.25 kgCO_2e/kg of H_2, i.e. 8.4 – 10.3 gCO_2e/MJ of H_2.

16.4 Costs

There is less reliable cost data available for hydrogen routes compared to, say, FT synthesis – all of the studies are theoretical, and most were written when hydrogen was at the height of its interest in the early 2000's – there is little recent information published. Available costs from the literature are summarised in Table 16-2, and discussed below.

The three plant hydrogen & power plant concepts modelled by Hamelinck & Faaij (2002) have capital costs of between $\$_{2001}$ 246-283m, which equates to $£_{2011}$ 326-375m. Hydrogen production costs are calculated at between $£_{2011}$ 13.2–17.0/GJ. For the other two plant concepts that produce only hydrogen, capital costs are $\$_{2001}$ 207m ($£_{2011}$ 274m) and $\$_{2001}$ 238m ($£_{2011}$ 315m). Hydrogen production costs in both cases are calculated at $£_{2011}$ 12.0/GJ. Based on assuming smaller and larger plant scales for all the plant concepts, the full range of hydrogen production costs is $£_{2011}$ 10-26/GJ.

The plants modelled by Lau et al. (2002) produce between 10 – 49 kt/yr of H_2. Capital costs for these plants vary between $\$_{2002}$ 37m and $\$_{2002}$ 100.9m, which converted into $£_{2011}$, gives

£47m and £127m respectively. Hydrogen production costs are calculated at between £$_{2011}$ 8.7/GJ for the largest plants, increasing to £$_{2011}$ 13.5/GJ for the smallest plants. This study appears to have significantly lower costs compared to the other studies, possibly due to simplistic operating cost assumptions, and the primary data coming from 1987.

Spath et al. (2005) give a detailed component cost breakdown, for a theoretical plant using an indirectly heating steam-blown gasifier. Capital costs are \$$_{2002}$ 144-154m, which equates to £$_{2011}$ 182-195m. Hydrogen production costs are calculated at between £$_{2011}$ 13.1-14.5/GJ, using a feedstock cost of \$$_{2002}$ 30/odt (£$_{2011}$ 38/odt). Using the same plant design, Kinchin & Bain (2009) provided an updated study, with capital costs of £$_{2011}$ 112-143m, and hydrogen production costs of £$_{2011}$ 10.4-12.2/GJ using feedstock prices of £$_{2011}$ 35/odt.

As for FT synthesis and lignocellulosic ethanol plants, current costs are likely decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through synthesis reactor process intensification, novel gas cleanup, and experience with efficient plant integration. Production costs could fall at a similar rate to those given in the FT synthesis chapter, although no studies have yet modelled this in detail.

Reference	Scale (MW$_{th}$ biomass input)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
Hamelinck & Faaij (2002)	380	326 -375 H_2 and power 274 – 315 H_2 only	13 – 15 11 – 13	13.2 – 17.0 12.0
Lau et al. (2002)	83 - 92 167 - 183 333 - 367	47 77 127	3.2 4.1 5.6	11.4 – 13.5 10.0 – 11.3 8.7 – 9.7
Spath et al. (2005)	417	182 – 195	29 – 30	13.1 – 14.5
Kinchin & Bain (2009)	417	112 - 143	18 – 27	10.4 – 12.2

Table 16-2 Range of biomass gasification + hydrogen economic data

16.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

Downstream of the process steps described, a completely new hydrogen distribution infrastructure and economy requires development, due to the unique properties of hydrogen – although some concepts have investigated the injection of small amounts of hydrogen into the existing natural gas grid (but only <10% due to embrittlement issues).

The hydrogen will need to be transported and stored using specialised equipment (e.g. high pressure storage tanks), before refuelling and use in specific vehicle engines (hydrogen ICE), or fuel cell vehicles. Alternatively, the hydrogen could be piped a short distance for use in local chemicals industry processes or refining, or used on site within a hydrogen gas turbine (potentially combined cycle), or large-scale fuel cell, to generate power with zero emissions (i.e. links to BIGCC power generation with CCS).

16.6 Deployment and development status

As there are no developers looking specifically at the whole biomass to hydrogen route (due mainly to poor economics versus natural gas steam reforming), assigning a TRL is not straight forward. The only integrated systems to date have been developed at lab-scale (TRL 3-4). However, given the relative simplicity of the technology, this is not a fair reflection of how quickly it could develop given the right economic environment – the TRL could rapidly catch up with those of other routes, such as FT synthesis, or IGCC.

This is because the majority of the plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, syngas cleanup and conditioning, H_2 separation, purification and compression. However, some alternative processes are only currently at pilot scale, such as pressurised O_2-blown biomass gasification, novel hot gas cleanup, and membrane H_2 separation.

There are no known developers working on biomass to hydrogen routes (Bacovsky et al, 2010), (E4tech, 2010) (Biofuels Digest, 2011). Some developers have a small amount of overlap, or partial relevance to the route, but hydrogen production is not a primary focus:

- Zeachem (US) use a hybrid approach based on C5 and C6 fermentation to acetic acid and esterification, with the gasification of the fractionation residues providing the hydrogen required for the hydrogenation of ethyl acetate to ethanol. However, the primary output of the plant is ethanol, not hydrogen
- Air Products (US and UK) are planning a 49MW_e waste gasification power plant for 2014 in Teeside, UK, and have mentioned the possibility of future hydrogen production for local industry applications, along with a potential demonstration of AFC Energy's fuel cell power generation technology. However, the primary focus is currently only power (Air Products, 2010)

16.7 Barriers to development and deployment

Barriers generic to all biomass gasification routes are given in the Gasification chapter.

One technical barrier to commercialisation of hydrogen as a fuel is its low volumetric heating value relative to competing fuels. The tendency for hydrogen to weaken steel, via embrittlement, requires the use of stainless steel piping for high-pressure lines. Both these factors make transporting and storing hydrogen much more expensive than transporting natural gas. A challenging economic barrier will therefore be building a capital intensive hydrogen infrastructure, as well as encouraging the uptake/purchase of more expensive hydrogen-consuming products (e.g. fuel cell vehicles or fuel cell CHP). Another challenge that must be overcome is the public's perception of hydrogen, as many people view hydrogen is “unsafe” or “explosive” in comparison to liquid fossil fuels (Lau et al. 2002)

16.8 UK Capabilities

Given the similarities between the upstream components of FT and hydrogen routes, the FT synthesis chapter already covers the discussion of UK capabilities in sizing, drying, gasification and syngas cleanup and conditioning steps.

Current H_2 separation, purification and compression technology is commercially mature. Air Products carry out R&D in this area in the UK, and Linde (BOC) also have a strong presence. However, both these companies are global players, with the UK only one of many regions, and there are also other industrial gas companies, such as Air Liquide and Praxair, with a much smaller UK presence. Equipment suppliers, e.g. for compressors, are mainly based in Germany, North America and Japan. On the whole, the UK's share of the global market in this final process step is likely to only be small.

As for FT synthesis, integration is typically carried out by technology developers/consortia, and EPC contractors conduct FEED studies and installation. The UK does not have any existing or confirmed biomass to hydrogen projects in planning – Air Products' plant in Teeside is only a future possibility if a change from power generation were favourable.

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Part 4: Technologies for liquid fuel production

17 First generation ethanol

17.1 Technology description

Currently, ethanol is produced using crops such as corn in North America, wheat and sugar beet in Europe, and sugar cane in Brazil. The processing of such feedstocks for the production of ethanol is termed “first generation” or conventional technology, and it is based on the fermentation of sugars using yeast and enzymes.

There are two predominant types of conventional ethanol production processes currently employed:

- Wet mill processes - Wet mill facilities are large-scale processing facilities capable of producing a wide variety of products. Wet mill facilities separate the feedstock into its basic components, i.e. starch, protein, wheat/corn germ, and fibre. These components are then processed to produce products such as gluten, syrups, and ethanol. The composition of the product stream can be adjusted depending on the prevailing market conditions.
- Dry mill processes - The dry mill process is the most commonly used to produce ethanol due to the lower capital and operational costs. They are designed to produce three products: ethanol, carbon dioxide, and distillers co-products, such as distillers dry grains (DDG), distillers dried grains with solubles (DDGS), wet distillers grains (WDG), or wet distillers grains with solubles (WDGS).

17.1.1 Wheat to Ethanol

The wheat to ethanol process normally consists of the following steps (see Figure 17-1):

- Milling

The first step in the process is milling. Wheat (or maize/corn) that has been received, cleaned, and stored in the storage silos is transferred to the first of a series of feed hoppers. During the transfer the grain is sieved to remove oversize and undersize materials, and then transferred to the mill feed hopper. The grain is ground and then transferred to a ground grain storage hopper which provides buffer storage in order to ensure a consistent flow of ground grain to the next step in the ethanol process.

- Liquefaction & saccharification (also known as hydrolysis)

The ground grain is mixed continuously with the correct proportion of water to form slurry. Heat, chemicals and enzymes are added to control pH and affect the breakdown of starch into dextrins and sugars. This process is a multi-step process and conditions are controlled to optimise the performance of the enzymes which catalyse the breakdown of the starch.

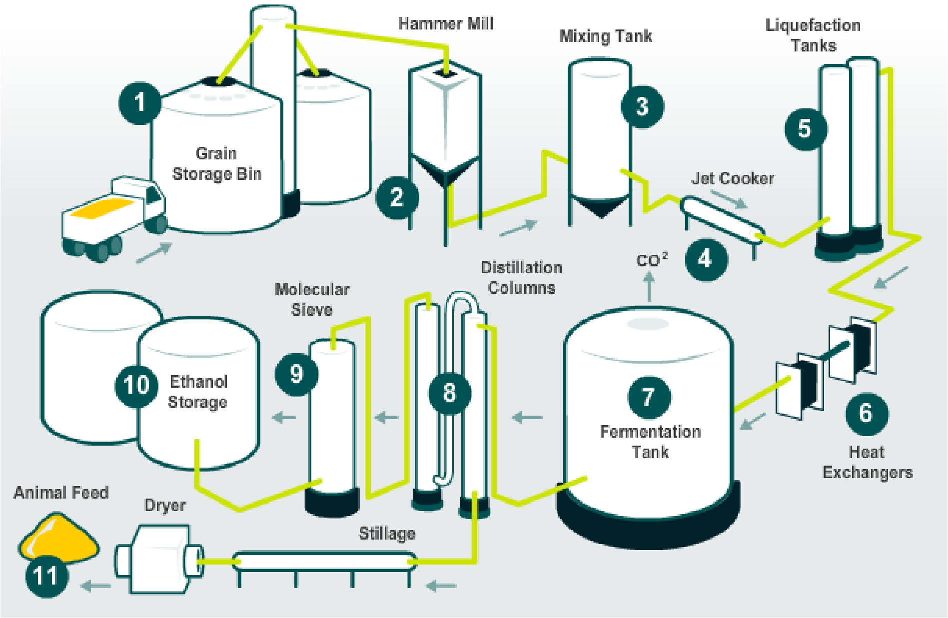

Figure 17-1 Wheat to ethanol Ensus process (Ensus, 2011)

- Fermentation

Fermentation uses yeast that assimilates simple sugars and converts this substrate via metabolism into ethanol and carbon dioxide. The process slurry from the saccharification tank is high in simple sugars and must be immediately fermented by the yeast into ethanol.

- Distillation/Rectification/Dehydration

The distillation process is a multi-column, multi-pressure system that removes the ethanol from the beer (solution of alcohol and non-fermentable solids), rectifies the ethanol into high concentration and then a dehydration unit dehydrates the ethanol. The stillage (beer minus the ethanol) leaves the beer still and is pumped to decantation for drying.

- Decantation

Centrifuges are fed with thin stillage from distillation. Here the insoluble solids are separated from the soluble, and fed into the dryer.

- Evaporation

Evaporation is the thickening of the decanted stillage from the centrifuges, which contains the soluble solids from the grain and some of the fine insoluble solids. Some of the yeast and yeast by-products are also present in this stillage component.

- Drying

The decanted cake is mixed with the concentrated stillage from the evaporators and is passed to driers. The dried product is DDGS which may be pelletised for animal feed.

17.1.2 Sugar beet to ethanol

The production of ethanol from sugar cane or sugar beet differs from the production of ethanol from starch primarily in the pre-treatment requirements.

This is because the sucrose needs to be extracted from the feedstock, and this is achieved by applying heat followed by mechanical extraction of the juices. The sucrose is then fermented by yeast to produce ethanol. From the point of fermentation, both sugar beet and wheat to ethanol production processes are essentially the same.

Figure 17-2 is a representation of the British Sugar refinery that includes ethanol generation.

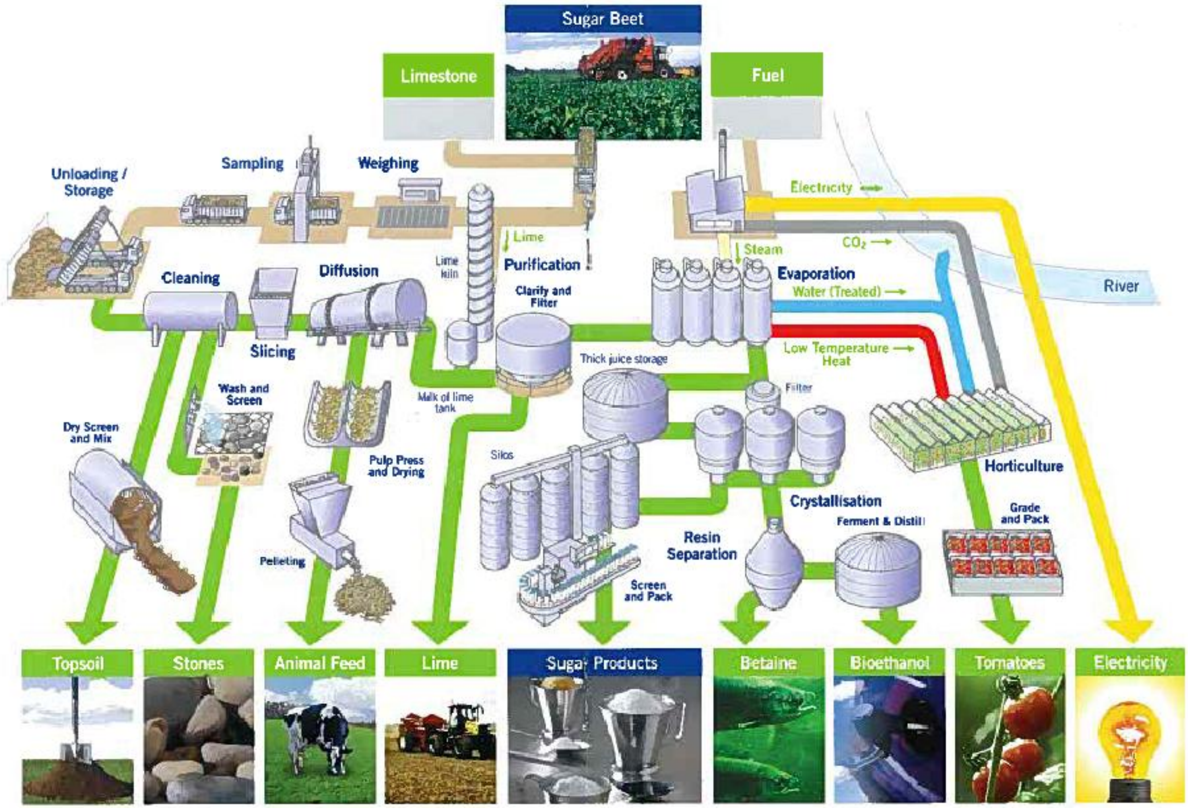

Figure 17-2 Ethanol production from sugar or starch (British Sugar, 2011)

17.2 Feedstock

Currently, first generation bioethanol plants in the US use primarily corn as feedstock. Sugar cane is used in Brazil, and wheat, sugar beet and wine alcohol are used in Europe. The yield available from the differing feedstocks is discussed in Section 17.3.2.

Conventional ethanol can also be generated from fruits, palm juice, barley, rye, rice, sweet sorghum and root plants like potatoes and cassava. In the UK, sugar beet is used by British Sugar and wheat is used by Ensus; these are the two existing operational plants.

17.3 Technical and environmental characteristics

17.3.1 Scale

In the US the scale of commercial plants varies between 38M lpa (30k tpa) to large scale plants of 1,000M lpa (780k tpa) (Ethanol Producer Magazine, 2011). Commercial ethanol plants in Europe have smaller capacities varying between 10 – 480 M lpa (8 – 375k tpa).

The UK has two operational plants; British Sugar with a capacity of 70M lpa (55k tpa) and Ensus with a capacity of 400 M lpa (312k tpa). A third plant is under construction in the UK. This is a joint venture between BP, ABF & DuPont and will have a 420 M lpa (320k tpa) capacity using 1M tpa of wheat as feedstock. The plant it is expected to be operational in the last quarter of 2011.

17.3.2 Efficiency

Due to the differing composition of the various feedstocks, there is a difference in the level of ethanol and DDGS that can be produced. For instance, the ethanol yield per tonne of wheat is slightly less than that of corn (corn starch content is c. 73-75% whereas starch in wheat varies from: 50-80%, with an average of 60-66% depending on the variety and where the wheat is grown. In addition, wheat has higher fibre and higher protein content), while the yield of distiller's co-products (i.e. DDGS) per tonne of wheat is slightly higher than that of corn. Typical yields are tabled below.

Process Characteristics	Tonne of ethanol/unit	Sugar Beet (molasses) (NNFCC, 2007)	Wheat Ensus, 2011
Biomass feedstock consumption (a.r)	tonne ethanol/tonne feedstock	0.25 at 75%mc	0.312 – 15%mc
CO_2 production	tonne ethanol/tonne CO_2	0.78	1.04
DDGS (35% mc)	tonne ethanol/tonne DDGS	0.55	1.16

Table 17-1 Conventional ethanol yields

The yield is affected by the grain size, hardness and variety of the grain and the starch content. The wheat-based ethanol production facility at Ensus yields 400 M litres of ethanol (312k tpa) per year from 1 M tpa of wheat. The facility also yields 350k tpa of DDGS (30% protein concentration) and 300k tpa of carbon dioxide which is generated during fermentation. Carbon dioxide is captured and liquefied on-site and sold to food and soft drinks producers (Ensus Group, 2011). The British Sugar plant produces 70M litres of ethanol per year (55k tpa) from 650k tpa of sugar beet or 110k tpa of molasses. The plant also generates 70k tpa of CO_2 from the fermentation process, and 100k tpa of DDGS.

17.3.3 GHG emissions

Most of the carbon dioxide emissions arise from the fermentation process and from the combustion of fossil fuels to generate the electricity consumed by the process. Figure 17-3 shows the net GHG emissions from conventional ethanol production via different pathways. These data includes emissions from cultivation, road transport, ethanol plant, ethanol transport and refuelling station. The GHG emissions can be reduced by using biomass by-products such as bagasse and straw to generate electricity.

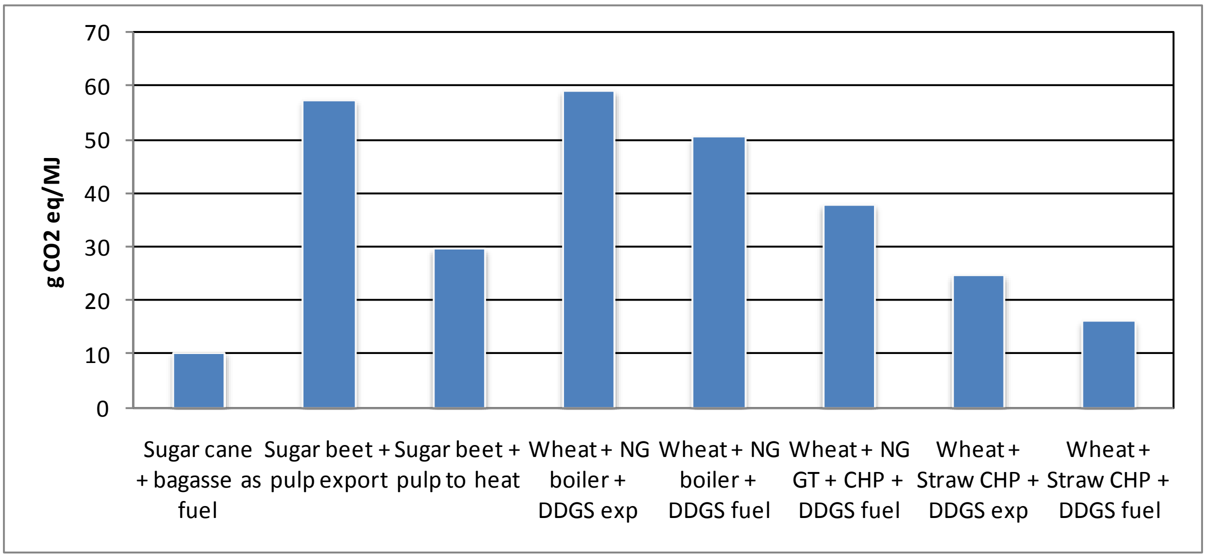

Figure 17-3 Net GHG emissions for ethanol production (JRC, 2006)

The International Energy Agency (IEA, 2011) has estimated that the following GHG emissions savings can be achieved by first generation ethanol compared to fossil fuel. These emissions include the energy consumed in growing the feedstock and exclude any indirect land use change impacts

Feedstock – Conventional Ethanol	GHG Emissions savings compared to fossil fuel (%)
Sugar cane	110 (Achieved when using by-products to generate electricity)
Wheat	90
Sugar beet	65
Corn	60

Table 17-2 GHG emissions savings compared to fossil fuels

17.4 Costs

17.4.1 Capital costs

B&V research indicates that currently the capital cost for first generation plants using corn in the USA is c. US$ 2 – 2.5 per gallon (£420 – 524/tonne of ethanol). In addition, B&V research shows that, in comparison, ethanol capital expenditure is c. 20% higher when using wheat as raw material. Based on B&V experience, the UK plant costs are c.30% higher than the USA, this is due to higher energy costs, labour and material costs. Therefore the capital cost of building a wheat to ethanol plant in the UK will be c. £820/tonne.

17.4.2 Operating costs

Generally, dry mill ethanol facilities require utilities such as electricity, process steam and water. Typically, process steam is generated on-site in a natural gas fired boiler. Natural gas is also utilised as a source of process heat for drying DDGS (some dry mill facilities utilise coal boilers to generate process steam, and these facilities utilise steam dryers to remove moisture from distiller's grains). Water is required for the makeup of both boiler feedwater and cooling water. In addition to the utilities required, the production of ethanol requires consumable materials, such as enzymes for the saccharification process; yeast for fermentation; water treatment chemicals; chemicals for the prevention of bacterial growth in fermentation tanks; and denaturant.

The main factor affecting the cost of production of conventional ethanol is the feedstock, followed by energy consumption (i.e. natural gas). However, in the last 30 years the energy consumption in ethanol plants has been reduced by c. 40% (Wang, M, et al., 2011). The International Energy Agency (IEA) has estimated that feedstock contributes 45% to 70% of the total production cost (IEA, 2011). The IEA has modelled the current production costs between £0.26 - 0.30/litre of ethanol produced from sugar cane and starch grains respectively.

Although conventional ethanol production is a mature and well understood technology, the IEA comment that production cost can still be reduced by:

- The development of more effective enzymes;
- A reduction in ethanol concentration costs; and
- Better use of co-products.

The IEA has modelled production cost reductions from the current £0.30/litre to £0.28/litre in 2020 and £0.27/litre in 2050 for ethanol produced from starch grains.

The cost of producing ethanol from sugar cane is expected to be almost the same in 2050 (£0.25/litre) as the process is a mature conversion technology.

17.5 Requirements of the upstream/downstream process and system considerations

Requirements upstream of the pre-treatment process are feedstock sourcing and transport of feedstock to site as feedstock requirements can be significant. For example, the British Sugar plant requires c. 650k tpa of sugar beet while Ensus plant requires c. 1 M tpa of wheat for its operation. It is important that long term contracts are in place in order to guarantee the provision of feedstock to the plant.

Downstream of the process, ethanol might need to be denatured and transported to the blending facility. For small ethanol plants it might not be economical to distill ethanol on site and therefore a central distillation plant that can serve a group of small ethanol plants in order to reduce costs and increase economies of scale may be used.

17.6 Deployment and development status

The production of conventional ethanol described in this section is a mature and well understood technology (TRL 9).

The United States is the major producer of conventional ethanol, with an installed capacity in 2010 of c. 51,127M lpa produced mainly from corn in c. 204 plants. As of January 2011, the RFA reported 10 plants under construction with a capacity of 1,975M lpa of ethanol (Renewable Fuels Association, 2011).

In 2010, the installed capacity in Europe was c. 7,252 M lpa (European Renewable Ethanol, 2011). The same source has reported 13 plants under construction with a capacity of 1,751M lpa.

In the UK, conventional ethanol production is relatively new, with two plants currently operational:

- British Sugar, with a capacity of 70M lpa of ethanol from molasses.
- Ensus has an installed capacity of 400 M lpa using wheat as feedstock. However, they have temporarily closed production at the end of May 2011.

There are several proposed projects in the UK, and a plant under construction (Vivergo), with a designed capacity of 320k tpa. However, the construction works are currently suspended after a dispute with the main engineering contractor.

17.7 Barriers to development and deployment

The temporary closure of the Ensus plant this year is evidence of the barriers for the deployment of conventional ethanol in the UK. The company announced that rising wheat prices, falling demand and delays in the implementation of the EU directive, have allowed heavily subsided US imports to flood the market (Business Green, 2011).

Other barriers to further implementation of conventional ethanol in the UK include:

- Feedstock availability. Large amounts of grain are required for the production of conventional ethanol.
- Conventional ethanol plants have limited feedstock flexibility and are more vulnerable to changes in commodities prices.
- Sustainability issues regarding the emissions generated from the potential indirect land use change due to increasing biofuel demand and competition of feedstock with food production and other sectors.
- Focus of research in recent years has been into the development of lignocellulosic ethanol.
- Ethanol is unsuitable to be transport through the existing fuel pipelines due to its hydrophilic nature, and therefore it needs to be blended at depots.

17.8 UK Capabilities

In terms of technology suppliers, there are several suppliers. Those with experience of using wheat as feedstock include: Abengoa, Voegelbusch, Katzen, and Prag. Presently, whilst these companies are able to offer their services in the UK, they do not have offices in the UK.

Pursuit Dynamics has developed a process optimisation that it is said to increase the yield by 3-6%, and also enhances the enzyme efficiency therefore reducing its consumption, by 20-30% (Pursuit Dynamics, 2011).

The UK does not have any particular strength in overall bioethanol production processes which will significantly affect the economics (i.e. > 20%) and, given the breakdown of the capital and operational costs, only incremental improvements in costs are expected.

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18 First generation biodiesel

18.1 Technology description

The most common path to produce biodiesel (Fatty Acid Methyl Ester – FAME) is through transesterification of vegetable oils extracted from seeds rich in oil (rapeseed, soyabean, palm kernel), animal fats and used cooking oil. This process is based on the reaction of oil with an alcohol (methanol or ethanol) in the presence of a catalyst (homogeneous - catalyst in the same phase as the reactant, heterogeneous – catalyst not in the same phase as the reactant, and/or enzymes). The products of this reaction are esters – biodiesel and glycerine. A flow diagram for the production of biodiesel is given in Figure 18-1 below.

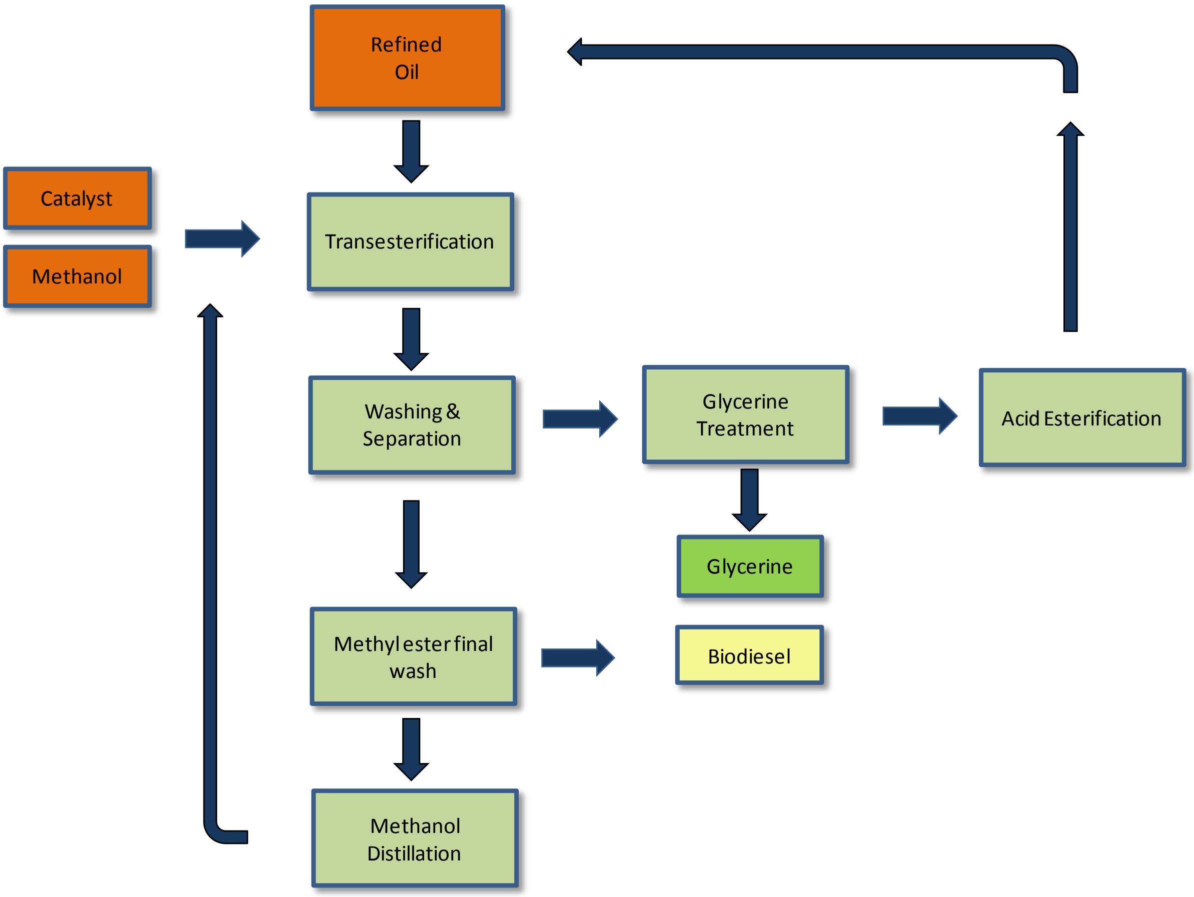

Figure 18-1 Biodiesel production

Oil extraction and refining prior to transesterification has been review in Chapter 8.

18.1.1 Biodiesel plant

The process for the production of biodiesel consists of the following steps as depicted in Figure 18-1 previously.

- Transesterification – reaction of vegetable oil with excess methanol, in the presence of a catalyst, in transesterification reactors;
- Acid esterification of free fatty acids (FFA) to biodiesel and glycerine;

- Glycerine separation and purification;
- Biodiesel drying and methanol recovery.

Glycerine is a by-product and contains residual catalyst, methanol and soaps and may be further processed for onward sale. To achieve this, the glycerine undergoes acidification and neutralisation to obtain 82 - 84% glycerine and the decision to include purification of the glycerine is dependent on:

- The incremental capital and O&M costs associated with glycerine purification;
- The purity specification of purified glycerine vs. that of various other markets;
- The market prices for either crude or purified glycerine.

18.1.2 Biodiesel from used cooking oil

Biodiesel can also be produced from used cooking oil (UCO). UCO typically contains high amounts of FFA and therefore it requires an additional processing step to reduce the FFA content, as per Figure 18-2.

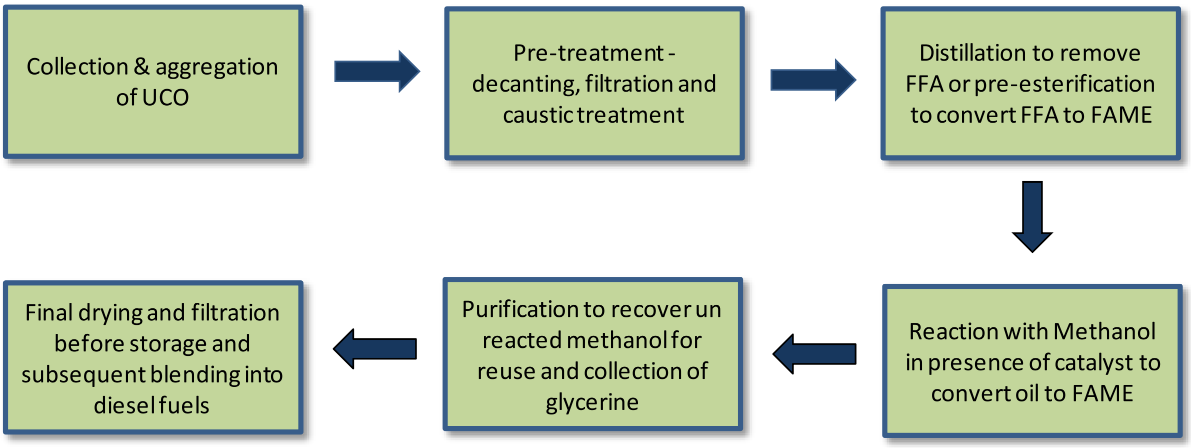

Figure 18-2 UCO into biodiesel (Greenergy, 2011)

18.2 Feedstock

Biodiesel can be derived from edible and non-edible vegetable oils, animal fats (tallow) or used cooking oil (UCO). Edible vegetable oils include oils extracted from rapeseed, soyabean, palm kernel, sunflower seed, peanut, coconut, cotton seed and olive seeds.

Non-edible oils include jatropha and oils derived from algae. In the UK, the most commonly used feedstocks are rapeseed, tallow and UCO.

18.3 Technical and environmental characteristics

18.3.1 Scale

Plant sizes vary depending on the feedstock, feedstock availability and transport costs. Plants using UCO tend to be smaller size plants due to the limited economic catchment area of the feedstock, whilst vegetable oil plants tend to be larger, ranging from 25k – 500k tpa. These plants tend to have feedstock flexibility, treating different types of vegetable oils.

18.3.2 Efficiency

The exact quantities of feedstock, intermediate products and final products depend on the quality of the incoming oilseed, such as its oil content. More specifically, the biodiesel yield is also dependent on the alcohol quantity, the reaction time, reaction temperature and catalyst concentration (Leung, D.Y.C, et al., 2010) such that:

- **Alcohol quantity**: Alcohol is used to ensure that the oils are completely converted to esters, but exceeding the optimal alcohol to oil ratio will increase the cost of alcohol recovery;
- **Reaction time:** Excessive reaction times (>90 min) will lead to a reduction in the product yield as this is a reversible reaction;
- **Reaction temperature:** An increase beyond the optimal reaction temperature (50 – 60°C) could result in a decrease in biodiesel yield;
- **Catalyst concentration:**Too high a concentration of catalyst (optimal concentration c. 1.5% weight) could reduce the biodiesel yield, as the excess catalyst could react with triglycerides to form soap.

Table 18-1 shows yields for biodiesel, rape meal and glycerine when using rapeseed as feedstock.

	Units	**Data (B&V data)**
Refined Oil	Tonne of biodiesel/tonne refined oil	0.99
Glycerine (82% purity)	Tonne of glycerine/tonne biodiesel	0.12

Table 18-1 Conventional biodiesel yield – rapeseed

Research in the field has reported similar oil yields to biodiesel for other feedstocks (Leung, D.Y.C, et al., 2010) including:

Soyabean	>95%
Palm	90%
UCO	95%

18.3.3 GHG emissions

Figure 18-3 shows the net life cycle GHG emissions from FAME biodiesel production when using different feedstocks (including cultivation, feedstock transport, oil processing, esterification, distribution and electricity sales). The GHG emissions are the lowest for UCO, as this is waste product and emissions associated with previous uses have not been taken into account. Besides cultivation, the second most important factor when accounting for GHG emissions are those generated from the esterification process (c. 400 kg eq CO_2/tonne biodiesel), with the exemption of oil palm for which oil processing generates the second highest GHG emissions.

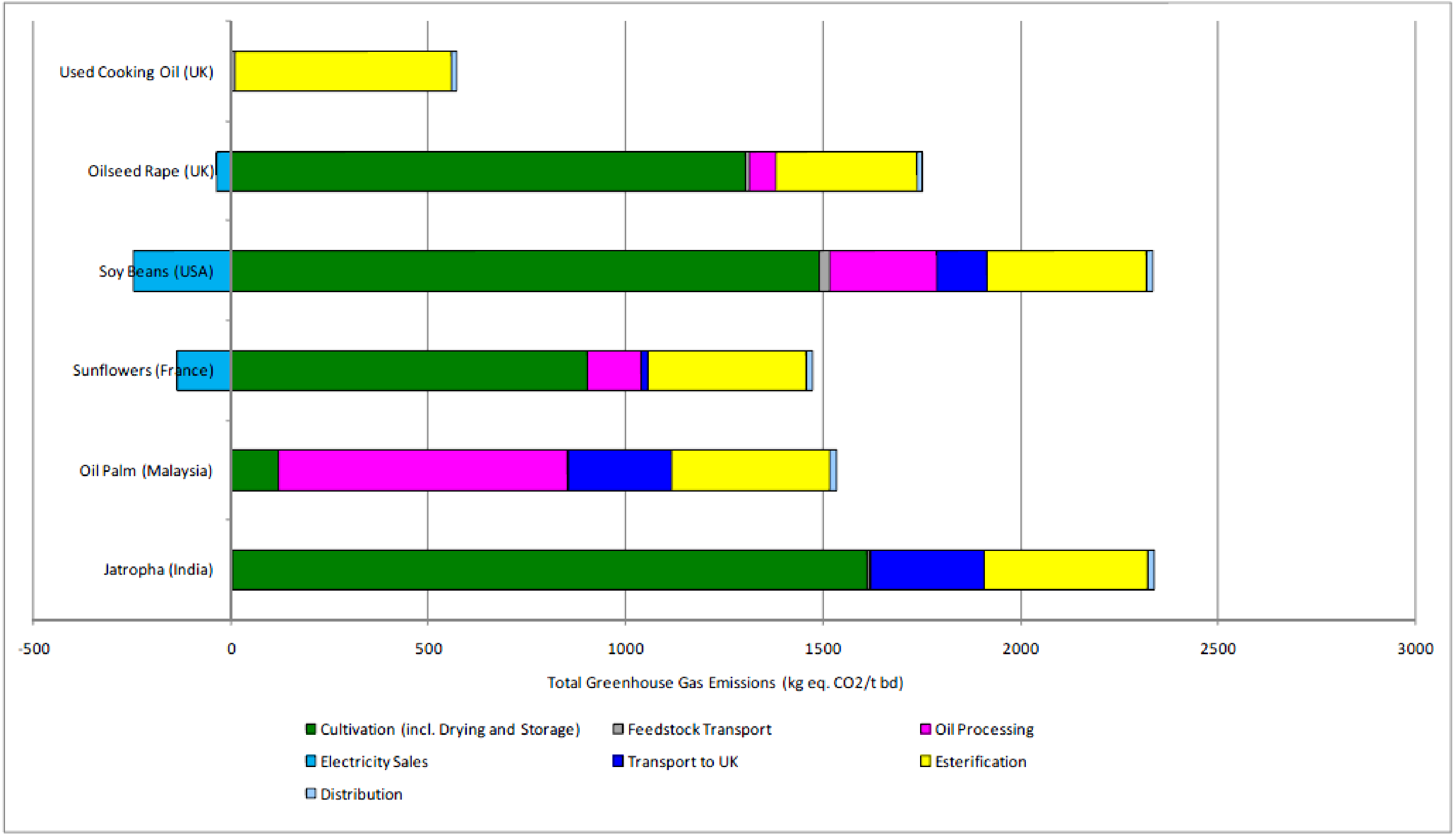

Figure 18-3 Net GHG emissions for ethanol production (NNFCC, 2010)

The International Energy Agency (IEA) has investigated the life cycle GHG emissions from the production and use of biodiesel generated from rapeseed in the UK and compared these to the emissions from petroleum diesel (Including: fuel dispensing, fuel distribution and storage, fuel production, feedstock transmission, feedstock recovery, ILUC, fertiliser manufacture, gas leaks and flares, emissions displaced, and combustion emissions). The Agency has estimated savings of c.76% are achieved when producing biodiesel compared to fossil based diesel. However, these savings exclude emissions from the indirect land use change (ILUC). When ILUC is accounted, the GHG savings are reduced to c.28% (IEA, 2011a) for the UK specifically.

The highest GHG emissions are concentrated within feedstock production, and it is here that the greatest improvements can be achieved over time.

18.4 Costs

18.4.1 Capital costs

The capital cost for biodiesel production is affected by economies of scale as shown in Figure 18-4. Capital expenditure varies from c.£190/tpa of refined oil for a 30k tpa plant to £60/tpa for a 200k tpa plant treating crude vegetable oil (NNFCC, 2007).

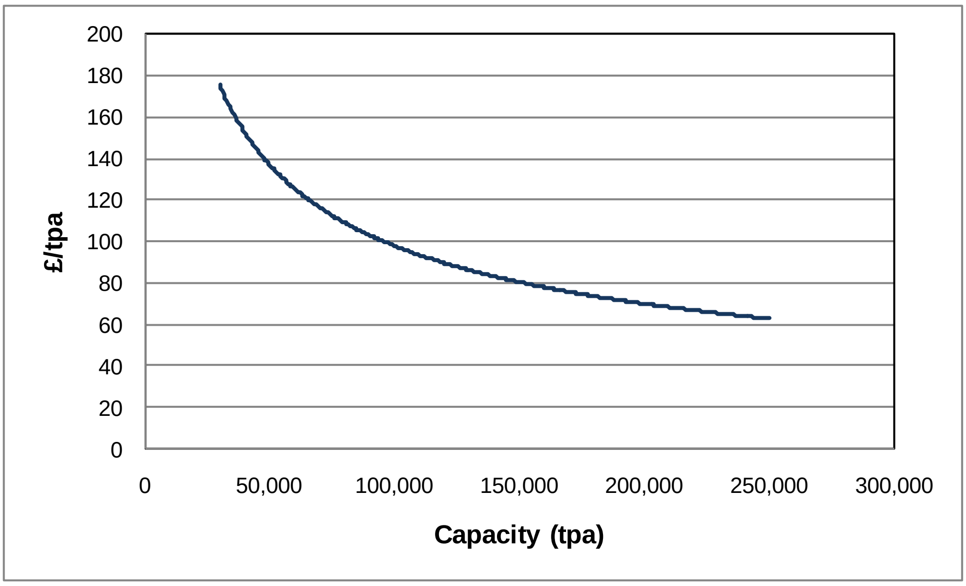

Figure 18-4 Capital cost - refined vegetable oil to biodiesel

18.4.2 Operational costs

The main factor affecting the production cost of biodiesel is feedstock (60-90%) (Al Zuhair, 2007). This cost is significantly reduced when producing biodiesel from UCO.

The IEA has estimated the current production cost of conventional biodiesel to be £0.5/litre in a low cost price scenario[17]. As this is a mature technology, the modelled production cost reductions expected for 2050 are low – typically from the current £0.5/litre (2010) to £0.47/litre in 2050, (both at 2010 prices (IEA, 2011b)).

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[17] Minimal impact of rising oil prices, biofuel production costs falls as scale and efficiency increase

18.5 Requirements of the upstream/downstream process and system considerations

Requirements upstream of the process are feedstock sourcing and transport to site, and oil extraction as described in Chapter 8.

Downstream of the process, biodiesel needs to be transported to a blending facility if it is to be used with diesel generated from petroleum.

18.6 Deployment and development status

Production of biodiesel from vegetable oils and waste vegetable oils (FAME) is a relatively mature technology (TRL 9) with limited potential for efficiency improvement. However, as identified by the IEA and the Department for Transport (DfT, 2006), areas of potential development include:

- More efficient catalyst recovery;
- Improved purification of the glycerine;
- Enhanced feedstock flexibility; and
- Better utilisation of co-products.

In recent years there have been some technology improvements in the processing of biodiesel. It is important to note that these processes are at different levels of development.

- BiOX (TRL 9) –process uses a co-solvent to convert both oil and FFA into methyl esters, allowing the conversion of both vegetable oils and animal fats. BiOX's first commercial plant has been in operation since 2007 with 67M lpa capacity.
- Esterfip-H process (TRL 9) –process has been developed by the French Institute of Petroleum and commercialised by Axens. The process eliminates neutralisation and washing steps by using heterogeneous catalysts. The process also generates higher purity glycerine. Axens has two operational plants: one in France and one in Sweden (160,000 tpa Perstorp).
- TMO Biotech (TRL 3) – has developed a process using methanol in the presence of a micro-organism, that generates a much cleaner glycerol (NNFCC, 2007).
- Blue North Energy (TRL 3) – BNE announced in March 2011 the acquisition of Quicksilver biodiesel technology. The technology has been validated at laboratory scale.
- In-situ conversion of oil in seed (TRL 3) – the dried milled oil seeds are treated directly with a mixture of methanol and catalyst at ambient temperature and pressure. It is claimed that this process could reduce production costs by eliminating the need for isolation, and possibly, the refining of the oil (Leung, D.Y.C., et al., 2010).
- Supercritical alcohol process (TRL 3) – this is a non-catalytic supercritical methanol method. The reaction takes place at high pressure and temperature in a short reaction time (Leung, D.Y.C., et al., 2010).

Europe is the main biodiesel producer in the world, with an installed capacity of c.21,904k tpa (c.254 plants). Production in 2009 was 9,046k tpa (65% of worldwide output), with Germany leading the league table of biodiesel production, (European Biodiesel Board, 2011). Clearly, there is current over-capacity in the market across Europe.

In 2009, 223M lpa (198k tpa) of biodiesel was produced in the UK, this represents a c. 50% reduction from production volumes in 2007 (485M lpa) (DECC, 2010). According to Dukes, the fall in biodiesel production is due to adverse trade conditions. Several producers went out of business and the remaining plants are operating at reduced capacity.

Current UK installed capacity consists of:

- Argent Energy – 50M lpa (45k tpa) biodiesel plant from tallow and UCO;
- Greenergy – 300M lpa (267k tpa) biodiesel plant from tallow and UCO;
- Harvest Energy – Took over the former Biofuels Corporation plant at Seal Sands in 2010. The plant has a capacity of 250k tpa of biodiesel generated from rapeseed, palm and soybean.

There is one project currently under construction: Four Rivers Bioenergy – this is a 120k tpa biodiesel plant using UCO and virgin oils – soyabean and rapeseed.

Also, there are several proposed plants, these include:

- Biodriven, Biosulis and BIP plants using UCO;
- Brocklesby 30k tpa facility using waste vegetable oils;
- Convert2Green plant using waste vegetable oils;
- ESL Fuels using new and waste vegetables oils; and
- PDM Group plant using UCO.

In summary, the UK has a biodiesel installed capacity of c. 560k tpa and more than 150k tpa under construction and in planning.

18.7 Barriers to development and deployment

Barriers to the deployment of conventional biodiesel in the UK include:

- **Trade conditions.** The European market has been inundated by cheaper biodiesel produced in the US and other markets. Although an attempt was made by the European Commission in 2009 to prevent this situation, biodiesel at lower prices than EU vegetable oil is still entering the market. This has contributed to the situation where biodiesel produced in the EU is not able to compete in global markets. As a result, the biodiesel industry in Europe has not grown at the same levels as those seen in 2008 (16% in 2009 compared to 36% in 2008). Among other European states, Germany, UK and Greece, have experienced a reduction in their production output.
- **Feedstock availability and cost.** Although plants are able to treat different types of vegetable oil and also UCO, feedstock availability is an issue, especially in terms of oil used for food. The viability of these plants is highly dependent on feedstock prices, which vary with the market conditions.
- **Market price of by-products.** Part of the viability of the plant is dependent on the market price of by-products, such as glycerine. Over supply of glycerine in the market will lower its selling price and therefore this will impact the potential revenue for the plant.
- **Sustainability issues.** Questions have been raised regarding the emissions generated from the potential indirect land use change due to increasing biofuel demand and

competition of feedstock with food production and other sectors. In some instances, this has called into question the carbon balance of using some feedstocks,

18.8 UK Capabilities

Several technology providers are available from which to source FAME production technology, these include but are not limited to:

- ADM Biodiesel – US;
- Lurgi – Germany;
- BDI – Austria;
- Desmet Ballestra – Belgium;
- Axens – France;
- AT Agrar-Technik – Germany.

The UK does not have any particular strength in overall biodiesel production processes which will significantly affect the economics (i.e. > 20%) and, given the breakdown of the capital and operational costs, only incremental improvements in costs are expected.

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19 First generation butanol

19.1Technology description

Butanol (n-butanol or 1-butanol, C_4H_9OH) is a bulk chemical used in the production of paints, polymers and plastics, and it can be also used as liquid fuel. Compared to ethanol, butanol has superior properties that make its use easier. For example:

- Butanol is less hygroscopic[18] than ethanol;
- Butanol has more energy content per litre than ethanol; and
- Butanol has the potential to be blended into diesel.

Biobutanol can be generated from starch or sugars via a process known as ABE fermentation, named after its products: acetone, butanol and ethanol..Biobutanol can be generated via batch or continuous processes, the latter offering higher efficiencies. The process for the production of biobutanol is shown in Figure 19-1.

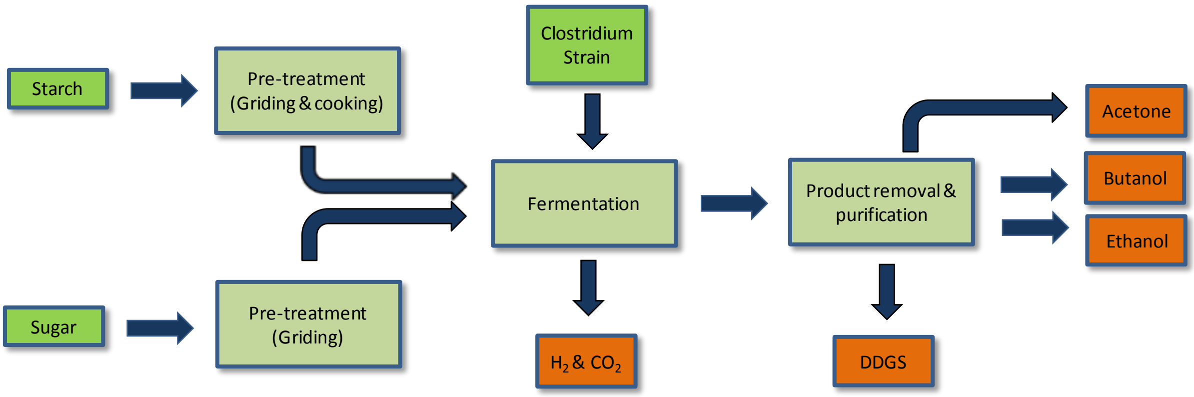

Figure 19-1 ABE process for the production of biobutanol (Garcia, V., et al., 2011)

The ABE process consists of the following steps:

- **Pre-treatment** is similar to that for the production of conventional ethanol.
- **Fermentation** – In the first stage of fermentation, hydrogen, acetic and butyric acids are generated. In the second stage, acetone, butanol, ethanol and CO_2 are produced. Clostridium strains are used during the fermentation process and different strains could be used for the production of Biobutanol with the choice dependent upon the feedstock. For example:
    - Clostridium acetobutylium and Clostridium beijerinkii is used to process starch: and
    - Clostridium saccharobutylicum and Clostridium saccharoperbutylacetonicum is used to process sugar/molasses.
- **Product recovery** – Distillation is the preferred method for product recovery, although it is energy intensive. Other methods such as adsorption, liquid-liquid extraction, gas stripping and membrane separation have been proposed for biobutanol recovery but are not proven at large scale application (Green, 2011).

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[18] Tending to absorb moisture from the air

- **By product** recovery - the following elements are recovered from the process: carbon dioxide, hydrogen and distillers dried grains with soluble (DDGS), which could be used as animal feed.

19.2 Feedstock

Biobutanol can be produced from the same feedstock as conventional ethanol, such as sugars (molasses) and starch rich biomass, including potato, wheat, rye and cassava. Equally biobutanol can also be produced from whey permeate (Qureshi, 2009). Commercially, biobutanol has been generated mainly from corn/maize (China and US) and sugar cane molasses (South Africa and Brazil).

19.3 Technical and environmental characteristics

19.3.1 Scale

Currently biobutanol is mainly produced in China with several plants having been built and/or restored in China since 2006. Chinese plants have installed capacities between 3,000 to 100,000 tpa using mainly corn/maize as feedstock (Ni, Y and Sun Z, 2009). Brazil has an 8,000 tpa plant which uses sugar cane molasses as feedstock (Green, E, 2010).

19.3.2 Efficiency

The typical biobutanol solvent molar ratio for acetone, butanol, ethanol is 3:6:1. By-products to the ABE process include: H_2, CO_2, isopropanol, isopentanol, acetic acid and butyric acid. These will vary depending on the feedstock and *Clostridium* strain used for fermentation (Ni, Y and Sun Z, 2009). Biobutanol production yields also depend on the fermentation conditions, such as pH and temperature (Garcia, V., et al., 2011). Yields reported in the literature are listed in Table 19-1.

	Units	**IJEE (Szulczyk, K., 2010)**	**Argonne (Wu, M., et.,al 2008)**
Corn consumption	tonne butanol/tonne corn	0.155 - .021	0.18
Acetone	tonne acetone/tonne corn	0.076 – 0.12	0.101
Ethanol	tonne ethanol/tonne corn	0.004 – 0.15	0.004
DDGS (11% mc)	tonne DDGS/tonne corn	0.33	0.31
CO_2	tonne CO_2/tonne corn	0.36 – 0.67	-

Table 19-1 Biobutanol yield when using corn as feedstock

One of the main limitations of the ABE fermentation is the low yield. Strains are toxic to the biobutanol generated in the second phase of the fermentation process and therefore most of the research is focusing on the development of new strains that can tolerate higher concentrations of butanol.

19.3.3 GHG emissions

The Argone National Laboratory in the US has evaluated the life cycle emissions from the production of biobutanol. The study included the emissions derived from corn/maize cultivation and transportation, biobutanol production, transportation and distribution and biobutanol use as a transportation fuel (Wu, May. et al., 2008). The study concluded that, compared to petrol production, biobutanol production can achieve c.50% GHG emissions savings when the acetone produced by the process replaced petroleum acetone and DDGS displaced animal feed produced from soy and maize.

The report also highlights that the major contributor to the GHG emissions is the production process itself, which requires 73% of the net energy consumption.

19.4 Costs

19.4.1 Capital Cost

Tao (2009) has modelled the capital cost of biobutanol production and has compared it with other processes for the generation of biofuels (corn to ethanol, sugar cane to ethanol, soybean to biodiesel, lignocellulosic ethanol via biochemical and thermochemical routes). The report concluded that, currently, biobutanol produced from corn has the highest capital investment. This is due to low biobutanol yields and the requirement for more specialised separation of the different products of the ABE process, namely, acetone, butanol, ethanol and also water recycling and solids handling. The capital cost figures in Table 19-2 have been reported in the literature.

Feedstock	Capex (£/tpa butanol)	Plant capacity (tpa)	Reference
Corn/maize	600	210,000	Green, E., 2011
Corn/maize	703	138,000	Tao, L and Aden, A, 2009

Table 19-2 Biobutanol plant capital costs

In the near future, capital costs could be reduced due to the implementation of integrated fermentation and recovery, however low biobutanol yields remain a limiting factor.

19.4.2 Operating Cost

The economics of biobutanol production are mainly dependent on feedstock cost, yield and product recovery (Ni, Y and Sun Z, 2009).

Tao has modelled corn to biobutanol production costs at £0.33/litre for a plant of 138k tpa capacity (Tao, L and Aden, A., 2009).

19.5 Requirements of the upstream/downstream process and system considerations

Qureshi and Blascheck have reported different upstream process requirements depending on the feedstock used (see Table 19-3).

Feedstock	Pre-treatment
Corn	Milling and cooking
Molasses	Dilution and centrifugation for sediment removal
Whey permeate	Lactose concentration by reverse osmosis
Soy molasses	Dilution, removal of sediment and addition of carbon source
Potatoes	Cooking, mashing, sediment removal and dilution

Table 19-3 Upstream process requirements for biobutanol production (Qureshi and Blascheck, 2006)

In addition to the requirements in Table 19-3, it is important that feedstock is sourced and contracts are in place to guarantee a constant provision of feedstock to the plant. Feedstock availability could be a limiting factor, as biobutanol can be generated from the same feedstock as bioethanol which is therefore a competing market.

Biobutanol is less hygroscopic than bioethanol and therefore it can be transported via the existing fuel pipelines and can be blended with petrol at up to 15% by volume (NNFCC, 2010).

19.6 Deployment and development status

This is an established technology (TRL 9) that was developed in the early 1900's. However, in the mid 1950's the process was unable to compete with petroleum derived butanol and so most of the biobutanol production declined. China, Brazil and South Africa continued its production until the late 1990's (Ni Y, Sun, Z, 2009). Currently, the majority of butanol produced is generated via the Oxo process (reaction of propylene, carbon monoxide and hydrogen in the presence of a catalyst); however, since the beginning of the 21st century the production of biobutanol has experienced a revival due to its potential as a biofuel and high oil prices.

Today, China has 11 plants installed with a combined capacity of 210k tpa. Five more plants are under construction or development with a planned capacity of c.275k tpa (Ni Y, Sun, Z, 2009). Brazil has one operating plant with an installed capacity of 8k tpa (Green, E., 2011). There are no operational biobutanol plants in the UK other than the Butamax facility detailed below.

Several biotechnology companies that are currently looking at different strains for the ABE process include the following; many of these are also concentrating on the use of lignocellulosic feedstocks:

- **Butamax Advanced Biofuels** – BP and Dupont are working on the production of biobutanol using sugar and starch as feedstock via a biocatalyst. In November 2010, their demonstration plant at Hull started operations using their own proprietary process. Their first commercial plant is expected to be complete in 2013. The company is also working on the production of biobutanol from lignocellulosic feedstocks; the retrofit of commercial scale ethanol plants; and the production of isobutanol (Butamax, 2011). .

- **Green Biologics Ltd. (GBL)** – Is focusing its research using several clostridial strains and also thermophilic strains. The company has used genetic modification techniques in order to improve the concentration and biobutanol yields of the strains. GBL also provides advice on retrofitting ethanol plants for the production of biobutanol. At the same time the company is working on the production of biobutanol from lignocellulosic feedstock (GBL, 2011)
- **Butylfuel** – It has been reported that Butylfuel has developed a two stage continuous fermentation process that produces butyric acid and then 1-butanol with a different bacterial strain in each vessel (Green, 2011).
- **Gevo** – Has engineered E. Coli to produce isobutanol in a continuous process using multiple feedstock including wheat, corn, sorghum, barley and sugar cane and also lignocellulosic feedstock. The company also offers to modify existing ethanol plants for the production of isobutanol.
- **Cobalt Technologies** – produces biobutanol via a continuous fermentation process using traditional feedstock such as corn and non-food feedstock. The company has developed a vapour compression distillation process that avoids the poisoning of the strain therefore increasing the production yield (Cobalt Technologies, 2011).
- **Cathay Industrial Biotech** – Cathay Industrial, based in China, is currently producing biobutanol from corn and working on the commercialisation of biobutanol from lignocellulosic feedstock (Cathay Biotech, 2011). Current installed capacity is c. 100k tpa of biobutanol.
- **Tetravita Bioscience** – Uses a patented *Clostridium* strain to convert conventional feedstock into biobutanol. However, the same strain can be used on lignocellulosic feedstock. The company has also developed a proprietary fermentation process and can retrofit ethanol plants to generate biobutanol (Tetravitae, 2011).

19.7 Barriers to development and deployment

Barriers to the development of ABE fermentation for the production of Biobutanol are reported to include (Green, 2011):

- High feedstock cost – It has been reported that feedstock contributes c. 80% to the operating costs and therefore low cost feedstock, such as lignocelluloses, would pose a more viable longer term alternative;
- Low biobutanol yields – there is the need to achieve higher biobutanol yields by developing new strains therefore reducing the production cost on a tonnage basis;
- Low biobutanol concentration increases the recovery cost. Acetic acid and biobutanol are toxic to the strains. The strains cannot tolerate more than 2% biobutanol concentration. This results in lower productivity, which in return has an impact on capital costs. It has been reported that a two fold increase in productivity reduces capital expenditure by c. 20% together with significant reductions in operating costs;
- Improved solvent recovery and purification – the current solvent recovery process and distillation has a high energy intensity therefore new techniques that offer a more cost effective alternative need to be found;
- High water consumption.

19.8 UK Capabilities

As mentioned in Section 19.6, Green Biologics and BP are leading the way in the UK for the commercialisation of biobutanol.

Other research efforts are being carried out by The Biofuel Research Centre at Edinburgh Napier University and the University of Nottingham. The former has developed a process to produce biobutanol from residues from the whisky industry, namely pot ale and spent grains. The latter, is working in association with TMO Renewables and the University of Newcastle on the development of new bacterial strains to increase biobutanol yields from lignocellulose. The programme is taking place under the auspices of the Biotechnology and Biological Science Research Council (BBSRC) Sustainable Bioenergy Centre.

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20 Lignocellulosic ethanol

20.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into ethanol. Pretreatment and hydrolysis are used to break down and convert the feedstock to produce sugars, which are then fermented to produce ethanol, as shown in the process schematic below.

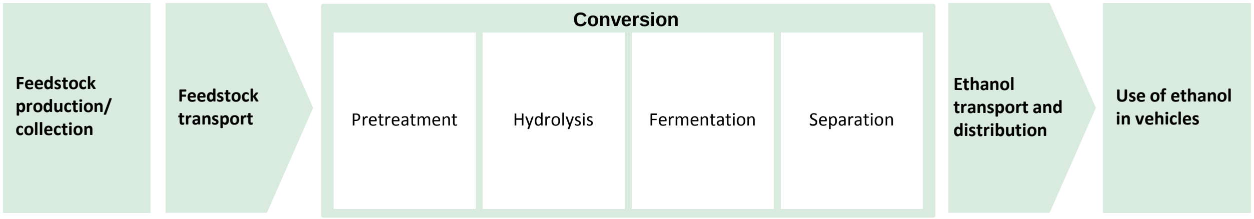

Figure 20-1 Process schematic for lignocellulosic ethanol production

20.1.1 Pretreatment

Lignocellulosic feedstocks contain complex sugar polymers, such as cellulose and hemicellulose, which are difficult to break down chemically, together with lignin, a biopolymer. Pretreatment is used to separate the biomass cellulose, hemicellulose and lignin, as efficient hydrolysis relies on the breakdown of hemicellulose and lignin, which surround and protect cellulose chains, and decreasing the crystallinity of the cellulose. The pretreatment process can also hydrolyse the hemicellulose to sugars.

There are many different physical, chemical and biological pre-treatment processes in development, as the pre-treatment processes currently in use are not ideal in terms of the cost or GHG intensity associated with them. The main categories are (IEA, 2008, E4tech 2009, Bacovsky, 2010):

- Chemical pre-treatment – acid and alkali treatment (often at high temperature/pressure) has been used commercially, most commonly the dilute acid process. Novel options could have more moderate temperature and pressure requirements e.g. near critical or supercritical fluids, ionic liquids and gas expanded liquids.
- Physico-chemical pre-treatment – The most common process is steam explosion which reduces the size of the biomass as well as beginning to break down the hemicellulose and lignin, although which has limitations such as destruction of a portion of the xylan fraction, incomplete disruption of the lignin-carbohydrate matrix and generation of inhibitors to microbial growth, enzyme hydrolysis and fermentation. A water wash is required to remove these inhibitors but this results in reduced sugar yields in the hydrolysis step.
- Combination – e.g. acid steam explosion, acid explosion and ammonia fibre explosion (AFEX). AFEX has been shown to significantly improve the saccharification rates of a number of crops, as it does not produce inhibitors that affect this process. However, it does not significantly solubilise hemicellulose and has shown to be not very effective on feedstocks with high lignin contents.

- Biological pre-treatment – in particular, the use of white-rot fungi which produce lignin-degrading enzymes. Although fungal degradation only has low energy requirements and needs mild environmental conditions, it is slow, and may not be economically viable to entirely replace more conventional kinds of pre-treatment.

Many of the pretreatment processes currently nearing commercialisation are designed for single source, homogeneous feedstocks, rather than mixed or variable feedstocks, such as municipal wastes.

20.1.2 Hydrolysis

Hydrolysis (also called saccharification) involves conversion of the cellulose fraction to sugars, by chemical routes, such as acid hydrolysis, which is a well-known process, or by biological routes, using enzymes, which are in demonstration. Enzymatic hydrolysis would reduce the need for harsh conditions and potentially be a more cost-effective process, and so most developers are using this approach. Hydrolysis of cellulose produces six carbon sugars (C6 sugars, or hexoses, such as glucose), whilst hydrolysis of hemicellulose produces both six carbon sugars and five carbon sugars (C5 sugars, or pentoses, such as xylose). The proportion of C5 and C6 sugars produced depends on the proportions of cellulose and hemicellulose in the feedstock. For example, wood can be 40-55% cellulose, 25-40% hemicellulose and 20-35% lignin, whereas wheat straw is 30% cellulose, 50% hemicellulose and 15% lignin. Note that lignin cannot be hydrolysed.

20.1.3 Fermentation and separation

Fermentation of C6 sugars to ethanol is a commercially available process, although there are still challenges relating to inhibition from lignocellulosic pre-treatment by-products and ethanol inhibition. Fermentation routes from C5 sugars to ethanol are in demonstration. The main R&D challenge here is finding or manipulating organisms (e.g. yeasts or bacteria) to metabolise C5 sugars.

Ethanol is then separated by common commercially available techniques: evaporation, rectification and dehydration.

20.1.4 Integration of steps

Systems where hydrolysis enzyme production, cellulose hydrolysis, hexose fermentation and pentose fermentation all take place in different steps (i.e. in different bioreactors) is called separate hydrolysis and fermentation (SHF). Processes which combine these steps are being demonstrated, as shown in Figure 20-2:

- simultaneous saccharification and fermentation (SSF), where cellulose hydrolysis and hexose fermentation are combined,
- simultaneous saccharification and co-fermentation (SSCF), where cellulose hydrolysis, hexose and pentose fermentation all take place simultaneously - this is the most commonly used approach currently
- consolidated bioprocessing (CBP) where all are combined in a single reactor.

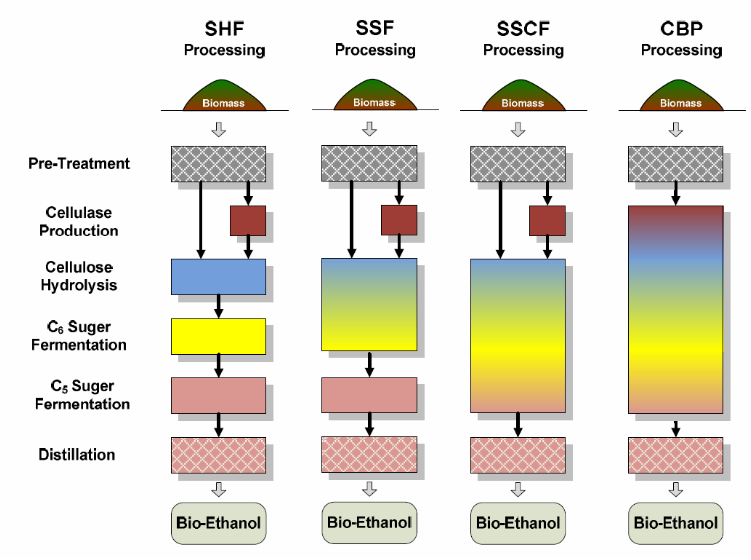

Figure 20-2: Process options for biological conversion of lignocellulosic materials to ethanol (Bacovsky et al, 2010)

20.2 Feedstock

In principle, any lignocellulosic biomass feedstock can be used as an input, including dedicated energy crops, agricultural residues and wood residues, and wastes. Most of the demonstration and early commercial plants are currently focusing on ‘soft’ feedstocks such as corn cobs, corn stover, and wheat straw, with others using wood waste, woodchips, sugarcane bagasse and spent sulphite liquor (Bacovsky et al, 2010). The type of pretreatment used will be matched to the feedstock characteristics, and therefore it is unlikely that one pretreatment process will dominate (IEA, 2008). There is no requirement for feedstock drying, as this is a wet process. The biomass is milled or chipped before pretreatment.

Note that there is scope for optimisation of crops for biological conversion, through reducing the lignin content, or adding the ability to produce enzymes to aid conversion.

20.3 Technical and environmental characteristics

20.3.1 Scale

The US Department of Energy defines a commercial scale biorefinery as having input of 700 tons of feedstock per day, with an output of approximately 20-30 million gallons (75 – 113 million litres) per year. The leading developers (around 5-10 companies) have planned plants at this scale, with current demonstration scale plants at under a quarter of this scale. In the longer term, developers envisage larger plants e.g. at 70mgpy, however, the scale used will depend on the trade-off between economies of scale in conversion costs and feedstock availability and transport costs.

20.3.2 Efficiency

The efficiency of conversion, in terms of the quantity of ethanol output per tonne of feedstock input, depends on the composition of the feedstock, in terms of the cellulose, hemicellulose and lignin content, and then the efficiency of each step in the process. Typical efficiencies are shown in Table 20-1 below:

	Feedstock	Ethanol yields (litres /dry tonne feedstock)
Humbird and Aden, 2009 based on 2007 data	Corn stover	303
Kazi et al, 2010, based on 2007 data	Corn stover	289 (dilute acid pretreatment) (177-300 with other pretreatment routes)
IEA, 2008, based on 2006 data	Agricultural residues	110-270
	Forest residues	125-300
Industry source used in current planning	Energy crops	303

Table 20-1 Ethanol yields from lignocellulosic feedstocks

20.3.3 GHG emissions

Emissions of the conversion process for ethanol production from lignocellulosic feedstocks are relatively low, as a result of the lignin and waste from the process being used to provide heat and electricity for the plant, and relatively few chemical inputs. Kazi et al (2010) assume that there is a net surplus of electricity from the plant that can be exported giving a credit for displacement of other electricity generation. Overall, lignocellulosic ethanol production is estimated to have GHG savings of 50-115% compared with fossil fuels (IEA, 2011), depending on the feedstock and process use, and excluding any indirect land use change impacts. Wang et al (2011) show emissions of 20gCO_2e/MJ ethanol (~78% saving) for ethanol from forestry residues, to 5gCO2e/MJ for switchgrass, to -5gCO_2e/MJ (~106% savings) for corn stover.

20.4 Costs

The US National Renewable Energy Laboratory (NREL), has published detailed cost modelling for lignocellulosic ethanol production, most recently in 2009 (Humbird and Aden, 2009). The minimum economic selling price for ethanol from an ‘nth plant’ using technologies demonstrated by 2008 was estimated at $2.61/US gallon (2007$), or £0.42/litre. Of this $1.71/gallon (~66%) is the conversion plant cost, with the rest being the feedstock. This is based on total project investment of $272.5m for a 56mgpy plant, with operating costs of $54.6m/year, and $7.4m/year income from exported electricity. IEA modelling (IEA, 2011) of current and potential costs shows similar 2010 costs of $2.73/US gallon (£0.44/l).

Costs are projected to decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through continued reduction in the cost of hydrolysis enzymes, improved fermentation, and development of consolidated bioprocessing. The IEA projects production cost reductions from the current £0.44/l to £0.36-0.42 in 2020, and £0.30-0.35 in 2050. Efficiency improvements are expected to be achieved, with an increase from around 300 litres ethanol/dry tonne feedstock now, to around 350 l/t (JEC 2008).

20.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the pretreatment process are feedstock sourcing and transport, and sizing if necessary, such as a chipping step.

Downstream of the process steps described the ethanol may need to be denatured (additives added to make it undrinkable). The ethanol must be transported, and blended for use.

20.6 Deployment and development status

Lignocellulosic ethanol conversion plants as a whole are at the early demonstration to full demonstration stage (TRLs5-7). Some pre-treatment processes are still at the early R&D stage, e.g. ionic liquids, or biological pre-treatment using fungi, whereas others, e.g. dilute acid hydrolysis are nearing commercialisation now, and have been widely used in the past. The pre-treatment processes nearing commercialisation currently use homogeneous rather than mixed feedstocks Enzymatic hydrolysis is being used in these demonstration scale plants. Fermentation of C6 sugars and separation are commercial (TRL9), but fermentation of C5 sugars is at the demonstration stage (TRL5-7). Combining all processes together in the consolidated bioprocessing approach is at the early demonstration stage.

There are around 37 active projects as of mid 2010, being undertaken by 26 developers (Bacovsky et al, 2010). The majority of plants built to date are in the US, with some in Canada and Northern Europe, with 5.2 million gallons per year (mgpy) total installed plant capacity at the end of 2010. However, other regions are now also building plants, for example, Mossi & Ghisolfi have broken ground in Italy on the largest plant to date, which is due to produce 13 mgpy from 2012. With the sum of developer’s announced plans, there could be up to 240mgpy installed by the end of 2014. (Biofuels Digest, 2011). In the UK, TMO Renewables has a pilot demonstration unit, planned capacity 1 mgpy. Other active UK companies are either at an earlier stage, or working on projects outside the UK.

20.7 Barriers to development and deployment

The principal barriers to further development and deployment for conversion of lignocellulosic feedstocks to ethanol are:

- Access to project finance for demonstration and early commercial plants. Potential investors are deterred by the uncertain prospects of individual technologies and the uncertain commercial benefit. Many investors e.g. private equity, institutional investors are too risk-averse to get involved at this stage, while less risk averse venture capital investors do not generally invest the amount of capital needed at this stage. This creates a funding gap for demonstration plants (E4tech 2011, IEA, 2011). There are several options for overcoming this: government support such as US Department of Energy grants and loan guarantees, and the European Industrial Bioenergy Initiative, which will spend €6-8bn over 10 years, funding 15 to 20 demonstration and/or reference plants of which some will be in this technology; involvement of strategic investors, such as oil majors; novel financing mechanisms

- Lack of a clear policy signal in some regions, or uncertainty in implementation of that policy. In the US, there are specific targets for cellulosic biofuels set out in the Renewable Fuels Standard, which calls for 16 bgpy of cellulosic biofuels to be blended by 2022 (EPA, 2011). In the EU, there is policy support for biofuels use in transport under the Renewable Energy Directive (RED), including double credits for ‘advanced biofuels’ including lignocellulosic ethanol, and for those based on use of wastes (EC, 2009). However, this is perceived to provide a less clear signal for the technology than the US policy, and it also remains unclear how individual EU Member States will implement the RED requirements in national policy. However, “neither [the US or EU measures] support measure addresses sufficiently the higher production costs of advanced biofuels compared with conventional biofuels and fossil fuels” (IEA, 2011). In many other regions, there is support for biofuels, but no specific support for lignocellulosic routes.

Other barriers set out in the IEA’s biofuels roadmap (IEA, 2011), relate to

- End-use infrastructure requirements - “blending walls” – the limiting of ethanol in gasoline to 10% to 15% because of vehicle compatibility constraints – would limit deployment, and would need to be overcome through introduction of flex-fuel vehicles (FFV) and high-level ethanol blends
- Need for increased investment in RD&D. In these technologies, this refers to improvement of micro-organisms and enzymes, and work on uses of lignin.
- Need for reduction of public and policymaker uncertainty on sustainability of biofuels

20.8 UK Capabilities

There are several companies working on deploying biological routes, with most of them also developing one or more component technologies

- BP acquired lignocellulosic ethanol technology from Verenium, one of the leading developers. They have a 1.4mgpy demonstration plant in the US, and are planning a 36mgpy first commercial scale plant in Florida, using energy grasses.
- TMO biofuels - developer of thermophilic bacteria optimised for conversion of complex sugars from lignocellulosic feedstocks to ethanol. TMO are at the pilot plant stage, and are planning on using waste-derived material, in partnership with Fiberight
- Biocaldol - developer of thermophilic microorganisms, and services optimising system integration

In pretreatment, the UK has around 10 academic groups working on a range of relevant technologies. For example, Richard Murphy at Imperial (Biological Sciences), researches biological pretreatment using fungal enzymes. There are also UK academics working on ionic liquids, such as Ken Seddon at Belfast (Chemistry and Chemical Engineering), Neil Bruce at York (Biology) and Tom Walton at Imperial (Chemistry). Research on supercritical fluids is also being carried out by Martyn Poliakoff at Nottingham (Chemistry) and Leeke and Santos at Birmingham (Chemical Engineering) and Paul Fowler (Biocomposites Centre) at Bangor University has worked on straw steam explosion techniques. Also relevant is research by scientists at Liverpool John Moores University (Biomolecular Sciences) and Dundee (Environmental and Applied Biology) who have been characterising a novel wood decaying fungus with the potential to be used as a pre-treatment technology. Mycologix (recently spun-out of Imperial) is developing fungal pre-treatment, and is the only UK company known to be focusing on this area.

Much of the research on improving cellulases for biofuel production takes place in large companies such as Novozymes and Genencor, outside the UK. There are capabilities in UK academic institutions in this area also, particularly, for example, in micro-organism manipulation and optimisation. However, most of the researchers in the UK with capabilities in cellulose hydrolysis or microbe manipulation are not primarily researching for the development purpose of producing second generation biofuels. There are a few examples of researchers in the UK doing R&D relevant to this area, with major BBSRC Sustainable Bioenergy Centre projects led by York and Nottingham.

C6 fermentation is a conventional process for which there are some capabilities in the UK for example at the International Centre for Brewing and Distilling at Heriot Watt. In C5 fermentation, Prof Ibrahim Banat at University of Ulster (Biomedical Sciences) has carried out research into the fermentation of C5 sugars by thermotolerant yeast strains. Similarly Dr David Leak (Imperial College) researches metabolic engineering of the fermentation pathways of thermophilic bacteria. Bath University also has experts in thermophilic bacteria, such as Michael Danson who focuses on the enzymology of these extremophiles (Department of Biology and Biochemistry). There are also UK companies developing hydrolysis and fermentation processes based on thermophilic microbes, such as TMO, Biocaldol, and Green Biologics.

For combining the processes described here through the UK has world class researchers in designing and optimising bioprocesses, as a result of developments in the pharmaceutical and industrial biotechnology sector, for example at CoEBio3 in Manchester, and demonstration facilities and the centre for Process Industry, who work on biofuels conversion. There are also UK engineering contractors with experience in ethanol plant design and construction.

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21 Lignocellulosic butanol

21.1Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into butanol. Pretreatment and hydrolysis are used to break down and convert the feedstock to produce sugars, which are then fermented to produce butanol, as shown in the process schematic below.

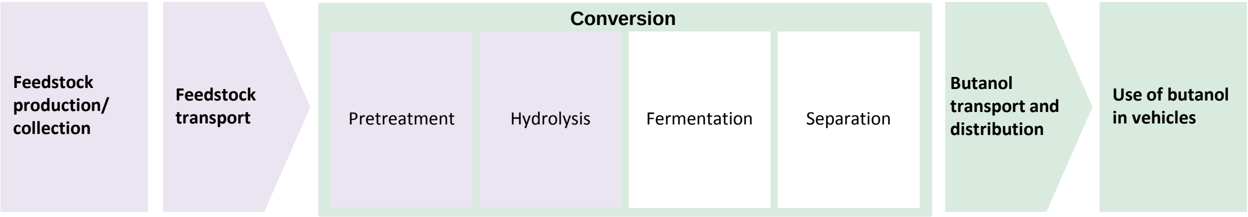

Figure 21-1 Process schematic for lignocellulosic butanol production

The steps shown in purple are the same as for the process for lignocellulosic ethanol production. (see Chapter 20) The remaining steps are similar to the processes for butanol production from sugars, derived from sugar or starch crops (Chapter 19). As a result, the processes being demonstrated currently for lignocellulosic butanol production are already covered by other route descriptions. However, there is research on consolidated routes to butanol that combine hydrolysis and fermentation in a single step, as is being done for lignocellulosic ethanol. This chapter therefore only covers areas where there are differences from either the lignocellulosic ethanol or sugars to butanol routes.

21.1.1 Process steps:

- Feedstocks – as for lignocellulosic ethanol
- Pretreatment and hydrolysis – as for lignocellulosic ethanol. However, there is scope to optimise the hydrolysis process for the fermentation bacteria for butanol, which could reduce costs (Green, 2011).
- Fermentation and separation – similar to the process for butanol from sugar or starch crops. Some of the bacteria used in butanol production, such as solventogentic clostridia can use five carbon sugars from hydrolysis of lignocellulosic biomass without modification and have good tolerance to inhibitors from pretreatment and hydrolysis (Green, 2011), unlike yeasts and bacteria used in ethanol production. However, these inhibitors have been shown affect to fermentation performance, particularly with some feedstocks (e.g. Qureshi et al, 2010), and so there is work underway on finding pretreatment processes producing fewer inhibitors, and on improving tolerance to inhibitors (Garcia et al, 2011).
- Integration of steps - there are several groups working on combined processes combining hydrolysis and fermentation into a single step (e.g. Qureshi et al, 2007), and on consolidated bioprocessing (e.g. Higashide et al, 2011)

21.2 Technical and environmental characteristics

21.2.1 Scale

The US Department of Energy defines a commercial scale biorefinery as having input of 700 tons of feedstock per day, or 20-30 million gallons (75 – 113 million litres) per year ethanol output. This scale would apply to butanol as well as ethanol plants, though the efficiency of conversion to butanol may be different than for ethanol, and is dependent on the fermentation process used.

The leading developers of butanol routes have planned plants at this scale, generally as retrofit, but not with lignocellulosic feedstocks. The largest plant using lignocellulosic feedstocks currently planned is the 0.47 mgal/year (1.78ml/yr) Cobalt Technologies demonstration facility. Cobalt state that their first commercial plant will have a 10-50 million gallon capacity (38-190ml/yr).

21.2.2 Efficiency

The efficiency of conversion, in terms of the quantity of butanol output per tonne of feedstock input, depends on the composition of the feedstock, in terms of the cellulose, hemicellulose and lignin content, and then the efficiency of each step in the process. Typical efficiencies are shown in Table 21-1 below for the whole process, from the few sources available. In most cases, the efficiency has been estimated by combining the efficiencies of lignocellulosic conversion to sugars, and then sugars to butanol, rather than modelling the whole process.

	Type	Feedstock	Product	Butanol yields (litres/dry tonne feedstock)
Gray, 2010 based on Qureshi 2008 data	Calculated in report	Wheat straw	n-butanol via ABE	209-230
Daza Montaño, 2009	Modelled	Wheat straw	n-butanol via ABE	87 (total products 148, including 45 acetone and 15 ethanol, plus heat and power)
Qureshi, pers comm 2011	Experimental	Ag residues	n-butanol via ABE	198 (total products 325, including 102 acetone and 25 ethanol)
Mu et al 2011	Experimental	Corn stalk	n-butanol via ABE	ABE yield of 98 (around 58 butanol if typical)

Table 21-1 Butanol yields from lignocellulosic feedstocks

Feedstock	Butanol yield litres/tonne
Switchgrass	203
Hybrid poplar	217
Pine	230
Mixed paper	214
Wheat straw	236

Table 21-2 Butanol yield variation with feedstock composition - Gray (2010)

21.2.3 GHG emissions

Emissions of the conversion process for butanol production from lignocellulosic feedstocks are likely to be relatively low, as a result of the lignin and waste from the process being used to provide heat and electricity for the plant, and relatively few chemical inputs. Emissions from lignocellulosic butanol routes are expected to be the same, or lower than from lignocellulosic ethanol routes (pers. comm. with butanol developers). If the efficiency of conversion to butanol (and potentially acetone and ethanol) is lower than for conversion to ethanol alone, GHG emissions of the route may be higher. However, there is potential for lower energy consumption in butanol separation than in ethanol separation (Gray, 2010).

21.3 Costs

There is little detailed economic modelling of the lignocellulosic butanol conversion process, as a result of the early stage of development of the route. An estimate was made by Gray (2010), based on combining costs for feedstock handling, pretreatment and enzymes for lignocellulose conversion from NREL (from 2000 and 2002) with capital costs for hydrolysis and fermentation to butanol, and operating costs, from a paper on the ABE process using corn from 2007, with all data inflated to 2008$. Yield data used was as above.

The resulting costs are shown below for a plant using wheat straw. Costs for plants using other feedstocks given are slightly higher, given the lower efficiencies.

Butanol output (mgpy)	Capex $m	Opex $m/yr	Acetone, ethanol and power revenues $m/yr	Butanol production cost excluding feedstock $/gal (£/l)
25	197	58	35	1.86 (0.32)
75	385	129	106	0.94 (0.16)

Table 21-3: Economics of butanol production from Gray (2010)

No projections are available for future production costs, however, the sources of cost reduction are likely to be similar to those for lignocellulosic ethanol: scale up and learning of plant, and from innovation, particularly through continued reduction in the cost of hydrolysis enzymes, improved fermentation to butanol (in particular moving from the ABE to butanol-only routes), and development of consolidated bioprocessing.

21.4 Requirements of the upstream/downstream process and system considerations

As for lignocellulosic ethanol, requirements **upstream** of the pretreatment process are feedstock sourcing and transport, and sizing if necessary, such as a chipping step.

As for butanol from sugar and starch, **downstream** of the process steps described the ethanol must be transported, and blended for use.

21.5 Deployment and development status

Lignocellulosic butanol conversion plants as a whole are at the early demonstration to full demonstration stage (TRLs5-7). As for lignocellulosic ethanol, some pre-treatment processes are still at the early R&D stage whereas others are nearing commercialisation now. Enzymatic hydrolysis is being used in demonstration scale plants. Fermentation of C5 and C6 sugars to butanol is commercial using the ABE process (TRL9), but at the demonstration stage for other process options (TRL5-7). Combining all processes together in the consolidated bioprocessing approach is at the research stage.

Most developers are currently focusing on demonstrating butanol production based on sugar and starch feedstocks, with an aim to move to lignocellulosic feedstocks in the longer term. For example, Gevo have licensed organisms from Cargill that would allow them to use lignocellulosic feedstocks. Globally, there are not yet any demonstration scale lignocellulosic butanol plants operational. Cobalt Technologies have an operational pilot plant using lignocellulosic feedstock, and a 0.47 mgal/year demo facility is planned for ethanol production from early 2012, with a switch to butanol production from mid 2012 (Cobalt, 2011).

21.6 Barriers to development and deployment

The principal barriers to further development and deployment for conversion of lignocellulosic feedstocks to sugars to butanol production are very similar to those for lignocellulosic ethanol:

- Access to project finance for demonstration and early commercial plants. Potential investors are likely to be deterred by the uncertain prospects of individual technologies and the uncertain commercial benefit, potentially more so for butanol than for ethanol as a result of the slightly earlier stage of technology development. Lignocellulosic butanol plants would be eligible for the same government support as for ethanol, and the funding gap could also be overcome through involvement of strategic investors, such as oil majors and novel financing mechanisms
- Lack of a clear policy signal in some regions, or uncertainty in implementation of that policy. Lignocellulosic butanol is covered by the same targets and support mechanisms as ethanol in the US and EU.
- Other barriers set out in the IEA’s biofuels roadmap (IEA, 2011), relate to
- End-use infrastructure requirements - “blending walls” for n-butanol
- Need for increased investment in RD&D.
- Need for reduction of public and policymaker uncertainty on sustainability of biofuels

21.7 UK Capabilities

UK capabilities from lignocellulosic ethanol production, and from butanol production from sugars and starch are relevant to lignocellulosic butanol production. UK butanol developers Green Biologics and Butamax (JV between BP and Dupont) are interested in lignocellulosic butanol production in the longer term, once their technology has been further demonstrated on other feedstocks. In particular, Green Biologics' thermophilic bacteria can ferment cellulose directly, which could facilitate a simultaneous hydrolysis and fermentation process. There is also UK academic research on lignocellulosic butanol specifically, such as the BBSRC-funded work at the University of Nottingham, with TMO Renewables. This project is using synthetic biology to produce and test bacterial strains that can convert lignocellulose to fermentable sugars efficiently to maximise butanol productivity (BSBEC, 2011).

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22 Gasification with catalytic Fischer-Tropsch synthesis

22.1Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into petrol, diesel or jet fuel. Gasification is used to thermo-chemically convert the feedstock into syngas, which is then catalytically converted into Fischer-Tropsch liquids, before upgrading to petrol, diesel or jet, as shown in Figure 22-1. Naphtha and power are also commonly produced as valuable by-products. Bacovsky et al. (2010) give a good overview of the whole route.

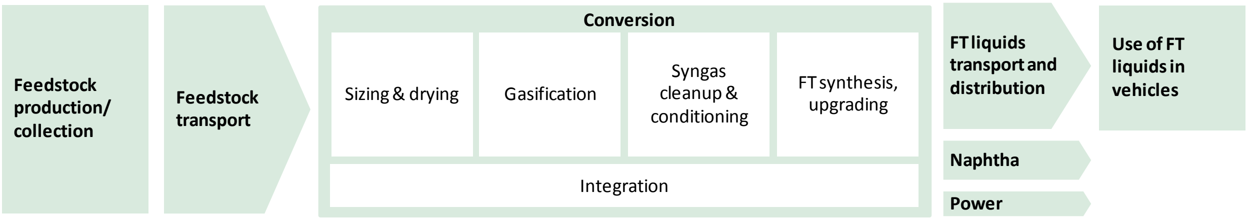

Figure 22-1 Process schematic for production of FT liquids from biomass

The FT process was invented in the 1920s by the German engineers Franz Fischer and Hans Tropsch. Currently the FT reaction is successfully used for fuel production from coal (Coal-to-Liquids, CTL) or natural gas (Gas-to-Liquids, GTL). The GTL process has become increasingly attractive in recent years, and provides high quality fuels which can be sold as premium quality fuel enhancers. CTL projects are also on the increase, given the high oil prices of recent years.

The biomass to FT liquids route shares many similarities with that of biomass to mixed alcohols route, including suitable gasifier types and syngas quality requirements, and only differs significantly in the final synthesis step (and hence the resulting end products). Bacovsky et al. (2010) give a good overview of the whole route. Each of the main process steps is described below.

22.1.1 Sizing & drying and Gasification

Given the downstream demands for FT synthesis, and multiple gas cleanup steps, the avoidance of nitrogen is required, and operating at elevated pressures is also advantageous. The gasifiers chosen are therefore most likely to be oxygen or steam blown, pressurised fluidised bed gasifiers (i.e. Bubbling, Circulating and Dual fluidised bed gasifiers), or Entrained flow gasifiers (which are all O_2-blown at pressure). These have the ability to achieve very large scales, and meet the minimum economic scale for FT synthesis.

The suitable gasifier types are described in more detail in the separate Gasification chapter, along with their sizing and drying requirements.

22.1.2 Syngas cleanup and conditioning

Reasons for gas cleaning are prevention of corrosion, erosion and deposits in the process lines as well as prevention of poisoning of catalysts. The following typical impurities can be found in the product gas:

Dust and alkali metal compounds

Dust, ashes, bed material and alkali metal compounds are removed from the product gas using cyclones and filter units.

Tar

Tars are high-boiling and highly viscous organic compounds, which condense at approximately 300 – 400°C. The tar removal is performed using physical methods, by cooling down the gas and performing a gas wash with special solvents (such as biodiesel) or using a condensation in a wet electro filter. Currently under development are catalytic tar removal processes where the tar is converted to gaseous compounds such as H_2 and CO.

Sulphur compounds

The removal of sulphur compounds is crucial due to its catalyst poisonous effects. Typical tolerances in the syngas are 1<ppm. The sulphur removal can be performed by known methods such as Amine gas treating, Benfield process or similar.

Nitrogen and chloride (halogen) compounds

Nitrogen and halogen compounds may cause corrosion and / or act as catalyst poisons, hence an efficient removal using for example wet washing is required. The amount of the mentioned impurities is strongly dependant on the applied gasification technology, obviously the best strategy to minimize their amount is the application of favourable process conditions.

Several processes are subsumed under the term gas conditioning:

Water-gas-shift (WGS) reaction:

Using the (reversible) water-gas-shift reaction: $CO + H_2O \leftrightarrow CO_2 + H_2$ the H_2 / CO ratio may be modified in order to obtain the required ratio of H_2 / CO (typically between 1.5 and 3.0, dependent on the choice of fuel synthesis reactor and catalyst)

Methane reforming:

Using the gas reforming reactions, the short-chain organic molecules may be converted to CO and H_2 by the following endothermic reaction (example for methane): $CH_4 + H_2O \leftrightarrow CO + 3\ H_2$

Removal of inert gas fractions – mainly CO_2:

CO_2 is on one hand inert in the subsequent reactions, however, it will increase the synthesis equipment size, and energy demand (for example for compression steps), hence its removal is advantageous. The CO_2 removal can be performed by:

- Physical methods: absorption to water or other solvents such as polyethylene-glycole (trade name “Selexol”) or cold methanol (trade name “Rectisol”)
- Chemical methods: chemical glycol or ethanolamine based absorbents
- Other methods such as Pressure Swing Adsorption or Temperature Swing Adsorption

Compression:

Depending on the operating pressure of the gasifier and cleanup equipment, (further) gas compression may be required to meet the specifications of the downstream catalytic synthesis.

22.1.3 FT synthesis, upgrading

Synthesis:

The simplest form of the FT reaction may be summarized by following reactions:

Production of alkanes: $n\ CO + (2n+1)\ H_2 \leftrightarrow C_nH_{2n+2} + n\ H_2O$

Production of alkenes: $n\ CO + (2n)\ H_2 \leftrightarrow C_nH_{2n} + n\ H_2O$

Beside this a number of side reactions take place, where the synthesis gas is degraded to carbon, CO_2 and metal carbides (beside other compounds). The reaction is performed in fixed bed or in slurry reactors. Based on the reaction temperatures and pressures, there are two process types used for the FT synthesis:

- HTFT – High Temperature Fischer-Tropsch Synthesis: The typical HTFT process conditions are temperatures of 300-350°C and pressures of 20-40 bar. The products obtained at this temperature have “light” character, i.e. this process may be used for the production of basic petrochemical materials (e.g. ethylene, propylene) as well as gasoline and jet production
- LTFT – Low Temperature Fischer-Tropsch Synthesis: The low temperature FT – counterpart takes place at temperatures of 200-220°C and pressures below 20 bar. This technology provides higher-boiling products, hence is more suitable for diesel production

FT synthesis is catalyzed by various catalysts based on iron, cobalt, ruthenium, nickel. Due to economic reasons currently only iron (HTFT) and cobalt (HTFT & LTFT) are widely used. Nonetheless, the selection of the appropriate catalyst determines the main product of the FT process, and the life-time of the catalyst affects the overall economy of the production, and specifies the gas contaminant cleanup steps required to avoid catalyst poisoning.

New developments in FT synthesis include the development of micro-channel reactors. These are characterized by parallel arrays of micro-channels, with typical dimensions in the 0.1 to 5.0 mm range. Processes are accelerated 10 to 1,000 fold by reducing heat and mass transfer distances, thus decreasing transfer resistance between process fluids and channel walls (the catalyst). System volumes can also be reduced 10-fold, and costs reduced through modular unit manufacture, thereby realising viable economies of scale at much smaller sizes compared with conventional hardware (Velocys, 2011).

Upgrading of the raw FT product:

The raw Fischer-Tropsch product as provided by the synthesis consists of a distribution of molecules, ranging from gaseous compounds, through liquid fractions ending with a solid wax fraction (at room temperature). Hence, the direct use as fuel is not possible. Even the amount of the desired fraction (petrol, diesel or jet) may be significantly increased through a suitable process control; following additional upgrading steps may be required:

- Distillation: using distillation the obtained raw FT product is split into fractions, the fractions may be further processed as required
- Hydration and isomerization C5-C6 fraction (for petrol use): in order to increase the octane number the mainly linear alkanes are isomerized
- Reforming C7-C10 fraction (for petrol use): is used to increase the octane number (as well as the content of aromatics)
- (Hydro- / fluid catalytic) cracking: converting long-chain fractions into petrol, jet or diesel fraction by application of hydrogen under high pressure

A significant amount of naphtha co-product is usually produced from FT synthesis along with FT jet, diesel or petrol.

22.1.4 Integration

Biomass to FT liquids plants tend to be heavily integrated, since the catalytic FT fuels production occurs at high temperature and pressure, and is highly exothermic. This waste heat can be recovered by the generation of steam, to either input into the gasifier, use for biomass drying, district heating or additional power generation using a steam turbine. Gasification is an endothermic reaction, hence heat need to be supplied (either from the biomass, or externally).

As well as the heat flows and integration in the plant, there are also several loops and components that need careful integration – e.g. example WGS reactors recycle gas loops, and the gasifier air separation unit heating and cooling requirements.

22.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Entrained flow, Bubbling, Circulating and Dual fluidised bed gasifiers.

22.3 Technical and environmental characteristics

22.3.1 Scale

Currently, catalytic fuel synthesis is economically viable above 100,000t/yr of fuel output, i.e. 320 MW_{th} biomass input (Choren 2009). Future developments such as process intensification could reduce this to 20,000t/yr output (60 MW_{th} biomass input) (Velocys, 2011). This minimum economic scale determines which types of gasifier might be the most suitable for liquid fuels production – i.e. oxygen or steam blown, pressurised fluidised beds, or entrained flow gasifiers as discussed above.

This scale is either as a single gasifier, or combining a small number of gasifier modules. Modular systems may not have the same economies of scale as single systems, but could have benefits in terms of use of different feedstocks, and of availability. The largest FT plants currently planned are at the 640 MW_{th} biomass input scale (a commercial Choren Sigma plant), and the largest current plant operating is the Choren Beta demonstration plant at 45 MW_{th} input (14,000 t/yr output).

22.3.2 Efficiency

Biomass to FT liquid efficiencies vary according to the gasifier, WGS, FT synthesis reactor and feedstock types, and the amount of co-products generated (naphtha, heat and power). However, the developers closest to commercial deployment (CHOREN, NSE Biofuels, Flambeau River) are currently designing plants with dry biomass to liquid fuel LHV efficiencies of 47-57%, which agree with research studies (Seyfried, 2008) (Brown, 2007) (Antares Group 2010).

Depending on the plant configuration and size of the power generation unit, this efficiency is typically comprised of FT liquids (30-43% LHV efficiency from feedstock), naphtha co-products (9-13%), and excess electricity available for export (3-15%).

IEA (2011) shows that efficiency improvements over time are expected, with an increase from an LHV average of around 50% currently to 59% in the future.

22.3.3 GHG emissions

Most emissions within the FT route are as a result of the upstream feedstock cultivation, use of fertiliser, harvesting and transport stages (using fossil fuel inputs). There are some emissions within the conversion plant itself, including the release of methane and other off-gases from the gas cleaning steps, or use of fossil fuel backup (Jungbluth et al. 2007).

However, in general, emissions of the conversion process for FT liquids from lignocellulosic feedstocks are relatively low, as a result of the excess heat from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. The net surplus of electricity exported from the plant can also be given a credit for displacement of other electricity generation. Available GHG values from the literature are summarised in Table 22-1, and discussed below.

Overall, a biomass to FT liquids route is estimated to have GHG savings of 55-120% compared with fossil fuels (IEA, 2011), depending on the feedstock and process use, and excluding any indirect land use change impacts. This is based on a UNEP and IEA review of 60 LCA “Well-To-Wheel” studies.

Based on data from CONCAWE, EUCAR and JRC (2006), E4tech (2008) gives a range of 91-94% savings. A LCA conducted on the Choren process shows a reduction in GHG emissions by 87% (Opdal 2006). DBFZ (2011) give a range of 7 – 39 gCO_2e/MJ fuel (92% - 55% saving), with an average of 35 gCO_2e/MJ (59%) currently, reducing to 30 gCO_2e/MJ (65%) in 2030, and 27 gCO_2e/MJ (69%) in 2050. Jungbluth et al. (2007) give a current range of 18 – 48 gCO_2e/MJ (79%-44% savings). These compare to a diesel baseline of 86.4 gCO_2e/MJ (JEC, 2006).

Reference	**GHG emissions (gCO_2e/MJ fuel)**	**GHG savings (% vs. diesel baseline)**
IEA (2011), based on UNEP and IEA LCA meta-review		55% - 120%
E4tech (2008), based on CONCAWE, EUCAR and JRC (2006)		91% - 94%

Reference	GHG emissions (gCO_2e/MJ fuel)	GHG savings (% vs. diesel baseline)
Opdal (2006), based on Choren		87%
DBFZ (2011)	7 – 39	92% - 55%
Jungbluth et al. (2007)	18 - 48	79% - 44%
Fossil diesel baseline, from JEC (2006)	*86.4*	

Table 22-1: Range of GHG emission savings from FT liquids compared to fossil diesel

22.4 Costs

RENEW has published cost modelling for FT liquids production from a variety of plant configurations (RENEW, 2007). Total project investment for a 500 MW_{th} biomass input plant is estimated at £400-450million.

Swanson et al (2010) also give a detailed cost breakdown for plant components. Total project investment for a 390 MW_{th} biomass input plant is estimated at $500-600 million (£315-380m). Associated operating costs are $160-170m/year (£100-110m/yr), including capital depreciation, income tax and average return on investment, and $6-7m/year (£3.8-4.4m/yr) income from exported electricity. The corresponding FT liquid production cost is currently $1.1-1.3/l (or £24-28/GJ), of which, approximately 30% is feedstock, 40-50% capital cost related, with the rest income tax (10-15%), along with fixed and variable operating costs (15%).

Based on Swanson et al (2010)'s pioneer plant cost analysis, the total capital investment for a pioneer plant is expected to be approximately double that of an 'nth' plant, i.e. $1.1-1.4 billion, with fuel production costs of approximately £44-47/GJ.

IEA modelling (IEA, 2011) of average FT liquids production costs show 2010 costs of $1.1/l (£24/GJ). Costs are projected to decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through FT synthesis process intensification, novel gas cleanup, and experience with efficient plant integration. The IEA projects production cost reductions from the current $1.1/l to $0.93-1.05/l in 2020 (£20-23/GJ), and $0.75-0.93/l in 2050 (£16/GJ).

Reference	Scale (MW_{th} biomass input)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
RENEW (2007)	500	400 – 450		
Swanson et al. (2010)	390	315 – 380	100 – 110	24 – 28 commercial 44 – 47 pioneer
IEA (2011)	180 today, 385 future	120 – 208 today 250 – 380 future		~24 today 20 – 23 in 2020 16 – 20 in 2050

Table 22-2: Range of biomass gasification + FT liquids economic data

22.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

FT liquids are a drop-in fuel for either petrol, diesel or jet applications (depending on the FT synthesis and upgrading steps chosen), hence **downstream** of the process steps described, there are no additional requirements on the fuel transport, storage and refuelling infrastructure, or end-use changes in vehicle engines. Blending can happen with fossil fuels at any proportion.

22.6 Deployment and development status

The biomass to FT liquids route is currently at the pilot and demonstration stage (TRL 5 and 6). Many of the plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, syngas cleanup, FT synthesis for coal and gas. However, some processes are only at pilot scale, such as pressurised O_2-blown biomass gasification, novel hot gas cleanup, and micro-channel fuel synthesis reactors. Plant integration experience is in line with the overall route, i.e. TRL 5 to 6.

For all gasifier types, there are now a handful of technology developers working on gasifiers for FT liquids applications, but these vary considerably in size and operating experience. EF and Dual gasifiers were the first gasifier types with pilot or field operating data regarding the production of high quality syngas suitable for liquid fuels, however, recent developments have seen all the other types (BFB, CFB and Plasma gasifiers) joining this list. Some of these pilot and demonstration plants are currently producing FT liquids, with large-scale commercial plants planned to start construction in the near future.

There are 11 known developers working on biomass to FT liquids routes, with around 30 active projects (Bacovsky et al, 2010), (E4tech, 2010) (Biofuels Digest, 2011). All of the projects listed below are planning to use only biomass, except where specified:

- Choren (Germany): Beta plant 4.5Mgy open, Bure-Saudron plant with electrolysis H_2 from Lurgi will output 7.6Mgy in 2014, and a Sigma plant at 33Mgy scale is planned for 2016. However, Choren announced insolvency in July 2011 after several years of failing to successfully commission its Beta plant
- Rentech-ClearFuel/Silvagas (US): 0.04Mgy coal/gas to liquids pilot open, 0.42Mgy joint demo at Rentech's PDU in Colorado in 2011, Rialto 8Mgy from wastes in 2013, Collinwood 20Mgy in 2014, White River Ontario 36Mgy in 2015, as well as a further possible project in Hawaii. Natchez 250Mgy coal project for 2014 might co-gasify some biomass
- NSE Biofuels (Finland): Joint venture between Stora Enso and Neste Oil: 0.2Mgy open, 33Mgy in 2016
- ThermoChem Recovery International (US): Durham 0.1Mgy pilot open, Flambeau Rivers 17Mgy in 2013, New Page Wisconsin Rapids 8Mgy in 2014
- Solena (US): Quantas Australia 16 Mgy jet from MSW in 2013, BA London 19 Mgy jet from MSW in 2014, similar plant with Alitalia in Italy, GreenSky California 30Mgy in 2015

- SGC Energia joint development agreement with Velocys: 0.015Mgy open at Güssing, Brazil 0.7Mgy in 2012 with Frontline Bioenergy
- BioTfuel (France): 2 pilots using torrefaction to FT liquids in 2012, with Uhde, Sofiproteol, CEA, IFP, Axens, Total
- UPM (Finland): 6.6Mgy plant in planning, possible future expansion to 66Mgy
- Core Biofuel (US): 4 plants planned in the US for 2013, totalling 17.8Mgy
- Primus Green Energy (US): 0.002Mgy open
- Renewable Energy Institute International (US): 0.1Mgy open with Red Lion Bio-energy and Pacific Renewable Fuels and Chemicals

However, currently, Choren's Beta plant (45MW_{th} biomass input) is the only sizable pilot/early demonstration biomass to FT liquids plant constructed globally to date, and is only just finishing commissioning. Numerous lab-scale biomass to FT liquids pilots have been built in the US and Europe, at research organisations such as Cutec and KIT (Germany), TUV (Austria), MiUn BTL Research Laboratory (Sweden), Gas Technology Institute, Iowa State, Research Triangle Institute and the Southern Research Institute (US).

Micro-channel reactor developments are also occurring at lab-scale at Joanneum Research Graz, TUV and Bioenergy 2020+ (Austria), along with a 1 bpd pilot at the Güssing plant from Velocys/Oxford Catalysts with SGC Energia (IEA Task 33, 2010).

22.7 Barriers to development and deployment

Barriers generic to all biomass gasification routes are given in the Gasification chapter. However, since FT liquids are a drop-in fuel, there are no downstream infrastructure or use barriers to be overcome

22.8 UK Capabilities

The UK does not have any particularly distinctive capabilities in the handling, pre-treatment transport, sizing and drying of woody biomass, although there are several UK companies with waste separation, pre-treatment and RDF expertise, including New Earth Energy, Aerothermal Group, SITA, and Ethos Energy. Globally, there are numerous large engineering firms who supply this equipment, e.g. Andritz, Foster Wheeler, and Siemens.

There are no UK firms with large gasifier technologies (i.e. those applicable for FT synthesis), and academics are only focused on small-scale gasification. A couple of groups carry out theoretical fluidised bed modelling, including University College London, Cambridge and Nottingham. This is compared to the 11 developers in Europe and the US, although with research strengths in Northern Europe (KIT, VTT, Cutec), major EU projects, and in North America (Gas Technology Institute, Oak Ridge National Laboratory).

In terms of gas cleanup and conditioning, the UK does have some capabilities:

- Porvair and Johnson Matthey are part of the EC FP7-funded GreenSyngas project, led by Lund University, on development of novel gas clean up and upgrading from biomass syngas for liquid fuel production. This is a 3 year, €4m project, involving several other universities (non-UK), based on work on the outputs of the Güssing gasifier in Austria

- MEL Chemicals, based in Manchester, develop and manufacture powders for mobile and stationary gas processing and emission abatement systems. They are developing zirconium oxide catalysts powders for use in the EU “BIGPower” project (Nano4water, 2010)
- Madison Filter Ltd, based in Stoke-on-Trent, design and manufacture filtration and screening technologies, and are also partners in the EU “BIGPower” project (Kurela, 2007)
- Work on syngas cleaning at the Universities of Nottingham, Sheffield and Newcastle
- Advanced Plasma Power are developing plasma sintering clean-up technology

However, there is plenty of competition and skills available globally. There are academic strengths at VTT, Lunds, Delft, Munich, KIT, and Bologna, with hot gas cleaning developed at ECN, along with several large firms, e.g. Linde, Lurgi, Air Products, who already supply equipment.

In terms of FT synthesis, the UK is considered a key player in catalysts and novel technologies:

- Oxford Catalysts produce speciality catalysts. They produce a carbide based catalyst which can be used in the FT process, to make liquid fuels from CO and $H_{2.}$ They also produces catalysts for other petrochemical processes, fuel cells, biogas conversion and portable steam. Their Velocys micro-channel FT reactor system is being tested at the Güssing gasifier in Austria, in conjunction with their commercialisation partners, SGC Energia. After a 6 month trial, this 100 l/day unit will then be installed at Patterson Air Force Base in Ohio (US) to produce synthetic jet fuel (Velocys 2009). This technology could enable smaller FT plants with lower feedstock requirements
- Johnson Matthey works on a range of process technologies and catalysts for syngas generation and also custom manufactures FT catalysts. Johnson Matthey are 1 of the 3 main FT catalyst suppliers globally. Together with Davy Process Technology and Aker Kvaerner, Johnson Matthey is a member of the One Synergy Alliance, which develops a portfolio of technologies and catalysts used in the production of methanol, methanol derivatives and syngas for FT. Its focus is on processes and catalysts for the GTL process but there is also some indication of an interest in biomass to FT liquids
- Other existing industrial FT capability e.g. BP (Saltend) and UOP
- Micro-channel FT synthesis is also being researched by Newcastle, and there are other UK research groups strong in catalysis, for example, Queens University Belfast carry out work on FT synthesis with Johnson Matthey

Large global players such as Sasol (South Africa) and Shell (Netherlands) also have commercial FT offerings, and Rentech, Syntroleum (US), JFE Holdings (Japan) have FT strengths. KIT also have micro-channel FT synthesis technology, as used by NTNU.

Integration is typically carried out by technology developers/consortia, and EPC contractors conduct FEED studies and installation. In terms of planned biomass to FT liquids projects, the UK only has one definite prospect (Solena’s jet fuel project with British Airways in East London) which will be using imported technology. More tentatively, the Integrated Biomass to Syngas project in the North East is still at the feasibility stage.

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23 Gasification with catalytic methanol synthesis

23.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into methanol. Gasification is used to thermo-chemically convert the feedstock into syngas, which is then catalytically converted into methanol, as shown in Figure 23-1 below.

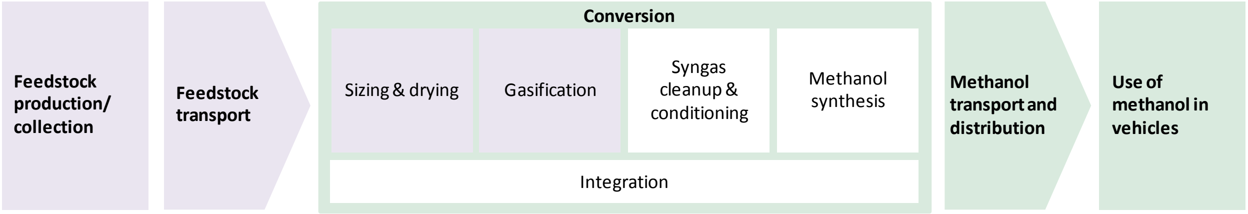

Figure 23-1 Process schematic for biomass gasification + methanol production

Methanol (CH_3OH) is a colourless liquid with a boiling point of 65°C. Methanol will mix with a wide variety of organic liquids as well as with water and accordingly it is often used as a solvent for domestic and industrial applications. It is most familiar in the home as one of the constituents of methylated spirits (Packer, 2002).

The route shares many similarities with that of biomass to FT liquids, including suitable gasifier types and syngas quality requirements, and only differs significantly in the final synthesis step (and hence the resulting end products). Hamelinck & Faaij (2006) give a good overview of the whole route. Each of the main process steps is described below.

23.1.1 Sizing & drying and Gasification

Given the downstream demands for methanol synthesis, minimum economic scales, and multiple gas cleanup steps, the avoidance of nitrogen is required, and operating at elevated pressures is also advantageous. The gasifiers chosen are therefore most likely to be oxygen or steam blown, pressurised fluidised bed gasifiers (i.e. Bubbling, Circulating and Dual fluidised bed gasifiers), or Entrained flow gasifiers. These have the ability to achieve very large scales, and meet the minimum economic scale for methanol synthesis.

The suitable gasifier types are described in more detail in the separate Gasification chapter, along with their sizing and drying requirements.

23.1.2 Syngas cleanup and conditioning

Gas cleaning and conditioning for methanol synthesis is very similar to that for FT synthesis. The discussion below only highlights those points where the two processes differ significantly. For the rest of the cleaning steps not mentioned here (to remove dust, tars, nitrogen and halogen compounds, inert gases as well as methane reforming), please refer to the FT liquids chapter.

Alkali and trace metals:

Removal of alkali metal compounds is particularly important for methanol synthesis, since these can promote other reactions, such as FT and mixed alcohols synthesis. There are also various other trace species that should be avoided, such as:

- As, P and Pb lower activity, as with other heavy metals
- Co leads to the formation of methane, and reduces catalyst activity
- SiO_2 promotes wax production, with surface area losses / risk of plugging
- free Al_2O_3 promotes DME production
- Ni and Fe both promote FT reactions, hence <0.001ppmv is required

Water gas shift (WGS) reaction:

Unlike other syngas catalysis routes which require control of the CO / H_2 ratio, the key ratio to control for methanol synthesis is the stoichiometric ratio of (H_2-CO_2) to (CO+CO_2). This ratio should be greater than 2 for fixed bed reactors using alumina supported catalysts, and around 0.68 for slurry based reactors. As an example, 11 molecules of H_2 and 4 molecules of CO to 1 molecule of CO_2 gives a stoichiometric ratio of 2.

Using the (reversible) water-gas-shift reaction, the (H_2-CO_2) to (CO+CO_2) ratio may be modified in order to meet the downstream reactor requirements.

CO_2 is no longer an inert component of the syngas that requires removal – it now needs to be present at between 4% and 8% (TSS Consultants, 2007). This is because the methanol synthesis reaction is very slow without any CO_2, but is also inhibited if too much present.

23.1.3 Methanol synthesis, upgrading

Synthesis:

Methanol is one of the most widely-synthesised chemicals in the world, via steam methane reforming (Swanson et al, 2010). Out of the 47 million tons of methanol sold globally in 2010, energy and fuel uses represented ~38% (Blokland & Dekker, 2011).

Methanol production from syngas involves reacting CO, H_2 and a small amount of CO_2 over a copper-zinc oxide catalyst, within either a fixed bed or liquid gas reactor design. The reaction proceeds via the water gas shift reaction, followed by hydrogenation of CO_2. Direct CO hydrogenation to methanol is much slower, hence syngas CO is primarily consumed in the water gas shift reaction.

Water gas shift: $H_2O + CO \rightarrow H_2 + CO_2$

CO_2 hydrogenation: $CO_2 + 3\,H_2 \rightarrow CH_3OH + H_2O$

CO hydrogenation: $CO + 2\,H_2 \rightarrow CH_3OH$

The process is carried out at 220˚C-300˚C and 50-100bar, with the raw products fed into a distillation plant to recycle unused syngas, volatiles, water and higher alcohols back to the reactor. Depending on the process conditions and syngas composition, the maximum per-pass conversion rate from syngas to methanol for fixed bed reactors is limited to around 25%. Slurry reactors can achieve higher per-pass conversion rates of up to 40%. By recycling the unreacted syngas, total methanol conversion rates of >90% can be eventually be achieved. Alternatively, some of the unused syngas could be combusted in a gas turbine combined cycle to generate power.

It is worth noting that these methanol per-pass conversion rates are significantly lower than for DME synthesis, due to the thermodynamic equilibrium of the respective set of reactions, and the need to recycle gas to stabilise reaction temperatures. Therefore, to achieve a certain total syngas conversion rate (say 95%), either much more extensive recycling or much higher pressures are required for methanol synthesis than for DME synthesis (Ohno et al. 2001).

Methanol synthesis has a very high catalyst selectivity (>99.5%) - i.e. of the range of reaction products synthesised, fewer than 0.5% of these products are not methanol. Furthermore, since the syngas C–O bond remains intact, methanol synthesis only involves a few simple chemical reactions compared to the complex reactions in an FT or mixed alcohols process.

Upgrading:

The product upgrading of the obtained alcohol mixture consists typically of de-gassing, drying and separation into 2 streams: higher alcohols (for recycling) and methanol. However, this separation and upgrading step is relatively simple in comparison to FT or mixed alcohol routes, mainly due to the high product selectivity (i.e. lack of by-products), and the ease of separating methanol from other alcohols.

Although methanol can be used directly as a liquid fuel, it can also be converted into the conventional transportation fuel range. This process is known as the methanol-to-gasoline (MTG) process and was developed by the Mobil Oil Corporation. In that process, methanol is heated to 300°C and dehydrated over alumina catalyst at 27 atm, yielding methanol, dimethyl ether (DME), and water. The exiting mixture reacts with a zeolite catalyst at 350°C and 20 atm to produce 56% water and 44% hydrocarbons by weight. Of the hydrocarbon product, 85% is in the gasoline range, with 40% of the gasoline-range product being aromatic. The thermal efficiency of the MTG process is 70%. The overall MTG process usually includes multiple MTG reactors in parallel to perform periodic catalyst regeneration by burning off coke deposits (Swanson et al, 2010).

Mobil built and operated a commercial MTG plant producing 14,500 barrels of gasoline per day in New Zealand from 1985. However, with the fall in global oil prices, the process became uneconomic and the plant was mothballed in 1996 (Packer, 2002).

Interestingly, NREL chose not to consider methanol synthesis or MTG routes for further techno-economic study because of time constraints and limited operational data (Swanson et al., 2010). However, recently there has been a rebirth in interest in MTG for new coal-to-liquids projects.

23.1.4 Integration

Methanol plants tend to be heavily integrated, since the catalytic fuel synthesis occurs at high temperature and pressure, and is highly exothermic. This waste heat can be recovered by the generation of steam, to either input into the gasifier, use for biomass drying, district heating or additional power generation using a steam turbine. Gasification is an endothermic reaction, hence heat need to be supplied (either from the biomass, or externally).

As well as the heat flows and integration in the plant, there are also several loops and components that need careful integration – e.g. example methanol reactor recycle loops, and the gasifier air separation unit heating and cooling requirements.

23.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Entrained flow, Bubbling, Circulating and Dual fluidised bed gasifiers.

23.3 Technical and environmental characteristics

23.3.1 Scale

Due to the very similar requirements in syngas clean up, recycling and exothermic heat management, the minimum economic scale for methanol synthesis is expected to be similar to that of FT synthesis (Haldor Topsoe, 2009), corresponding to 100,000 t/yr methanol output (21 Mgy), i.e. ~120 MW_{th} biomass input.

Future developments such as process intensification (as for FT) could reduce this to 20,000t/yr output (4.2Mgy) or ~24 MW_{th} biomass input (Velocys, 2011). This minimum economic scale determines which types of gasifier might be the most suitable for liquid fuels production – i.e. oxygen or steam blown, pressurised fluidised beds, or entrained flow gasifiers. This scale is either as a single gasifier, or combining a small number of gasifier modules. Modular systems may not have the same economies of scale as single systems, but could have benefits in terms of use of different feedstocks, and of availability.

The largest biomass to methanol plants currently planned are at the commercial 132 Mgy output scale (BioMCN, 2011), although there are currently no pilot or demonstration plants producing only methanol. Range Fuels' Soperton demonstration plant operated for a few months during 2010, producing methanol at a 4Mgy output scale, but then converted to produce ethanol before closing in 2011 (Biofuels Digest, 2011).

23.3.2 Efficiency

Biomass to methanol efficiencies vary according to the gasifier, synthesis reactor, product recycling and feedstock types, and the amount of co-products generated (heat and power). Overall plant efficiencies are thought to be in a similar range to FT plants (Brown, 2006), although some methanol plant concepts might be able to achieve slightly higher efficiencies.

Hamelinck & Faaij (2006) model various plant concepts with overall LHV efficiencies between 54% and 57% for methanol production only, with the small amount of exported/imported power accounting for ±4%-points within this overall efficiency. With continued technology innovation and learning, future efficiencies could reach 57-60% (Stark, 2010). A slightly lower range of efficiencies (51% to 56%) is modelled for current theoretical plant concepts that co-produce a substantial amount of electricity via the inclusion of a combined cycle unit burning the unused syngas. It is worth noting that these efficiencies are only theoretical – Ludoc et al. (2009) suggest a current value of 40% is used as the technology is not fully commercialised.

BioMCN (2011) have stated that they plan to convert 1.5 million tons/yr of residual wood into more than 500m litres/yr of methanol. However, the moisture or energy content of the input feedstock is not given – assuming 30% moisture content, then the overall LHV plant efficiency would be approximately 47%.

Including a 70% efficient MTG process downstream of the methanol plant concepts considered by Hamelinck & Faaij (2006) would give overall biomass to gasoline efficiencies of approximately 38% to 40%, i.e. significantly lower than an FT route.

23.3.3 GHG emissions

Most emissions within the biomass to methanol route are as a result of the upstream feedstock cultivation, use of fertiliser, harvesting and transport stages (using fossil fuel inputs). There are some emissions within the conversion plant itself, including the release of methane and other off-gases from the gas cleaning steps, or use of fossil fuel backup (Jungbluth et al. 2007).

However, in general, emissions of the methanol conversion process from lignocellulosic feedstocks are relatively low, as a result of the excess heat from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. The net surplus of electricity exported from the plant can also be given a credit for displacement of other electricity generation.

Wahlund et al. (2004) give estimated GHG emissions of 29-35 gCO_2e/MJ methanol (a saving of 63%-55%). If the excess heat from the plant can also be used, these emissions fall by 4-10 gCO_2e/MJ fuel (an extra saving of 5-13%). There is a wider range of GHG emissions for plant concepts that produce larger amounts of electricity, depending on the exported power credit. The values above are compared to a diesel baseline of 77.5 gCO_2e/MJ.

BioMCN claim GHG emissions of around 23 gCO2e/MJ, i.e. a saving of around 73% versus a 86.4 gCO2e/MJ gasoline baseline (JRC, 2006). However, this is only for glycerine feedstocks (a by-product from 1G biodiesel production), which under the EU's RED count as having zero life-cycle GHG emissions up to the process of collection of the crude glycerine. Using lignocellulosic feedstocks is therefore likely to increase the emissions of BioMCN's route, due to upstream cultivation and harvesting emissions.

23.4 Costs

There is less reliable cost data available for methanol routes compared to, say, FT synthesis – all of the studies are theoretical. Available costs from the literature are summarised in Table 23-1, and discussed below.

Leduc et al. (2007) give a detailed component cost breakdown, for a theoretical plant using an indirectly heating steam-blown gasifier. A range of plant scales from $25MW_{th}$ to $500MW_{th}$ biomass input are modelled, with overall methanol production costs estimated to decrease from €40/GJ to around €25/GJ at the largest plant scales (32 to 20 $£_{2011}$/GJ). Taking a $200MW_{th}$ reference case with a production cost of €27/GJ methanol (22 $£_{2011}$/GJ), of this cost, €12/GJ (9.7 £$_{2011}$/GJ) is attributed to the conversion plant costs (capex and opex), €9/GJ (7.3 £$_{2011}$/GJ) to the biomass, and €6/GJ (4.9 £$_{2011}$/GJ) to feedstock transport. These costs are generally high in comparison to other studies, since a lower pre-commercial efficiency of 40% is assumed. Sensitivity analysis using different biomass costs and plant efficiencies show a wide range of €15-63/GJ (12 – 51 £$_{2011}$/GJ).

Hamelinck & Faaij (2006) model various plant concepts, with an input biomass scale of 380MW$_{th}$.Total investment costs range from $220m to $270m in 2001, which converted equate to £290m to £360m in 2011. Operating costs are taken as a simple ratio (4%) of the total investment costs. Overall methanol production costs range from 8.6-12 \$$_{2001}$/GJ, which converted equates to 11.4-15.9 £$_{2011}$/GJ. However, this assumes a biomass price of only $2/GJ (£2.6/GJ), i.e. the biomass contributes to 40%-55% of the total production costs. Assuming a higher biomass price of $3/GJ (£4.0/GJ) leads to a higher production cost range of 10 – 16 \$$_{2001}$/GJ (13 – 21 £$_{2011}$/GJ). As a further comparison, using the older data behind Wahund et al. (2004) and converting into £2011 gives a production cost of 16.7 £$_{2011}$/GJ methanol. The review of different papers carried out by Stark (2010) gives a range of 10-22 \$$_{2007}$/GJ, i.e. 6-13 £$_{2011}$/GJ methanol, and noted that methanol is likely to be one of the cheapest biofuels to produce.

As for FT synthesis and lignocellulosic ethanol plants, current costs are likely decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through synthesis reactor process intensification, novel gas cleanup, and experience with efficient plant integration. Production costs could fall at a similar rate to those given in the FT synthesis chapter, although no studies have yet modelled this in detail.

Reference	Scale (MW$_{th}$ biomass input)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
Leduc et al. (2007)	200			22 reference, 12 -51 full range
Hamelinck & Faaij (2006)	380	290 - 360	12 - 14	11.4 – 15.9 13 – 21 with higher biomass costs
Wahund et al. (2004)				16.7
Stark (2010)				6 - 13

Table 23-1: Range of biomass gasification + methanol economic data

23.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

Downstream of the process steps described, the methanol will need to be transported and stored using corrosion-resistant materials, before use in vehicle engines directly, or blending with fossil petroleum.

23.6 Deployment and development status

The overall biomass to methanol route is currently at the pilot and demonstration stage (TRL 5 to 6). The majority of the plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, syngas cleanup and methanol synthesis, and hence one of the developers (BioMCN) are planning on jumping straight to building first commercial plants (TRL 8) in the near future. However, some processes are only currently at pilot scale, such as pressurised O_2-blown biomass gasification, novel hot gas cleanup, and micro-channel fuel synthesis reactors. Plant integration experience is in line with the overall route, i.e. TRL 5 to 6.

There are only 3 known developers working on biomass to methanol routes, since bioliq are only focusing on producing bioDME directly (not via methanol). There are only 3 active projects, based in the US and Europe (Bacovsky et al, 2010), (E4tech, 2010) (Biofuels Digest, 2011)

- BioMCN (Netherlands): current plants use natural gas or glycerine (a biodiesel by-product). Planning a first commercial wood to 132Mgy methanol plant at Delfzijl with the Investment and Development Agency of North Netherlands, Linde, Visser & Smit Hanab and Siemens, although currently awaiting funding from the NER300 competition
- Range Fuels (US): Denver 0.9Mgy methanol/ethanol pilot opened in 2008. Their Soperton 4Mgy commercial plant was producing methanol from mid 2010, then made one batch of ethanol before closing. Planned expansion to 60Mgy would again be ethanol only, i.e. methanol is not currently a key focus for Range Fuels
- Chemrec (Sweden): uses black liquor feedstocks from adjacent paper mills. Piteå bioDME pilot plant opened in 2010 (part of the EU project 'bioDME'). A 95kt/yr (40Mgy) demonstration plant in Örnsköldsvik is due to open in 2013, producing both methanol and bioDME. However, bioDME remains the key focus for Chemrec

23.7 Barriers to development and deployment

Barriers generic to all biomass gasification routes are given in the Gasification chapter.

Existing fossil fuel methanol plants worldwide produce about 2,500m tonnes per day of methanol. Some stranded gas is currently converted to methanol for the chemical industry or as a petrol additive. Methanol can also be used directly in spark-ignition or compression engines, and has potential use as a transport fuel in fuel cell vehicles. However, despite its low cost and high octane number, methanol is seen as having several compatibility issues for vehicle applications, which have lead some people to reject methanol as a transport fuel in favour of more suitable alternatives (Stark, 2010). Methanol has the following issues:

- Low energy density means larger fuel tanks are required, otherwise vehicle range is shortened
- Poor cold start properties, due to its low vapour pressure and high latent heat of vaporisation, although these are avoided by blending with fossil fuels (such as M85)
- Although fairly moderate relative to many other biofuels, the toxicity and environmental safety risk posed by methanol is seen by many as a major barrier (public opinion is poor),

citing safety hazards in the event of spills, leaks or crashes during transport or use of the fuel

- In terms of pipeline transport and storage, methanol is corrosive, and highly soluble in water, which raises contamination issues similar to those for ethanol

23.8 UK Capabilities

Given the similarities between FT and methanol synthesis routes, the FT synthesis chapter already covers the discussion of UK capabilities in sizing, drying, gasification and syngas cleanup and conditioning steps.

Methanol synthesis is a mature and well-developed process and many large industrial plants are under operation. Companies such as Haldor Topsøe, Lurgi, Davy Process Technology (owned by Johnson Matthey) and Mitsubishi Gas Chemicals are leading in this area. The UK is considered a key player in catalysts and novel intensification technologies (with Johnson Matthey and Oxford Catalysts' Velocys), and does have some methanol capabilities, although is mainly focused on FT catalysis. Other players with micro-channel reactor offerings could enter the market in the future, for example, KIT are conducting research specifically on methanol micro-channel reactors (Bakhtiary-Davijany et al. 2011).

As for FT synthesis, integration is typically carried out by technology developers/consortia, and EPC contractors conduct FEED studies and installation. The UK does not have any existing or planned biomass to methanol projects.

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24 Gasification with catalytic mixed alcohols synthesis

24.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into a mixed C2-C6 range of alcohols. Gasification is used to thermo-chemically convert the feedstock into syngas, which is then catalytically converted into alcohols, before product upgrading, as shown in Figure 24-1. Some developers are focused on producing a mix of different alcohols for vehicle fuel blending, whereas other developers are focusing exclusively on optimising for ethanol production, with the other synthesised alcohols and any excess power sold as by-products.

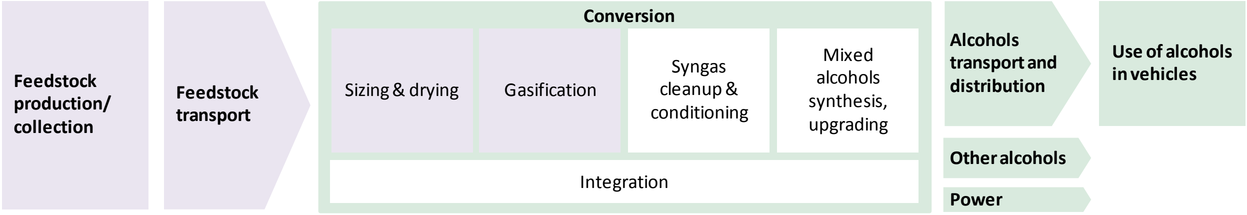

Figure 24-1 Process schematic for mixed alcohols production from biomass

The route shares many similarities with that of biomass to FT liquids, including suitable gasifier types and syngas quality requirements, and only differs significantly in the final synthesis step (and hence the resulting end products). Bacovsky et al. (2010) give a good overview of the whole route. Each of the main process steps is described below.

24.1.1 Sizing & drying and Gasification

Given the downstream demands for alcohols synthesis, minimum economic scales, and multiple gas cleanup steps, the avoidance of nitrogen is required, and operating at elevated pressures is also advantageous. The gasifiers chosen are therefore most likely to be oxygen or steam blown, pressurised fluidised bed gasifiers (i.e. Bubbling, Circulating and Dual fluidised bed gasifiers), or Entrained flow gasifiers. These have the ability to achieve very large scales, and meet the minimum economic scale for mixed alcohols synthesis.

The suitable gasifier types are described in more detail in the separate Gasification chapter, along with their sizing and drying requirements.

24.1.2 Syngas cleanup and conditioning

Gas cleaning and conditioning for mixed alcohols synthesis is very similar to that for FT synthesis. The discussion below only highlights those points where the two processes differ significantly. For the rest of the cleaning steps not mentioned here (to remove dust, alkali metals, tars, nitrogen and halogen compounds, inert gases as well as methane reforming), please refer to the FT liquids chapter.

Sulphur compounds

For the sulphide synthesis catalyst, some sulphur (between 50-100ppmv) is actually required in the syngas, rather than needing to be removed (Spath & Dayton, 2003). However, although this higher sulphur tolerance requires less clean-up of the syngas before conversion, it may require sulphur removal downstream in the mixed alcohol fuel.

Water-gas-shift (WGS) reaction:

Using the (reversible) water-gas-shift reaction: $CO + H_2O \leftrightarrow CO_2 + H_2$, the H_2 / CO ratio may be modified in order to obtain the required H_2 / CO ratio of between 1 and 1.2 for mixed alcohols synthesis. Therefore, the need for a WGS during syngas conditioning is significantly reduced compared to most FT synthesis processes.

24.1.3 Mixed alcohols synthesis, upgrading

Synthesis:

Mixed alcohols synthesis, also known as Higher Alcohol Synthesis (HAS) is very similar to both FT and methanol synthesis. It often uses catalysts modified from those processes, with added alkali metals to promote the mixed alcohols reaction. The process produces a mixture of alcohols such as methanol, ethanol, propanol, butanols and some heavier alcohols. For example, ethanol synthesis follows the reaction:

$$3\,CO + 3\,H_2 \leftrightarrow C_2H_5OH + CO_2$$

One group of catalysts consists of modified high pressure (alkali-doped ZnO/Cr_2O_3 at 125-250bar) or low pressure (alkali-doped Cu/ZnO or $Cu/ZnO/Al_2O_3$ at 50-100bar) methanol catalysts, operating at temperatures of 250-425°C. The second group of catalysts are based on modified FT catalysts (alkali-doped $CuO/CoO/Al_2O_3$; at 50-100bar and 260-320°C). Further molybdenum and ZrO_2 based catalysis have been investigated as well as an alkali-doped sulphide catalyst.

The catalytic HAS transformation of the syngas to alcohols is typically performed in fixed bed reactors. Due to the fact, that the HAS process is highly exothermic, the optimization of the heat removal is of particular interest. Beside fixed bed reactors, there are for example multiple reactor systems (such as double bed type) under investigation, where in separate beds particular processes may be optimized. For example methanol production at lower temperature is performed in the first bed and higher alcohol synthesis at higher temperature in the second bed. In case higher alcohols are in the focus of the process, slurry reactors may be used. This reactor type is particularly suitable for reaction heat removal. In general, methanol formation is favoured at low temperatures and high pressures.

Regardless of the type of catalyst used, typically 40 to 90% of the product stream needs to be recycled to maximize mixed alcohol production, and minimise methanol output. Unavoidably, the main reactions produce H_2O and CO_2 as by-products, and large amounts of methane are often produced. WGS plays a major role and depending on the catalyst’s shift activity, some chemical dehydration of alcohols can be undertaken in-situ to produce higher alcohols, esters, and ethers. Secondary reactions also produce hydrocarbons including aldehydes and ketones.

Upgrading:

The product upgrading of the obtained alcohol mixture consists typically of de-gassing, drying and separation into 3 streams: methanol, ethanol and higher alcohols.

24.1.4 Integration

Mixed alcohols plants tend to be heavily integrated, since the catalytic HAS synthesis occurs at high temperature and pressure, and is highly exothermic. This waste heat can be recovered by the generation of steam, to either input into the gasifier, use for biomass drying, district heating or additional power generation using a steam turbine. Gasification is an endothermic reaction, hence heat need to be supplied (either from the biomass, or externally).

As well as the heat flows and integration in the plant, there are also several loops and components that need careful integration – e.g. example mixed alcohols reactors recycle gas loops, and the gasifier air separation unit heating and cooling requirements.

24.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Entrained flow, Bubbling, Circulating and Dual fluidised bed gasifiers.

24.3 Technical and environmental characteristics

24.3.1 Scale

Since the mixed alcohol catalysts and reactors are based on FT or methanol technology, and due to the very similar requirements in syngas clean up to FT and methanol synthesis, the minimum economic scale for mixed alcohols synthesis is expected to be similar to that of FT synthesis, corresponding to 100,000 t/yr mixed alcohol output (33Mgy), i.e. ~200 MW_{th} biomass input.

Future developments such as process intensification (as for FT) could reduce this to 20,000t/yr output (6.7Mgy) or ~40 MW_{th} biomass input (Velocys, 2009). This minimum economic scale determines which types of gasifier might be the most suitable for liquid fuels production – i.e. oxygen or steam blown, pressurised fluidised beds, or entrained flow gasifiers. This scale is either as a single gasifier, or combining a small number of gasifier modules. Modular systems may not have the same economies of scale as single systems, but could have benefits in terms of use of different feedstocks, and of availability.

The largest mixed alcohols plants currently planned are at the pre-commercial 10 Mgy output scale, and the largest plant currently operating is Enerkem’s Westbury demonstration plant at 1.3 Mgy.

24.3.2 Efficiency

Biomass to mixed alcohol liquid efficiencies vary according to the gasifier, synthesis reactor, product recycling and feedstock types, and the amount of co-products generated (higher alcohols, heat and power).

The handful of active developers (Range Fuels and Enerkem) that are currently building plants quote dry biomass to liquid fuel conversion efficiencies of between 313 – 397 litres of ethanol/tonne of oven dry feedstock (Enerkem, 2011). By 2020, this could increase to 439 litres of ethanol/odt (Genecor, 2011). Converting to LHV plant efficiencies, this corresponds to 36-46% today, and 51% in 2020, for ethanol output from input feedstock. This agrees with recent biofuels analysis presented by the ethanol industry (Biofuels Digest, 2011).

Phillips et al. (2007) model an overall plant LHV target efficiency of 45.9% for mixed alcohols, based upon 2012 research targets and the use of an indirectly heated (steam-blown) gasifier. This equates to a mixed alcohols product yield of 393 litres/odt feedstock, for a 72.7 Mgy (275m litres/yr) plant. Alternatively, for an ethanol only plant, yields are estimated at 335 litres/odt for a 61.8Mgy (234m litres/yr) plant, i.e. an overall efficiency of ~39% to ethanol. These efficiencies are also used by Antares Group (2010) in their modelling. Using a directly heated gasifier leads to lower plant efficiencies of around 38.4% to mixed alcohols, due to higher parasitic loads with the air separation unit, char carbon losses, reformation of methane, and addition of CO_2 required (Dattu & Phillips, 2009). This equates to a mixed alcohols product yield of 321 litres/odt feedstock, for a 59.3Mgy (225m litres/yr) plant. Alternatively, for an ethanol only plant, yields are estimated at 273 litres/odt feedstock, for a 50.4Mgy (191m litres/yr) plant, i.e. an overall efficiency of ~32% to ethanol.

The RENEW modelling given in Seyfried (2008) has two different mixed alcohols plant configurations: one using torrefaction and an entrained flow gasifier, the other using an indirectly heated dual gasifier and tar reformer. Overall plant efficiencies to mixed alcohols and power are between 38% and 46%, depending on the input of natural gas in addition to biomass. These plant outputs are typically comprised of methanol (6-9% LHV efficiency from feedstock), ethanol (15-22%), higher alcohol co-products (9-13%), and excess electricity available for export (0-12%).

Reference	**litres ethanol /dry tonne**	**litres mixed alcohols /dry tonne**	**LHV % efficiency**
Enerkem (2011)	313 – 397		36-46% to ethanol only
Genecor (2011), based on likely 2020	439		51% to ethanol only
Phillips et al. (2007), based on 2012 targets	335	393	39% to ethanol only 45.9% to mixed
Dattu & Phillips (2009), directly heated gasifier	273	321	32% to ethanol only 38.4% to mixed
Seyfried (2008), based on torrefied EF, and atmospheric Dual			38% - 46% to mixed

Table 24-1: Range of LHV efficiencies from biomass to ethanol and/or mixed alcohols

24.3.3 GHG emissions

Emissions of the conversion process for mixed alcohols from lignocellulosic feedstocks are relatively low, as a result of syngas and the excess heat from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. The net surplus of electricity exported from the plant can also be given a credit for displacement of other electricity generation.

Overall, a biomass gasification to ethanol route is estimated to have GHG savings of 72-93% compared with fossil fuels (RFA, 2010), depending on the feedstock and process used, and excluding any indirect land use change impacts. However, Hsu et al. (2010) give a range of

30 – 65 gCO_2e/MJ fuel (65% - 24% saving), with an average of 48 gCO_2e/MJ (only a 44% saving). These are compared to a petrol baseline of 86.4 gCO_2e/MJ (JEC, 2006).

It is worth noting that developers (especially those using MSW) claim savings more in line with the RFA rulings: Fulcrum Bioenergy claim a 75% reduction in GHG emissions compared to petrol (Fulcrum, 2011), whereas Enerkem claim an 80% reduction (Enerkem, 2011).

Reference	**GHG emissions (gCO_2e/MJ fuel)**	**GHG savings (% vs. diesel baseline)**
RFA (2011)		72% - 93%
Hsu et al. (2010)	30 - 65 48 average	65% - 24% 44% average
Fulcrum (2011), using MSW		75%
Enerkem (2011), using MSW		80%
Fossil petrol baseline, from JEC (2006)	*86.4*	

Table 24-2: Range of GHG emission savings from mixed alcohols/ethanol

24.4 Costs

There is far less reliable cost data available for mixed alcohol routes compared to, say, FT synthesis. RENEW has published cost modelling for thermo-chemical mixed alcohols production from two different plant configurations (RENEW, 2007). Total project investment for a 500 MW_{th} biomass input plant is estimated at £285-340million, depending on the plant configuration chosen. The lower estimate is for an entrained flow gasifier using torrefied material, and the higher cost estimate is a Dual gasifier operating at atmospheric pressure, which therefore requires larger cleanup equipment, along with steam generation and significant gas compression. This further evidence for the preference of only using pressurised gasifiers in catalytic fuel synthesis applications.

Phillips et al. (2007) and Dattu & Phillips (2009) also give a detailed cost breakdown for plant components, for theoretical indirect and direct gasifier systems. Total project investment for a 417 MW_{th} biomass input plant is estimated at $\$_{2005}$ 191-254million (£$_{2011}$ 191-254m). Associated operating costs are \$62-77m/year, including capital depreciation, income tax and average return on investment, and ~\$13m/year income from higher alcohol co-products and exported electricity. If built today, the corresponding ethanol production cost could theoretically be \$1.01-1.57/gal (or £13-20/GJ), of which, approximately 35-40% is feedstock, 40-50% capital cost related, and -10% to -15% co-product revenues.

As for FT synthesis and lignocellulosic ethanol plants, costs are likely decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through mixed alcohol catalyst development, synthesis reactor process intensification, novel gas cleanup, and experience with efficient plant integration. Production costs could fall at a similar rate to those given in the FT synthesis chapter, although no studies have yet modelled this in detail.

24.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

Downstream of the process steps described, the methanol and ethanol fractions may need to be denatured (additives added to make it undrinkable). The alcohols must be transported, and blended for use.

24.6 Deployment and development status

The overall mixed alcohols route is currently at the pilot and demonstration stage (TRL 5 to 6). Many of the plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, and syngas cleanup. However, some processes are only at pilot scale, such as pressurised O_2-blown biomass gasification, novel hot gas cleanup, mixed alcohol synthesis and micro-channel fuel synthesis reactors. Plant integration experience is in line with the overall route, i.e. TRL 5 to 6.

There are 9 known developers working on mixed alcohols liquids routes, with around 12 active projects, all of which are based in North America (Bacovsky et al, 2010), (E4tech, 2010) (Biofuels Digest, 2011b) (Nexant, 2006). These projects are focusing on either biomass or wastes:

- Enerkem (Canada): Sherbrooke 0.13Mgy pilot opened in 2003, Westbury 1.3Mgy demo opened in 2009, Edmonton 10Mgy commercial MSW plant in 2011, Mississippi (US) 10 Mgy plant planned in 2013
- Range Fuels (US): Denver 0.9Mgy pilot opened in 2008, Soperton 4Mgy commercial plant was producing methanol from mid 2010, then made one batch of ethanol before closing (Biofuels Digest, 2011c). Planned expansion to 60Mgy is uncertain
- Gulf Coast Energy / Pearson Technologies (US): Livingston 0.3Mgy pilot open, 1.1Mgy demo in Aberdeen, Mississippi open, 7-25Mgy plans for Hawaii, California and south eastern US
- Fulcrum Bioenergy (US): Sierra Biofuels MSW to 10.5Mgy ethanol by late 2012
- Maverick Biofuels (US): Pilot plant in North Carolina in 2012
- Power Energy Fuels (US): possible 0.6Mgy “Ecalene” pilot at Wabash River IGCC plant
- Standard Alcohol Company of America (US): “E4 Envirolene”, no pilot plant yet
- Syntec Biofuel/Synthenol (Canada): no pilot plant yet

A few lab-scale pilots have been built in the US, at research organisations such as Iowa State, Research Triangle Institute and the Southern Research Institute (US). Micro-channel reactors are currently only being considered for FT synthesis, but could be applicable for mixed alcohols.

24.7 Barriers to development and deployment

Barriers generic to all biomass gasification routes are given in the Gasification chapter.

One of the key drivers for the development of mixed alcohol synthesis is that mixed alcohols are a more attractive blending stock than pure methanol. Mixed alcohols have lower vapour pressure, better solubility with hydrocarbon components, improved water tolerance, and higher overall heating value compared to methanol. The environmental impact of oxygenates in gasoline was another driver which increased interest in mixed alcohols in the 1990s.

However, there are no commercial plants in operation, and the route suffers from low yields and poor selectivity. Single pass yields are on the order of 10% syngas conversion (39% CO conversion) to alcohols with methanol typically being the most abundant alcohol produced (Phillips et al., 2007).

There are several technical barriers to be overcome in order to achieve the 2012 efficiencies and costs estimated in Phillips et al. (2007). Specific mixed alcohol catalyst research targets include:

- Increase the single-pass CO conversion from 38.5% to above 50%, and improve the CO selectivity to alcohols from 80% to 90%.
- Higher activity that will require a lower operating pressure to significantly lower process operating costs. Combined with the lower volumes of unconverted syngas to recompress and recycle, this lower pressure has the added benefit of lowering the energy requirement for the improved synthesis loop
- Precise temperature control reactor designs need to be developed for the mixed alcohol synthesis reaction to improve the yields, selectivity and the economics of the process

This NREL modelling uses a modified FT catalyst based on the former Dow/UCC catalyst, with conversion performance based on target 2012 results. In addition to higher total CO conversion and higher alcohol selectivity, the projected distribution of ethanol and methanol used in the NREL model differs from current results seen in industry. The Phillips et al. (2007) model assumes that 71% of the alcohol production is ethanol, and 5% is methanol. In contrast, the Dow distribution was 30-70% methanol and 34.5% ethanol (Antares Group, 2010).

24.8 UK Capabilities

Given the similarities between FT and mixed alcohol synthesis routes, the FT synthesis chapter already covers the discussion of UK capabilities in sizing, drying, gasification and syngas cleanup and conditioning steps.

Globally, past players in mixed alcohols synthesis have been Dow, Lurgi, IFP and Snamprogetti/Haldor Topsoe, although most only demonstrated their technologies at pilot scale (even using fossil fuel syngas), and few are still working in the area. Other players with FT or methanol synthesis strengths could also enter the market in the future, as could other micro-channel reactor offerings. However, mixed alcohol plant developers currently tend to have their own proprietary alcohol synthesis technology. Although the UK is considered a key player in catalysts and novel technologies (with Johnson Matthey and Oxford Catalysts' Velocys), the UK is mainly focused on FT catalysis, although could expand to mixed alcohols synthesis in the future.

As for FT synthesis, integration is typically carried out by technology developers/consortia, and EPC contractors conduct FEED studies and installation. The UK does not have any existing or planned mixed alcohols projects.

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25 Gasification with syngas fermentation

25.1 Technology description

This route involves converting lignocellulosic feedstocks, such as energy crops, residues or wastes, into ethanol. Gasification is used to thermo-chemically convert the feedstock into syngas, which is then anaerobically fermented by micro-organisms into ethanol, before product upgrading, as shown in Figure 25-1. Other alcohols or organic acids could also be produced (e.g. butanol, acetate), although most developers are focused on producing ethanol only.

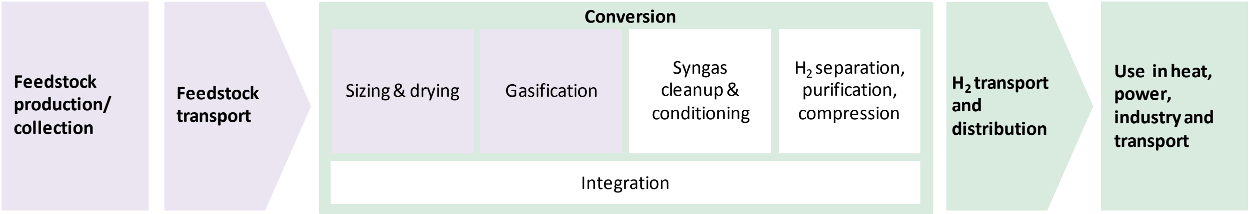

Figure 25-1 Process schematic for syngas fermentation production from biomass

The route is significantly different to the catalytic fuel synthesis routes, since syngas quality requirements are much less strict, economies of scale are different, and the fuel production step relies on low temperature and pressure biological processes, rather than high temperature and pressure chemical reactions. Bacovsky et al. (2010) give a good overview of the whole route. Each of the main process steps is described below.

25.1.1 Sizing & drying and Gasification

Downstream demands for syngas fermentation are much less strict than for catalytic routes, hence whilst pressurised gasification and the avoidance of nitrogen might still be advantageous, they are not essential requirements. Therefore, there is a wider choice of suitable gasifier types, such as fluidised beds, entrained flow or plasma gasifiers, since these are able to achieve the medium to large scales required for syngas fermentation. The suitable gasifier types are described in more detail in the separate Gasification chapter, along with their sizing and drying requirements.

25.1.2 Syngas cleanup and conditioning

Gas cleaning and conditioning for syngas fermentation is rather different to that for FT synthesis. The discussion below highlights the points where the two processes differ significantly – please refer to the FT synthesis chapter as a starting reference.

The main requirement for syngas for fermentation is the avoidance of tars or hydrocarbons (to within a similar level as for FT synthesis), as they inhibit fermentation and adversely affect cell growth.

Most of the organisms grow better on CO than H_2, or are insensitive to the syngas H_2 to CO ratio, i.e. they will grow on either gas. As a result, the syngas H_2 to CO ratio can be low and does not need to be controlled, i.e. a water-gas shift (WGS) reaction is not needed.

In general, the biological process is not sensitive to many of the other requirements for the chemical catalytic processes, although tolerance to particular compounds (e.g. sulphur, nitrogen, halides), will depend on the particular type of organism used, with the presence of some compounds even being advantageous for micro-organism growth. Since the fermentation step process conditions are close to atmospheric temperature and pressure, syngas compression is not required, and syngas cooling (with possible heat recovery) will also be required during syngas cleanup.

25.1.3 Syngas fermentation, upgrading

Fermentation:

The microbiological production of alcohols is a fermentative process based on the utilization of hydrogen, carbon monoxide and carbon dioxide in the syngas. A variety of microorganisms can use syngas as an energy and carbon source to produce ethanol, with some able to form butanol, acetate, formate and butyrate instead (Fischera et al. 2008). These include *Acetobacterium woodii, Butyribacterium methylotrophicum, Clostridium carboxidivorans P7, Clostridium drakei, Clostridium scatologenes, Clostridium ljungdahlii, Clostridium thermoaceticum, Eubacterium limosu, Moorella and Peptostreptococcus productus* (Henstra et al. 2007).

Current syngas fermentation efforts are predominantly focused on ethanol production. The main advantage of the microbiological process is the mild process conditions, similar to biogas production. The process operates at low pressures (atmospheric to 2 bar) and low temperatures (most use near 37°C, although some species can survive and grow in temperatures ranging from 5°C to 55°C), with the exact reactor conditions and pH depending on the type of microorganism used.

The main disadvantage is the generally limited gas-to-liquid mass transfer rate, and control of micro-organism which requires specific reactor designs. This will generally give low per-pass conversion rates, and hence a large proportion of the syngas will remain unreacted. This off-gas can then either be recycled to maximize ethanol production, or combusted to generate heat and power for the internal needs of the plant. Unlike FT and other catalytic fuel synthesis steps, syngas fermentation is not a highly exothermic process, hence large amounts of heat and power cannot be recovered from this step.

Depending on the micro-organism chosen (or genetically designed), desired product selectivity can be very high – for example, it is possible to produce 100% ethanol with no other by-products. This is a significant advantage over say, mixed alcohol catalysis, which produces a large range of methanol, ethanol and higher alcohols.

Upgrading:

The product upgrading of the obtained alcohol mixture consists typically of de-gassing, drying and separation of the ethanol product from the micro-organisms and water. This would traditionally be using distillation, but as the ethanol is generally at low concentrations of less than 5% (to avoid micro-organism poisoning), novel membrane techniques are also being developed to reduce the energy and costs of this separation step.

25.1.4 Integration

Biomass to syngas fermentation plants tend to be heavily integrated, since although the syngas fermentation step is not highly exothermic, the heat generated from syngas cleanup and cooling, or from the combustion of unreacted syngas, can be used to generate power or steam, to either input into the gasifier, or use for biomass drying. Gasification is an endothermic reaction, hence heat needs to be supplied (either from the biomass, or externally).

As well as the heat flows and integration in the plant, there are also several loops and components that need careful integration – e.g. example reactor recycle gas loops, and possible gasifier air separation unit heating and cooling requirements.

25.2 Feedstock

Please refer to the Gasification chapter for those feedstocks suitable for Entrained flow, Plasma, Bubbling, Circulating and Dual fluidised bed gasifiers.

25.3 Technical and environmental characteristics

25.3.1 Scale

The minimum economic scale for syngas fermentation is expected to be considerably smaller than conventional FT processes, at around 30,000 t/yr ethanol output (10Mgy), which equates to a gasifier biomass input of ~ 60MW$_{th}$ (Ineos Bio, 2010).

This minimum economic scale determines which types of gasifier might be the most suitable for liquid fuels production – i.e. fluidised beds, entrained flow or plasma gasifiers. This scale is either as a single gasifier, or combining a small number of gasifier modules. Modular systems may not have the same economies of scale as single systems, but could have benefits in terms of use of different feedstocks, and of availability.

The largest plant currently operating is Coskata's Madison pilot plant at 0.04 Mgy. However, Coskata have stated that they expect their commercial plants to produce 50 or 100Mgy ethanol. Ineos Bio have stated that they are planning small plants at around 10Mgy ethanol + 5MW$_e$, or larger plants at 50Mgy + 25MW$_e$ (Rice, 2008), although the largest planned plant could eventually reach 160 Mgy (Ethanol Producer, 2010).

25.3.2 Efficiency

Biomass to ethanol efficiencies vary according to the gasifier, micro-organism, reactor vessel, product recycling and feedstock types, and any co-products generated. However, unlike for many of the other fuel synthesis routes, there are no detailed techno-economic studies available, hence the only data available is from developers and the literature. These values are summarised in Table 24-1, as well as converted into corresponding LHV plant efficiencies.

The handful of active developers (Coskata, Ineos Bio) that are currently planning commercial plants quote dry biomass to liquid fuel conversion efficiencies of between 379 – 400 litres of ethanol/tonne of oven dry feedstock (Coskata, 2011) (Rice, 2008). Ineos Bio is also planning on using the syngas off-gas to generate power, and exporting power at overall efficiencies of 6-12%, with a similar amount of power being consumed with the plant (Rice, 2008).

By comparison, Virkajärvi (2010) states a current yield of 300 litres/odt, Wei et al. (2009) gives 37% LHV conversion efficiency from biomass to ethanol, whilst Genecor (2011) gives a current yield of 340 litres/odt, increasing to 398 litres/odt by 2020. Therefore, whilst it appears that the values quoted by developers are currently ambitious, they could be achieved in the next 10 years.

Reference	litres ethanol /dry tonne	LHV % efficiency
Coskata (2011)	379	43%
Rice (2008)	400	46%, plus 6-12% power export
Virkajärvi (2010)	300	34%
Genecor (2011), now and likely 2020	340 398	39% 46%
Wei et al (2009)	333	37%

Table 25-1: Range of LHV efficiencies from biomass to ethanol via syngas fermentation

25.3.3 GHG emissions

Emissions of the conversion process for ethanol from biomass feedstocks are relatively low, as a result of syngas and the excess heat from the process being used to provide steam and electricity for the plant, and relatively few chemical inputs. Any net surplus of electricity exported from the plant can also be given a credit for displacement of other electricity generation. Available GHG values from the developers are discussed below. It is notable that both developers are focusing on wastes, hence GHG savings from woody biomass are likely to be lower (i.e. higher emissions from upstream cultivation, harvesting and transport).

Coskata (2011) state that their route reduces GHG emissions by as much as 80-90% when input materials such as grass, agricultural waste or woodchips are used, based on Argonne National Laboratory analysis. Using garden and wood waste to produce ethanol via Ineos Bio's processes, Eunomia (2010) have calculated GHG emissions of approximately -20gCO_2e/MJ (i.e. a 123% saving vs. fossil petrol), since the power output is sufficient to offset all of the fossil emissions from the production process and pre-treatment. Residual MBT and MHT wastes have higher emissions of 8-14 gCO_2e/MJ (a 91%-84% saving).

25.4 Costs

There is essentially no reliable cost data available for syngas fermentation routes – the only complete plant estimates available are high level figures from the developers, with incomplete plant data available in the literature. The cost data available is summarised in Table 23-1, and discussed below.

Genecor (2011) gives a current capex of $5/gal (£0.84/litre), falling to $3/gal (£0.5/litre) by 2020. Coskata (2011) claim that a full scale plant producing 100Mgy (379m litres/yr) would have capital costs of $3-4/gallon (£0.5-0.68/litre), but production costs of less than $1/gallon (~£8/GJ of ethanol).

Ineos Bio have quoted a variety of capital costs, ranging from £52m for the 8Mgy Seal Sands project in the UK (Ineos Bio, 2010b), to $130m (£83m) for the 8Mgy Vero Beach plant (Ineos Bio, 2011), and $254m (£163m) for the 42Mgy Powers Energy plant (Ethanol Producer, 2010).

Operating costs for a syngas fermentation plant are expected to be low, due to the syngas contaminant tolerance and low pressure and temperature fuel production step (unlike for FT), and the avoidance of pre-treatment enzyme costs (as for lignocellulosic ethanol)

Based on analysis from Piccolo & Bezzo (2009), Munasinghe & Khanal (2010) give a range of ethanol production costs via syngas fermentation. These vary from $1.60 – 1.79/litre ethanol (equating to £48-54/GJ), for feedstock costs between $36 – 63/odt (i.e. £1.2 – 2.2/GJ). This analysis even excludes the cost of the biocatalyst, since it is stated that this is not presently available on the market. Costs given here are already significantly higher than those for lignocellulosic ethanol, and would likely be even higher, were the cost of the micro-organisms included.

As for FT synthesis and lignocellulosic ethanol plants, costs are likely decrease considerably, both as a result of scale up and learning of plant, and from innovation, particularly through micro-organism development, synthesis reactor process intensification, novel gas cleanup, and experience with efficient plant integration. Production costs could fall at a similar rate to those given in the FT synthesis chapter, although no studies have yet modelled this in detail.

Reference	Scale (MW_{th} biomass input)	Capex (£m)	Opex (£m/yr)	Fuel production costs (£/GJ)
Piccolo & Bezzo (2009), excluding biocatalyst costs	420	342	13	47 – 54 base case 45 mid-term 40 long-term
Coskata (2011)		300 – 400		target of ~8
Ineos Bio (2010)	50 263	52, 83 163		

Table 25-2: Range of biomass gasification + syngas fermentation economic data

25.5 Requirements of the upstream/downstream process and system considerations

Requirements **upstream** of the sizing and drying process are feedstock sourcing and transport, and intermediate sizing if necessary, such as a chipping step.

Downstream of the process steps described, the ethanol may need to be denatured (additives added to make it undrinkable). The ethanol will then be transported, and blended for use.

25.6 Deployment and development status

The overall biomass to syngas fermentation route is currently at the pilot stage (TRL 5). Many of the plant components are nearing commercial availability in other applications, e.g. biomass chipping and drying, gasification and syngas cleanup. However, some processes are only at pilot scale, such as novel hot gas cleanup, and syngas fermentation reactors. Plant integration experience is in line with the overall route, i.e. TRL 5.

There are 3 known developers working on biomass to syngas fermentation routes, with around 10 active projects (Bacovsky et al, 2010), (E4tech, 2019) (Biofuels Digest, 2011b). These projects are focusing on wastes and woody biomass:

- Coskata (US), using an AlterNRG/Westinghouse Plasma gasifier: Madison 0.04Mgy pilot opened in 2009. Boligee, Alabama 55Mgy commercial plant in 2016 with $250m US DOE loan guarantee, and likely to use modular gasifier trains
- Ineos Bio (US and UK): Fayetteville pilot plant since 2004, 8Mgy + 6MWe Indian River BioEnergy Center is under construction in Vero Beach, Florida with $75m US DOE loan guarantee, operational on wood and food wastes in 2012. Also advanced plans for similar scale plant at Seal Sands in Teeside, UK, operational in 2013, and expansion plans post-2015. Further 42Mgy plant also planned by Powers Energy of America, with expansion possibilities up to 160 Mgy.
- Lanzatech (NZ), using waste syngas from the steel industry, not from biomass gasification: Baosteel and Chinese Academy of Sciences 0.1Mgy ethanol demonstration plant under construction, starting in 2011, with future commercial plants planned. Lanzatech partnerships with Mitsui, LCY Chemical Corporation, Posco (Korea), IndianOil and Jindal Steel and Power Limited. Also have US DARPA funding with PNNL to develop a syngas to jet route via 2,3-Butanediol

Some of the original syngas fermentation research was carried out at Oklahoma State University and the University of Oklahoma, leading to the discovery of a set of anaerobic microorganisms for the conversion of synthesis gas to ethanol. Experimental work to advance the organisms and build a biofermentation technology team was initiated at Argonne National Laboratories. Mississippi State University has also conducted syngas fermentation research.

Interestingly, NREL chose not to consider syngas fermentation routes for further study within a biomass-to-liquids techno-economic analysis (Swanson et al., 2010), because of limited commercial scale experience.

25.7 Barriers to development and deployment

Despite the advantages of syngas fermentation, such as high yields, low operating costs, tolerance to impurities and feedstock flexibility, there are several remaining challenges to overcome (Advanced Biofuels USA, 2011).

The principal barriers to further development and deployment for conversion of biomass to ethanol are the same as those outlined in the lignocellulosic ethanol chapter, i.e. access to project finance for demonstration and early commercial plants, and lack of clear policy signals. Barriers generic to all biomass gasification routes are given in the Gasification chapter. Other barriers set out in the IEA's biofuels roadmap (IEA, 2011), relate to:

- End-use infrastructure requirements "blending walls" – the limiting of ethanol in gasoline to 10% to 15% because of vehicle compatibility constraints – would limit deployment, and would need to be overcome through introduction of flex-fuel vehicles and high-level ethanol blends
- Need for increased investment in R&D. In these technologies, this refers to maintenance and nutrition of a "living system", improving reliability and designing continuously operating plants, improving mass transfer and energy balance in the fermentation and separation steps, and reducing high capital costs.
- Need for reduction of public and policymaker uncertainty on sustainability of biofuels

25.8 UK Capabilities

Given the upstream similarities between FT and syngas fermentation routes, the FT synthesis chapter already covers the discussion of UK capabilities in sizing, drying, gasification and syngas cleanup and conditioning steps.

There are no global players in syngas fermentation. All 3 of the biomass to syngas fermentation developers (Coskata, Ineos Bio, Lanzatech) currently have their own proprietary syngas fermentation reactor technology, a suite of optimised micro-organisms, along with novel ethanol separation concepts. Most of the upstream technologies (sizing, drying, gasification and syngas cleanup and conditioning steps) are expected to be bought "off-the-shelf".

Ineos Bio does have a strong UK presence, and is planning a MSW to ethanol plant at Seal Sands in Teeside. However, Ineos Bio's core technology was developed in Fayetteville, Arkansas (US), where most of the R&D efforts are still focused

As for FT synthesis, plant integration is expected to be carried out by technology developers/consortia, with EPC contractors conduct FEED studies and installation.

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26 Pyrolysis oil upgrading

26.1 Technology description

As described in the Pyrolysis chapter, crude pyrolysis oil (also called ‘bio-oil’) from fast pyrolysis is a dark brown viscous liquid, which contains a complex mixture of oxygenated hydrocarbons with water, and potentially also solid char particles. Crude pyrolysis oil can be used in some applications without further treatment. However, for others, including advanced boiler systems, industrial gas turbines, or combined cycle systems and for transport fuels (Stevens, 2009), further processing is needed.

The properties of pyrolysis oil that result in the need for upgrading include:

- high acidity - causing corrosion
- high and increasing viscosity – and so high pumping costs
- high density - which has implications for design of pumps
- presence of char – causing blocking of filters and catalysts
- lack of miscibility with hydrocarbons - making refinery integration difficult
- poor stability and potential for phase separation
- potential presence of contaminants or catalyst poisons such as sulphur

Different fractions of the pyrolysis oil could be converted to different products such as gasoline, diesel, jet fuels and chemicals (Homgren, 2009, Dynamotive, 2011). Upgrading steps such as catalytic stabilisation and deoxygenation would be used to convert pyrolysis oil to fuels. There is also ongoing RD&D on new processes for upgrading pyrolysis oils with lower hydrogen requirements, and on developing new catalytic processes to produce better quality oils directly, which require less upgrading.

In terms of process configuration, pyrolysis upgrading can be carried out in two ways:

- In a standalone upgrading process
- Through integrating pyrolysis oils directly into a conventional oil refinery, which would first require some upgrading to lower acidity and water content. This could be done at the point of pyrolysis, or after transport of the pyrolysis oil to the refinery. The upgraded pyrolysis oil would then be incorporated into an existing refinery process, such as hydrocracking or FCC (fluid catalytic cracking), producing conventional refinery products such as diesel or gasoline

Note that the specifications of jet fuel mean that converting pyrolysis oil to jet fuel through hydrotreating would require more hydrogen than for production of a low blend road transport fuel, leading to increased high costs and emissions. Producing small proportions of jet fuel components, such as aromatics, alongside road transport fuels, could be a viable option.

26.1.1 Potential upgrading routes

The potential upgrading routes are still at a very early stage of development. Upgrading of pyrolysis oils can be divided in to three main routes: gasification, hydrotreating, and zeolite cracking (Bridgwater, 2011). Each of these routes is discussed briefly below:

- Gasification: The pyrolysis products can be gasified and fed to alcohol, methanol or Fischer Tropsch synthesis processes. These processes are discussed elsewhere in this report
- Hydrotreatment: hydrotreating of hydrocarbons - use of catalyst at high pressure in the presence of hydrogen - to remove nitrogen, sulphur and oxygen is a common and well established refinery process. However, pyrolysis oils contain a much higher proportion of oxygen than is usually found in refinery feedstocks and thus the processes must be adapted to account for this. This development is still largely in the research phase (Jones et al., 2009). Multi-stage hydrotreating of pyrolysis oils has been found to result in the almost complete deoxygenation of the oil by a combination of hydrodeoxygenation (HDO) and decarboxylation (DCO) (Jones et al., 2009). Other researchers have suggested that deep deoxygenation may not be necessary if the resulting stabilised oil is further processed in a conventional FCC process (Mercader, 2010). The main issues to be overcome here are catalyst deactivation, reactor clogging and minimization of the required hydrogen input
- Zeolite cracking: this process, which uses complex aluminosilicates as catalysts, rejects oxygen in the form of carbon dioxide from the pyrolysis oils in either liquid or vapour phase. Unfortunately, pyrolysis oil feeds tend to coke easily (Bridgwater, 2011)

Co-processing of pyrolysis oil in conventional refinery units could allow use of existing infrastructure and commercial technologies, along with any spare hydrogen, giving significant cost savings compared to dedicated upgrading units using hydrodeoxygenation

26.2 Feedstock

Pyrolysis oil is the feedstock for the upgrading process. Pyrolysis oil composition will depend on the feedstock used, in particular the proportion of lignin. Lignin is a complex oxygenated aromatic and its presence in pyrolysis oil makes it more gasoline-like in character (Nexant, 2008).

Most proposed upgrading processes also use hydrogen, which could itself be biomass-derived (from pyrolysis oil or solid biomass), produced from natural gas or other fossil fuel refinery streams.

26.3 Technical and environmental characteristics

26.3.1 Scale

Pyrolysis oil upgrading is likely to be done at a large scale: either from a large pyrolysis plant, or from aggregation of supply from distributed pyrolysis plants. It could also be done at a refinery by mixing the pyrolysis oil with the conventional crude feedstock.

Wright et al. (2010) and Jones et al. (2009) model theoretical upgrading plant scales ranging from 36 Mgy (136m litres/yr) to 72 Mgy (275m litres/yr), using a pyrolysis oil production unit taking in 2,000 odt/day of biomass. If other smaller pyrolysis oil units at scales of 200 – 1,000 odt/day are considered as in the pyrolysis Chapter, a correspondingly smaller upgrading plant output scale would be 3.6 – 36 Mgy (13.6 – 136m litres/yr). However, commercially viable scales are not yet known.

26.3.2 Efficiency

The upgrading process yields different products depending on the system configuration, e.g. an equal share of diesel and naphtha. As discussed in more detail in the cost section below, Wright et al. (2010) and Jones et al. (2009) model five upgrading scenarios, with various methods of hydrogen production. The mass conversion yields from pyrolysis oil (containing 10-20% water) to upgraded fuel vary from 22% - 39%. This equates to an energy efficiency range from pyrolysis oil to upgraded fuel of 56% - 97%, or 56% - 75% if the energy input of any natural gas or hydrogen is also accounted for.

26.3.3 GHG emissions

Given the early stage of development of many pyrolysis oil upgrading processes, there is little information available on their greenhouse gas emissions. In general, the emissions will depend on

- The degree of upgrading required, depending on the specification of the end use
- The hydrogen requirements of the upgrading processes, and the method of production of the hydrogen e.g. whether it is from natural gas or biomass
- The degree of integration with the pyrolysis process, or with refinery processes – this will affect the source of the heat and power required to run the process, for example, whether it can be provided from biomass, or from co-products such as pyrolysis gases and char

26.4 Costs

There are only a few theoretical studies that have analysed the techno-economics of pyrolysis oil upgrading. The studies examined in this chapter all consider pyrolysis and upgrading to fuel, and are the same studies as used in the pyrolysis oil upgrading chapter – this was done so that there is consistency between the two chapters. However, the costs discussed below, and summarised in Table 9-2, only refer to the upgrading part (i.e. production of diesel-type transport fuels from pyrolysis oil).

As for the GHG emissions discussion above, there are multiple configuration options for pyrolysis oil upgrading, that therefore vary widely in their costs. The production economics for pyrolysis oil upgrading are strongly influenced by pyrolysis oil price and oxygen content, hydrogen production method and process integration.

Wright et al. (2010) model two plant configurations: one with hydrogen production via hydrotreating of 38% of the input pyrolysis oil, and another with hydrogen purchase from a refinery. Both sets of costs considered below are for detailed “nth” plants – pioneer cost analyses give significantly higher production costs, although are not available in the same level of detail, i.e. split into pyrolysis and upgrading.

Jones et al. (2009) model three plant configurations: one with hydrogen production via natural gas reforming, one with reforming of 35% of the input pyrolysis oil, and another with hydrogen purchase from a refinery.

Nexant (2008) model three upgrading scenarios: co-processing in an existing hydrocracker, processing in a new dedicated hydrocracker, and co-processing hydro-treated pyrolysis oil in an existing Fluid Catalytic Cracker. Upgrading plants scales or efficiencies are not specified, and a common pyrolysis oil cost of £180/ton (£9.7/GJ) is assumed. The scenarios have upgraded fuel costs of £23.6/GJ, £16.6/GJ and £30.3/GJ, respectively. Raw materials are the primary component in the scenarios using existing refinery equipment, and capital cost is the primary component in the scenario using new refinery equipment.

Reference	Scale (Mgy output)	Capex (£m)	Opex (£m/yr)	Char & gas revenues (£m/yr)	Fuel production costs (£/GJ)
Wright et al. (2010), pyrolysis oil hydrotreating	35.9	51	3.6	5.4	0.9 without feedstock, 12.2 with feedstock
Wright et al. (2010), H_2 purchase	60.3	16	15.6	2.2	2.0 without feedstock, 8.5 with feedstock
Jones et al. (2009), natural gas reforming	72.4	115	26		4.2 without feedstock, 8.2 with feedstock
Jones et al. (2009), pyrolysis oil reforming	47.1	115	12.4		4.2 without feedstock, 10.4 with feedstock
Jones et al. (2009), H_2 purchase	72.4	47	13		2.0 without feedstock, 6.0 with feedstock
Nexant (2008), existing hydrocracker					23.8 with feedstock
Nexant (2008), new hydrocracker					16.6 with feedstock
Nexant (2008), existing Fluid Catalytic Cracker					30.3 with feedstock

Table 26-1: Range of pyrolysis oil upgrading economic data

26.5 Requirements of the upstream/downstream process and system considerations

Prior to upgrading, the pyrolysis oil may need to be filtered to remove solids, and reduce the ash and alkali metal content. In addition, solvents can be added to homogenize the pyrolysis oil and reduce its viscosity (Bridgwater, 2011).

Downstream of the upgrading, the products will either be mixed with conventional feedstocks and fed into refinery processes, or, if sufficiently upgraded, blended directly with fuels (Bridgwater, 2011).

26.6 Deployment and development status

There are a relatively large number of companies and research institutions conducting work in the area of pyrolysis oil upgrading research: Albemarle, Anellotech, Arkema, ConocoPhillips, CRI/Criterion, Dynamotive, Ensyn, Evergent, GTI, Haldor Topsoe, Kior, Renewable Oil Corporation (ROC), Shell, UOP. However, most of the research is still at bench or small scale, with targets such as proving 1,000 hours of operation (DOE, 2010).

The most advanced of this work is now moving into pilot scale demonstration (TRL 4). Despite the relatively early stage of development of pyrolysis oil upgrading, it is considered by some industry experts that if proven successful at pilot scale, it could be scaled up very quickly. There have been some optimistic statements on this route. For example, UOP have stated that they expect pyrolysis derived fuels to be 2-3 years from commercialisation (Ellis, 2008), but consider the principal barrier to this to be ‘a definitive mandate’ for this route (presumably policy favouring second generation biofuels), however it is not yet known whether these goals are feasible.

The US DOE has funded a number of projects in this area including the following teams:

- Pacific Northwest National Laboratory (PNNL), NREL, UOP and Albemarle
- W.R. Grace & Company
- Gas Technology Institute
- Battelle Memorial Institute

The main industries involved are pyrolysis reactor developers, catalyst developers and petrochemical companies. There is also significant interest from the academic community, including in the UK. UOP, Shell, Arkema, Albermarle, Sasol and Sabic are all involved in US DoE and EU funded projects in this area. ConocoPhillips is also working with ADM and the University of Iowa on fast pyrolysis and oil upgrading.

26.7 Barriers to development and deployment

The principal barriers to further development and deployment for pyrolysis upgrading are (Pyne, 2011, Stevens, 2009, E4tech):

- Uncertainty over potential pyrolysis oil markets, given the early stage of upgrading technology, and relatively limited experience in use of pyrolysis oil in heat and power. As a result, progress is currently within companies planning the whole system to heat, power or fuels, rather than intending to focus on oil sales.
- Limited supplies of pyrolysis oil are available for testing and development of upgrading
- There is a lack of standards for use and distribution of bio-oil and inconsistent quality inhibits wider usage; considerable work is required to characterise and standardise these liquids and develop a wider range of energy applications
- Environment health and safety issues in handling, transport and usage of pyrolysis oil

26.8 UK Capabilities

The UK has world-class capabilities in pyrolysis, particularly in academia. A comprehensive view of UK activities in pyrolysis was published this year (Bridgwater and Watkinson, 2011), highlighting UK activity and links with work underway internationally. This report lists several world class academic groups undertaking research into pyrolysis oil upgrading in the UK: Aston University, Cardiff University, Cranfield University, University of Manchester, University of Nottingham, and the University of Warwick.

There are a few UK companies active in pyrolysis oil upgrading, together with others with skills in process design and evaluation, although none of the main technology developers with demonstration plants are based in the UK.

- 2G BioPOWER
- Conversion and Resource Evaluation (CARE)
- Future Blends, the Carbon Trust’s Pyrolysis Challenge company
- Johnson Matthey

BP, Rotawave, Centre for Process Innovation (CPI), Catal International, Greenergy, and Oxford Catalysts could also add industrially relevant expertise.

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27 Hydrotreatment

Hydrotreatment involves the conversion of vegetable oils into automotive diesel and jet fuel, referred to as hydrogenated vegetable oil (HVO) and hydrotreated renewable jet (HRJ) respectively. HVO is often called "renewable diesel" in the US. Unless HVO or HRJ are specifically mentioned, explanations within this chapter refer to both fuels.

27.1 Technology description

An overview of the hydrotreatment process is given Figure 27-1. The process of hydrotreatment for HVO production consists of a thermal decomposition process, followed by a hydrogenation and isomerisation reaction. An additional selective cracking process after the hydrogenation and isomerisation is needed to produce HRJ (IATA, 2009).

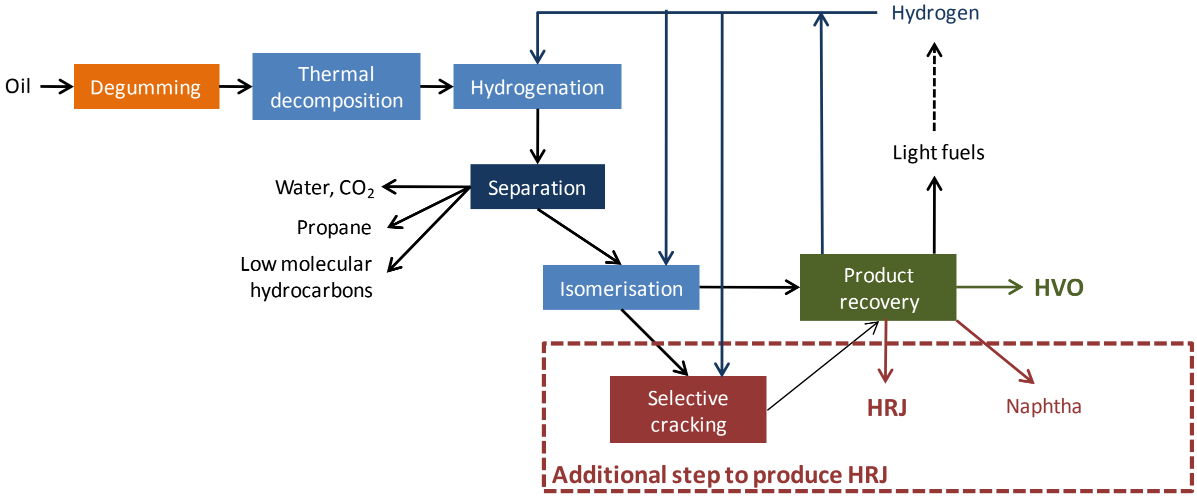

Figure 27-1: Hydrotreatment process diagram (adapted from Kalnes et al, 2011)

27.1.1 HVO production

In more detail, the hydrotreatment process to produce HVO consists of the following steps:

- **Degumming**: Prior to the hydrotreatment process, impurities in the vegetable oils need to be removed
- **Thermal decomposition**: the vegetable oils are broken down by a thermal decomposition process (IATA, 2009).
- **Hydrogenation**: hydrogenation is undertaken in a multi-stage adiabatic, catalytic hydrogenation reactor that removes oxygen from the triacylglycerides and adds hydrogen as the high molecular weight of oxygen is unsuitable for diesel or kerosene-like fuels (Kalnes et al., 2008; UOP, 2011).
- **Separation**: The hydrogenation of vegetable oils produces a range of paraffinic hydrocarbons (see Figure 27-2), with carbon numbers in the range of fossil diesel fuel (C14 to C20), (Bogers, 2008; ICAO, 2009). Propane, low-molecular weight hydrocarbons, carbon dioxide and water are produced as by-products, and separated from paraffinic hydrocarbons. Propane may be combusted for on site heat production.

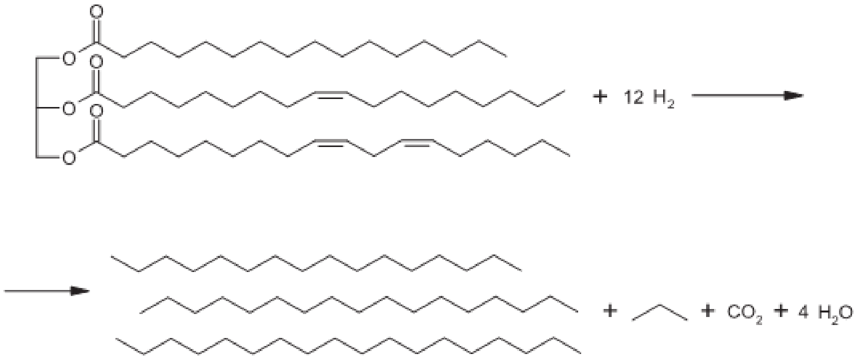

Figure 27-2: Transformation of triglyceride and hydrogen into paraffinic chains, propane, carbon dioxide and water by hydrogenation (Arvidsson et al., 2011)

- **Isomerisation**: In order to produce a diesel-like fuel, the paraffinic chains are isomerised. Isomerisaton is needed to meet freeze point fuel specification, for successful operation in cold temperatures. The same applies for jet fuel.
- **Product recovery**: the main product of isomerisation is vegetable oil based diesel, suitable for road transport. The HVO is separated in a gas/liquid separator from light fuels and the remaining hydrogen. The hydrogen is recycled and used again in the hydrogenation and isomerisation steps. Additional hydrogen could be produced via stream reforming from the light fuels separated at the end of the process (Kalnes et al., 2008).

As all fossil diesel fuel requirements are met by hydrotreatment, HVO can be used directly without blending it with fossil diesel (Neste, 2011a). However, Neste is currently using it in a 10% blend with fossil diesel (Neste, 2011).

27.1.2 HVO/HRJ co-production

Some or all the HVO produced by hydrotreatment can be transformed into HRJ. The additional steps to produce HRJ from HVO are the following:

- **Selective cracking**: The carbon number of the isomerised paraffins is in the range of C14 to C20, which is higher than the C8 to C16 molecules needed for jet fuel (HRJ) (Bogers, 2008; ICAO, 2009). These isomerised paraffins are suitable as HVO for road transport, however in order to transform it into a jet fuel, an additional selective cracking step is necessary. The selective cracking takes place after the isomerisation reaction by adding additional hydrogen. Depending on the plant configuration, different shares of HRJ can be produced. The remaining part will be HVO, light fuels, naphtha and hydrogen which can be recovered (EC, 2011; EC, 2011a; UOP, 2009; IATA, 2009; ICAO, 2009).
- **Product recovery**: the products of selective cracking - HRJ, HVO, light fuels, naphtha and hydrogen - are then separated in a conventional gas/liquid separator(Kalnes et al., 2008; UOP, 2011).

After the separation, the minimum aromatic compound content required to achieve seal swell can be achieved by blending the HRJ either with fossil jet fuel or with aromatics from other processes in a blend with maximum 50% HRJ.

27.1.3 System design

Two different options are possible for the hydrotreatment process: co-processing in an existing refinery in a separate unit or in a new built stand alone plant. Even though the hydrogenation of crude oil and vegetable oil together appears to be attractive as equipment can be reused and hydrogen is often readily available, several draw backs exist: a pre-treatment reactor is necessary to remove trace metals that can be found in vegetable oils and quench capabilities are necessary due to the exothermic property of some of the hydrotretment reactions (Holmgren et al., 2007). As a consequence Holmgren et al (2007) state that dedicated vegetable oil hydrotreatment plants or units are more suitable.

27.2 Feedstock

Any vegetable oil such as palm oil, rapeseed oil, or jatropha oil can be used to produce HVO and HRJ. Tallow, used cooking oil and oils from microalgae are also potentially suitable feedstocks. It is important to note that palm oil and tallow, which are rich in saturated fats, need less hydrogen than soybean or rapeseed oils (Kalnes et al., 2008).

27.3 Technical and environmental characteristics

27.3.1 Scale

The scale of currently operating or planned hydrotreatment plants is in the range of 190,000 to 800,000 t/a (EC, 2011; Syntroleum, 2011; US DoE, 2011; BiofuelsDigest, 2011). Depending on the plant configuration, it can be a dedicated HVO plant or a co-production plant with different shares of HRJ and HVO as products.

27.3.2 Efficiency

The efficiency of the hydrotreatment process (expressed as energy content in products over total energy content in inputs) varies from 68% to 83% depending on the feedstock (UOP, 2011). Higher efficiencies are achieved using tallow while rapeseed and palm oil offers lower efficiencies (Kalnes et al. 2008). As HRJ requires more hydrogen (for selective cracking) than HVO, the efficiency for HRJ is marginally lower than for HVO.

27.3.3 GHG emissions

The GHG emissions for the hydrotreatment process to produce HVO are 9.4gCO_2e/MJ (UK Carbon Calculator, 2011), assuming that hydrogen is produced by steam reforming of natural gas. The additional GHG emissions for the selective cracking process to produce HRJ are 6.0 gCO_2e/MJ (ICAO, 2009). The GHG emissions to produce HRJ from vegetable oil are thus 15.4gCO2e/MJ. In general, the GHG emissions from hydrotreatment are heavily dependent on how the hydrogen for the hydrotreatment process is made.

27.4 Costs

In the European Commission study “Sustainable Way for Alternative Fuels and Energy in Aviation” (EC, 2011a), current capital costs are 95 £/t of biofuel and projected to decrease to 87 £/t in 2050. The operational costs, excluding feedstock costs, are currently around 75 £/t and expected to remain at a similar level in 2050.

27.5 Requirements of the upstream/downstream process and system considerations

In case of co-processing of vegetable oils with crude oil in a refinery a pre-treatment reactor will be necessary upstream as vegetable oils contain trace metal contaminants that need to be removed beforehand (Holmgren et al., 2007). The removal of solids and salts could be necessary as well in a pre-treatment step (Kalnes et al., 2008). Additional upstream requirements are sourcing of the feedstock and transport.

Downstream of the hydrotreatment process, the HVO can be blended with fossil diesel. Based on the standard approved on July 1st 2011 (ASTM D7566) HRJ or other bioderived synthetic fuels have to be added to fossil jet fuel in a blend up to 50% (European Biofuels, 2011).

27.6 Deployment and development status

HVO plants are considered to be commercial, whereas dedicated HRJ plants would require financial incentives to make them commercially worthwhile (EC, 2011). The current TRL of the HVO process is 8, as the technology is operating successfully in various commercial plants. The current TRL including the HRJ production process is slightly lower (TRL 7) as only one commercial plant has been operating for several months.

Hydrotreatment technology has been developed by Neste, UOP and Syntroleum (EC, 2011; Syntroleum, 2011; US DoE, 2011; BiofuelsDigest, 2011). Table 27-1 shows a non-exhaustive list of currently operating or planned hydrotreatment projects. HVO is currently produced commercially for road transport by Neste and Syntroleum. The plans announced by UOP for an HVO plant to be operating in 2010 and a dedicated HRJ plant by the end of 2011 are still in the planning stage (EC 2011; UOP, 2009).

Start of operation	Current status	Operator	Technology	Location	Size (t/a)
2011	under construction	Neste	HVO	Rotterdam, Netherlands	800,000
2010	operating	Neste	HVO	Singapore	800,000
2009	operating	Neste	HVO	Finland	190,000
2007	operating	Neste	HVO	Finland	190,000
Nov. 2010	operating	Syntroleum & Tyson Food	HVO & HRJ	Geismar, Louisiana, U.S.	240,000
	in planning	UOP – Galp Energia	HVO & HRJ	Spain	330,000

Start of operation	Current status	Operator	Technology	Location	Size (t/a)
	in planning	UOP - ENI	HVO & HRJ	Italy	330,000
	in planning	UOP for Valero Energy Cooperation	HVO	Louisiana, U.S.	437,000

Table 27-1: Current & planned hydrotreatment plants

All plants under operation by Neste are separated hydrotreatment units at existing oil refineries. This has the advantage that vegetable oils are not mixed with crude oil, however existing logistics, hydrogen, energy and other facilities can be used (Aatola et al, 2008). The first and currently only plant co-producing HRJ is in Louisiana, US and co-operated by Syntroleum and Tyson Food. It is a dedicated hydrotreatment plant; however the share of the production of HRJ is unknown. Moreover, HRJ has been tested in several flight demonstrations since 2008 (UOP, 2011b).

As the production process of HRJ is similar to the process for making HVO for road vehicles, with the only difference being the additional cracking process, current HVO plants could be used to produce both HVO and HRJ.

27.7 Barriers to development and deployment

The barriers for the further deployment of HVO and HRJ are similar, however for HVO a market exists – road transport in cold countries such as Finland or Canada – given adequate policy support. Therefore the hurdles of policy support, more stable financing mechanisms and sustainability concerns are even more relevant for more extensive HRJ deployment, despite the first co-operating plant in the U.S. (EC, 2011; UOP, 2011):

- 2nd generation biofuels are more expensive than kerosene, therefore adequate policy incentives are crucial to accelerate the deployment. However, these policy incentives are currently missing for HRJ beyond the EU ETS exemption (EC, 2011a). The additional cost of using HRJ is thus prohibitive for airlines as policy makers are waiting for the implementation of the sustainability criteria for different vegetable oils
- There is a lack of adequate financial instruments and understanding for needed capital investment for the construction of plants to support investors given the unsecure demand for jet biofuels
- Lack of any long-term off-take agreements between biofuel producers and the aviation industry (EC, 2011)
- Sustainability concerns for the production of non-renewable hydrogen and for the availability of sustainably produced oils and fats are having a negative impact on further deployment. Policy makers are waiting for the implementation of sustainability criteria and airlines have stated that they require sustainability criteria that are more stringent than the RED for transport fuels, e.g. no use of food crops.

27.8 UK Capabilities

The UK capabilities for hydrotreatment of either HVO or HRJ are limited, and no hydrotreatment plant has been build or planned in the UK so far. However, one of the leading technology developers, UOP, has an engineering design centre in the UK.

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Part 5: Technologies for heat, power, and combined heat and power generation

28 Biomass boiler (for heat applications only)

28.1 Technology description

In a biomass boiler, the biomass fuel is burned to produce heat or steam that can be used for either process or space heating (as well as cooling via absorption chillers). A typical biomass heat system comprises:

- Biomass reception, storage and fuel extraction - where the fuel is discharged by delivery vehicle and held in storage until it is extracted to the boiler;
- Energy conversion — conversion of the biomass in a boiler into heat or steam;
- Heat distribution – heat is delivered from the boiler to the point of use.

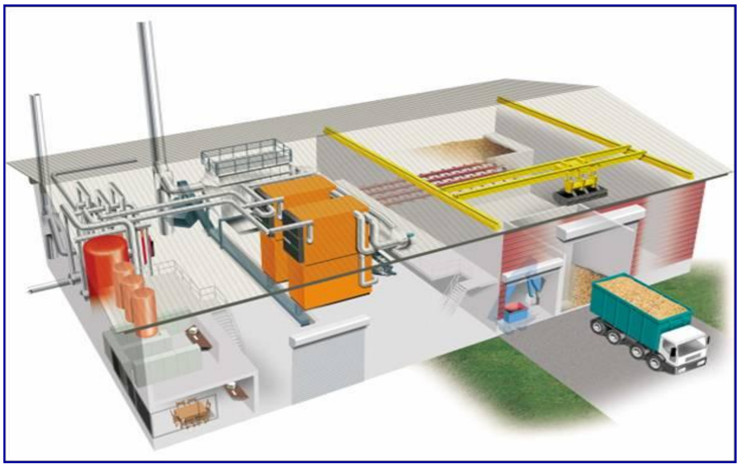


Figure 28-1 Biomass Heat System

28.1.1 Biomass heat system options

Biomass boilers for heating application are available in a range of configurations with selection dependent upon the scale of application and the characteristic of the intended biomass fuel. Essentially the technology is concentrated at the sub 10MWth scale with volume opportunities in the 100-700kWth range which focuses on space and service heat applications. Larger boilers with application between 700kW to 5MWth are applied in the commercial and industrial sector, supplying primarily process heat and steam. A limited number have been applied above this threshold and deliver to large industrial process heat users.

For the combustion of biomass fuels for heating, there are essentially four general types of combustion plant:

- Inclined grate boilers – which are installed in greater volumes for application >500kW$_{th}$.
- Plane grate boilers - , for greater application between 10-500kW$_{th}$. These boilers are able to burn woodchip and wood pellets;
- Stoker burners – primarily for smaller applications <50kW$_{th}$ which are able to burn both wood chip and wood pellets;

- Batch boilers – which are installed in greater volumes for applications below 50kW$_{th}$ and tend to burn logs or briquettes.

Typically, inclined grate systems are more flexible in terms of the fuel that they can accommodate but are more expensive due to their construction being more robust and complex. Nevertheless, all boilers have a similar construction and are differentiated by the following points which in turn impact the fuel type that can be accommodated:

- Fuel extraction from the store to the combustion chamber (pneumatic feed, auger, stoker etc);
- The area of the grate and combustion furnace, with a larger area being able to accommodate a greater tolerance of fuel moisture as the combustion area allows a degree of drying;
- The extent of the refractory lining within the furnace area;
- The configuration of the heat exchanger (vertical versus horizontal tubes;
- The means of ash collection.

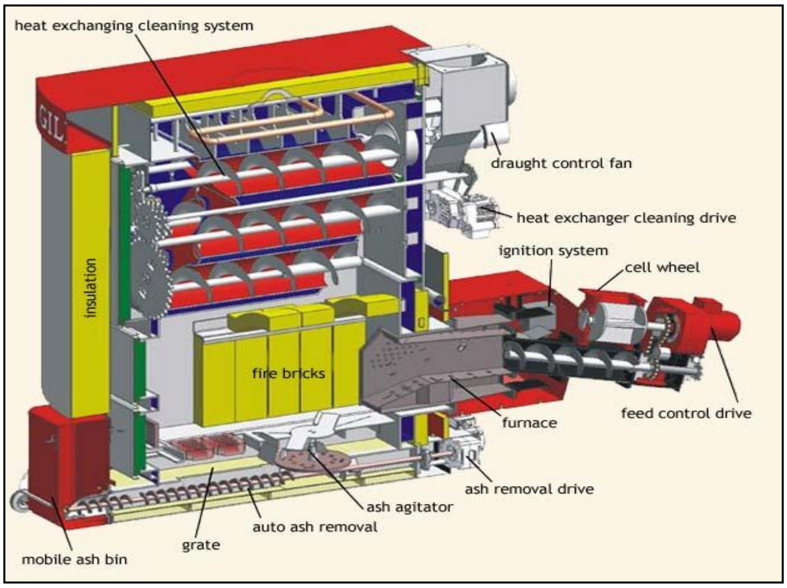
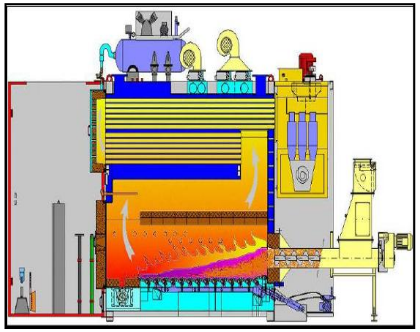


Figure 28-2 Biomass Boiler

Overall grate fired boiler is technology that has been developed over 150 years, its operation is therefore well understood, robust and reliable, (TRL 9). The overall merits of each option are detailed below in Table 28-1.

Grate Type	Advantages	Disadvantages
Inclined Grate (step grate) Boiler  Source: Econergy	- Wide tolerance of fuel type, moisture content (up to 60%), and particle size. - As a result of wide fuel tolerance, cheaper fuel may be procured, helping to offset higher capital cost. - Positive movement of fuel down grate avoids clinkering and blockages. - Well-regimented combustion leads to high efficiency.	- Relatively large fuel inventory in the plant leads to a slow response to load swings, although modulating controls improve controllability. - Large amounts of refractory (heat reflective) material on wet wood plants can result in a long warm-up time from very low to full-load (up to 2 hours). - Prolonged low-load mode operation can result in higher maintenance costs and reduced efficiency as a result of tarring of heat exchangers and condensing gases. - More complex design and bulky components can lead to higher capital costs.
Plane Grate Boiler  Source: Imperative Energy	- Smaller combustion area and less refractory material mean that these types of plant have a smaller spatial footprint. - Commonly dual fuel plants, therefore providing flexibility of operation. - In total capital cost terms (£/kW, installed) they are cheaper than the moving grate systems due to the simpler design and exclusion of refractory material.	- Due to the smaller combustion bed, the plant require lower fuel moisture content – typically 20-35% – rising to 40% if the plant has some refractory material lining the combustion chamber. - Due to the smaller combustion bed and lower moisture content tolerances, these systems require consistently good quality fuel. As a result they are best suited to applications where site owners are confident of securing good quality fuel (<35% MC).

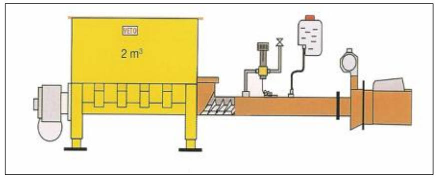
Grate Type	Advantages	Disadvantages
Stoker Boiler  Source: Veto	• Small fuel inventory makes for relatively rapid response to load swings. • The heat generated on slumber (when there is no heat requirement and the unit is simply maintaining ignition with as little heat output as possible) is very low. • Often lower cost than plane grate or moving grate systems.	• The fuel must be fairly dry: preferably <30%, never more than 35%. • The fuel particle size and moisture must be consistent: the small, intense combustion zone is easily disrupted. • In the lowest cost, smaller units, no separate provision for primary and secondary air supply exists, limiting the opportunity for fine-tuning to the needs of varying fuel.
• Batch Boiler  • Source: Froling	• Simple and cost-effective solution where biomass material and labour are available at low cost and efficiency is not a prime consideration for the system. • Robust designs mean lower (non-fuel) maintenance issues.	• The fuel must be fairly dry: preferably <25%. • A high level of user input – often on a daily basis.

Table 28-1 Biomass Boilers for Heat Generation (Carbon Trust, 2009)

28.1.2 Operating Availability

To date the three major factors affecting boiler plant availability have been:

- Variability in fuel quality and consistency:
    - Fuel quality has been problematic in terms of grade, moisture content and contaminants though this has significantly improved since 2007;
- Mechanical handling system breakdown: the sector has experienced significant problems with fuel reception, fuel handling, pre-processing and boiler furnace feeding equipment.
    - Poorly designed mechanical handling systems remain problematic for a number of sites resulting in excessive attendance impacting both cost and system acceptance.
    - Fuel hopper sizes have been inappropriately sized which exacerbate fuel supply issues and cost exposure;
- Skill base within the supply chain: Much of the technology used for biomass heating is imported from mainland Europe, consequently the UK skill base has struggled to offer a level of service which the professional heating market demands. Poor commissioning and design has led to significant downtime whilst installations underwent technical troubleshooting. This situation is improving significantly.

Since 2006/6 there has been a marked improvement in service delivery and now overall system availabilities can be expected to be in the order of 80 to 90% depending upon type of biomass.

28.2 Feedstock

In the UK, the principal biomass materials, which are available as fuels for energy conversion plants in sufficient quantities to be relevant for biomass combustion include:

- Surplus cereal straws and other dry agricultural residues although these are principally located in the east and south of England. The most significant cereal crop in this context is wheat;
- Forestry and sawmill residues in woodchip form. As produced, the residue materials have high moisture content (50-60% wet basis) and are variable in quality although the raw material can be air dried to reduce the moisture content prior to chipping to produce woodchip at c.30-40% moisture content;
- Wood pellets produced from sawdust and other sawmill residues The advantage of wood pellets is the low level of moisture content and the consistent quality for combustion which mean that they are particularly suited to heating applications where space is limited for fuel storage or where any user involvement with the system needs to be minimised. This requirement typically falls at the lower end of application (<200kW or in urban situations;
- Energy crops are plants grown specifically for use as fuels. Short rotation coppice wood and perennial crops are currently preferred, as they require relatively low energy inputs in the form of fertilisers and other chemicals. Short rotation coppice wood (SRC) is harvested on a 2-4 years cycle and then chipped. Perennial crops, which are harvested annually, such as miscanthus, switch grass and reed canary grass, are also being

considered as potential biomass feedstock for heating application, but consideration must be given to the boiler selected due to the chemical composition of the fuel

28.3 Technical and environmental characteristics

28.3.1 Scale

Biomass boilers for heat only applications typically have a capacity of less than 7-10MW$_{th}$ as beyond this point the option of applying combined heat and power becomes more financially attractive.

Biomass boilers can operate with systems as small as 5kWth for wood pellet boilers and as low as c. 30kW$_{th}$ for woodchip systems. Equally automatic log boilers are also available with units as low as 10kW.

28.3.2 Efficiency

Boiler efficiency is defined as the percentage of the fuel energy that is converted to steam energy. Major efficiency factors in biomass combustion are moisture content of the fuel, excess air introduced into the boiler, and the percentage of uncombusted or partially combusted fuel.

Typical boiler efficiency for boiler combustion units firing biomass is approximately 70 to 75 percent based on GCV. This is highly dependent on fuel moisture content. For typical biomass with a 46% fuel moisture content, boiler efficiency of c. 76% would be expected.

28.3.3 GHG emissions

Most biomass projects target use of biomass waste material for energy production, which saves valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that fuel harvesting and collection practices are sustainable to ensure long-term operation and do not adversely affect the environment.

Lifecycle CO_2 emissions have been reported as 10-23 kg CO_2/MWh for biomass heating (Carbon Trust 2009) with actual offset largely dependent upon the fuel which is being displaced.

28.4 Costs

28.4.1 Capital Costs

Biomass boilers are significantly more expensive than their fossil fuel equivalent on a £/kWh basis primarily because of the boiler requirements specific to biomass fuels; the fuel handling and reception requirements; and finally the housing for fuel storage (and the boiler). Costs can range from as low as £300/kW installed rising to over £1000/kW installed for some of the smaller system applications (e.g. <100kW). Throughout this range, there are significant economies of scale with the most expensive systems placed at the smaller scale (sub 200kW).

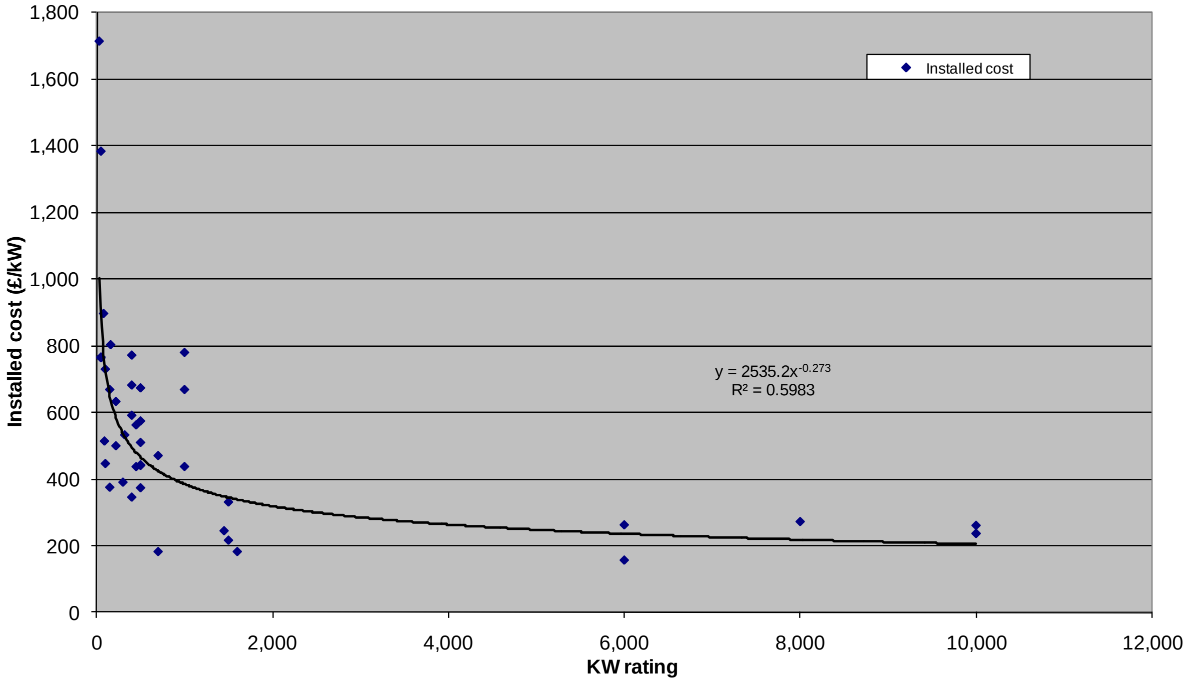


Figure 28-3 Biomass Boiler Capital Costs (Carbon Trust)

28.4.2 Opex Costs

Operating costs for biomass plant consist of the attendance time, annual servicing and parts annual service costs and finally electricity for the significant mechanical handling requirement. This translates to an operating cost range of £4.40 to £88 / MWh with the lower range reflecting larger scale industrial plant with high availability and capacity factors (e.g. 5MW at 85% availability) to £88/MWh for smaller scale plant with much lower capacity factors (e.g. 200kW with 30% CF), (Carbon Trust, 2009). This is a little lower than those figures presented by DECC (DECC, 2011) wherein the levelised cost of non-domestic sector biomass heat is noted as being in the range £22-£156 in 2010, (DECC, 2011). However it should be noted that this figure includes biogas and biomass district heating whilst the Carbon Trust figures denote boiler operation only for small scale heat.

28.5 Requirements of the upstream/downstream process and system considerations

Biomass feedstocks have to be prepared, stored, and transported to the energy conversion process before they can be used to generate power or produce steam. The majority of systems use either woodchip or wood pellets.

Equally, the biomass system has to be appropriately sized and integrated with the heat / process requirements of the end user. Consequently successful operation will rely an appropriate control strategy to integrate the biomass system with on-site fossil fuel plant as well as any heat store capacity to even out demand on the biomass boiler.

28.5.1 Biomass combustion issues arising from fuel properties

The majority of biomass materials of industrial interest have key chemical characteristics which have an influence on the high temperature corrosion processes that any biomass combustion system must be designed to withstand:

Biomass materials have significant levels of inorganic matter as impurities. Many of the practical problems encountered with the combustion of biomass are therefore associated with the nature and behaviour of the biomass ash. Ashes from biomass have, in general, relatively low fusion temperatures and have relatively high levels of the alkali metals, characteristically containing high levels of potassium and other alkaline earth/metals such as sodium, calcium and magnesium and other non alkali elements such as silicon and phosphorus. These compounds can vapourise or react with other elements as they pass though the boiler, condensing onto surfaces and forming sticky deposits on metal and refractory surfaces.

Potassium is the most common alkali metal in herbaceous biomass fuels and is responsible for much of the fouling and corrosion found in biomass boilers. Alkaline earth materials such as calcium form more stable compounds and are less volatile. This explains in part why woody materials with a high concentration of calcium in the ash pose less problems than herbaceous materials such as, straws and grasses with ash containing higher concentrations of alkali material.

Consequently suppliers of standard biomass boilers specify acceptable fuels for use in their boilers and establish a maintenance regime to deal with any fouling issues. The majority of boilers are specified for virgin woodchip or wood pellets whilst systems able to tolerate herbaceous fuels such as miscanthus are much less common for heat only applications, particularly at the smaller scale (<1MW).

28.6 Deployment and development status

Biomass fired boilers for the provision of heat are a mature technology (TRL 9) with markets well established in mainland Europe and North America. As for the UK, the UK Government do not presently have data on installed capacity for biomass heat, however it does collect data on the quantity of fuel used which is reported in DUKES, but not on the number or size of heating units installed. From these data, it suggests that in 2010 the UK generated 12.4 TWh of renewable heat from biomass, and 12.1 TWh of this is suggested to come from biomass boilers and 0.3 TWh from Energy from Waste (DECC, 2011). B&V experience suggests that this is high, but the Government does not currently collect pipeline data for renewable heat on a routine basis but will do so from the end of 2011 as a consequence of the renewable heat incentive.

With the commitment to sourcing 15% of energy from renewable sources by 2020, the demand for biomass heat is expected to rise significantly and Government predictions suggest that non-domestic biomass heat could contribute up to 50 TWh by 2020.

The majority of this would come from biomass boilers (including some from district heating and CHP), with a smaller contribution from biogas injection to the gas grid. However attaining this central forecast would require an annual growth rate of up to 17% (DECC, 2011).

Current deployment levels in the UK fall significantly behind that of other EU states where shares of biomass heating in the national heating demand of EU countries fall anywhere between 10 and 40% of total demand. Presently renewable heat accounts for less than 1% of the UK heating demand.

28.7 Barriers to development and deployment

The market for biomass heating has significantly improved in recent years as a consequence of dedicated programmes funded by the Carbon Trust, Regional Development Agencies and DEFRA. As a consequence, the fuel supply chain is maturing whilst the skill base across the sector is professionalising to meet the market requirement of the HVAC sector. However barriers still remain, notably:

- Investor confidence – Whilst the market will benefit from a long term incentive regime, current investor confidence remains low. This is partly because heat off take contracts are more difficult to secure as the long term presence of the heat customer cannot be guaranteed and therefore contracts have to be sufficiently flexibile to deal with this eventuality.
- Air quality regulation - Biomass boilers generate particulate matter and nitrogen oxides, which fall under our legally binding EU air quality targets. However, whilst there is regulation to control these emissions from biomass boilers of 20 MW_{th} or more, there is no similar framework for smaller units below 20 MW_{th}. Consequently there remains uncertainty over approval rates and the local impact on air quality as a result of a lack of clear regulation on air quality impacts for boilers under 20 MWth.
- Cost - Without action to tackle cost, it is unlikely that deployment will increase to meet the projected forecast. This puts much of the additional 11-21 TWh of heat from biomass boilers at risk.
- Supply chain - Although national and global markets for sustainable biomass are developing rapidly, they are still less mature than markets for conventional fossil fuels. As a result, prospective generators of biomass heat sometimes struggle to secure a long-term source of sustainable feedstock, either from within the UK, the EU or beyond.

Similarly, although UK companies are increasingly focusing on installation, operation and maintenance, developers still report a lack of qualified engineers to install and maintain biomass boilers. These factors could constrain progress in deploying the additional 11 – 21 TWh of biomass boilers anticipated.

28.8 UK Capabilities

There is very little indigenous capacity for the manufacture and assembly of biomass plant in the UK. Those that are active tend to address niche markets selling the smaller scale batch boilers of <300kW_{th} (Teisen and Dragon Boilers) or they target most of their activity to small scale manufacturing waste combustion units (e.g. Ranheat). Consequently the majority of UK suppliers therefore import commercially proven EU technology from mature markets such as Austria, Germany and Scandinavia. Accordingly, whilst UK suppliers do not manufacture, the UK skill base manage the actual installation and are responsible for commissioning and ongoing maintenance.

UK suppliers in this field have grown significantly recently from c. 5-6 suppliers in 2004 to over 50 in July 2011.

For larger commercial plants (> 1MWth), it is also the case that the larger UK manufacturers are continuing to provide manufacturing capability for the heat exchangers, but the combustion chambers and fuel handling are all being sourced from established markets in Europe – again Austria, Germany and Scandinavia.

28.9 References

DECC, 2011 – DECC, Renewable Energy Roadmap, June 2011. http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf

Carbon Trust, 2009. Biomass heating - A practical guide for potential users

29 Dedicated biomass steam cycle

29.1 Technology description

This chapter covers steam cycle plant fuelled on biomass only. A biomass-fired steam cycle plant is an integrated power system that comprises three main components:

- Biomass reception and feedstock preparation - biomass feedstocks have to be prepared, stored, and transported to the energy conversion process before they can be used to generate power or produce steam;
- Energy conversion — conversion of the biomass in a boiler to raise steam. This includes necessary environmental control equipment;
- Power and heat production - conversion of the steam into electric power using a steam turbine generator, with process steam or hot water extracted from the process.

The biomass fuel is burned in a boiler to produce high-pressure steam that is used to drive a steam turbine-driven power generator. In many applications, steam is extracted from the turbine at medium pressures and temperatures and is used for process/space heating/cooling.

29.1.1 Steam turbine type and integration into steam cycle

29.1.1.1 Electricity only

Steam turbines used for electricity generation only systems are condensing type as shown in Figure 29-1. Condensing steam turbines exhaust the entire flow of steam to a condenser that maintains vacuum conditions at the discharge of the turbine and are manufactured with capacities ranging to over 1000 MWe.

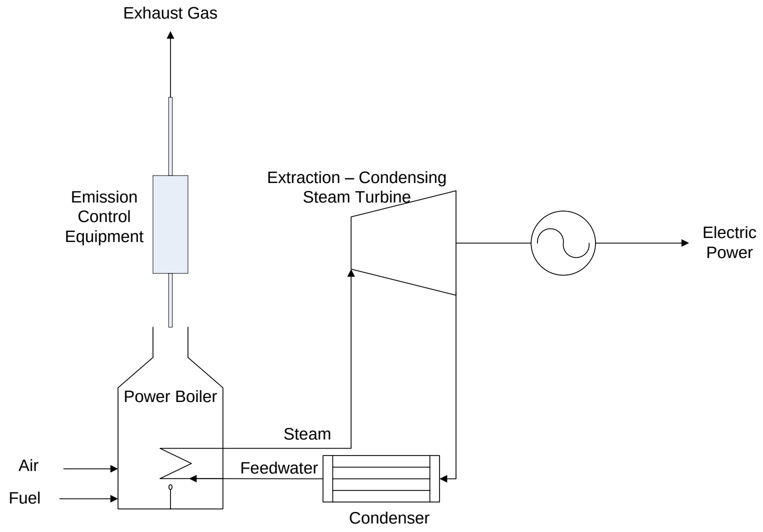


Figure 29-1 Configuration of a condensing steam turbine system

29.1.1.2 CHP

Steam turbines used in CHP systems are usually either:

- Back-pressure systems; or
- Extraction-condensing systems.

These are shown in Figure 29-2 and Figure 29-3 respectively. For industrial CHP applications, steam turbine designs are generally less complicated than steam turbines for electrical production. This is because:

- Below c. 5 MWe some suppliers produce less efficient, simpler and less costly units to assist project economics at this smaller scale;
- Large scale electrical generation turbines operate at higher steam pressures and temperatures and have more stages of expansion in the turbine.

Steam turbines come in a wide range of outputs and are manufactured with capacities ranging from under 100 kWe to over 1000 MWe.

Extracting-condensing turbines have higher electrical efficiencies than back-pressure turbines, as more energy is extracted, but are more complex to design. Energy extracted from the steam in extraction-condensing systems is maximised by exhausting the steam from the turbine at less than atmospheric pressures.

Back-pressure (non condensing) turbines exhaust steam at or above atmospheric pressure. For CHP applications using conventional steam turbines, extraction condensing configurations are frequently used with full condensing on the steam turbine to ensure maximum electrical generation. For some smaller CHP applications (less than 2 MW_e), Organic Rankine systems are frequently used (see Chapter 32).

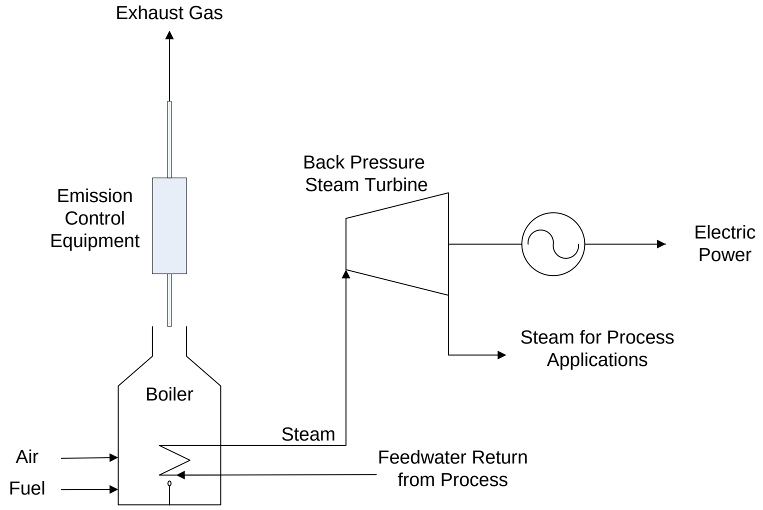


Figure 29-2 General configuration of a back pressure steam turbine system

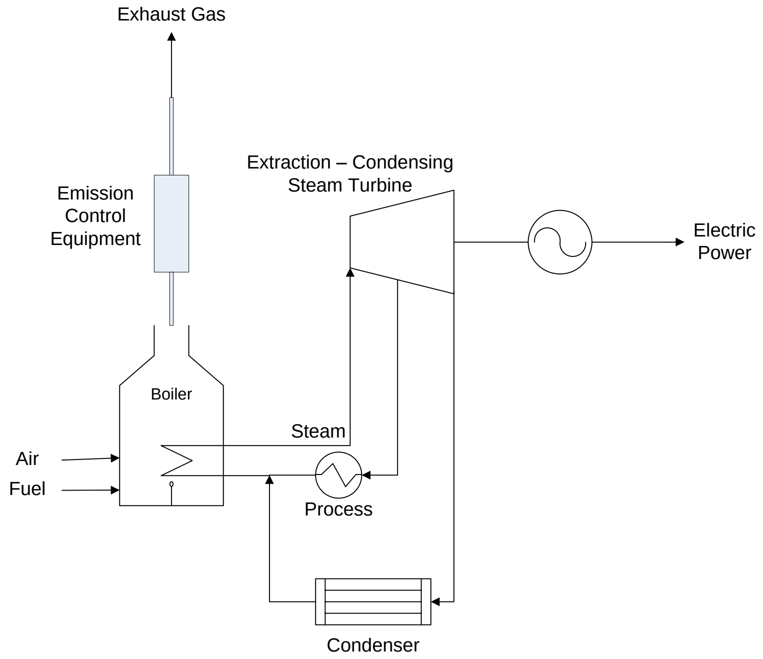


Figure 29-3 Configuration of an extraction-condensing steam turbine CHP system

29.1.2 Biomass combustion system

For most industrial biomass fuels, there are essentially two general types of combustion plant:

- Grate combustors, which are generally employed for the small and medium sized applications (<50 MWe);
- Fluidised bed combustors: bubbling bed (BFB) and circulating types (CFB).

The principal combustion technologies for biomass are in Figure 29-4.

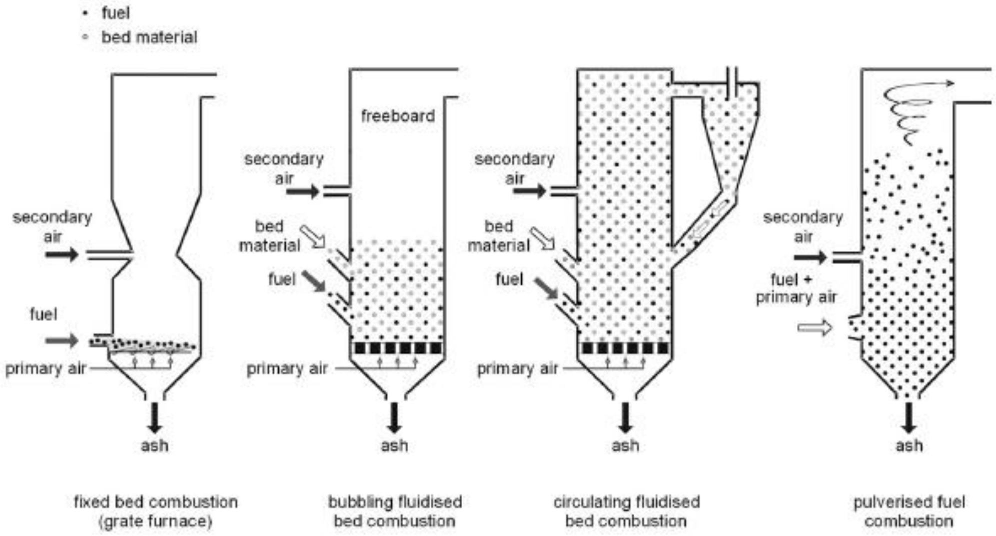


Figure 29-4 Fluidised bed (Van Loo, S and Koppejan, J., 2008)

29.1.2.1 Grate combustion

Grate combustion systems for biomass are generally limited to plant outputs not greater than 50 MWe due to their ability to feed large quantities of fuel onto a grate. They can be either stationary or moving.

Stationary Grates - Numerous biomass boilers have been constructed with stationary grates, particularly in the developing world where biomass is plentiful. The stationary grate is simply a rectangular grid at the bottom of a refractory lined furnace through which combustion air passes and which also allows the removal of ash either manually or using tipping sections. The fuel fed to the furnace may be in the form of anything from logs down to flour. Logs may be loaded by hand whereas grape pip flour, for example, may be burned in suspension above the grate.

Moving Grates - Moving grates are available on the market in a wide range of types. The most well know are the chain grate and the reciprocating grate.

- A chain grate stoker comprises a continuous chain type belt constructed from a multitude of links connected with pins. Fuel is fed onto the grate by gravity from a hopper at the front of the boiler and the grate transports the fuel away from the feeder. Primary combustion air is fed through the grate and acts as a coolant for the grate. The problem comes when it is necessary to preheat the combustion air so that wet fuels may be burned. Preheating the air means that its cooling effect is limited and the grate is more vulnerable, especially if the bed of fuel or ash is insufficient to protect the grate from radiant heat in the furnace. The fuel dries out at the front end of the grate and is fully burned by the time it reaches the back of the boiler. The ash falls off the end and discharges into a waste collection system. As a high proportion of the combustible content of wood and other biomass fuels burns in the form of volatile compounds, it is necessary that a large proportion of the combustion air requirement is added above the fuel in stoker and fluidised bed boilers as 'overfire air'. The use of preheated combustion air will reduce the time required for fuel drying prior to ignition and may be essential to spreader stoker systems (those that distribute the fuel over the grate using am air jet).
- A travelling grate stoker is the same as a chain grate except the fuel is projected onto the grate. The grate moves from the back to the front and the ash falls off the grate at the front of the boiler.
- A reciprocating grate comprises a number of sets of grate bars that move to and fro in sequence. The grate is inclined downwards so that the movement of the grate causes the fuel to move downwards. Primary air passes up through the gaps between the grate bars. Ash is discharged from the end of the grate but some gridlings tend to get through the grate and may be separately collected below the grate.
- A water cooled grate is a type of reciprocating grate in which the grate bars are maintained at the required working temperature by passing water through the grate. The passage of water through the grate reduces the damage to the grate that may be caused by excessive air, temperature or by too much radiant heat.

In conclusion, grate fired boilers are a well developed technology and have evolved over 150 years. Consequently, their operation is well understood, robust and reliable. However it is generally less efficient than more modern technologies, as fuel burn out is dependent on the residence time on the grate and bed depth.

29.1.2.2 Fluidised bed combustion

Fluidised bed combustion was developed in the 1970s and 1980s as a means of burning a range of solid fuels including materials such as coals containing higher than average ash or sulphur and high moisture fuels such as sewage sludge and other biomass fuels.

Fluidised bed combustion involves the combustion of a fuel in a bed of sand. The sand and fuel is kept in suspension by passing a current of air upwards through the bed, this current of air causes the bed of sand to bubble. Fuel is added to the bed in a consistent manner and is immersed in the high temperature bubbling sand bed. Oversize material including ash is withdrawn from the bed on a continuous basis and recycled back into the bed after cooling and sizing.

There are basically two types of fluidised bed combustor:

- Bubbling Bed (BFB): Bubbling beds tend to use low fluidising velocity and the bed behaves rather like a pan of boiling water.
- Circulating Bed (CFB): Circulating fluidised beds use much higher fluidising velocities in which the sand and fuel are carried upwards through the furnace. At the top of the furnace, the solids are removed from the gases in a cyclone and the solids are returned to the bed by gravity.

Most of the ash leaves the fluidised bed in the form of fly ash generally. The combustion temperatures that apply in fluidised beds are somewhat lower than those that apply in fixed beds. Fluidised bed and freeboard temperatures when burning biomass materials tend to be in the range of 800 to 900°C. At these temperatures, the levels of release of alkali metals in the combustion gases and the degree of fusion of the ash tends to be significantly lower than those that apply at the much higher temperatures in grate combustors. Where the ash is exposed to higher temperatures in a grate furnace, there may be increased fouling of heat transfer surfaces.

In fluidised bed boilers the control of bed temperature is important. If fluidisation is not uniform, there is a tendency for hot and cold spots to form. This can lead to uneven combustion and variations in gaseous emissions and in the worst case, caused by the low melting temperature ash components, agglomeration of the bed. If left unchecked, this can lead to bed 'slumping' in which case it may be necessary for the operators to bring the boiler off-line to remove and replace the bed material

29.1.2.3 Operating advantages and disadvantages of biomass combustion systems

The literature comments (EPA, 2007) that stoker and fluidised bed boilers have specific operating advantages and disadvantages with biomass fuels depending on the fuel characteristics and site requirements. Biomass fuels are extremely variable in terms of heating value, moisture content, and other factors that affect combustion. Wood and most other biomass fuels are composed primarily of cellulose and moisture. The high proportion of moisture in the fuel is significant because it acts as a heat sink during the combustion process. The latent heat of evaporation depresses flame temperature, taking heat energy away from steam production and contributes to the reduced efficiency when burning biomass fuels.

In contrast to coal fired plant a high proportion of the combustible content of wood and other biomass burns in the form of volatile compounds. It is therefore necessary that a large proportion of combustion air is added above the grate/fluidised bed.

Fluidised bed systems offer significant operating flexibility because they can operate under a wide range of load conditions. The thermal inertia of the bed material allows it to withstand changes in moisture and heating content of the fuel without negative impacts.

In general, grate fired boilers may be compared with fluid bed combustors as follows.

Grate Fired Boilers	Fluidised Bed Boilers
Grate fired boilers have been developed over a period of approximately 150 years	Fluid bed boilers have been developed over the past 30 years.
Moving grates consist of mechanical parts that are kept moving in a hot environment.	There are no moving parts to a fluid bed.
Fuel tends to sit motionless in a bed on the grate. Burn out is dependent on the time the fuel sits on the grate and the depth of the bed. As a result, combustion efficiency tends to be lower than fluidised bed.	Fuel is agitated by the action of the sand and in the process is gradually broken down until all the combustible material has been burned. As a result, combustion efficiency tends to be high.
The combustion temperature in the bed tends to be higher than in the fluidised bed. This means that NOx may be created more easily.	The bed temperature is rarely above 850°C so NOx is less likely to form in the bed.
As there is no agitation of the fuel in the bed, pockets of wet fuel will not burn properly and carbon monoxide forms.	Good mixing takes place between the fuel, the sand and the combustion air. Emissions of carbon monoxide are low.
Dosing the fuel with limestone is not so effective at neutralising the acid gas as fluidised bed or flue gas treatment.	The fluidised bed is a perfect place to capture sulphur dioxide that may be released during the combustion of the fuel.
Power requirements are less than for a fluidised bed because the bed of fuel gives less resistance than the sand.	The power required to force air through the bed of sand is much greater than that required to pass air through the bed of fuel on a grate.

Table 29-1 Grate fired boilers vs. fluidised bed boilers

29.1.3 Biomass combustion issues arising from fuel properties

The majority of biomass materials of industrial interest have the following key chemical characteristics (Livingston, W., 2007b), which have a key influence on the high temperature corrosion processes that any biomass combustion system must be designed to withstand:

- Biomass ash tends to be relatively rich in alkali metals, typically containing high levels of potassium and other alkaline earth/metals such as sodium, calcium and magnesium and other non alkali elements such as silicon and phosphorus. These compounds react with other elements and as they pass though the boiler, condense onto surfaces and form sticky deposits on metal and refractory surfaces;

- Most biomass materials have relatively low total sulphur contents, generally less than 0.5% w/w;
- The chlorine content of biomass materials varies significantly, 0.05 to 0.5% w/w; and the material has the potential to have high moisture contents, up to 60% w/w.

Potassium is the most common alkali metal in herbaceous biomass fuels and is responsible for much of the fouling and corrosion found in biomass boilers. Alkaline earth materials such as calcium form more stable compounds but are less volatile. This explains in part why woody materials with a high concentration of calcium in the ash pose fewer problems than herbaceous materials such as straws and grasses with ash containing higher concentrations of alkali material.

29.1.4 Boiler design considerations

The biomass ash deposits that form on the boiler surfaces tend to be rich in potassium salts, principally sulphates and chlorides. This can have a significant impact on the system corrosion, particularly at high metal temperatures on superheater surfaces. In general, therefore, it is necessary to design dedicated biomass boilers with final steam temperatures that are significantly lower than those that apply in large coal-fired boilers with consequent reduction in cycle efficiency.

To attain steam temperatures in the range of 400-500°C, the boilers are of a water tube with high pressure steam conditions of 45 to 100 barg. The fire tube design of boilers is limited to a lower steam pressure more suited to heat generation only: typically 10 to 25 barg saturated steam at temperatures of 184 to 226°C (Livingston, W., 2007b).

Ash deposition control in biomass combustors and boilers is a fairly complex issue, involving both boiler design and operation (Livingston, W., 2007b). The key factors are:

- Use a large radiant furnace section in the boiler to reduce the flue gas temperatures at the entry to the first tube bank to keep flue gas temperatures below 700°C
- For the same heat release as a coal fired boiler, biomass boilers need to have larger furnaces and combustion volumes for increased residence time. This gives lower furnace exit temperatures and exit velocities to minimise tube erosion, deposition and to aid the removal of ash.
- Gas side surfaces should be cleaned using soot blowers that direct a high velocity jet of steam, water or compressed air at deposits that have built up on boiler surfaces.
- Homogeneous feed of biomass. Biomass fuels have to be carefully sized and processed. The moisture content of wood and other biomass waste can vary over a wide range, from 10% to more than 60% w/w as received and fuel mixing may be required to ensure that the feedstock is consistent.

29.1.5 Operating Availability

The two major factors that will affect boiler plant availability are:

- Variability in fuel quality and consistency – Whilst this may be a seasonal issue, it may affect boiler combustion with consequent increased boiler fouling and slagging. Variations in moisture content may also result in excessive emissions of carbon monoxide (CO) or NOx;

- Mechanical handling system breakdown – This often has scope to reduce availability unless adequately designed, for instance, baled materials such as straw have significant fuel reception, handling, pre processing and boiler furnace feeding equipment.

Even though the technology of fluidised bed combustion is not new, the fluidised bed units currently used in power generation are, for the most part, 20-30 years old or less. Some of the major availability issues have involved the bed, including in-bed tube leaks and bed agglomeration and boiler fouling. Provided fuel handling can be managed, then typically for both stoker and fluidised boilers operating on woody biomass there would be a reasonable expectation of achieving availability in the order of 90%. The availability maybe significantly less if firing waste, straw or energy crops as there may be significantly different fouling and corrosion issues.

The availability of steam turbines is typically quite high with a typical availability of 98%. When a steam turbine is operated properly, maintained regularly, supplied with steam of the specified quality, its service life can exceed 30 years.

In view of the above, overall system availabilities can be expected to be in the order of 80 to 90% depending upon the type of biomass used.

29.2 Feedstock

In the UK, the principal biomass materials, which are available as fuels for energy conversion plants in sufficient quantities to be relevant for biomass combustion are discussed below (Livingston, W., 2007a):

- Surplus cereal straws and other dry agricultural residues are available in large quantities, principally in the east and south of England. The most significant cereal crops in this context are wheat and barley. A number of dry residue materials from other crops are also available including oats, oilseed rape and linseed.
- Forestry and sawmill residues are available in certain parts of the country in large quantities, the largest areas of managed woodland are in Scotland and Wales, in the north of England and in East Anglia. As produced, the residue materials have high moisture content (50 to 60% w/w as received) and are variable in quality.
- Wood pellets formed from saw dust and other sawmill residues are available in the UK with large plants located in Scotland and Northern Ireland. The advantage of wood pellets is the low moisture content (10% w/w) and the consistent quality for combustion. Pellets are also produced in large quantities in North America, Scandinavia, Russia and in some other Northern European countries and can be imported.
- Energy crops are plants grown specifically for use as fuels. Short rotation coppice (SRC) wood and perennial crops are currently preferred, as they require relatively low energy inputs in the form of fertilisers and other chemicals. SRC is harvested on a 2-4 years cycle and then chipped. Perennial crops, which are harvested annually, such as miscanthus, switch grass and reed canary grass, are also being considered as potential biomass feedstock as the market develops. Of these grasses, miscanthus is being grown commercially in the UK as an energy crop specifically for power generation.
- Olive processing wastes are available in large quantities, as dry granular or pelletised materials, from Spain, Italy, Greece, Turkey, Tunisia and Portugal. The quality, and

particularly the moisture content and calorific value, of the solid residue material are dependent on the oil extraction process.

- Industrial, agricultural and other waste materials of plant or animal origin are available in specific locations. A number of these are in the form of meals, dried or partially dried sludges, or distillers grain, from agricultural sources, paper and food processing, food and beverage and from municipal sewage works.

29.3 Technical and Environmental Characteristics

29.3.1 Scale

29.3.1.1 Electricity Only

Current UK biomass power systems are typically below 50 MWe in size, compared to coal-fired plants, which are in the 100 to 1,000 MW range. The largest biomass wood plant in Europe is at Simmering, Vienna with an output of 66 MWe. However with this said, there are projects in planning up to 300 MWe but these are located close to ports to facilitate the use of biomass fuel imports.

Below 50 MWe grate or fluidised bed would be suitable for woody biomass combustion and between 50 and 100 MWe the BFB technology is more appropriate since it is beyond the size limit for conventional stoker boilers. The minimum economic scale of a BFB would be in the 5 to 10 MWe range. Above 100 MWe the CFB would be recommended as the technology is better suited for large fuel addition or bed make up. The fuel may be fed into the circulating media and this is much more easily achieved than feeding across a large grate or bubbling bed.

29.3.1.2 Biomass CHP

Biomass CHP plants usually have a capacity of less than 50 MWe because of the need to combine the output with a suitable heat requirement.

A plant at Tullis Russell in Scotland is currently under construction in the UK with an output of 50 MWe and a thermal demand of 120 MWth.

The minimum economic capacity for biomass with a steam turbine would be c. 2 to 5 MWe but this largely depends upon specific site conditions to secure financial viability.

29.3.2 Efficiency

29.3.2.1 Overall system

For utility power generation using fossil fuels, complex cycles involving several stages of superheating and reheating are often used and can be justified for large-scale plant.

For biomass power generation however, simpler steam cycles with less extreme steam conditions than conventional utility electricity generating plant may be used. The emphasis is more on achieving high plant availability due to biomass combustion issues and low construction cost rather than small gains in the efficiency of electricity generation.

Also, due to the higher moisture content of the fuels, biomass plants are commonly less efficient than modern utility fossil fuel plants.

A modern steam cycle power plant using biomass will have a gross overall electrical generation efficiency in the range of 20 to 35% (Mott MacDonald, 2010) depending upon scale, although efficiencies on a GCV basis seldom exceed 30%. This may be compared with utility sized coal fired power station that may have an electrical generation efficiency of 43%.

With a steam cycle power plant, heat at sufficiently high temperature to be useful for district heating can only be taken at the cost of power output and the electrical efficiency may drop to 15% (steam flow dependant).

Even though the CHP electrical efficiency is low, the effective overall system efficiency of steam turbine systems is generally high because of the recovered heat and typically ranges from 60% to 80%.

29.3.2.2 Boiler efficiency

Boiler efficiency is defined as the percentage of the fuel energy that is converted to steam energy. Major efficiency factors in biomass combustion are:

- Moisture content of the fuel - The higher the moisture content, the lower the heating value and the lower the boiler efficiency. If the moisture content is higher than 65 percent, the fuel can still be burned provided supplemental fuel is burned or some other process is used to recover exhaust heat for air or fuel preheating.
- Excess air introduced into the boiler;
- The percentage of uncombusted or partially combusted fuel.

The typical boiler efficiency for bubbling bed combustion units firing biomass is approximately 70 to 75 percent based on GCV. This is highly dependent on fuel moisture content. For typical biomass with a 46% fuel moisture content, boiler efficiency in the range of 76% would be expected.

In general, a fluid bed boiler would have about a 1 to 2% overall improvement in boiler efficiency compared to stoker, based on:

- Improved carbon burnout for the fluid bed boiler (but this will be fuel dependent);
- More uniform combustion with a fluid bed than stoker;
- Less excess air.

29.3.3 GHG emissions

In Table 29-2, the emissions of CO_2 and N_2O are compared for firing of typical wood and typical bituminous coal. These metrics exclude any accounting for the carbon cycle wherein biomass from sustainable sources such as managed forestry is considered to have a much reduced CO_2 footprint to that of coal.

Isolating energy generation alone, the total GHG equivalents on an energy basis are similar, however the contribution from CO_2 is by far the greater. However, the emissions from the combustion of wood have little effect on the net increase of CO_2 in the atmosphere over the full biomass life cycle.

	Wood	Coal
CO_2 (gCO_2/MJ)	88.9	88.5
N_2O (gCO_2e/MJ)	1.24	0.46
Total GHG equivalent (gCO_2e/MJ)	90.1	89

Table 29-2 Greenhouse gas emissions (EPA, 2009)

Biomass combustion not only contributes to the reduction of GHG emissions but also reduces the emissions of sulphur oxides and heavy metals, such as mercury.

29.4 Costs

29.4.1 Capital and Operating Cost Electricity Only

Capex and Opex costs based upon DECC's recent publication are given below in Table 29-3 to Table 29-6 (DECC, 2011). The operating cost ranges for biomass power generation exclude fuel cost.

Capex	2010	2015	2020	2025	2030
High	3,871	3,852	3,861	3,913	3,966
Medium	3,342	3,326	3,334	3,378	3,424
Low	2,607	2,594	2,600	2,635	2,671

Table 29-3 Dedicated biomass boiler Capex for plants greater than 50MWe (£000/MWe–DECC 2011)

Capex	2010	2015	2020	2025	2030
High	2,801	2,787	2,794	2,832	2,870
Medium	2,417	2,405	2,411	2,443	2,476
Low	2,258	2,247	2,252	2,283	2,313

Table 29-4 Dedicated biomass boiler Capex for plants less than 50MWe (£000/MWe–DECC 2011)

Opex	2010	2015	2020	2025	2030
High	254	250	247	247	248
Medium	168	165	163	164	164
Low	123	121	120	120	120

Table 29-5 Dedicated biomass boiler Opex for plants less than 50MWe (£000/MWe–DECC 2011)

Opex	2010	2015	2020	2025	2030
High	218	214	212	212	212
Medium	144	142	140	140	140
Low	106	104	103	103	103

Table 29-6 Dedicated biomass boiler Opex for plants greater than 50MWe (£000/MWe–DECC 2011)

From the above it can be seen that it is expected that costs are expected to remain fairly constant. The largest driver going forward is labour cost. However, the labour index used by DECC does not suggest substantial rises. Learning effects should marginally decrease/control the cost of O&M contracts as projects develop.

29.4.2 Capital and Operating Cost CHP

Capex and Opex costs based upon DECC's 'Review of generation costs and deployment potential of renewable electricity technologies in the UK' are given below in Table 29-7 and Table 29-8.

	2010	2015	2020	2025	2030
High	5,100	5,016	4,970	4,978	4,987
Medium	4,188	4,119	4,081	4,088	4,095
Low	3,561	3,502	3,470	3,476	3,482

Table 29-7 Capex for biomass CHP (£000/MWe – DECC, 2011)

	2010	2015	2020	2025	2030
High	269	273	277	281	285
Medium	189	192	195	197	200
Low	138	140	142	144	146

Table 29-8 Opex for biomass CHP generation excluding fuel costs (£000/MWe – DECC 2011)

29.5 Requirements of the upstream/downstream process and system considerations

Biomass feedstocks have to be prepared, stored, and transported to the energy conversion process before they can be used to generate power or produce steam. The major steps can be divided into four categories:

- Fuel pretreatment prior to delivery;
- Receiving: truck/rail /ship discharge and fuel storage;
- Site processing: reclaim feeder from reception, conveyor, metal separator, dryer, screens;
- Fuel feeding and handling systems.

A CHP plant has to be matched to a heat demand as it is the use of a necessary heat load that allows cost effective power generation.

29.6 Deployment and development status

According to the US Department of Energy, there is over 40,000 MW of installed biomass combustion capacity worldwide. The majority of this capacity is in combined heat and power applications in the pulp and paper industry using steam turbines. Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago for steam turbines and combustion technologies based on stokers used for at least 60 years. The use of or fluidised beds has been available for the past 30 years and in the recent years the technology has become more robust to meet the more arduous design criteria of biomass (TRL 9).

29.6.1 Electricity Only

The largest size is effectively capped at 300 MWe because of the requirement that all new boiler plant designed and installed post 2009 should be designed to be “carbon capture ready” above this threshold.

The Large Combustion Plant Directive (LCPD) and Industrial Emissions Directive (IED) impose emission constraints on existing fossil power generation plants from 2015. After this date which there is great potential for growth in biomass plant as one of the few non-intermittent renewable energy options.

In the UK in 2009 electricity generated by renewable fuels from steam turbine systems was 2311 GWh (DECC, 2010a). At present in the UK, the largest biomass electricity only plant is the 44 MWe Steven's Croft plant owned by EON near Lockerbie in Scotland. The boiler used is a BFB.

29.6.2 CHP

In the UK in 2009 electricity generated by renewable fuels from CHP steam turbine systems was 408 GWh, of which back pressure steam turbines contributed 196 GWh and pass out condensing steam turbines 212 GWh. As of October 2010, 305MWe has been installed in the UK across 16 facilities. New projects are constantly appearing, with the Forestry Commission predicting that a further 3,763.7 MWe is in planning, although not all of those planned will make it through to fruition.

In the UK the largest CHP plant is located at Slough Heat and Power with multiple boilers and associated steam turbines capable of generating 47 MWe from biomass. The heat is used to supply the local industrial estate and its main sources of fuel are wood chips, biomass and waste paper.

29.7 Barriers to development and deployment

The following is a list of generic barriers to biomass power and biomass CHP deployment:

- Typically financial investors and lenders will only discuss projects in detail when planning permission is secured, which elongates project timescales;
- Cost of biomass plants is high due to the nature of the fuel. Biomass fuel requires specific combustion technology and a reliable biomass fuel supply;
- Fuel supply risks affect economic viability and fuel mix can affect ease of planning process, i.e. a balance between fuel supply risk with a single fuel and planning risks (such as transportation issues) arising from a diverse mix of fuel must be assumed by the developer. At present the fuel supply chain for energy crops is not well developed in the UK and the uncertainty over the future market size of conventional forestry material could threaten investment decisions particularly for plant where the fuel inventory is significant. As a result a number of developers are also looking to secure imported biomass fuel as a part of their fuel inventory;
- Uncertainty of long-term renewable obligation certificates (ROC) in terms of the predicted revenue stream has been an issue in the past due to confusion governing “grandfathering” protocol and the timing and results of any ROC reviews. Currently, whilst these two issues have been broadly resolved, investor confidence is being affected by recent announcements concerning the reform of the electricity market and the consequent replacement of the ROC system post 2013.
- Planning aspects for electricity only biomass plants are significant as transportation impacts of biomass may have more significance than other environmental concerns at a regional level. This has and will continue to cause some difficulties with developers of the larger facilities now favouring locations at port side with the majority of fuel being imported;
- System reinforcement of the local electrical system may be required, particularly in rural areas, and the cost associated with this work may have a major impact on plant viability;
- Lack of qualified engineering, procurement and construction (EPC) contractors with experience in the construction and commissioning of biomass projects is leading to elongated negotiations;
- No tradition of long term fuel supply contracts with immature supply chain.

29.8 UK Capabilities

In the UK there have been relatively few power stations constructed over the past 20 years and, as a result, the UK-based supply chains for power generation plant have been eroded quite considerably. Thus, although the UK power equipment and services sector has a turnover of £30 billion and provides employment for 30,000 people in the UK, it is estimated that since 1990 the UK has lost approximately 70% of the supply chain for components/plant in the power generation sector (Court, S., 2008). There is now within the UK market a strong and consolidated international competition for the supply of industrial equipment items.

Further development of advanced conversion technology outside the UK from established companies could displace any emerging UK providers.

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30 Co-fired biomass steam cycle

This chapter covers steam cycle technologies for power and combined heat and power generation using fossil fuels co-fired with biomass.

30.1 Technology description

The great majority of biomass co-firing projects worldwide have involved the utilisation of solid biomass materials and have been as retrofits to existing pulverised coal-fired power stations. The options for co-firing in this type of plant can be categorised as follows, and are illustrated in Figure 30-1 below:

- Direct co-firing - Pre-mixing the biomass with coal and co-milling (routes 1 and 5 in Figure 30-1);
- Direct co-firing - Co-firing of pre-milled biomass to the coal firing system (routes 2, 3 and 4 in Figure 30-1);
- Indirect co-firing - Involves the gasification of the biomass and the combustion of the product fuel gas in the furnace as indicated by route 6 in Figure 30-1);
- Parallel co-firing - Involves the combustion of the biomass in a separate combustor and boiler.

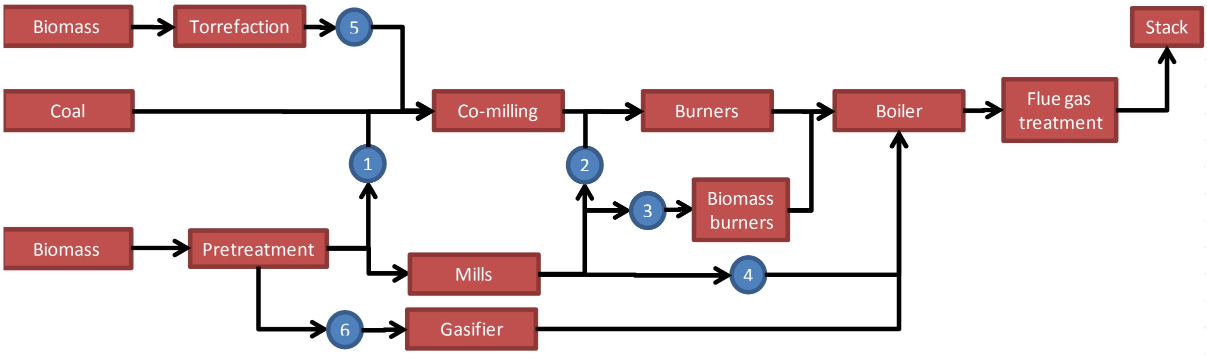

Figure 30-1 Principal direct and indirect co-firing routes (IEA, 2009)

This section focuses upon direct co-firing only whilst gasification (route 6) and torrefaction (route 5) of biomass are covered in Chapter 13 and 7 respectively.

30.1.1 Co-milling biomass and coal

Biomass is premixed with coal and the mixture is fed into bunkers. The mixture is processed through existing coal milling and firing equipment. The pre-mixing and co-milling of chipped, pelletised and granular biomass materials with coal in large coal mills has been practised in a number of UK coal-fired power stations on a commercial basis since c.2002. The maximum achievable co-milling ratio, and hence the level of co-firing, is limited and depends on the design and operation of the coal mill and the nature of the biomass material. In most cases, co-firing of biomass at up to 10% (Livingston 2007) by heat input is technically possible but the normal co-firing ratio is less than this (typically 5%). The main reason for this is that coal is brittle whilst biomass tends to be soft and durable; consequently, the biomass materials tend to build up in the mill, restricting the co-firing ratio and possibly increasing mill absorbed power. Torrefaction is intended to mitigate this issue.

Similarly, hot air is used to dry coal in the mill and this added heat tends to drive off the volatiles in the biomass fuel. This can lead to temperature and pressure excursions, which can be reduced by restricting throughput.

30.1.2 Direct injection of pre-milled biomass

The benefit of pre-milling the biomass is that it avoids the throughput constraints associated with co-milling and therefore it can allow higher co-firing ratios. All of these applications involve the pneumatic conveying of milled biomass from the mills to the boilers.

There are three basic direct co-firing options for pre-milled biomass in retrofit applications:

- Route 2 – The injection of the biomass into the pulverised coal pipework or at the burner and co-firing with coal through existing burners;
- Route 3 – The installation of new dedicated biomass burners with associated combustion air supplies;
- Route 4 – The direct injection of the biomass into the furnace, with no stabilisation and no additional combustion air.

Route 2, which is the most popular method in the UK, involves the pneumatic injection of pre-milled biomass into the pulverised coal firing system downstream of the coal mills, i.e. into the pulverised coal pipework or directly into the burners. In both cases, additional air and fuel are introduced to the mill group burners and the mill primary air and coal flow rates have to be reduced accordingly to maintain both the coal mills and burners within their normal operating envelopes. The options for the location of the biomass injection points are:

- Directly into the burner;
- Into the pulverised coal pipework, just upstream of the burner;
- Into the mill outlet pipework local to the mill outlet.

In all cases, the introduction point of the biomass to the pulverised coal pipework or directly to the burner, is fitted with fast-acting, actuated biomass isolation valves to allow rapid isolation of the biomass system from the coal firing system.

The preferred technical option for any particular application will depend on the type of biomass to be co-fired, on the desired co-firing ratio and on a number of site-specific factors. A number of these direct firing systems are in commercial operation.

30.2 Feedstock

A wide range of biomass fuels have been adopted in various co-firing plants. Many biomass or biomass-derived fuel types have chemical and physical properties that deviate significantly from the properties of coal. The key differences as identified in IEA Bioenergy Task 32 (IEA, 2009) include:

- Some biomass materials can have very high moisture contents and may need dewatering or drying prior to combustion;

- The majority of biomass materials have lower ash contents than most coals;
- The calorific value of most biomass materials on a dry basis is lower than those of most coals;
- The volatile matter content of most biomass materials is relatively high compared to most coals. This means that biomass materials are more reactive to combustion processes than are most coals. They are easier to ignite, produce a smaller quantity of char and the char particles are more reactive then coal chars. This means that larger biomass particles, up to 1 mm or so in diameter, can be fired efficiently in pulverised fuel flames;
- Most biomass materials have significantly lower nitrogen contents than most coals.

The IEA confirms (IEA, 2009) the following biomass materials have been co-fired with coal in a variety of furnaces and locations.

Examples of Co-fired biomass		
Peat (Indonesia/Finland/Sweden)	Plantation forest waste (Australia)	Bark (Austria)
Woodchips (Various)	Green waste (Australia)	Straw (Denmark/Germany)
Bark (Austria/Sweden)	Sawdust (Australia/ Austria)	Wood pellets (Various)
Sludge (Finland)	Shavings	Paper waste (Finland)
Sewage sludge (Austria/Germany/ Scotland)	C&D waste timber	Straw pellets
RDF (UK CFB) RDF (Thailand/Netherlands)	Lignite (Austria)	Kernels (Netherlands)
Paper sludge	Shells (Netherlands)	Compost residues (Netherlands)
Meat and bone meal (Netherlands)	Coffee (Netherlands)	Rubber waste (Sweden)
Animal feeds (UK)	Olive waste (Sweden)	Grass
Husks and pulp in meal and pellet form (UK)	Tallow (Wales)	Palm oil (Wales)
Miscanthus (Wales)	Rape grass (Wales)	Shea (England
PKE (England)	Dry distillers grain (Canada)	Urban wood waste (USA)
Switchgrass (USA)	Soy beans (USA)	Tyres (USA)

Table 30-1 Range of co-fired biomass fuels (IEA, 2011)

At the end of 2010 there was 2.5 GW of biomass electricity capacity operating in the UK, accounting for 11.9 TWh of generation. Of this, co-firing accounts for 21% (2.5TWh) whilst dedicated biomass accounts for 17%. (DECC, 2011).

Of the biomass used for co-firing in the UK the Biomass Energy Centre report that:

- 33% was imported co-products from the palm oil industry (palm kernels and residues such as empty fruit bunches and fibre);

- 21% was imported co-products from the olive oil industry (olive cake and pellets, their quality is dependent on the oil process extraction);
- 20% was wood products including sawdust, wood shavings, pellets and chips, predominantly imported;
- 17% was liquid biomass; and
- 7% was straw and other co-products of cereal production.

As produced, the forestry and saw-mill residues have high moisture content and are variable in quality. The long term storage of wood in chip form can be problematic as rapid biological activity can lead to loss of dry matter and a significant deterioration in the physical quality of the fuel. A number of power stations have been co-firing imported fuels such as dried and pelletised wood fuels, which are produced in large quantities in North America, Scandinavia, Russia and in some Northern European countries.

Industrial, agricultural and other waste materials of plant or animal origin have been trialled. A number of these are in the form of meal, dried or partially dried sludges from agricultural sources and food processing and from sewage sludge. These have been used for co-firing in modest quantities.

Energy crops are grown specifically for use as fuel. Short rotation coppice (SRC) wood and perennial crops are currently preferred as they require relatively low energy inputs. None of the energy crop materials are, as yet, available in the quantities relevant to co-firing in large power plants. In the UK, the Renewables Obligation has tried to target energy crops in general and SRC in particular as indigenous fuels and a number of species have been planted, including willow, poplar and miscanthus.

Liquid co-fired biomass includes oils, examples of which include:

- Palm oil (predominantly used as the cheapest vegetable oil replacing heavy fuel oil (HFO) in both dedicated oil fired power stations like Littlebrook in Kent, and for start up and stabilisation purposes in coal fired power stations);
- Other vegetable oils;
- Tall oil, an imported by-product from the paper industry;
- Tallow;
- Waste vegetable oil (WVO), although Environment Agency approval is required; and
- Pyrolysis oil from a range of biomass sources.

The majority of these liquid biofuels would be imported with the exception of waste vegetable oil, tallow and pyrolysis oil.

30.3 Technical and environmental characteristics

30.3.1 Scale

The maximum achievable co-milling ratio, and hence the level of co-firing, is limited and depends on the design and operation of the coal mill and the nature of the biomass material. In most cases, co-firing of biomass at up to 10% (Livingston 2007) by heat input is technically possible but the normal co-firing ratio is less than this (typically 5%).

In the UK most of large biomass plants have carried out trials burning biomass with coal at levels ranging from 2 to 10%.

30.3.2 Efficiency

Provided the biomass particle size is controlled prior to combustion then at low biomass co-firing rates (<10% on a heat input basis and with dry (<10% moisture content)) the impacts on combustion efficiency and plant operation have been modest.

Biomass co-firing is mainly a retrofit application. A basic principle of co-firing is that significant changes to the boiler are not required beyond some burner modifications or additions necessary to introduce and burn the supplemental fuel. To limit the effect on overall boiler efficiency and ensure effective combustion, co-firing biomass fuel is carried out on a limited basis, with the amount of biomass ranging from 5 – 15 % of the total heat input to the boiler and is also practically limited by the actual generation capacity on large plant.

Typically, co-firing biomass in an existing coal boiler requires modifications or additions to fuel handling, processing, storage, and feed systems. Slight modifications to existing operational procedures, such as combustion air supply might also be necessary, as well as increasing fuel feeder rates to compensate for the lower density and heating value of biomass.

To be able to fire a diversity of fuel types without influencing the boiler efficiency or capacity and avoiding unwanted effects such as slagging, fouling and corrosion is an increasing issue.

Fuel characteristics that could affect the efficiency are below:

- Biomass materials tend to have lower ash contents than most power station coals but the nature of biomass ash is very different from that of most coal ash. In general, biomass ash has a relatively low ash fusion temperature and relatively high level of the alkali metals, particularly potassium. Biomass ash has a greater propensity towards the formation of both slagging and fouling deposits. The experience has been that, with low co-firing ratios, there have been very few significant operational problems due to increased ash deposition on boiler surfaces. However, at higher co-firing ratios, especially with high ash biomass materials, the risks of ash deposition are significant. There is also a risk of fouling of selective catalytic reduction (SCR) catalysts.
- Some biomass fuels have high chlorine content that can lead to unmanageable ash deposition problems on heat exchange and ash-handling surfaces. Chlorine in combustion gases, particularly at high temperatures, can cause accelerated corrosion of combustion system and flue gas cleanup components. These problems can be minimised by limiting materials high in chlorine and alkalis. In practice, this means limiting the biomass contribution to boiler heat input to <15%, using fuel additives, or increasing soot-blowing. The most troublesome biomass resource tends to be agricultural residues, including grasses and straws, which have high alkali and chlorine contents. In contrast, most woody materials are relatively low in alkali and chlorine and should not present this problem.

30.3.3 GHG emissions

Biomass co-firing directly offsets fossil fuel use; therefore co-firing biomass with coal tends to reduce NOx because it tends to encourage staged combustion and reduces the peak temperature in the furnace.

NOx is GHG neutral but N_2O has a Global Warming Potential (GWP) of 310 times that of CO_2. In Table 30-2, the emissions of CO_2 and N_2O are compared for firing of typical wood and typical bituminous coal. Whilst the total GHG equivalents on an energy basis are similar, the contribution from CO_2 is by far the greater. However, the emissions from the combustion of wood have little effect on the net increase of CO_2 in the atmosphere over the full biomass life cycle.

	Wood	Coal
CO_2 (gCO_2/MJ)	88.9	88.5
N_2O (gCO_2e/MJ)	1.24	0.46
Total GHG equivalent (gCO_2e/MJ)	90.1	89

Table 30-2 Greenhouse gas emissions (EPA, 2009)

Co-firing not only contributes to the reduction of GHG emissions but also reduces the emissions of sulphur oxides and heavy metals, such as mercury.

30.4 Costs

Based upon DECC 2010 capital expenditure for co-firing is give in Table 30-3 below. Capital expenditure varies widely depending on the type of co-firing employed. These figures excludes pre-development costs, that can vary from £39,000/MW to £72,000/MW

	2010	2015	2020	2025	2030
Conventional co-fired (conventional co-firing mixes biomass with coal prior to the pre-combustion process)	167	162	159	159	159

Table 30-3 Capex Co-firing, excluding pre-development costs (£000/MWe – DECC, 2010)

The main reason for the reduced investment cost compared with dedicated biomass is the fact that the complete coal fired power station already exists and the investment cost covers mainly the additional cost required for fuel reception/storage and handling costs associated with the biomass. As co-firing is a mature technology a significant reduction in Capex is not expected.

Table 30-4 below gives the operating cost ranges for co-firing. These operating costs include maintenance, spare parts for the additional equipment required. According to DECC's appraisal of generating costs (DECC 2010) the major contributor to the maintenance costs is labour.

	2010	2020	2050
Conventional co-fired	20	21	21

Table 30-4 Opex Co-firing (£000/MWe – DECC, 2010)

30.5 Requirements of the upstream/downstream process and system considerations

Biomass feedstocks have to be prepared, stored, and transported to the energy conversion process before they can be used to generate power or produce steam. The major steps can be divided into seven categories:

- Fuel pre-treatment prior to delivery – The nature of the pre-treatment would depend on the form that the biomass was required to be delivered to the power station. For example, forest biomass may be chipped in the forest. Pelletised fuel is prepared in a pellet production plant. Feedstocks may be wood, sawdust, straw etc. Other fuels may need to be dried or graded to ensure they comply with the requirements of the power station.
- Fuel reception depends on the type of fuel and the method of delivery – Typically, fuel may be delivered by articulated bulk tippers by road or by rail. Fuel may be tipped into an underground reception hopper and plate feeder discharging onto a belt elevator.
- Screens – Depending on the expected quality of fuel at arrival, it may need to pass through a screen, which could be a rotating disc screen.
- Shredders – Oversize fuel may need to be shredded or passed through a hogger. Additional elements may be added for detection or removal of metals prior to store.
- Elevation of fuel to the top of the silo may be by belt conveyor, by bucket elevator or by en masse chain conveyor.
- Fuel storage and reclaim - Storage of biomass fuel is required to be undercover in the UK so as to ensure that the CV is maintained and that the fuel may be conveyed without problems.
- Site processing: metal separator, dryer, screens.

30.5.1 Mechanical Handling Considerations

Several problems can be encountered by fuel feeding and handling biomass systems:

- Materials sticking to chutes and hopper walls that may lead to blockages and down time. Bridging of materials above the extraction screws can cause uneven extraction from the hopper;
- Biomass materials are notorious in generating dust. This can be an explosion hazard in certain circumstances and it is important that dust is not allowed to build up on any surfaces.
- Because of the potential problems that can be caused by dust, consideration should be given at an early stage to conveyors and drop chutes being either covered or contained. At conveyor intersections it is common practice to extract air from the hood and to pass this air to a de-duster prior to exhaust to atmosphere;

- Sometimes, the biomass can smell and if this is the case, the gases would need to be scrubbed and or passed through a carbon filter to remove the odour thereby avoiding nuisance complaints;
- Belt cleaning is important otherwise materials tend to build up on belt surfaces and can eventually cause problems in belt tracking. This can lead to a belt being caught and breaking thereby leading to potentially serious downtime;

Mechanical handling of biomass tends to be an area causing the most down time and consideration should be given at the design stage to making sure that there is sufficient redundancy, particularly for critical flow lines.

30.6 Deployment and development status

Co-firing of biomass fuel in fossil fuel power stations is not a new idea. Technically it has been proven in power stations worldwide, although, until 2002, it was not practised in the UK Given the scale of global practise at a commercial scale it has a TRL of 9.. According to the Task 32 (IEA, 2009), the total number of power plants in the world, with experience in co-firing biomass and fossil fuels was 234 in 2009, of which 18 were in the UK.

As reported by DECC (2010a) the generation of electricity via biomass co-firing with fossil fuels has decreased since 2005 (see Table 30-5).

	2005	2006	2007	2008	2009
Co-firing GWh/year	2,533	2,528	1,956	1,613	1,806

Table 30-5 Trend in co-fired generation in the UK (DUKES, 2010)

The UK utilities have carried out co-firing in large-scale utility boilers for a number of years and have shown that co-firing with biomass has been successfully accomplished in a wide range of boiler types, including cyclone, stoker, pulverised coal, and bubbling and circulating fluidised bed boilers.

30.7 Barriers to development and deployment

- The LCPD and IED impose emission constraints on existing fossil power generation plants from 2015. Therefore, the amount of biomass co-firing is likely to reduce in and is dependent upon the extent to which the existing coal fired generation continues to operate. Any decreasing trend could be mitigated by the construction of new coal generation plant although this may not be suitable for co-firing.
- It is possible that by 2030 no more than a few of the existing coal generation units will remain in service, significantly reducing the potential for biomass co-firing. In addition, the load factor on this remaining coal generation beyond 2015 is predicted to reduce.
- Fuel supply risks affect economic viability and fuel mix can affect ease of planning consent, i.e. a balance between fuel supply risk with a single fuel and planning risks (such as transportation issues) arising from a diverse mix of fuel must be assumed by the developer.;

- Co-firing with non-energy crops is currently receiving 0.5 ROC per MWh. Co-firing on non-energy crop (regular) biomass with CHP has a level of support of 1.0ROC/MWh. Co-firing of energy crops with CHP has a level of support of 1.5ROCs/MWh. The Government's objective has been to maintain an incentive for home grown biomass fuel whilst reducing the incentive for generating electricity from imported biomass. The extent to which the UK takes up the planting of energy crops will be market driven rather than technology driven.

30.8 UK Capabilities

Future significant growth of co-firing in the UK with major plant modifications is unlikely. Given the global interest and deployment in co-firing, the UK does not have any significantly different capabilities from other major countries deploying the technology.

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31 Stirling engine

31.1 Technology description

Stirling engines are indirectly fired gas engines. The words “gas engine” mean that the working fluid (or process medium) of the engine is a gas, typically compressed air, helium, nitrogen or hydrogen, which is used in a closed cycle (i.e. the engine features a fixed amount of gas, which does not need to be fed into the engine cyclically). The words “indirectly fired” (or alternatively “external combustion”) mean that the heat is transferred to the working fluid indirectly from an external heat source. Both these features are different than for an internal combustion engine (ICE), which works in an open cycle, and heat is generated within the engine in a combustion chamber.

The thermodynamic cycle of a Stirling engine consists of: compression of the working gas in a cold cylinder volume; supply of heat to the gas; an expansion of the gas in a hot cylinder volume; and cooling of the gas before the cycles starts again. During the expansion, force is transmitted to a crankshaft which can then be used for electrical power generation. The cycle can be easily visualised on a temperature/entropy diagram as in Figure 31-1. In the diagram 1-2 is the gas compression, 2-3 is the gas heating at constant volume, 3-4 is the gas expansion, 4-1 is the gas cooling.

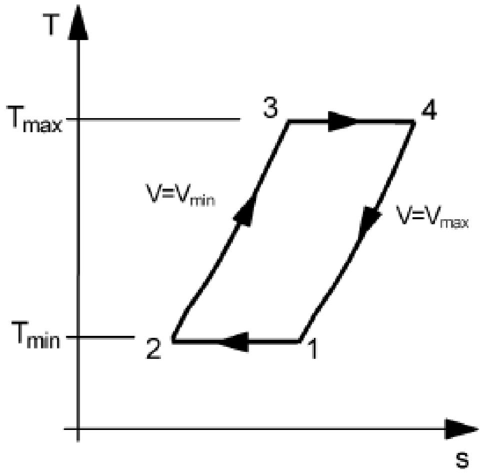

Figure 31-1 Temperature/Entropy diagram for the Stirling Cycle (van Loo et al. 2008)

31.1.1 Components

The main components of a Stirling engine are:

- Heat source
- Heat exchanger
- Cylinders and pistons
- Regenerator
- Cooler and heat sink

Regarding the **heat source**, the most important advantage of Stirling engines when compared to ICE is that in principle any heat source can be used to transfer heat to the process medium via the heat exchanger. Stirling engines that work with a wide range of heat sources have been built in the past, from concentrated solar energy to waste heat. As regards biomass, hot gases from the combustion of solid, liquid or gaseous feedstock can be used. In case of solid feedstocks, the heat source is a biomass furnace (or combustion chamber). For liquid feedstock, the heat source could be a burner running on pyrolysis oil. Last, for gaseous feedstock, the heat source could be a burner running on biogas, landfill gas, as well as gases from a gasifier.

The **heat exchanger** is where the heat from the heat source is transferred to the working fluid. When flue gases are used as heat source, they must be as clean as possible to avoid problems such as fouling or corrosion of the heat exchanger surfaces. This typically results in constraint on ash and heavy metal contents in the biomass feedstock. Also, the heat exchanger needs to be built such that it can be easily accessed for cleaning.

The **piston** moves or is moved within a **cylinder** by the working fluid during expansion and compression, and is connected to a crankshaft. There are different configurations of Stirling engine, which differ in the number of pistons, the number of cylinders, and whether the piston has a sealed or loose fit within the cylinder. The two main configurations are the Alpha and the Beta Stirling engines (Figure 31-2).

- In the Alpha configuration, the engine features two pistons in two separated cylinders, one hot (i.e. connected to the heat exchanger) and one cold (i.e. connected to the cooler). Both pistons are connected to a crankshaft to generate power
- In the Beta configuration, two pistons are in line within the same cylinder. One piston (called the displacer) is loosely fit within the cylinder and its purpose is to move the working fluid from the hot part of the cylinder to the cold one. The displacer cylinder does not extract any power, which is extracted by the power piston in the compression space. The main advantage of the Beta configuration is that it avoids the issue of having a hot moving sealed piston.

The **regenerator** is a heat exchanger where the excess heat of the working fluid is temporarily stored when the working fluid passes from the hot to the cold cylinder or volume. The function of the regenerator is to increase the efficiency of the engine by ensuring that the least heat is exchanged at temperatures others than the maximum and minimum temperature, as required by the ideal thermodynamic cycle. In the simplest case, the regenerator is a block of woven wires where the working fluids passes through.

The **cooler** is indeed another heat exchanger where the working fluid is cooled exchanging heat to a **heat sink**. For small engine, the walls of the cold cylinder act as a cooler themselves, with the ambient air as heat sink. For larger applications, radiators or similar devices may be used, with water as heat sink.

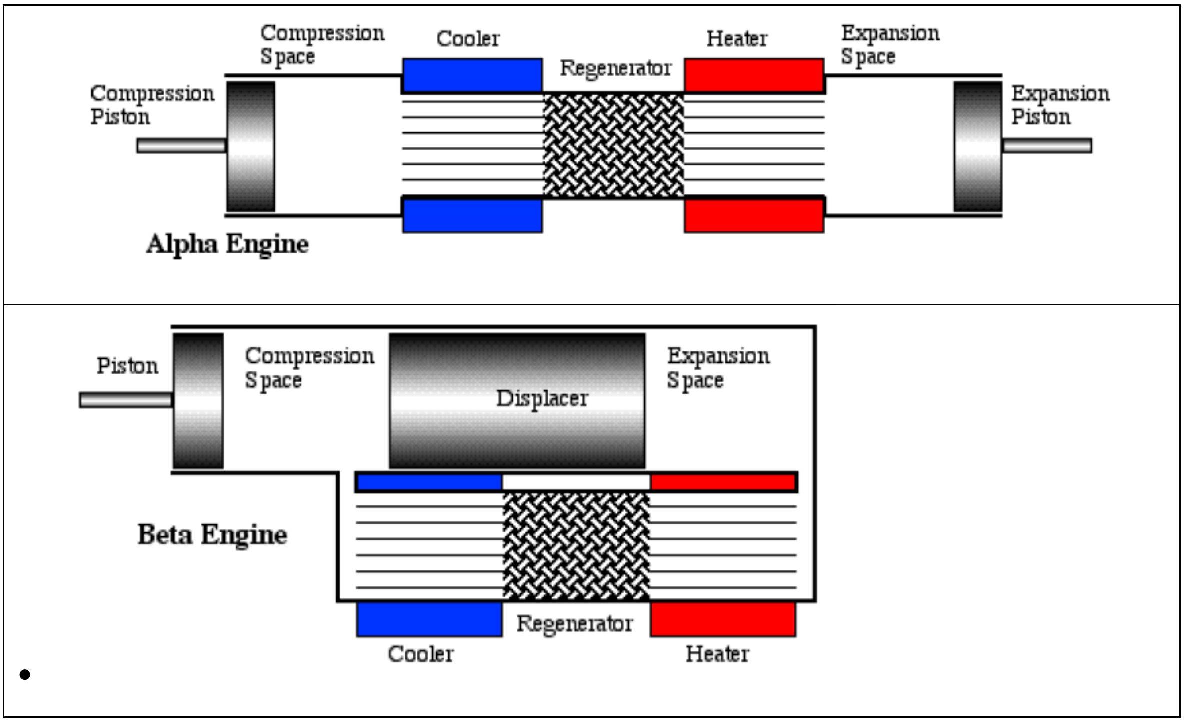

Figure 31-2 Alpha (top) and Beta (bottom) Stirling engine configurations (Maier et al, 2007)

A prototype of a 3kWe Stirling engine (Alpha configuration) is shown in Figure 31-3 (left): (a) is the heat exchanger, (b) the expansion cylinder, (c) the compression cylinder, (d) the cooler, (e) the regenerator and (g) the crankshaft mechanism. Commercial 35 kWe Stirling engine in shown in Figure 31-3 (right)

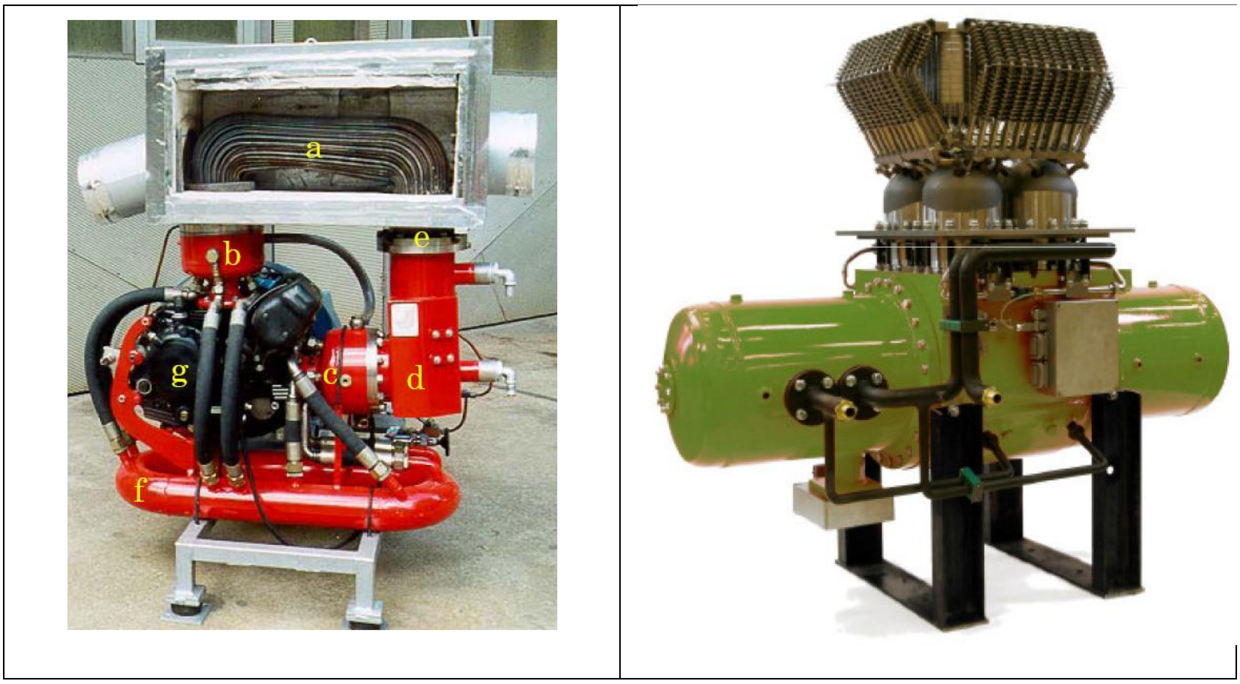

Figure 31-3 Left: Prototype 3 kWe Stirling engine (Zeiler et al., 2010). Right: Stirling engine by Stirling DK (Stirling DK, 2011). Heat exchanger at the top, and cylinder in green.

31.1.2 CHP systems

As Stirling engines require an external heat source, often Stirling engines are designed, produced and installed together with the heat source. This often ensures, amongst other things, better heat integration and the combined production of heat and power (CHP).

A schematic of a CHP system with a solid biomass boiler furnace is shown in Figure 31-4. Air pre-heater and economisers are included with the scope of increasing the system efficiency.

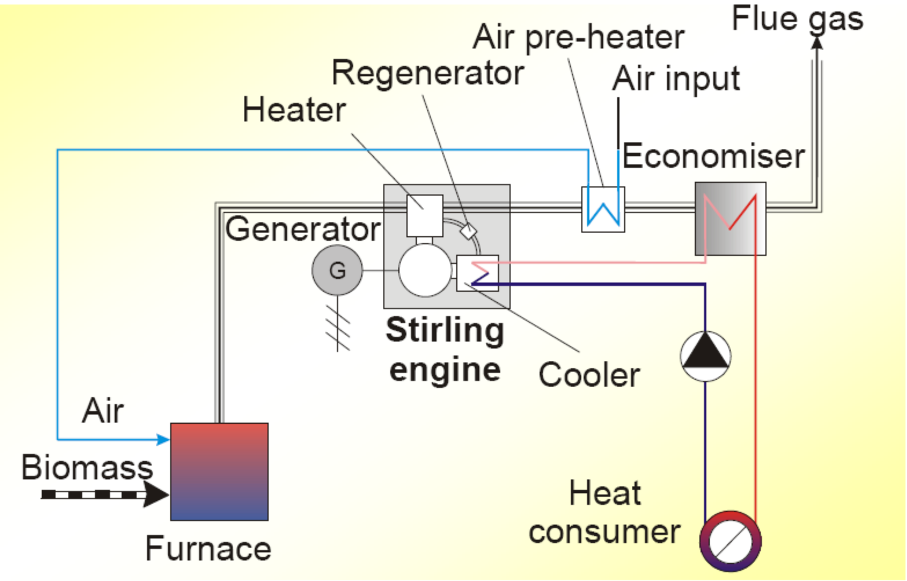

Figure 31-4 Schematic of a biomass CHP plant based on Stirling engine (Obernberger, 2010)

The following types of CHP systems using Stirling engine currently exist:

- Wood chip furnace plants (Figure 31-5)
- Direct biogas combustion plant
- Updraft gasifier for CHP generation (Figure 31-6)
- Pyrolysis plant, for CHP generation as well as biochar production

In terms of technology prospects, they depend on: improving low reliability due to fouling of high temperature heat exchanger areas; improving efficiency by improving process control, heat integration, and seal development for high pressure systems; and by increasing the working hot-end temperature by using low cost, high-temperature materials in the hot-end components.

Figure 31-5 Wood chip furnace system with 5 Stirling engines (Stirling DK, 2010)

Figure 31-6 Updraft gasifier plant at the Technical University of Denmark (DTU). 35 kWeStirling engine on the left in green, combustion chamber in the centre in blue, and gasifier on the right (Stirling DK, 2011)

31.2 Feedstock

Stirling engine per se do not require any feedstock to operate. However, feedstocks are required as fuel to the heat source.

Biomass fuelled heat source include biomass furnaces, biogas or landfill gas burners, bio-oil and pyrolysis oil burners. However, only installations with fresh woodchips have achieved satisfactory reliability performance so far (Stirling DK, 2011). Reliability using feedstock other than woodchip has been limited so far by the fouling or corrosion of the heat exchanger surfaces.

Requirements on the feedstock are associated with the need to minimise ash slagging and fouling problems in the combustion system and heat exchanger. However, if the equipment is designed to minimise deposit formation and the combustion chamber temperature is adequately controlled, many problems can be overcome. In general, feedstocks with low fly ash content are recommended for reliable operation of Stirling engine (Obernberger, 2010)

31.3 Technical and environmental characteristics

31.3.1 Scale

Stirling engines are suited for small scale applications in power generation and combined heat and power (CHP) generation, in the scale from 1kWe up to a bit over 100 kWe (van Loo et al. 2008). Stirling engines currently under operation include:

- A direct biogas combustion system with 35 kWe Stirling engine and 165 kWth output is in operation since 2010, fuelled on landfill gas (Wudag, 2011)
- An updraft gasification unit with 2 35kWe Stirling engines and 240 kWth output is in operation since 2009, fuelled on woodchips (Stirling DK, 2011)
- A system using pyrolysis oil as fuel in the combustor is in operation since 2008 in Denmark, with 35 kWe and 110 kWth of electricity and heat respectively. The system is also producing char for agricultural uses (BlackCarbon, 2011).

In general, larger scales could be achieved with modular systems.

31.3.2 Efficiency

The thermodynamic cycle underpinning the Stirling engine is a thermodynamically ideal process for transforming heat to mechanical energy, as it offers the same theoretical efficiency as the Carnot cycle. In practice, though, its potentially very high efficiency is reduced – inter alia - by friction within the engine, limitation in the heat transfer and heat recuperation, and pressure losses in the process medium. The actual electrical efficiency of existing units is in the range of 10 to 15% (Obernberger 2010), depending on the heat output. An example of energy flow chart for a CHP plant is shown in Figure 31-7.

Future targets for CHP systems with Stirling engine are 20% electrical efficiency and 60% thermal (van Loo et al., 2008). Improvement in efficiency can be achieved by improving the efficiency of the hot heat exchanger, of the pre-heater and of the entire combustion system.

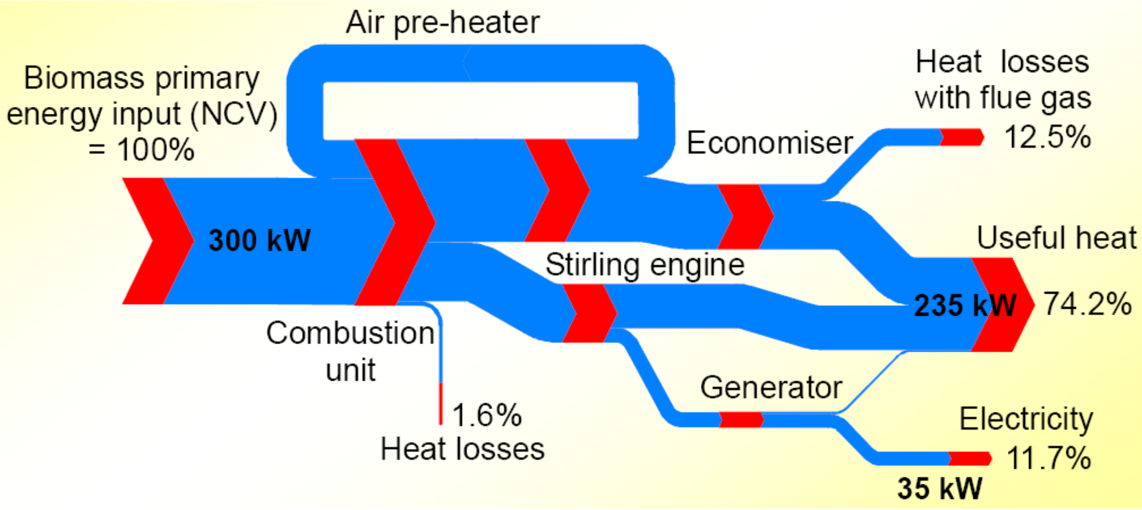

Figure 31-7 Energy flow chart for a CHP system based on a Stirling engine fuelled by a biomass combustion unit (Obernberger, 2010)

31.3.3 GHG emissions

Emissions of systems with Stirling engines are generally only those associated with the heat source and their feedstock input.

Typically, 7% of the nameplate capacity of Stirling engine systems is for self-consumption (Stirling DK, 2010), which needs to be accounted for.

31.4 Costs

Total installed costs for a four engines installation with updraft gasifier for a 140kWe and 600kWth output are estimated to be 1.4 M€. Total service and maintenance cost for 7,000 annual operating hours (including feedstock costs) are 45,000 € (Stirling DK, 2010).

Higher costs are reported by Bios Bioenergiesysteme (2004), where for a biomass CHP plant based on a Stirling engine with 70 kWe and 500 kWth output, capital costs are estimated at 2.2 M€. Annual operating costs (excluding feedstock costs) are at 169,000 €.

31.5 Requirements of the upstream/downstream process and system considerations

No specific requirement exists in association to Stirling engines, besides that of low fly ash content in the feedstock. Stirling engines are typically designed to operate with high temperature (1000 to 1300°C) heat source, so other low temperature waste heat sources are not suitable.

The cogenerated heat production is in the form of hot water for heating/district heating rather than steam.

31.6 Deployment and development status

According to IEA (2011), Stirling engines are at the market introduction stage (TRL 7). They are not widely deployed worldwide, although some commercial units are in operations and more are being developed. A Danish technology developer Stirling DK, which appears to be the worldwide leader in the sector, has at least 6 plants with 12 engines installed and at least 2 more plants with 8 engines under construction (Stirling DK, 2010).

31.7 Barriers to development and deployment

The main barrier to the deployment of systems featuring Stirling engines is the high capital costs compared to other alternatives. Also, it is not clear yet which are the best applications for Stirling engines. Also, the development of a wider range of systems (e.g. wider scale range) could expand the areas where Stirling engines can compete (IEA, 2011)

31.8 UK Capabilities

Capabilities on Stirling engine technologies in the UK are very limited. The only company involved in systems with Stirling engine is Mawera UK, which is the UK subsidiary of the Austrian company Mawera (Viessmann group). Mawera is a supplier of furnaces which have been used in the past as heat sources for Stirling engines.

31.9 References

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32 Organic Rankine Cycle

32.1 Technology description

The Organic Rankine Cycle is a thermodynamic cycle which is similar to the conventional Rankine cycle used in water steam cycles to generate power, with the difference that instead of water it uses an organic liquid (typically oil) as process medium. Such organic liquid is chosen to have a lower boiling temperature than water. The differences in physical properties of organic oil compared to water have the following advantages:

- the cycle can be used with low temperature heat sources (from 70 to 300°C)
- the expansion of organic oil superheated steam in the turbine does not lead to wet steam (see the entropy/temperature diagram in Figure 32-1 right. Area under the curve is wet steam, on the left is liquid, and on the right is dry steam), thus avoiding issues related to steam condensation in the turbine
- due to the low operating temperatures, the organic liquid does not need to be evaporated directly in the boiler, but it can be heated in a secondary circuit by a thermal oil that is heated in a tube boiler operating at atmospheric pressure. This allows for the working medium of the ORC to run in a completely closed circuit, separated from the boiler. The advantage of this feature is that no steam boiler is needed and therefore investment and maintenance costs of the boiler are considerably lower than for a comparable steam plant.
- an ORC plant can operate in a much wider part-load operation range (between 30 and 100 per cent of full load) than conventional steam plants

The organic working fluid is generally an oil-derived hydrocarbon fluid. The choice of the right working fluid depends on the required thermal stability over the range of operating temperatures and a minimal degradation over time. Examples of working fluids are butane, heptane, cyclohexane, benzene, toluene, orthoxylene and ethylbenzene. Silicon-based oils are also used.

Organic Rankine Cycles are used to produce both power and combined heat and power. In the case of CHP application, heat is in the form of hot water and not steam (due to the low operating temperature).

Figure 32-1 (left) provides a schematic representation of a cogeneration plant using an ORC cycle. An ORC plant can be divided into two main components: the heat source, which is typically a furnace with a boiler, and the ORC turbogenerator, where the ORC cycle takes place. In Figure 32-1 (left), item 1 is the wood furnace with thermal oil boiler, with m_1, m_2 and m_3 the fuel input, the air input, and the flue gases respectively. The rest is part of the turbogenerator: 2 is the economiser which can be used for heat (hot water) generation, 3 is the evaporator for the organic working fluid in the cycle, 4 is the expansion turbine, 5 is the electric generator, 6 is the organic working fluid pre-heater, 7 is the condenser for further heat (hot water) generation, 8 is the feed pump and 9 are all control valves. A schematic illustration of an ORC plant is also given in Figure 32-2.

The heat source and the ORC turbogenerator are always integrated in one single unit. Due to the low operating temperatures, it would not make technical sense (as well as economic) to have heat transported from a heat source separated from the turbogenerator.

On an entropy/temperature chart (Figure 32-1, right), the ORC cycle consists of the following steps:

- A–B: Pressure increase of the organic fluid in the feed pump
- B–C: Preheating of the organic fluid
- C–D: Pre-heating, evaporation and superheating in the evaporator
- D–E: Expansion in the turbine
- E–F: Cooling in the recuperator (or pre-heater)
- F–A: Condensation in the condenser

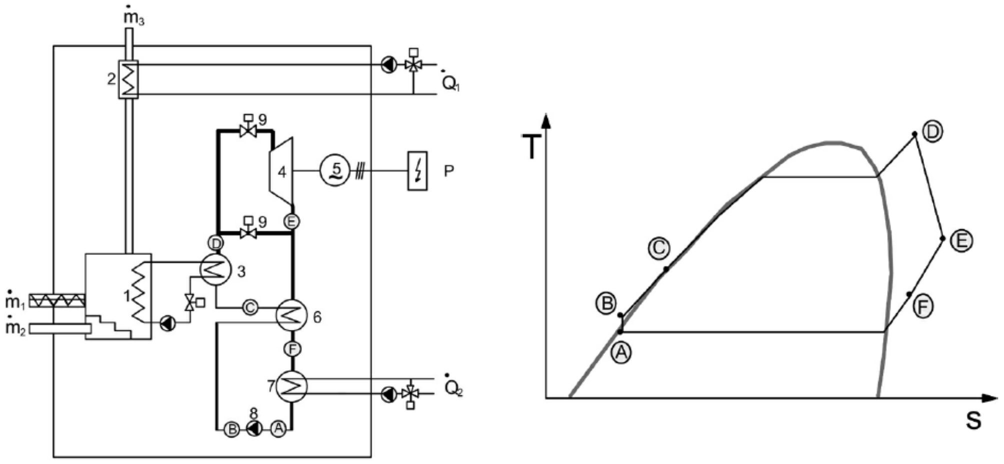

Figure 32-1 Mass flow diagram (left) and entropy/temperature diagram (right) for a cogeneration plant using an ORC process.

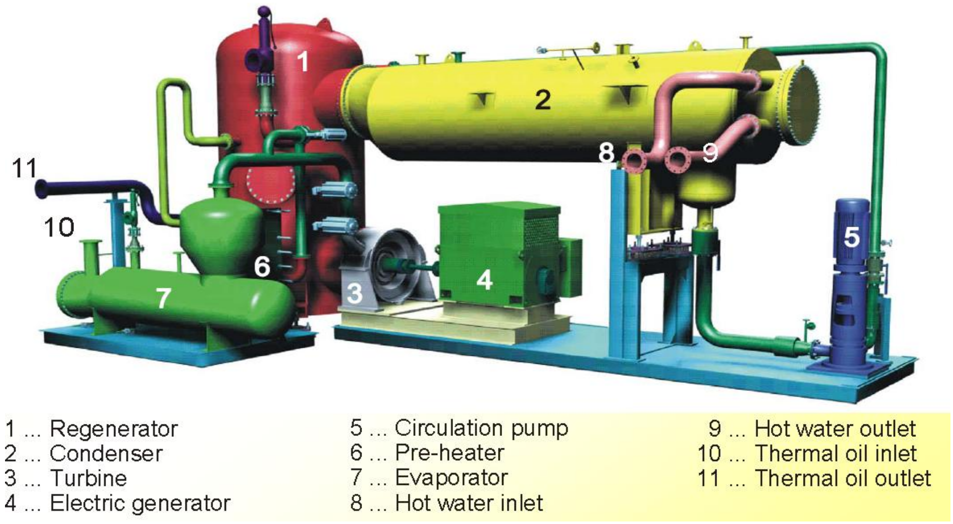

Figure 32-2 Schematic illustration of an ORC unit (Obernberger, 2010)

One ORC plant developer is also offering ORC system with two fluid loops in the boiler at different temperatures, in order to improve efficiency further (Figure 32-3).

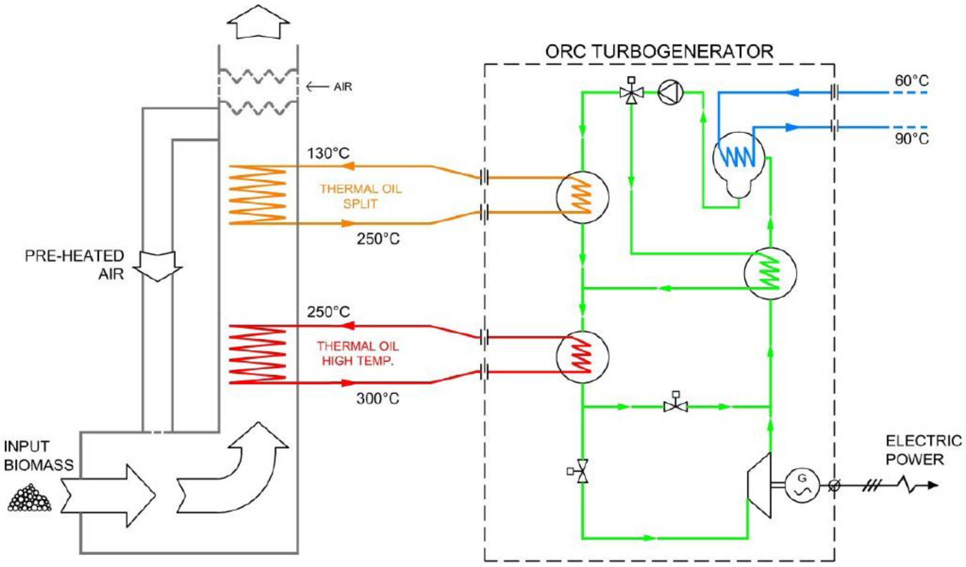

Figure 32-3 "Split system" by Turbonden, for cogeneration (Bini, 2010). Two thermal oil loops exist, one at high temperature, the other at low temperature

32.2 Feedstock

Similarly to Stirling engine (and any other thermodynamic cycles), ORC turbogenerators per se do not require any feedstock to operate. However, feedstocks are required as fuel for the heat source.

Biomass fuelled heat source typically include biomass boiler. See related chapter for information on biomass boiler feedstock

32.3 Technical and environmental characteristics

32.3.1 Scale

Typical sizes for ORC generators range from 300 kWe to 2MWe, with possibility of modular products of up to 10MWe (van Loo et al, 2008). The average power of most ORC plants installed in Europe is about 1 MWe (Bini, 2010).

32.3.2 Efficiency

Typical CHP plant based on ORC technology can achieve 17% electrical efficiency (gross) or 15% (net, i.e. taking into account the self-power consumption of the plant). At about 17% of the gross power consumption, self power consumption for ORC plant is relatively high when compared to steam plants. The technology developer Turboden reports (Bini, 2010) that commercially available 1MWe ORC plant can achieve up to 20.4% electrical efficiency or 16.2% if operating in co-generation with production of water at 60-70 °C. It is not clear though if efficiency is net or gross.

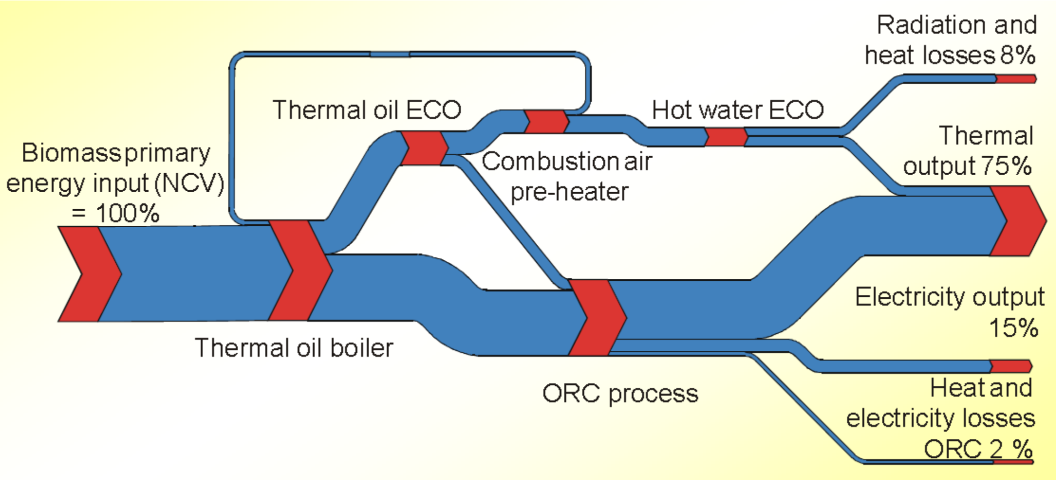

Figure 32-4 Energy flow chart for a CHP system based on a ORC system fuelled by a biomass combustion unit (Obernberger, 2010)

32.3.3 GHG emissions

Emissions of ORC plants are only those associated with the heat source and their feedstock input.

As already mentioned in the efficiency section, a share of the gross power production of an ORC plant is used for self-consumption, which needs to be accounted for.

32.4 Costs

Installed capital costs (as sale prices, including biomass furnace and thermal oil boiler) can be found in (Turboden, 2009), and range from 10,200 €/kWe for a 345kWe plant down to 4,500 €/kWe for a 1803 kWe plant (both including the cost of the heat source).

In a techno-economic assessment done for the NREL for concentrated solar power generation via ORC, Prabhu (2006) reports capital costs of 5.6 M$ (2006) for a 1MWe system (excluding the concentrated solar system), and operating costs (excluding feedstock) of 5.4 c$/kWh (2006).

32.5 Requirements of the upstream/downstream process and system considerations

No specific upstream requirement exists in association to ORC plants, besides the requirements applicable to the feedstock to the heat source.

Due to the low temperature heat source, cogenerated heat is always in the form of hot water for heating applications.

32.6 Deployment and development status

ORC can be considered a market-proven technology (Obernberger, 2010) - at TRL 7 - with more than a hundred plants already operating worldwide, including CHP systems, concentrated solar power generation, heat recovery, and geothermal power.

The main ORC technology developer worldwide appears to be the Italian company Turboden (part of the Pratt&Whitney group). As of July 2011, Turboden have 195 ORC plants installed in 21 countries worldwide, for more than 220 MWe installed (Turbonden, 2011), Figure 32-5.

Figure 32-5 Typical single skid 700 kWe ORC unit for biomass cogenerationby Turboden (Bini, 2010).

32.7 UK Capabilities

Capabilities on ORC technologies in the UK appear to be just with one main player. The company Blue-NG (owned by 2OC) is developing a 20 MWe plant in East London (2OC, 2011). Such plant is based on a heavily energy-integrated layout, and makes use of an internal combustion engine running on crude rapeseed oil and the high enthalpy of the natural gas mains, being co-located with a National Grid gas pressure reduction station. The plant uses an ORC cycle to recover the heat from the expansion of the natural gas from the gas mains before entering the distribution network. The completion of the first Blue-NG plant is due from early 2012 and more are under planning application. Some R&D capability in novel micro ORC exists at the University of Nottingham.

32.8 References

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33 Internal combustion engine

33.1Technology description

33.1.1 Internal Combustion Engine

Internal combustion (IC) engine technology has been the most widely applied technology for generating electricity from gas. This is due to its scale, cost and efficiency:

- IC engines are available in a wide range of sizes allowing systems to be scaled to match production rate;
- IC engines are a mature technology with a lower capital and operating cost compared to other relevant technologies;
- IC engines can provide a higher efficiency than many other technologies; and
- IC engines have availabilities of c. 93%.

The internal combustion engine has an intake valve, through which the air-and-fuel mixture (or air) is introduced into the cylinder, and an exhaust valve, through which exhaust gases escape from the cylinder.

Figure 33-1 represents a diagram showing the full cycle of a four-stroke engine. The name refers to four stages of the engine's operation:

- Intake of air or air and fuel mixture;
- Compression;
- Power; and
- Exhaust.

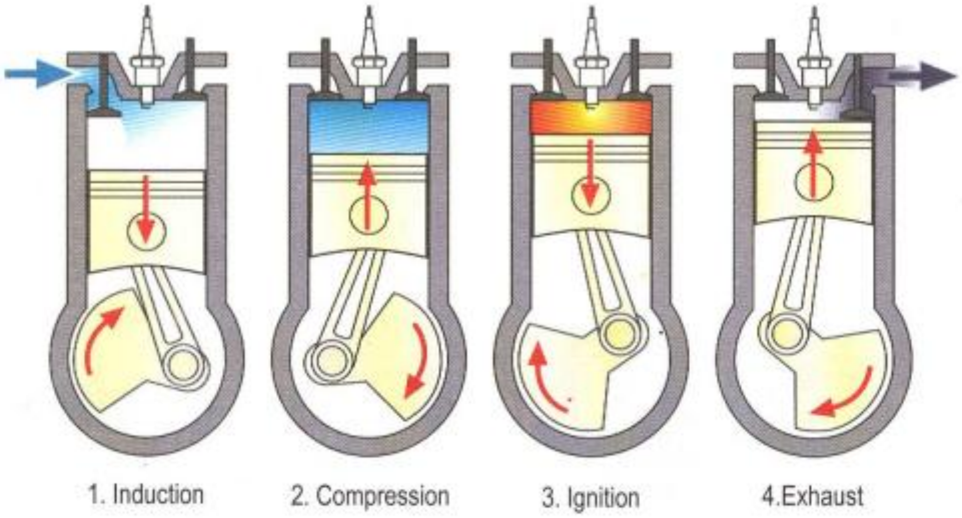

Figure 33-1 4-stroke engine cycle diagram

Gas-powered internal combustion engines are modified versions of medium- and high-speed engines powered by liquid fuels. The modifications applied in gas-fuelled engines typically include:

- A change in the shape of the cylinder head and the top part of the pistons;
- adding a gas handling fuel system;
- expansion of the engine cooling system and the exhaust heat removal system

33.1.2 Combined heat and power (CHP) systems

The excess heat produced by the ICE in the engine cooling system and the exhausts can be used to produce heat by using heat exchangers.

The major technologies available for cogeneration of heat and power are steam turbines, gas turbines and reciprocating engines. Steam turbines and gas turbines are better suited to larger industrial application due to the heat to power ratios and temperatures of the processes whereas IC engines are used in the commercial, residential and agricultural sector, due to lower energy demand, lower temperature requirements for heat and simplicity of operation and cost.

A basic CHP system (Figure 33-2) comprises:

- Gas engine combined heat and power unit;
- Auxiliary drive switchgear;
- Cooling system;
- Oil system;
- Power safety system.

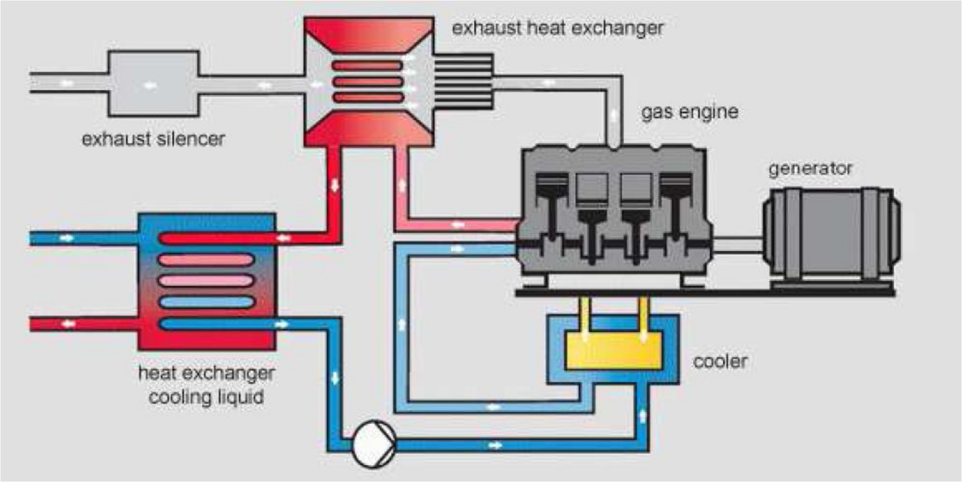

Figure 33-2 Diagram for cogeneration with gas engine (INIG, 2010)

Gas Engine CHP - The engine powers a generator that produces electricity. During operation, the reciprocating engine warms up, producing heat which is recovered by the oil cooling system, and emits large amounts of heat (to the atmosphere or heat recovery system) in the form of exhaust gases.

For its operation, a reciprocating engine needs air which, together with the fuel (gas), is combusted in the engine’s combustion chambers. A gas-and-air mixture is created by drawing air through a filter. The gas feeding system comprises a gas control system with a zero pressure regulator, and a metering valve.

Oil System - Each reciprocating engine requires oil to lubricate the moving parts. A small amount of oil may enter the combustion chamber where it is combusted along with the fuel. Therefore, an external oil system must be provided, to both supplement oil in case of shortages and /or enabling continuous operation of the CHP unit.

Power Control System - To enable electricity produced by the generator to be beneficially used, suitable devices must be installed to protect the generators against overloading and short-circuit conditions.

Advantages and disadvantages of a CHP system over a power only system are listed in Table 33-1:

Advantages of CHP	Disadvantages of CHP
• Reduced (operational) energy costs; • Diversification of energy supply; • Simultaneous generation of heat and power, albeit in some instances the higher electricity recovery the lower the heat recovery; • Reduced CO_2 emissions; • Conservation of valuable fuel resources; • Transmission and distribution losses may be reduced by an average of 7.5% of transmitted power (Arnold, 2009).	• CHP systems require that a plant is located close to consumers in order to supply heat; • The chimney may require planning permission depending on the height of existing local buildings and plume dispersion studies may be required by the local authority; • Noise generation can vary from moderate to high. This can be mitigated by placing the CHP in an acoustic enclosure, which will reduce (typically) the noise levels below 75 dBA, and, silencers can also be installed in the engine air system.

Table 33-1 Characteristics of CHP

33.2 Feedstock

The biomass feedstocks for an IC engine CHP plants may be the following biomass-derived gases:

- Biogas: a gas mixture of methane and carbon dioxide produced by anaerobic digestion;
- Landfill gas: a gas mixture of methane and carbon dioxide produced and extracted from landfill sites (produced by anaerobic digestion); and
- Syngas: a gas mixture of carbon monoxide and hydrogen obtained from the thermal treatment (gasification or pyrolysis) of biomass.

In addition to gas, other biomass-derived liquid fuels can be used in ICE for power and CHP production. However, due to their higher energy density, liquid fuels are more typically used for transport applications

33.3 Technical and environmental characteristics

33.3.1 Scale

Reciprocating (natural gas or biomass derived gas) engines are used for a variety of stationary power generation applications, including emergency power, base-load power, and peaking service. These engines are generally available for smaller power generation applications in sizes ranging from c. 100kWe to c, 5 MWe, but multiple reciprocating engines can be used to increase generating capacity and improve availability. Most biogas and landfill gas applications are < c.5MWe, but more than one engine is often used to provide wider operational envelopes and increased redundancy.

Heavy-duty reciprocating engines are extremely efficient and reliable power producers with the ability to generate hot water or low-pressure steam for CHP applications.

33.3.2 Efficiency

33.3.2.1 Electricity only

Internal combustion engines are relatively efficient at converting gas into electricity, achieving efficiencies in the range of 25 to 35%.

Genset efficiency is the net electrical power output divided by the heat power input in the gas. Heat rate is the inverse of the efficiency and is the heat power input in the gas divided by the net electrical power output.

Efficiency and heat rate are calculated using the following data:

- Genset net electrical power output;
- Gas flow rate;
- Fraction of methane(i.e the % of methane in the gas); and
- Calorific value of methane.

Full-load average efficiencies of gensets of different sizes are provided in table below. Note that efficiencies are net CV basis after averages parasitic loss of 4.5% average.

Engine size (kWe)	Full-load Efficiency (%)
1950	37.0%
1150	31.7%
1030	28.5%
850	28.5%
400	27.2%

Table 33-2 Genset Efficiency

33.3.2.2 CHP

Total CHP efficiency varies slightly depending on size. Gas engines typically have total CHP efficiencies between 70% and 80% and CHP electrical efficiencies that range from 30% to 40%. The energy balance of a typical CHP unit is summarised in the diagram in Figure 33-3.

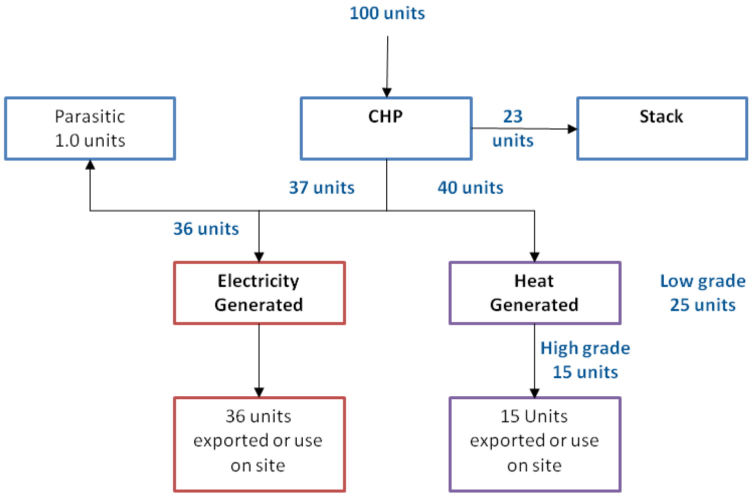

Figure 33-3 Heat and electricity efficiency of a CHP engine (B&V, 2011)

33.3.3 GHG emissions

There are no GHG emissions associated with the use of renewable gas in ICE engines. Instead there are savings to be gained from the use of renewable gas in CHP as against the use of natural gas. The amount of savings depends on the amount of electricity displaced and the percentage of heat exported/used on site. GHG emission savings are between 0.22-0.54 $kgCO_2$/kWh of electricity displaced and 0.204$kgCO_2$/kWh of natural gas displaced in heating (DECC, 2010).

33.4 Costs

The capital cost and operating costs given below relate solely to the investment and operation of the gas engine, front end technologies to convert feedstock to gaseous form are commented upon elsewhere in this report.

33.4.1 Capital cost

The specific cost of a reciprocating engine and generator set is generally lower than gas turbine generating systems. Installed costs for reciprocating engine CHP systems vary from about £600 to £1,200/kWe. The capital cost of a biomass-derived gas CHP engine is affected by economies of scale as shown in Figure 33-4 below. Capital costs are not expected to reduce significantly in future as this is a mature technology with very extensive existing deployment.

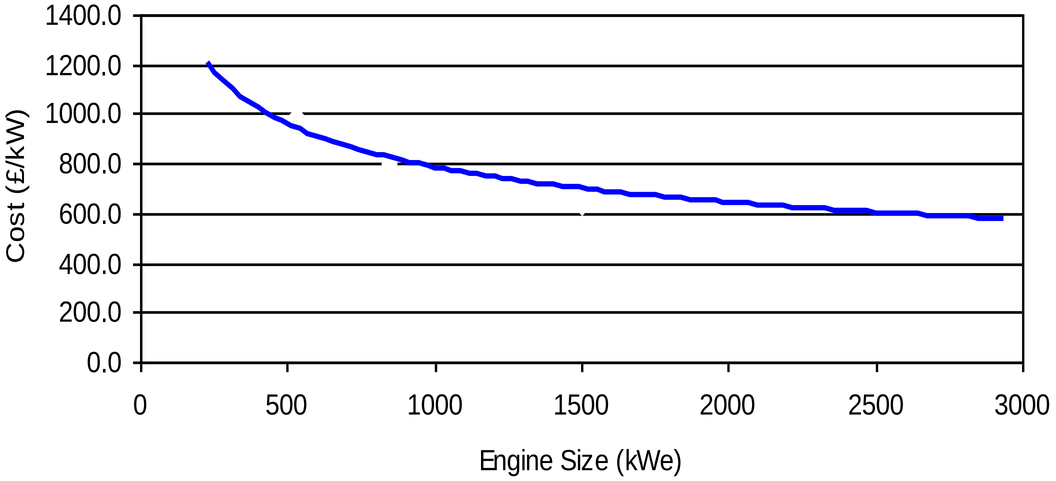

Figure 33-4 Capital cost for biomass-derived gas CHP (B&V, 2011)

33.4.2 Operating cost

Reciprocating engines have higher electrical efficiencies than gas turbines of comparable size, and thus lower fuel-related operating costs. Although maintenance costs for reciprocating engines are higher than for gas turbines, the maintenance can often be performed by in-house staff or a local service provider.

The OPEX for CHP engines for the different plant sizes up to 1 MWe are shown in Figure 33-5. Larger engine sizes have an OPEX of c. 1p/kWh. These are based on an availability of 93% and exclude all fuel related costs.

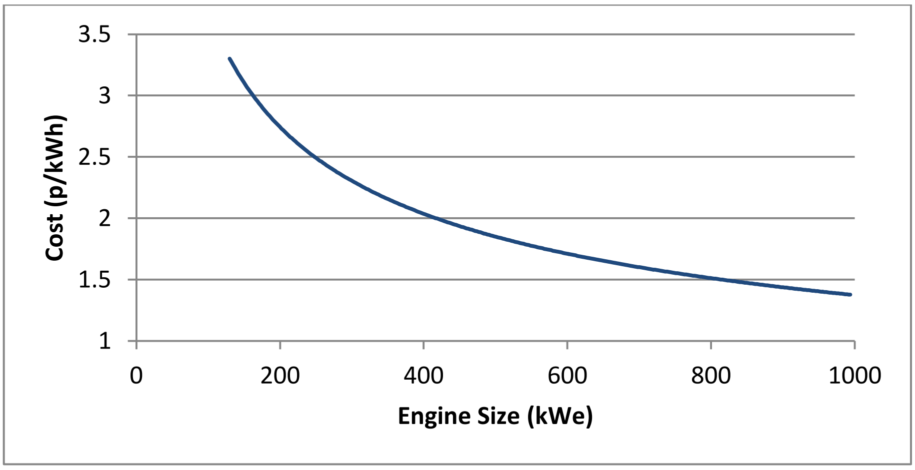

Figure 33-5 Operating cost for CHP (B&V, 2011)

33.5 Requirements of the upstream/downstream process and system considerations

In order to feed biomass derived gas to a CHP plant, the gas needs to be cleaned and dried to limit any damage to the engine. The majority of gas engines have maximum limits for the content of hydrogen sulphide (H_2S), halogenated hydrocarbons and siloxanes as shown in Table 33-3.

Component	Limits (based on 60% CH4)
• H_2S	• < 200 ppm v/v. • Higher levels would be controlled by increased frequency of engine oil changes, or by scrubbing, typically when levels are of the order of 750ppm or above.
• Halogens (Cl & F)	• Less than 60 ppm.
• Silicon compounds (Si)	• Low levels (typically less than 12 mg/Nm3) can be controlled by engine oil changes. Higher levels of siloxane would require the installation of activated carbon filters.
• Ammonia	• Of the order of 40 ppm desirable to ensure that engine NOx emissions are controllable.
• Gas moisture content	• Less than 50 to 80% relative humidity at the lowest temperature.

Table 33-3 Indicative gas contaminant limits for CHP engines

The above limits need to be considered because:

- Siloxanes do not decompose biologically and during digestion they volatise and transfer to the gas. They can turn into hard, abrasive silica in the combustion chamber of the engine and thereby reduce the engine life. Low levels of siloxanes can be controlled by oil changes. However, higher levels will require the treatment of the feed gas with a synthetic resin adsorption system or activated carbon.
- High levels of H_2S can cause the acidification of the oil, thus reducing oil lubricity and can damage gas pipelines and exhaust pipes if the temperature of the feed gas is below dew point. (Dena, 2009).
- Chlorine can break down in the engine during combustion. In the presence of water it forms hydrogen chloride (HCl) which is highly corrosive. HCl, even in trace amounts, could lead to cracking of stainless and cast iron components in the engine.
- Ammonia is present in the biogas when the feedstock used contains high amounts of nitrogen (e.g. protein containing waste). During combustion, ammonia forms nitrous oxide that can be released to the atmosphere. Nitrogen oxides (NOx) are highly reactive gases and therefore their release is controlled.
- Biogas contains c.40% of carbon dioxide. Carbon dioxide in the presence of water can produce carbonic acid which will corrode the ferric components of the engine.

- Water present in the feed gas needs to be removed, as it contributes to corrosion. This can be achieved by pre-drying the gas or by maintaining the gas above the dew point. Pre-drying may be expensive, particularly if the gas volume is high.

33.6 Deployment and development status

CHP plants on the whole are “mission proven” and in successful operations stage (TRL 9). In the UK, gas CHP has been applied extensively to industries requiring large quantities of heat and power, i.e. paper, chemical and oil refinery sectors. According to the Department for Business Enterprise and Regulatory Reform (BERR), in 2009 there were 1,439 schemes with an installed capacity of 5,469MWe and 10,924 MWth, operating at an overall efficiency of 67.2% (GCV) (Lee, 2010). The total electricity and heat generated by these plants was 27,911 GWh and 52,197 GWh respectively, which represent over 7% of the total electricity generated in the UK (Lee, 2010) and 8% of heat required in the UK (Arnold, 2009).

In terms of the number of schemes, the majority (80%) are schemes of less than 1MWe. These schemes are in the agricultural, commercial, public administration, residential and transport sectors. The majority of schemes in the UK are fired on natural gas (71%), whilst schemes using renewable fuels (sewage sludge, other biogases, and municipal waste and refuse derived fuels) account for only 4% of all fuels used in CHP.

33.7 Barriers to development and deployment

The following are barriers to development and deployment of biomass-derived gas CHP:

- Economic viability often relies upon a facility being able to secure a sale or shadow price for the resulting heat from the system. In the event that the heat off take is secured by a third party, there is often contractual difficulty in securing a long term off take by a commercial entity whose long term demand or even presence cannot be guaranteed.
- In the case of solid biomass gasification projects, developers have in the past often encountered difficulty during the required consenting process. Measures to simplify the planning process and speed up deployment are required.
- For medium and large sites, reinforcement of the local electricity distribution network grid may be required. For some schemes, the high upfront cost of grid connection or indeed upgrade, particularly in rural areas, can have a high and negative impact on project development.
- Deployment of renewable CHP in the UK will remain highly dependent on financial support. Until recently, there has been an inertia in the development of biomass related CHP due to the confusion over the support mechanism and long term grandfathering given the forecast rise in fuel supply costs as rising demand is likely to increase fuel supply costs. This has now been resolved, though a replacement of the existing ROC based system post 2013 has continued to cause nervousness in the market with the resulting slowing of development.

33.8 UK Capabilities

There are many manufacturers providing biomass-derived gas to electricity generators in the UK, therefore there is no perceived lack of expertise or skill capacity serving this market. Providers fro prime mover packages in the UK, include but are not limited to: Clarke Energy, finnings, Co-genco, Edena and ENERG. There are many manufacturers worldwide (including UK Suppliers) that produce engines. Major manufactures offereing highly reliable engines and other ancillary equipments include: Caterpillar (USA), Jenbacher Energie (Austria), Perkins (UK), Cummins (USA) and Deutz (Germany).

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34 Close-coupled gasification

34.1 Technology description

In close-coupled gasification, syngas is generated by the gasifier and then it is either combusted directly (without syngas cleanup) in the gasifier itself, or downstream in an adjacent boiler

Close-coupled gasification technologies can be groups into small scale and large scale technologies.

34.1.1 Small scale

Small scale close-coupled gasification-boiler systems are available commercially and are predominantly used to substitute either natural gas or heating-oil boilers at sites, such as wood manufacturing sites, that have easy access to woody residues as fuel. The systems typically produce space heat, and / or process heat or steam and can also be combined with downstream equipment such as steam turbines and absorption chillers to produce electricity and cooling respectively (Peterson and Haase, 2009).

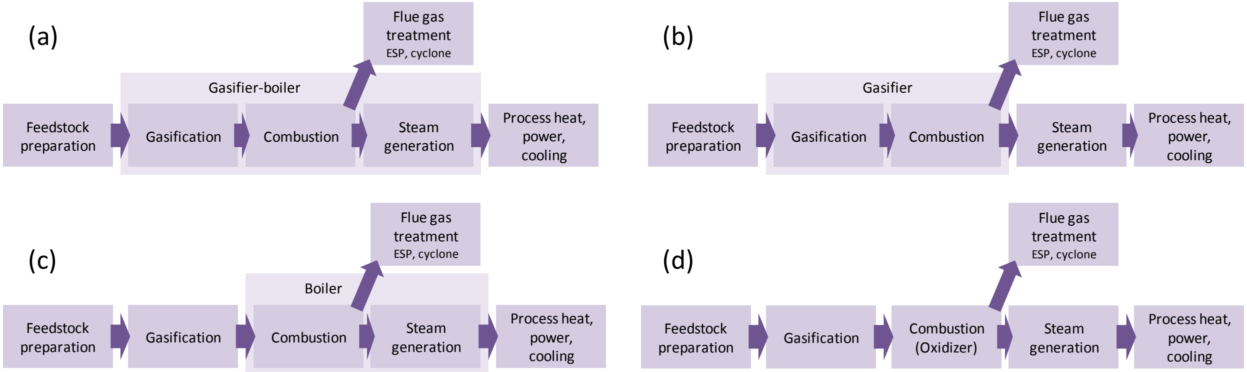

Figure 34-1 Schematic diagrams of representative close-coupled gasification systems

Figure 34-1 shows representative schematic diagrams of close-coupled gasification systems. Figure 34-1 (a) shows a fully integrated gasifier-boiler such as the Uniconfort system. Figure 34-1 (b) shows a system, such as those proposed by Chiptec, where the output of the gasifier is hot flue gas and steam generation takes place in a downstream heat recovery steam generator (HRSG). Figure 34-1 (c) shows a system where the gasifier provides syngas to a gas-fired boiler. And finally, Figure 34-1 (d) shows a system, along the lines of those being developed by Nexterra, where gasification, combustion and steam generation each occur in separate vessels.

The principle advantage of these close-coupled gasification-combustion systems over a direct biomass combustion boiler are reduced emissions, along with greater controllability (ability to ramp the heat output up and down quickly) (Uniconfort, 2010). Furthermore, configurations (b), (c) and (d) can all, at least in principle, be retro-fitted to an existing boiler or HRSG thus replacing natural gas or fuel oil with biomass.

For close coupled gasification systems the process steps are:

- Feedstock preparation – the gasifiers used in small systems require feedstock that is chipped, or shredded wastes. In some instances, waste process heat is used to dry the feedstock prior to it being fed into the gasifier.
- Gasification – this is typically achieved in a fixed-bed or moving grate updraft or down-draft gasifier.
- Combustion – the combustion is either integrated in the gasifier (Figure 34-1 (a) and (b)) (Alternative Energy Solutions International, 2010a), or takes place directly downstream of the gasifier in a boiler (Figure 34-1 (c)) (Chiptec Wood Energy Systems, 2005a) or separate oxidizer (Figure 34-1 (d)) (Nexterra, 2008). The use of a separate oxidizer can allow technology to reduce NOx emissions such as a selective non-catalytic reduction system (SNCR) to be included (Nexterra, 2008).
- Steam generation – occurs with combustion of the syngas in a boiler which is either integrated with the gasifier (Community Power Corporation, 2009) or separate (Chiptec Wood Energy Systems, 2005a), or in an HRSG downstream of an oxidizer (Nexterra, 2008).
- Downstream CHP components – Systems with steam generation may also include other downstream CHP components such as steam turbines for power generation or absorption chillers for cooling (Peterson and Haase, 2009).
- Flue gas cleaning – particulates in the flue gas from the boiler or oxidizer are removed with an electrostatic precipitator (ESP) (Nexterra, 2008) or cyclone (Chiptec Wood Energy Systems, 2005a) prior to the flue gas being sent to the stack.

34.1.2 Large scale

The process steps for large scale heat systems are very similar to the small-scale systems described above:

- Feedstock preparation: The biomass feedstock is pre-treated by drying and sizing, depending on the moisture content and size necessary for the gasifier type
- Gasification: there are several different gasifier types being used for large-scale heat and power production: Entrained Flow (EF), Bubbling Fluidised Bed (BFB), Circulating Fluidised Bed (CFB), Dual Fluidised Bed (Dual) and Plasma gasifiers – fixed bed gasifiers cannot scale up to very large units.
- Combustion: in close-coupled systems the syngas is burnt directly in a boiler for heating.
- Flue gas cleaning – particulates in the flue gas from the boiler, generator or turbine are removed with an electrostatic precipitator (ESP) or cyclone prior to being sent to the stack

34.2 Feedstock

34.2.1 Small scale

As the commercial small scale gasifiers have mostly been installed at wood industry sites they are predominantly used with woody residues (wood chips, green wood mill residues, pellets, etc) however, the systems can be and have been used with other types of biomass such as agricultural residues (e.g., corn stover, nut shells and husks, olive and fruit pits), animal and municipal waste or industrial or commercial wastes (e.g., pallets, cardboard, paper, sludge) (Chiptec Wood Energy Systems, 2005a; Alternative Energy Solutions International, 2010a). The fixed bed or moving grate gasifiers used in these systems can accept 5-60% biomass moisture content (wet basis) and up to about 10% mineral content, and require a maximum fuel size in the range of 30-60 mm (Chiptec Wood Energy Systems, 2005a; Alternative Energy Solutions International, 2010a).

34.2.2 Large scale

Large scale close-coupled systems use a wide range of gasification technologies. Thus the feedstock requirements vary considerably between gasifiers, with plasma being able to take mixed wastes at large sizes, down to entrained flow requiring uniform, dry powdered woody biomass. In general, gasifier designs with shorter residence times (such as EF) require a more uniform and reactive feedstock, whereas designs with longer residence times (e.g. Plasma) are able to accept a much wider, and varying, range of feedstock sizes and compositions, moisture and ash contents (E4tech, 2009). Additional details on feedstock requirements for each gasification technology are given in the Gasification chapter.

34.3 Technical and environmental characteristics

34.3.1 Scale

The majority of manufacturers of updraft and down-draft gasifiers that use wood as a feedstock offer systems that are at sizes of less than 10 odt/day (less than about 2 MW of thermal input). However, systems exist in the range of 0.2–180 odt/day of feedstock input (corresponding with around 40 kW to 15 MW of thermal input). Systems fired on MSW, RDF or other wastes run to even larger sizes spanning from the 10’s of odt/day up to around 500 odt/day (114 MW of thermal input), or into the thousands of odt/day when co-fired with coal.

34.3.2 Efficiency

Reported biomass thermal input to thermal output efficiencies for small scale gasifiers are in the range of 65–85%, at 20% moisture content on a wet basis (Alternative Energy Solutions International, 2010a).

Large scale gasifiers have thermal or cold gas efficiencies between 70% and 93%, with most operating at between 75% and 88% (based on the ratio of the syngas and feedstock LHVs, Yassin et al., 2009).

In general, the higher the reaction temperature, the larger is the potential thermal efficiency of the process. Typical syngas combustion temperatures are slightly lower than those of natural gas, due to its lower energy density (kJ/m^3), although minimising the presence of inert syngas species (e.g. N_2, CO_2) reduces this temperature difference (Valler et al., 2009). Gasification heat-only plants can therefore reach efficiencies of 80-90% (IEA, 2008).

34.3.3 GHG emissions

Estimates of the GHG emissions for the production, sizing, drying and transport of typical gasification feedstocks (e.g., forestry residues, waste wood, energy crops and MSW) based on the data in Biomass Energy Centre’s Biomass Environmental Assessment Tool (BEAT2) range from about 2.3–37 gCO_2e/kWh (Biomass Energy Centre, 2008). Factoring in the process efficiency ranges listed above yields emissions in the range of about 3–60 gCO_2e/kWh of thermal output. Thus compared to a baseline of natural gas with fuel emissions of about 220 gCO2$_e$/kWh and a typical new boiler efficiency of 90% (DECC, 2010) the close-coupled gasification systems yield emissions savings in the range of 77–99%

34.4 Costs

34.4.1 Small scale

Reported installed costs for close-coupled systems vary widely given the wide range of system configurations that are possible. The 2009 NREL Market Assessment cites example projects in the size range of 3–100 odt/day (0.6 – 21 MWth input) with normalised costs of £45–160k per odt/day of capacity, although no information is given as to what is included in this total project cost. Close-coupled system capital costs are likely to be dominated by the gasifier-combustor, as the systems are simple, and downstream steam turbine or boiler equipment is inexpensive - however, an average cost breakdown is not available due to the variety of system designs available.

34.4.2 Large scale

There is very limited cost information on large scale gasification for heat systems. The IEA lists typical costs in the range of £440k to £640k per kW$_{th}$ (IEA, 2008). Similarly, an example of plasma gasification is £48m for a 40 MW$_{th}$ MSW plasma power plant, equivalent to £1.2k per kW$_{th}$ of input (Mott MacDonald, 2008).

34.5 Requirements of the upstream/downstream process and system considerations

For close-coupled gasifier-boilers, at both small and large scales, the boiler combustor is either directly downstream of the gasifier (Chiptec Wood Energy Systems, 2005b) or may be integrated with it (Alternative Energy Solutions International, 2010a). There is therefore no downstream processing of the syngas.

34.6 Deployment and development status

Small scale close-coupled gasifiers are commercially available, at TRL 8 (Chiptec has more than 175 units installed, and Uniconfort has several thousand units installed worldwide (Peterson, D. and S. Haase, 2009; Alternative Energy Solutions International, 2010b).

Similarly, large scale close-coupled systems using BFB and CFB gasifiers are established commercial technologies for heat applications, using a wide variety of biomass or wastes. There is a lot of operational experience with these plants – most operate using air at atmospheric pressure.

34.7 Barriers to development and deployment

The barriers to deployment of close-coupled gasification for heat are fundamentally those that are relevant for all gasification technologies as has been discussed in Chapter 13.

34.8 UK Capabilities

In the UK there are two developers for close-coupled technologiy, both focusing on waste feedstocks: Ethos Energy, with its Advanced Thermal Treatment technology to produce heat and power, and Envirothermal, which has developed a pilot unit for thermal treatment of waste.

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35 Biomass co-fired integrated gasification combined cycle (IGCC)

Integrated gasification combined cycle (IGCC) plants combine coal gasification technology with combined-cycle generation technology (Miller, 2010). The gasifier converts coal into syngas, which is cleaned and then combusted in a gas turbine to generate power. The hot flue gases from the gas turbine are used to supply heat to a steam cycle, thus increasing the overall efficiency. The main advantage of IGCC over coal combustion is the higher efficiencies due to the combined gas and steam cycle. As a further advantage, IGCC plants are potentially very attractive for pre-combustion CO_2 capture as the syngas is produced at high pressures and can be shifted to enrich the CO_2 concentration[19].

Similarly to coal combustion plants, the IGCC technology allows direct co-gasification of coal with biomass and wastes. All of the descriptions and data given in this chapter on IGCC are also applicable to IGCC with biomass co-firing; specific parts that relate only to co-firing of biomass are highlighted. Dedicated biomass integrated gasification combined cycles plants (BIGCC), which are likely to be of a significantly smaller scale, will be discussed in Chapter 36.

35.1 Technology description

35.1.1 Main components

An Integrated Gasification Combined Cycle (IGCC) plant is made of four main components (see Figure 35-1):

- Air separation unit (ASU),
- Solid fuel preparation and gasification
- Syngas cleaning and de-dusting
- Power generation with combined cycle (gas turbine with heat recovery and steam turbine)

The ASU produces high pressure, pure oxygen for the gasifier, as well as pure nitrogen for the gas turbine.

Solid fuels (coal and biomass) are crushed and partially oxidised with oxygen to give the heat needed by endothermic gasification reactions of coal and biomass with steam. The vast majority of coal gasifiers are entrained flow, with few fluidised beds or other designs used, due to the required scales, pressurised operation and high temperatures. Hence the focus of this chapter will be on entrained flow gasifiers. In general, the differences between the entrained flow gasifier options from various developers are small in comparison to the differences between plant configurations and gas turbine efficiencies.

The produced syngas is mainly composed of CO and H_2, with minor components such as methane, CO_2, HCl, HCN, ammonia, H_2S, COS and residual N_2 and Ar. There is no significant presence of O_2, NO_2 or SO_2 in the syngas.

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[19] IGCC with CO_2 capture is out of scope for this project, hence all graphs, descriptions and figures given in this report will relate to IGCC without capture.

The syngas is then cooled, dedusted and washed in order to remove alkaline gases and minor acid gases. After COS conversion into H_2S in hydrolysis catalyser, the H_2S is removed using chemical solvents (high grade amines activated with e.g. piperazine) or physical solvents (Selexol^{TM}, using polyethylene glycol dimethyl ether, or Rectisol^{TM} using chilled methanol). The Claus unit transforms the captured H_2S into pure sulphur, which can then be sold as a co-product.

The clean syngas is then diluted with waste nitrogen provided by the ASU before being fedinto the combustion chamber of the gas turbine. The nitrogen dilution increases syngas volume and decreases the NO_x production of the gas turbine by lowering the combustion temperature. The flue gas heat from the gas turbine is recovered in order to generate steam, which is expanded in a steam turbine to generate additional power.

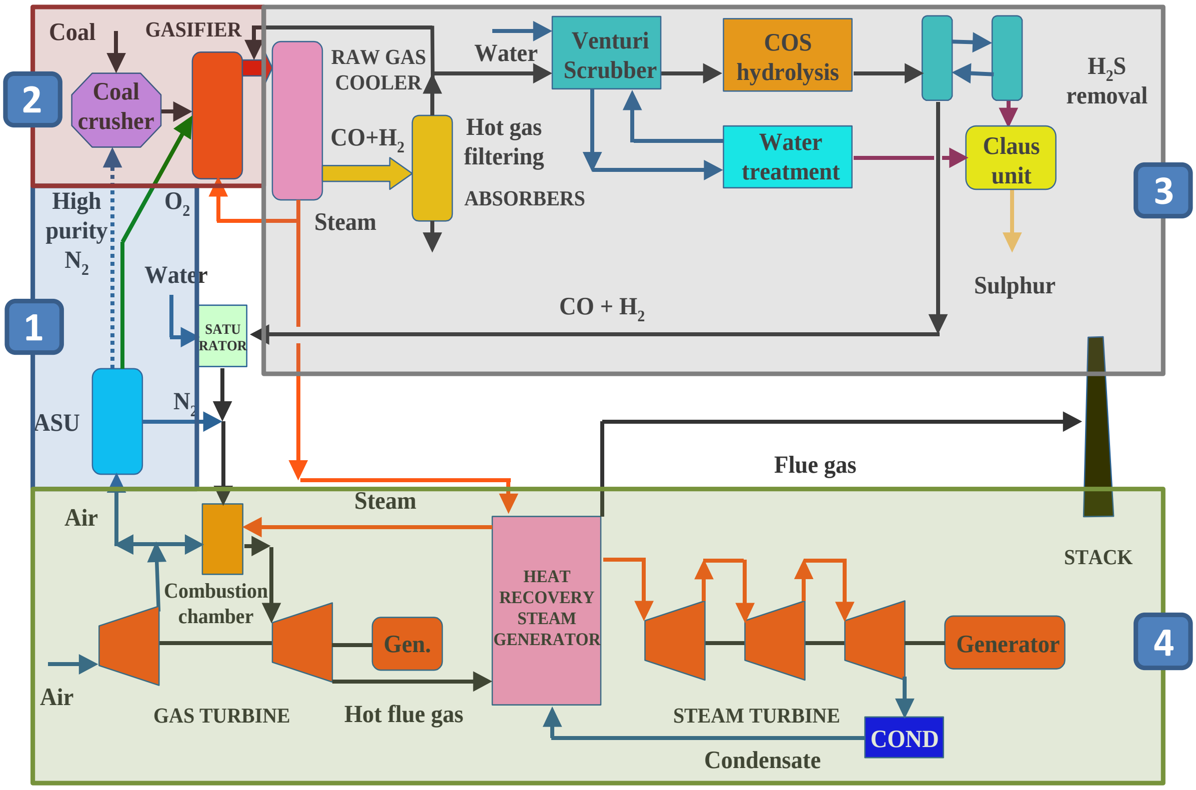

Figure 35-1: Generic schematic of an IGCC plant, without CO_2 capture (Kanniche et al, 2010). Components are: 1) ASU, 2) Solid fuel preparation and gasification, 3) Syngas cleaning and de-dusting, 4) Power generation with combined cycle

35.1.2 Limitation to the amount of co-firing

Direct co-firing of biomass in a coal IGCC plant raises a very similar set of issues as for direct co-firing in pulverised coal boilers, since the main limitations are still those associated with coal mills and burners. Biomass co-milling for co-firing for both combustion and gasification is currently limited to ~10% of the input coal thermal energy, because of coal mill limitations, despite the literature suggesting a limit nearer 15% (Perry and Rosillo-Calle, 2006; Wils et al, 2011). Biomass is harder to grind therefore mills need more energy, are less reliable and durable and the burner has to cope with uneven partical sizes from biomass. Real-world experience at E.ON's Ironbridge plant in the UK shows that 10% co-milling with sawdust is possible, before a significant reduction in the coal mill ginding performance is observed (Goh, 2005).

To achieve higher biomass percentages, mills and burners suitable for both coal and biomass should be used, or alternatively, separate mills and separate burners built for different coal and biomass streams (Kanniche, 2011). For dedicated biomass IGCC plants refer to Chapter 36. There are still issues due to potassium chloride (KCl) present in the biomass that have to be solved to avoid fouling and corrosion. Depending on type of biomass, there are some positive and negative impacts of co-firing in a coal IGCC plant. Co-firing could reduce ASU energy requirements and desulphuration plant investment because of the higher amount of oxygen and lower amount of sulfur contained in biomass relative to coal. However, higher biomass moisture contents require more energy to evaporate – this may offset the co-firing advantages to give a neutral impact on plant energy balances and economics.

From a technical point of view, there are no major difficulties that cannot be overcome regarding the conversion of IGCC to 100% biomass. If, for example, the biomass feedstocks considered contain much more water than coal, the plant's heat integration could be designed to minimise heat loss by using waste heat in drying the feedstock. Ash fusion in the entrained flow gasification could be adjusted using additives (e.g. lime) in order to acheieve a feedstock fusion temperaure suitable for the gasifier temperature, and to also avoid early ash fusion leading to unburned cabon in the produced ash (high carbon conversion).

35.2 Feedstock

Please refer to the gasification section for feedstock suitable for entrained flow gasifiers.

35.3 Technical and environmental characteristics

35.3.1 Scale

Studies have assessed the technical and economical feasibility of IGCC with 1000 MW_e gross output using standard F-class technology gas turbines (IEA GHG, 2003), and 1200 MW_e gross output using more efficient H-class technology gas turbines that work at a higher temperature (Kanniche et al, 2010). H-class gas turbines are available commercially, but not yet deployed widely within the industry.

The higher capital cost per unit of output inherent to very small units will restrict these plants to specific applications, or locations where incentives are favourable. The likely scale for fully commercial coal IGCC plants is thought to be between 250 and 1200 MW_e, this is not likely to change significantly in the future for single-gasifier plants. However, significantly larger IGCC plants could potentially be feasible in the future by using a modular approach with multiple trains.

Given the current 10% co-firing limits (Perry and Rosillo-Calle, 2006; Wils et al, 2011), the biomass co-firing of IGCC plants would be in the range of 25-120MW (see section 35.1.2). As described in section 35.1.2 this range could be increased with a specific mill or burner.

35.3.2 Efficiency

The efficiency of existing IGCC plants (without CO_2 capture) currently varies between 38 to 44% (Finkenrath, 2011), depending on gasifier type, on type of coal and especially, the combined cycle efficiency. However for new built plants the efficiency is typically around 45% (Miller, 2010).

Combined cycle power generation is highly efficient, and the best-in-class equipment (H technology turbines) can reach electrical efficiencies of 60% from the input gas (Kanniche, 2011). Provided that this gas turbine technology is successfully adapted to lower calorific value syngas, then this should enable overall IGCC plant efficiencies close to 50%, as the parasitic load of IGCC auxiliaries including cryogenic air separation is around 10%.

Moreover the efficiency will be influenced by the gasifier type used and by the coal-biomass feeding technology. Dry radiant gasifiers are more efficient than non radiant gasifiers and oxygen-blown gasification has a higher efficiency than slurry gasification. The latter one is less efficient because the slurry cannot contain more than 64% solids (IEA GHG, 2003) and therefore needs more oxygen to evaporate the excess water compared to dry coal gasification. Slurry gasifiers can be operated at very high pressure (over 60 bar) for the benefit of economics (volume reduction of materials). However, compared to radiant gasifiers, these benefits are balanced by efficiency losses due to the excess slurry water and non-recovered heat. Additionally the efficiency will decrease when feeding lignite as it contains more water than bituminous coals or biomass with a higher moisture content. However the efficiency differences between various gasifier options are negligible compared to plant configurations or gas turbine efficiencies.

Overall plant efficiency could increase in the long term future to exceed 55% (Wicks and Keay, 2005) with potential improvements in compressors and turbines efficiencies, and the ability of turbines to accept higher inlet temperatures (close to 1430°C nowadays for H-class turbines). Improving cryogenic Air Separation Unit (ASU) in terms of energy demand and cost will also improve efficiency, as would a potential technology break-through in favour of membrane air separation or other less energy intensive technologies.

The impact of co-firing biomass on the efficiency is about ~0-1% for 10% of co-firing (Livingston, 2011), the penalty increasing with the moisture and ash content of the biomass feedstock

35.3.3 GHG emissions

GHG emissions arise from the following input in the IGCC co-firing process besides the burning of coal and biomass:

- Electricity needed for milling the coal and biomass and the air separation unit. Some of the electricity may be produced on site. Torrefaction or pyrolysis could be used in the future as pre-treatment in order to reduce this energy consumption and the linked GHG emissions.
- The chemical or physical solvents needed to remove the H2S and to transfer it into sulphur. These are petroleum-derived products, which come with an emission factor

A co-product of the oil IGCC plant is sulphur. GHG emissions of the IGCC plant have to be allocated to the electricity and the sulphur on an adequate basis. However in this case, sulphur production is negligible compared to the electricity produced, hence emission can be fully allocated to the electricity output.

35.4 Costs

The cost chapter will first elaborate on the cost for IGCC without co-firing and then explain the additional costs due to co-firing. All costs refer to plants without CO_2 capture. The current capital cost of coal IGCC is approximately 25% greater than pulverised coal combustion (PCC): an IEA study (Finkenrath, 2011) gives an average in OECD countries of 2,586 \$/kW$_e$ and 2,162 \$/kW$_e$ respectively for IGCC and PCC, based on 2010 economic conditions. Converting to £ in 2011, this is 1,642 £/kW$_e$ and 1,372 £/kW$_e$ respectively. These are estimates for generic, early commercial plants (at around ~550MW$_e$ output) based on feasibility studies, which have an accuracy of ±30%, and do not reflect project-specific costs or costs for first large-scale demonstration plant, which are likely higher.

An EPRI study from 2008 (Booras et al., 2008) has slightly higher estimates for both IGCC and PCC capital costs, with IGCC plants without capture at 600MW$_e$ estimated to cost between 2,500 and 3,750 \$/kW$_e$ (1,600-2,400 £/kW$_e$). The lowest cost in this EPRI study was for a General Electric water-quench gasifier, and the highest cost for a Shell gas-quench gasifier. For comparison, the value given by the EPRI study for a 600MW$_e$ supercritical PCC is with 2,250 and 2,600 \$/kWe without capture (1,440-1,670 £/kW$_e$) also higher than the value presented in the previous paragraph.

The operating costs of a coal IGCC plant without capture are 70 to 90 \$/kWe/yr (53 – 68 £$_{2011}$/kWe/yr). The power generation cost, or levelised cost of electricity (LCOE), of IGCC without capture is on average 75 \$/MWh (48 £$_{2011}$/MWh) in the OECD, which is 14% greater than PC combustion (at 66 \$/MWh) (Finkenrath, 2011).

Large-scale fossil fuel power plant capital costs have more than doubled in the seven years from 2000 to 2007, and then fluctuated from 2007 to 2011. They could be subject to further fluctuations depending on the demand for materials and future plant construction prices. However, this is unlikely to significantly modify the relative positions of PC and IGCC.

The additional cost of biomass co-firing depends primarily on the biomass fuel cost, which is usually significantly higher than the cost of coal. The fuel cost typically accounts for 40% of the total power generation costs for coal IGCC, hence its key sensitivity.

It is expected that the additional capital costs of biomass co-firing will be similar to those for PCC. Based on the large co-firing retrofit schemes in Europe, the capital costs of the biomass storage, handling and co-firing systems (up to the current 10% limit) are approximately €200 - 400 per kW$_e$ of co-firing capacity (175 - 350 £/kW$_e$). If co-firing shares of above 10% are required, then higher additional capital costs would be incurred for the dedicated biomass mills and burners.

35.5 Requirements of the upstream/downstream process and system considerations

Requirements upstream of the IGCC plant are feedstock sourcing and transport (for both coal and biomass), and intermediate sizing of the biomass if necessary, such as a chipping step. Due to the significant milling energy involved in sizing biomass for an entrained flow gasifier, future plants could have upstream torrefaction or pyrolysis pre-treatment steps to reduce this energy input.

As for any large power generation technology, downstream a connection to the electricity network of sufficient capacity is required. Depending on the feedstock the ash can either be sold or disposed. The small amount of sulphur will be sold as a by-product. Sale of waste heat for a local demand could increase efficiencies and revenues, but is not a strict requirement for IGCC operation.

35.6 Deployment and development status

The co-firing of biomass at IGCC plants is at TRL 7, as a couple of large scale demonstration projects exist. It is lower than for coal IGCC, which is at TRL 8-9, as it is not a mature commercially available technology at exist at utility scale. Some new innovative components could appear during the period, for example, oxygen-air separation with Ionic Transport Membranes (ITM) or efficient hydrogen separation membranes.

The main driver for interest in IGCC is the higher efficiency despite higher capex and complexity of IGCC plants.

Coal IGCC started its development in the early 1980’s after the first oil crisis. As the technology uses coal – a resource spread across the globe with expected reserves lasting centuries – the avoidance of geopolitical constraints was seen as a key advantage at the time.

However, IGCC technology has lost some interest in the last decade because of increased interest in shale gas (Furfari, 2010), which has been discovered in wide quantities in USA and also in Europe. Cheap gas supplies could lead to gas combined cycle plants continuing to be more economically competitive than coal IGCC or biomass co-fired IGCC, especially as gas combined cycle plants are flexible enough to load follow network variations, whilst coal IGCC plants do not have this flexibility. The technology also faces competition from the recent arrival of high efficiency Ultra-Supercritical coal combustion.

Co-firing with biomass has been driven by tighter regulation on CO_2 emissions. However, only three out of circa twenty IGCC plants currently operating worldwide are co-fired with biomass.

Currently there are only three co-firing IGCC power plants worldwide among approximately twenty IGCC plants: Puertollano, Spain (320 MW_e), Buggenum, the Netherlands (250 MW_e) and Schwarze Pumpe, Germany (1600MW_e). Buggenum has been co-firing a range of secondary fuels up to 30% input, among them chicken litter, waste wood and sewage sludge; Puertollano has co-gasified meat and bone meal as well as olive oil waste; Schwarze Pumpe has co-gasified several types of solid waste (Fernando, 2009).

35.7 Barriers to development and deployment

The main barriers to further deployment are the lower availability, the longer start-up time, hence no possibility to serve as a peak power plant, the need to develop more efficient gas turbines and for co-firing the additional capex needed for co-firing shares above 10%.

Some availability problems remain in installed IGCCs, with the load factor of some existing IGCC plants not exceeding 80%. This low availability is specific to coal IGCC, and mainly due to difficulties in solid fuel handling. Full process integration between gas turbine, air separation unit (ASU fed with compressed air coming from gas turbine compressor) and gasification unit leads also to longer starting-up of the power plant and to a decreased availability. Due to the flexibility of the gas turbine, some European power utilities argue that an IGCC plant is potentially easier to control than a pulverized coal plant. However, in most situations, the gasification unit will generally be running continuously, so the producer gas must have an alternative end-use application, or be stored, when the turbine is part-loaded or off (Dijkema, 2009). IGCC start up times from cold are slow in comparison to PCC, and can be as high as 24 hours, although times are considerably reduced for hot start-up. However, it is not expected that co-firing biomass would add major problems to the plant’s flexibility.

IGCC plants have the ability to change their output by about 3%/minute, which is slower than most other plants. It has been suggested that IGCC plants co-firing coal and biomass can currently operate down to ~30% of their nominal capacity (Seebregt and van Deurzen, 2011), which should also apply to dedicated biomass BIGCC. However, other studies suggest that the minimum acceptable part-load for IGCC plants is assumed to be 60% of the full load, due to problems with part-load operation of the steam turbine system (economiser steaming with sliding pressure operation) and increased NO_x production from the gas turbine (Marbe, 2004). In summary, IGCC technology, with or without capture, with coal or biomass, is not suitable for peaking plant operation (Kanniche, 2011).

PCC plants appear more flexible than IGCC plants in terms of only suffering small efficiency losses whilst reducing the plant load, whereas IGCC net efficiencies decrease much more quickly when going from full, nominal load to partial load (Seebregt and van Deurzen, 2011). At its minimum load, IGCC plant efficiencies can decrease by as much as 15-20% compared to efficiencies at nominal load, whereas as pulverised coal plants might only lose 5-8%.

More demonstration projects of coal IGCC are probably needed to compete with PCC availability (over 90%). Unless future IGCC projects demonstrate better power plant availability, this parameter may take decades to progress (Kanniche, 2011).

There is also a need to develop higher efficiency gas turbines, modified to use low calorific value syngas. In the current gas turbine technology, the low calorific value syngas is diluted with nitrogen before combustion in air, within the gas turbine. More development is needed to burn syngas as done nowadays for natural gas, i.e. the fuel is carefully mixed with air before combustion, and without dilution in nitrogen, which could save up to 1%-point in overall plant efficiency.

Moreover from a financial viewpoint the additional capex needed for increasing the co-firing shares of current IGCC plants above 10% remain a barrier to further increase the co-firing of biomass.

35.8 UK Capabilities

Currently, there are no IGCC plants in the UK. Therefore, biomass co-firing in the UK's pulverised coal fleet is not currently possible, nor is the conversion of an existing plant to 100% biomass. However, as part of the EU's NER300 competition (DECC, 2011), the UK has very recently entered seven CCS project applications, with three involving new IGCC plants in North East England:

C.GEN is planning a new 520MW$_e$ plant in Killingholme, Yorkshire, and may co-fire up to 30% biomass or petcoke. Plan to enter operation in 2015 (C-GEN, 2011)

Don Valley Power Project: 900MW$_e$ coal IGCC power station in Stainforth, Yorkshire, plans to commission in 2016. This was formerly the Hatfield Project, until Powerfuel Power Limited were bought out by 2Co Energy in May 2011 (2Co Energy, 2011). No co-firing planned yet.

Teeside CCS project: consortium led by Progressive Energy Ltd, and plans to build a 850 MW$_e$ IGCC on a brown-field site at Eston Grange, and store the CO_2 offshore (Progressive Energy, 2011). No co-firing planned yet.

Therefore, provided that at least one of these projects receives NER300 funding and goes ahead, UK capabilities and expertise in IGCC will increase significantly before 2020. Rio Tinto Alcan have also been planning converting one of the PCC boilers at their Lynemouth power plant into an IGCC unit with capture.

UK capabilities and expertise in IGCC and co-firing are therefore likely to increase significantly before 2020.

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36 Dedicated biomass integrated gasification combined cycle

This section covers dedicated biomass integrated gasification combined cycle (BIGCC) technology, where the feedstock is exclusively biomass. The working principle of a biomass integrated gasification combined cycle is similar to that of fossil fuelled or co-fired Integrated gasification combined cycle (IGCC), covered in Chapter 35: the syngas produced in a gasifier is combusted in a gas turbine to drive a generator, with exhaust heat recovery raising steam to drive a further steam turbine and generator.

BIGCC plants are potentially very suitable for pre-combustion CO_2 capture, as the syngas is produced at high pressures and can be shifted to enrich the CO_2 concentration. The main advantage of a BIGCC plant with CO_2 capture is the fact that it offers negative carbon emissions. However, CO_2 capture is outside the scope of this report, hence all graphs, descriptions and figures given in this section cover only BIGCC without CO_2 capture.

36.1 Technology description

A Biomass Integrated Gasification Combined Cycle plant consists of several steps (Cormos et al, 2011), see Figure 36-1:

- Feedstock preparation (step 1): Biomass sizing and drying, and feeding into the gasifier
- Gasification (step 2): Reaction of the biomass feedstock at high temperatures with a controlled amount of air, oxygen and/or steam to create syngas. All gasifier types except fixed bed gasifiers are suitable for BIGCC applications (please refer to the gasification chapter).
- Gas cleanup (step 3): Series of complex cleanup steps and processes used to clean the syngas from particulates, tars and other contaminants, down to specifications required by the gas turbine (Babu, 2008). The tolerance levels for different contaminants for the gas turbine are given in Table 36-1.

Contaminant	Tolerance level
Sulphur, ppmv	20
Halides, ppmv	1
Ammonia, ppmv	-
Sodium + Potassium, ppmw	0.08
Particles (total), ppmw	3.0
Particles (5-10 μm), ppmw	0.15
Particles (> 10 μm), ppmw	0- 0.03

Table 36-1: Tolerance limits of syngas contaminants (Bain and Dayton, 2005)

- Power generation (step 4): Combustion of the syngas in a gas turbine to drive a generator, with heat recovery raising steam to drive a further steam turbine and generator. The exhaust gas discharged from the heat recovery steam generation (HRSG) can be further used for drying biomass feedstock or for supplying heat to other processes (Pang and Li, 2006)

The design for a pressurised air-blown BIGCC plant with the four steps described above is shown in Figure 36-1 (other system combinations are discussed below the figure).

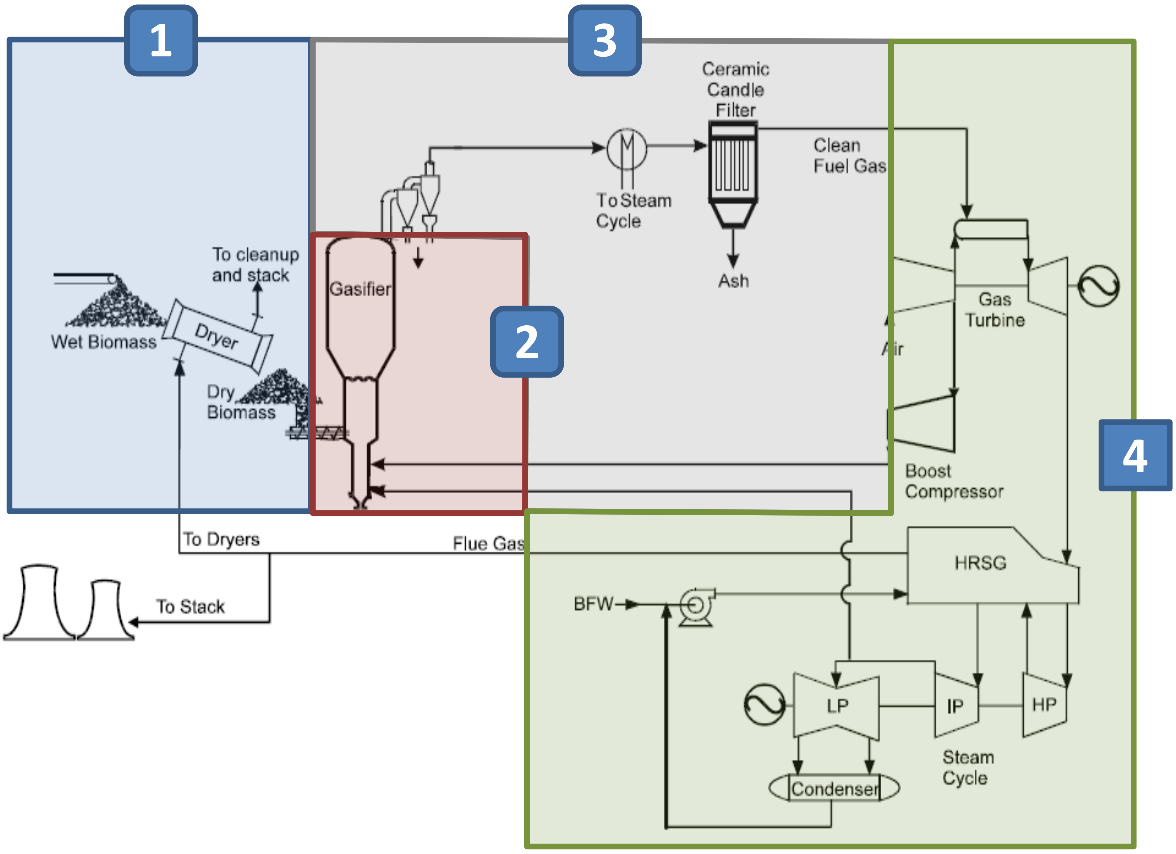

Figure 36-1: Generic schematic of a pressurised BIGCC plant (Craig and Mann, 1996)

Some of the key tradeoffs involved in designing and commercializing BIGCC systems relate to atmospheric vs. pressurised gasification, hot vs. cold cleanup, the use of air, steam or oxygen for gasification, the adaptability of commercial gas turbines, and the thermal integration between the biomass dryer, gasifier, cleanup equipment, and the turbines (Consonni and Larson, 1996).

Atmospheric vs. pressurised gasification

Atmospheric gasification is simple, flexible, reliable and relatively mature (Piterou et al, 2008). However, the condensation of tars during gas turbine pre-compression needs to be avoided, hence a cleaning system consisting of a tar cracker, gas cooler, bag house filter and wet scrubber is usually required (Bridgwater, 1995).

Pressurised gasifier systems avoid the energy penalty of downstream gas compression, and allow the use of more efficient hot gas cleanup, and can burn relatively high tars content gas in the gas turbine (since condensation is avoided). Pressurised BIGCC plants have therefore been evaluated by several studies to have higher electrical efficiencies than atmospheric BIGCC systems (Schmidt et al, 2010; Marbe et al, 2004). However, the system is more complex, less flexible, pressurised feedstock mechanisms are needed, and there is much less operational experience available (Wang et al, 2008).

Air-blown gasification:

Using air has been favoured historically for biomass gasification (Stahl et al, 2004; Jin et al, 2009), but leads to nitrogen dilution. This gives a low calorific value (CV) syngas (typically 4-7 MJ/Nm³), and not only increases the cost of energy recovery and gas cleanup, but also requires modification of the gas turbine by de-rating the firing temperature (Delong, 2005).

Oxygen-blown gasification:

Using only oxygen avoids nitrogen dilution, and enables smaller gasifier and downstream equipment, but oxygen separation costs are currently high. Plant scales of above approximately 80 MW_e are thought to be required to justify the addition expense of oxygen separation costs (Jin et al, 2005). Although pressurised, O_2-blown biomass gasifiers are not yet commercial, development activities are ongoing, and interest is increasing for biofuels and hydrogen applications (Jin et al, 2005; Lau et al, 2003).

Steam-blown gasification:

Indirectly-heated steam-blown gasification with a Dual gasifier avoids both the problems of nitrogen dilution and oxygen separation costs, resulting in a medium CV syngas that is high in hydrogen and methane, and that can readily be used in existing gas turbines (Pellegrini, 2010).

36.2 Feedstock

Uncertainty exists about the suitability and impact on plant performance of different biomass feedstock. Most BIGCC techno-economic studies assume wood as the biomass fuel, since it is relatively easy to gasify. Energy grasses and agricultural residues are potential feedstock, however as they contain more ash (which complicates the gasification and gas cleaning processes), they are expected to cause lower plant performance.

36.3 Technical and environmental characteristics

Only a few early demonstration BIGCC plants have been realised (Brown et al, 2009; Faaij, 2008), hence BIGCC techno-economic studies (Klimantos et al, 2009) analysing different commercial plant configurations are either theoretical, extrapolated from smaller plants or other applications. This results in some uncertainty about the projected techno-economic performance of potential large-scale BIGCC plants (Klein et al, 2011).

36.3.1 Scale

Minimum and maximum scales for commercial BIGCC plants are primarily determined by the type of gasifier, ranging from 2 MW_{th} biomass input for atmospheric Bubbling fluidised bed (BFB) gasifiers to 2,000 MW_{th} for entrained flow (EF) technology. Early commercial availability is projected by 2020 in the range between 30 and 200 MW_e output (EIBI, 2011; EIBI, 2010; IEA, 2009).

The range of past BIGCC plants (see Section 36.6), was from 6- 32MW$_e$ output (Pitcher et al, 1998; Piterou et al., 2008; and Salo, 2007; Patel and Salo, 2004; Waldheim and Carpentieri, 1998; Salo, 1998; Lange and Barbucci, 1999; Ståhl et al, 2004; Klimantos, 2009). Current projects under construction or in the mature development stage have a scale of 20MW$_e$ and 55MW$_e$ (Biomass Gas & Electric, 2011; Rentech, 2011; Taylor Biomass Energy, 2011; Waste Management World, 2011). In addition the US Department of Energy (DOE) is currently supporting pilot scale projects up to 30MW$_e$ and the European Industrial Bioenergy Scheme (EIBI) intends to fund 1 or 2 BIGCC projects above 100MW$_e$ to be built in the period 2014-2016 (McCann, 2010).

36.3.2 Efficiency

Theoretical BIGCC plant LHV efficiencies range from 40% to 50%, with 45% even achievable at small-scales for the most efficient plant designs as shown in Figure 36-2 (Schmidt et al., 2010; Klimantos et al, 2009; Jin et al., 2009; Klein et al., 2011). This efficiency range is confirmed by IEA giving BIGCC efficiencies at ~40% currently, with future designs offering the potential for efficiencies over 50% (IEA, 2008). Particularly hot gas clean-up is expected to increase overall plant efficiencies by 3-4 %-points compared to cold gas cleanup (Klimantos et al, 2009).

When comparing BIGCC net system efficiencies to other biomass power generation technologies, even at very small scales (1-20MW$_e$), BIGCC is at least 10%-points more efficient than gasification with Internal Combustion Engines (ICE), pyrolysis or direct combustion (Bridgewater et al, 2009). The higher theoretical efficiencies for BIGCC compared to other technologies are also confirmed at larger scales by several studies (IEA, 2009).

The internal power consumption (parasitic load) for a large scale BIGCC plant is between 11% and 15% of the gross generated electricity (E4tech, 2009).

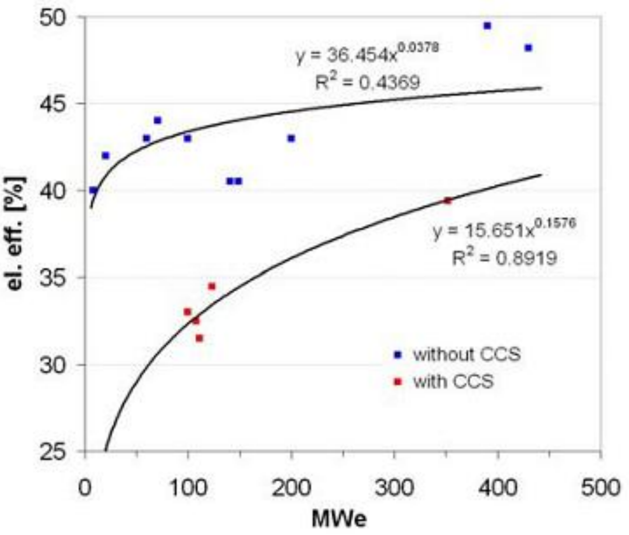

Figure 36-2: BIGCC plant electrical efficiency with and without CCS, obtained from literature (Klein et al, 2011)

36.3.3 GHG emissions

Lifecycle GHG emissions for a BIGCC plant are expected to be in the range between 50-92 gCO_2e/kWh (NREL, 2002; Gustavsson and Karlsson, 2002). The GHG emissions will vary depending on the biomass upstream, the plant scale and efficiency.

36.4 Costs

As stated at the beginning of section 36.3 cost estimates for BIGCC plants are either theoretical, extrapolated from smaller plants or from other sources as only a limited number of demonstration plants operated.

The capex values for BIGCC without carbon capture and storage (CCS) (on the red line given in Figure 36-3) are 1,600 - 2,000 $£_{2011}/kW_e$ for a 100 MW_e plant, and around 1,200 – 1,300 $£_{2011}/kW_e$ for a 400 MW_e plant. For comparison, IEA gives a similar range of capital costs of 1,150 – 2,300 $£_{2011}/kW_e$ for future commercial plants (30 – 200 MW_e).Capital costs estimates vary depending on specific modelling assumptions, plant configurations, feedstocks, and have also risen significantly in the past decade (IHS, 2011). Based on the literature review by Klein et al. (2011) and additional reports (Piterou et al, 2008; Stahl et al, 2004; Jin et al, 2009; Pitcher et al, 1998; Brown et al. 2009; Schmidt et al, 2010; IEA, 2009; Larson and Jin, 2006; Rhodes and Keith, 2005; Uddin and Barreto, 2007), costs can be estimated at different plant scales.

Figure 36-3 shows the marked effect that plant scale has on capital costs, especially below 100MW_e. IEA gives considerably higher capital costs of 2,500 to 5,650 $£_{2011}/kW_e$ for smaller scale (5-10MW_e) demonstration plants (IEA, 2009). This agrees with Klimantos et al. (2009), who state that BIGCC plants require additional innovation and experience before achieving the desired capex range of 1,300-1,750 $£_{2011}/kW_e$ necessary to make BIGCC competitive.

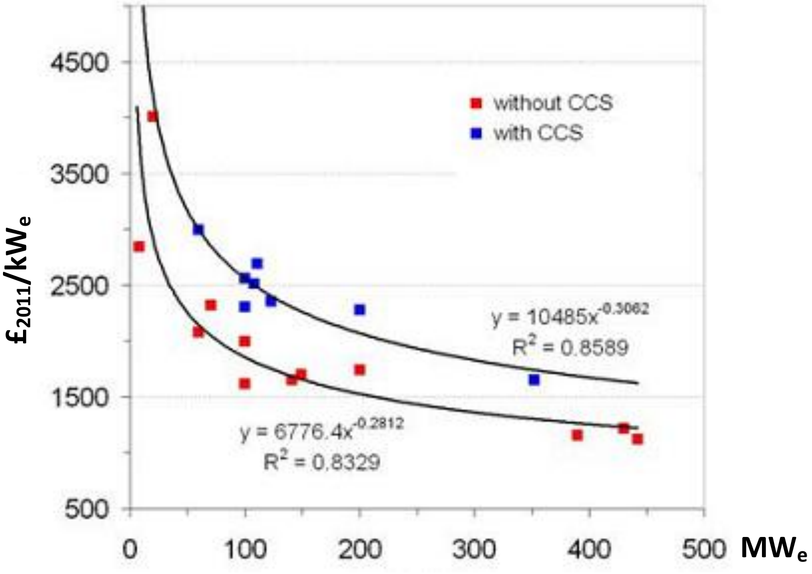

Figure 36-3: BIGCC plant capital costs with and without CCS (Klein et al, 2011)

As already discussed above, based on the available literature and plants, there is no clear distinction that can be made between the costs of BIGCC systems incorporating Entrained flow, BFB, circulating fluidised bed (CFB) and Dual fluidised bed gasifiers. A few studies estimate that BIGCC specific capital costs (in terms of £/kW$_e$) for pressurised fluidised systems are around 10-15% lower than atmospheric systems (Jin et al., 2009; Klimantos et al, 2009; Marbe et al., 2004).

In comparison to other dedicated biomass power generation technologies (e.g biomass combustion) and coal IGCC , BIGCC is currently significantly more expensive (Finkenrath, 2011;Caputo et al, 2005). However, BIGCC is expected to have comparable capital costs in the long-term, once the technology and efficiencies are proven at scale.

BIGCC plant operational costs can be split into fixed costs (e.g. labour, insurance) and variable costs (e.g. consumables, biomass fuel). Excluding biomass costs, IEA Bioenergy estimates the annual plant opex at about 4% of the total capital costs (IEA, 2009). This corresponds with the majority of values given by the individual studies considered in this section (Ståhl et al, 2004; Brown et al, 2009; Piterou et al, 2008; Pitcher et al, 1998; Rhodes and Keith, 2005; Uddin and Barreto, 2007; Larson and Jin, 2006; Jin et al, 2009), that indicate values around £35/kW$_e$/yr for the fixed operational costs in addition to the biomass fuel costs (Jin et al, 2009; Uddin and Barreto, 2007). Only one study, modelling a Dual gasifier, gave significantly higher operational costs at £93/kW$_e$/yr (Rhodes and Keith, 2005).

36.5 Requirements of the upstream/downstream process and system considerations

Requirements upstream of the BIGCC plant are feedstock sourcing and transport, and intermediate sizing of the biomass if necessary. Many plant stoppages are due to clogging of feeding mechanisms, either due to inhomogeneous feedstock or foreign objects. Blockages are particularly problematic for pressurised systems, which use a pressurised biomass feeding system – this is a technology area where additional development is needed to improve reliability and reduce costs (Wilen and Rautalin, 1993; Lau et al, 2003). As a consequence suitable sizing and pre-treatment of the biomass are crucial. For each gasifier type and for specific sizes, please refer to the gasification chapter.

Due to the significant milling energy involved in sizing biomass for an entrained flow gasifier, future plants could have upstream torrefaction or pyrolysis pre-treatment steps to reduce this energy input.

As for any large power generation technology, downstream a connection to the electricity network of sufficient capacity is required. Depending on the feedstock the ash can either be sold or disposed. Sale of waste heat for a local demand could increase efficiencies and revenues, but is not a strict requirement for BIGCC operation.

36.6 Deployment and development status

Based on the developments from 1990 to 2005 (see below), BIGCC reached the early demonstration stage (TRL 6) with the success of the Värnamo project. However, BIGCC technology has not progressed since this date. Nevertheless the knowledge and experience on gasification still exists (even though it may have been diluted by change in research direction) as large scale gasifier developers have focused on biofuel applications. Furthermore, there is also increasing worldwide commercial activity in the gasification of fossil fuels. This BTL and coal IGCC experience and the related cost reductions being accumulated are likely to spill over to BIGCC applications. Due to this ground-work, it is expected that once BIGCC technologies are introduced commercially at large scale, costs and reliability may rapidly mature.

By 2020, BIGCC technology is likely to have reached TRL 7 or 8. This depends on the success of the EIBI and US DOE programs, plus ongoing industry projects (e.g. Taylor Biomass Energy, Rentech-Silvgas, Air Products). These are likely to prove BIGCC plants can achieve high efficiencies, and significantly improve plant reliability and capital costs. It is worth noting that the leading industry project concepts are currently using Dual gasifiers and/or waste feedstocks.

In comparison with conventional combustion of biomass and other biomass gasification power plants, the BIGCC system concept is expected to have several advantages once at commercial scale, including high electrical efficiency, low electricity production costs, and low emissions. Technically, BIGCC also shares many similarities with coal IGCC, and hence is likely to be able to profit from the experience gained with the first coal IGCC plants (Klein et al, 2011).

In the period 1990 to 2005, there was significant global interest in building BIGCC demonstration plants, including the EU's THERMIE programme (Pang and Li, 2006). During this period, several developers tried to demonstrate BIGCC technology, but with little success (Pellegrini et al., 2010). An 8MW_e plant in Eggborough, UK with an atmospheric CFB gasifier was closed in 2002 during commissioning because of slagging and tar cracking problems (Piterou et al., 2008). Two plants in Italy and a Dual gasifier plant in the U.S. were never converted to BIGCC (Granatstein, 2003; Cain, 2009). Further projects in the range of 7-32MW_e in India, Brazil, Denmark/Finland and Italy did not raise enough funds or were never constructed (Patel and Salo, 2007; Patel and Salo, 2004; Waldheim and Carpentieri, 1998; Salo, 1998; Lange and Barbucci, 1999).

Globally, only one BIGCC early demonstration plant to date has been successfully constructed and operated from 1993 to 2000 generating 6 MW_e power and 9 MW_{th} heat for district heating.. The Växjö Värnamo project in Sweden (Ståhl et al, 2004). The system used a pressurised air-blown CFB gasifier at 18bar with a hot gas filter (as in Figure 36-1), and successfully demonstrated the in-situ use of dolomite catalysts to reduce the tars leaving the gasifier. Despite the slowdown of the BIGCC activity at the beginning of the previous decade, the EU's FP6 framework gave €1.7m of funding for the "BiGPower" project which ran between 2005 and 2008 to work on necessary technological improvements.

In 2011, there have been a few announcements regarding large-scale BIGCC projects – both of which are planning on using Dual gasifiers:

- Taylor Biomass Energy (TBE) has recently started construction of a 20MW_e BIGCC power plant in Montgomery, New York, US (Waste Management World, 2011). This plant will be using a mix of Municipal Solid Waste (MSW), commercial & industrial waste and wood waste, with gasification occurring in three parallel Dual fluidised bed gasifiers (Taylor Biomass Energy, 2011).

- The “Northwest Florida Renewable Energy Center” in Port St. Joe, Florida will be developed, owned and operated by Biomass Gas & Electric (BG&E) of Florida (Biomass Gas & Electric, 2011). Rentech-SilvaGas are providing the Dual fluidised bed gasifier to this 55 MW_e BIGCC project, taking in 930 odt/day of woody biomass (Rentech, 2011). Construction is planned to begin in August 2011, with operation in 2013.

Recently the European Industrial Bioenergy Initiative (EIBI) and the US Department for Energy have launched new funding initiatives. The EIBI scheme is proposing to make €20-40m grants available for 1 or 2 demonstration plants from 2013, followed by €150-250m loans for 1 or 2 flagship plants at scales of above 100MW_e (EIBI, 2011; EIBI 2010). Given the construction timescales, this should allow these demonstration and first commercial plants to be built in the period 2014-2016, allowing early commercial availability of BIGCC by 2020. The ‘Biopower’ initiative of the US DoE aims to accelerate, develop and deploy advanced biopower technologies over the next six years. The initiative is expected to have $70m of funding in 2011-2012 as part of the department’s wider Biomass Program, and will look to support pilot scale projects up to 30 MW_e (McCann, 2010).

36.7 Barriers to development and deployment

Dedicated BIGCC plants are not expected to be any more flexible than coal IGCC plants, and may be less flexible depending on the heat integration for feedstock drying. Please refer to the same chapter in the IGCC section.

There are several remaining unsolved technical R&D and development needs that have been highlighted in the literature (Bhattacharya et al, 2011) and other sector reviews (E4tech, 2011; U.S. DoE, 2010) in order for BIGCC to be successfully demonstrated, and validated at commercial scale. Many of the component technologies in a BIGCC plant are already commercially available at scale, although a few key steps are not yet fully developed. These are discussed in detail below.

Biomass gasification: not yet commercial for the large-scale BIGCC plants, but expected to be commercialized within a few years (Larson et al, 2009).

- Syngas clean-up (tars): syngas clean-up of contaminants is a significant cost (Maniatis, 2001), and efficient syngas cleanup, and avoidance of tar accumulation has only been recently solved by a few players, and long-term reliability at commercial scale, using real-world syngas, is still to be proven (Stahl et al, 2004; Klimantos et al, 2009).
- Power generation: the utilisation of a gas turbine for low calorific value (CV) gas still requires some modification (Pang and Li, 2006) – the total mass flow through the gas turbine has to increase significantly, compared to a natural gas fired unit, in order to attain the same turbine inlet temperature (Rodrigues et al., 2007). However technical solutions have been developed to generally overcome this problem.
- Project development, engineering, and operation: financial shortages in project execution (sustained investment is required), and unrealistic profit expectations by the developers from the first small-scale demonstration plants.

Successful design and operation of BIGCC plants requires further research to optimize the plant scale and operating parameters. The close thermal integration between the biomass dryer, gasifier, cleanup equipment and the turbines is also essential to allow for maximum recovery and use of process waste heat, and ensure high overall plant efficiencies.

36.8 UK Capabilities

Since there are very few demonstration plants or system developers, we consider players in each of the BIGCC plant components in turn, before considering the overall combined system (E4tech, 2011):

- Feedstock preparation: the UK does not have any particularly distinctive capabilities in woody biomass.
- Gasification: the UK does not have any developers with large-scale (CFB, BFB, Dual or EF) gasifier technology that would be applicable to BIGCC and academics are focused on small-scale gasification.
- Gas cleanup & conditioning: the UK has some capabilities within syngas cleanup, with organisations such as Johnson Matthey working on novel cleaning in EU project “GREENSYNGAS”, APP developing novel plasma cleanup, and ongoing research at Nottingham, Sheffield and Newcastle.
- Power generation: in the UK, Siemens Industrial Turbomachinery, based in Lincoln, develop medium CV gas turbines, which are directly relevant to BIGCC applications.
- Project development, engineering, and operation: there is now increasing interest in UK biomass gasification. This is especially true for wastes to biofuels developers like Ineos Bio and Solena, who are planning large projects in the North-East and London, respectively. Also, Air Products are planning a Westinghouse waste plasma gasification-open gas turbine power plant in Teeside (Air Products, 2010a).

More generally, the UK’s strengths in biomass co-firing, and the UK’s chemicals industry sector, will ensure relevant engineering skills are available if a new BIGCC plant were to be built in the UK. The UK Government also appears willing to support first-of-a-kind plants in the UK, with significant funding towards Ineos Bio’s feasibility study. Under the Renewables Obligation, dedicated biomass BIGCC plants would also be guaranteed to receive 2 ROCs/MWh$_e$ (currently ~£100/MWh$_e$) as an ‘Advanced Conversion’ technology.

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37 Gasification with internal combustion engine or gas turbine

This chapter covers the generation of power in internal combustion engines (ICE) or open cycle gas turbines via the combustion of syngas from biomass gasification. In many instances, a CHP system is used such that waste heat from the prime mover is recovered. Some aspects of the technology are scale dependent (e.g. the type of gasifier and prime mover) and, where relevant, the description has been split in to small and large scale subsections to highlight these differences.

37.1 Technology description

Biomass is gasified to produce syngas, which can then be combusted for power generation. The process steps are as follows (see also Figure 37-1:

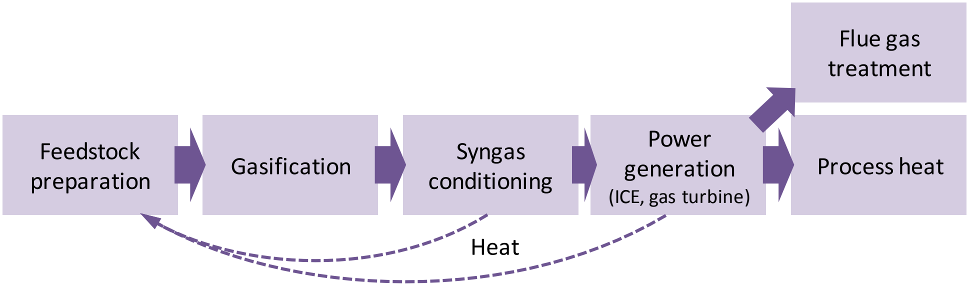

Figure 37-1 Schematic diagram of a gasification power generation system

- Feedstock preparation: The biomass feedstock is pre-treated by drying and sizing, depending on the moisture content and size necessary for the gasifier type
- Gasification: there are several different gasifier types being used for large-scale heat and power production: Entrained Flow (EF), Bubbling Fluidised Bed (BFB), Circulating Fluidised Bed (CFB), Dual Fluidised Bed (Dual) and Plasma gasifiers. However, small scale units primarily use fixed bed gasifiers which cannot be scaled up to very large units.
- Gas cleaning: for power or CHP applications, the syngas is usually cooled and cleaned of tars and particulates.
- Energy generation: the syngas is used in a gas engine or turbine for power/CHP. Large power generation systems can also use a combined gas turbine-steam turbine cycle to produce additional power – this is known as Integrated Gasification Combined Cycle (IGCC), see Chapter 36
- Flue gas cleaning – particulates in the flue gas from the boiler, generator or turbine are removed with an electrostatic precipitator (ESP) or cyclone prior to being sent to the stack

The wide range of different designs reflects, at least in part, the different origins of the companies developing the technology. These range from companies from the boiler / coal power industries (e.g. Babcock & Wilcox) to spin-outs from university research programmes (e.g. XyloWatt) to engineering companies that are developing systems around someone else’s gasification technology (e.g. XyloPower). In addition, several technology developers seem to have focussed on particular niche markets and propose solutions that are tailored to the needs of those specific markets. For instance, Ankur, Netpro and Community Power Corporation have all made systems that are targeted at the developing world, whereas Enerwaste and Energos are both focussing on waste management.

37.2 Feedstock

37.2.1 Small scale

For small scale systems, the feedstock requirements are the same as in close-coupled gasification as described in Chapter 34?.

37.2.2 Large scale

As discussed in Section 13.4 of the general chapter on gasification, feedstock requirements vary considerably between gasifier types, with plasma being able to take mixed wastes at large sizes, down to entrained flow requiring uniform, dry powdered woody biomass. In general, gasifier designs with shorter residence times (such as EF) require a more uniform and reactive feedstock, whereas designs with longer residence times (e.g. plasma) are able to accept a much wider, and varying, range of feedstock sizes and compositions, moisture and ash contents (E4tech, 2009).

37.3 Technical and environmental characteristics

37.3.1 Scale

The majority of manufacturers of updraft and down-draft gasifiers that use wood as a feedstock offer systems that are at sizes of less than 10 odt/day (less than about 2 MW of thermal input). However, systems exist in the range of 0.2–180 odt/day of feedstock input (corresponding with around 40 kW to 15 MW of thermal input). Systems fired on MSW, RDF or other wastes run to even larger sizes spanning from the 10’s of odt/day up to around 500 odt/day (114 MW of thermal input), or into the thousands of odt/day when co-fired with coal.

As discussed in Section 13.4, the minimum economic scale for fluidised bed and plasma gasifiers is around 10odt/day (2MWth feedstock input), and can be scaled up to around 480odt/day (100MWth) for a single atmospheric unit, or around 1,700odt/day (350MWth) for pressurised systems. Larger gasification plants can be built using modular systems, although currently only plasma gasifier developers are looking at modular systems for power applications.

37.3.2 Efficiency

Reported electrical efficiencies for small scale systems with gensets are about 30–37% (Nexterra, 2010; Community Power Corporation, 2009b), which are consistent with the typical efficiencies of internal combustion engine gensets. Typical CHP system efficiencies reported by the IEA are in the range of 60–80% (IEA, 2008).

Large scale gasifiers have thermal or cold gas efficiencies between 70% and 93%, with most operating at between 75% and 88% (Yassin et al., 2009) based on the ratio of the syngas and feedstock LHVs.

For power plants, the electrical efficiency of downstream energy generation equipment improves with increasing scale. Available material alloys limit practical steam temperatures to 655°C (World of Renewables, 2010), therefore basic steam turbines only have modest efficiencies of up to 35% (Bridgwater et al., 2002). Gas turbine combustion temperatures are typically much higher (900-1,500°C), and hence can reach greater efficiencies. Gas turbine exhaust gases are also usually hot enough (450-650°C) to choose to include a further steam cycle downstream (combined cycle) to generate additional power.

The internal power consumption (parasitic load) for a large scale gasification power plant is between 11% and 15% of the gross generated electricity (Yassin et al., 2009). Therefore, combining the gasifier and energy generation efficiencies leads to a net plant electrical efficiency of (IEA, 2008; Bridgwater, 2002):

- 20-30% for gasifier-steam turbine systems
- 30-40% for gasifier-gas engine systems
- 35-45% for gasifier-gas turbine systems
- 40-50% for gasifier-CCGT systems (IGCC)
- Overall CHP efficiencies can be up to 80%

37.3.3 GHG emissions

Estimates of the GHG emissions for the production, sizing, drying and transport of typical gasification feedstocks (e.g., forestry residues, waste wood, energy crops and MSW) based on the data in Biomass Energy Centre’s Biomass Environmental Assessment Tool (BEAT2) range from about 2.3–37 gCO_2e/kWh (Biomass Energy Centre, 2008). Factoring in the process efficiency ranges listed above yields emissions in the range of about 4.6–190 gCO_2e/kWh of electricity produced. Thus compared to the average direct emissions for electricity produced on the UK grid of 486 g CO_2e/kWh (DEFRA, 2011) the gasification with ICE/gas turbine systems yield emissions savings in the range of 61–99%.

37.4 Costs

37.4.1 Small scale

Small-scale gasification systems are still in the development and demonstration phase and thus cost data tends to be based on individual projects:

- A case study for a 50 kWe (1.1 odt/day) CPC Biomax system lists a cost of £190k–260k or £180k–240k/odt/day (CoolCalifornia.org)
- Urbas’s downdraft 150 kWe (2.7 odt/day) CHP unit in Austria cost £500k, or £186k per odt/day (Urbas, 2010)
- Xylowatt gave an example price of £5.2m, or £271k per odt/day for their downdraft 1 MWe CHP system (19 odt/day) in Brussels (Xylowatt, 2010)

These estimates are all at the low end of the range of £240-480k/odt/day estimated in Hofbauer (2008), which also estimates electricity production costs of >17p/kWh (although no feedstock cost assumptions are given). Gasification with ICE system costs are usually dominated by the gas engine (i.e. the power or CHP generation step) at 30-50% of the total capex, with the gasifier, gas cleanup and biomass drying & feeding steps making up the majority of the remaining capital costs.

The IEA Energy Technology Perspectives 2008 also gives typical capacities, efficiencies and capital costs for a range of bioenergy technologies – those for gasification are summarised in Table 37-1, and are in line with the costs listed above:

	Typical capacity	Net efficiency	Investment costs
Gasification for heat (close coupled)	0.24 - 2.4 odt/day (0.05 - 0.5 MW_{th})	80 - 90%	£80-110k per odt/day (£440 - 640/kW_{th})
Gasification for CHP using gas engines	0.48 - 4.8 odt/day (0.1 - 1 MW_{CHP})	60 - 80% overall CHP efficiency	£120-350k per odt/day (£800 - 2400/kW_{CHP})

Table 37-1 Typical plant size, efficiency and capital cost for biomass gasification technologies

In terms of operating costs, while biomass gasification plants have higher operation and maintenance costs than natural gas boilers that they may be substituting, in situations where feedstock is available at very low cost, the economics can be quite favourable. Several manufacturers cite payback periods in the range of 2-4 years, based on the avoided cost of natural gas or fuel oil (Logging & Sawmilling Journal, 2006; Business in Vancouver, 2005).

37.4.2 Large scale

Large scale, fluidised bed gasification CHP plants have specific investment costs of between €3-5m/MW_e and levelised electricity production costs of €100-140/MWh_e (Hofbauer, 2008). This is equivalent to a capital cost of £190k – 317k per odt/day of capacity and electricity production costs of 8.7-12p/kWh, which falls within the range of IEA gasification CHP costs given above in Table 37-1.

The IEA also give biomass IGCC costs for current 24–48 odt/day (5–10 MW_e) demonstration plants, with 40–50%+ efficiency as £260–370k per odt/day (£2800–4000/kW_e). Biomass IGCC plant capital costs are dominated by the gas turbine at 35%, and gasifier and cleanup steps at around 25% each (Sadhukhan, 2009).

Plasma gasification costs are also not widely available in the public domain – one example is £48m for a 186 odt/day MSW plasma power plant, equivalent to £263k per odt/day (Mott MacDonald, 2008).

37.5 Requirements of the upstream/downstream process and system considerations

For applications where the syngas is used in a genset or gas turbine, the syngas goes through gas conditioning (Nexterra, 2010) or cooling and filtering (Community Power Corporation, 2009a). These process steps are necessary to avoid equipment fouling due to the deposition of condensable tar components and to avoid equipment erosion and corrosion due to the presence of particulates or other contaminants such as alkali metals (Baratieri et al., 2009). There is limited published data on the syngas requirements for combustion in either internal combustion engines (ICE) or gas turbines. Representative limits are shown in Table Table 37-2 (Baratieri et al., 2009; Milne et al., 1998).

Power generation unit	Max allowable tar concentration (mg/Nm^3)	Max. allowable particulates concentration (mg/Nm^3)	Max. allowable alkali metal concentration (mg/Nm^3)
ICE	50–100	30	
Gas turbine	0.03–0.5	0.1–120	0.1

Table 37-2: Syngas cleaning requirements for gas engines and turbines

For comparison, requirements for chemical synthesis processes such as Fischer-Tropsch are ~10 parts-per-billion (ppb) of tars, which is equivalent to ~0.01 mg/Nm^3.

37.6 Deployment and development status

37.6.1 Small scale

Small scale systems are largely at an early commercial phase (TRL 7)—with each developer only installing single digit numbers of units to date—and are therefore not yet considered fully commercially available. Gasifiers fuelled by MSW are also available commercially in the waste management market (e.g. Waste2Energy, Nippon Steel).

37.6.2 Large scale

Large scale gasification technologies generating electricity from MSW and other wastes are commercially available, with numerous plasma and BFB plants built to date (TRL 8-9). However, plasma gasification experience with other feedstocks is limited. Gasification for power or CHP generation not using wastes is at the demonstration / pre-commercial stage (using BFB, CFB and Dual gasifiers), with developers only currently having single figures of units installed globally. Furthermore, pressurised gasification at large scale has only been demonstrated, and has not yet reached commercial status.

Several large-scale demonstration IGCC plants were built between 1992 and 2003, however, most of these have had problems, proven costly, and have been shut down (E4tech, 2009):

- The Växjö Värnamo Bioflow gasifier was mothballed in 2000 after completing testing, because the plant was too small to be viable in the Swedish power market
- Lurgi’s Bioelettrica project in Pisa, Italy failed due to slag accumulation
- TPS’s Aerimpianti plant in Italy suffered from frequent stoppages due to boiler tube slag accumulation, and a shortage of operating funds, and is no longer operating
- TPS’s ARBRE plant in the UK failed due to bankruptcy of the owners, Kelda Group in 2002, during commissioning

Interestingly, although there are several major EF gasifier players co-gasifying biomass with coal at major power stations (building on their EF coal gasification experience), there are currently no EF gasifier developers focusing on heat and power applications using only biomass. This is because EF is only viable at scales above 480odt/day (100MWth), hence would only be applicable for very large heat & power applications, plus the requirement to powder the feedstock before EF gasification requires large amounts of energy for biomass compared to coal.

37.7 Barriers to development and deployment

As mentioned above, small scale systems are still largely in the demonstration phase and have yet to demonstrate robust, economic operation of extended periods of time. At the large scale, plants operating on MSW are the most established and are available commercially. In contrast, a number of the IGCC demonstrations have run in to problems with plant economics, feedstock supplies, and slag accumulation resulting in the demonstrations being terminated or abandoned. Thus, in addition to the general barriers discussed in Section 13.9, the application of gasification to power generation still requires additional demonstration of the durability and viability of the different approaches before a larger deployment beyond the waste management sector will be possible.

37.8 UK Capabilities

There are a number of UK companies involved in pilot or early demonstrations of mostly small scale gasification with ICE/gas turbine systems, listed in Table 37-3. British Gas Lurgi seems to be the only UK company that is involved in larger scale, IGCC plants and they have 2 units installed.

Technology supplier	Number of installations	Installation locations	End use	Gasifier type	Feedstocks	Size range (odt/day)
Biomass Engineering	5 units in operation in 2007	UK, Germany	CHP-ICE	DDFB	Wood	6
British Gas Lurgi	2 units	UK, Germany	IGCC		Coal, RDF, MSW, wood, sludge	800–2,000
Ethos Energy	1 unit since 2001, 2 scheduled for 2009, 4 mobile units planned for 2010	UK	Heat, steam		MSW	2–300
Energos	7 units in operation, 3 planned	Norway, Germany, UK	CHP	UDMG	MSW	30–240
Envirothermal	1 unit	UK		Combined UD DD	Sewage sludge	
Graveson Energy Management	2 units	UK, USA	CHP-ICE	“Thermal cracking”	RDF, MSW, ISW	58
ITI Energy	1 installed, 2 permitted, 2 under development	UK	CHP-ICE	DD	RDF	33–55
Air Products and Westinghouse	Announced in 2010	UK	Open cycle gas turbine		Waste	(49 MWe)

Table 37-3 Gasification with ICE/gas turbine projects in the UK

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38 Glossary

Name	Meaning
°C	degrees Celsius
ABC	Carbon Trust's Algae Biofuel Challenge
ABE	Acetone, butanol, ethanol
AD	Anaerobic digestion
Al	Aluminium
As	Arsenic
ASU	Air separation unit
BBSRC	Biotechnology and Biological Sciences Research Council
BERR	Department of Business Enterprise and Regulatory Reform
BFB	Bubbling Fluidised Bed
BIGCC	Biomass integrated gasification combined cycle
bioSNG	Biomass-derived Synthetic Natural Gas
BMW	Biodegradable Municipal Waste
BTL	Biomass to liquids
C#	Hydrocarbons containing # carbon atoms
C&I	Commercial and industrial
C_2H_5OH	Ethanol
C5	Five carbon sugar e.g. xylose
C6	Six carbon sugar e.g. glucose
CBP	Consolidated bioprocessing
CCS	Carbon Capture and Storage
CFB	Circulating Fluidised Bed
CH_3OCH_3	Dimethyl ether (DME)
CH_3OH	Methanol
CH_4	Methane
CHP	Combined Heat and Power

Name	Meaning
CNG	Compressed natural gas
CO	Carbon Monoxide
Co	Cobalt
CO_2	Carbon Dioxide
COGPP	Code of Good Practice for Pellets
ConFor	Confederation of Forest Industries
COS	Carbonyl sulphide
CPI	Centre for Process Innovation
CPM	California Pelletising Machines
Cr	Cromium
CTL	Coal to Liquids
CTU	Conzepte Technik Umwelt AG
Cu	Copper
CV	Calorific value
DARPA	(US) Defense Advanced Research Projects Agency
DCO	Decarboxylation
DDG	Distillers dry grains
DDGS	Distillers dried grains with soluble
DECC	Department of Energy and Climate Change
DfT	Department for transport
DHN	District heat network
DME	Dimethyl Ether
DMEA	Di-methyl ethanol amine
DNO	Distribution network operator
DS	Dry solids
Dual	Dual fluidised bed
EA	Environment Agency for England & Wales

Name	**Meaning**
EC	European Commission
ECN	Energy research Centre of the Netherlands
EDRF	European Regional Development Fund
EF	Entrained flow (gasifier)
EIBI	European Industrial Bioenergy Initiative
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EU	European Union
FAME	Fatty acid methyl ester
FCC	Fluid catalytic cracking
Fe	Iron
FEED	Front-End Engineering Design
FFA	Free fatty acids
FICFB	Fast Internally Circulating Fluidised Bed
FP	Framework Programme
FT	Fischer-Tropsch
GBL	Green Biologics Ltd
gCO_2e	grams of Carbon Dioxide equivalent
GCV	Gross calorific value
GDNO	Gas distribution network operator
GHG	Greenhouse Gases
GS(M)R	Gas Safety (Management) Regulations
GTI	Gas Technology Institute
GTL	Gas to Liquids
GWP	Global warming potential
H_2	Hydrogen
H_2O	Water

Name	**Meaning**
HAS	Higher Alcohol Synthesis
HCl	Hydrogen Chloride
HDO	Hydrodeoxygenation
HDPE	High density polyethylene
HFO	Heavy fuel oil
HRJ	Hydrotreated renewable jet
HSE	Health and Safety Executive
HTFT	High Temperature Fischer-Tropsch Synthesis
HTS	High Temperature water-gas Shift
HVAC	Heating Ventilation and Air Conditioning
HVO	Hydrotreated vegetable oil
IEA	International Energy Agency
IED	Industrial Emission Directive
IGCC	Integrated gasification combined cycle
ILUC	Indirect land change use
ITM	Ionic Transport Membranes
KIT	Karlsruher Institut für Technologie
L	litre
LCA	Life Cycle Assessment
LCPD	Large Combustion Plant Direct
LFG	Landfill gas
LFTGE	Landfill gas to electricity
Lge	litres of gasoline equivalent
LHV	Lower Heating Value
LNG	Liquefied natural gas
LTFT	Low Temperature Fischer-Tropsch Synthesis
LTS	Low Temperature water-gas Shift

Name	**Meaning**
MBT	Mechanical Biological Treatment
mc	Moisture content
MEA	Liquefied natural gas
Mgy	Million gallons per year
MHT	Mechanical Heat Treatment
MJ	Mega-Joule
MSW	Municipal Solid Waste
MTG	Methanol to Gasoline
MW	Mega-Watt
MW_{bioSNG}	Mega-Watt of bioSNG output
NER300	New Entrants Reserve of the European Emissions Trading Scheme
Ni	Nickel
NOx	Nitrogen oxides
NREL	(US) National Renewable Energy Laboratory
NTNU	Norwegian University of Science and Technology
O	Oxygen (atom)
O&M	Operational and maintenance
O_2	Oxygen (molecule)
odt	oven dry tonne
OLR	Organic loading rate
OPEX	Operating costs
ORC	Organic Rankine Cycle
ORNL	Oak Ridge National Laboratory
P	Phosphorus
PAS	Publically available standard
Pb	Lead
PCC	Pulverised coal combustion

Name	Meaning
PDU	Pilot Demonstration Unit
PF	Pulverised fuel
PPA	Power purchase agreement
ppm	parts per million
ppmv	parts per million by volume
PSA	Pressure-Swing Absorption
RD&D	Research Development & Demonstration
RDF	Refuse derived fuel
REA	Renewable Energy Association
RED	European directive on renewable energy
RFA	(the US) Renewable Fuels Association
RFS	US renewable fuels standard
RHI	Renewable Heat Incentive
ROC	Renewable obligation certificates
RTFO	Renewable transport fuel obligation
RTO	Regenerative thermal oxidizer
SCR	Selective catalytic reduction
SEPA	Scottish Environment Protection Agency
Si	Silicon
SMR	Steam Methane Reforming
SNRHW	Stable Non-Reactive Hazardous Wastes
SRC	Short rotation coppice
SRT	Solids retention time
SSCF	Simultaneous saccharification and co-fermentation
SSF	Simultaneous saccharification and fermentation
t/yr	tonnes per year
TRL	Technology Readiness Level

Name	Meaning
TUV	Vienna University of Technology
UCO	Used cooking oil
UK	United Kingdom
US	United States of America
VS	Volatile solids
VTT	Technical Research Centre of Finland
w/w	By weight
WDG	Wet distillers grains
WDGS	Wet distillers grains with soluble
WGS	Water Gas Shift
WID	Waste incineration directive
WVO	Waste vegetable oil
Zn	Zinc
Zr	Zirconium