Combining renewable energy with coal

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Abstract

There are various possibilities for incorporating biomass into coal-fuelled processes and a number of these are already being deployed commercially. Others are the focus of ongoing research and development. Biomass materials can vary widely, although the present report concentrates mainly on the use of woody biomass in the form of forest residues. Potentially, large amounts are available in some parts of the world. However, not all forested regions are very productive, and the degree of commercial exploitation varies considerably between individual countries. The level of wastage associated with timber production and associated downstream processing is frequently high and considerable quantities of potentially useful materials are often discarded. Overall, forest residues are a largely underexploited resource.

Combining the use of biomass with coal can be beneficial, particularly from an environmental standpoint, although any such process may have its limitations or drawbacks. Each coal type and biomass feedstock has different characteristics although by combining the two, it may be possible to capitalise on the advantages of each, and minimise their individual disadvantages. An effective way is via cogasification, and useful operating experience has been achieved in a number of large-scale coal-fuelled gasification and IGCC plants.

Cogasification can be the starting point for producing a range of products that include synthetic natural gas, chemicals, fertilisers and liquid transport fuels. It also has the potential to form the basis of systems that combine coal and biomass use with other renewable energy technologies to create clean, efficient energy-production systems. Thus, various hybrid energy concepts, some based on coal/biomass cogasification, have been proposed or are in the process of being developed or trialled. Some propose to add yet another element of renewable energy to the system, generally by incorporating electricity generated by intermittent renewables such as wind or solar power. A number also aim to incorporate some form of carbon capture and storage.

Currently, not all such hybrid schemes have been fully developed and some may yet prove to be impractical or economically unviable. However, ongoing developments into areas, such as advanced gasifier and electrolyser design, is improving performance and driving down costs. The technology behind some proposed schemes appears to be sound and a number of these could have potential for deployment in the mid term.

Acronyms and abbreviations

ABARES	Australian Bureau of Agricultural and Resource Economics and Sciences
AEBIOM	European Biomass Association
ASU	air separation unit
BECCS	bioenergy with carbon capture and storage
BFB	bubbling fluidised bed
BFBG	bubbling fluidised bed gasification
BGL	British Gas/Lurgi
BOP	balance of plant
BRICS	Brazil, Russia, Indian, China and South Africa
BTL	biomass-to-liquids
CBTL	coal-biomass-to-liquids
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CFB	circulating fluidised bed
CFBG	circulating fluidised bed gasification
CSP	concentrated solar power
CV	calorific value
DECC	Department of Energy and Climate Change, UK
DME	dimethylether
EJ	exajoule (1 EJ = 277.78 TWh)
EPA	Environmental Protection Agency, USA
EU	European Union
FT	Fischer-Tropsch
GCCSI	Global Carbon Capture and Storage Institute
GE	General Electric Corporation
Gha	giga hectares
GHG	Greenhouse Gas
GHGI	Greenhouse Gas Emission Index
GWh	gigawatt hours
Gt	gigatonne (10^9 tonne)
Ha	hectares (1ha = 2.47 acres)
HHV	higher heating value
HTW	High Temperature Winkler
IEA	International Energy Agency
IEA CCC	International Energy Agency Clean Coal Centre
IEA GHG	International Energy Agency Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
IPCC	International Panel on Climate Change
LPMeOH	Liquid Phase Methanol Process
LHV	lower heating value
MBM	meat and bone meal
MDEA	methyl diethanolamine
MHa	mega hectare
MHI	Mitsubishi Heavy Industries
MLW	municipal liquid waste
MSW	municipal solid waste
MTBE	methyl tert-butyl ether
Mtce	million tonne coal equivalent
MTG	methanol-to-gasoline
Mtoe	million tonne oil equivalent

NETL	National Renewable Energy Laboratory, USA
NGO	non-governmental organisation
O&M	operations and maintenance
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PCC	pulverised coal combustion
PEM	polymer electrolyte membrane (also known as Proton Exchange Membrane)
PSA	pressure swing adsorption
RDF	refuse-derived fuel
RES	renewable energies
RPS	renewable portfolio standard
SNG	synthetic natural gas
SRC	short rotation coppice
SRF	solid recovered fuel
WEA	World Environment Agency
WEC	World Energy Council
WEO	World Energy Outlook
USDA	US Department of Agriculture
US DOE	US Department of Energy
UNIDO	United Nations Industrial Development Organization
ZEP	European Technology Platform for Zero Emission Fossil Fuel Power Plants

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1 Introduction

There are strong incentives to develop improved sources of energy. Forecasts indicate that by 2040, the world's population will have risen to nearly nine billion. By then, global energy demand will be around a third greater than current levels. Despite efforts to diversify, coal remains important to many economies. Since 2000, apart from renewables, it has been the fastest-growing global energy source. During this time, consumption has risen by nearly 60%, increasing from 4.6 Gt in 2000, to around 7.2 Gt in 2010. Most of the growth in demand has occurred in non-OECD countries, most notably China and India.

As well as the ever-increasing use of fossil fuels of all types, there has been a marked increase in the uptake of renewable energies around the world. For a combination of political, environmental and economic reasons, in many countries, these now represent a rapidly growing share of energy supply. Of these technologies, the biggest contributions have been made by wind power and biomass.

In recent years, global wind capacity has grown significantly, as has interest in the use of biomass. Biomass is often considered to be the renewable energy with the highest energy-producing potential.

Biomass can take many forms although the present report concentrates mainly on the use of forest residues. Large tracts of the earth are covered with forests, but not all are very productive, and only some are currently exploited commercially. The degree of exploitation varies considerably between individual countries and in some cases, only a small proportion of the residues available are actually used. Even where a mature logging industry is in place, a high degree of wastage can occur and it is not uncommon for up to two thirds of a harvested tree to be discarded. Sawmilling and other downstream processes can increase wastage further. Overall, forest residues are often a largely underexploited resource.

When combined with coal, biomass can provide a number of advantages, although it can also have characteristics that work against it, particularly where large-scale use is contemplated. Biomass can be cofired in coal power plants, or cogasified. Gasification is an effective, versatile technology that can be used to produce energy from coal and biomass. It has long been used on an industrial scale as the basis for power generation, chemicals, liquid fuels, and refining. Over many years, the merits of gasification have been well established with coals, and various aspects of these systems can now be applied (with significant economic benefits) to both biomass gasification and to coal/biomass cogasification.

Many different individual coals and biomass materials have been gasified, but often on their own, and not always at commercial scale. Each feedstock has its own advantages and disadvantages. On the plus side, coal often has a high energy value, there are large reserves and it is widely available, and it is usually cheaper than biomass. However, there can be obvious environmental issues associated with its production, as well as with emissions from coal-fired plants.

Biomass may take the form of a low cost (or even no-cost) waste or residue, and replacing part of a plant's coal supply with biomass will normally reduce pollutant species such as NOx and SOx. Assuming that the biomass has been produced sustainably, overall CO_2 emissions will also be reduced. However, CVs are generally lower, chemical and physical properties can vary widely, supplies may be limited or seasonal, it may be expensive to harvest and treat, and there are sometimes operational issues when combusted or gasified.

Combining the two via cogasification can be beneficial. Cogasifying biomass in large coal gasifiers can achieve high efficiencies and improve process economics through the greater economies of scale that can be tapped into. It can also help smooth out fluctuations in biomass availability and variable properties. On the emissions front, adding biomass may help a coal plant to obtain credits for the use of a renewable fuel, and when combining the two, some useful catalytic and synergetic effects have been observed, such as lower activation energies. Thus, combining biomass and coal in this way can be useful, both environmentally and economically, as it may be possible to capitalise on some of the advantages of each individual feedstock, and overcome some of their individual disadvantages. Cogasification has been undertaken on a commercial scale and several coal-fuelled gasification and IGCC plants in operation have at least trialled combining biomass with their coal feed.

The use of cogasification as the starting point for producing liquid fuels has been examined. This has long been an area of interest to oil-consuming countries that possess significant coal reserves. Gasification is the foundation for converting coal and other feedstocks to gasoline, diesel and jet fuel. Two main processes have been demonstrated at full commercial scale for coal-to-liquids, namely Fischer-Tropsch (FT) and methanol-to-gasoline (MTG). Both start with coal gasification and follow this stage with further downstream processing. The global potential for producing liquid fuels from coal and biomass combinations is substantial, and various studies have examined the possible scale of production for different countries. Most conclude that producing transport fuels from coal and biomass is best achieved by cogasifying, followed by either FT or MTG synthesis – these two appear to offer the most viable and economic options.

A major aim of this report was to examine different systems that combine coal use with various other technologies to create efficient and clean energy-producing systems. In a number of countries, hybrid concepts for the production of SNG, electricity and/or heat, and liquid transport fuels have either been proposed or are in the process of being developed or trialled. A number are based on the cogasification of coal and biomass in various ways. However, as well as incorporating biomass, some propose to take this a step further by adding yet another element of renewable energy to the system, generally by incorporating electricity generated by intermittent renewables (such as wind and solar power).

A major drawback with wind and solar power is their intermittency. Consequently, times of peak output may not correspond with periods of high electricity demand, and vice versa. At times, there can be significant amounts of surplus unwanted energy available, particularly from wind farms. This can be quite a widespread phenomenon, and the usual solution is to take wind turbines off line. However, rather than waste this electricity, it would clearly be beneficial to put it to good use. One way would be to use it to electrolyse water, producing hydrogen and oxygen. Both gases have the potential to be component parts of such hybrid systems, and there are various schemes where the hydrogen could be fed into the syngas from a gasification system, used in fuel cells, used directly as a transport fuel, or stored for later combustion in gas turbines to generate electricity. Similarly, oxygen could be stored, used for a number of industrial applications, or fed to a coal/biomass gasifier or an oxyfuel combustion plant to generate electricity. Different concepts and schemes combining gasification, intermittent renewables and electrolysis are currently being examined. Some also aim to incorporate some form of carbon capture and storage.

Some hybrid systems are at early stages in their development or have been undertaken at a very small capacity. Hence extrapolating up to commercial scale and obtaining firm process costs remains problematic. For a variety of reasons, not all of the schemes proposed are likely to be economically viable. However, from a technological standpoint, some others appear to be much more robust. Ongoing improvements in gasifier and electrolyser design are likely to encourage further development of such systems for energy production. Where hydrogen and/or oxygen production forms part of such schemes, the reduction in the cost of electricity supplied by renewable energy sources such as wind and solar would also be beneficial as it would reduce the cost of electrolysis.

2 Global energy demand and supply – fossil fuels and renewable energy sources

Forecasts suggest that by 2040, as the world's population increases to nearly nine billion, global energy demand will be around 30% higher than current levels. Much of the growth will come from non-OECD countries where energy demand is expected to increase by nearly 60%. The requirement for electricity will remain the single biggest driver; by 2040, this will account for >40% of global energy consumption. Of the fossil fuels, oil, natural gas and coal will continue to be the most widely used, accounting for up to ~80% of total energy consumption in 2040. In recent years, global energy demand has continued to increase steadily, rising by >3% in 2011. Non-OECD countries were responsible for most of this (IEA, 2012a).

2.1 Fossil fuels

At the end of 2011, the proved global reserves of natural gas, oil and coal were still substantial (*see* Table 1).

Since 2000, apart from renewables, **coal** has been the fastest-growing global energy source. It is the second source of primary energy in the world after oil, and in 2011 provided >30% of global primary energy needs. During 2011, for the twelfth successive year, global coal production increased (by 6.6%). Worldwide, coal consumption has risen by nearly 60%, from 4600 Mt in 2000, to ~7200 Mt in 2010. This trend is expected to continue for the foreseeable future.

The growth in demand has varied widely between individual nations, with most of the global increase occurring in non-OECD countries (most notably China and India) where (in 2011) production climbed by 9%. In OECD member countries, the increase was only 0.8% (IEA Coal Information, 2012). Overall, coal remains a vital source of energy for a range of industrial applications and power generation – around 42% of the world's energy is currently generated by coal-fired plants. The largest individual proven national coal reserves are shown in Figure 1.

Table 1 Proved global reserves of natural gas, oil and coal, end of 2011 (BP, 2012)

Region	Natural gas		Oil		Coal*	
	Proved reserves, trillion m^3	Share of total, %	Proved reserves, thousand, Mt	Share of total, %	Proved reserves, Mt	Share of total, %
North America	10.8	5.2	33.5	13.2	245,088	28.5
South & Central America	7.6	3.6	50.5	19.7	12,508	1.5
Europe & Eurasia	78.7	37.8	19.0	8.5	304,604	35.4
Middle East	80.0	38.4	108.2	48.1	32,895	3.8
Africa	14.5	7.0	17.6	8.0		
Asia-Pacific	16.8	8.0	5.5	2.5	265,843	30.9
World	208.4	100.0	234.3	100.0	860,938	100.0

* aggregated totals for anthracite, bituminous coals, subbituminous coals and lignite

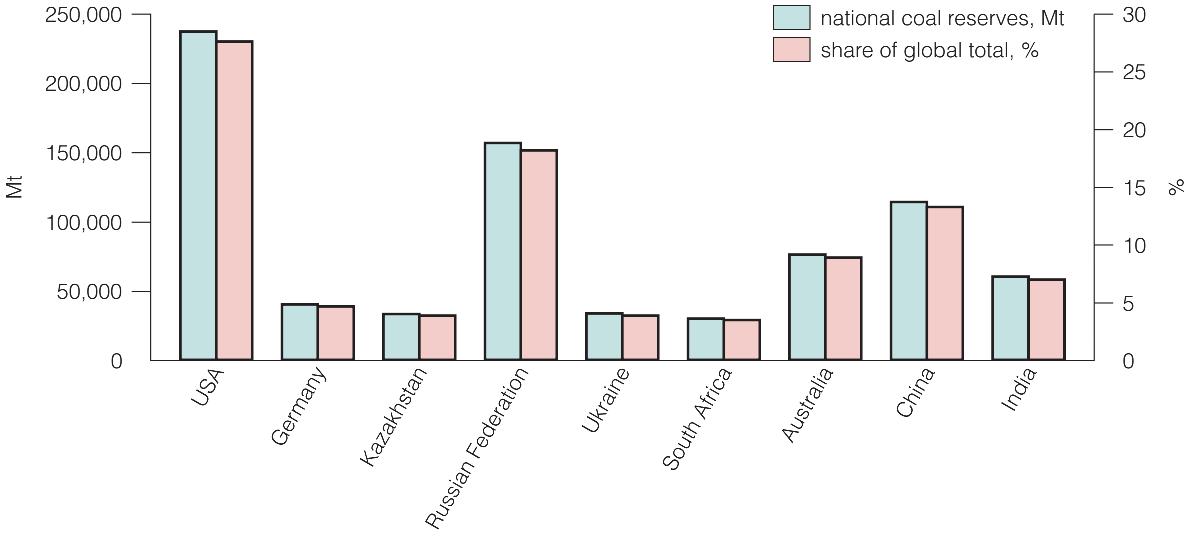


Figure 1 Largest individual proven national coal reserves (end of 2001) (BP, 2012)

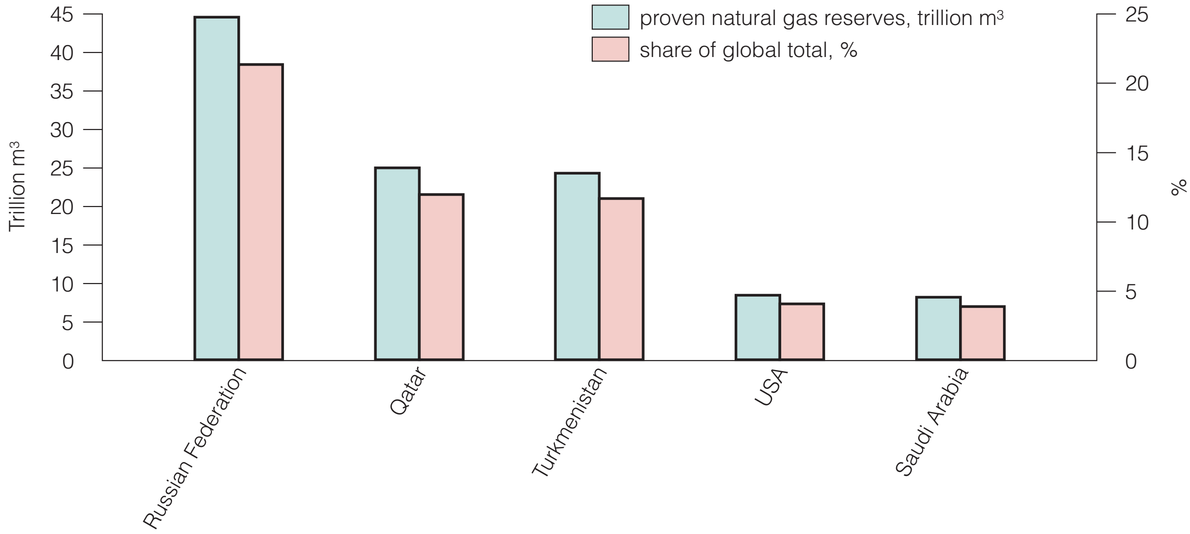


Figure 2 Largest individual proven national natural gas reserves (end of 2011) (BP, 2012; oil and Gas Journal, 2011)

For some years, the use of **natural gas** has also been increasingly steadily. In 2011, global production increased by >2%. Natural gas consumption is forecast to continue rising until at least 2040 and demand is expected to increase by more than 60% above current levels. It is possible that by 2025, natural gas will overtake coal to become the world's number-two fuel behind oil (ExxonMobil, 2012). Demand is expected to grow in every part of the world, but particularly in non-OECD countries in the Asia-Pacific region, where it is expected to triple over the next 30 years. China's gas demand growth will be split between the industrial and residential/commercial sectors. In India, about half of the growth in gas demand in the period up to 2040 will come from the industrial sector. And, in the Middle East, demand is being driven by the need for electricity generation as well as for industrial applications. Natural gas produced by conventional methods is growing in many regions, although it is declining in other; output is falling in Europe and the USA. However, in the latter, the decline is likely to be offset by growth in unconventional gas production (from shale and other rock formations). By 2040, it is suggested that unconventional gas could account for 30% of global production, up from 10% in 2010 (ExxonMobil, 2012). The largest individual proven national natural gas reserves are shown in Figure 2.

Oil remains the world's most widely used energy source and demand continues to increase. During the next five years, almost half of global oil demand growth will come from China, a trend set to

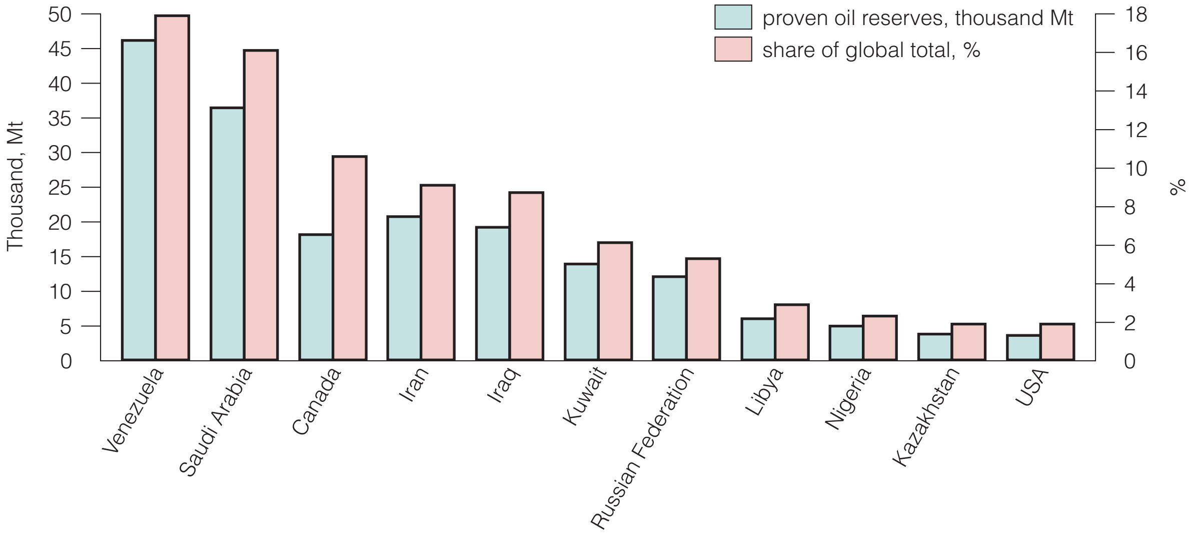


Figure 3 Largest individual proven national oil reserves (end of 2011) (BP, 2012)

continue up to 2035. Oil demand from the transportation sector is also growing strongly in countries such as India. In contrast, demand in OECD countries is expected to decline over the next two decades, driven mostly by government policies on fuel efficiency and the fact that vehicle ownership is already high. In 2011, ~89 million bbl/d of oil and liquid fuels were consumed worldwide (nearly 32 billion barrels a year). In the short-medium term, the pace of oil demand growth is expected to remain relatively steady, with annual gains of 0.8 million bbl/d (0.9%) in both 2012 and 2013 (Oil & Gas Journal, 2011).

Over the past decade, the scale of proven oil reserves has increased steadily. OPEC countries now represent >72% of global oil reserves. The largest individual proven national oil reserves are shown in Figure 3.

2.2 Renewable energy technologies and resources

Recent years have witnessed a global upsurge in interest in the large-scale use of renewable energy sources of all types. However, within the context of the present report, the following section concentrates predominantly on selected aspects, namely the use of biomass with coal, plus the possibilities of coupling such processes with intermittent renewable energy sources such as wind and solar power. These technologies are considered in greater detail in the following chapters.

Across much of the world, for a variety of reasons, there is growing emphasis on the use of renewable energy sources. These are sources that can be either replenished continuously or within a moderate time frame through natural energy flows and include solar energy, wind power, hydropower, geothermal energy, and bioenergy. In many countries, there is a strong commitment to financing greater sustainable development and power generation.

Alongside the ever-increasing use of fossil fuels of all types, for a combination of political, environmental and economic reasons, there has been a marked increase in the deployment of renewable energies; they now represent a rapidly growing share of energy supply in many developed and emerging economies. For instance, in OECD countries, the share of renewable energy in total primary energy supply continues to increase steadily, rising from 7.8% in 2010 to 8.2% in 2011. Within the OECD, wind power is the leading non-hydro renewable energy source of electricity, and has also experienced the fastest growth. In many countries, interest in the use of biomass has also increased, driven by moves to reduce national dependency on energy imports, prolong the lifetime of existing fossil fuel reserves, and to reduce CO_2 emissions from power generation and other industrial applications. In some parts of the

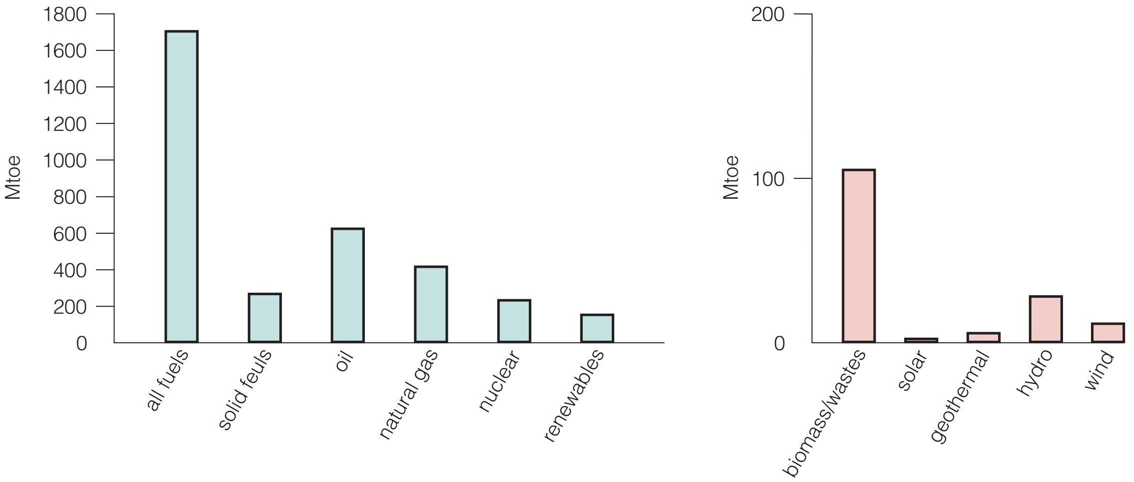


Figure 4 The gross inland consumption by fuel type in the 27 EU Member States (AEBIOM, 2011

world, biomass-based systems now make up a significant proportion of the renewable technologies deployed. For example, its level of contribution within the European Union (EU) is shown in Figure 4. In 2009, biomass made up 69% of the total EU renewables-based fuel consumption.

Although the overall deployment of renewable energy systems continues to increase, local and national circumstances differ, and the scale and nature of energy resources available in a particular country often dictates the scale and ratio between the different energy-producing technologies adopted. One country may possess extensive biomass resources in the form of forests, whereas another may be particularly suitable for the deployment of wind power, and so on. Such technologies are often used in conjunction with various forms of fossil fuels, with either coal- or gas-fired power plants used to provide back-up (as well as often base load capacity) when output from intermittent sources such as wind and solar diminish or are unavailable (Mills, 2011).

Renewables currently provide ~16% of global final energy consumption. Of this total, ~10% comes from 'traditional' biomass (used mainly for heating) and 3.4% from hydro power. The so-called new renewables (micro hydro, advanced biomass, wind, solar, geothermal, and biofuels) account for a further 3%. The share of renewables in global electricity generation is ~20% (16% hydro, ~3% new renewables). A breakdown of the global total installed renewable electrical power capacity is shown in Figure 5.

Recent years have witnessed a significant growth in some of these categories and, to date, wind and hydroelectric power have been the market leaders. The former is being driven by a raft of governmental support mechanisms and incentives, although alongside this, global interest in the use of biomass continues to increase. Many countries have recognised that indigenous (and even imported) biomass can play a greater role in the provision of heat, power and transport fuels, either alone, combined with coal, or as part of a portfolio of other energy resources.

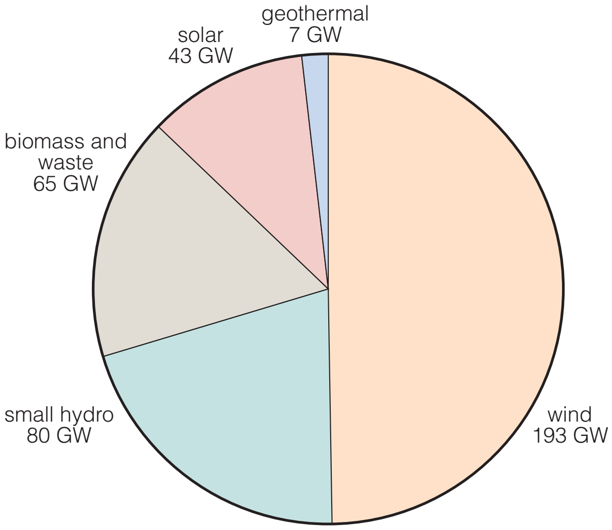


Figure 5 World total installed renewable electrical power capacity (Business Insights, 2011)

Renewables currently produce around a fifth of global electricity, although there are wide disparities between individual countries; for instance, nearly three quarters of New Zealand's electricity is generated by renewable sources. Within the European Union (EU), they accounted for >70% of total electric capacity additions made in 2011, bringing their overall capacity share to 31%. Much of this comprised wind and solar power installations (REN21, 2012). In the same year, in North America, renewables made up ~39% of new US electric capacity. Nine US states now generate >10% of their electricity with non-hydro renewables.

Within the Asia-Pacific region, China now has more renewable power capacity than any other nation, with an estimated 282 GW; around 70 GW of this total is non-hydro. Of the 90 GW of new capacity installed during 2011, renewables accounted for more than one-third, and non-hydro renewables were more than one-fifth (REN21, 2012). The level of renewables also continues to increase in countries such as India and Australia. In the latter, the state of South Australia now meets 20% of its electricity demand from wind.

The biggest users of non-hydro renewable electricity generation are China, the USA, Germany, Spain, Italy, India, and Japan. Combined, these account for 70% of total global capacity. By region, the EU hosts nearly 44% of global non-hydro renewable capacity, with the BRICS (Brazil, Russia, India, China and South Africa) nations accounting for almost 26%. The 2012 edition of the IEA *World Energy Outlook* suggests that by 2015, renewable energy will become the world's second largest source of power generation, surpassing coal as the primary source of power by 2035.

2.3 The growth of wind power

Recent years have seen wind power become one of the most widely deployed renewable technologies; latest capacity additions have been around 45 GW/y. In 2012, global wind capacity increased by 20% to a total of ~280 GW. Around 50 countries made further additions and 70 now have more than 10 MW of installed wind capacity (Figure 6). In 2011, more new capacity was added in developing countries and emerging markets than in OECD countries. The ten biggest players now account for nearly 87% of total capacity (REN21, 2012); these include China, the USA, India, Germany, the UK, and Canada. China alone installed nearly 18 GW of new capacity, accounting for almost 44% of the world market; the country now has 77 GW of cumulative capacity, more than a quarter of the world's total. To date, all of this has been land-based. However, focus is now extending to off-shore sites; in January 2013, Fujian Datang International Wind Power Development announced plans for China's first off-shore wind farm to be built off the coast of Fujian province. The US$964 million facility will have a capacity of 300 MW.

Figure 6 Part of the 68 turbine Smola wind farm in Norway (photograph courtesy of Statkraft)

The USA now has 60 GW of wind power, the European Union 94 GW, India ~16 GW, and

Canada 5.3 GW. There has also been significant growth in Latin America. However, irrespective of location, an important characteristic of wind (and solar) power is the fact that it remains dependent on prevailing weather patterns, hence unlike conventional thermal generating plants, its output is intermittent and may not be available when needed. Conversely, excessive output produced at times of low demand may be wasted. For instance, up to 20% of the time, wind farms in northern Germany are switched off as the power they produce is not needed. In 2010, the German power grid was unable to accommodate 150 GWh of electrical energy, simply because it was already operating at full load.

Despite such drawbacks, the use of renewable energy technologies, particularly for power generation, look set to carry on increasing. The growing global population will continue to drive demand for additional installed electricity capacity. Greater demand will also come from more urbanisation and increased access to grid electricity supply. Thus, global demand for electricity from *all* sources is forecast to continue increasing until at least 2035. The scale and nature of power generation projects and programmes will continue to be influenced by national needs and resources, thus the ratio between different renewable technologies adopted will vary widely, reflecting individual circumstances. For instance, the possibility of water scarcity resulting from climatic variations, limited site availability, and the high installation costs could limit future major additions of hydropower plants, shifting the focus to other technologies such as those based on wind and biomass.

A number of ways to integrate electricity generated by wind power with coal use have been proposed; the direct coupling of wind- and coal-based power generation has been examined in a number of US and European studies and reported in a previous Clean Coal Centre report (Mills, 2011). A number of schemes for incorporating wind-generated electricity as part of coal and biomass-based processes are discussed later in the present report.

2.4 Increasing use of solar power

Like wind power, there is increasing deployment of various forms of solar power technologies in suitable parts of the world. A number of projects are examining possible ways to combine these with coal and other renewable energy sources. For instance, some propose to incorporate electricity produced by photovoltaic systems with coal and/or biomass-based systems (these are discussed later in this report).

There are also projects under way that propose to combine solar power (in the form of concentrated solar power – CSP) with existing thermal (gas- and coal-based) power stations. Efforts to develop such coal-solar hybrids are being pursued in several parts of the world that have the appropriate weather conditions. An advantage of adding a solar thermal module to an existing coal-fired power plant is that much of the necessary infrastructure (steam cycle, etc) and plant requirements already exist. This can make the economics more attractive than those of a stand-alone solar thermal generating unit.

Solar energy input can be harnessed by parabolic troughs, compact linear Fresnel reflectors (CLFR), or power towers. As part of a hybrid system, these raise steam that is fed into a power plant, reducing the amount of coal (or gas) required. Such thermal hybrid projects may be the most cost-effective option for large-scale use of solar energy. According to US studies carried out by EPRI, potentially, a solar trough system could provide 20% of the energy required for a steam cycle. The IEA GHG R&D Programme has recently examined the integration of solar energy technologies with CCS-equipped plants (IEA GHG, 2012).

Globally, there are around twenty hybrid solar thermal plants being developed, some based on gas and some on coal. In the USA, a major demonstration project (using parabolic trough solar collectors) was undertaken at Unit 2 of Xcel Energy's coal-fired Cameo Generating Station. Main aims were to decrease coal use, increase plant efficiency, lower CO_2 emissions, and to test the commercial viability of combining the two technologies. After a year's demonstration, the station was closed. The solar component was deemed to have operated satisfactorily – coal use was lower, and overall SO_2, NOx and CO_2 emissions reduced. During operation, the system produced the equivalent of one MW (of the plant's 49 MW) from solar power. The parabolic trough system used glass mirrors to concentrate the sun's energy into a series of tubes filled with a heat transfer fluid (mineral oil). When this reached 300°C, it was fed to a heat exchanger where the heat was transferred to water, bringing it to near boiling point, before being fed into the existing plant steam system.

In Chile, GDF Suez and German renewable energy company Solar Power Group are developing a 5 MW concentrated thermal solar power plant. The facility will provide steam to the 150 MW Mejillones coal-fired plant in the northern part of the country. This pilot plant was scheduled to become operational in 2012.

In Australia, the utility CS Energy is building a 44 MW solar thermal add-on to its 750 MW coal-fired supercritical Kogan Creek plant in Queensland. This US$110 million project (the Kogan Creek Solar Boost Project) is using Compact Linear Fresnel Reflector technology. This is the largest solar project in the Southern Hemisphere, the world's largest hybrid integrated solar steam/coal-fired power plant augmentation project, and the world's largest linear Fresnel reflector solar CSP installation. The Fresnel technology uses flat or slightly curved mirrors to focus sunlight on to a linear receiver to boil water, generating 270–500°C high-pressure direct steam to power the steam turbine genset. The direct steam technology eliminates the need for costly heat transfer fluids and heat exchangers. The add-on will allow increased electricity production and avoid an estimated 35,600 tCO_2. Construction began in 2011 and is expected to be completed in 2013. Recent site activities have included civil works, structural changes to the power station to facilitate the solar field's connection to the plant, and the installation of a 16 metre long solar reflector. Fourteen rows of solar steam generators, each 500 metres in length, are now under construction.

A second Australian CSP project (using a Linear Fresnel reflector system with a total mirror surface of 18,500 m^2) is also under way at Macquarie Generation's 2 GW coal-fired Liddell Power Station in New South Wales. This incorporates a 9.3 MW capacity Novatec solar boiler to generate steam that is fed into the existing plant, helping reduce coal requirements and plant emissions. The reduction in coal use is expected to cut CO_2 emissions by 5000 t/y. The solar system became fully operational in February 2013.

A scoping study examining possible ways of harnessing solar power with brown coal (within an Australian context) was recently completed (Lovegrove and McDonald, 2012). This examined ways of combining input from a CSP facility with particular emphasis on coal gasification. There is increasing interest in using concentrated radiation from CSP to drive directly thermochemical reactions in this manner. Direct conversion of coal to liquids is also possible. The study examined the technical and economic viability of various options for combining brown coal and concentrated solar and identified the following possible approaches:

- use of solar process heat;
- low temperature supercritical water gasification of brown coal in a linear concentrator;
- direct coal to liquids reactions in a linear concentrator;
- gasification within a high temperature solar heated molten salt tank;
- high temperature supercritical water gasification using a tower or dish concentrator;
- entrained flow or fluidised bed gasification using a tower concentrator.

Such solar-driven technologies are still at the R&D stage and it is expected that associated costs will decrease over time. Advantageously, their input into a coal-based process should reduce CO_2 emissions by effectively replacing part of the coal feed. Concentrating solar thermal technologies have been proven on a large utility scale, although so far, they have only been employed commercially to heat working fluids for power generation. However, the principle of driving high-temperature endothermic reactions with concentrated solar energy is well established in the R&D phase. Conversion of hydrocarbons such as brown coal using solar heat appears to be technically feasible via a number of possible routes.

2.5 Increasing global biomass use

Amongst the renewable technologies, biomass is one of the world's oldest energy sources and is used widely for cooking and heating. In some countries, it is also used for power generation/cogeneration applications. There is also growing interest in its use (alone or combined with coal) for the production of liquid fuels and other products. When grown sustainably, biomass-based systems have the potential to be carbon-neutral (or if combined with carbon capture and storage, carbon-negative) hence are currently the focus of considerable interest (Figure 7).

Figure 7 Rapeseed (canola) plantation. Rapeseed oil is used for the production of biodiesel (photograph courtesy of Russell Mills Photography)

Growing concerns over links between climate change and fossil fuels has boosted interest in the greater use of biomass for both existing and new applications. As an energy source, biomass can provide advantages but there are also a number of issues that can restrict its usefulness (*see below*). However, some of these can be overcome by combining it with fossil fuels such as coal. For instance, in the USA, major programmes are examining the cogasification of coal and biomass (Weiland and others, 2010). Studies are also looking at how best to couple US coals and biomass sources that make sense geographically – pairing up specific coal types with locally-available biomass to minimise transport requirements (NETL, 2010a). In many countries, biomass is already the leading source of renewable energy. At present, it contributes ~14% of global primary energy whilst using only ~40% of existing biomass energy resources. There therefore remains significant potential for increasing its use for a variety of applications.

Worldwide, the use of renewable energies will continue to rise. Many countries have set goals to increase the use of renewables in their respective energy mixes, particularly where based on biomass (Ladanai and Vinterbäck, 2009). A number of studies have suggested that, in principle, energy produced from biomass could meet all the world's energy needs. However, the real technical and economic potential is much lower. The WEC *Survey of Energy Resources* estimates that bioenergy could theoretically provide 2900 EJ/y, but that technical and economic factors limit its current practical potential to just 270 EJ/y. Projections by the WEC, WEA and IPCC estimate that by 2050, bioenergy could be supplying between 250 and 450 EJ/y, representing around a quarter of global final energy demand (Best and others, nd). IEA estimates suggest that sustainably-produced bioenergy could contribute between 25% and 33% to the future global primary energy supply (up to 250 EJ) in 2050. It is the only renewable source that could replace fossil fuels in all major energy markets (heat, electricity, and transport fuels).

Although biomass can be used for a range of applications, a major use is for power and/or cogeneration. A number of major economies already use biomass to generate electricity, although the scale varies significantly between countries, often reflecting local requirements and circumstances.

Table 2 Share of biomass and waste in total electricity net generation, %, 2009 (Business Insights, 2011)

	Biomass and waste electricity net generation, GWh	Share of biomass in country's total electricity net generation, %	Share in total world biomass power generation, %
USA	65.41	1.7	38.1
Germany	38.30	6.9	22.3
Brazil	21.35	4.6	12.4
UK	12.02	3.5	7.0
Sweden	11.32	8.8	6.6
Finland	8.59	12.6	5.0
Italy	8.36	3.1	4.9
China	2.50	0.1	1.5
India	2.00	0.2	1.2
Australia	1.97	0.9	1.1

Table 3 World bioenergy potential by feedstock, 2050 (Doornbosch and Steenblik, 2008)

Feedstock type	Bioenergy potential, EJ
Agriculture + forest residues + waste	40–170
Agriculture intensification	140
Surplus agriculture	120
Surplus forest	60–100
Degraded land	70
Total	100–600

In 2009, the largest biomass users (for electricity generation) were the USA, Germany and Brazil (*see* Table 2).

Inevitably, political and other uncertainties mean that estimates of future potential vary widely. For instance, Doornbosch and Steenblik (2008) suggest that world bioenergy potential will be between 100 and 600 EJ by 2050, with agriculture, forest residues, and waste accounting for the majority share (28.3% of total potential) (*see* Table 3).

Despite disagreement on the scale of biomass potential, all agree that many parts of the world have considerable potential to produce larger amounts of biomass for energy-related applications. Geographically, sub-Saharan Africa is forecast to offer the highest potential for bioenergy, in the form of dedicated energy crops, agricultural and forest residues, and surplus forest increment. This could account for more than 22% of total potential by 2050 (*see* Table 4).

A combination of rising fossil fuel prices, environmental issues, and concerns over security and diversification of national energy supplies have increased interest in the use of biomass for energy production. However, despite its attractions, a major issue is the possible conflict with land used for food production; the current estimate of the world's land area is 13 Gha. Of this, 5 Gha is used for agriculture (1.5 Gha for arable land and permanent crops), and 3.5 Gha for permanent meadow and pasture (Wenzel and Hamelin, 2012).

Of the renewable energy technologies, biomass-based is by far the largest. Biomass resources are widespread and available in many countries (Ladanai and Vinterbäck, 2009). Biomass accounts for >10% of global primary energy supply and is the world's fourth largest source of energy after oil, coal, and natural gas. During the last four decades, its use for energy production has doubled. In

Table 4 Global biomass resource by resource potential by region, 2050 (Business Insights, 2011; citing research carried out by the University of Copenhagen)

Region	Bioenergy potential, EJ
Sub-Saharan Africa	49–347
Latin America (including Caribbean)	89–281
CIS and Baltic countries	83–269
North America	39–204
East Asia (including Japan)	24–194
Oceania	40–114
Middle East and North Africa	2–39
South Asia	23–37
Western Europe	13–30
Eastern Europe	5–29

recent years, global demand has grown at an average rate of 1.4%/y. Some market applications have been long-established (such as smaller-scale heat and power), although newer uses continue to be developed. The scale of demand and the types of application vary from country to country. Current global biomass demand for energy purposes is estimated to be 53 EJ. Much of this (~86%) comprises ‘traditional’ uses such as heating, cooking, and various commercial applications; much of this biomass is burned directly and inefficiently. Of the remainder, three quarters is used for electricity generation/cogeneration, with the balance used for the production of liquid biofuels for road transport (mainly ethanol and biodiesel).

At the end of 2011, global electricity generating capacity based on biomass had risen to 72 GW, an increase from ~66 GW in 2010. The USA leads the world in biomass-based power generation, and other major users include several EU countries, China, Brazil, India, and Japan. Many biomass facilities capitalise on local supplies; for instance, sugar producers in South America and Africa often use bagasse for on-site heat and power generation. However, there is also a growing international trade in some types of biomass such as wood pellets. This is easing supply constraints previously experienced in some places. During the last decade, global pellet production has increased by ~25%/y, and total production is now in excess of 18 Mt/y. The world’s biggest producers are the USA, Canada, and several European countries. The number of new pellet plants being developed continues to increase. For instance, recently announced new facilities in the USA include large plants in Mississippi and Louisiana. Like a growing number of others, both will focus on exports to European power utilities. An estimated 12.6 Mt/y of pellets is currently exported from the USA; this is forecast to increase to 20 Mt/y by 2020.

For a number of reasons, assessing accurately the potential scale of future global biomass resources can be difficult; this is especially so for energy crops. The amount of land currently devoted to growing energy crops for biomass fuels is only 0.19% of the world’s total land area and only 0.5–1.7% of global agricultural land (Ladanai and Vinterbäck, 2009). Many national and/or regional studies have attempted to determine the future scale of biomass resources. However, there has often been little consistency and many have adopted different assessment criteria; available potential assessments often differ in methods, time horizons, framework conditions, and specific biomass resources. As a consequence, in terms of future potential, there is frequently considerable disagreement between studies (Thrän and Bunzel, 2010). There are also problems with obtaining accurate data; this results from unclear political developments, lack of data (especially for developing countries), lack of consistent definitions for specific biomass fractions (such as logging residues), and interpretation of what constitutes degraded land. Furthermore, overall global biomass potential is likely to be significantly influenced by future food and feedstock demand. This is driven by population growth, per-capita consumption, development of yields for food, fodder and biomass production, and issues associated with possible climate change.

The future scale and availability of sustainably-produced biomass resources will depend heavily on global political agreements concerning food security and sustainability, as well as consumer behaviour in developed countries. Consequently, the most meaningful indicators may be obtained by adopting the use of a number of possible alternative scenarios. For instance, studies by Thrän and Bunzel (2010) addressing the spatial distribution of biomass potentials suggested:

- ***Business as Usual scenario*** **–** this assumes further technological advances in agricultural development (such as short rotation forestry), land use changes (such as forest clearance), increasing population levels, but with an overall emphasis on food production.
- ***Bioenergy scenario*** **–** this assumes the vigorous promotion of biomass as an energy source, the cultivation of energy crops with the highest yields, combinations of forestry and the most productive region-specific energy crops, significant increase in the prices of agricultural commodities, plus strong incentives to achieve >50% higher yield increases compared to Business as Usual.
- ***Bioenergy with increased restrictions due to environment and nature protection*** **–** this assumes that the cultivation mix and yield increases (as with the Bioenergy scenario), no further forest clearing or ploughing up of grassland, plus protection for selected areas of boreal, temperate and tropical primary forests, and agricultural land.

Clearly, each scenario will be dependent on a range of technical developments, environmental issues, and political decisions. This means that with many national or regional-specific studies of biomass potential, the range of possible results is likely to be very wide. This is especially true when addressing the scale and potential future cultivation of energy crops. However, it is suggested that globally, in the period up to 2020, under all scenarios considered, there are significant areas of arable land available, with very large national potentials. It seems likely that in some cases, national supply strategies will comprise a mixture of domestically-produced and imported biomass, a situation already being experienced in some countries. Despite the apparent inconsistencies between studies on the scale of the future potential of biomass, all scenarios predict the growing importance of biomass as a source of renewable energy. Increased future potential is viewed widely as considerable. However, on a localised basis, availability may be more restricted.

2.5.1 Types of biomass

'Biomass' is an umbrella term used widely to denote any plant-derived organic matter that is available on a renewable basis. However, biomass materials with the potential for energy use are very varied and the definition encompasses a number of different basic categories:

- ***dedicated energy crops*** **–** herbaceous energy crops are perennials that are harvested annually, having taken two to three years to reach full productivity. These include grasses such as switchgrass, miscanthus, bamboo, sweet sorghum, tall fescue, kochia and wheatgrass;
- ***short-rotation woody crops*** are fast-growing hardwood trees that are harvested within five to eight years of planting. They include hybrid poplar and willow, silver maple, eastern cottonwood, green ash, black walnut, sweetgum, and sycamore;
- ***agricultural crops*** include products such as corn starch and corn oil, soybean oil and meal, wheat starch, and vegetable oils. They generally yield sugars, oils, and extractives, although they can also be used to produce a number of chemicals and other products;
- ***agricultural crop residues*** are primarily stalks and leaves not harvested or removed from fields in commercial use. Examples include corn stover, wheat straw, and rice straw. With ~80 Mha of corn planted annually, corn stover is expected to become a major feedstock for biopower applications;
- ***forestry residues*** include materials not harvested or removed from logging sites in commercial hardwood and softwood stands, as well as material resulting from forest management operations such as pre-commercial thinning, fire prevention and removal of dead and dying trees;
- ***biomass processing residues*** **–** these are by-products and waste streams that have significant energy potential. They include wood processing residues such as sawdust, bark, branches, and leaves/needles;
- ***municipal waste*** **–** residential, commercial, and institutional post-consumer waste contains a significant proportion of plant-derived organic material that constitutes a renewable energy

resource. This can include waste paper, cardboard, wood waste, and yard waste;

- ***animal waste* –** farms and animal-processing operations create animal wastes that constitute a complex source of organic materials with environmental consequences. Some can be used to make many products, including energy.

Globally, the dispersal and availability of these different feedstocks varies. Whereas some materials such as municipal waste are generated in all built-up areas, others such as energy crops may only be available in certain geographical regions (US DOE EERE, 2011). There are many bioenergy routes that can be used to convert raw biomass into a final energy product. Technologies for producing heat and power are already well developed and competitive in many applications, as are some first generation routes to biofuels for transport. Where biomass is gasified, the most widely used applications are cogeneration, cogasification with coal, and production of syngas (Hofbauer and Rauch, 2010). A range of other conversion technologies are under development, offering prospects of improved efficiencies, lower costs and improved environmental performance. Biomass is the only renewable source that can replace fossil fuels in all major energy markets: the production of heat, electricity, and transport fuels (IEA Bioenergy, nd-a).

The properties of biomass materials with potential for energy production can vary widely. Feedstocks can range from woody to grassy in nature. Commonly encountered examples include crop residues (wheat straw, corn stalks, nut shells, orchard prunings, bagasse), forest residues (slash, forest thinning), urban wood waste (construction residues, garden prunings), and energy crops such as miscanthus and short rotation coppiced (SRC) wood. Some energy crops grow quickly; for instance, wheat straw and switchgrass. Both are available in large quantities in the USA, and NETL is evaluating these and other biomass sources (such as corn stover, forestry and lumber wastes) as candidates for cogasification with a range of indigenous hard coals and lignites (NETL, 2010a).

A growing number of biomass feedstocks have been trialled or are in use – the potential range is very wide. Properties of selected examples are compared with coals in Table 5. It is evident that their properties differ significantly from those of typical coals and there is also greater variability. Heating values and bulk densities are much lower, ash contents can vary widely (<1–>20%), and moisture content can be very high, although sulphur contents are usually low (Fernando, 2009).

Potentially, many different types of biomass can be utilised or co-utilised. Historically, it has been both cofired and cogasified with coal and other feedstocks. Currently, cofiring dominates, largely using wood, forestry residues and associated wastes, and agricultural residues. Various refined products, such as wood pellets, are also used in, for instance, Danish and Dutch power plants. Globally, more than 150 power plants have cofired biomass or wastes, at least on a trial basis. There are ~40 pulverised coal combustion plants that cofire biomass on a commercial basis with an average of 3% energy input from biomass (Fernando, 2012). Cogasification experience is more limited.

In some cases, supplies of indigenous biomass are inadequate to meet demand and a number of countries have found it necessary to resort to imports (often as pelletised wood) from North America, Scandinavia, Russia and parts of northern Europe. For instance, The Netherlands is a major user of biomass, cofiring all of its major coal-based power plants; it is also used by the chemical industry. National supplies are limited hence imports are required. As part of this, the *Sustainable Biomass Import Programme* has been set up to stimulate, support and ensure sustainability requirements are met (Elbersen, 2006). Imported biomass includes Canadian wood pellets, various agro-residues, and palm oil from Malaysia and Indonesia. Some forms of biomass are also exported; for instance, wood waste, RDF pellets, and the paper/plastic fraction from household waste is exported to Germany. In some instances, significant quantities of material, specific to particular regions, have become available. For instance, Spain, Italy, Greece and Turkey have large amounts of olive processing wastes, usually in dry granular or pelletised form. Numerous other forms of biomass are available on a localised basis that often reflect local circumstances and may result from the dominance of a particular industry or production of a particular crop in the locale. Many have potential for energy recovery.

Table 5 Fuel analysis of coals and selected supplementary fuels (Fernando, 2009)

	Hard coal	Brown coal	Wood	Straw	RDF	Dried sewage sludge	Poplar	Corn stover	Chicken litter	Black liquor
LHV, MJ/kg	28	9	12.4	15	23.5	10.6	12.49*	13.10*	9.68*	6.56*
Moisture, %	5.1	50.4	33	10.6	4.1	3	4.80	6.06	11.61	9.61
Volatile matter, %	34.7	52.1	83.2	74.4	82.6	49.5	81.99	75.96	58.21	32.56
Ash, %	8.3	5.1	0.34	6.1	12.2	45.1	1.16	4.75	18.65	52.01
Fixed C, %	57.1	42.8	16.5	19.9	5.2	2.4	13.05	13.23	11.53	6.11
C, %	72.5	65.9	48.7	47.4	56.8	25.0	47.05	43.98	32.00	32.12
H, %	5.6	4.9	5.7	4.5	7.9	4.9	5.71	5.39	5.48	2.85
N, %	1.3	0.69	0.13	0.4–0.78	0.74	3.2	0.22	0.62	6.64	0.24
S, %	0.94	0.39	0.05	0.05–0.11	0.25	1.1	0.05	0.10	0.96	4.79
Cl, %	0.13	<0.1	<0.1	0.4–0.73	0.82	<0.1	<0.01	0.25	1.14	0.07
O, %	11.1	23	45	40.4	21.3	17.7	41.01	39.1	34.45	0.71
Ash fusion temp, °C	1250	1050	1200	850	1120	1200				

* adjusted from HHV values (less 7%)

2.5.2 Advantages and disadvantages of biomass use

Although the use of biomass alone or co-utilised in a coal-fuelled process can provide a number of benefits, its large-scale use can also pose a number of challenges. The heating value and bulk density of biomass is lower than that of coal, consequently, greater volumes need to be collected, handled, transported and stored in order to provide the equivalent amount of energy available from a smaller quantity of coal. Various pre-treatments may also need to be applied. A combination of additional costs and sometimes limited availability mean that large biomass-fuelled units are usually impractical. Smaller unit size and lower heat content usually results in biomass plants being less efficient than coal-fired units (Fernando, 2012). Co-utilisation with coal may overcome some drawbacks and help derive the benefits of both fuel types. In the case of cogasification, as is true with most emerging technologies, a major driver in its large-scale commercialisation is economics. Thus, in locations where energy prices are increasing and suitable supplies of coal and biomass are readily available, alternative approaches such as this become more attractive.

Advantages

Biomass can be an attractive option or addition for a number of applications and is often considered to be the renewable energy source with the highest potential to provide energy. In the case of power generation, there are a number of incentives for adopting renewable energy technologies in general. However, their large-scale deployment may not be problem-free. A major issue is that the output (particularly from wind and solar power) is intermittent and dependent upon prevailing weather patterns. Biomass-fired plants are not weather-dependent, are capable of delivering base load electricity, and integrating more easily with utility grids. To date, several small (gasification-based) grid-connected biomass-to-electricity plants are in operation in Ireland and Germany, and others are being developed in different parts of the world (ZeroPoint, 2012). For instance, in Cambodia, Soma Group is building a grid-connected power plant to gasify waste rice husks, due on line in 2013 (Power Technology, 2012). However, compared to a typical coal-fired power plant, all such units are of small capacity.

Unlike energy crops, some sources of biomass such as garden wastes and demolition wood are often classified as waste products, often of little or no commercial value. They can be expensive to collect and frequently end up in landfills, an increasingly expensive option. Combusting or gasifying can transform these materials from a waste to a feedstock. It also helps reduce land requirements, minimise methane emissions from landfills, and reduce groundwater contamination.

Inevitably there are costs and complications associated with biomass collection, handling, treatment and storage. However, in some situations (for instance, forestry) much of the necessary infrastructure and systems may already be in place. Thus, the addition of a biomass combustor or gasifier may make an attractive option for on-site cogeneration; it may displace or reduce the use of fossil fuels.

Increasingly, the use of biomass is being explored as a cost-effective means of reducing the environmental impacts associated with fossil fuel use. The replacement of a proportion of the coal feed to a power plant with sustainably-produced biomass can help minimise conventional emissions (such as NOx and SO_2) as well as reduce overall CO_2 emissions. For instance, in the USA, new EPA regulations covering maximum allowable emissions of particulates, metals and acid gases (as well as CO_2 considerations) are driving utilities to examine alternative fuel options for repowering existing coal-fired plants. For some, cofiring or repowering with biomass may allow them to meet renewable energy portfolio standards (RPS) requirements (Paskach and Reardon, 2011). Replacing a proportion of a coal feed with biomass helps reduce the carbon footprint of a particular coal-fuelled plant or process (Weiland and others, 2010). If produced on a sustainable basis, biomass feedstocks have the advantage of being carbon-neutral or even carbon negative.

Reducing coal requirements in this way effectively prolongs the lifetime of coal reserves. Combining coal with biomass for combustion and/or gasification can enable a viable transition between fossil and biomass technologies.

Disadvantages

Biomass has various qualities that make it attractive for use in various energy-related processes. However, for use at commercial scale, it may have certain characteristics and limitations that require consideration. The main challenges facing effective large-scale use include:

- possible conflict over land availability and use. Land may be required for the growth of foodstuffs;
- supply is often limited and availability can vary significantly with the weather, seasons and other local factors;
- because of supply limitations, biomass is usually restricted to smaller-scale applications (compared to coal). Economics dictate that biomass plants are usually limited to a maximum of 50–80 MW (Long and Wang, 2011); as most plants are small, capital and production costs are higher than coal, making biomass-based electricity generation expensive. This remains a significant challenge for utilities;
- for efficient operations, the supply of biomass feedstock needs to be regular, reliable and of consistent quality;
- bulk density is usually low and feedstocks may lack durability. Some biomass may require expensive transport, handling and storage, adding to costs;
- moisture content is often high. Furthermore, unlike coal, many biomass materials require indoor storage to control moisture content and minimise decay. Some require drying prior to use;
- biomass generally has a relatively low calorific value that can impact on combustion properties. High levels of moisture reduce the temperature inside a boiler or gasifier, reducing its efficiency;
- many biomass materials are non-friable; this can create problems with size reduction and

grindability. Biomass can come in a range of particle sizes. For utilisation (for instance, for gasification) it needs processing to a uniform size/shape to allow consistent feeding and high conversion rate;
- some biomass feedstocks have high chlorine content and may be hydrophilic;
- biomass energy crops depend on a reliable source of water. In countries with abundant feedstock availability, biomass production is led by fertiliser price pressures, as well as competition for available land and water resources. Many parts of the world experience water scarcities, affecting humans and crop production;
- biomass properties can set demanding requirements for power plants; this includes ash content, melting behaviour and chemical composition. Biomass usually contains less ash than coal although alkaline metals present may cause fouling of heat transfer surfaces.

To overcome the seasonal availability of biomass, in the USA (as elsewhere), NETL has been examining ways to reduce the impact of such variations by cogasifying biomass with coal. The intention is that coal will provide a steady baseline supply that can be supplemented by biomass whenever available. Such combinations would increase economic margins and help ensure that a steady supply of fuel is available to a power plant or industrial facility throughout the year (Vreugdenhil, 2009). In many parts of the world, coal reserves remain relatively abundant and the necessary production infrastructure is in place. For instance, in the USA, over 200 years of supply is considered to be available. In some economies, coal's continued exploitation will remain crucial in providing heat and power to the population. Introducing biomass into a coal-based energy market could help overcome some of coal's perceived drawbacks, allowing the benefits of both fuels to be capitalised on.

Note on nomenclature:

There are a number of definitions applied to wood and other forest-produced materials. However, there is no hard and fast rule as to how they are used, and their precise meaning can differ between countries. However, their generally accepted meanings are:

- **woodfuel** (also wood fuels, wood-based fuels, wood-derived biofuel) – all types of biofuels originating directly or indirectly from woody biomass such as trees and shrubs grown on forest and non-forest lands;
- **fuelwood** (fuel wood) – trees that will yield logs suitable in size and quality for the production of firewood logs or other wood fuel, or the logs of such trees;
- **roundwood** – wood used in its natural state as felled (with or without bark) for various industrial purposes, either in its round form (for transmission poles or piling) or as raw material to be processed into industrial products such as sawn wood, panel products or pulp:
- **pulpwood** – wood used in making pulp for paper;
- **shortwood** – pulpwood less than 10 feet (3 m) in length, or trees or portions of trees delivered in product lengths of less than 15 feet (4.6 m). These are often defined as logs short enough to be stacked across the deck of a truck;
- **sawlogs** – logs taken to be manufactured in lumber.

2.6 Case study – forest residues

Large tracts of the earth are covered with forests, many of which are already exploited commercially. In some countries, wood and associated residues are produced in considerable quantities, although in others, only a small proportion of the residues potentially available are used. The distribution of

Table 6 Global distribution of forests (FAO, 2010)

Region/sub-region	Forest area, 000 ha	% of total forest area
Eastern and Southern Africa	267,517	7
Northern Africa	78,814	2
Western and Central Africa	328,088	8
Total Africa	674,419	17
East Asia	254,626	6
South and Southeast Asia	294,373	7
Western and Central Asia	43,513	1
Total Asia	592,512	15
Russian Federation	809,090	20
Europe (excl. Russia)	195,911	5
Total Europe	1,005,001	25
Caribbean	6933	<1
Central America	19,4990	<1
North America	678,961	17
Total North and Central America	705,393	17
Total Oceania	191,384	5
Total South America	864,351	21
World	4,033,060	100

forests by region and sub-region are given in Table 6. The top five individual countries, in order of size, are the Russian Federation, Brazil, Canada, the USA, and China.

Forest-derived residues from logging and associated downstream timber processing operations have great potential for energy production. In some locations, such as parts of mainland Europe, downstream residues are already fully utilised, hence not available for energy recovery. However, other forest-derived materials may be available and have potential as a fuel source.

During forestry operations, high quality logwood is normally directed to a saw mill. Other parts of the tree may be discarded, even though they may have the potential for energy recovery. These residues comprise combinations of small trees, distorted wood, small round wood, tree branches, stumps, tops, bark, and brash. Depending on the location, the type of tree, and harvesting methods used, the ratio between these may vary. All such residues are typically of low value and low density. It is not uncommon for up to 60% or more of the total harvested tree to be left in the forest and for non-commercial species to be subjected to slash and burn, or merely felled and left to rot. Practices such as sawing and squaring logs in the forest, rather than at the saw mill, can waste a further 8–10% and 30–50% respectively (FAO, 2012a).

Depending on location and other local circumstances, different harvesting methods may be used; each produces different combinations of residues (Figure 8). For instance, in the UK, five major harvesting systems are currently in use:

- ***pole-length harvesting* –** the tree is de-limbed at source and the entire trunk extracted in one piece; the crown and branch are discarded;
- ***part pole-length harvesting* –** similar to pole-length, but sawlogs (the part of a tree stem that will be processed at a sawmill) are removed from the main stem at the stump;

Figure 8 **Tree harvester** (photograph courtesy of Logging On Newsletter)

- ***shortwood harvesting*** **–** the tree is de-limbed and crosscut into different products at the stump with saleable produce (including woodfuel) extracted. The stem, crown and branch wood down to a specified size are discarded;
- ***terrain chipping*** **–** wood chipping takes place at the stump as part of the harvesting process. The whole tree is used;
- ***whole-tree harvesting*** **–** the entire tree is used, leaving few or no residues. It can combine elements of other harvesting systems, with conventional roundwood products extracted and residues chipped either in the forest or at the roadside, or the whole tree chipped.

Prior to transport, residues may be chipped or reduced in size. This can be carried out at the felling site (terrain chipping), on an adjacent roadside (landing chipping), at a terminal, or at a centralised plant.

Forest residues often require further drying before they can be used. As harvested, they can have a moisture content of between 30% and >65%, although for many applications, this needs reducing to less than 25%. Various pre- and post-harvesting techniques are sometimes used. Although forest residues can be an attractive energy source, collection, handling, transport and pre-processing costs must be factored in. In order to be economically viable, these all need to kept as low as possible. At times, their seasonal nature may also restrict availability. Unlike fossil fuels that usually occur in large deposits and can be produced at a constant cost, forest-based fuels tend to be scattered and require gathering from a large number of separate locations. Thus, production costs depend on many steps within the logistic chain (such as harvesting, sizing, and transport) as well as the scale of operation, the biomass source, and the quality requirements placed upon it. The largest component in procurement costs is transport.

Apart from residues associated directly with logging operations, there are also a range of materials that result from downstream treatment of the felled trees; some arise during processing at the saw mill. The amounts generated can be considerable. In typical saw mill operations, ~45–55% of the log input becomes waste. However, the scale differs from plant to plant, depending on factors such as the type of wood and its properties, the nature of the processing plant, and its mode of operation. Wood waste and bark from such plants is produced in a wide range of sizes with varying moisture contents; often, a significant portion remains unused. The main residues from wood processing comprise:

- bark – depending on size and species, around 10–20% of the total log volume is bark;
- coarse residues – this includes slabs, edgings, off-cuts, veneer clippings, sawmill and particleboard trim;
- cores – from logs peeled for plywood manufacture;
- sawdust – a product of all mechanical wood processing operations;
- planer shavings result from dimensioning and smoothing lumber;
- sander dust produced during the abrasive sanding of lumber and other products during the finishing stage;
- particleboard waste.

Not all may be available in sufficient quantities to make a viable fuel source and some may already have other higher-value commercial applications. The value of wood residues for energy production will also be affected by the heating value. This depends heavily on the individual species and the part of the tree being used – it varies between 17 and 23 MJ/kg of (oven dry) wood. Generally, softwoods have higher caloric values than hardwoods, with an average value of 21 MJ/kg for resinous woods and 19.8 MJ/kg for other types. The wood's value as a fuel is also affected by moisture content, particle size, and the type and efficiency of combustion equipment being used. Freshly logged wood generally has a moisture content of 50–55%, although this varies according to species, age, and the portion of the tree from which it originated. There can be other seasonal-related fluctuations; for instance, storage during spring and summer can reduce moisture content by 10–25 % (FAO, 2012a). Artificial drying of wood-based residues can be accomplished by a variety of means, although all have cost implications. Overall, the handling, treatment and storage of forest residues and wood wastes can be considerably more costly and complex than that required for conventional solid fossil fuels.

With regard to storage, the type of system deployed will be determined largely by the physical form, moisture content, the frequency and reliability of deliveries, land availability, climatic conditions, the need for air drying, and the volumes involved. Depending on circumstances, residues may be stored outside or in covered facilities. Outdoor piles are the least expensive option and are generally suited for stocks of 20–30 days capacity of green forest residues, bark, moist wood slabs or chips. However, precautions must be taken to avoid deterioration and fires from overheating and biological action. The temperature of stored biomass can increase to 60°C within a few days, although no such increase occurs if the particle size is greater than 20 cm (Fernando, 2012). High dust and spore concentrations in the stored fuels can also give rise to dust explosions, resulting in health and safety problems. Covered storage systems are more expensive and used for materials that are readily wind-borne or freely absorb moisture, such as dry sawdust, planer shavings and sander dust. Where biomass is stored in enclosed structures for long periods, significant release of CO, CO_2 and CH_4 can occur and may require venting for personnel protection and fire prevention. A study of US utilities considering co-utilising biomass with coal revealed that a primary concern was the space requirements for the storage and processing of the biomass (Princeton Energy Resources International, 2003).

In some circumstances it may be appropriate to densify residues via a compaction process. This generally produces briquettes or pellets. Pellet production requires feedstocks to be reduced to the size of sawdust and dried to ~12% moisture content before compaction or extrusion. Pelletising produces a product with good handling and storage characteristics, with four times the energy content of woodfuel. This greatly reduces transport costs (FAO, 2012a). However, the process is capital-intensive and is strongly influenced by transport distances involved.

In Europe and Scandinavia, counties such as Finland and Sweden use large amounts of forest residues. Bioenergy from these is an important part of the Swedish energy system, and the country is a world leader in this field. Most of the residues (>70%) are derived from final tree fellings. The use of forest residues for energy purposes is also increasing in the UK, Ireland and Germany.

A major driver for increased biomass use is in mitigating CO_2 emissions from energy production processes; the greater use of forestry residues could play a part in this. Recently, there has been some controversy regarding the timing of the carbon savings that result from biomass use, and the concept of carbon payback time (or so-called carbon debt). However, proponents such as European Biomass Association (AEBIOM) suggest that studies critical of using biomass in this manner have failed to fully take into account actual sustainable harvesting and biomass feedstock utilisation practices. Neither have they taken note of the certification of bioenergy. In some parts of Europe and the USA, the area of land under sustainable forestry is actually increasing. A demand for wood generates investments in forest management and new forest plantations. During the past two decades, the European carbon stock has increased by 26% as a result of this increased forest area (an extra 3.5 Mha between 2000 and 2010). Only around two thirds of this new cover is actually being harvested. Many forests have continued to increase in size, even though the use of bioenergy has been increasing at the same time (AEBIOM, 2011). Much of this has come from forest residues that would have no other use. Instead of being wasted, increasingly, this is being used to replace fossil fuels and to deliver socio-economic benefits in rural communities.

2.6.1 Future potential as an energy source

Despite increasing interest in the use of forest residues, in some parts of the world, only a small proportion is actually harvested for energy production and/or other applications. In some places, none is used; for instance, in some EU countries, no logging residues are collected. This may be a consequence of the remoteness of the resource or other geographical or topographic limitations. However, there are regions where residues are readily accessible and available in sufficient quantities to make their use viable. Despite this, forest residues have remained a largely underexploited resource. Selected countries/regions with the potential to make significantly greater use of this resource are considered below.

In **Europe**, in many EU Member States, wood and forestry-derived products form a major energy resource; these comprise forestry residues, secondary residues, and wastes from wood processing industries. In 2010, forest and other wooded land covered ~178 Mha, around 40% of the EU-27's land area. The overall extent of forest cover is actually rising, increasing by 5% during the past two decades. However, the individual amounts vary widely between countries. European countries with the largest wood and waste production are Finland by far, followed by France, Austria, Sweden, Poland and Germany. These materials are a major asset for energy production although only ~60% of the net annual increase in forest available for wood supply is currently being harvested.

Current total EU-27 round wood production is 74 Mtoe; additional supplies potentially available are probably ~54 Mtoe. It is estimated that, potentially, wood and wood wastes could provide nearly 45% of EU-27 renewable energy production (Biomass Futures Project, 2011). Various forecasts suggest that biomass from forestry could increase from the 2006 level of 60 Mtoe, to 65 Mtoe in 2015, and 73 Mtoe in 2020 (AEBIOM, 2011). However, some European forest reserves are nearly fully-exploited for sawn timber and other industrial uses. Thus, in some countries, the adoption of large-scale energy generation from biomass would be heavily dependent on imported biomass, making the EU a net biomass importer (Coffey, 2011).

With the exception of Finland and Sweden, forest residues have the potential for much greater utilisation. Within the EU, the maximum potential of all forest-derived fuels is estimated to amount to 543 million m^3 (94.6 Mtoe) of which logging residues make up 251 million m^3 (43.7 Mtoe). However, as elsewhere, it is not practical to harvest this in its entirety; limiting factors include inaccessibility and environmental and biodiversity reasons. Thus, the harvestable (technical) potential is estimated to amount to 140 million m^3 (55–60% of the maximum forest residues potential). This comprises 72 million m^3 of residues from current fellings, plus 68 million m^3 of roundwood and other felling-related residues (such as13 million m^3 of stump wood). Overall, less than 5% of the EU's harvestable potential is currently utilised (AEBIOM, 2009). This could be increased significantly though the development of national support schemes and other incentives.

Within Europe as a whole, the largest volumes of available felling residues (excluding stump wood) are in Sweden, Finland, France and Germany (Table 7). When stem wood from additional fellings and other residues is added, the available felling residues for these countries amounts to ~20 million m^3; for comparison, Sweden's total alone amounts to nearly 25 million m^3. As in other regions, the main barriers to the greater use of forest residues are harvesting, handling and transportation costs.

In the **Russia Federation**, forests cover ~800 Mha (roughly 20% of world's forest resources) and the country is the world's wood richest country. The majority of existing forest industry is located in the European part of Russia, where most of the timber has been already cut. The main timber resources are located beyond the Urals, where timber processing industries are barely developed. Overall, the utilisation rate of Russian forests is low (IEA Bioenergy, 2011a). The most productive forests are in Northwest Russia; 17% of all Russian timber is concentrated in this region that also contains 60% of forests in the European part of the Federation. Generally, the forest sector is not a priority of national policy. Although the country accounts for >20% of the world forests, its share in the global forest products trade is less than 4%.

Table 7 Felling residues available – Top five EU producers (AEBIOM, 2009)

Country	Total felling residues, million m^3/y	Available residues of felling, million m^3/y	Available residues of balance, million m^3/y
Finland	26.7	11.4	6.3
France	22.6	8.6	10.2
Germany	23.4	6.0	13.9
Poland	12.5	3.6	2.9
Sweden	35.2	15.0	6.9
Total EU-25	173.2	62.6	63.6

As elsewhere, the roundwood supplied to wood processing units generates residues. These, together with other residues such as bark, sawdust and waste-wood, constitute a huge, under-utilised resource. For example, harvesting and mechanical wood processing alone produce ~30 million m^3 of residues, potentially suitable for energy production (Energy-Enviro Journal, 2010). Efforts to increase activity in parts of the sector are under way. For instance, wood pellet production is increasing, with new large capacity mills being built. Around 50 new mills are expected to be established in the near future, several with capacities of between 70 kt/y and 125 kt/y.

Although the utilisation of forest residues is likely to increase in the coming years, the remoteness of some sites and lack of transport links will limit activities. If transport distances are more than 50 km, profitability suffers. However, the potential for using forestry-derived materials is considerable and it is expected that the manufacturing of forestry-based products will grow in the period up to 2030 (FAO, 2012b). According to the Federal Forestry Agency, annual forest waste in Russia amounts to at least 100 million m^3 a year. This has the potential to produce ~20 Mt of pellets (IEA Bioenergy, 2011a).

Significant areas of **North America** are also well endowed with major forests. The land base of the **USA** encompasses nearly 915 Mha. About a third (303 Mha) is classified as forestland, nearly a third of the country's total land area. It estimated that ~368 Mt/y (dry) of sustainably removable biomass could be produced from the country's forestlands. This comprises 52 Mt of fuelwood, 145 Mt of residues from wood processing mills and pulp and paper manufacturing, 47 Mt of urban wood residues, 64 Mt of residues from logging and site clearing operations, and 60 Mt of biomass from fuel treatment operations to reduce fire hazards. All of these forest resources are viewed as being sustainably available. Currently, around 75% of biomass consumption in the USA (~142 Mt, dry) comes from forestlands although it is considered that significantly greater quantities of forest- derived residues could be used in the future (Perlack and others, 2011). Some estimates suggest that the total amount of biomass available would be between 325 and 423 Mt/y (dry) (Weiland and others, 2010). Thus, there is the potential to hugely increase the use of forest residues for energy production. In addition, if waste smallwood was harvested for fuel, this could supply a further 15–59 Mt/y. US harvesting technologies are considered to be generally well developed, although the use of forest residues for energy production remains patchy. Considerable quantities are generated by logging and other operations; these have significant potential although, as elsewhere, the sometimes high cost of transport to the point of utilisation acts as a deterrent. In the short term, the biggest potential market for forest residues would appear to be cofiring in existing coal-fired power plants.

Several US states are actively considering the increased use of forestry residues as part of their RPS requirements. For instance, New Mexico is currently pursuing new state legislation that includes a senate bill to permit Renewable Energy Certificates to be issued for electricity produced from thermal energy derived from biomass materials such as forest slash created by tree thinning and fire reduction

Table 8 Annual Canadian forest biomass, kt (oven dry) (Bradley, 2007)

Province	Mill residues	Bark	Roadside	Total	Total, economic
British Columbia	1,000	0	9,280	10,280	1,280
Alberta	451	0	992	1,443	1,195
Saskatchewan	164	181		345	345
Manitoba	13	0		13	13
Ontario	476	839	1,497	2,812	1,989
Québec	100	707	940	1,746	1,276
New Brunswick	69	32	144	245	245
Nova Scotia	43	19	0	62	62
Newfoundland	30	2		32	32
Totals	2,347	1,780	12,853	16,980	15,438

operations. Most such woody biomass residues are not currently used. It is envisaged that these would be used to fuel small- to medium-sized local power plants. There is support for the bill from a number of rural electric cooperatives.

Surprisingly, the amount of woody biomass used in the USA declined during 2012. This was blamed on the falling price of natural gas – this decreased by ~45% during 2011. This had the effect of reducing the urgency for investing in woody biomass projects. Most of the decrease in wood usage has been for the domestic electricity market, although the pellet industry continued to expand its capacity to serve the growing demand in Europe. Despite the decrease, proposals for more facilities utilising woody biomass were announced during 2011 and 2012 in both Canada and the USA, with some projects nearing completion and others in start-up mode. The USA currently has around 450 proposed and operating bioenergy projects that include the production of wood pellets and liquid fuels, plus electricity generation and cogeneration.

Canada's forests are similarly large and diverse. More than 400 Mha of Canada's land (44%) is forested, mostly under provincial jurisdiction. The country is a major forest products producer and is one of the world's largest pulp, paper and lumber producers. Its large, well-developed forestry sector is a major exporter of wood products. From its pulp mills and saw mills, the forest products industry produces various woody biomass by-products such as bark, sawdust and shavings (>21 Mt, dry). Over 60% of Canada's renewables-based generating capacity is supplied by biomass.

Canada has extensive experience with full tree chipping, both in-forest and at the roadside, but little experience with treating harvest residue or thinnings. A large proportion of saw mill wastes are already utilised for on-site energy production. As a result, forestry and energy companies and provincial governments are examining the greater use of tree harvesting residues; at the moment, much of this is simply burned at the roadside. The quantities of residues ('harvest slash') available from tree harvesting vary between provinces. Depending on economics (such as transport costs), there is considered to be significant potential for the greater utilisation of both saw mill wastes (such as bark, often unused) and harvest residues. Total forest-derived biomass available with the potential for utilisation as a fuel source or for other applications is shown in Table 8.

Asia-Pacific region

The use of biomass for energy purposes varies significantly between the countries making up the region. Some are not major producers or consumers of biomass, whereas in others, it has long been a

Table 9 World and Asia-Pacific region wood fuel use (Gumartini, 2009)

	World			Asia-Pacific region		
	Fuelwood, million m^3/y	Charcoal, Mt/y	Woodfuel, million m^3/y	Fuelwood, million m^3/y	Charcoal, Mt/y	Woodfuel, million m^3/y
2010	1602	55.8	1941	721	6.3	759
2015	1591	61.2	1861	691	6.4	730
2020	1573	66.3	1975	659	6.6	699

major source of energy. In some, forest residues are (or could be) a major resource. Recent estimations made by the Asia-Pacific Forestry Commission suggest that mill and logging residues available in the region amount to ~70 million m^3/y (FAO, nd). In a growing number of countries, driven mainly by concerns over energy security and increasing overall demand, the intention is to make greater use of indigenous biomass.

As elsewhere, there can be competition with land used for food production. However, in all key Asian countries, the area needed for food production has stabilised and seems unlikely to increase significantly. Additional food grain needs are expected to be met by increased crop productivity and intensity. Overall, there are large areas of degraded non-crop and marginal crop lands that are potentially available for bioenergy production, either in the form of new forests or for growing energy crops. The dominant energy consumers of the region have set targets for biofuels in general, thus increased production and utilisation is expected in countries that include China, India, Japan, Malaysia, Indonesia, and Thailand (Ravindranath, 2008). For instance, in the case of the latter, the Ministry of Energy has set a renewables target of 25% in total energy consumption by 2021, with a high priority being given to development of second generation biofuels. As part of this, the Federation of Thai Industries is investing in a pilot biomass gasification project in Saraburi. This will use imported Spanish technology to gasify fast-growing energy crops and MSW. A total of five plants may be set up within the next few years.

Wood-based fuels are of particular importance in many Asia-Pacific countries, who between them consume more than 40% of the global wood fuel total (Table 9). The high population density in much of the region is a major factor; the region is home to more than half of the world population, and includes three of the most populous countries – China, India and Indonesia. Almost two thirds of this population lives in rural areas, where traditional biomass is the most important source of energy. Globally, woodfuel consumption is expected to continue increasing towards 2020, reaching ~2 billion m^3/y. However, within the region, the consumption trend is downwards, although absolute volumes are still considerable. Despite the dip, wood will remain an important source of energy in the future (Gumartini, 2009).

Australia has ~4% of the world's forests, the sixth largest forest area in the world. These cover a fifth of the continent and comprise 147 Mha of native forests plus 2 Mha of plantations. The country's forests are diverse. Native forest types are dominated by eucalypts (78%) followed by acacias (7%) and melaleucas (5%), whereas around half of the plantations are made up of conifers (mainly Pinus radiata). Multiple-use public forests, where timber harvesting is generally permitted, cover 9.43 Mha, or ~6% of Australia's total native forest estate. In 2010-11, 26.5 million m^3 of wood (used for sawn timber and other products, paper and paperboard) was harvested from production forests; around two-thirds came from plantations with the remainder from native forests. Other uses include the production of wood chips and in 2010-11, over 5 Mt were exported, mainly to Japan (ABARES, 2012). The country's total potential forestry biomass residue is estimated at 12 Mt/y (dry) (New South Wales Government, 2011). Current estimates suggest Australian wood waste has the potential to generate up to 3000 GWh of electricity by 2020 (nearly 7% of the 2020 Renewable Energy

Technology target). However, although some states appear to have considerable potential for using forest residues as an energy source, in 2012, the Federal Parliament banned its use for biomass-fuelled projects. Despite having the highest area of forest per capita of the developed nations, Australia lags behind in the use of bioenergy, which represents just ~ 0.9% of energy production (Australian Climate Change Authority, 2012). It is estimated that with the appropriate permissions and incentives, the country could generate at least 50 Mt/y of economically available biomass, with potentially millions more coming from sustainable forest management (Lang and others, 2012).

In **New Zealand,** there is growing interest in making greater use of the country's biomass (both alone and in conjunction with coal) for a range of applications that include heat, power and liquid fuels. In this respect, the country has considerable potential. The main drivers for increasing the use of biomass are policy and environmental considerations, the increasing cost of natural gas and petroleum, and climate change issues. A national biomass energy strategy was launched in 2010 aimed at promoting economic growth by increasing production and use of biomass-derived energy and biofuels. A major target is to increase bioenergy from the current 8.5% (consumer energy) to 25% by 2040; this will include 30% of the country's transport fuels. The target will be implemented in three phases: foundation building (2010-15), development (2015-20), and expansion (2020-40) (Li, 2011).

Studies have identified significant opportunities for developing a purpose-grown forestry-based biomass resource capable of meeting national-scale demands for consumer energy. This could utilise low productivity grazing land on steep terrain with low current financial returns. Over 60% (9.3 Mha) of New Zealand's available productive land is hill country which is unsuitable for cropping but potentially suitable for forestry. A further 23% (3.6 Mha) is unsuitable for pasture. Given the country's economic drivers (agricultural exports) and land resources, the use of steeper lands to grow biomass through additional forestation could provide a large-scale solution to carbon neutral energy supply. There are millions of hectares suitable for forestry that are currently in scrub, gorse or low-to-moderate productivity grazing (Hall, 2010).

As part of a major study, four afforestation scenarios of different geographical areas were considered (0.8, 1.8, 3.3 and 4.9 Mha of purpose-grown forest). It was estimated that recoverable forest biomass production of 640 to 900 m^3/ha was possible from a 25-year rotation, biomass-focused forest management regime. A significant percentage of the crop could also be used to produce saw logs for traditional markets, with residues used for energy recovery. An advantage of adopting a forestry-based scheme is that yields obtainable would be significantly higher than those obtained from arable crops. For example, if producing liquid fuels, canola could yield 1360 L/ha/y of biodiesel, whereas forests could potentially produce the equivalent of 2400 L/ha/y (Hall and Jack, 2009). It was concluded that the development of large-scale bioenergy from forestry on low quality lands would be viable in terms of scale and ability to compete for the land on an earnings basis. Currently, the biomass sources with the biggest potential are viewed as being forest residues and associated downstream processing and other wastes. As noted, there is considerable potential for significantly greater use in the future (Table 10).

Table 10 Biomass available from New Zealand's forestry activities, PJ/y (Hall and Jack, 2009)

Type	2005	2030	2050
Forest residues	14.6	34.4	29.5
Wood process residues	7.0	9.1	18.4
Municipal wood waste	3.5	2.2	2.9

The current annual production of woody biomass residues from plantation forestry alone is estimated to be between 4 and 6 Mt. Wood-based energy provides ~5% of New Zealand's total energy supply, being used mainly by the timber industry and for residential applications. The use of biomass from forestry operations is viewed as being more efficient in its land use than seed or nut crops as the entire biomass volume can be used, as opposed to just a specific part of the plant.

Table 11 Types and quantities of forest biomass available in China for energy production (Zhang, 2010)

	Available harvesting area, Mha	Available woody biomass technically available, billion t/y	Available woody biomass available for energy production, Gt/y
Forestry – branches and residues	142.79	0.153	0.04
Forestry energy crops	3.03	0.048	0.03
Shrubs coppicing	45.30	0.15	0.05
Branches and residues from forest thinning	91.00	0.239	0.05
Branches and residues from commercial forests	21.40	0.15	0.03
Branches and residues from bamboo forests	4.84	0.05	0.01
Branches and residues from outside forests	–	0.03	0.01
Others	4.2	0.137	0.03
Total	312.56	0.957	0.29

In terms of woody biomass resources, there are two species of particular interest, similar to those highlighted in Australia. These are Pinus radiata (or Monterey Pine) and Eucalyptus nitens, a Eucalypt species. Pinus radiata makes up more than 90% of New Zealand's plantation forests and includes the Kaingaroa Forest, the largest planted forest in the world. It grows quickly and is widely available. Eucalyptus nitens is also fast growing and is cultivated in many parts of the world (Levi, 2011). There is considerable potential for cogasifying biomass species such as these with indigenous lignite. Biomass gasifiers are available from several technology developers (such as Fluidyne Gasification and Windsor Engineering) and RD&D on biomass gasification and cogasification is being pursued by CRL Energy Ltd and the University of Canterbury. CRL is developing an oxygen-blown fluidised bed gasifier, with the aim of cogasifying up to 45% biomass with indigenous lignite/coals (Li, 2011).

As with other forms of energy, potentially, **China** has vast biomass resources available. Significant parts of the country are covered with large and diverse natural forests. There are also large areas of plantation. According to the Seventh National Forest Resources survey, China has 195.5 Mha of forests, covering a fifth of the country. Plantations amount to 62 Mha. Although the recovery of forest residues is well developed in some countries, the process is still at an early stage in China although new initiatives and incentive policies are being pursued with a view to making greater use of this largely untapped resource. China's central government has proposed a biopower target of 24 GW by 2020, encouraged by a series of relevant policies. However, currently, there is only limited use of most forest-derived materials. Since the 1990s, wood pellets (mainly for boiler fuel) have been produced although mainly on a small scale (Zhang, 2010). Greater utilisation is hampered by underdeveloped forestry residues supply infrastructure, lack of production standards and pricing system, lack of official data on national production and trading, and the relatively high costs involved. The types and quantities of forest biomass available for energy production are shown in Table 11.

In parts of the country there are significant areas of largely degraded and unused land with the potential for growing trees and bushes that could be harvested for energy use. For instance, Southwest China has been officially targeted as the area for the developing the growth and utilisation of Jatropha,

Table 12 Current and proposed growth of Jatropha in China (Ravindranath, 2010)

Province	Estimated current area in use, ha	Planned area, ha
Guizhou	1300	26,667
Sichuan	20,000	333,333
Yunnan	50,000	666,667
Total SW China	71,300	1.03 million

a shrub that can be used for the production of a feedstock suitable for biodiesel production. Already grown in some regions, significant increases in production are planned in several provinces (Table 12) (Ravindranath, 2010).

Over the past decade, various studies have assessed the extent of land availability in **India**. These defined different categories of land potentially available for producing biomass and covered degraded forests, uncultivated land, and land unsuitable for normal cultivation. Depending on the criteria used, the total area of land identified varied between 41 and 130 Mha. Recent estimates suggest that the country has ~50 Mha of degraded wasteland that lie outside the areas demarcated as national forests, and another 34 Mha of protected forest area; much of the tree cover in the latter is severely degraded.

There are also considerable tonnages of forest residues and urban green waste available. In early 2012, plans were announced aimed at the greater development of forest biomass in the period up to 2020. The aim is to produce 1.5% of India's renewable energy from forest biomass by 2015, and 2% by 2020. The amount of biomass generated from agriculture, forestry, and plantations has been assessed as between 540 and 565 Mt/y. Of this total, 189 Mt/y would be available for electricity generation and other applications. An estimated 16 GW of grid-quality electricity could be generated from such residues (Clarke Energy, 2011) with, potentially, a further 5 GW generated using bagasse. The estimated total biomass power potential lies between 21 and 25 GW (Malik and Stephan, 2012; Sukumaran, 2009).

Indonesia has many forested areas. Sustainable forestry feedstock comes from rubber wood (2.8 Mt/y), woody residues from logging, plus wood processing residues (8.3 Mt/y). Studies indicate a potential for collected annual forest biomass of 135 Mt/y (dry) (Netherlands Programmes for Sustainable Biomass, 2012). Forestry residues have the potential to become a significant energy source, although they are currently underexploited.

In peninsular **Malaysia**, around seven main types of biomass are available, totalling ~12.2 Mt/y. Oil-palm residues contribute roughly three quarters of this total, followed by rice and forestry residues. Significant areas of the country are forested (Table 13) and the country produces a large volume of wood. Forestry operations are important to the country's economy and Malaysia is a significant exporter of wood and wood-based products. Around two thirds is supplied to other Asian countries. More than 4100 sawmills and other wood processing plants are in operation. Forestry and wood residues (logging and saw milling residues, plywood and veneer residues, and secondary processing wastes) are considered to have the greatest potential for energy production. However, at the moment, only 60% to 65% of these are currently utilised (Mekhilef, 2010). Forest residues comprise 5.1 million m^3/y of logging wastes, plus 4.7 million m^3/y from wood processing and other manufacturing activities. The total amounts to 9.83 million m^3/y.

Table 13 Malaysian land use, Mha (Norchahaya binti Hashim, 2012)

	Total land area	Total forest area
Peninsular Malaysia	13.2	5.9
Sarawak	12.3	8.0
Sabah	7.4	4.3
Total Malaysia	32.9	18.2

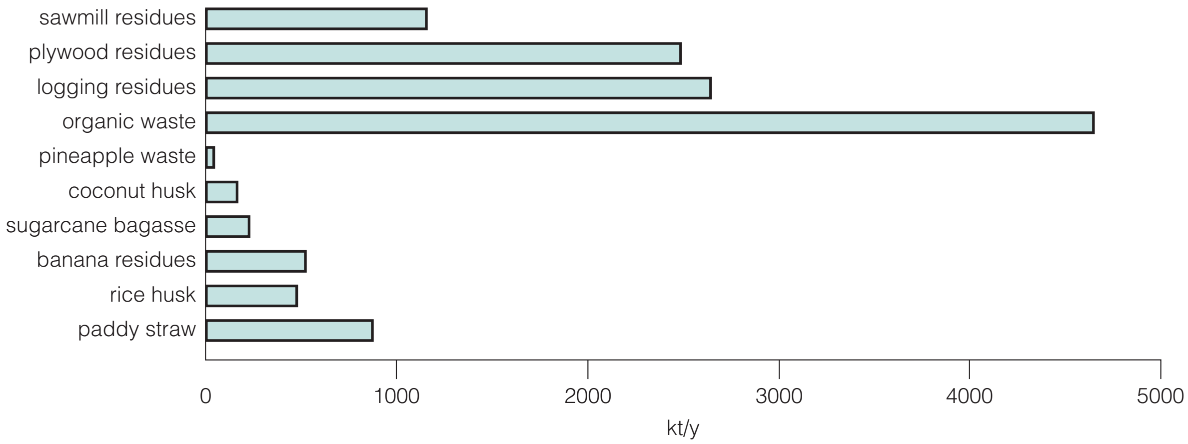


Figure 9 Main Malaysian biomass resources (Mekhilef, 2010)

The biggest source of biomass is palm oil-derived material (81,500 kt/y). Forestry-derived residues and other non-palm oil-derived biomass available are shown in Figure 9. After various materials originating from palm oil production, the largest potential resources are forestry-based.

In **Sri Lanka**, total forest cover amounts to 1,942,000 ha or 29.6% of the land area. Interest in using this as a source of biomass for energy recovery has increased and changes are being made as to how the forestry sector is managed. Efforts are under way to establish a permanent forest estate and to classify forests into appropriate management classes. The sustainable supply of biomass from natural forests has been assessed at 1.46 Mt/y plus 0.5 Mt/y from forest plantations. At the moment, this resource is underutilised. Biomass available from other sources includes ~5.3 Mt/y from agricultural lands. In total, the country's biomass supply is nearly 9 Mt/y (Government of Sri Lanka, 2009).

In other countries of the region, on a localised basis, biomass has long been an important source of energy. For instance, in **Thailand**, various types of agricultural and forestry residues are available. In the case of agricultural residues, an estimated 72 Mt was available for energy production in 2010. The major sources were sugar cane, paddy, and oil palm; these comprise more than 95% of the total. However, partially because of the cost of collection and transport, only about 5 Mt/y is currently used. Although nearly a third of the country is forested, biomass from forestry operations is much less. The two main sources of industrial wood are eucalyptus and rubber plantations; this generates some wood chips and particles, although firm data on the total is lacking. Logging is banned in natural forests.

Although ranked 109th globally by land mass, and despite lacking fuel resources, **South Korea** is in the top ten for power consumption. Under a compulsory quota introduced in 2012, power generators must now deliver 2% of their energy from renewables; this will increase to 10% by 2022. Biomass (alone and cofired with coal) is expected to be the biggest player, possibly providing up to 60% of total renewable electricity. A major reforestation programme is under way. Of the country's total land area of 9.7 Mha, around 6.5 Mha (~65%) is now forested.

Like South Korea, **Japan** is also exploring ways to increase the uptake of biomass for energy production. Here, solar power is being promoted strongly although biomass is also expected to make an increased contribution although forest residues amount to only 3.7 Mt/y. An estimated 400,000 ha of unused arable land has been identified for possible biomass projects (Milbrandt and Overend, 2008).

Currently, although countries such as Thailand, Indonesia and Malaysia use significant quantities of biomass, Japan and South Korea look set to dominate the sector in Asia; both are instrumental in driving international trade (Evans, 2013). Imports for both countries are likely to come initially from Asian pellet suppliers, although in the longer term, supplies from North American, Australia and New Zealand could become a reality.

2.7 Non-forestry-derived sources of biomass

Forestry wastes and residues are not the only types of biomass suitable for energy recovery and other important sources include agricultural wastes and energy crops. The cost of different biomass materials can vary considerably. Some types of wastes can be virtually free, whereas energy crops can be much more expensive. Use of the latter, either alone or co-utilised with coal, may only be viable if the additional costs are subsidised (Fernando, 2012). However, depending on local circumstances, the quantities of such materials available may be much greater than those from forestry operations. As with the latter, their availability (as well as future potential) varies, often reflecting the climate, geography and topography of different countries and regions. The situation regarding non-forestry-derived biomass for selected areas is examined in the following Section.

Within **Europe**, the gross inland consumption by fuel type of the 27-EU Member States is ~1700 Mtoe. Renewable energies account for 152.6 Mtoe of this total, with biomass providing the biggest share (69% in 2009). Across much of Europe, the use of most types of renewable energy has increased considerably in recent years. Its contribution to European final energy consumption was 96 Mtoe in 2005, 132.2 Mtoe in 2010, and is forecast to reach173.4 Mtoe by 2015. Beyond that, the situation is less clear and will be influenced by political and other decisions taken. However, by 2020, renewable energies are forecast to amount to between 232 and 276 Mtoe, rising to 364–425 Mtoe by 2025, and 498–572 Mtoe by 2030. Bioenergy is expected to make the biggest contribution (Table 14).

The use of biomass for electricity generation is expected to continue increasing in Europe and forecasts suggest that by 2020, nearly 20% of Europe's renewable electricity will be produced from biomass. In 2005, an estimated 69 TWh of electricity were generated from biomass sources. By 2010, this had increased to 113 TWh; it is expected to reach 167 TWh in 2015 and 230 TWh in 2020. The largest increase will come from solid biomass, increasing from 77 TWh in 2010 to 160 TWh in 2020 (AEBIOM, 2011).

Within the EU-27 territory, the *Utilised Agricultural Area* represents 38% of the total land mass, although individual national shares vary widely. Arable land represents almost a quarter of the entire territory, and permanent grassland represents 14%. Land under permanent crops accounts to less than 3%, although again, individual national amounts vary widely. The main types of non-forestry biomass available comprise agricultural residues such as straw, and energy crops such as poplar, rapeseed and maize. It is estimated that potentially, between 10% and 30% of European arable land could be used for growing energy crops. However, some (such as micanthus and switchgrass) also have the potential for growing on marginal land not suitable for food production. Europe currently has ~5.5 Mha of agricultural land used for dedicated bioenergy crops. Most is used for oil crops that are processed into biodiesel, with the balance used for ethanol crops, biogas, and perennials. At the moment, dedicated energy crops are only important in some EU countries (predominantly France and Germany) although there are also significant areas of oil crops for biodiesel in the UK, Poland and Romania. An estimate produced by the University of Copenhagen (Fischer and others, 2010) suggests that by 2030, the EU-15 countries will have a bioenergy potential of 1.2 EJ from agricultural residues. In Europe, an estimated 85,000 ha of land is used for short rotation forests and energy crops, produced mainly for combustion purposes.

Table 14 Contribution of renewable energy technologies to European final energy consumption, Mtoe (AEBIOM, 2011)

Technology	2005	2010	2015	2020	2025	2030
Wind	6	14.7	25.8	42–55	64–75	86–95
Hydro	29	29.8	30.6	32–34	32–34	33–34
Bioenergy	60	82.2	103.8	134–145	184–200	236–255
Total RES	96	132.3	173.4	232–276	364–425	498–572

Table 15 Domestic European (EU-27) biomass supply (2006-20), ktoe (AEBIOM, 2011)

	2006	2015	2020
Biomass from forestry	60.094	65.088	72.692
Biomass from agriculture and fisheries	15.420	29.183	40.555
Biomass from waste	9.397	12.190	16.366
Total biomass supply	84.913	106.462	129.614

The overall European supply of biomass is expected to increase substantially over the next few decades. Forestry and forest-based industries currently provide the bulk of supply, and this will still be the case in 2020 (over half of the total). However, a large increase is expected to come from the agricultural sector (Table 15). It is considered that there is considerable potential for the further development and application of bioenergy in Europe (AEBIOM, 2011).

There are also several other sources that could provide increased quantities of biomass in the future. These include materials sourced from the waste/recycling sector. Annually, between 95 and 100 Mt of waste is recycled within the EU-27. In 2009, on average, 38% of municipal waste was landfilled, 20% incinerated, 24% recycled and 18% composted (Eurostat, 2011). However, as in other areas, the extent of recycling varies widely between individual countries.

There is also considerable potential for greater biomass use in **North America**. In the **USA**, there is growing interest in producing energy from wood-based feedstocks and herbaceous energy crops such as switchgrass. The physical near-term sustainable biomass potential has been assessed as more than 1 Gt of biomass (18 EJ of primary energy equivalent) (WEC, 2007). Most of the material identified as a near-term resource comprises lingo-cellulosic material. Although the USA relies on its indigenous coal resources to meet a large proportion of its domestic energy needs, in the future, biomass could make a significant contribution, either alone, or co-utilised with coal.

Agricultural lands account for ~46% of the US land base; 26% is grassland pasture and range, and 20% cropland. The Department of Energy and the US Department of Agriculture (USDA) have estimated that biomass available from agricultural lands (while continuing to meet food, feed and export demands) could amount to 910 Mt/y. This comprises mainly 390 Mt from crop residues, 343 Mt from perennial energy crops (both tree and herbaceous), 80 Mt of grains for biofuels, and 96 Mt (dry basis) from animal manure, process residues, and miscellaneous other sources (WEC, 2007). The latest NREL-assessed biomass resource (compared with coal) is shown in Figure 10. The major contributions come from croplands, crop residues, forest residues, and urban wood waste.

In the case of **Canada**, farmland occupies 67.5 Mha, or 6.7% of the country's total land base. Crops are grown on 36.4 M ha, or 54% of farmland. Agricultural activity generates millions of tonnes of biomass each year that includes dedicated energy crops and wastes, the residual fraction of primary harvests, and livestock wastes. Cereal straw is the most abundant agricultural residue. Of the country's available cropland, >85% (~32 Mha), are found in the three prairie provinces of Alberta, Saskatchewan and Manitoba, where cereal crops dominate. An estimated 20 Mt/y of agricultural residues could be available (~350 PJ/y) (Preto and Coyle, 2010). Significant quantities of corn stover and flax straw are also generated. On average, around 37 Mt/y of straw is produced, although not all is available for energy recovery. As elsewhere, some is left on the field to help prevent soil erosion and maintain nutrient levels, and some used for livestock bedding. Overall, between 15 and 17 Mt/y could be available (Bradley, 2006; Preto and Coyle, 2010). This includes a harvestable corn stover supply of 3.5 Mt/y.

In the **Asia-Pacific** region, many countries are examining the greater use of biomass. For instance, in **China**, there is a growing emphasis on the use of renewable energies. Alongside a push for wind and solar power, the country is looking to biomass to help meet its heating, power and transportation

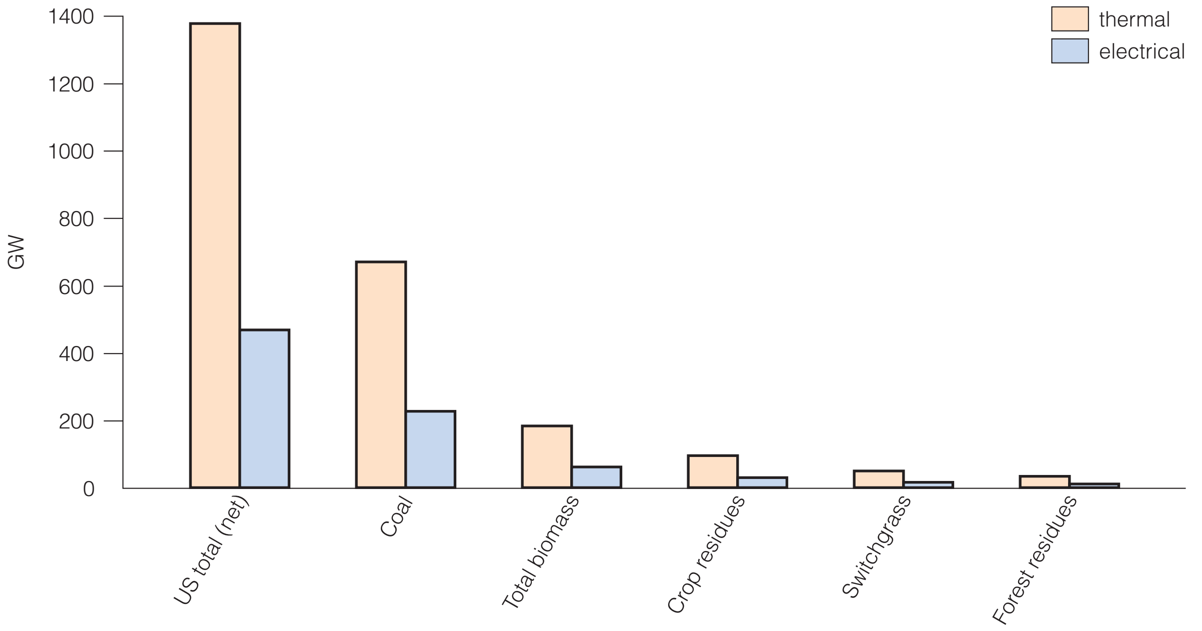


Figure 10 Current US biomass resources (Weiland and others, 2010)

needs. Biomass is already important in China, and a renewable energy development strategy report released by the Academy of Engineering (in 2011) indicated that the country's biomass energy capacity was twice that of hydropower and 3.5 times that of wind power. At the end of 2010, biomass power generation capacity reached 5.5 GW.

China is one of the largest agricultural countries in the world. Much of its arable farmland is situated in or near to the high energy-consuming coastal areas of eastern China. Since the 1980s, crop yields have increased significantly, and the resultant straw yield has risen rapidly. Historically, much has been used as fuel in rural areas or simply burned in the fields; an estimated 150 Mt/y of rice, wheat and corn straw is still being burned (Zhang and others, 2011). The total amount of crop residues produced is estimated at between 600 and 800 Mt/y, although these are not evenly distributed across the country. Net available crop residues amount to ~500 Mt/y, equivalent to ~254 Mt/y of coal (7.4 EJ/y), 8.3% of the country's total energy consumption in 2009 (Zhuang and others, 2012). Some estimates suggest that if biomass development was fully capitalised, it would be equivalent to the energy provided by 1.2 Gt/y of coal, more than the entire country's annual energy consumption (Nanjing Shanglong Communications, 2011). The three principal straws produced comprise maize (41%), wheat (16%) and rice (24%). The amount of crop residues produced in 2009 is shown in Table 16. Straw densification is being expanded and there are currently around 100 bio-pellet plants with a combined production capacity of 3 Mt/y. A national standard for densified biomass fuel is currently being established.

Table 16 Estimate of annual amount of crop residues in China. 2009 (Jiang and others, 2012)

Crop	Crop residue	%
Rice	195.1	24.2
Wheat	126.6	15.7
Maize	327.4	40.6
Beans	30.0	4.1
Tubers	30.0	3.7
Oil-bearing crops	63.1	7.8
Cotton	19.1	2.4
Fibre crops	0.6	0.1
Sugar crops	12.2	1.5
Totals	806.9	100

In August 2012, China unveiled its latest five-year renewable power targets. The country's National Energy Administration set a target of total renewable energy consumption of 478 Mtce by 2015, representing around 10% of the overall energy consumption mix. Total biomass energy consumption is forecast to amount to 50 Mtce.

Renewable energies are also making headway in **India**. In 2010, wind power capacity was 48 GW and small hydro 15 GW. Biomass-based power amounted to 16 GW, bagasse cogeneration to 5 GW, and waste-to-energy to 2.5 GW (Sukumaran, 2009). Historically, particularly in rural areas, biomass has long been an important source of energy, the country producing around 450–500 Mt/y. This currently provides 32% of the country's primary energy. Agricultural and forestry residues available are estimated at 120–150 Mt/y (corresponding to a potential of 16 GWe). It is expected that the proportion of biomass in India's energy demand will decrease over time, although its proportion (27% in 2007 and 15% in 2030) is considerably higher than the world average (9.8% and 9.5% respectively). The amount used is forecast to continue increasing, although at a lower rate than that of fossil fuels. Biomass will remain a major source of energy for the foreseeable future, particularly in rural areas. The residential and commercial sectors will continue to be major biomass consumers until at least 2030. The WEO 2007 *Reference Scenario* projects that in 2030, 436 million Indians in rural areas will still rely on biomass to meet a significant part of their energy needs (in 2005, it was 597 million).

As India produces a large amount of biomass, it has a high biomass potential. Table 17 provides an estimate of the country's biomass potential beyond 2020 under two different scenarios.

There are about 63 Mha of waste land in India; around 40 million have the potential for use as plantations for plant species such as Jatropha. The government is targeting a Jatropha plantation area of 11.2 Mha by 2012. As industrialisation and urbanisation increases, the country is also expecting to generate much greater volumes of municipal waste; assuming that the appropriate collection, recycling and treatment infrastructure can be put in place, this holds significant potential for use in energy recovery systems, either alone or co-utilised with coal.

In terms of liquid fuels produced from biomass, the current share of biofuels in total fuel consumption

Table 17 Potential for biomass power in India (EAI India, 2012)

Type	Potential 2010, MWe	% 2010	Future – 'Realistic' scenario, MWe			Future – 'Optimistic' scenario, MWe		
			2010-13	2014-20	Post 2020	2010-13	2014-20	Post 2020
Agro	18,728	54	19,295	20,687	21,743	21,680	30,506	38,934
Livestock	9332	27	9332	9767	10,470	18,183	19,126	20,639
Fruits	660	2	738	963	1165	764	1084	1392
Vegetables	1220	3	1292	1481	1633	1416	2008	2578
Industrial wastes	1470	4	1679	2289	2857	1878	2918	3998
Subtotal	31410	90	32,337	35,188	7868	43,921	55,642	67,541
Urban wastes								
MSW	3190	9	3992	6773	9781	4277	7818	12,029
MLW	361	1	397	492	574	442	622	794
Subtotal	3551	10	4389	7225	10,355	4719	8440	12,823
Grand total	34,961	100	36,725	42,413	48,223	48,640	64,082	80,364

is extremely low and confined mainly to 5% blending of ethanol in gasoline. Biodiesel is not currently available on the Indian fuel market, although the government plans to meet 20% of the country's diesel requirements by 2020 using biodiesel.

Although coal and oil are currently the main sources of primary energy supply, renewables are also being promoted in **Indonesia.** The country has a renewable energy potential of nearly 50 GWe (Faizal, 2011) although some estimates suggest it could be significantly higher. In 2006, a presidential decree promoting biofuels was issued, and there is currently a strong push to increase the contribution of biomass in the national energy mix. By 2025, the share of crude oil is to be reduced to ~20%, coal is to be increased to 33%, with biofuels (bioethanol, biodiesel, and other types of biomass-derived oil) to be 5%. As part of this, an ongoing programme of the Forestry Ministry aims to plant a Gt of trees, covering more than a million hectares. Forestry and estate management currently covers a land area of ~12 Mha, thus there is the potential to produce significantly more energy using biomass from such sources.

Biomass available from the agro-industry sector includes wastes and other materials such as palm oil (the country has >600 palm oil mills), sugar residues (from ~70 mills), rice and tapioca starch residues, and wastes from wood processing industries (Rauch, 2011). The combined total of biomass/residues produced amounts to more than a Gt a year. The major sources comprise forestry (>15 million m^3/y), agriculture (144.5 Mt/y), MSW (11.3 kt/d), and estates (~64 Mt/y). The main components of the latter include palm oil (48.6 Mt/y) with smaller contributions from rubber production (2.6 Mt/y), coconuts (3.9 Mt/y), and sugar cane (0.14 Mt/y) (Panaka, 2006).

In the future, coal-to-liquids and coal-biomass-to-liquids may have an important role to play if issues around CO_2 emissions can be suitably addressed.

In **Australia**, interest in the deployment of renewables is growing and there is currently a strong push for sustainable energy. The development of the country's renewable energy sector is being supported by various government initiatives and it is anticipated that wind energy will provide the largest share of Australia's targeted 20% renewable energy by 2020. Around 23% of Australia's renewable electricity (and 2% of the country's total electricity) is currently provided by wind (wind farms generate ~5000 GWh/y). The country has abundant biomass resources and amongst the renewable technologies, biomass is viewed widely as being the most cost-competitive energy source.

However, although there is strong governmental support for renewables, biomass resources remain underutilised. For instance, only 50% of bagasse produced from sugar production is collected and used. Similarly, a significant proportion of crop residues are not used. The extent of use varies between states and territories (Australian Bureau of Statistics, 2011).

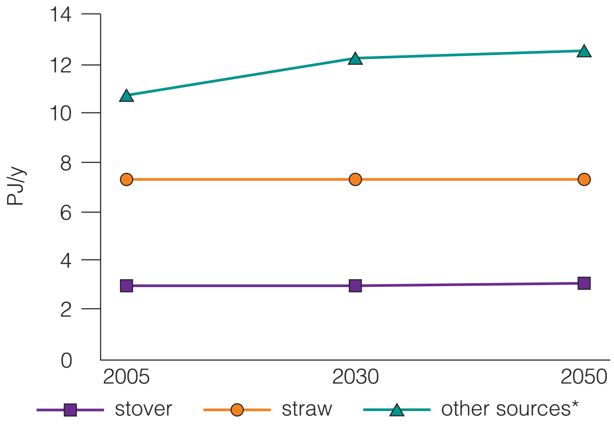
It is estimated there are sufficient forestry by-products to provide 3000 GWh/y of renewable energy without requiring any additional tree harvesting. At the moment, bioenergy generates an estimated 2500 GWh/y of electricity, only 0.9% of the country's electricity. Dedicated installed bioelectricity generating capacity is 867 MW (excluding cofiring). This includes 226 MW fired from biogas, 464 MW from bagasse, 73 MW from wood waste, and 104 MW from other sources. Biomass materials available comprise mainly stubble from grain and cotton crops, bagasse, sugar cane residues, and forest residues (native forests, plantations, and processing residues) (Schuck, 2012). Currently, most of the energy created from biomass fuels is in the form of heat from firewood, bagasse and wood wastes.

Several detailed analyses suggest that within Australia, bioenergy is capable of playing a significant role in future energy supply. Biomass resources are potentially available across all states, with most regions engaged in agriculture, forestry and food production. Each sector produces significant quantities of biomass and wastes that could be used to support power production and/or other applications. Interest and activity is also increasing in growing dedicated energy crops. For instance, Delta Electricity, one of Australia's largest utilities, is embarking on an A$200 million project to grow oil mallee eucalypts as an energy crop in central New South Wales. Pellets will be produced from coppiced mallee for cofiring (20%) at the Wallerawang 2 x 500 MW power station; this equates to 100 MW of biomass power per unit. By 2050, it is forecast that bioenergy could potentially provide Australia with >72,000 GWh/y. Although there is some interest in gasifying biomass, as yet, there are no commercial-scale plants in operation although several small demonstration units have been built. It appears likely that a combination of avoided waste costs plus income from energy production will be the key drivers for bioenergy processes such as gasification in the near to medium term (Sanderson, 2011).

Australian studies into the use of renewables have also examined the possibility of combining coal power with geothermal energy. The level of heat available from a geothermal source would determine where the hot water stream was integrated with a coal-fired plant. Although not yet developed in the commercial sense, the technique is considered to have some level of potential (Gurney, 2013). Geothermal energy is an emerging industry in Australia, with exploration being conducted in all states and the Northern Territory. Although significant resources have been identified and there are several companies in advanced stages of exploration, there is not yet any commercial production of geothermal energy. However, there is considered to be significant potential for geothermal energy in Australia.

New Zealand has a range of energy resources that include in-ground coal reserves of ~15.5 Gt, of which 8.6 Gt is considered to be recoverable. This comprises the lignite deposits of Southland and Otago (~72% of the total), subbituminous deposits in both the North and South Islands (20%), and bituminous deposits off the west coast of the South Island (8%) (Whitney and others, 2011). The country has ten times more coal per capita than the average for the rest of the world (Levi, 2011). The Government has also recognised the importance of renewable generation (hydro, geothermal, wind and biomass) and the current energy strategy includes a target of 90% electricity from renewable sources by 2025, up from the current level of 79% (Li, 2011).

The vast majority of the biomass potentially available is expected to be provided by forest residues and downstream processing wastes. Agricultural residues are expected to provide ~10% of the total. A summary of the main non-forestry-derived residual biomass resources and their potential as energy sources is given in Figure 11. The overall total of forestry wastes plus all other major biomass resources is forecast to increase substantially in the period up to 2050. In 2005, this amounted to 47.8 PJ/y; this is expected to increase to 68.5 PJ/y in 2030, and 74.0 PJ/y in 2050 (Hall and Gifford, 2010).



* other sources include MSW plus a variety of farm, dairy, piggery, poultry and meat industry wastes

Figure 11 New Zealand's main residual biomass resources (Hall and Gifford, 2010)

2.8 Use of wastes for energy recovery

As well as biomass produced from energy crops or generated by operations such as forestry, municipal solid waste (MSW) also contains a significant proportion of biomass and biomass-derived materials. By its nature, MSW is very heterogeneous, comprising a range of different materials. Generally, it consists of varying proportions of paper and card, plastics, textiles, glass, metals, putrescible, and miscellaneous combustibles. Although primarily generated by households, MSW streams may also include some commercial and industrial waste. Generally, MSW contains around

20–40% of materials that originate from fossil fuels (such as plastics), with the remainder derived from biomass and thus, considered to be a renewable resource. Typically, MSW has about a third of the calorific value of coal (8–12 MJ/kg as received).

Even in countries with highly developed recycling infrastructure, significant tonnages of MSW remain after recycling – this makes energy recovery an environmentally justified and economically viable option (IEA Bioenergy, nd-b). MSW can be converted to energy via several routes such as incineration, gasification and pyrolysis. With the exception of mass burn or incineration systems, other process routes tend to use an upgraded fuel (such as Solid Recovered Fuel – SRF). This can be co-utilised with other solid fuels such as coal and/or biomass. Using MSW or SRF as an energy source can help reduce greenhouse and acid gas emissions, and help conserve other fuel reserves.

Although the extent and nature varies between locations, each year the world generates at least 4 Gt of waste. This comprises 1.7–1.9 Gt of municipal waste and 1.2–1.7 Gt of industrial waste. On a per capita basis, the more developed economies produce more than developing countries. In the developed economies, around a billion people generate on average 1.4 kg/d of MSW. In the USA, it is 760 kg/y, in Japan it is 434 kg/y, and in urban India, 163 kg/y (Chalmin, 2011). The overall amounts of MSW generated on a regional basis are shown in Figure 12.

In many locations, MSW can form a useful resource for electricity generation, heat production or cogeneration. For instance, the USA has ~75 waste-to-energy plants operating in 20 states, with a total electric generating capacity of 2.24 GW. These generate ~14 million MWh/y of electricity, around 0.3% of total US generation. In 2010, 29 Mt of MSW was burned in the USA. However, a lot more (~54%) was landfilled. A recent addition to the US fleet was the first electricity-generating gasification plant to be fuelled on MSW. The 20 MWe *Montgomerry Biomass Power Plant* was completed at the end of 2012. It uses a circulating fluidised bed gasifier fuelled on combinations of MSW, demolition wood and other wood wastes. Its success may encourage replication of the system elsewhere.

The rate of MSW utilisation varies considerably between countries, although it tends to be higher in some countries; for instance, in Sweden, more than 46% is used for energy recovery, providing annually 1.5 TWh of electricity and 12.2 TWh of heat. In other places, the potential of municipal waste remains largely untapped. For example, in India, growing industrialisation and urbanisation is generating increasing amounts of MSW. This is often disposed of in unregulated landfills, creating major environmental problems. The urban population of India is currently ~341 million; it is projected that the quantity of MSW produced will increase from 34 Mt in 2000, to 84 Mt in 2015, and 221 Mt

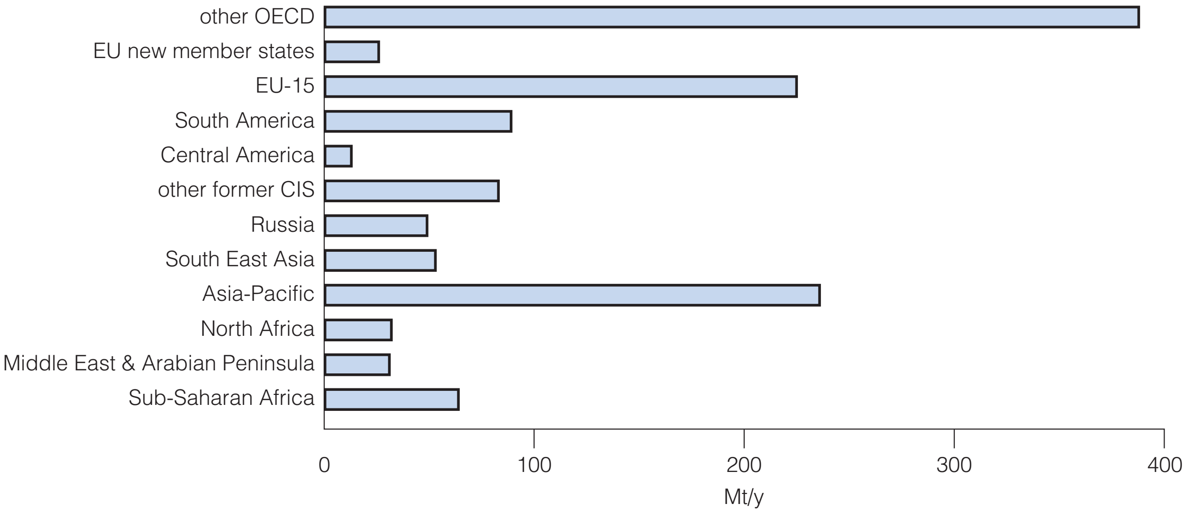


Figure 12 Municipal waste production – by region (Chalmin, 2011)

in 2030. By this time, the urban population is expected to be 586 million. Incineration of MSW is seen as a poor option because of its relatively high organic content, high inert content, and low CV. There are no large-scale MSW incineration plants currently in operation. Gasification has been considered although only a few small-scale gasifiers are in operation, mainly using biomass such as agro-residues, sawmill dust, and forest wastes. A small gasifier using treated MSW is being operated in New Delhi by Tata Energy Research Institute (Kaushal and others, 2012). However, there is some use of refuse derived fuel (RDF) produced from MSW, with a number of plants in operation. Ironically, some are hampered by limited supply.

2.8.1 Use of industrial wastes

Much industrial waste is of non-renewable origin, comprising various materials such as plastics produced from fossil fuels. However, some sectors generate large amounts of wastes directly from the processing of biomass; for instance, the building and furniture manufacturing industries create wood waste, and the pulp and paper sector generate large quantities of black liquor. In some cases, wastes remain underutilised whereas in others, a high degree of utilisation already takes place. For instance, globally, around 500 Mt/y of black liquor is produced, much of which is used as an energy source, supplying heat, steam and electricity for on-site operations. Thus, many mills are nearly energy self-sufficient, generating on average, up to two thirds of their own electricity needs. In the USA, paper companies now consume nearly all of the black liquor they produce and around 28.5 million MW/h of electricity is produced each year. Where appropriate, such biomass sources are considered elsewhere in this report.

3 Gasification processes

Gasification is a versatile conversion technology that can add flexibility to energy systems. For many years, it has been used reliably on a commercial scale in numerous countries by the power generation, chemicals, refining, and fertiliser industries. Unlike combustion, the goal is to produce syngas that can be separated into different components that have the potential for a range of applications. Virtually any carbon-based material can be gasified and, over the course of nearly two centuries, many types have been utilised. However, the most widely used feedstock has been coal; this has been gasified extensively for a range of commercial and industrial applications and an extensive body of experience has been established. Globally, there is a significant further potential for coal gasification, particularly where countries have large coal reserves but lack easy access to oil or natural gas.

Recent years have seen sophisticated gasification systems developed by a number of major technology suppliers. This has included the introduction of integrated gasification combined cycle (IGCC) technologies. These have used mainly coal and oil refinery residues, although increasingly, biomass is being incorporated into plant feedstocks; this is explored later in the report. The main drivers for adopting IGCC and gasification technology in Europe have included the introduction of increasingly stringent emissions legislation, concerns over security of national energy supply, and a desire to retain coal as part of the national portfolio of electricity generating capacity (Mills, 2006).

The Gasification Technologies Council estimates that worldwide, there are currently more than 150 gasification plants (with more than 430 individual gasifiers) operating. This equates to an equivalent thermal capacity of more than 56 GW; coal gasification accounts for ~31 GW of this total. World gasification capacity is projected to increase by more than 70% by 2015. Some forecasts suggest a total of 155 GWth by 2014 (IEA ETSAP, 2010). Most of this growth is expected to be in Africa, the Middle East and the Asia-Pacific region, with China's capacity additions expected to the largest. Clearly, not all new units will be coal-based and a variety of feedstocks are expected. However, overall, coal will retain an important role.

Although a number of different coal gasification systems have been developed and deployed, most operate on the same basic principal, with the gasification reaction taking place under oxygen shortage. Initially, the coal is heated in a closed reaction chamber where it undergoes a pyrolysis process at temperatures in excess of 400°C. During this phase, hydrogen-rich volatile matter is released, along with tars, phenols and gaseous hydrocarbons. The char is then reacted (at 800–1800°C) with air and/or oxygen and steam to generate syngas, a mixture comprising mainly carbon monoxide (CO), carbon dioxide (CO_2), and diatomic hydrogen (H_2). There may also be smaller amounts of methane (CH_4), nitrogen and water vapour present. Depending on the individual feedstock, the syngas may also contain various contaminants such as H_2S, COS, HCN, HCl and Hg. Most will need removing prior to utilisation of the syngas.

Specific operating conditions depend on coal type, properties of the resulting ash, and the individual gasification technology. The most important variable in a gasification process is the oxidant – either air or oxygen. Systems relying on the latter require an air separation unit (ASU), which imposes additional costs and reduces net power output. Where air is used, extra nitrogen is introduced into the process. This results in higher NOx emissions and a lower syngas heating value, and requires larger plant components and gas clean-up systems. In practice, a steam/oxygen mixture is commonly used.

Gasification systems are many and varied. The performance and costs of a coal gasifier depend largely on its design and the final production objectives; a gasification system feeding a chemicals plant will differ substantially from one supplying an IGCC unit. Coal quality also affects gasifier design (IEA ETSAP, 2010). Compared to coal-fuelled plants, a typical biomass facility is usually much smaller. Most are too small to countenance the use of oxygen supplied by an ASU and consequently rely on various forms of air-blown gasification technology. As such, they are less expensive to build and have a smaller footprint. Whilst a large coal- (or petcoke-) based industrial gasification plant may process between 2500 and 15,000 t/d of feedstock, with a typical biomass plant it is more likely to be between 25 and 200 t/d. As with coal, there are a number of different generic types of gasification technology that have been developed for biomass feedstocks. Most are used for producing heat and/or power although there is growing interest in the production of liquid fuels.

As with coal, the design of gasifier, operating conditions, and the type of biomass influence the composition of the syngas produced. The chemical make-up of biomass can vary significantly. For instance, lingo-cellulosic materials comprise mainly cellulose, hemicellulose, and lignin in varying proportions. The proportion of the different species present influences the composition of the gasification products (Brar and others, 2012). For instance, more cellulose produces higher levels of CO_2 and CH_4 in the product gas. Similarly, when cogasifying, the ratio of biomass:coal also affects syngas composition; adding some types of biomass increases the hydrogen content (Kezhog and others, 2010).

3.1 Types of gasifier

There are many types of gasifier available commercially, some of which are better suited to specific types of feedstock. Coal gasification processes and gasifiers have been examined in detail in a number of IEA Clean Coal Centre reports (for instance, Collot, 2002; Fernando, 2008, 2009; Barnes, 2011), and are not addressed in detail here, although their basic strengths and weaknesses are noted below. Biomass gasification and cogasification are considered in greater depth. Table 18 provides a short summary of the main characteristics of the three main generic gasification technologies.

Recent years have seen some commercially available gasification and IGCC technologies change hands whilst others have faded into obscurity. Apart from those mentioned in Table 18, gasifiers of various design are also manufactured or offered by BHEL in India; Kawasaki Heavy Industries, IHI and Hitachi/Babcock KK in Japan; and Harbin Power Equipment Corporation in China (Mills, 2008).

The merits of gasification have been well established with fossil fuels such as coals. Coal gasification technologies are mature and their application to efficient IGCC power generation and the production of chemicals, fertilisers, SNG, and liquid fuels has been proven commercially. Many aspects of these technologies can now be applied (with significant economic benefits) to biomass gasification (Hofbauer and Rauch, 2010). Although biomass can be utilised in a number of ways, such as combustion, pyrolysis and carbonisation, many recent efforts have concentrated on its use as a gasification feedstock (Pavani and others, 2009). Compared to combustion, this offers the potential for producing a wider range of end-products.

Surveys of major suppliers suggest that there are between 20 and 30 biomass gasification variants offered commercially, split between moving/fixed beds, fluidised beds, and entrained flow systems. Operating pressures up to ~2 MPa and temperatures up to 980°C have been used (with both air and oxygen). Of the various biomass systems, directly heated bubbling bed gasifiers have been widely demonstrated, although the make-up of the market tends to vary with location. For instance, a survey of (mainly) Northern Europe and Scandinavia identified projects based on entrained flow, up-draught, down-draught, bubbling fluidised bed, and circulating fluidised bed gasifiers. However, the dominant technologies were based on various forms of fluidised bed technology (Hansson and others, 2011). A similar survey of existing North American biomass gasifiers identified mainly up-draught and down-draught bed systems in use in the USA and Canada (Pytlar, 2010). The preference for particular type of technologies also varies with location. For instance, in Thailand and Cambodia, the vast majority of biomass gasifiers are of the air-blown fixed bed down-draught type. Globally, biomass gasifiers sold for commercial use are thought to comprise about 75% down-draught, 20% fluidised bed, 2.5% up-draught, and 2.5% other types (Gautam, 2010). The main types of gasifiers available and their use with coal and biomass is examined in the following sections.

Table 18 Characteristics of main generic gasification technologies (Fernando, 2008; Harris and Roberts, 2010)

	Entrained Flow	Fluidised Bed	Fixed Bed
Suppliers – examples	Shell, GE, Siemens, MHI, PRENFLO, ConocoPhillips, MPG	High Temperature Winkler, SES, KBR TRIG	Lurgi, Sasol-Lurgi, British Gas-Lurgi
Unit capacities, MWth	Up to 700	100–700	10–350
Coal	Most types suitable. Pulverised. For slurry feed, low moisture or hydrophobic coals preferred	Crushed. Mixed with a bed material to aid heat transfer and to capture sulphur species	Lump coal – may require caking and agglomerating properties
Fuel size limits	<0.1 mm	<5–6 mm	5–80 mm
Reactivity	High reactivity coals may be cheaper to use although most types can be accommodated	Lower operating temperature means reactive coals, such as subbituminous and lignite, are favoured	Can handle a range of reactivities due to long residence time. Best suited to coals of moderate-high reactivity
Ash Content	Refractory systems: less ash is preferred. Possible issues with slag corrosion/erosion. Non-refractory systems: minimum ash requirement to protect wall	High ash fusion temp required to prevent ash melting/sticking. Agglomerating FBGs have stringent requirements on ash melting and softening behaviour	Dry-bottom units have similar requirements to fluidised bed gasifiers Slagging – low ash content preferred
Ash content limits	<25% preferred	No limits	Dry: no limits Slagging: <25 % preferred
Preferred ash melting temperature. °C	<1300	>1100	Dry: >1200 Slagging: <1300
Slag	Slag flow with 25 Pa/s or less at tapping temperature. Temperature of critical viscosity less than operating temperature	Ash softening and/or melting is not desirable	Dry: requirements similar to fluidised bed. Slagging: requirements similar to entrained flow
Exit gas temerature, °C	1260	925–1040	425–650
Gasification pressure, MPa	<8	0.1–3	3

3.1.1 Fixed bed down-draught gasifiers

Fixed bed gasifiers have a tendency to produce large quantities of tars, oils, and char. They have not been prime candidates (particularly when using biomass) for producing syngas for power generation or chemical synthesis applications. However, down-draught gasification has been well proven, and is simple and low cost. In this design, air or oxygen for combustion is injected into the top of the gasifier and flows downwards towards the base. As coal and/or other fuels are often also fed from the top, this type of unit is sometimes referred to as a *cocurrent* or *coflow* gasifier.

In operation, the internal temperature is typically between 420°C and 650°C. As both streams flow in the same direction, the highest temperatures occur during the combustion phase, with pyrolysis and thermal cracking occurring in this high temperature zone. Less tar and ash is produced than some other types of gasifier, hence syngas clean-up requirements are lower. However, down-draught gasifiers have some limitations:

- input feedstocks need to have relatively low moisture content (20% max) and it is not possible to utilise slurry-based materials;
- a portion of the char produced during pyrolysis (typically ~6%) remains unconverted; and
- syngas is expelled at fairly high temperatures. Unless recovered in some way, heat can be wasted.

Where biomass is gasified, it is fed with the coal and air or oxygen and ignited in the reaction zone at the top of the reactor. This generates pyrolysis gas which burns intensely, producing 5–15% char and hot combustion gases. The latter flow downward and react with the char present (at 800–1200°C), generating CO and H_2 whilst being cooled to less than 800°C. Unconverted char and ash pass through the bottom of the grate and are removed for disposal.

A major advantage of this technology is that nearly all tar formed (up to 99.9%) is combusted, hence, only minimal gas clean-up is required. Most mineral matter from the fuel is retained in the residual char. Disadvantages when using biomass are similar to those when using coal. Feedstocks may need pre-drying, between 4% and 7% of the carbon in the fuel remains unconverted, and tight control of oxidant distribution in the bed is required. These issues restrict the technology to small capacity units. A secondary heat recovery system may be needed to minimise heat loss from the syngas. Because of its relative simplicity and ability to eliminate tar, down-draught gasifiers have been deployed widely for more than half a century, particularly for biomass use.

3.1.2 Fixed bed up-draught gasifiers

Although similar to the down-draught gasifier, in up-draught units the gasification agent (oxygen or air) enters from the bottom and travels upwards. However, coal or other feedstock is fed from the top. Such units are also called *counter-flow* or *counter current* gasifiers. The different direction of input oxygen or air flow in the unit changes significantly the performance and characteristics.

In operation, a grate at the bottom of the reactor supports the bed that comprises fuel and char. Air and/or steam is injected and diffuses upwards. Char combustion occurs at the bottom of the bed, producing CO_2 and water. These hot gases pass upwards through the bed where they are reduced to CO and H_2. The reducing gases pyrolyse the descending feedstock and, higher up, reduce the moisture of the incoming fuel feed. Gases exit the reactor at a relatively low temperature of ~500°C (Fernando, 2009). Major advantages of the technology are that systems are well proven, simple and low cost. As air or oxygen enters at the bottom, it functions as a cooling agent for the hotter syngas exiting from the same general location. Furthermore, after gasification and combustion, the remaining hot air helps dry incoming fuel as it passes over it. Thus, less heat is wasted, increasing overall process efficiency beyond that of the down-draught equivalent. The drying effect means that fuels with much higher moisture content can be utilised.

As well as coal, up-draught gasifiers can also process some types of biomass. They can operate successfully with feedstocks such as wood but have proved unsuitable for fuels such as straw or miscanthus (unless in briquetted form). Usefully, high moisture content fuels can be processed. However, the principal disadvantage (unlike down-draught gasifiers) is that the syngas contains high levels of tar (10–20%). As such, there is a significant loss in efficiency and greater syngas clean-up requirements. In addition, the peak temperature in an up-draught gasifier is much higher than in a down-draught unit and can be high enough to damage various internal devices and components (such as grates). Consequently, these components must be manufactured from stronger, less temperature-sensitive materials, or be protected by blowing in steam or some other coolant to

Table 19 Examples of up-draught and down-draught biomass gasifiers (Andritz, nd; E4Tech, 2009; Pytlar, 2010; Hansson and others, 2011)

Supplier	Gasifier type	Status	Feedstocks
Bioneer, Finland	Up-draught	Around a dozen plants built 1980s-90s	Wood, forestry wastes, straw, RDF
PRM Energy, USA	Up-draught	Around a dozen plants built for heat, steam, cogeneration. Three plants generating electricity	Rice hull, straw
Nexterra, Canada	Up-draught	Several recent installations for power generation	Wood, wood waste
Biomass Engineering, UK	Down-draught	Around a dozen plants in Europe (100–400 kW)	Wood
Aruna, India	Down-draught	Many small-scale projects	Wood
Ankur Scientific, India and USA	Down-draught	Many in India (25–400 kW). Also in Russia, Africa, Australia, Cambodia (40–500 kW)	Rice husk, wood, forestry wastes
Community Power, USA	Down-draught	Around a dozen demo units in USA. Up to 25 kWe	Wood
MasWest, USA	Down-draught	Six units in Canada and USA	Dried sludge, paper biosolids, chicken litter, manure, waste wood
Jiangsu Antai New Energy Technology (JAE), China	Both down- and up-draught units	Heat and power applications. 100 kW to 20 MW	Wide range of agricultural and forestry wastes

maintain a more tolerable temperature in that part of the unit. Examples of up-draught and down-draught gasifiers for biomass are given in Table 19.

3.1.3 Fluidised bed gasifiers

Fluidised bed gasifiers can be air- or oxygen-blown, bubbling (BFB) or circulating bed (CFB), and usually operate with crushed fuel particles that are introduced into an upward flow of gas. This fluidises the bed and provides reactants for gasifying the fuel particles. The bed may be formed from various combinations of sand, char, sorbent, and ash. Fluidised bed (FB) gasifiers operate at lower temperatures than entrained flow units (normally well below the ash fusion temperatures to avoid ash melting). Air-blown FB gasifiers produce low heating value gas and oxygen-blown units produce medium heating value gas. Because they operate at lower temperatures than entrained flow units, fluidised bed gasifiers usually produce a lower rate of carbon conversion. To improve this, char is either recirculated into the gasifier or burned in a separate combustion unit. However, fluidised bed gasifiers do not require expensive high temperature gas cooling systems (Collot, 2002).

Relatively few coal-based units are operating commercially although a number of system variants have been successfully developed. These include CFB gasifiers developed by BHEL in India, High Temperature Winkler (HTW) technology, and the Integrated Drying Gasification Combined Cycle (IDGCC) system in Australia. An advanced version of CFB technology has been developed in the USA; the KBR *Transport Reactor Integrated Gasifier* (TRIG) is an advanced (low rank) coal gasification technology capable of producing clean, particulate-free syngas for various industrial applications. It uses a non-slagging transport gasifier that, compared to other CFBG systems, has higher velocities, riser densities, and circulation rates. As the system can be operated as both a combustor and a gasifier, it is sometimes referred to as a 'transport reactor', rather than transport gasifier. With this technology, there is no true 'bed' in the gasifier itself, as the feedstock and gasifying agent are constantly in motion throughout the system (much like an entrained flow gasifier), but with larger particles, as making an entrainment is not necessary. During operation, larger particles of ash and unconverted char are removed using a gravity-driven 'disengager', with smaller particles removed using a high-temperature cyclone. Particles thus separated are returned to the mixing zone where the feedstock enters the unit. The transport gasifier operates at a temperature of ~1000°C. Recent coal-based projects include IGCC and chemical production plants in China, and the Kemper County IGCC plant in the USA. Although such plants were designed primarily for coal, extensive pilot-scale testing has also been undertaken successfully using combinations of various biomass feedstocks with different types of coal. Cogasification of coal and biomass is being examined as in some locations there are insufficient sustainable supplies of biomass available to fuel a biomass-only plant. Therefore, there are clear incentives to cogasify.

Although commercial-scale coal-only applications remain limited, many smaller fluidised bed gasification units use biomass alone, or combinations of coal with biomass and/or wastes. Many modern biomass/waste gasifiers are based on variants of fluidised bed technology, with bubbling beds most commonly used. With these, fuel can be fed in either from above or directly into the bed. BFB gasifiers have been operated over a wide range of temperature, pressure and throughput using a variety of biomass feedstocks. They have been operated with air, oxygen, and steam; varying the relative amounts of oxygen and steam can be used to adjust the H_2:CO ratio. Oxygen-blowing can provide several benefits over air-blowing. For instance, the heating value of the syngas is higher, the gas volume is approximately half that for a corresponding an air-blown system, and the gas handling and clean-up units and heat exchangers required are smaller (Whitney and others, 2011). Where syngas is generated for the production of chemicals or fuels, it is advantageous to operate at higher temperatures (as with coal gasification). If this is not possible, tar cracking may be necessary. Apart from this possible requirement, gas clean-up requirements may be minimal. The main advantages of using a BFB gasifier to process biomass are:

- they produce a uniform product gas and exhibit a nearly uniform temperature distribution throughout the reactor;
- they can accept a wide range of fuel types and particle sizes. Fuels include wood, wood pellets and chips, waste wood, mixed plastics and aluminium, MSW, RDF, agricultural and industrial wastes, sewage sludge, switchgrass, discarded seed corn, corn stover and other crop residues;
- units are tolerant to fluctuations in feed quantity and moisture; feed moisture contents of 10–55% can often be accommodated although 10–15% is usually considered as optimal;
- they provide high rates of heat transfer between the inert bed material, fuel and gas;
- high conversion efficiencies are possible, with low tar production and unconverted carbon;
- BFB gasifiers are among the lowest capital cost options of the advanced biomass gasification technologies.

The main disadvantage of BFB systems is that in operation, large bubbles may be formed that result in gas bypass through the bed. There is also a risk of bed agglomeration in BFB (and CFB) gasifiers when using feedstocks with low ash melting temperatures (such as some types of straw). However, an appropriate mix of feedstocks with higher ash melting temperatures may allow safe operation, even at high gasification temperatures. Alternatively, mineral binding products such as dolomite can be added to the inert bed material to counteract the agglomeration problem. Fuel gas produced by biomass-fuelled plants is currently used to fire cement and lime kilns, and in various industrial drying systems, air heaters, steam boilers, and turbine or diesel generator sets. Technically, the simplest application for a fluidised bed gasifier is to fire or cofire an existing steam boiler.

Various BFB gasifiers have proven reliable with a variety of feedstocks at pilot and smaller commercial applications. The technology is more economic for small-medium range capacities and during the past few years, a number of BFB gasifiers have been built for cogeneration. Recently, developers have focused increasingly on scaling up their respective technologies and are also examining the use of BFB gasifiers for liquid fuels production. To date, experience has been based on both atmospheric and pressurised systems, although many of these have been air-blown. Emphasis is shifting increasingly to the development of oxygen/steam oxidants in pressurised systems. Examples of biomass BFB gasifiers and technologies in use or under development that have progressed to pilot scale at least are shown in Table 20. There are also many other smaller-scale projects at various stages in their respective development or commercialisation.

Alongside bubbling bed gasifiers, circulating bed variants have also been used in a number of commercial-scale plants. As with BFB, most of the experience has been with air-blown, atmospheric units producing heat and/or power. However, more recently, development has focused increasingly on pressurised oxygen-blown systems. Historically, CFB technology has used mainly woody feedstocks, although peat and straw have also been used. Various others such as waste plastics, RDF and shredded tyres have been tested. A generic advantage of CFB technology is that it is fuel-flexible, capable of

Table 20 Examples of bubbling fluidised bed gasifiers/technologies in use or under development (Andritz, nd; E4Tech, 2009; Hansson and others, 2011)

Developer	Technology	Status	Feedstocks
Carbona/Andritz RENUGAS technology	Pressurised, directly heated, oxygen and steam-blown BFB. Used to provide heat, power or syngas	Plants (up to150 t/d) in Finland, Hawaii, Denmark, USA. Plans for 1440 t/d FT biodiesel plant with forestry supplier UPM	Wood pellets/chips, bark, wood and forest residues, sawdust, bagasse. Various others tested
Foster Wheeler Energy Ecogas technology	Atmospheric, directly heated, air and steam-blown process. Syngas used in a boiler	An 82 t/d plant operating in Finland	Plastics, aluminium waste. MSW-RDF also tested
Outotec Energy (formerly EPI)	Pressurised, directly heated, oxygen/steam blown gasifier. Syngas used for heat/power	Plants in the USA and UK (up to 6 MWe). Plant being developed will use 1040 t/d cattle manure	Wood chips, agricultural and industrial waste, sewage sludge, RDF, MSW
ThermoChem Recovery International (TRI)	Atmospheric, steam-blown gasifier with indirect heating. Syngas used for heat and power. Plans for FT diesel production	Plants (up to 580 t/d biomass, 50 MWe) in Canada and USA. Other projects include ethanol from wood, plus pilot FT testing with Rentech	Existing plants use only black liquor. New plants will use forestry residues
Iowa State University	Indirect batch heating for steam atmospheric BFB	5 t/d input pilot plant. Commercial partnerships with ConocoPhillips and Frontline Bioenergy	Switchgrass, waste corn seeds and stover, wood chips, other residues
Enerkem BioSyn technology	Pressurised, directly heated, air/oxygen-blown BFB. Syngas used for methanol and ethanol production	Plants in Canada and the USA. Largest capacity 228 t/d MSW. 30 t/d plant being commissioned. Also 913 t/d RDF plant planned	Numerous woods and wastes tested. Future plants will use MSW or RDF

adapting to different fuel type and/or specification. Feedstocks typically require reducing in size to less than ~20 mm. Unlike entrained flow gasifiers, CFBs are fairly tolerant to fluctuations in feed quantity and moisture. Under appropriate conditions, the technology is capable of accepting feedstocks with moisture content in the range 5% to 60%. However, from a pre-treatment energy viewpoint, 10–15% is usually considered optimal.

Circulating fluidised bed gasification (CFBG) is now considered to be technically well proven and has high market attractiveness. For large-scale applications, the technology is sometimes considered the preferred and most reliable system, although for small-scale applications, down-draught gasifiers may be more suitable. There are a number of technology developers who are (or have been) active in the development and deployment of CFBG. Major players have included Foster Wheeler of Finland and Lurgi GmbH of Germany, although a number of other organisations also offer systems commercially (Table 21). Foster Wheeler's technology was introduced in the 1970s; it will tolerate inexpensive waste-derived feedstocks, has good fuel flexibility, and provides the opportunity of combusting the product gas in a separate PCC boiler. The latter concept (whereby part of the coal feed is replaced with biomass/wastes) offers lower emissions, reduced coal use, improved fuel flexibility, and high plant availability. To date, the company has supplied seven commercial scale CFB/BFB gasifiers producing low CV gas for different applications (Nowak, nd).

There are numerous small-scale biomass gasification projects and plants in operation. There are also a number of commercial-scale applications using CFBG technology. Of these, direct cofiring (whereby fuel gas from a biomass gasifier is fed directly into an existing coal-fired boiler) is the most commonly encountered concept; this technique avoids some of the potential drawbacks associated with biomass use. The simplest way to co-utilise biomass with coal is to add the biomass directly to the coal feed. However, various technical issues can arise because all of the components in the biomass enter the coal boiler. These can be largely avoided where the biomass is gasified in a detached unit and the resultant syngas is co-combusted in a separate coal-fired boiler ('indirect cofiring'). Compared to directly blending biomass with coal, the indirect approach provides several advantages:

- alkali and chloride species are kept out of the boiler. Gasifying the biomass separately gives the opportunity to remove unwanted species from the gas before it is fed to the boiler's combustion chamber. This helps avoid operational issues such as slagging, fouling and corrosion that may result from the direct addition of a biomass feedstock;
- the effects of feedstock variability are reduced. Biomass feedstocks can vary significantly in terms of their moisture content, heating value and ash profile. By gasifying these, much of this variability can be reduced or eliminated, thus aiding stable boiler operation;
- feedstock flexibility may be increased. Through the judicious choice of gasification system, a wider choice of feedstock may become available. This broadening of options can reduce feedstock availability and price risk;
- biomass and coal ashes are kept separate. By keeping biomass and coal ash streams separate, neither is compromised in terms of disposal or commercial utilisation. For instance, uncontaminated coal ash can be used as a component of concrete, and biomass ash as a soil amendment/fertiliser.

However, indirect cofiring is more expensive than direct cofiring. Hence, although there have been over a hundred coal-fired power plants that have directly fired biomass, only a handful have incorporated indirect cofiring (Fernando, 2009). These include the Amer 9 cogeneration plant in The Netherlands (Mills, 2010), the Kymijärvi cogeneration station in Finland, and the Electrabel Ruien power plant in Belgium.

In March 2013, the world's largest biomass gasifier (140 MWth) was inaugurated by Finnish power company Vaskiluodon Voima Oy in the city of Vaasa (Figure 13). The new 40 million plant gasifies mainly forestry wastes, with the syngas fed to an adjacent 565 MW coal-fired boiler. An estimated 40% of the coal requirement will be replaced by the biomass-derived syngas, saving around 230 kt/y

Table 21 Circulating fluidised bed biomass gasifiers (to at least at pilot scale)

Developer	Technology	Status	Feedstocks
Foster Wheeler Energy	Air-blown, atmospheric, directly heated CFB. Syngas used for cofiring lime kilns or PCC coal boilers	Plants (up to 336 t/d) in Finland, Sweden, and Belgium. 768 t/d waste plant planned in Finland	Wood chips, bark, sawdust, wood waste, RDF, plastics, tyres, MSW. Able to handle 20–60% moisture content
Lurgi (Air Liquide)	Atmospheric pressure CFB gasifier design. Raw fuel gas cleaned at low temperatures by scrubber/baghouse	Lurgi sold the technology to Envirotherm, but no new projects yet under way. Commercial plant at Amer 9 power station. Also 100 MWth waste plant in Germany and 29 MWe plant in The Netherlands	Wood and other wastes
Metso	Air-blown CFB technology	140 MWth commercial plant at Vaasa in Finland. On line at end of 2012	Mainly forestry residues
VTT, Finland	Ultra-Clean Gas project – pressurised, directly heated, oxygen and steam blown	VTT active in biomass gasification since the 1980s. Several pilots and ongoing R&D programmes. Commercial plants in development. Planned FT diesel production	Forestry residues and by-products. Also bark, energy crops, RDF and peat
Uhde GmbH – High Temperature Winkler gasification (HTW)	Directly heated, pressurised, oxygen and steam blown. Syngas used for heat and power. Planned for methanol/gasoline production	576 t/d peat plant operating in Finland since 1988. 15 t/d MSW plant in Japan. Large-scale BTL gasoline and diesel concept planned	Lignite, peat, MSW, waste wood, straw
Vaxjo Varnamo Biomass Gasification Centre (CHRISGAS)	Bioflow (Foster Wheeler Energy/Sydkraft JV) built original Varnamo IGCC plant (pressurised, air blown, directly heated CFB)	Varnamo reopened in 2005 (as CHRISGAS project). Will upgrade to steam/oxygen blown system, with hot gas filter, catalytic HT reformer and syngas conversion to biofuels	Wood chips, pellets, bark, straw
Fraunhofer Institute	Atmospheric, directly heated, air blown CFB gasifier with catalytic gas treatment	Reached 2.4 t/d pilot scale	Forestry wood chips, bark, coarse lumber shavings, sawdust
CUTEC Institute	Atmospheric, directly heated, oxygen/steam blown CFB gasifier, gas cleanup and FT plant	Reached 2.7 t/d pilot scale. Larger plants (possibly up to 70–100 t/d) in development	Sawdust, wood pellets, wood chips, chipboard residues, straw pellets, sunflower seed residue, energy crops
ANDRITZ Carbona	Updated former Ahlstrom CFB gasification technology	Gasifier designed to produce 10–150 MWth fuel gas	Various

Figure 13 The Vaskiluoto biomass gasification plant in Finland (photograph courtesy of Vaskiluodon Voima Oy)

of CO_2. In the USA, a similar concept is being promoted by Outotec Energy Products (formerly Energy Products of Idaho – EPI).

3.1.4 Dual fluidised bed gasifiers

Another variant used commonly for biomass is the dual bed gasifier. There are various types available although they all utilise two chambers – a gasifier and a combustor. The gasifier component can be based on BFB or CFB technology. Biomass is fed into the gasification chamber (usually with steam) and converted to syngas and char. The char is then burnt in air in the combustion chamber, heating the accompanying bed particles; the hot bed material is then fed back into the gasification chamber, providing the indirect reaction heat. Thus, indirect heating is provided by material exchange with a parallel combustion chamber. Cyclones are used to remove any CFB chamber syngas or flue gas. The system usually operates at temperatures below 900°C to avoid ash melting and sticking.

Although dual bed gasifiers utilise CFB and/or BFB technologies, compared to the commercially available individual CFB or BFB technologies, the combined process is still considered to be at the development stage. A major advantage is that dilution of the syngas with nitrogen is avoided without the cost and complexities of using pure oxygen (E4Tech, 2009). Dual biomass gasifiers use mainly woody feedstocks such as wood chips, pellets and wood residues although various other feedstocks such as herbaceous crops, grasses and sewage sludge have also been tested. Input feedstock requirements are similar to those of the individual base technologies. To date, cogasification has not been investigated extensively, with most operations appearing to have been limited to biomass. The companies mentioned in Table 22 have developed and tested biomass-based dual bed gasification technologies to at least pilot scale.

3.1.5 Entrained flow gasifiers

Entrained flow gasification processes have been well developed and demonstrated on a large scale

Table 22 Dual bed biomass gasifiers (to at least pilot scale)

Developer	Technology	Status	Feedstocks
ECN	Indirectly heated, dual-bed CFB steam gasifier and air-blown BFB char combustor. Hot gas cleaning and syngas methanation to produce bio-SNG	Pilot plant operational. Plans to license a 10 MW demo in 2012-15. Larger projects planned for post-2018	Beech wood, grass, sewage sludge, wood pellets
SilvaGas	Atmospheric, indirectly heated CFB steam gasification with parallel air-blown CFB char combustion chamber providing heated sand. Syngas for heat and power, although also plans for FT liquids	Demonstrated at 350 t/d wood. 540 t/d wood waste plant being developed in USA. Rentech using a SilvaGas gasifier to make FT liquids and 35 MWe of power from ~800 t/d urban waste wood	Wood chips, wood pellets, straw, switch grass, poultry litter, MSW, waste wood, paper mill sludge
Taylor Biomass Energy	Same technology as SilvaGas. Syngas will be used for ethanol production or heat and power	Providing 300–400 t/d biomass gasifier for ethanol project in Kansas, USA	Biodegradable wastes and waste wood
REPOTEC/ TUV	Fast internally circulating bed (FICFB). Atmospheric steam BFB gasification with separate air blown CFB char combustion chamber heating the sand (indirect heating)	Pilot plant operational. 40 t/d plant in Austria. 500 t/d plant in Germany	Wood chips, wood working residues

with coal. There are seven entrained flow gasifiers currently available from major technology suppliers, namely ConocoPhillips E-Gas (formerly DOW), GE (formerly Texaco), Shell, PRENFLO, MHI, Siemens (formerly GPS/Future Energy) and MPG (Lurgi/Air Liquide). Larger entrained flow units (>200 MW) are generally found in power plants situations as they can achieve the necessary high syngas mass flow rates, higher than most other types of gasifier. A number of technologies are used in commercial-scale IGCC plants (*see* Section 4.5.3).

A major strength of the technology is that it can accept a wide variety of feedstocks. As the flow regime is essentially simply a gas with particles suspended in it, any liquid or powdered/pulverised solid can form a viable fuel input, regardless of its atomic make-up. Solid feedstocks such as coal and biomass generally require pre-treatment (such as size reduction) prior to feeding. When operating with coal, a particle size in the range 50–100 µm is normal. However, as biomass feedstocks are more reactive than coal, particles as large as 1 mm can be tolerated. Thus, energy requirements for milling are lower and, advantageously, screw feeding (rather than pneumatic feeding) is possible. This requires less electricity consumption for compression of inert gas, minimal syngas dilution by inert gas, and consequently, a higher efficiency (van der Drift, 2004). Where existing pneumatic feeders are used, because of their fibrous nature, biomass particles must be reduced to less than 100 µm, a process that can be very energy-intensive. To utilise particles of 1 mm or larger, screw feeders are generally suggested, although commercial experience is limited. As the residence time is short, if particles are too large, there is the risk of excessive levels of unconverted biomass. If the particular biomass requires pulverising to a small particle size, this will increase operating costs. As well as size reduction, pre-drying may be required to produce particles with the necessary characteristics. Excessively high moisture content reduces gasification efficiency; a maximum of ~15% moisture is usually suggested.

Some entrained flow gasifiers operate at very high temperatures (>1100°C), meaning that virtually no tar forms inside the unit. During operation, slag is formed that creates a coating on the sides of the unit, protecting the walls from corrosive substances that may be present. Liquid slag is removed from the bottom of the gasifier. To ensure proper operation, the slag mass flow should be at least 6% of the fuel flow. Industry opinion suggests that where entrained flow technology is used, biomass is best gasified in a slagging-type unit. This is likely to require the addition of a fluxing material (such as clay or silica) in order to obtain the appropriate slag properties at reasonable temperatures (van der Drift and others, 2004). For coal-fuelled plants, limestone or another calcium-rich material is sometimes used.

Most entrained flow gasifiers use oxygen (normally supplied by an ASU) as the gasifying agent, rather than air. Few use air as the high temperatures and pressures can result in high NOx levels, limiting the usefulness of the syngas. Syngas exiting the gasifier is at a higher temperature than with alternative gasifier designs and consequently, there can be a resultant energy loss during the cooling stage, prior to entering the gas clean-up system.

Globally, a number of different entrained flow gasifier variants are operating although only a few have significant large-scale experience with biomass (Pavani and others, 2009) or cogasification with coal. However, a number of competing biomass-based entrained flow gasification systems have been developed and tested to at least pilot scale (Table 23).

In principle, entrained flow gasifiers appear attractive for biomass gasification as they generate tar-free syngas and the low melting point of some types of biomass-derived ash helps minimise oxidant demand. However, the aggressive properties of some types of biomass ash may be problematical for gasifiers using a refractory or a cooling membrane; ash behaviour is one of the major hurdles for this type of biomass gasification. Some biomass ashes (for example, some woods) show only minimal melting at operating temperatures of 1300-1500°C. This is because the ashes are rich in CaO, while alkali metals (which generally reduce melting temperatures) are removed in the gas phase. Thus, a fluxing material is required in order to obtain the proper slag properties at reasonable temperatures. Ash viscosity is of critical importance to gasification reactor design. In the case of entrained flow gasifiers, feedstocks such as straw can be used, but in low and constant proportions (E4Tech, 2009). Thus, some difficulties may be encountered when gasifying biomass alone. However, some of these issues can be overcome or minimised if the biomass is cogasified with coal (*see* Chapter 4).

Ideally, the characteristics of the biomass feedstock must not change significantly over time, hence a steady supply of quality-controlled material is an important requisite (E4Tech, 2009). Some entrained flow gasifiers are capable of accommodating mixed feedstocks. However, these must also fall within the prescribed design and operating parameters. Various types of biomass have been tested or demonstrated in entrained flow units. Many have been wood-based fuels (such as wood chips, forestry residues, sawdust and waste wood), although a range of other materials including waste plastics, RDF pellets, classified MSW, sewage sludge, and energy crops such as straws and grasses has also been tested.

Depending on the feedstock/combination, entrained flow gasification can provide certain advantages over alternative gasifier designs. This may include lower emissions, higher carbon conversion, and lower tar production. However, further RD&D is considered necessary to address areas such as the limited data on coal-biomass cogasification, issues of feeding, carbon kinetics, residence time, plant emissions, and the deployment of warm gas clean-up systems (Laumb, 2011).

Table 23 Examples of biomass-based entrained flow gasification systems (to at least pilot scale) (E4Tech, 2009; IEA Task 33)

Developer	Technology	Status	Feedstock
Range Fuels	Separate reactors for low and high temperature gasification. Indirectly heated with steam. Syngas used for ethanol/mixed alcohols	US pilot plant (5 t/d biomass) operating. Larger commercial projects being developed	Up to ~50% moisture content acceptable. Includes timber/forestry residues, various wood types
CHOREN	Low temperature gasification producing gases and coke that are fed separately into a pressurised, directly heated, oxygen-blown high temperature gasifier. Syngas used for FT diesel	Several pilot plants operating. Commercial projects being developed. Choren technology bought by Linde Group in 2012	Woods, forest chips, sawmill waste, plastics, MSW, straw briquettes, miscanthus, cereal products, and energy crops. Max of 15% moisture
MHI	Biomass Gasification Methanol Synthesis (BGMS) – slagging, atmospheric, directly heated, oxygen and steam-blown gasifier. Syngas used for methanol synthesis	Pilot plant has operated but no recent activities	Wood chips, waste wood
KIT, Siemens, Future Energy, Lurgi	Initial pyrolysis to produce bio-oil (Lurgi). Then fed to pressurised, directly heated, oxygen-blown gasifier. Syngas used for FT synthesis	Pilot plant in Germany. Larger more advanced systems being developed	Candidates include a variety of biomass and wastes
CHEMREC	Second generation pressurised oxygen-blown technology. 30 bar, 950°C	Plants in Sweden and the USA. Commercial-scale plants proposed	Black liquor
Future Energy	GSP-type pressurised gasifier using pressurised water-cooled screen to protect the high-temperature gasifier with a layer of slag. 80 bar, 1200°C	Pilot plant operated at 26 bar. Technology developed and demonstrated at 3–5 MWth scale	Pulverised or pumpable fluid biomass. Has been used in Germany to gasify solid waste streams
ECN	Operates on pulverised char. 80 bar, 1200°C		Torrefied biomass
Clear Fuels, USA	Dry ash indirect entrained flow. 28 bar, 980°C	7.5 t/b biomass plant developed. Large-scale FT liquids plants planned with Rentech	

3.2 Biomass preparation for gasification/cogasification

There are a large number of biomass types, potentially suitable for gasification, each with different physical and chemical characteristics; these may include particle size and shape, bulk density, moisture content, energy content, chemical composition, and ash fusion characteristics.

Table 24 Biomass feedstock gasification requirements (E4 Tech, 2009; Fernando, 2008; Brar and others, 2012; Williams, 2010a)

Gasifier type	Particle size, mm	Moisture content, %	Composition
Entrained flow	<1 max	10–15	Should not change over time. Proportion of high-ash agricultural residues is limited
BFB and Dual systems using BFB	<13–150	10–55	Can accommodate changes but care needed with some agricultural wastes
CFB and Dual systems using CFB	<13–80	5–60	Can accommodate changes but care needed with some agricultural wastes
Fixed/moving beds	6–100	Up-draught: max 45–50% Down-draught: max ~40%	Limited suitability for fines. No limit on ash content

In terms of feedstock properties, the requirements depend on the type of gasifier. For instance, entrained flow gasifiers require small particle sizes, optimal moisture content and a consistent composition over time. CFB, BFB and dual bed systems have intermediate feedstock requirements and can tolerate larger particle sizes and a wider range of moisture contents, although ash melting temperature can be an issue. The main feedstock requirements for the main gasifier variants are summarised in Table 24. Depending on the particular type and manufacture of gasifier, specifications for both particle size range and moisture contents can vary widely; ranges suggested by different technology developers are noted in the table.

Raw biomass has a lower energy density than a typical coal, making it less convenient and efficient for storage, transport and feeding. Prior to feeding, most will require some form of pre-treatment such as drying and size reduction; some gasifier/feedstock combinations will require more pre-treatment than others. Pre-treatment renders such materials less problematic although inevitably, increases energy requirements and adds to costs.

Some biomass materials cannot be easily pulverised or slurried, hence continuous feeding tends to be an issue. The highly fibrous, sinewy structure often encountered makes some difficult to reduce in size and prone to blocking feeding systems. However, several technologies are available for converting biomass into a more convenient form (for instance, flash pyrolysis and torrefaction). Pyrolysis is the initial phase of the overall gasification process. Flash pyrolysis is carried out before the biomass is fed into the gasifier, converting it to char and ‘bio-oil’. The latter can be fed easily into most types of gasifier. The process occurs at a very fast rate, with biomass particles reaching ~650°C in less than a second. Some technology variants produce gaseous (syngas) products, rather than bio-oil. Clearly, the various pre-treatment processes applied to biomass prior to gasification also apply where it forms part of the feed to a coal-fuelled plant. Biomass pre-treatment steps may include:

Moisture reduction – Reducing moisture levels is important for both combustion and gasification systems as excessive levels reduce system efficiency and create operational problems. Efficiency of both processes increases as biomass moisture levels are reduced. For gasification, biomass moisture content should ideally be 10–15% or less, although the manageable level will depend on the particular gasification technology. High moisture content can reduce the temperature achieved in the gasification zone, resulting in incomplete gasification. As energy is expended in evaporating the water present, levels in excess of ~30% tend to reduce gasification thermal efficiency. Furthermore, the resultant steam may also affect the gas composition. Higher levels also increase the propensity for tar formation due to incomplete cracking. Drying to a suitable level requires energy and therefore entails extra cost. Typically, drying of biomass is carried out at 100–120°C. Heat may be provided externally or extracted from the gasifier syngas and/or other plant process steps. In practice, it is often uneconomic to reduce moisture levels to less than 10%, hence in practice, feedstocks may be dried to 10–20%.

Moisture content also affects on transport and storage, as transport is less efficient and more expensive if a significant proportion of the load comprises water. Storage of high moisture content biomass also brings other problems that include increased risk of composting, causing loss of biomass, and increased propensity for fire and mould formation.

Size reduction – It is important to achieve the appropriate feedstock particle size for the particular gasifier. Ideally, for most systems (as with coal gasification) it is preferable to use a biomass feedstock that is homogenous and of uniform size, shape and density. Particle size is an important factor; smaller particles have larger surface area and porosity (for a given mass) that facilitates faster heat transfer rates and removal of gasification products from the solid surfaces. They are also more readily and effectively transported within the system. Gasification of small particles results in faster reaction rates, lower tar and higher gas yields.

Depending on the particular feedstock, a number of size reduction processes may be applied, such as milling, chipping and shredding. For very small particle sizes, a suitable pulverising and screening system is required – this is likely to be an energy-intensive procedure. The amount of energy consumed during size reduction depends on many factors that include biomass characteristics (fibrous materials require more energy), moisture content, initial size, screen size, and processing equipment properties. Conversely, with some feedstocks such as loose crop residues, it may be appropriate to increase size and bulk density by pelletising or compaction/densification. This eases feeding and promotes improved solids flow in the feed systems and into the gasifier.

Ash level and composition – Ash levels in biomass materials can vary enormously. Whereas some types of wood may contain <1%, black liquor and dried sewage sludge may have more than 50%. Low-ash feedstocks (less than 5%) are generally preferable as this eases ash disposal problems. Where cogasified with coal, it also minimises any adverse impacts on the resultant ash where used commercially.

Ash composition is also important as biomass with low ash melting points can be difficult to gasify in some reactors; for instance, in fluidised bed systems, low melting ash can cause bed particles to agglomerate, defluidising the bed. Biomass containing alkali oxides and salts with ash content >5% can result in clinkering/slagging problems. Some ashes can cause sintering, deposition, and corrosion of the gasifier and other components. In practice, the ash melting characteristics of individual biomass feedstocks (or combinations of biomass and coal) may need to be determined prior to use.

Conversely, coal gasification can be improved by the addition of biomass. For instance, adding wood waste to a low-grade coal (ash content 32%) was found to improve operations. This was a result of the high volatiles, low ash content, and low sulphur level in the biomass that helped counterbalance the negative effects of the high sulphur content of the coal (Brar and others, 2012).

Torrefaction – A process showing significant promise is torrefaction, a mild thermal treatment (20–30 minutes at 200–300°C in the absence of oxygen) being increasingly applied to woody feedstocks. The process drives off moisture, completely decomposes hemicellulose and partially decomposes cellulose (Brar and others, 2012). It generates a product that is dry and relatively brittle and has a low oxygen content. Torrefied wood is much easier to grind than untreated wood, using 80% less energy for a given sizing, and with a significant increase in milling plant capacity.

There is an energy loss during the process, although the loss of mass is greater than the loss of energy, effectively increasing the heating value of the biomass. Torrefied biomass not only retains 79–95% of feedstock energy, it also produces a more reactive feedstock with lower H:C and O:H content than the original material. The product is usually referred to as torrefied biomass or 'biocoal' – visually, it resembles coal and also has some similar properties. The energy content of typical 'white' wood pellets is ~17 GJ/t, whereas a torrefied equivalent has an energy content of up to 22 GJ/t. The mean energy content (weighted fuel average) of bituminous coal is ~25 GJ/t (Coffey, 2011).

When gasified, torrefaction results in a high production of H_2 and CO. During the entrained flow gasification of beech wood (at 1400°C), H_2 and CO production were increased by 7% and 20% respectively, compared to the original wood (Brar and others, 2012). Torrefaction is considered to be of particular importance for this type of gasifier as feedstocks need to be in pulverised form; torrefied biomass is very brittle and easily pulverised. Although the process increases overall costs, this is somewhat cancelled out by advantages that include:

- higher energy density, significantly reducing transport costs;
- more friable and less fibrous structure, reducing power requirements for milling. Milling wood to 100 mm size requires a considerable amount of electricity (~0.08 kWe/kWth wood). Torrefaction can reduce this to 0.01–0.02 kWe/kWth wood (van der Drift and others, 2004);
- easier handling and feeding;
- improved stability during prolonged storage – greater resistance to biological degradation;
- very low moisture content regardless of the environmental conditions of storage – hydrophobic in nature;
- greater homogeneity than the original feedstock;
- improved burn-out.

By way of example, the characteristics of torrefied beech wood pellets are presented in Table 25.

Table 25 Characteristics of torrefied beech wood pellets (Gil, 2011)

Property	
Carbon content, %daf	54.3
Hydrogen content, %daf	6.0
Nitrogen content, %daf	0.18
Moisture content, % wet basis	3.8
Ash content, % dry basis	1.8
LHV, MJ/kg dry basis	19.8
Bulk density, kg/m^3 as-received	680
Energy density, GJ/m^3	13.5
Fines content, %	2.0
Pellet durability, %	97.2
Hardgrove Grindability Index	26

Torrefaction is now being deployed commercially. At Duiven in The Netherlands, Topell Energy and RWE Innogy have built a plant for the production of biocoal pellets. This came on line in 2011 and has a production capacity of 60 kt/y. RWE's Dutch subsidiary Essent will be the first company to use biocoal pellets over a five-year period for combustion in the Amer coal-fired power plants. In New England, USA, in 2013, Cate Street Capital plans to open the Thermogen Industries plant at the Millinocket paper mill. This new plant will produce 110 kt/y of torrefied wood for export to coal-fired power plants, primarily in mainland Europe and the UK.

In November 2012, it was announced that the 600 MW baseload pulverised coal Boardman power plant in Oregon, USA, was to be assessed for possible conversion to firing torrefied biomass. As with other large-scale biomass projects, sourcing an adequate supply of fuel will be a major issue. An estimated 4 Mt/y of green biomass would be needed. However, because of seasonal variations in supply, the plant would only run for six months of the year. The possibility of also using a fast-growing perennial grass (arundo donax) similar to switchgrass, is being examined.

4 Coal/biomass cogasification

Numerous coals and biomass materials have been gasified separately in a variety of gasifier types. Each individual feedstock comes with its own set of advantages and disadvantages. However, through the judicious blending, there is the opportunity for the shortcomings of each to be reduced, boosting the efficacy of the overall system (Pavani and others, 2009). Thus, cogasification offers the potential for cleaner coal utilisation as well as a means for the utilisation of biomass (and wastes) in an economic, safe, and environmentally acceptable manner. Recent years have seen the introduction of many incentive schemes aimed at encouraging the greater use of biomass for energy production. However, its use on an industrial scale may not be without problem or limitation. Some of these drawbacks can be overcome by combining it with coal. Many countries possess significant coal reserves and some already combine coal and biomass, particularly for power generation.

Currently, the biggest area of co-utilisation is combustion in existing power plants. Combining both and cogasifying can also provide a number of benefits. Although there are many commercial-scale plants that gasify coal and numerous small units that gasify biomass, relatively few have so far cogasified combinations of the two (Fernando, 2009). However, interest in cogasification has been growing, as adding biomass to a coal-fuelled facility can be advantageous. Gasifying biomass in a large coal gasifier can achieve higher efficiency and improve process economics through economies of scale. The biomass may be a no-cost waste. Hence it may be possible to take advantage of a lower cost feedstock (Fernando, 2009); cogasifying with coal may help smooth out the seasonal fluctuations in the availability of biomass, and so on. Furthermore, replacing a portion of the coal feed with biomass may enable a coal plant to obtain credits for the use of a renewable fuel. The advantages and disadvantages associated with co-utilisation are examined further below.

Coal has been gasified commercially for many years and the various reactions involved in the process have been well examined and described. Similarly, gasification of many biomass materials has been studied. However, the chemical processes involved when cogasifying coal-biomass mixtures are less well understood, and investigations continue (for instance, NETL, 2010b). Whereas coal comprises mainly carbon, biomass is often a mixture of complex compounds such as cellulose, hemicelluloses, lignin, extractives and minerals (Brar and others, 2012). When gasified, minor oxidation and major pyrolysis occurs, and as the temperature increases, a series of pyrolysis reactions take place:

- below 125°C, drying occurs;
- between 125°C and 500°C, hemicelluloses, cellulose, and lignin (partially) decomposes;
- above 500°C, remaining lignin degrades.

During gasification, all of the volatiles and some tars are thermally cracked and broken down into simple gaseous products. Remaining tars (and some alkali minerals) exit with the product gases.

Because of their different chemical and physical properties, a number of issues may arise when cogasifying coal and biomass, and these can present some technical challenges. Biomass has a higher hydrogen:carbon ratio and oxygen content than coal, making it more reactive under less severe (lower temperature and pressure) gasification conditions. This lower severity can lead to tar formation that can constitute a major challenge for gas clean-up. Trace elements present in coal and biomass may also be different, requiring alternative gas clean-up methods for each feedstock. Whereas char and tars are of greater importance for biomass gasification, species such as sulphur and heavy metals are likely to be of greater concern with coal. Biomass tends to have a much higher metallic ion content than coal. This can result in higher levels of acidic species capable of producing highly corrosive products. However, because of their lower sulphur and ash contents, biomass materials generally produce cleaner syngas than coal. Because of such issues, it may be more economically attractive and less technically challenging to cogasify biomass with coal (Long and Wang, 2011).

In terms of gasifier operating conditions, there are a number of similarities, but also some significant differences between biomass and coal. The minimum temperature required for coal gasification is ~900°C and that for biomass is generally in the range 800–900°C. Thus, the temperature required for the complete thermal gasification of biomass may be similar to that of coal (Fernando, 2009). However, dissimilarities attributable to differences in fuel properties may include:

- unlike coal particles, some biomass materials are very fibrous in nature;
- biomass is a more reactive fuel than coal;
- biomass ash has a comparatively low melting point and under some circumstances, in the molten state, can be very aggressive;
- at low gasification temperatures, biomass can produce high tar levels in the product gas.

Advantageously, studies have detected the existence of synergetic effects when cogasifying coal and biomass. However, there appears to be no firm consensus on the precise nature of the chemical reactions occurring and a number of possible reactions and processes have been suggested. Under some circumstances, the addition of biomass to a coal feed has been found to increase both the rate and extent of gasification reactions occurring – reaction rate has sometimes been observed to double (NETL, 2010a). This may be a consequence of the catalytic activity of char formed, or the high oxygen content of the biomass and investigations are continuing. From a technical standpoint, biomass gasification can be improved in the presence of coal as tar content in the product gas is often significantly reduced (Vreugdenhil, 2009; Bi, 2005). Furthermore, certain types of biomass ash have been found to catalyse coal gasification (Brar and others, 2012).

However, whilst cogasification is advantageous from a chemical point of view, there can be technical challenges associated with the gasification stage as well as a number of upstream and downstream processes. Upstream, the uniformity, size and characteristics (such as moisture content) of the coal and biomass particles are of importance and various pre-treatments may be required prior to feeding. While upstream processing influences material handling, the choice of gasifier operating parameters (temperature, gasifying agent, and catalysts) determines product gas composition and quality. As biomass decomposes at a lower temperature than coal, different reactors suited to the particular feedstock mixture may be required (Brar and others, 2012). The choice of feedstocks and the type of gasifier and its operating parameters not only influence product gas composition, they also dictate the amount and types of impurities to be handled downstream. Some downstream processes may require modification when biomass is added to a coal gasification process. For instance, alkalis stemming from biomass may result in corrosion problems in downstream pipes and components.

Over the course of several decades, studies into the cogasification of coal and biomass have been carried out, although RD&D efforts are still continuing. Many investigations have been undertaken using different types of gasifier and specific types of coal and biomass in North America, Europe and the Asia-Pacific region, although most have been at a small scale. Despite these efforts, some of the chemical pathways involved are still unclear and practical operating experience, particularly on a large scale, remains limited. Various programmes are addressing these issues. For instance, entrained flow cogasification is being actively pursued in several parts of the world. In the USA, the entrained flow gasification of a variety of coal-biomass combinations is being investigated. Work is examining operating parameters, analysis gasification products, and assessing gas clean-up systems (NETL, 2010b; Laumb, 2011). Similar themes are being studied elsewhere. For instance, for some years, ECN in The Netherlands has been examining both entrained flow and fluidised bed cogasification (Carbo and others, 2012). Elsewhere, work has not been limited to the use of hard coals and the potential for cogasifying biomass and lignite has also been examined (Vreugdenhil, 2009). Although historically, a large body of work has already been generated, RD&D programmes focused on cogasification are continuing, motivated mainly by combinations of environmental and economic concerns. Some projects are examining cogasification as a means for the large-scale production of hydrogen. Here, the critical challenges and major RD&D needs have been identified as further development of biomass/coal cofed gasifiers, the need to reduce process costs and improve overall system efficiency, the removal/control of feedstock impurities, and the minimisation of process carbon footprint (EERE, 2009). Thus, there are still some technical uncertainties associated with the process, largely because of the limited experience with cogasification at a commercial scale. For instance, Weiland and others (2010) and Brar and others (2012) noted:

- the technology for feeding mixed feedstocks via pressurised dry feed systems is not mature. Particle size and shape are critical factors for specific feeder types;
- gasifier performance – more operational data is required on reaction kinetics, material interactions, and product effects. Detailed models have not yet been developed or validated;
- in-depth studies and practical evaluation of some combinations of coals and biomass types is lacking;
- process optimisation requires further more detailed examination.

In the case of cogasification of forest residues with coal, there are still issues that have not yet been fully explored. For instance, the tar evolution profile needs further investigation in order to tailor gasifier design, plus determine operating conditions and tar removal systems. In addition, further studies are required to determine the influence of particle size and specific energy consumption for forest residues. This information will be critical to performing sustainability and economic analysis of the size reduction process (Brar and others 2012). Similar issues remain with some other types of biomass.

4.1 Advantages and disadvantages specific to biomass/coal cogasification

Recent years have seen increased concern over global warming and the impact of fossil fuel plants. Advantageously, if grown sustainably, biomass is viewed as both renewable and carbon-neutral. The general issues associated with the production and use of biomass have been considered earlier (*see* Section 2.4.2). However, there are a number of considerations that are more specific to cogasification. There may be certain advantages accruable by cogasifying, rather than gasifying independently. Synergetic effects may increase reaction rates, and blends of coal and biomass have shown lower activation energy than the individual components – total activation energy needed is nearly always less. Consequently, reaction times are faster and less gasification agent (oxygen or air) is usually needed to complete the reactions.

Combining biomass with coal can provide some advantages to the latter as it enables coal to play a major role in simultaneously enhancing energy security and decarbonising, for example, the production of transportation fuels. The first systems, co-processing up to ~10% biomass, could be built during the coming decade using suitable coal gasifiers (before suitably large biomass gasifiers become commercially available). Co-utilisation in this way would help establish lingo-cellulosic biomass supply chains in the market long before it would be feasible with any biomass-only approach.

The difference in the chemical properties of coal and biomass provides an opportunity to tailor the syngas composition by changing the ratio of the fuels and operating parameters, as dictated by the end products required (Pavani and others, 2009). Various factors influence the composition of the product gas that include the type of gasifier, its operating temperature and pressure, flow rates of coal-biomass mixtures and oxidising agents (air and/or steam), type and amount of catalysts, proportion of biomass in the fuel mixture, and the properties of the individual feedstocks used.

The main advantages of cogasifying biomass with coal (rather than biomass alone) are summarised in Table 26.

4.2 Upstream processing and gasification

The physical characteristics of mixed coal-biomass feedstocks can vary widely and will depend largely on the particular combination used. The type of coal and biomass selected, their ratio, and the

Table 26 Main advantages of cogasifying biomass with coal (Bi, 2005; Long and Wang, 2011; Fernando, 2009, Hanssen and Hagen, 2006)

Disadvantages of stand-alone biomass gasification	Advantages of cogasification with coal
Separate, stand-alone gasification can be expensive	Reduction of specific investment costs. Cogasification has the potential to reduce investment cost and improve efficiency compared to separate gasification facilities
Capacity of biomass plants sometimes limited to relatively small scale	Improved efficiency by allowing operation in a larger system (compared to biomass-only gasification facilities)
Seasonal variations in biomass supply. Overall supply maybe limited. Mainly limited to small scale processes and small capacity plants	Coal is easily available in many countries. Larger scale possible; improved process economics Adding biomass to existing coal-fired processes provides economies of scale and helps smooth out seasonal fluctuations in biomass availability
Some feedstocks unsuitable for stand-alone gasification	Some biomass sources are unsuitable for alternative utilisation hence would remain unused (as a waste). There may be associated disposal costs. Cogasification may provide a cost-effective disposal route
Low gasification temperature Tar production may be excessive	Biomass has higher reaction rate than coal; synergistic improvement when cogasified with coal Bio-ash can act as catalyst for coal gasification Cogasification usually produces higher overall efficiency than individual feedstocks. Higher gas yield Little/no tar production; most tars converted to gas at high temperature
Low heating value gas High CO_2 content	Higher heating value gas produced CO_2 converted to CO at high temperatures
Fluidisation quality (in fluidised bed gasifiers) Anomalistic shape Inert bed particle (sand) can cause problems of abrasion	Improved fluidisation quality Coke as bed particles – abrasion reduced and power saved
Biomass is carbon-neutral but a limited resource	CO_2 emissions – although not carbon-neutral, coal is a huge global energy resource. Biomass is seen as carbon-neutral and renewable. Combining the two reduces overall CO_2 emissions
Biomass harvesting and pre-treatment can be expensive	Cogasification in IGCC plant – compared to coal firing alone: – power output increases; – emissions of SO_2 and NOx decrease; – process efficiency improves slightly; – less energy required for H_2S removal; – less water required for FGD scrubbers
	Co-utilisation would reduce competition with land use for food production. Also, large releases of CO_2 from standing biomass and/or soil carbon when new lands are cultivated would be avoided

influence of any pre-treatment processing all affect the final mechanical and transport characteristics of the blend. This area appears to have received only limited examination, although as interest in the use of mixed feedstocks increases, a number of studies have been initiated. These are exploring the relationships between selected coal-biomass feedstock combinations and the resultant blend (in terms of mixture composition, stress, strength, rheology and permeability).

As materials are subjected to compaction and stress, they tend to become stiffer and harder. Permeability also reduces. Studies of different bituminous coal-biomass blends under these conditions indicate that pure biomass is the most compliant and weakest, and coal the stiffest and strongest. Such data is useful for, for instance, assessing the feed characteristics of dry-feed coal-biomass mixtures, so that gas flow back is avoided and feed rates maintained into pressurised gasifiers (Chandra and others, 2012).

The composition of syngas generated is affected by various gasification parameters as well as upstream and downstream processes. For instance, some upstream processes (such as torrefaction) increase levels of H_2 and CO in the gas. Different end-uses will impose different syngas requirements. The main variables are:

Ratio of biomass to coal – The ratio affects the composition of the product gas. For instance, studies of wood/coal cogasification found that as the wood component increased, the amount of hydrogen in the syngas decreased and the CO_2 content increased. Other gaseous species (CO, CH_4 and trace gases) were largely independent of biomass ratio (Brar and others, 2012). A lower biomass ratio produced a gas favourable for methanol and hydrocarbon fuel synthesis, whereas a high ratio generated a gas better suited to chemicals synthesis (Kumabe and others, 2007). Thus, the ratio of the different gaseous species produced varies with the amount and type of biomass used. The type of coal also has an influence. The specific outcomes will depend on the particular combination of coal and biomass used and generally will need to be determined on a case-by-case basis.

Air and steam flow rates – Accurate flow rates of air and steam are important in creating the appropriate stoichiometric gasification conditions and adequate reaction/residence time for high molecular weight volatile compounds and tars to be broken down into gaseous species. The type of gasifying agent is also important. Excess air is likely to provide high conversion but produce a syngas with a high CO_2 concentration and low calorific value. The use of steam assists the water-gas shift reaction and produces hydrogen-rich syngas. If air is used, less hydrogen is produced.

Gasifier temperature profile – The temperature profile through the gasifier affects the chemistry of gasification and significantly influences the composition and calorific value of the syngas. Adjusting the temperature range influences the amounts of H_2, CO, CO_2 and hydrocarbons in the resultant syngas. Furthermore, the relative sizes of the three main reactor zones (combustion, reduction and pyrolysis) will also have an influence. Studies suggest that the temperature profile will be specific to a particular coal-biomass mixture.

Catalyst – Catalysts have proven effects in gasification and on syngas quality. The use of appropriate catalysts can reduce reaction temperature, improve gasification rate, change the H_2:CO ratio, and reduce tar formation. Potentially, a range of materials can be used (such as dolomite and nickel-based catalysts).

Dolomite catalysts can also help reduce sulphur and chlorine emissions.

4.3 Downstream processing

Following upstream processing and gasification, the syngas produced is likely to require some form of clean-up. This may encompass small particulates, alkali species, nitrogen, sulphur compounds, and tars. The type and intensity of clean-up requirements will depend on the end use of the syngas. Clean-up may involve a combination of the following:

Particulate removal – Particulates comprise mainly ash and char particles; their characteristics and quantity will depend on the type of gasifier and the feedstock combination used. Particulate removal systems can deploy cyclones, ceramic filters, wet scrubbers, or bag filters. However, filters operating at temperatures less than 450°C may encounter problems of tar deposition.

Alkali removal – At gasification temperatures above 700°C, any alkali species (Na, K, Mg, Ca) and/or sulphur present in the feedstock will form oxides and vaporise. At temperatures below ~650°C, these may condense and deposit on downstream sections of the gasification system, causing corrosion. Alkali oxides are also likely to deactivate catalysts used for tar removal. Under some operating conditions, higher gasification temperatures can promote higher alkali levels.

Ammonia removal – Nitrogen is generally present as ammonia and can be removed by wet scrubbing of the cold gas and by destroying ammonia using dolomite, or nickel- and iron-based catalysts.

Tar removal – Gasifying coals alone can produce tars, although levels are generally less than when biomass is included in the process. The amount formed depends on the amount and type of biomass used, the gasifier and its temperature profile, the type of gasifying agent, and the steam-to-biomass ratio.

Tars are high molecular weight compounds that exit the gasifier with the product gas. They can be very damaging to the gasifier as they tend to stick to the walls and clog entrance and exit ports, especially when slag is also being generated. Most tars will condense at temperatures below 450°C although some will remain in the product gas in the form of a suspended aerosol. Tar condensation can occur in downstream pipelines and particulate clean-up devices. For most applications, it will need to be eliminated. Ideally, this can be accomplished by avoiding its formation through judicious choice of gasification technology, gasifier operating conditions, and the use of the appropriate catalysts. In higher temperature gasification (such as in entrained flow and some down-draught gasifiers) tars can be thermally cracked as they form in the gasifier, thus avoiding downstream problems. Where this is not possible, suitable tar removal techniques will need to be employed and various processes have been demonstrated or proposed. These include the use of suitable catalysts (such as NiO_2/Al_2O_3 catalyst), secondary air injection at 850°C to crack the tars into gaseous compounds, and the use of cooled solvent techniques to condense and collect the tars.

4.4 Utilisation of syngas

Globally, most syngas is currently produced from fossil fuel gasification. Major applications include the production of ammonia and methanol, hydrogen for refineries, Fischer-Tropsch products, and electricity generation. In some parts of the world, reserves of fossil fuels are becoming depleted, hence the growing interest in the use of biomass as a means for extending their lifetimes and reducing energy import dependency. In the future, biomass is expected to play a greater role in the global energy infrastructure for the generation of power and heat. It will also be used, however, for the production of chemicals and fuels. The dominant biomass conversion technology will be gasification.

When biomass is gasified at a temperature of 1200°C or more, the resultant gas is referred to as **biosyngas**. The biomass is completely converted to H_2 and CO (plus CO_2 and H_2O). Biosyngas is chemically similar to that derived from fossil fuels and can replace its fossil equivalent in all applications. In the longer term, biosyngas is expected to be dominant for synthesis-type applications.

If the gasification temperature is less than 1000°C, **product gas** is generated – this can be converted into biosyngas via catalytic or thermal cracking (Boerrigter and Rauch, 2005). Product gas comprises mainly CO_2, H_2, H_2O, CO, CH_4, various aliphatic hydrocarbons, benzene, toluene, and tars. Typically, the syngas components (H_2 and CO) contain only ~50% of the energy in the gas; the remainder is contained in CH_4 and higher (aromatic) hydrocarbons.

Different end-uses for these gases impose different gas specifications – these are determined by the end-use. Product gas is usually preferred for power generation and SNG synthesis, whereas biosyngas is the choice for more advanced applications such as Fischer-Tropsch synthesis, ammonia and hydrogen production, and the production of olefins and alcohols. The removal of inorganic impurities that act as catalyst poisons (such as Na, K, P, S, and Cl) is a major challenge in the cleaning of biosyngas. The main applications and potential uses for biosyngas and product gas are discussed below.

4.5 Commercial utilisation of cogasification

As the composition of typical product gas is more complex than biosyngas, more advanced applications are not necessarily the first choice. This is because the syngas components (H_2 and CO) represent only around half of the energetic value of a product gas. An exception is the production of SNG, where higher CH_4 levels are beneficial ('methane-rich synthesis gas'). Product gas, biosyngas and syngas produced from cogasification have a number of applications and potential uses. These are discussed below.

4.5.1 Substitute Natural Gas (SNG) production

Parts of the world lack natural gas or depend heavily on imported supplies. Where coal and biomass are available, they have the potential for conversion to SNG. This has properties similar to those of natural gas – it is mainly methane, the main component (>90%) of natural gas. Theoretically, it can be produced from any hydrocarbon such as coal as well as from various biomass materials. There are several options for producing SNG, although currently, only steam-oxygen gasification is used commercially. Syngas is generally shifted and cleaned to remove unwanted species before methanation, where it is purified and converted to methane and water in a fixed-bed catalytic reactor. The high temperature gasification of biomass alone tends to produce biosyngas with a high concentration of CO and low level of CH_4. However, gasification processes that yield product gases with high levels of CH_4 are more appropriate to SNG production.

Historically, there has been interest in producing SNG, particularly in the USA and latterly in China (Sudiro and Bertucco, 2011). Both have substantial coal reserves as well as ample supplies of biomass, and various studies and proposals have examined the potential of cogasifying for the production of SNG. However, at the moment, there are no commercial coal-biomass cogasification SNG facilities operating in either country.

Potentially, SNG has a number of useful advantages over some alternative fuel sources:

- it can be transported efficiently and cheaply using existing natural gas pipelines and distribution networks;
- it is an easily convertible feedstock; it can be used in natural gas combined cycle (NGCC) power plants and petrochemical facilities;
- it can have a greater social acceptance than conventional coal;
- it can be stored underground, enabling efficient operation throughout the year, and making it independent of fluctuations in demand.

Various studies have examined the potential for producing SNG from coal and/or biomass in particular regions or countries. For instance, in The Netherlands, generating SNG via the cogasification of coal and biomass has been considered. Here, natural gas is a major energy source although reserves are declining and alternative sources of supply will become increasingly important. Studies suggest that the cogasifying up to 50% biomass with lignite could be an economically viable option, although 35% was considered the optimum (Vreugdenhil, 2009). As elsewhere, cogasification was proposed on the basis that coal is available widely and cheaper than biomass. Thus a combination of the two would increase the economic margin and improve the environmental acceptability of an SNG production facility.

Similar studies in the USA have noted the potential of producing SNG from coal and biomass. Drivers cited included the diversification of US energy options, reduction of natural gas imports, stabilisation of fuel prices, and reduction of CO_2 emissions. An SNG plant was proposed by Hunton Energy and was to be built at Freeport in Texas. The facility was to produce SNG by cogasifying coal, petcoke and biomass. All of the CO_2 produced was to be captured and used for EOR. However, scheduled to start up in 2015, the project foundered due to commercial reasons. At the moment, in the USA, SNG production from coal is limited to the Great Plains facility in North Dakota, although several other proposed coal- and/or petcoke-based projects are also at various early stages in their development. However, the current low price of natural gas and the increased availability of shale gas has led to the cancellation of a number of proposed SNG projects. In countries with coal resources but lacking natural gas, there is a greater incentive to develop large-scale coal or coal/biomass projects.

The only commercial scale biomass-to-SNG plant is in Sweden (the Gothenburg Biomass Gasification Project – GoBiGas). This started up in 2008 and gasifies forest residues. Elsewhere in the country, a 20 MW SNG plant was scheduled to be commissioned in 2012 and an 80 MW plant in 2016 (Sudiro and Bertucco, 2011).

4.5.2 Chemicals production

Globally, around a third of total primary energy consumption is for transportation fuels and chemicals. Syngas is a versatile building block for the chemical industry and major uses include ammonia synthesis for fertiliser manufacture, generation of hydrogen for oil refining, and methanol production. Liquid fuels are produced from coal in considerable quantities by Sasol in South Africa. Most current syngas production is from coal-based plants, although in the future, syngas from biomass and biomass/coal combinations is likely to become a key intermediate in the production of some renewable fuels and chemicals.

Historically, the cogasification of various biomass and wastes with coal has been demonstrated using several types of gasification technology. Two of these were in Germany. At Berrenrath, during the 1980s and 90s, lignite was cogasified successfully with several waste materials (MSW pellets, dried sewage sludge and loaded cokes) in a 600 t/d pressurised circulating fluidised-bed High Temperature Winkler (HTW) gasifier. Biomass materials were fed without problem by the existing plant solids handling and feeding systems and during all trials, gasifier operation was virtually trouble-free. In the case of MSW, up to 50% was gasified successfully. There were no appreciable changes in gasification temperature or syngas output and composition (Fernando, 2009). Syngas produced was used for methanol production. In late 2010 ThyssenKrupp Uhde acquired the HTW technology from RWE/Rheinbraun.

Cogasification was also carried out successfully at the Schwarze Pumpe plant in Germany where a range of coals, biomass and wastes were gasified in the site’s three gasifiers (operated in an integrated manner). These comprised an oxygen-blown FDV rotating grate unit, an oxygen-blown GSP entrained flow gasifier, and an oxygen-blown BGL slagging gasifier (Mills, 2010). Between 1995 and 2002, wastes such as demolition wood, sewage sludge, plastics and household waste were processed. Different combinations of materials were regularly used and at times, up to 80% waste and 20% lignite was cogasified. Syngas was supplied to an on-site methanol production unit. However, operations have now ceased. The FDV and GSP gasifiers were taken out of service and the BGL gasifier was shipped to India for use in a coal-to-ammonia plant. As noted earlier, there are a number of biomass-based gasification processes being developed for the production or co-production of methanol; one of the largest is the Värmlands Methanol Project in Sweden that will gasify forest residues.

Other applications for syngas include the hydroformylation (oxo-synthesis) of olefins. Here, olefins are reacted with syngas in the presence of homogeneous catalysts (often Rhodium-based) to form aldehydes and alcohols. The most important oxo-products are in the range C3-C19. These are converted to alcohols, carboxylic acids, aldol condensation products, and primary amines. Other applications of syngas have relatively small markets or the processes involved are still in early stages of development. These include the production of mixed alcohols, CO (for acetic acid and phosgene production), and aromatics (Boerrigter and Rauch, 2005). Although various commercial plants operate with coal, predominantly in China, there do not yet appear to be any co-utilising coal and biomass.

Recently, the concept of combining coal and biomass cogasification as part of an integrated IGCC and chemicals production facility has been proposed. In 2009, a consortium comprising Polish companies ZAK and PKE announced plans to develop such a polygeneration facility (with CCS) at the Kedzierzyn Chemical Plant in Poland. The proposed complex would enable the simultaneous generation of clean electrical power, heat, and syngas to be used by an adjacent methanol plant, as well as the capture and storage of CO_2 emitted (~2.5 Mt/y) by the production process. A proportion of the CO_2 would be utilised in the manufacture of fertilisers and plastics, as well as chemical raw materials, urea and hydrogen. It may also be used later for the production of synthetic fuels. It is expected that the combination of coal/biomass gasification technology coupled with CCS and a source of renewable energy, will potentially produce negative carbon emissions. Details of the gasification technology proposed have not yet been made public.

It is anticipated that the Kedzierzyn complex will produce 1.55 billion m^3/y of syngas and generate a total of 300 MWe (gross electricity production will be 2.4 TWh/y). Around 137 MW of thermal energy will also be produced as well up to 550 kt/y of methanol. Fuel for the plant will be 2 Mt/y of coal plus 0.25 Mt/y of biomass. Pre-feasibility and feasibility studies for various parts of the project were undertaken in 2009 and 2010. A completion date of 2015 has been suggested for the plant (PKE and ZAK, 2010; Uliniarz, nd).

Power generation/cogeneration

Biomass-derived syngas gas can be used for direct combustion in power generation/cogeneration plants, although most such facilities are of small scale. Alternatively, it can be gasified in a stand-alone gasifier and the resultant syngas injected into the combustion zone of a coal-fired power plant. A major advantage of this technique is that biomass does not enter the plant's boiler, thus avoiding any issues with unwanted species such as alkalis. It also avoids any impact on the properties or quality of fly and bottom ash, often sold commercially. Examples of commercial plants using this technology have been examined earlier in Section 3.1.3. To date, these have been limited to conventional pulverised coal boilers. However, syngas generated by gasifying biomass also has the potential for use in integrated gasification combined cycle (IGCC) plants. IGCC employs a combined cycle format that incorporates a gas turbine fired on syngas; heat is recovered from the turbine's exhaust gas and used to generate steam to drive a steam turbine. Typically, more of the power produced by an IGCC plant (~60−70%) comes from the gas turbine. Coal-based IGCC plant configurations and operation have been examined in detail in a number of IEA Clean Coal Centre reports (for instance, Mills, 2006; Henderson, 2008), and are not therefore considered in detail here. Several technology variants are offered commercially and a number of plants are in commercial operation; many others have been proposed and several are close to completion. However, largely because of a combination of prevailing market conditions and economic issues, a number of other projects have been cancelled or delayed.

Most coal-fuelled IGCC plants use oxygen-blown technology. This has a number of fundamental advantages over air-blown systems that include smaller gasifier size (and hence lower cost), the heating value of the cooled/purified syngas is higher, syngas volume is about half that for an air-blown unit for the same amount of gasification energy (thus gas handling and clean-up requires smaller units), and smaller heat exchangers are required to recover sensible heat from the syngas prior to clean-up. Technical disadvantages include the energy needed for air separation and the higher degree of plant integration required. Auxiliary power consumption in an air-blown system is estimated to be ~8%, compared with 10–15% for oxygen-blown systems.

As part of their commercial operations, a number of existing coal-fuelled IGCC plants cogasify combinations of coal and biomass. In addition, various studies have examined the potential advantages and disadvantages associated with the use of such fuel combinations (for instance, Long and Wang, 2011). These suggest that using biomass in an existing coal-based IGCC can provide a number of benefits. Long and Wang modelled the impacts of adding up to 50% (wt) biomass on the performance of a 250 MW coal-fuelled IGCC. This was the highest proportion thermodynamically feasible, and also the one that produced the most significant results. It was suggested that, initially, plant efficiency would increase as 10% biomass was added. At 30%, it would decrease, but increase again when biomass addition reached 50%. The variation of efficiency was minor, only within one percentage point between 38% and 39% (Long and Wang, 2011). The results suggested that system efficiency, emissions and power output are not linear functions with biomass blending ratio. The authors concluded that by cogasifying biomass with coal in this manner:

- net power output would increase;
- emissions would decrease;
- efficiency would improve slightly.

Adding biomass to the feed reduced plant auxiliary power requirements as overall pollutant (such as SO_2) levels were lower, reducing syngas clean-up requirements. Water requirements for the particle scrubber were also reduced, suggesting that higher levels of biomass produce less fly ash and slag output. There was also a positive impact on CO_2 emissions. Other investigations have reached similar conclusions.

Some studies have modelled cogasification as the basis for clean electricity generation combined with hydrogen production. For instance, work carried out at Babes-Bolyai University in Romania examined combining coal with various types of biomass and solid wastes in an IGCC-based system. This was capable of producing varying amounts of electricity and hydrogen, and was coupled with 90% carbon capture. The process modelled was based on a Siemens gasifier and generated between 400 and 500 MW net electricity, with a flexible output of 0–200 MWth hydrogen. Evaluations were undertaken for gasifying (80:20) combinations of coal with sawdust, wheat straw, corn stalks, MSW, waste paper, sewage sludge, and meat and bone meal.

Unlike most other IGCC + CCS evaluations, where hydrogen is only used to generate power in a combined cycle gas turbine plant, this concept proposed purifying part of the hydrogen-rich gas coming from acid gas removal system and exporting it either for direct use (chemicals/liquid fuels production, or fuel cell use) or for temporary storage. With the latter, hydrogen could then be converted to electricity at times of high power demand, taking advantage of high electricity prices. It could also help smooth out variations in supply from the growing level of intermittent renewables being deployed in many countries. Such a concept could provide a high degree of operational flexibility as it would allow the plant to operate solely on base-load, irrespective of electricity demand, offering significant technical and economic advantages. Overall, the process would capture 90% of the feedstock carbon, enhance security of supply by fuel diversification, and improve plant flexibility in terms of varying the energy vectors according to the instant grid demand. Such flexible plant operation would offer some advantages within the context of the emerging hydrogen market. In the initial stages of the developing the hydrogen economy, plants could operate predominantly in electricity production mode, with low or even zero hydrogen output. However, as hydrogen applications increase, more plant energy could be delivered in form of hydrogen (Cormos, 2012).

Several commercial coal-fuelled IGCC plants in operation have at least trialled combining a proportion of biomass with the coal feed. A number of proposed projects aim to do likewise. To date, significant operational experience of coal-gasifying has been accrued. The plants that have or are (or have) cogasifying are:

The Willem Alexander IGCC plant, Buggenum, The Netherlands

Developed initially by Demkolec BV, initial syngas trials were carried out in 1994-95. In 2001, the plant was bought by NUON for operation as a commercial base load station. Based on Shell gasification technology, it can gasify a range of coal types as well as petroleum coke. Gross power output is 284 MWe (156 MW from the gas turbine and 128 MW from the steam turbine). The plant generally operates at a net efficiency of ~43% (LHV).

Around 2000 t/d of imported coal is used, usually cogasified with biomass. The Dutch Coal Covenant requires that CO_2 emissions from the plant are reduced by 200 kt/y – the equivalent of ~35 MWe from biomass, or ~30% (wt) of biomass in the coal feed. Eventually, up to 50% biomass may be used, generating 60 MWe of 'green power'. Biomass is cogasified with coal in a Shell single-stage upflow entrained flow, oxygen-blown, dry feed gasifier. This is of the membrane walled type and operates at a temperature of 1500°C and a pressure of 2.8 MPa. Cleaned syngas is diluted with nitrogen and steam to achieve the required specification for the gas turbine. The gasifier has a design capacity of ~4.0 million m^3/d of syngas. In order to maximise thermal efficiency, the cycle uses full integration with extraction of air from the gas turbine compressor for the Air Products ASU (Mills, 2006).

A programme of biomass cogasification began in 2001-02. Testing included 34 types of biomass that included wood, chicken litter, municipal sewage sludge, grape seed, palm-pits, cacao meal, sunflower pits, paper/plastic residue, and paper mill wastes. Up to 30% (wt) were used. However, in order to maintain the required power output, biomass addition was limited to 10–15% (Fernando, 2009; van der Drift, 2010). Biomass feedstocks currently used include dried sewage sludge, chicken litter, and sawdust. Ideally, particle size is limited to ~1 mm, and moisture content to ~5%.

Initial cogasification operations threw up a number of technical issues although these were systematically resolved. The successful programme undertaken at Buggenum has confirmed that a wide range of secondary fuels can be cogasified at relatively high ratios on a continual basis for significant periods of time.

For some years, Vattenfall/NUON has also been planning the construction of a 1200 MWe multifuel IGCC plant at Eemshaven in the north of the country. This was originally intended to house three Shell gasifiers and between three and five combined cycle units. About 60% of the fuel was to be supplied by the gasifiers, with the remaining 40% coming from natural gas. The coal feed was to be substituted by secondary fuel and biomass up to 50% (wt). This multifuel strategy was viewed as providing several important advantages:

- IGCC produces low environmental emissions and offers the most cost-effective route to CO_2 control via pre-combustion capture technology;
- in a volatile energy market, the ability to switch fuels would allow the maintenance of high efficiency with low marginal costs. A multifuel plant operating on coal and biomass for base-load, with natural gas for peak load, would be well placed in The Netherlands as well as in the merit order for North West European plant;
- gasification would afford opportunities beyond power generation (for example, production of hydrogen or methanol).

Assuming that the gasification systems are eventually installed, they will benefit from various technological advances developed during plant operations at Buggenum. However, changing market conditions (such as rising construction costs) have forced NUON to rethink its strategy. As a result, the plant will initially only operate as a gas-fired CCGT when it comes into operation. When appropriate, the gasification trains could be added later.

ELCOGAS IGCC plant, Puertollano, Spain

Puertollano is the location of Spain's 335 MWe coal/petcoke-fuelled IGCC plant. This was built by ELCOGAS, a consortium of eight European utilities and three technology suppliers, set up in 1992 to develop the project. The plant uses a Krupps-Koppers PRENFLO single-stage, oxygen-blown entrained flow gasifier with dry pulverised coal feed. Fuel is transported pneumatically to the gasifier using nitrogen as carrier gas. Steam/nitrogen is used as moderator, fed through four horizontally arranged burners located in the lower part of the gasifier. The reaction chamber has a membrane wall with an integral cooling system that produces pressurised steam. Gasification takes place at a pressure of 2.5 MPa, at a temperature of 1200–1600°C (Fernando, 2009). The plant started commercial operation in 1996 with natural gas, but has operated with syngas since 1998.

The plant's basic fuel is local high ash (~40%) subbituminous coal blended in equal proportion with high sulphur (5.5%) petcoke from the Puertollano REPSOL refinery. At full operational capacity, the plant burns 700 kt/y of mixed fuel. Although designed to operate primarily on this fuel combination, a number of cogasification trials have been carried out using different biomass feedstocks. A dedicated preparation system was used to feed up to 10% (wt) of materials that included olive wastes, almond shells, waste wood, and vineyard and grape wastes. These were cogasified with the coal/petcoke; total operating time under these conditions was more than 1100 hours.

The plant also successfully cogasified Meat and Bone Meal (MBM – 1% and 4.5%). In this case, around 2% limestone was added to the feed to capture chlorine and avoid high-temperature chemical corrosion. There were no observable operational differences in the behaviour of the fuel preparation and sluicing systems. During gasification, there were no effects with the 1% test, although at 4.5%, there was an appreciable reduction in the fouling values, which was coincident with a limestone reduction. There was also a progressive increase in chlorate level in the wet scrubber system. However, there were no changes in hazardous emissions.

More recently (during 2007 and 2008) further cogasification trials were undertaken using olive oil waste (orujillo). Initial tests were undertaken using 1–2%, although this was subsequently increased to 4%. The appropriate amount of orujillo was mixed with limestone and introduced into the gasifier with a 50% mixture of coal/petcoke. The limestone/orujillo mixture tended to cake in the storage hopper so was fed manually. However, overall, no significant operational problems were encountered.

Polk IGCC plant, Florida, USA

Tampa Electric's 250 MWe Polk plant was built with support from the US Department of Energy (DOE) as part of its Clean Coal Technology Program. Since 1996, the facility has been operating using a 2000 t/d oxygen-blown GE gasifier. Coal for the process is stored on-site in two 5000 tonne capacity silos. The gasifier generates syngas with a CV of ~9.3 MJ/m^3; this is cooled to 750–800°C, then cleaned. Particulates and HCl are removed using a water scrubber, and sulphur species removed via COS hydrolysis. H_2S removal is by means of an MDEA-based acid gas removal system, with sulphur produced in a Claus unit. Since start-up, the plant's reliability and availability have increased steadily. According to the DOE, the Polk facility is now one of the world's cleanest coal-fired power plants. More than 98% of SO_2 and 90% of NOx is captured. Particulate emissions are also very low.

A project is under way at the plant that will evaluate a combination of syngas clean-up and CO_2 capture (the *Warm Gas Cleanup (WGC) and CCS Demonstration*). A DOE co-operative agreement was put in place in 2010 to demonstrate RTI's Warm Gas Cleanup sulphur removal technology which cleans syngas at elevated temperatures. This was followed by the announcement of DOE support for the addition of CCS to the existing WGC project. The new development will involve the addition of a shift reactor and syngas cooling systems. RTI will design, construct, commission and operate a 50 MWe test facility that will treat around 20–30% of the IGCC plant's syngas output. Following the water gas shift reactor stage, the syngas will be cooled and fed to a carbon capture plant that will use BASF activated methyl diethanolamine (MDEA). Up to 300 kt/y of CO_2 will be captured. Specific project goals include an 8000 hour operating programme, >90% trace contaminant (Hg, As, Se) removal, and >90% CO_2 capture. The latter will be stored in a saline aquifer 1500 m beneath the Polk plant. It is scheduled that engineering, procurement and construction for the project will take place between 2011 and 2013, with commissioning and operation between 2013 and 2015.

Cogasification tests using eucalyptus and bahia grass were carried out between 2001 and 2004. The eucalyptus trials used a total of 8.8 tonnes of coarsely ground material (moisture content ~47%, ash content 5.3%). Felled trees were reduced in size using a hammer mill and trommel screen. This produced small particles capable of passing through the pumps and screens of the plant's slurry feed system. The ground material was introduced into the process via a stirred recycle tank and mixed with water. It was blended with the normal coal (and petcoke) mixture to form a slurry that was fed to the gasifier. The biomass comprised 1.2% of the plant's fuel input. During the test, plant performance was unaffected. In 2004, further testing examined the addition of 5% bahia grass to the coal feed. A total of 50 tonnes was used. Again, apart from some difficulties in material handling, there was no significant impact on syngas quality or emissions. It was confirmed that up to 5% biomass addition was technically feasible. However, the amounts used and the length of the test periods was relatively short, hence the trials gave little indication of what issues might arise if a greater proportion of biomass was cogasified on a continuous basis. Such a move would require the installation of dedicated biomass handling and preparation systems.

Other cogasification projects and proposals

In recent years, there have been several coal/biomass IGCC projects proposed. Two of these were in Rotterdam in The Netherlands. CGEN NV proposed the development of a 450 MW IGCC plant (fuelled on coal and biomass) that could also produce hydrogen. Foster Wheeler has reportedly undertaken a feasibility study. CO_2 from the plant would be captured and stored in a depleted oil and gas field. In 2011, the project was reportedly at the feasibility stage.

Essent and Shell also proposed the construction of a 1000 MW IGCC plant. This would use Shell gasification technology and be fuelled on coal and biomass. Most of the CO_2 produced would be captured and a number of onshore and offshore storage options, such as depleted oil and gas fields, were investigated. A proposed start-up date of 2016 was originally suggested. However, the project is currently on hold (Mills, 2010).

The use of coal/biomass cogasification as the starting point for the production of liquid fuels is considered in the following chapter.

5 Production of liquid products

5.1 Coal-to-liquids (CTL)

In oil-consuming countries that possess significant coal reserves, CTL production has obvious attractions, particularly for the producing Fischer-Tropsch liquids. Liquid products from coal have the potential to be made in large quantities, using existing technologies. Capitalising on indigenous coal reserves, rather than relying on imported or diminishing oil or gas supplies can improve security of domestic energy supply. It is suggested that some CTL processes become cost-competitive (at least within a US context) when oil costs around 60 US$/bbl or higher (Larson, 2011). A major drawback is that GHG emissions from unabated CTL processes are higher per unit of energy than those from petroleum-derived fuels. However, application of suitable CCS technology to CTL processes has the potential to reduce CO_2 emissions to a similar level.

Gasification is the foundation for converting coal and other solid feedstocks into transportation fuels such as gasoline, ultra-clean diesel, jet fuel, naphtha, and synthetic oils. There are two commercially demonstrated routes for converting coal to transportation fuels via gasification; these are **Fischer-Tropsch (FT)** and **Methanol-to-Gasoline (MTG) synthesis**. In both processes, coal is first converted to syngas then transformed to the final liquid products. However, their respective product slates are very different. The FT process produces a broad spectrum of straight chain paraffinic hydrocarbons that require upgrading to produce diesel fuel, lube feedstock and paraffinic naphtha for petrochemical applications. In contrast, MTG selectively converts methanol to a single product – low sulphur, high quality gasoline. The production of liquid fuels from coal was comprehensively examined by Couch (2008).

There are four main steps to producing FT liquids: syngas generation, syngas purification, FT synthesis, and product upgrading to a liquid petroleum product. Synthesis takes place at high temperatures and pressures and is characterised by the liberation of large amounts of heat. The process was used by Germany during World War II and since the 1950s, has also been utilised in various forms by Sasol in South Africa. It is now also used in Malaysia and the Middle East with natural gas as the feedstock. Proposals have also been made for coal-based FT plants in a number of countries that possess significant coal reserves such as China and India. However, no commercial scale coal-to-liquid plants based on FT technology have been built since the Sasol plants.

The MTG process couples coal gasification and methanol synthesis technologies and offers an effective route to premium transportation fuel from coal. The process (developed by Mobil/ExxonMobil) converts crude methanol to high quality clean gasoline. Initially, syngas is converted to methanol which is then transformed by reacting it over a bed of catalysts. A major advantage claimed for the process is that unlike FT synthesis that produces a broad spectrum of hydrocarbons that require upgrading, MTG selectively converts methanol to gasoline – this can be either blended with refinery gasoline or sold separately. Approximately 90% of the hydrocarbon in methanol is converted to gasoline as the single liquid product. It is also claimed to be easier to scale up the reactor due to the simple fixed bed process design.

The MTG process was first commercialised in New Zealand in the 1980s. Other commercial projects, using more advanced second generation technology, are now under development or operating in China and the USA. In China, since 2009, Jincheng Anthracite Mining Company has been operating a 100 kt/y methanol plant based on ExxonMobil technology. Output is expected to eventually increase to 1 Mt/y. In Erdos, Inner Mongolia, a second MTG project is being developed by Inner Mongolia Yuanxing Natural Alkali Company and China Coal Energy Company (Mengda New Energy). Construction of the plant began in 2011 and start-up is scheduled for 2013. The methanol plant is being built to provide feedstock for a 400 kt/y dimethylether (DME) plant. There are many other

Chinese plants already producing methanol from coal. In the USA, DKRW Advanced Fuels has licensed the ExxonMobil MTG technology through its subsidiary Medicine Bow Fuel and Power LLC for a 15 kt/d plant in Medicine Bow, Wyoming.

The use of coal and biomass combinations has been examined for the possible co-production of electricity and methanol. US studies have developed detailed process simulations for several different coal- and coal/biomass-to-MTG plant designs (Princeton University, 2011). These included fuel-cycle-wide GHG emission balances and prospective capital and operating costs. A key finding was that coal/biomass-to-MTG and electricity generation process designs (using separate coal and biomass gasifiers) offered promising economics.

An alternative to the MTG technology is the liquid phase methanol process (LPMeOH). In the USA, this is used at the Eastman Chemical Company coal gasification complex in Kingsport, Tennessee. The process was developed by Air Products and Eastman and uses coal-derived syngas generated on site. Traditionally, methanol has been produced by bringing compressed syngas into contact with high temperature solid catalysts. The resulting reaction is exothermic hence requires careful temperature control. In order to keep the reaction from proceeding too quickly and damaging the catalyst, the traditional practice has been to slow down the reaction by limiting the amount of CO in the syngas. However, the development of the liquid phase process (where finely divided catalyst is suspended in a mineral oil) obviates the cooling problem. For a given catalyst, a liquid-phase reactor is preferred as its basic characteristics allow it to be cooled internally. This is a significant advantage for removing the large net heat of reaction encountered during methanol synthesis. By removing this heat with an internal heat exchanger, steam can be cogenerated and employed for various process uses. An LPMeOH reactor can reliably generate more than five times as much methanol per pass through the reactor, which translates into considerable cost savings. Methanol produced at Kingsport is used for the manufacture of carbonylation-derived acetic anhydride. The required methyl acetate is made from methanol and acetic acid.

Although not directly coal-based, an alternative approach to methanol production is being pursued by the America-Icelandic company Carbon Recycling International (CRI). The company's **Emission-to-Liquid** (ETL) technology takes CO_2 from any industrial source such as fossil fuel-fired power plants, and converts it to 'renewable' methanol (RM). ETL consists of a system of electrolytic cracking and catalytic synthesis, leading to a low pressure/low temperature electrochemical production process.

The system comprises a series of stages, namely CO_2 capture and purification, hydrogen production, syngas production and compression, methanol synthesis and finally distillation. Electricity required by the process can be supplied from any source, including renewables such as wind and solar. Amongst the different routes being taken towards methanol production, this is viewed as being one of the most developed. A pilot plant, used for testing process flow sheets for CO_2-to-liquid fuels started operation in 2007. This can produce 0.05 million litres per year of methanol. The process has since moved to a commercial plant (started up in 2011) with a capacity of 5 million litres per year. The plant requires around 5 MW of power and about 4500 t/y of CO_2, sourced from a nearby geothermal cogeneration plant. The only by-product is oxygen. Around 18 tCO_2 produces 12,500 litres of methanol. CRI has plans to construct a larger commercial plant in Iceland that will produce up to 50 million litres per year of RM (known as Vulcanol) for export to European countries for gasoline blending. The first commercial shipments from the smaller plant were delivered in early 2013 to Dutch oil company Argos in Rotterdam. During 2013, CRI expects to ship all of its production not consumed by the domestic market to The Netherlands. In 2012, the Dutch Renewable Energy Directive was amended to allow fuel distributors to meet the blending mandate for renewable transport fuels with fuel produced using electricity from renewable sources and CO_2. Although the existing system utilises CO_2 from a geothermal power plant, in principle, there appears to be no reason why it could not take this feed from any CCS-equipped coal or cofired power plant.

A similar concept is being developed by Air Fuels Synthesis (AFS) of the UK. The system has harnessed expertise from the petrochemical industry and is based on Mobil-developed catalytic gas-to-methanol technology. The usual intermediate stage of converting CO from syngas into CO_2 is avoided. Instead, CO_2 is converted directly. The process aims to produce sustainable liquid fuels using a combination of CO_2 from point sources and electricity from renewables. Using the latter, water is electrolysed and the resultant hydrogen reacted with CO_2 to produce liquid hydrocarbon fuels. Most of the components of the AFS process exist either as demonstrations or are available off the shelf. Reportedly, a small demonstration unit has confirmed that the technology is practical and viable. In the period up to 2015, a larger demonstration facility and initial commercial projects of between 1 and 10 t/d of fuel are planned.

In a similar vein, in the USA, Dioxide Materials is developing a process using catalytic ionic liquids and other catalysts to break down CO_2 inside an electrolyser to create syngas. The technique uses an electrochemical cell as a flow reactor, which separates the oxygen output and CO_2 input from a liquid electrolyte catalyst, using gas-diffusion electrodes. Although electrochemical recycling of CO_2 is not a new technology, the company has patented a catalyst claimed to greatly reduce the amount of energy required. The overall aim is to couple CO_2 captured from power plants with electricity from renewable energies to obtain high value downstream transport fuels and chemicals. This novel technique allows the direct use of renewable energy and was inspired by the chloralkali process used to make chlorine and sodium hydroxide from salt water. In 2012, the project was awarded US$4 million to advance the technology further and create the first industrially relevant prototype.

5.2 Biomass-to-liquids (BTL)

Conventionally, depending on the technology deployed, liquid biofuels can be termed ‘first generation’ or ‘second generation’.

5.3 First and second generation biofuels

First generation (‘conventional’) biofuels are those produced from food crops such as sugar, starch, animal fats and vegetable oils. The most commonly encountered type is biodiesel (or *FAME* – fatty acids methyl ester) produced by trans-esterification from rapeseed, palm or other plant oils. Other variants include bio-alcohols (such as ethanol) produced by the fermentation of starches and sugars. Ethanol can be used directly as a fuel or as a gasoline additive. Bio-ethanol is the most widely encountered product; global production began in 2003, and has grown at a significant rate, due primarily to government support in the form of subsidies. Production has increased from 33,500 million litres in 2003, to 1754 in 2010. Forecasts suggest that for the foreseeable future, this will continue to increase. Other biomass-derived compounds with potential as transport fuels include MTBE (methyl tert-butyl ether) and DME (dimethylether) (EUBIA, nd).

Production of biodiesel started in 2005 with a global production of 4900 million litres; by 2011, this had increased to 23,600 million litres. Government subsidies are expected to continue supporting future growth of the biodiesel market. The key global biodiesel exporters in 2010 were Germany, China, the Netherlands, Argentina, Belgium and the USA (Progressive Media Group, 2012).

Various production technologies are being developed for a range of biomass variants. These include processes for cellulosic bio-ethanol, bio-methanol, DME, FT diesel, and mixed alcohols. The technologies proposed or in use comprise mainly bio-chemical (where enzymes and micro-organisms convert cellulose-type materials to sugars prior to their fermentation to produce ethanol) or thermochemical (using syngas produced by gasification, pyrolysis or torrefaction). Many first generation production systems depend on subsidies and are not cost competitive with existing fossil fuels. Furthermore, on a life cycle assessment basis, greenhouse gas emissions can sometimes approach those of traditional fossil fuels. In general, first generation biofuels are considered to be limited in their ability to achieve targets for oil-product substitution, climate change mitigation, and economic growth (Sims and others, 2008). Although some may be beneficial in terms of CO_2 reduction, potential drawbacks may include:

- higher food prices due to competition with food crops;
- they are an expensive option for energy security, taking into account total production costs, excluding government grants and subsidies;
- most provide only limited greenhouse gas reduction benefits and at relatively high costs in terms of US$/t$CO_2$ avoided;
- they may not meet their claimed environmental credentials as the biomass feedstock may not always be produced sustainably.

Such reservations have increased interest in developing biofuels made from non-food biomass (‘second generation’ biofuels). These could avoid many of the issues associated with first generation biofuels and, in the longer term, may prove to be more cost-effective. A major aim of second generation processes is to greatly increase the amount of biofuel that can be produced sustainably through the use of residual non-food crop parts (stems, leaves, husks), along with crops and feedstocks not used for food purposes; these include switchgrass, jatropha, whole crop maize, miscanthus, and industry wastes such as woodchips and food processing wastes. Various second generation technology routes being pursued include (thermochemical) options such as pyrolysis and gasification of forest and agricultural residues.

So-called ‘third generation’ biofuels are produced from extracting oil of algae – ‘oilgae’. Some reports suggest that production costs are low and yields are high, reportedly yielding nearly 30 times the energy per unit area that can be realised from current, conventional ‘first generation’ biofuel feedstocks. Algal biofuel projects are under way in Australia where a large plant is being fed with CO_2 from a neighbouring ethanol plant. Germany, Spain and India are hosting similar projects (Bowden, 2013).

Common second generation biofuels include vegetable oils, biodiesel, bioalcohols, biogas, solid biofuels, and syngas. The latter can be the starting point for producing a range of products. Well-established gasification technologies are used as intermediaries. However, where processes are reliant solely on biomass feedstocks, the production of transport fuels using FT technology involves a high energy investment and consequently, is not yet considered to be economically viable. Although many of the component technologies such as feedstock preparation, gasification, and FT and methanol synthesis, are commercially viable or technically mature for other applications, most systems as a whole are at the early demonstration stage, with further development and learning needed to achieve commercially viable fuel production (E4Tech, 2009). Development efforts are continuing in several parts of the world. For instance, in the USA, the latest DOE budget includes a newer focus on second generation biofuel development.

IEA analysis suggests that in the near- to medium-term, the biofuel industry will grow at only a moderate rate and encompass both first and second generation technologies that can be shown to be capable of meeting agreed environmental, sustainability and economic policy goals. The sector is expected to develop gradually over the next two decades as the infrastructure and experience gained from deploying and using first generation biofuels is transferred to support and guide second generation development. In some situations, combining biomass feedstocks with coal may provide some advantages and speed up commercial-scale deployment.

Thus, there are a number of possible technological options for producing liquid fuels from biomass feedstocks. Like coal, the main commercially demonstrated options comprise FT and MTG syntheses, whereby biomass is first gasified to produce syngas. In non-selective catalytic FT synthesis (carried out at 200–350°C/2.5–6 MPa) CO is reacted with hydrogen to form mainly paraffin straight-chain hydrocarbons, plus smaller amounts of branched and unsaturated hydrocarbons and primary alcohols.

Table 27 Scale of operation for second generation biofuel plants using energy crop-based ligno-cellulosic feedstocks (Sims and others, 2008)

Plant type	Plant capacity range	Assumed hours of operation each year	Biomass fuel required, (oven dry) t/y	Truck movements for deliveries
Small pilot	15–25 thousand L/y	2000	40–60	3–5 a year
Demonstration	400–500 thousand L/y	3000	100–1200	10–140 a year
Pre-commercial	1–4 million L/y	4000	2000–10,000	25–100 a month
Commercial	25–50 million L/y	5000	60,000–120,000	10–20 a day
Large commercial	150–250 million L/y	7000	350,000–600,000	100–200 day and night

FT processes can be used to produce either a light synthetic crude oil and light olefins, or heavy waxy hydrocarbons. The synthetic crude can be hydrocracked and/or isomerised to produce diesel fuel, lubricating oils, and naphtha; the latter can be cracked to produce olefins. Where gasoline or light olefins are required, the FT process is carried out at higher temperature (330–350°C). For diesel fuel, lower temperatures are used (220–250°C). Several types of catalysts (mainly iron and cobalt-based) can be used for FT synthesis.

Methanol can be produced via the catalytic reaction of CO and CO_2 with hydrogen. A certain level of CO_2 is necessary to optimise the reaction. Various side reactions can lead to formation of by-products such as methane, higher alcohols, or DME. Currently, on an industrial scale, methanol is exclusively produced by the catalytic conversion of syngas. Several processes are available, operated under different pressures, although low pressure (5–10 MPa) processes dominate; their main advantages are lower investment and production costs, improved operational reliability, and greater flexibility in the choice of plant size (Boerrigter and Rauch, 2005).

As well as the FT and MTG processes, in 2010, the Liquid Phase Methanol (LPMeOH) Process, in use in the USA to produce methanol from coal, was licensed to Woodland Biofuel. The intention is to use the technology as part of a wood gasification process to produce methanol from scrap wood. The first facility is planned in New York State. Several other gasification-based projects based on a variety of technologies are still at relatively early stages in their development.

Even after many years of RD&D and the development of demonstration projects, there is currently no clear commercial or technical advantage between the biochemical and thermochemical pathways. Both remain unproven at full commercial scale. Both are under continual development and evaluation, although technical and environmental barriers still remain. However, overall, as some major system components have already been developed and proven, there appears to be fewer technical hurdles with the thermochemical route. For large commercial-scale plants, a common concern is that of procuring an adequate supply of biomass (at a reasonable delivered cost) to the plant gate. For a biomass-only plant, requirements could be considerable (Table 27). Thus, combining biomass with coal could offer reduced technical risk, a more consistent and reliable source of fuel, and considerable savings through economies of scale.

The IEA Bioenergy study (Sims and others, 2008) noted that technical barriers remain for second generation biofuel production, associated costs are uncertain and vary with the feedstock available, there is not yet a clear candidate for 'best technology pathway' between the competing biochemical and thermochemical routes, and that even at high oil prices, second generation biofuels will probably not become fully commercial nor enter the market for some years without significant additional government support.

5.4 Use of biomass-derived liquid fuels

Liquid fuels produced from biomass currently account for 2–3% of global road transport fuels. The production of biofuels (largely for the transport sector) is expected to increase significantly in the medium to long term, with a sharp rise post-2030. By 2050, global demand is expected to have risen from the current level of 2.3 EJ to 32 EJ. In several countries, first generation biofuels already make useful contributions towards the national total. Currently, the main drivers that motivate policies towards biofuels are (IEA Bioenergy, 2011b; Ladanai and Vinterbäck, 2009):

- the rapid growth in demand for transport energy;
- the depletion of easily accessible supplies of oil;
- the increasing costs of oil extraction and refining;
- concerns about climate change;
- the necessity to achieve energy security;
- concerns about development of rural areas.

Biofuels have potential to reduce oil dependency and help decarbonise the transport sector, although at the moment they provide only a small proportion of the total global transport fuel. However, emerging technologies offer potential for growth in the future and long-term development programmes are under way in North and South America, Asia, and Europe. The specific strategies adopted and routes pursued are influenced by the type and scale of local/regional resources available and individual national circumstances.

Currently, production capacity of biofuels (mainly ethanol and biodiesel) is centred primarily in the USA, Brazil, and Europe – in each, output is increasing (REN21, 2012; Schuck, 2012). For instance, in the USA, the Environmental Protection Agency has increased the 2013 volume requirement for biomass-based diesel fuel to 1.28 billion gallons (a 16% rise from the previous record production). However, there is some debate about the current mandate for oil refiners to supplement their product with 20 million gallons/year of biofuels (cellulosic ethanol) made from wood chips, switch grass and municipal waste. The aim is to supplant the production of ethanol from corn, avoiding any conflict with food production. However, the quantity required has been described as unrealistic in the short term. In Europe, the transport sector fuel mix has also seen the level of biofuels increase. The share of biofuels in total final energy consumption in transport within the EU-27 Member States is now ~4% (AEBIOM, 2011).

Globally, in the longer term, as a result of rising oil prices and government support, the production of transport fuels produced from biomass is expected to increase in the period up to 2035. A growing number of countries now have regulatory mechanisms, incentives and subsidies in place aimed at encouraging the production of biofuels. Currently, as a part of its 2020 plan, the EU's mandate calls for a 10% renewable content in transportation fuels. At the moment, the production and consumption of liquid biofuels for transport remains highly concentrated in a few countries. The USA and Brazil account for between 60% and 70% of world ethanol production (produced from corn and sugar cane), and Germany and France account for nearly 60% of biodiesel production and consumption (Business Insights Ltd, 2011).

5.5 Liquid fuel production using combinations of biomass and coal

To date, no mature biomass gasification technology exists which is suitable for commercial-scale BTL production; gasification systems available are often small scale and/or still under development. Although second generation liquid fuels such as biodiesel produced from wood residues offer significant potential, many of the processes involved are not yet fully commercialised (EECA New Zealand, nd). However, well-proven and commercially available gasification technologies have long been available for coal. Cogasification of biomass with coal offers the possibility of producing significant amounts of bio-syngas without the requirement for major system modifications. In the short term, this option is considered to offer the easiest, most cost-effective approach to bio-syngas production on an industrial scale. It has been suggested that the first commercial-scale BTL plants could initially be operated on biomass-coal mixtures, gradually increasing the share of biomass as appropriate. When technically and economically feasible, some could eventually operate on biomass alone. However, further development is required, especially where the use of entrained flow gasifiers is contemplated (Boerrigter and others, 2009).

The global potential for producing liquid transport fuels from coal and biomass is substantial. In recent years, various studies have examined the scale of the potential for different countries. For example, US studies examined the production of liquid transport fuels via cogasifying coal and biomass. These concluded that this route could become an important part of US energy strategy, combining the environmental benefits of biomass with the relative abundance and lower costs of coal. It was estimated that 550 Mt/y of biomass could be available in the USA by 2020. If this was combined with coal (at a 60:40 ratio of coal:biomass), 60 billion gallons of gasoline equivalent could be produced each year; this equates to ~45% of annual light-duty vehicle gasoline usage. If CO_2 produced in the conversion process was stored in geological formations, over its life cycle, GHG emissions of this combined fuel would be close to zero. It was suggested that the first production plants could be built by 2020. Assuming a 20% growth rate in construction, by 2035, the country could potentially produce 2.5 million barrels of gasoline equivalent per day from combined coal-and-biomass sources (National Academies of Science, 2009). Potentially, similarly large amounts could be produced in other major economies.

Various studies agree that the production of transport fuels via cogasification of coal and biomass appears to offer the most economical option (Vreugdenhil, 2009) and efforts are under way to determine the most effective way forward. For instance, in April 2012, in the USA, the Department of Energy awarded US$3 million towards the development and testing of novel technologies for the conversion of such combined feedstocks to liquid transportation fuels; different concepts are being assessed and evaluated with a view to building and operating a US-based commercial scale coal-biomass-to-liquids (CBTL) production facility. Major feedstocks are limited to coal and agricultural biomass with a minimum plant capacity of 10,000 bbl/d. A major aim is to overcome the shortcomings associated with the production of liquid fuels from biomass by combining it with coal and cogasifying. Studies continue and a number of trials are being undertaken.

Cogasification of coal and biomass and the production of synthetic fuels is also being addressed in the USA by the Department of Defense. The US Air Force aims to obtain half of its fuel from domestic sources by 2016. One route being explored is coal-to-liquids production via coal gasification and FT synthesis. An important requirement is that any suppliers of synthetic fuels must minimise associated CO_2 levels. Feasibility studies have examined the possibility of producing 100,000 bbl/d of jet fuel from coal and biomass (as woody biomass, switchgrass and corn stover) using entrained flow gasification and FT technology, with a net carbon footprint 20% less than that of jet fuel produced from petroleum. It was determined that FT diesel could be produced at the target CO_2 level by cogasifying coal with only a modest amount of biomass. Between 10% and 15% (wt) of woody biomass, or 12–18% of switchgrass or corn stover would allow the CO_2 reduction target could be met (Fernando, 2009). However, the amount of actual field data available on the gasification of biomass in pressurised gasification systems is limited, hence further RD&D is needed to confirm these findings. A conceptual plant with a capacity of 7500 bbl/d of diesel would require a sustainable annual supply of biomass of about 1000 t/d.

Other US studies being undertaken by NETL are investigating the use coal and coal/biomass mixtures to generate electricity and co-produce zero-sulphur diesel via low temperature FT technology. Thus, detailed economic and environmental assessment have been undertaken for both CTL and CTL with 15% (wt) biomass addition. As they represent 90% of the US reserve base, both bituminous and subbituminous coals were evaluated. Switchgrass was selected as a representative type of biomass for evaluating CBTL facilities. The plant designs envisaged the production of 50,000 bbl/d of FT liquids, comprising 34,000 bbl/d of FT diesel, with the balance consisting of FT naphtha. To meet CO_2 emission requirements under this polygeneration scenario, diesel fuel produced from coal alone would require the addition of a small amount of biomass. This would slightly increase its cost. However, if 15% switchgrass was added, on a life cycle basis, the resulting fuel would produce a third less GHG emissions than petroleum-derived diesel (White and Gray, 2011). Studies are continuing (Tarka, 2012).

A further US research project (announced in January 2013) is to develop an innovative method for producing liquid transportation fuels from domestic coal and biomass; it aims to improve process economics and reduce life cycle impacts of CTL and CBTL processes. Through the addition of a moderate amount of biomass, the carbon footprint should be lower than that of petroleum-based fuels. Using novel FT catalysts (developed by Chevron), The Southern Research Institute is developing a process based on the highly selective conversion of coal-derived and coal/biomass-derived syngas to gasoline and diesel. This approach should eliminate the typical FT product upgrading and refining steps and enhance the ability of CTL and CBTL processes to compete with petroleum-based processes. An air-blown transport coal gasifier (TRIG) located at the US DOE's National Carbon Capture Center in Wilsonville will form part of the programme. A successful outcome to the project could encourage commercialisation of CBTL processes.

A number of US studies have addressed the possibilities of combining domestic coal and biomass for liquid fuel production on a state-wide basis. For instance, the potential for CBTL (in West Virginia), cogasifying local coal and switchgrass for the production of FT liquid fuels was assessed. Most of the biomass would be sourced from the forestry sector. The optimum level of biomass input into a CBTL facility was determined as 30% (wt), although 10–18% would be needed to produce CO_2 emission levels comparable with those of a petroleum-based equivalents. Different levels of addition were addressed. A CBTL plant using a coal:biomass ratio of 85:15 with a capacity of 40,000 bbl/d of liquid fuel would require 1 Mt/y of biomass. A facility using a ratio of 80:20 with a capacity of 100,000 bbl/d would require ~2.6 Mt/y of biomass and 14.6 Mt/y of coal. At this level, the import of additional biomass from surrounding states would be necessary (Wang and McNeel, 2009).

Given EU mandates to increase the use of biofuels, other studies have examined the European perspective. Over the course of two decades, under the auspices of the Framework Programmes, various EU-sponsored multi-partner projects (such as the APAS Clean Coal Technology Programme, and Joule/Thermie programmes) examined the cogasification of coal and biomass/wastes. These provided a foundation from which many projects later developed, some focused on the production of liquid fuels via cogasification. The preferred production biofuel production routes suggested have been mainly bioethanol from lingo-cellulose, and (second generation) FT fuel production, respectively, for gasoline and diesel substitution.

A number of studies have been carried out by EU Member States to examine the possibilities associated with coal/biomass co-utilisation. These often reflected individual circumstances such as the types of biomass and coals available within a particular country. On occasions, cogasification has not been limited to a single coal and biomass, and a third component has been added. For instance, Spanish studies investigated the cogasification of different combinations of coal, biomass and petcoke (Fermoso and others, 2010). Similar studies aimed at producing liquid fuels via gasification and FT technology have been undertaken elsewhere using different fuel combinations.

In Turkey, as part of the TUBITAK 1007 research programme, an ongoing four-year project (the Trijen Project) is investigating the cogasification of local coal and biomass for the production of FT liquids. Work is being taken forward by a consortium comprising Turkish Coal Enterprises and the General Directorate of Electrical Power Resources Survey & Development Administration, with a number of other supporting bodies. The main aim is the development of an economically-viable process for the production of liquid fuels from domestic lignite and biomass, followed by technology demonstration at pilot scale (Akgun and others, 2009). The programme is examining fuel feeding, gasification, syngas cleaning, conditioning (steam and shift reactors) and separation, and FT processing. A CBTL production process based on a fluidised bed gasification pilot plant (1000 kWth) is being developed. To date, a 150 kWth laboratory-scale CFB gasifier has been built and a design produced for a larger 1.1 MWth pilot-scale bubbling fluidised bed gasifier. Liquid fuel production will focus on the low temperature (180–250°C) FT process, using a slurry phase reactor and novel Fe-based catalysts (Ziypak, 2011).

Historically, as part of the operation of its CTL fuel production, the feasibility of cogasifying coal and biomass was investigated by Sasol in South Africa using a Sasol-Lurgi fixed bed dry bottom gasifier. Biomass evaluated comprised bark and bark/wood pulp combinations. It was concluded that such blends could be gasified successfully although further investigations were required in areas concerning operating stability, high gasifier outlet temperature, lower carbon conversion, and higher CO_2 conversion (Fernando, 2009). With the aim of determining whether cogasification of such blends was technically possible, Sasol also investigated the use of pellets comprising fine coal, wood pulp and biosludge, although the maximum level of addition or optimum gasifier operating conditions were not determined. Despite some operational difficulties, it was concluded that such blends could be used successfully.

6 Combined gasification and renewable energy concepts

In several parts of the world, concepts are being developed that propose combining several technologies to form effective, cost-effective energy-producing packages. Through such combinations, it may prove possible to capitalise on the respective individual strengths of the individual technologies. Some propose combining the cogasification of coal and biomass with the electrical output from intermittent renewable energy sources (predominantly wind power). Off-peak or excess electricity that would otherwise be wasted would be used to generate hydrogen and oxygen via the electrolysis of water. The resultant oxygen could be fed to either a gasifier, an oxyfuel combustion power plant, or directed to some other industrial application. Similarly, hydrogen could be stored and used in a variety of ways. Some projects have focused on gasifying combinations of coal and biomass, whereas others have concentrated on using coal or biomass alone; with both, woody biomass has frequently been selected as the biomass of choice. A number of promising concepts are described below.

NREL concepts (USA) (gasification/cogasification + electrolysis) – NREL has projects under way examining a range of concepts and issues associated with the gasification of biomass (and potentially, cogasification) applications and also several that propose to combine these with electricity from renewable energy sources. A number of US studies have suggested using electrolysers to produce hydrogen and oxygen from wind-generated electricity – for instance, the NREL/Xcel Energy wind-to-hydrogen (Wind2H2) demonstration project in Colorado (*see* Section 7.2). Biomass gasification or cogasification coupled with wind power/electrolysis has the potential to convert unwanted electricity into useful energy and could provide dispatchable electricity for local utilities.

Both directly and indirectly heated gasification-based hybrid systems are being examined. Both require a source of oxygen, currently produced using conventional ASUs. Under certain circumstances, oxygen from electrolysis could form a viable alternative, with the added benefit of producing a pure hydrogen stream. Initial research suggests that from both technical and economic perspectives, such hybrid options hold promise (Dean and others, 2010). However, in the case of pressurised gasification plants, replacing an ASU with an alternative system would remove the source of nitrogen used for pressurised feeding, necessitating another source of inert pressurisation.

The indirect system proposed features a two-stage fluidised-bed process where the heat needed for reaction is produced by burning char in a separate chamber to heat sand. This is then circulated through the reaction chamber to drive the reaction kinetics. A directly heated gasifier typically has a single combustion/reaction chamber and burns a small portion of the fuel feed to create heat. It is suggested that such hybrid systems would allow switching between fuel production and electricity production, based on grid demand. This would be accomplished by routing some or all of the syngas from the gasifier to a gas turbine instead of to fuel-production reactors. In addition to power production, the use of surplus electricity to heat the gasifier is being investigated. Excess or low-value electricity generated during periods of low demand could be used to heat the gasifier reaction chamber. As the temperature of the gasifier increased, the proportions of syngas and char change. Adding heat energy would produce additional syngas, increasing plant efficiency. To optimise economics, the ideal plant would continuously adjust both feed use and fuel production.

Gasification and pyrolysis plants usually also require an external source of power for operation, and the use of renewable sources has been proposed. However, how to achieve the successful direct coupling of the process with intermittent sources such as wind power is rarely addressed. Although the commercial use of wind power is now well established in the USA, as elsewhere, the major drawbacks are often location and intermittent output; at times this can be zero and at others, surplus electricity may be produced. None of the current electricity storage systems are yet available for utility-scale operation, hence the attractiveness for its use in electrolysis plants.

Key factors identified as affecting the viability of producing oxygen and hydrogen via electrolysis are the value of the end products and the price of electricity supplied to the electrolysers. The proposed hybrid systems would run associated electrolysers intermittently. Thus, surplus or low-value electricity would be used to produce oxygen (and hydrogen) for use by the gasifier or stored for later use. During periods of peak electricity demand, rather than feeding the electrolysers, the stored oxygen could be used to produce syngas in the gasifier. However, replacement of a single ASU supplying oxygen would require multiple electrolysers. It is estimated that a 2000 t/d fluidised bed gasifier would require ~27,800 kg/h of oxygen. Based on the technology currently available, this would require around 160 electrolysers running at full capacity.

Modern wind turbines use power electronics that permit variable speed constant frequency operation; this improves annual energy production, limits drivetrain torque, and supplies quality power to the electric utility grid. NREL studies suggest that if the wind turbine was supplying only an electrolyser load, deleting the grid-quality requirement would significantly reduce the capital and operation and maintenance (O&M) costs of the turbine's electrical generating system, as well as reduce process energy losses. NREL is currently investigating this.

With the aim of investigating hybrid hydrogen production systems, other NREL studies have examined how to combine gasification with renewable energy sources. These have included concepts for combining wind power and biomass gasification, combined electrolysis and biomass gasification, and combined coal and biomass cogasification with CCS. Each focused on the co-production of electricity and fuel. Thus, various gasification pathways for hydrogen production and how they could be hybridized to support renewable electricity generation were considered. Several concepts were identified with the potential to increase efficiency and reliability, and reduce the cost of hydrogen production, or improve the sustainability of hydrogen production from non-renewable resources. Those with the highest potential were direct wind and wind-electrolyser combinations coupled with biomass gasification (indirectly heated gasifier) producing both electricity and hydrogen. An electrolyser (replacing the ASU) coupled with a directly heated fluidised-bed biomass gasifier was selected for the co-production of fuel and power. Both systems proposed to overcome wind intermittency by feeding stored hydrogen to a gas turbine (used for peaking duties), and/or absorbing excess renewable power (in the form of hydrogen) during periods of low demand.

It was determined that the direct gasification concept was unlikely to be cost-competitive in the near future, largely because of high electrolyser costs. However, the various systems examined do not require significant technology breakthroughs and could become cost-competitive in the near term (Dean and others, 2010). The work may be expanded to cover pathways such as hybrid coal gasification with CCS as well as the production of other fuels such as DME and FT liquids.

NETL hydrogasification process (coal gasification – SNG and electricity + biodiesel)
Arizona Public Service (APS) investigated the development of a coal gasification process for the co-production of SNG, electric power and biofuels. The main aim was to develop a commercially viable, advanced gasification-based process capable of producing pipeline-quality SNG and electricity whilst meeting the following performance targets:

- overall process efficiency >50%;
- SNG cost below that of the natural gas market price;
- 90% CO_2 capture and storage;
- water usage at least 50% less than SNG from partial oxidation gasification followed by syngas methanation.

The process centred on the gasification of western coals using hydrogen as the reactant gas instead of oxygen (hydrogasification). Hydrogen would be produced using renewable sources, primarily wind. Operational parameters (high pressure and moderate temperatures) of the hydrogasification process were ~7 MPa and 870°C. This would produce a high methane-content syngas directly in the gasifier. SNG would be cleaned, dried, compressed, and injected into the local natural gas pipeline system.

Unconverted coal from the gasifier would be withdrawn and sent to a low-pressure, oxy-combustion process to generate electricity. A portion of the CO_2 stream from this combustion process would be compressed and recycled to convey the coal into the hydrogasifier, with the remainder fed to an algae farm for re-utilisation. Algae could be used as an additional fuel source or as a feedstock for biodiesel fuel production (Hobbs, 2007; NETL, 2009).

The first two phases of the project demonstrated that the development of a commercially viable integrated process was feasible. An overall process efficiency analysis and preliminary economics for a conceptual facility concluded that the process design met or exceeded the project goals. An engineering-scale field test of the carbon recycling concept was carried out, using flue gas from a commercial power plant to feed a closed-system algae farm. Results suggested that the concept has potential.

APS plans to build a plant adjacent to a New Mexico coal mine that will use hydrogen to gasify 3000 t/d of coal in three gasification trains, generating 2.8 million m^3/d of pipeline-quality SNG. Hydrogen and oxygen will be supplied by wind-powered electrolysis, with unconverted coal fuelling a low-pressure oxygen combustor to generate 41 MW of electricity via a steam turbine. The process will capture and store 90% of the CO_2 emissions from the power production portion; this will be fed to an algae farm for biodiesel production. An algae farm pilot test has shown that algae can capture 60 t/ha/y of CO_2, producing 50,000 L/y of biofuel and 20 t/ha/y of cattle feed. The overall energy efficiency of the process is estimated to exceed 70%. The US DOE is providing US$10.2 million towards the US$14.8 million project (Chemical Engineering, 2007).

In a further recent development, a project aimed at combining solar energy with natural gas was announced. The system uses concentrated solar energy to power a chemical reactor and several heat exchangers. This heats natural gas flowing through the reactor's channels, which contain a catalyst that converts it to syngas. The exchanger's channels help recycle heat remaining from the chemical reactions, increasing process efficiency. Prototype testing suggested that >60% of the solar energy collected was converted into chemical energy contained in the syngas. It is claimed that a gas-fired power plant equipped with the system would consume ~20% less natural gas while producing the same amount of electricity. It is further suggested that the system could be adapted to produce syngas that could be used for the production of liquid transport fuels. The current project is receiving about US$4.3 million combined from DOE's SunShot Initiative, which aims to advance American-made solar technologies, and industrial partner SolarThermoChemical LLC. Other organisations involved include the DOE's Pacific Northwest National Laboratory, and Oregon State University.

CRL Energy, New Zealand (coal/biomass cogasification + electrolysis)
In New Zealand, CRL Energy is developing a technology package that aims to combine oxygen-blown fluidised bed cogasification of indigenous lignites/subbituminous coals and woody biomass with intermittent renewable energy technologies (primarily wind, but possibly wave power later). The country has plentiful intermittent renewable energy resources and weather conditions and a long coastline well suited to generating electricity from wind. Conditions are favourable for much greater deployment of wind power in the country. The current total installed capacity is 622 MW; this generates 4–5% of the country's total electricity. However, forecasts suggest that by 2030, there will have been a six-fold increase in wind generated electricity. Numerous new wind projects are proposed or in development (New Zealand Wind Energy Association, nd).

Cogasification of indigenous coals and renewable biomass would provide an opportunity for effectively converting the latter into fuel gases using fluidised bed gasification technology. Advantageously, New Zealand lignites are very reactive – chars are generally very reactive and undergo conversion at low temperatures (Levi, 2011). Furthermore, New Zealand lignites usually have ash fusion temperatures in excess of 1100°C, hence should not cause problems of bed agglomeration. Potentially, syngas from cogasification can be used in several ways that include the production, via FT technology, of low carbon footprint chemicals and synfuels.

Table 28 Typical raw syngas compositions (Whitney and others, 2011)

Fuel	Gas, %			
	H_2	CO	CO_2	CH_4
100% lignite	15	12.5	15	<1
80% lignite + 20% biomass A	9	11	15	1.5
80% lignite + 20% biomass B	8	10	14	1.5
100% subbituminous coal	11	15	12	1
Subbituminous coal + 20% biomass A	14	16	13	2
Subbituminous coal + 20% biomass B	11	13	14	1.5

Notes: Biomass A = P.radiata – a type of pine; Biomass B = E.nitens – a type of eucalyptus. The % balance of the gas is nitrogen

It is proposed that cogasification would be integrated with the high efficiency electrolysis of water to produce hydrogen and oxygen; the latter would be fed to the gasifier. Hydrogen could be used to enrich the product gas or employed as a means for storing excess off-peak renewable electricity. It also has the potential for direct use as a transport fuel or for electricity generation using fuel cells.

CRL's initial focus has been on the development of an air-blown gasification process. The gasifier and its associated syngas clean-up line have operated successfully for more than 2000 hours. Steady plant operation (with air and steam) has generated good quality syngas using suitably sized indigenous coals alone or combined with 30% woody biomass. Steam injection slightly increases the hydrogen concentration of the syngas. Typical raw syngas compositions when using different coal and biomass combinations are given in Table 28.

Particulates are removed from the syngas in two stages using a high efficiency cyclone (~95% capture) followed by a venturi scrubber that quenches the syngas and removes any remaining particulates, tars and condensables. Only trace quantities of the latter two have been detected, indicating that a high level volatile breakdown is achieved in the gasifier freeboard section. Syngas can be further cleaned using a hypochlorite and caustic soda wash, reducing sulphur content to very low levels. If the syngas is destined for hydrogen or electricity production, it could be water-gas-shifted. Alternatively, it could be fed to a separation plant to extract further hydrogen to add to the electrolysis stream for direct use as a fuel, or directed to a FT process. However, in order for this integrated co-fuelled co-production process to be viable, considerable quantities of low-cost electricity must be available. There must also be a suitable market for the hydrogen produced. As the country's intermittent wind power capacity increases in the future, the CRL process may become suitable for load balancing. The plant would consume electricity when prices were low. When they were high, hydrogen from the process could be used to fire turbines to generate electricity.

When water-gas-shifted (WGS), syngas composition from the air-blown gasifier is typically around 20.8% hydrogen, 6.6% CO, 20.1% CO_2, 1.9% CH_4, and 51.2% nitrogen. The large quantity of nitrogen present in the syngas highlights a major advantage of gasifying with oxygen rather than air – by using oxygen, nitrogen can be virtually eliminated. Consequently, CRL is now focusing on oxygen-blown fluidised bed gasification. A newly developed gasifier operates at ambient pressure, has a maximum temperature of 1150°C, and can accommodate a variety of feedstocks that include different coals, alone or with high proportions of woody biomass. Furthermore, the unit can be operated with pure oxygen, air, or combinations of the two. The H_2:CO ratio from the gasifier (without WGS promotion) is generally 1.2:1. In order to upgrade it to 2:1, an additional 0.8 mole of H_2 is required per mole of CO.

To avoid the expense and energy penalty associated with a cryogenic ASU, CRL plans to supply the oxygen required for gasification using a modular electrolysis plant designed by Industrial Research Limited of New Zealand (*see* Chapter 7). This is being developed as part of a programme to investigate production technologies suitable for cost-effective production of hydrogen from small-scale wind and other renewable resources (Whitney and others, 2011). The concept of combining cogasification with renewable-powered electrolysis offers the prospect of using the country's coal, biomass and intermittent renewable resources for near carbon neutral production of hydrogen, synthetic hydrocarbons and biofuels (Levi and others, 2010; Levi, 2011). It offers a real possibility for building on the respective strengths of each resource.

Other studies

In the **USA**, the Leighty Foundation and partners has investigated the cogasification of coal and biomass combined with electrolysis. This examined a large-scale, long-distance transmission system for hydrogen produced by electrolysis using wind-generated electricity. Oxygen produced from the process would be supplied to an oxygen-blown gasifier, either gasifying coal alone or cogasifying coal and biomass. As it is uneconomic for oxygen to be piped over large distances, it was determined that the electrolysers should be in close proximity to the gasification plant.

Advanced Alternative Energy Corporation (AAEC) of Lawrence, Kansas, has conceptualised an energy system that offers to combine cleaner coal-derived power with that produced from municipal wastes and urban and agricultural biomass (Blevins, 2013). The AAEC system would call up such solid fuels to back up wind when insufficient wind was available. The system has not yet been constructed and as the process is still in the process of patenting, full details have not yet been released. In 1993, a patent was secured for the biomass portion of the system termed the Sequential Grates System; further R&D has since been carried out. In operation, electricity would be generated primarily through wind turbines until the wind began to drop, at which time system operators would dispatch the biomass burning furnaces to make up the shortfall. If biomass supply became inadequate, this would be backed up with coal. Thus, the concept would comprise a plant that could be fired on coal, biomass, or municipal solid waste, all of which would be transformed into clean electric power or potentially, various types of biofuels. Overall system efficiency could be high. The technology could have application in both developing and developed nations. It is claimed to be clean, highly efficient, low cost, modular, scalable, expandable and provide waste disposal and energy efficiency (AAEC, 2013).

A number of other studies have examined the concept of combining biomass-only gasification with the production of hydrogen from electrolysis using electricity from intermittent renewables. For instance, studies carried out by the University of Lund in **Sweden** examined process costs associated with an integrated biomass (wood) gasifier coupled with an electrolysis plant generating hydrogen and oxygen; the latter was supplied to an oxygen-blown gasifier. The primary goal of this particular combination was the production of hydrogen. However, it was concluded that under the plant capacity and set of conditions adopted, no clear production cost advantage was achieved by combining the two processes. Under optimum conditions, the hydrogen generated would be at least twice the cost of that produced from natural gas steam reforming (Hulteberg and Karlsson, 2009). Cogasification using coal and wood was not considered, yet this may have provided advantages in terms of economies of scale.

In **Denmark**, the REtrol Vision (*VEnzin-visionen* – **RE**newable energy + pet**rol**) was originally developed by Danish power company Elsam (now DONG Energy). This proposed integrating several technologies to produce combinations of electricity, heat and transport fuels. In Denmark, heat and power production are already highly integrated, with around half of the country's electricity coming from cogeneration plants. This provides environmental and economic benefits, compared to producing each separately. The REtrol concept proposed integrating transport fuel production with cogeneration, increasing products from two to three (heat, power and transport fuels). This would provide further advantages and allow outputs to be tailored to prevailing market requirements. Combining liquid transport fuel production with the other processes would reduce cost and increase the energy and exergy (the portion of the total energy available for conversion to useful work) efficiency of the system.

Six plant configurations were studied and compared, each with a different syngas production method; each design was based on the use of sustainable energy sources for methanol production. Thus, the latter was produced using combinations of biomass gasification, electricity from renewable sources, water electrolysis, CO_2 from post-combustion capture, and autothermal reforming of natural gas or biogas. Hydrogen from electrolysis was used for syngas production, and oxygen for either biomass gasification or gas reforming. Both gases were stored underground in order to allow the electrolyser to follow the variations in power generated by renewables. The different processes in the plants were highly heat integrated and the low temperature waste heat used for district heat production. This resulted in high total energy efficiencies (~90%) for the plant designs. The lowest cost methanol was obtained using water electrolysis, gasification of biomass, and autothermal reforming of natural gas for syngas production (Clausen and others, 2010). Reportedly, the cost of methanol produced by some of the designs could compete with the current production cost of second generation ethanol, but not with that of methanol. The cost of electricity supplied to the process had a significant effect on production costs; between 23% and 65% of the total costs for the six plant configurations was for electricity supply. Although the studies focused primarily on the Danish situation and did not consider the gasification or cogasification of coal, useful data was produced that could improve the understanding of appropriate systems using both coal and biomass.

In **Switzerland**, The Laboratory of Industrial Energy, Ecole Polytechnique Fédérale de Lausanne, has examined the production of SNG from wood using both directly and indirectly heated gasification, integrated with an electrolyser. Due to an inherent lack of hydrogen for complete conversion of wood into methane and the possibility for rational use of oxygen from the electrolyser, it was suggested that electrolysis would be an efficient and potentially economical option for increasing the gas output of the process, whilst storing renewable electricity and producing low carbon fuels (Gassner and Marechal, 2008). If inexpensive electricity were available, hydrogen from the electrolyser could be injected into the methane synthesis, where it would be bound to the abundant carbon from the biomass, increasing the SNG yield. Even if not operated at base load, this would allow for peak shaving electricity to be generated from intermittent sources such as wind power, plus storage as a ‘green’ fuel in the gas grid (Gassner and Marechal, 2009). A similar concept was examined by the University of Pisa in **Italy**. This also considered oxygen-blown gasification of wood combined with a commercially available alkaline electrolyser fed with electricity from renewable sources such as wind (Biagini and others, 2009).

Work has also been undertaken in **China** to examine different ways in which to combine fossil fuels, biomass and renewable energies. For instance, patents (issued in 2009-11) have been granted for the large-scale production of methanol via the use of wind power and gasification. Wind-generated electricity is used to electrolyse water, generating oxygen and hydrogen. Oxygen is employed as gasification agent for the gasification of coal to produce syngas, with hydrogen used to adjust the proportion of carbon and hydrogen in the desulphurised syngas. The suitably adjusted syngas is then used for the production of methanol (Weidong and Weidou, 2011).

Other Chinese studies have examined the possibility of producing methanol, SNG and ethylene glycol by combining coal gasification with wind power and electrolysis. In each case, the system proposes the use of wind power to provide electricity to an electrolyser. The oxygen generated is fed to the coal gasifier and the hydrogen mixed with the syngas produced to adjust the H_2:CO to an appropriate ratio suitable for methanol synthesis. Use of an electrolyser avoids the requirement of an ASU for oxygen production and reduces the WGS process. The combination of these technologies is claimed to reduce raw material requirements and reduce associated CO_2 emissions (Ni and others, 2009; Gu and Yan, 2009, 2010). These systems could be particularly attractive in the regions of China with abundant wind and coal resources. The country already has a large coal-to-chemicals sector.

7 Hydrogen and oxygen production by water electrolysis

Electrolysis is a means for separating water into gaseous hydrogen and oxygen. The process occurs when an electric current flows through an electrolyte from an anode to a cathode. Water molecules are instantly split into hydrogen and oxygen in a volume ratio of 2:1 respectively – oxygen is generated at the positive anode, and hydrogen at the negative. The anode electrolyte contains oxygen bubbles and the cathode electrolyte contains hydrogen bubbles. To avoid over-concentration in the cathode compartment and dilution at the anode, the electrolyte requires constant mixing. The inputs to the electrolysis process are simply feedwater and low voltage direct current supplied to the electrolyser. It is essentially the reverse of the reaction in a fuel cell (Gardner, 2009).

Electrolysers are made up of a series of cells, each comprising a pair of electrodes (anode and cathode) with a gas separation membrane sandwiched between them. An electrolyte is used to conduct ions between the two electrodes. The main component parts of an electrolysis system comprise some or all of the following: a transformer/rectifier that converts the AC high voltage supply into DC current input, an electrolyser and electrolyte system, a scrubber (to remove residual traces of electrolyte, cool the hydrogen, and act as a feedwater tank), a gas holder (a buffer tank between the electrolyser and compressor), one or more compressors, a de-oxidiser and dryer (to remove nitrogen and traces of oxygen and water), and a (pressurised) gas storage system.

Several different types of electrolyser are available commercially, and each functions in a slightly different way. The main technology variants are:

- proton exchange or polymer electrolyte membrane (PEM) electrolyser; the electrolyte is a solid specialty polymeric material;
- alkaline electrolysers – similar to PEM electrolysers but use an alkaline (NaOH or KOH) solution as electrolyte;
- solid oxide electrolysers – these operate at high temperature (~500–800°C) and use a solid ceramic material as the electrolyte.

The electricity can be provided from any suitable source although to make large-scale electrolysis viable, this needs to be low cost.

Despite its intermittent output, wind energy is currently the lowest-cost renewable energy. However, it is the leading candidate for providing a means of ‘storing’ excess electricity in the form of hydrogen and oxygen. Ongoing research is examining the potential of using different renewable energy sources such as wind, solar and tidal power for electricity supply, particularly using excess output and off-peak surpluses.

Hydrogen is regarded widely as having significant potential as an energy carrier for a range of commercial and industrial applications. Against a background of concerns over global warming associated with the use of fossil fuels, it has several potential advantages. When combined with oxygen (in, for instance, a fuel cell) the only by-products are water and heat. Furthermore, hydrogen can be made via a number of processes and from numerous sources. ‘Renewable’ hydrogen can be produced by the electrolysis of water, by solar conversion, or from biomass, and holds considerable promise as a source of CO_2-free energy. Similarly, the oxygen co-produced from electrolysis has numerous possible applications including both combustion and gasification-based systems. The incorporation of both into integrated energy-producing systems that combine several technologies could provide high process flexibility and efficiency, allowing production to be adjusted so that it best matches resource availability, operational needs, and market factors (Gardner, 2009). Thus, when electricity demand was low, hydrogen and oxygen could be stored. When demand increased, hydrogen could be fired in gas turbines or supplied to fuel cells to generate electricity. Similarly, oxygen could be fed into combustion or gasification-based processes.

A total of seven promising options for producing hydrogen have been identified (EERE, 2009); these fall into three broad categories: thermal, electrolytic, and photolytic processes. Current global hydrogen production is estimated at around 50 Mt/y, used mainly for industrial applications. Most is produced from fossil fuels although a small percentage is generated by electrolysis. The main sources comprise natural gas (48%), oil (30%), coal (18%), and electrolysis (4%) (IPHE, 2011). An advantage of electrolysis is that it is capable of producing high purity hydrogen (>99.999%), of particular importance for fuel cell applications.

Hydrogen can be used for a number of energy-related purposes and similarly, oxygen also has various possible applications. Oxygen is the second largest volume industrial gas (after nitrogen) and is used for a range of industrial processes. It is produced commercially in gaseous or liquid forms by several routes:

- cryogenic air separation – a process that compresses and cools atmospheric air then separates the resulting liquid into its components in a distillation column;
- Pressure Swing Adsorption (PSA) – several non-cryogenic technologies that use a molecular sieve material to selectively absorb atmospheric components at specific temperatures and pressures;
- membrane separation – these use hollow fibres, most frequently made of organic polymers, to recover gases such as hydrogen from oil refineries or CO_2 from natural gas supplies.

The total global quantity of oxygen used for commercial and industrial applications is not known. However, considerable quantities are consumed in processes such as steel making and glass manufacture. In the energy sector, it is used for the gasification of fossil fuels and has the potential to supply further gasification plants, IGCC facilities and coal-based oxyfuel combustion power plants in the future. Reportedly, on-site production using an ASU becomes competitive at capacities of ~1000 m^3/h (Gassner and Marechal, 2009); this equates to around 1.5 t/h of oxygen. Below this output, PSA would be more cost-effective, although oxygen purity would be lower (Henderson, 2012). A 400 MW IGCC plant requires ~200 t/h of oxygen.

The energy penalty associated with oxygen production can be considerable. In the case of an ASU supplying a power plant, this can amount to 15–25% of the electrical output or 5–10% of the total energy input. Other systems (such as Ion Transfer Membrane technology) have the potential to produce oxygen at industrial scale but at a lower cost, although these are some years from commercial deployment. This has increased interest in electrolysis as a means for producing oxygen for combustion and gasification processes. Most such applications currently rely on conventional cryogenic ASUs.

The impacts associated with the integration of large amounts of electricity generated from intermittent renewable energies on existing thermal power stations has been examined previously (for instance, Mills, 2011). It might therefore be construed that the addition of hydrogen from electrolysis to an energy mix would only exacerbate operational difficulties being experienced by operators of coal- (and gas-) fired plants. Many existing electricity grids are supplied by a portfolio of different generating technologies. Currently, when electricity from intermittent producers such as wind power is available, the capacity of conventional base-load generators is reduced. However, if at least some wind power was directed to electrolysers, less would be available to feed into the grid. This would then allow some existing stations to increase their operating hours and minimise the impacts of frequent cycling, or even revert to base-load operation. Even though electrolysis remains a relatively expensive way of producing hydrogen, once the impact on the capacity mix and on other power plants on the system was taken into account, it could still be a viable mechanism for integrating large amounts of wind power (Green and others, 2009).

The main factors that determine the overall cost of hydrogen and oxygen from electrolysis are the capital cost of the electrolysis plant, its overall efficiency, and the cost of the electricity input. The relative importance of each will depend on the scale of the facility and its operating profile. If the capital cost per kW can be reduced, then plant capital cost becomes less important and intermittent operation at lower capacity factor becomes more feasible.

The amount of electricity required depends on the efficiency of the particular electrolyser. A 100% efficient unit requires ~39 kWh of electricity to produce 1 kg of hydrogen. However, typically, systems are currently limited to efficiencies between 56% and 73%, meaning that ~53–70 kWh of electricity is needed for every kg of hydrogen produced (Dean and others, 2010; FCHEA, nd).The cost of producing hydrogen is highly dependent on the electricity price (up to three quarters of the final cost). US studies note that the power required (at an electricity cost of 0.05 US$/kWh) would impose a cost of at least 2.65 US$/kg of hydrogen. IEA studies suggest costs around ~3 €/kg of hydrogen (for a 40 €/MWh electricity price) (IEA HIA, 2009). System efficiency is always important – at lower production rates, the basic cell operates more efficiently than at full power. This feature can only be exploited if the balance of plant (gas processing, power conditioning, electrolyte management, safety and control equipment energy use) is kept low (Whitney and others, 2011).

An advantage of water electrolysis is that, unlike other technologies, it does not necessarily require large centralised plants, and the cost of hydrogen production scales up easily from the larger to smaller systems. However costs are still heavily influenced by plant capacity, with smaller (kW) sized plants costing up to 20,000 US$/kW, and very large (MW) plants levelling out at ~500 US$/kW (Whitney and others 2011). Studies carried out by Siemens on hydrogen production via electrolysis suggest that costs are currently 10,000 €/kW (~US$13,100) of installed load. However, it is anticipated that by 2018, further system development and refinement will reduce this to less than 1000 €/kW (US$310). By then, Siemens expects to have developed its third generation electrolysers. These should be able to accommodate up to 100 MW, allowing excess wind-generated electricity to be converted to hydrogen in large quantities. A 60–90 MW electrolyser will be adequate to convert the surplus energy of a large wind farm. Volume production of electrolysers will be an important factor in reducing unit capacity cost (Leighty and others, 2004).

For large commercial-scale operations producing hydrogen and oxygen, electrolysers will require:

- MW-scale availability;
- high DC input voltage; >200 volts, or be series-connectable, to match high voltage output of large-scale wind turbine electrical generation systems;
- integration into generation system design;
- high energy conversion efficiency;
- low long-term operation and maintenance costs;
- an installed capital cost no more than 250 US$/kWe input.

Alkaline (NaOH and KOH) MW-scale modules are commercially available. The best are ~80% efficient, although transformer-rectifier and balance-of-system losses reduce the complete electrolysis process efficiency to 60–70%. Furthermore, output pressure is often near atmospheric, so compressors and energy are needed to feed any attendant pipeline system. However, more advanced designs are being developed by several major manufacturers. For instance, US-based Proton Onsite offer PEM electrolysers that are claimed to out-perform alkaline electrolysis systems. Systems are used for a range of applications such as power plant generator cooling; a single (HOGEN 40) unit will furnish the cooling hydrogen for a power plant incorporating two GE 7FA gas turbines and a steam turbine. Proton electrolysers can supply hydrogen at pressures up to 3 MPa. They are claimed to have a turndown range between 0% to 100% net output, and to be suitable for operation with renewable sources such as wind, solar, hydro, and wave power (Proton, nd). Several technology suppliers are also developing electrolysis systems that operate at much higher pressures, reducing the need for downstream compression, hence minimising energy and cost requirements.

Where electrolysers were supplied with varying amounts of electricity from intermittent sources, they would clearly need to ramp up and down and to respond quickly to match the input. This needs taking into account at the design stage (Davison, 2013). Some of the newer electrolysers under development or being offered commercially are claimed to have a much faster response than earlier versions.

Electrolysers are relatively expensive items. This has been due partly to the limited number of

Table 29 Examples of electrolyser suppliers (Fuel Cell Markets, nd; also individual company websites)

Company	Technology	Comments
AccaGen, Switzerland	Alkaline	Direct production of hydrogen at high pressure Single electrolysis module of 60 m^3/h
Acta Energy, Italy	PEM – Anionic solid polymeric membrane	Several different capacities available Produces dry, pure, compressed hydrogen at 3 MPa
Air Liquide, France	High pressure alkaline	HYOS technology produces hydrogen at 1MPa without compressor
Air Products, USA	PEM	Links with Proton PEM technology. Packaged PRISM hydrogen systems produce between 250–1000 m^3/h Standard pressure 0.8 MPa
Angstrom Advanced Inc, USA	Alkaline	Hydrogen capacity up to 500 m^3/h Pressure up to 5 MPa
Avalence, USA	Alkaline	Hydrofiller technology produces ultra-high pressure (Maximum Rated Pressure up to 44.8 MPa) hydrogen directly in the electrolysis cells. No compressor needed Utility-scale unit under development – 300 kg/d output
H-TEC, Germany	PEM	Produce compressed hydrogen at 3 MPa
Hydrogenics, Canada	Pressurised alkaline and PEM units	HySTAT alkaline electrolysers produce hydrogen at up to 2.5 MPa directly from module Supplying turnkey electrolyser and hydrogen production system to E.ON's German power-to-gas demonstration
IHT, Switzerland	Alkaline	Up to 760 m^3/h of hydrogen produced. Pressures up to 3.2 MPa Low energy input claimed Supplied possibly world's largest unit to Zimbabwe (21,000 m^3/h hydrogen + 10,500 m^3/h oxygen)
ITM, UK	Alkaline and PEM units	Novel ion-conducting materials claimed Developing alkaline solid polymer electrolyte for use in low cost electrolysers Produce hydrogen at 1.5 MPa
MVS Engineering, India	High pressure alkaline	Produce up to 500 m^3/h. Pressure of 3 MPa. No compressor required Also offer PEM units in conjunction with Proton
NorskHydro, Norway	High pressure alkaline	Supply some of the world's largest electrolysers; up to 485 $m^3/$ h of hydrogen Electrolyser pressure of 0.1 MPa; production pressure of 3 MPa
Proton OnSite, USA	PEM	Supply hydrogen at pressures up to 3 MPa Turndown range between 0 to 100% net output Proton claimed to account for ~80% of the US power station market
R2 Gas Ltd, UK	Alkaline	
RE Hydrogen, UK	Alkaline	Combination of atmospheric electrolysers and novel high pressure compressor (3.5 MPa). 5 kW stacks have been developed Claimed to produce green hydrogen at 3.6 £/kg A 5 kW fully integrated electrolyser will be supplied to BOC/Linde under the RABH2 project (with Arcola Energy) Also 50 kW electrolysers being tested for grid balancing
Siemens, Germany	PEM and solid oxides	A 60 MW unit could convert surplus energy from large wind farm Expects to have an electrolyser that can handle up to 100 MW by 2018
Teledyne Energy Systems, USA	PEM	TITAN units produce hydrogen up to 1 MPa Up to 56 m^3/h hydrogen production

commercial suppliers, although more are entering the market; for instance, market activity is increasing in countries such as China. Technology developments, standardisation, mass-production, and greater competitiveness are expected to gradually bring prices down. Some major technology developers/suppliers are shown in Table 29.

7.1 Electrolyser RD&D activities

Water electrolysis is a mature and well understood technology – 1 kg of water will produce 0.68 m^3 of oxygen and 1.35 m^3 of hydrogen. If renewable electricity is used, the oxygen and hydrogen produced can effectively be carbon-free. In the longer term, large-scale water electrolysis using wind (and solar) derived electricity could become commercially feasible; wind-based processes are currently lead contenders (EERE, 2009).

Although electrolysers have been used commercially for many years, there is still considerable scope to improve their overall efficiency. Electrolysis at 100% electrical higher heating value (HHV) efficiency can be demonstrated in the laboratory. However, the majority of mature electrolyser technologies are relatively inefficient, delivering only 50% to 75% HHV system efficiency. Up to 10% of the energy input is used in the balance of plant (BOP) for power management, pumping, and gas clean-up processes. However, using new state-of-the-art materials, significant efficiency improvement appears possible. On this basis, using PEM technology, the US DOE has set a target of 87% HHV system efficiency for 2017 (Hamdan, 2012). The challenge for electrolyser manufacturers is to create a durable technology that approaches these levels at small size and low cost.

As part of a recent roadmap for the production and utilisation of hydrogen, the outstanding technical challenges associated with water electrolysis were examined (EERE, 2009). These were identified as the relatively low system efficiency, high capital costs, issues of integration with renewable energy sources, and development of appropriate designs for commercial manufacture. Major RD&D needs were identified. Several of these are common to a number of alternative hydrogen production techniques. In order to drive the large-scale commercialisation and widespread use of hydrogen as an energy carrier, efforts are under way to address such issues, particularly to reduce capital and operating costs. This is being pursued by applying the principles of 'design for manufacture' – identifying better materials, decreasing the number of component parts required, designing simplified systems, and moving into mass production. Therefore, operating costs should decline as equipment developers identify improved materials, consolidate processing steps, reduce maintenance and labour requirements, and otherwise enhance equipment performance and integration (EERE, 2009). Main RD&D requirements specific to the individual types of electrolyser systems are summarised in Table 30.

Table 30 Main RD&D requirements for different types of electrolyser (Smolinka and others, 2012; Moon and Moon, 2012)

Alkaline electrolysers	Polymer electrolyte membrane (PEM) electrolysers	High temperature solid oxide electrolysers
Increase current density	Increase life time of materials/stack	Develop adapted electrodes/electrolyte for solid oxide systems
Faster dynamics of the complete system (BOP)	Scale up concepts for stack and system	Improve cell and stack design
Higher part load range	Decrease costs by substitution or reduction of expensive materials	Proof of lifetime
Decrease production costs through economies of scale	Decrease production costs through economies of scale	Pressure tightness
		Cycling stability

Development remains ongoing for the cost-effective large-scale production of hydrogen and oxygen by electrolysis using electricity from intermittent renewable sources. To fully realise its potential, such systems require optimisation and capital and operating costs need to be lower. A reduction in the costs associated with renewable energies in general would also be beneficial.

Research into such issues is being pursued in several parts of the world. For instance, in **New Zealand**, as part of a package to effectively couple coal and biomass cogasification with intermittent renewable energy, CRL Energy Ltd and Callaghan Innovation (formerly Industrial Research Ltd – IRL) are co-operating on the development of a modular electrolysis plant. The aim is to develop technological solutions suitable for the cost-effective production of hydrogen from small-scale wind and other renewable resources. Research is focused on developing a unit of low manufacturing cost, high stack efficiency, low balance-of-plant (BOP) energy use, and good durability (Whitney and others, 2011). Alkaline technology is being adopted, with zero-gap membrane construction and bubble-lift electrolyte circulation. Callaghan Innovation is developing the 5 kW electrolyser component of the technology package. This self-contained unit is claimed to have a wide operating range, fast turn-up and turn-down, produce oxygen and hydrogen of the appropriate quality, and have very low peripheral power demand. Efficiency is 70% HHV without any special electrode surface preparation. The target module efficiency level is ~85% (Whitney and others 2011). Studies suggest that the current cost of hydrogen produced by a centralised 50,000 kg/d or greater hydrogen production plant would be ~3 US$/kg. At this scale, around 100 MW of electricity would be required. Hourly production would be 12,500 m^3 of oxygen and 25,000 m^3 of hydrogen. As elsewhere, the proposal is that hydrogen would be used directly for electricity generation, as a transport fuel, or stored as excess off-peak renewable electricity. There are a number of potential uses for the oxygen, such as feeding to a gasifier.

In the **USA**, the DOE and others are funding RD&D on all three main electrolyser variants, and progress is being made in reducing costs whilst increasing efficiency, durability, and safety. As part of the ongoing Fuel Cell Technologies Program, a Water Electrolysis Working Group has been set up to bring together industry, academia, and national laboratories. The National Renewable Energy Laboratory is currently examining issues associated with the production of hydrogen by electrolysis using electricity from renewable sources (NREL, 2011). RD&D aims include:

- characterisation of electrolyser performance under variable input power conditions;
- design and development of shared power electronics packages and controllers to reduce cost and optimise system performance;
- identification of opportunities for system cost reductions through breakthroughs in component integration;
- testing, evaluation and optimisation of system performance for both hydrogen production and electricity/hydrogen cogeneration.

A major area of US DOE/industry partners' activity is on cost reduction and efficiency improvements and ongoing development has already realised significant reductions in capital costs. This has been achieved by developing advanced low-cost membranes, improved optimised stack design, and reductions in energy requirements. During the last decade, alongside cost reductions, significant gains have been made in efficiency, hydrogen production rate, and production pressure. Projected stack cost for high volume production has been reduced by ~90%, hydrogen production capacities have increased tenfold, efficiency has been increased by ~20%, and hydrogen production pressures have increased by a factor of ten (from ~3MPa to 34.5 MPa). Development efforts continue, focused on decreasing costs further, enhancing production rate and efficiency at high pressure production, improving the efficiency of the BOP components, and improving overall durability when integrated with renewables (Sutherland, 2012). It is anticipated that the scaling-up of electrolyser technology will help provide useful economies of scale (especially in the BOP components) as well as reduce capital and operating costs. A conceptual design has been produced for a 50,000 kg/d hydrogen (plus oxygen) production plant. Reportedly, in some situations, current DOE threshold costs can already be met using electrolysis to produce hydrogen from wind-generated electricity.

In Boulder, Colorado, USA, NREL in partnership with Xcel Energy is developing the Wind-to-Hydrogen (Wind2H2) demonstration project. This feeds electricity generated by two different types of wind turbine to electrolysers to produce hydrogen and oxygen for storage. The fluctuating alternating current output from the turbines is converted to direct current and fed to the electrolyser stack. Two commercial PEM electrolysers and an alkaline electrolyser are being evaluated (NREL, 2012). A major aim is to create synergies between the co-production of electricity and hydrogen, and to improve system efficiency such that hydrogen can be produced from renewables in sufficiently large quantities, and at costs low enough to compete with traditional energy sources. As with other studies, the main near-term challenges for large-scale hydrogen/oxygen production by electrolysis have been identified as electricity cost reduction, capital cost reduction, improved integration with renewables, and compression storage and dispensing issues. Longer-term requirements include further cost reductions, and reduced O&M requirements (Sutherland, 2012).

A similar project is proposed for Minnesota, where a larger-scale hydrogen-from-wind process is being developed. Project partners are Norfolk Wind Energy and Emerald H2 of Minneapolis. The aim is to install initially 40 MW of wind turbines, with the possibility of eventually increasing this to 100 MW. As with other projects, electricity would be fed to the grid when demand was high, but used to feed electrolysers when demand was low. Emerald holds rights to electrolysis technology claimed to be more efficient than competing systems. The project would include a capacity for using 10 MW of wind-generated electricity to produce 500,000 kg of hydrogen. This would be sold to local customers for a range of applications that could include the manufacture of anhydrous ammonia for fertiliser production. Construction could begin during 2013.

In Hawaii, a planned hydrogen production plant will generate hydrogen from water electrolysis. The electricity input will be provided by a geothermal-based system; the electrolyser will require ~4 MWh/d of electricity. Initially, the hydrogen will be supplied to a refuelling station and used by vehicles powered by fuel cells although later phases of the project will explore the use of hydrogen for electricity generation. A near-term goal is to analyse the performance of the electrolyser under different operating conditions and to evaluate the feasibility of using hydrogen as an energy storage and grid management tool. This aim is to smooth out fluctuations in power supplied by wind and solar resources.

At the Hydrogen Research Institute of the University of Quẻbec in **Canada**, a wind/photovoltaic hydrogen/oxygen production system was installed and operated. This comprised a wind turbine, a PV array, and a 5 kW electrolyser. The premise was that hydrogen would be stored for later use at times of high electricity demand, or fed to fuel cells or gas turbines. After purification and drying, oxygen produced by the electrolyser would also be stored at high pressure (Agbossou and others, 2004). This could be re-utilised as oxidant in place of compressed air in a fuel cell, or fed to a combustion or gasification system.

In **Japan**, AIST has been conducting RD&D on the production of hydrogen by water electrolysis using porous photo-electrodes composed of various oxide semiconductors; a high-performance multi-layered semiconductor-based system (carbonate electrolyte and multi-layered oxide films) is being developed. The electricity required is being supplied by solar energy. It is anticipated that the technology will significantly reduce the electrolysis voltage required for electrolysis, helping reduce the cost of the hydrogen/oxygen produced. Reportedly, the voltage for water electrolysis can be reduced by >40% (AIST, 2012).

In **Europe**, a number of projects are under way examining the use of renewable energy sources for electrolysis of water, coupled with hydrogen and oxygen storage and utilisation. Part of Task 24, the IEA Implementing Agreement on Hydrogen Production and Utilisation, is examining such issues. This is reviewing the current state-of-the-art of electrolysers and other related equipment, determining system enhancements required, and examining possible improvements in the integration of the main components (primarily the wind turbine and electrolyser). To develop appropriate specifications, electrolyser durability under a very dynamic workload is being addressed.

Other European activities include the multi-partner ELYGRID project, being undertaken as part of the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) with funding from the EU 7th Framework Programme. This is investigating improved integration of high pressure alkaline electrolysers for hydrogen/oxygen production, predominantly using wind-generated electricity. The main emphasis is on electrolysers of at least 0.5 MW capacity. Major objectives are to improve overall system efficiency by 20% and reduce costs by 25%. The project is being co-ordinated by the Foundation for the Development of New Hydrogen Technologies in Aragon, Spain. Project partners comprise Spanish, Swiss, French, German and Belgian organisations. A further initiative announced in December 2012 (also under the auspices of the FCH JU) is the five-year 'Don Quichote' project that is developing a system comprising a PEM electrolyser, an electrochemical compressor, and fuel cell system. The aim is to demonstrate the technical and economic viability of an integrated hydrogen production and storage system based on the use of renewable electricity. As well as the European Commission and the European Hydrogen Association, project partners include organisations in Belgium, The Netherlands, Iceland, Canada and Germany.

Also part of the 7th Framework Programme is the RESelyser project. This is investigating the production of hydrogen from renewable energies using an advanced, high efficiency prototype pressurised alkaline electrolyser. This features a novel separator membrane with internal electrolyte circulation and an adapted cell design for improvements at very low and high power (to improve mass transfer, especially gas evacuation), coated electrodes to improve efficiency and lifetime when operating with renewable energy sources, and a process design adapted to intermittent operation (Weidner, 2012). The project has partners from Belgium, Denmark and Germany and is being co-ordinated by the Institut für Technische Thermodynamik in Stuttgart.

As part of its efforts to reduce greenhouse gas emissions, promote energy efficiency and encourage the use of renewable energies, the multi-partner EU Greenlysis project is focusing on the production of hydrogen and oxygen from wastewater treatment plants. The project will build a pilot plant to demonstrate the production of hydrogen and oxygen by water electrolysis. Electricity will be supplied by wind and thermal solar units. Hydrogen will be used to generate on-site power; oxygen could be supplied to combustion and/or gasification systems (EU, 2010).

At Falkenhagen in north-east **Germany**, E.ON has built a €5 million power-to-gas (P2G) pilot plant that uses surplus electricity from wind farms for the production of hydrogen by water electrolysis. Multiple electrolysers are used. Output from the region's wind farms frequently exceeds demand. When this happens, instead of taking the turbines off line, some of the electricity will now be fed to the electrolysers. To date, the plant has produced ~360 m^3/h of hydrogen from ~2 MW of wind power. This was piped to a connection point and injected into the regional high-pressure natural gas transmission grid. The grid acts as a storage system for electricity produced from intermittent renewables. By storing excess power in this manner, wind farms, often shut down at times of low demand, could continue to generate. Over a 24-hour period, the Falkenhagen facility will be able to store >30 MWh of energy. It should be fully operational by 2015. Hydrogenics Corporation has supplied the turnkey electrolyser and hydrogen production system. The package encompasses installation, connection and commissioning of the facility and gas compression system.

The combination of renewables and electrolysis is attractive for several reasons. There are often issues of balancing variable electricity output from intermittent sources with demand. Electricity may be produced at times of low demand and conversely, unavailable at times of high demand. Solutions to store excess off-peak electricity at large scale are needed (Folke, 2102) and the gas grid and infrastructure offers one such large storage capacity option. It is anticipated that E.ON's project will help move the technology to a much larger scale. However, at the moment, existing regulations limit the amount of hydrogen that can be fed into the gas grid to ~2% volume. To increase the energy storage potential, the next step will be to convert the hydrogen (by methanation) to SNG (E.ON, 2012). Theoretically, the entire storage capacity of the gas grid could then be utilised. This concept (P2G) is being developed by The Centre for Solar Energy and Hydrogen Research of Baden-

Württemberg, together with SolarFuel GmbH and the Fraunhofer Institute for Wind Power and Energy System Technology. The primary aim is to develop a large-scale storage technology with sufficient capacity to store the unwanted output from intermittent renewables. Since 2009, a 25 kW pilot plant has been successfully producing SNG and a 250 kW plant was due for completion in 2012.

Another German 'power-to-gas' project is being undertaken by RWE Power (at the Niederaussem power-plant) in association with Bayer and Siemens (Siemens, 2011). This will couple wind-generated electricity with Siemens PEM electrolyser technology to generate hydrogen and oxygen. Building and trialling the system forms part of the CO2RRECT research project supported by the Federal Ministry of Economics and Technology. The main aim is to develop a system capable of storing hydrogen produced using excess renewables-based electricity. The plant will be capable of producing methane using hydrogen from water electrolysis with CO_2 captured from the adjacent power plant's flue gas. As chemical energy in the form of SNG, this has the potential to be stored and used when necessary. System testing will begin in 2013. There are also a number of other small-scale German projects under way, mainly investigating the production and storage of hydrogen via electrolysis with wind power.

Elsewhere in Europe, several small-scale demonstrations of wind electrolysis units have been undertaken (Zoulias and others, 2002). These included a project undertaken by ENEA in **Italy** which comprised a wind turbine, electrolyser, AC-DC converter, and battery storage system, and evaluated the performance of several alkaline electrolysers. Historically, many European research activities have concentrated on using solar power as this is sometimes less variable than wind power.

Efforts have not been limited to academia, and variants of the technology are also being pursued by major technology developers. As noted above, Siemens has developed a new electrolyser based on novel membranes that are claimed to increase hydrogen yield. This will operate on surplus electricity from wind farms. The programme is also examining the potential for storing the hydrogen produced in subterranean caverns or salt domes, already used for storing natural gas. Potentially, this could then be blended (~40–50%) with natural gas to control combustion temperatures and fired in gas turbines; Siemens is working towards the development of hydrogen-fired turbines. Alternatively, it could be utilised for CO_2-free chemical and fuels manufacture.

The new generation of Siemens electrolysers are claimed to be capable of very rapid response to changes in the available electricity. They can be temporarily overloaded to a maximum of three times their rated output and can also operate at hydrogen pressures of 5–10 MPa, which reduces costs and improves yield. A 300 kW demonstration unit was due to begin operation in 2012 and the first commercial electrolyser is expected to be ready by 2014. The latest Siemens technology is focused on solid oxide electrolysis; this is considered to have advantages over alternative lower temperature electrolysers. To date, findings suggest that high efficiency production of hydrogen and oxygen is feasible, although there are potential efficiency gains through increasing operating pressures. Similarly, SNG production (via methanation) is possible with similar efficiency due to heat integration. Integration of the system with, for instance, a gasifier, would improve load flexibility (Tremel and others, 2012).

Development work is also under way in **Denmark**, where the major catalyst producer Haldor Topsøe is undertaking conceptual studies aimed at converting CO_2 to SNG using hydrogen produced by water electrolysis. The aim is the development and demonstration of a complete novel solid oxide electrolysis system. As with similar projects elsewhere, the technology has the potential for storing surplus power produced by renewables in the natural gas grid. Funding is being provided by the Energy Technology Development and Demonstration Programme (EUDP). Project partners include DONG Energy, the Danish Gas Technology Centre, and Risø DTU – National Laboratory for Sustainable Energy.

Around the world, a number of other projects are investigating the application of intermittent renewable energies (predominantly wind power), using excess or off-peak electricity for electrolysing water. In most cases, the primary object appears to be the production of hydrogen, although clearly, sizable quantities of oxygen would also be created by the electrolysis process. Potentially, this could be supplied to various power generation and industrial processes.

7.2 Economic viability of using only 'surplus' electricity

The premise behind some schemes based on the use of electricity from intermittent renewable sources such as wind is that at times of low demand, surplus electricity would be fed to electrolysers to generate hydrogen and oxygen. However, depending on the individual circumstances, over the course of a year, there may not always be enough 'surplus' electricity available to make the process economically viable. For instance, in the UK, most periods of high demand occur during the windier winter months. During the summer months when demand is lower, there is less wind, so less surplus electricity is available. Where excess output from intermittent sources was limited, utilisation of the electrolysers would therefore be low, so even though the electricity would be cost-free, the cost of hydrogen would be high. Only with very high amounts of wind and other variable renewables in the electricity system would there be enough hours during the year when there was 'surplus' wind energy to give the electrolysers a reasonable load factor (Davison, 2013). In such a situation it might be more favourable for electrolysis where it formed an integrated part of a system combining several technologies; for instance, where co-produced oxygen was fed to a gasifier.

A study examining the introduction of wind energy into the Irish energy market considered the integration of hydrogen systems as a means for facilitating a large penetration of wind energy; this would help overcome some of the barriers that constrain its deployment and lessen its value. Ireland has significant wind resources but is constrained by a weak grid and interconnections. It is anticipated that in the future, levels of wind-generated electricity will increase substantially, which could lead to more periods of excess generation that, without reinforcement, the electric system will be unable to readily assimilate. Where electrolysis was contemplated, overall cost reductions, low surplus wind electricity average value, and high hydrogen market prices would be needed to render the technology cost-effective, allowing for the installation of electrolysis units of sufficient capacity to attain the desired levelling effect (Gonzalez and others, 2003). However, simulations revealed that, even allowing for significant cost-reductions in electrolyser and associated balance-of-plant equipment, low average surplus wind electricity cost and a high hydrogen market price would also be necessary to achieve economic viability. Clearly, the situation will vary significantly between locations and in other countries, year-round wind may be available, or periods of high wind might correspond with times of low demand. Consequently, more electricity would be available for electrolysis.

8 CO_2 reduction/capture using biomass

Used either alone or as a replacement for part of the fuel feed to a coal-fuelled facility, biomass has obvious attractions for reducing CO_2 emissions. In recent years, its greater use has been encouraged in many countries. For example, US states are enacting renewable energy portfolio standards (RPS) that require electricity providers to procure a portion of their electricity from qualifying renewable sources. Although definitions vary between states, biomass power is included in all state RPS. Some have specifically included co-utilisation with biomass as a qualifying resource (Fernando, 2012).

Greater biomass use is also being encouraged in Europe. In July 2012, as part of the European Commission's New Entrants' Reserve (NER 300) of the European Emissions Trading Scheme, a series of biomass-based projects was announced. NER 300 is a financing instrument for subsidising installations of innovative renewable energy technology and CCS. The projects selected encompass a number of promising technologies (such as flash pyrolysis, several types of gasification, and torrefaction) and propose the use of a range of biomass feedstocks that include forest residues, energy crops, and agricultural wastes. As well as power and heat generation, end-products will include SNG, ethanol, biodiesel and other liquid fuels (European Commission, 2012).

Relatively large-scale biomass use has already been adopted in many EU Member States that include Finland, Germany, Poland, Sweden, Denmark, Italy, the Netherlands, Austria, Spain, Belgium, Hungary and the UK. For instance, in the case of the latter, most of the UK's coal-fired power plants have now cofired biomass in various ways. At the Drax power station, the second largest in Europe, there are plans to gradually replace half of the coal feed with biomass. In July 2012, Drax confirmed plans to transform into a predominantly biomass-fuelled generator. Initially, plans are to convert three of its six generating units to run on sustainable biomass; the first unit will be converted in the second quarter of 2013, and the second a year later.

Although not universally accepted, biomass is generally considered to be a CO_2-free energy carrier. This is because, during its growing phase, it is assumed to absorb the carbon emitted when combusted or otherwise used. Thus, replacing a proportion of the coal used in a coal-fuelled process with biomass will reduce overall CO_2 emissions. Assuming that the biomass is grown in a sustainable, regenerative way, its combustion does not produce any net CO_2 emissions. In light of concerns over links between the use of fossil fuels and climate change, there is continuing interest in combining coal and biomass as a means of minimising or reducing emissions of both conventional pollutants and CO_2. Efforts to reduce the latter remain at the forefront and many countries have initiated incentives to encourage the greater use of biomass (both on its own and in conjunction with coal) for power generation, cogeneration and other processes. However, invariably, the addition of biomass to an existing coal-fired facility such as a power plant increases complexity and incurs additional costs.

As with combustion processes, based on the assumption of carbon-neutrality, CO_2 emissions when gasifying coal are higher than those when using biomass. Again, replacing a portion of the coal with biomass can reduce these. When considered on a greenhouse gas emission index (GHGI) basis (defined as the life cycle GHG emission associated with the energy products, divided by the life cycle GHG emissions associated with the fossil-fuel-derived products displaced) studies have confirmed that combining biomass and coal is beneficial in terms of CO_2 emissions. For instance, a coal gasification process was determined to produce a GHGI of 1.71, although this fell to 0.96 when 40% of the coal feedstock was replaced with biomass (Liu and others, 2011). Other US studies concluded that cogasifying coal and switchgrass to produce FT diesel would produce lower greenhouse gas emissions than a petroleum-derived equivalent. If combined with CCS, overall GHG emissions could be reduced by more than 60% (Brar and others, 2012).

8.1 Carbon capture from biomass and cofired plants

Numerous CCS development programmes and projects are under way around the world, many focused on coal-fuelled processes. The three main routes being pursued are pre-combustion capture, post-combustion capture, and oxyfuel firing technology; the status of many of these was reported in a recent Clean Coal Centre report (Mills, 2012). The potential of using CCS on biomass- and biomass/coal-fuelled plants is also being examined. Substituting part of the coal feed to a coal-fuelled process with biomass will help reduce overall CO_2 emissions, although clearly, if carbon capture technology is also deployed, the impact will be even greater. Where a process is fired only on sustainably-produced biomass, the addition of CCS could be expected to produce a net overall removal of CO_2 from the atmosphere, making the process 'carbon negative'. This combination (Bioenergy with Carbon Capture and Storage, or BECCS) is claimed to be the only large-scale technology currently capable of achieving net negative emissions. Potentially, BECCS could be applied to any process where CO_2 forms a significant proportion of the flue gas stream. The OECD considers that BECCS will make an important contribution towards meeting global CO_2 reduction targets. However, its efficacy has sometimes been disputed; biomass may not be readily available in sufficient quantities, and there are concerns about how increased biomass demand would be met if BECCS were deployed widely. The neutrality of biomass carbon emissions based on assumed regrowth and re-storage has also been questioned. The debate continues.

In the case of forestry-supplied biomass, there are concerns that it might be impossible to meet demand using only residues, as opposed to increased tree harvesting (Smolker and Ernsting, 2012). On a localised basis, the quantities of biomass required could be considerable. For example, Smolker and Ernsting suggest that a 50 MW biomass-fuelled power plant would require woodchips/pellets made from ~500 kt/y of wood. Thus, the practicality of adequately supplying even larger capacity biomass plants with forest residues sourced locally (to avoid long distance transportation) has been questioned. However, where biomass formed only part of the fuel supply (for instance, to a coal-fuelled facility) issues of supply would diminish.

In 2012, the Zero Emissions Platform (ZEP) and the European Biofuels Technology Platform (EBTP) published (via the Joint Task Force for Bio-CCS) a report considering the future for biomass with CCS within a European context. This concluded that in order to minimise CO_2 emissions, effective carbon-negative solutions (such as BECCS) will be required. The report suggested that within Europe, by 2050, Bio-CCS could potentially remove 800 Mt/y of CO_2 from the atmosphere through the use of sustainable biomass. This is equivalent to >50% of current emissions from the EU power sector and would be in addition to any emissions reductions achieved by replacing fossil fuels with biomass. Combining biomass with CCS could produce a global saving of up to 10 Gt/y of negative CO_2 emissions by 2050 (IEA GHG/Ecofys, 2011), equivalent to a third of all current global energy-related emissions.

CCS in general is considered to have significant potential, and bodies such as the IPCC, IEA and UNIDO have flagged up its importance for both coal and biomass-fuelled systems. A recent IEA Technology Roadmap set out a vision for CCS in industrial applications up to 2050 and examined its potential for a number of applications, including biomass conversion. It concluded that the application of CCS to biomass processes is likely to start modestly; by 2020, some 14 Mt/y of CO_2 could be captured, mostly from ethanol and hydrogen production (ZEP, 2012). Both North America and China are expected to play key roles in CCS deployment in biomass conversion. The IEA Roadmap flagged up a number of technology actions for the latter (IEA, 2012b) that included:

- R&D into the removal of tars produced during the gasification of certain types of biomass and conversion of cellulose through chemical or biochemical routes;
- continued research into the most suitable types of biomass fuels that can be produced in a sustainable manner, and their quantification;
- R&D on combining the shift and CO_2 capture steps in a single reactor to lower capital costs, increase the CO_2 capture ratio, and reduce the energy penalty;

- realise six commercial-scale biomass conversion plants combining CO_2 compression, transport and storage by 2020, including an industrial-scale biomass gasification demonstration plant with CCS.

Globally, there are already around sixteen BECCS plants proposed or being developed. These are in the USA, the Netherlands, Sweden, Brazil, France, Germany and Tanzania (Biorecro/GCCSI, 2010). In the USA, three projects have a reported combined capacity of ~550 kt/y CO_2:

- Illinois – claimed to be the world's first commercial BECCS project. The first CO_2 was captured as a by-product from ethanol production in November 2011. Currently, some 300 kt/y are being injected although this will increase to 1 Mt/y from 2013. The project is being led by the Illinois State Geological Survey;
- North Dakota – a biomass gasification/CCS pilot plant is being developed by the Energy and Environmental Research Center at the University of North Dakota and Biorecro;
- Kansas – a BECCS plant is under construction and due on line in 2013, led by the Kansas Geological Survey. CO_2 will be sourced from an ethanol plant and stored in a deep sandstone aquifer.

However, not all of the carbon-negative processes being proposed worldwide are considered to be viable, at least in the near term (Baxter, 2012). However, successful demonstration and operation could encourage wider uptake. For instance, in late 2012, a workshop organised by the IEA, in co-operation with the Indonesian Ministry of Energy and Mineral Resources and others, considered the potential of BECCS as part of the country's energy mix. And in New Zealand, a consortium comprising CRL Energy, the University of Canterbury, and Industrial Research Limited have secured US$215,000 funding from the Ministry of Business, Innovation and Employment Research Fund to develop a carbon capture technology suitable for medium-scale biomass and coal gasification projects producing hydrogen, chemicals and biofuels (Carbon Capture Journal, 2012). The outcome will help the government and industry make informed decisions about the feasibility of combining these technologies in New Zealand and elsewhere.

Investigations in the USA are focusing on the use of coal/biomass cogasification (coupled with pre-combustion CCS) as a means for co-producing combinations of electricity, chemicals and low carbon transport fuels. A number of concepts are being simulated and assessed for lifecycle GHG emissions and cost analyses. Different system configurations, coal:biomass ratios, and product combinations are being addressed (Williams and others, 2010b). These include cogasification in existing entrained-flow coal gasifiers, as well as gasification of each feedstock in separate gasifiers, followed by combination of the syngas streams prior to FT synthesis. Unconverted syngas would be used to power a gas turbine combined cycle power island and captured CO_2 compressed and piped to underground storage. Indications are that, in terms of overall GHG emissions and process economics, co-producing electricity and liquid fuels (rather than just electricity) is advantageous – such flexible co-production is favoured both thermodynamically and economically (Larson, 2011). Furthermore, co-processing biomass with coal produces higher yields of low-emission liquid fuel per unit of biomass input, compared to 'pure' biofuel such as cellulosic ethanol. Compared to the latter, biomass requirement could possibly be halved. Importantly, this would help control biomass demand – global supplies are considered to be 'modest', relative to liquid fuel demands. In many cases, the process economics of coal-biomass-to-liquids (with CCS) fuels are likely to be better than those produced from biomass alone. Co-utilisation allows the cost benefits of scale of coal conversion also to apply to biomass, average feedstock costs are lower than for biomass-only systems, and less biomass per unit of low-carbon fuel is required than with 'pure' biofuel (Larson, 2011).

Opportunities associated with the repowering of older coal-fired US power plants are also being examined as some may be suitable for gasification-based repowering to produce combinations of electricity and synthetic fuels. Under a carbon-mitigation policy, the co-processing of biomass with coal coupled with CCS could be an economically attractive low-carbon option for repowering written-off coal power plants. Repowering in this manner could offer a cost-competitive approach to synfuels production, requiring less capital investment than many other options, thereby facilitating plant financing (Williams, 2010b).

At the moment, despite the perceived advantages of producing liquid fuels from coal and biomass, progress towards large-scale commercial deployment remains limited (Williams, 2011). As well as technical considerations, this results from economic issues such as:

- difficulties in financing large conventional synfuel plants that can capture adequate scale economies to protect investors against risk of oil price collapse;
- carbon concerns about conventional synfuels (even if plants adopt CCS) make governments reluctant to use public policy to facilitate financing;
- difficulty in co-processing enough biomass in large systems with CCS to enable deep reductions in GHG emissions;
- environmental NGO opposition to any use of coal for synfuels.

However, progress is being made in the area of cogasification combined with CCS. As noted in Section 4.5.3, the application of CCS to coal/biomass cogasification facilities is under way at several existing IGCC power plants. Two of these currently cogasify biomass with their coal feed and both are also hosting carbon capture projects. At Buggenum in 2011, NUON/Vattenfall opened a new pilot CO_2 capture plant. A two-year research programme linked to the project also involves ECN, Delft University of Technology and KEMA. Data from the ongoing test programme is being used for NUON's (delayed) larger Magnum coal/biomass IGCC + CCS plant (De Kler, 2007). Two other proposed Dutch IGCC plants (CGEN NV and Essent) plan to cogasify coal and biomass and deploy CCS technology. Elsewhere, several IGCC projects in the USA propose to do likewise (for instance, the deferred Twin River Energy Center in Maine). And in Poland, the planned PKE + ZAK polygeneration facility would be the world's first power and chemicals production complex based on co-fuelled IGCC with CCS.

The concept of cogasification coupled with carbon capture was explored as part of the European multi-partner FLEXGAS project. This was co-ordinated by the Istituto di Ricerche sulla Combustione in Italy and focused on the production of hydrogen-rich syngas via fluidised bed cogasification using different combinations of coal, biomass and wastes. A number of different scales of operation, novel plant configurations, and CO_2 capture schemes were investigated. The effects of different fuels, composition, and gasification medium on the quality of the syngas were also evaluated.

Other European activities include the ongoing FECUNDUS project, which is examining advanced concepts and process schemes for CO_2-free fluidised bed and entrained flow cogasification of coals with biomass and wastes. The aim is to integrate different cogasification schemes with processes for CO_2 separation and capture. The 36-month project is being co-ordinated by the Italian-based Consiglio Nazionale delle Ricerche Italia. Project partners are from Spain, the Czech Republic, the UK, Portugal and Austria.

8.2 In-bed CO_2 capture

Alongside the three main carbon capture technologies noted above, there are a number of other routes being pursued. Amongst these, the (in-bed) use of calcium oxide (CaO) to capture CO_2 in fluidised bed gasification is a promising option. The reversible reaction between CaO and CO_2 provides a method for capturing CO_2 and generating a pure stream suitable for storage. Potentially, the technology has a number of advantages that include:

- the relatively small efficiency penalty imposed on a power plant (~6–8 percentage points, including compression of the CO_2);
- application in large-scale circulating fluidised beds (a mature technology);
- the opportunity for integration with cement manufacture;
- the low cost of crushed limestone.

When CaO is used as a sorbent in fluidised bed gasification, as CO_2 is removed from the reactor, it drives H_2 (product gas) formation; its removal enhances the conversion of CH_4 and CO to hydrogen. The carbonation reaction is exothermic, and the heat released is close to the heat required for the endothermic reactions involved. Thus, the carbonation reaction provides heat for the reformer, which is otherwise difficult to supply. The remainder of the heat for reforming comes from the sensible heat of the regenerated CaO, which is returned from the calciner at >900°C. Accordingly, the heat supplied to the calciner is fully utilised in the reformer (Blamey and others, 2010). Furthermore, CaO and $CaCO_3$ catalytically enhance the destruction of tars that can be a major problem when using hydrogen in, for instance, fuel cells.

Studies carried out by the University of Sydney in Australia have examined biomass gasification coupled with in-bed CO_2 capture using CaO. The main aims were to investigate the effectiveness of CO_2 capture and to increase production of hydrogen from the process. It was concluded that CaO materials were the most suitable sorbents for in situ capture and increasing hydrogen concentration (Florin and Harris, 2008). A further advantage of the coupled gasification-CO_2 capture process was the production of a concentrated stream of CO_2 as a by-product. The process also has potential for application to cogasification processes.

Ideally, any CaO-based sorbent needs to be resistant to physical deterioration and demonstrate high reactivity, maintained through multiple CO_2 capture and release cycles; although promising, there are still some operational challenges that are considered to need further development. These include:
- sorbent durability;
- limits to the maximum achievable conversion;
- decay in reactivity through multiple capture and release cycles.

Possible strategies to enhance the multi-cycle reactivity of CaO include development of optimised calcination conditions, and sorbent hydration procedures for reactivation of spent CaO.

The use of in-bed capture using CaO forms part of the development programme being undertaken in New Zealand by the consortium of CRL Energy, the Wood Technology Research Centre at Canterbury University (WTRC) and Industrial Research Limited (IRL). Currently, a proof-of-concept study to integrate and extend current research is being undertaken. The aim is to develop a capture technology suitable for medium-scale biomass and coal gasification projects for the production of hydrogen, chemicals and FT fuels. Coal/biomass cogasification coupled with FT synthesis is considered to be one of the best options for producing second generation biofuels from the country's forestry resources. Incorporating CCS would provide the opportunity for negative CO_2 emissions. In-bed CO_2 removal is an option for the capture stage, suited to the medium-sized CO_2 emitters characteristic of New Zealand's economy.

As part of this programme, IRL has built a low cost, high-efficiency prototype system for CO_2 capture, based on the reversible ability of CaO to absorb CO_2 in a fluidised bed reactor to form limestone. More than 98% capture efficiency after 200 cycles (in a fixed bed reactor) have been demonstrated. A 2 kW fluidised bed reactor system has now been developed as a step towards larger-scale demonstration. Thus, calcium looping will be used to remove CO_2, linked to a limestone reactivation process developed by IRL. CaO absorbs CO_2 readily at temperatures up to 600°C to form calcium carbonate. As noted, this reaction is reversed in a calciner by heating the carbonate to 900°C. However, each time CaO particles undergo the carbonation-calcination cycle, their capacity to take up CO_2 decreases, falling to less than 15% of its theoretical capture capacity after ~20 cycles. IRL has developed a patented two-stage reactivation process comprising steam hydration and controlled dehydration in the presence of CO_2. In addition to providing a cost competitive means for in-bed CO_2 capture, the system has the potential to improve gasification reactivity and enable lower temperature gasification, manage biotar and methane production, and reduce or avoid the need for a shift reaction prior to chemical conversion of syngas in FT processes. CRL has been awarded >US$200,000 in funding from the Ministry of Business, Innovation and Employment's Energy and Minerals Research

Fund. This will be used for the proof of concept study into integrating in-bed CO_2 management with the gasification processes via calcium looping and the limestone reactivation process.

9 Conclusions

There are strong incentives to develop improved sources of energy. Forecasts indicate that by 2040, the world's population will have risen to nearly nine billion. By then, global energy demand will be around a third greater than current levels. This increase will not be distributed evenly, with much of the growth coming from non-OECD countries where energy demand is expected to increase by nearly 60%. Oil, natural gas and coal will continue to be the most widely used fossil fuels, accounting for up to ~80% of total global energy consumption.

Despite efforts to diversify, coal remains important for many economies. Since 2000, apart from renewables, it has been the fastest-growing global energy source. It is the second source of primary energy after oil, and currently provides more than 30% of global primary energy needs. Around 42% of the world's electricity comes from coal-fired plants. For the past 12 years, year-on-year, global coal production has increased. During this time, consumption has risen by nearly 60%, increasing from 4.6 Gt in 2000, to around 7.2 Gt in 2010. Most of this growth in demand has occurred in non-OECD countries, most notably China and India.

Alongside the ever-increasing use of fossil fuels of all types, in many parts of the world, for a combination of political, environmental and economic reasons, there has been a marked increase in the uptake of renewable energies. These now represent a rapidly growing share of energy supply in many economies. Of these technologies, the biggest contributions have been made by wind power and biomass. In 2012 alone, global wind capacity increased by 20%, reaching a total of 282 GW. In that year, around 50 countries made further capacity additions. China alone installed nearly 18 GW of new capacity, accounting for almost 44% of the world market; the country now has 77 GW of capacity, more than a quarter of the world's total. Globally, the ten biggest players now account for nearly 87% of total capacity – these include China, the USA, India, Germany, the UK, and Canada.

The other renewable energy source currently the focus of considerable interest is biomass, often considered to be the renewable energy with the highest energy-producing potential. This can take many forms although the present report concentrates mainly on the potential of forest residues. However, as there can sometimes be a degree of overlap with some other categories, where appropriate, sustainable energy crops and wastes were also examined.

Biomass can provide a number of advantages when combined with coal, although it can also have characteristics that work against it. For instance, some types are classified as waste products, with little or no commercial value. These are frequently landfilled, an increasingly expensive and unsustainable option. Combustion or gasification can effectively transform them from a waste to a feedstock. This helps reduce land requirements, minimise landfill methane emissions, and reduce groundwater contamination. Furthermore, replacing part of the coal feed to a particular process with biomass reduces the amount of coal required, effectively extending the working lifetime of coal reserves. Its addition can also help reduce conventional emissions from coal plants, and if produced sustainably, its 'carbon neutrality' can also help minimise CO_2 emissions.

However, using biomass on a large, commercial scale has the potential to throw up a number of issues. For example, as heating value and bulk density is lower than that of coal, the volumes to be harvested and handled can be substantial, various pre-treatments (such as drying and pulverising) may be needed, and so on. Inevitably, this adds complexity and cost to energy production.

The type and scale of availability of different biomass materials tends to vary with location. However, a major source could be forest residues as in some parts of the world considerable quantities are potentially available. Large tracts of the earth are covered with forests, but not all are very productive, and only some are currently exploited commercially. The degree of exploitation varies considerably between individual countries and in some cases only a small proportion of the residues available are actually put to good use. Even where a mature logging industry is in place, a high degree of wastage can occur and it is not uncommon for up to two thirds of a harvested tree to be discarded. Sawmilling and other downstream processes can increase wastage further.

However, even where large quantities of such residues are produced, depending on location, it may not be economic to collect them – some sites are too remote, transport infrastructure may be lacking, and so on. The cost of harvesting and transport may simply outweigh the commercial value of the biomass. However, there *are* many regions where forest residues are more readily accessible and available in sufficient quantities to make their use a viable proposition. But despite this, at the moment, these residues are often a largely underexploited resource.

Gasification is an effective, versatile technology that can be used to produce energy from coal and biomass. It has long been used on an industrial scale as the basis for power generation, chemicals, liquid fuels, and refining. Virtually any carbon-based material can be gasified and over the course of nearly two hundred years, many different types have been utilised. However, the most widely used feedstock has been coal. Gasification systems are many and varied, but consist mainly of three well-known types: entrained flow, fluidised beds, and fixed beds.

Compared to coal-fuelled plants, a typical biomass gasifier is usually much smaller. Most are too small to warrant the use of an air separation unit for oxygen supply, and consequentlyrely on various forms of air-blown technology. There is often a considerable difference between biomass and coal plants in terms of throughput. As with coal gasification, there are a number of different technologies available; 20 to 30 biomass gasifier variants are currently offered commercially. Around three quarters of these are of the down-draught fixed bed type, and most of the others are fluidised beds. Most are used for producing heat or power although recent years have seen growing interest in their use for producing liquid fuels. Over many years, the merits of gasification have been well established with coals, and various aspects of these systems can now be applied (with significant economic benefits) to both biomass gasification and to coal/biomass cogasification.

Many different individual coals and biomass materials have been gasified, but often on their own, and not always at commercial scale. Each feedstock has its own advantages and disadvantages. On the plus side, coal often has a high energy content, there are large reserves and it is widely available, and it is usually cheaper than biomass. However, there can be obvious environmental issues associated with its production, as well as with emissions from coal-fired plants.

Biomass may take the form of a low cost (or even no-cost) waste or residue, and replacing part of a plant's coal supply with biomass will normally reduce pollutant species such as NOx and SOx. Assuming that the biomass has been produced sustainably, overall CO_2 emissions will also be reduced. However, CVs are generally lower, chemical and physical properties can vary widely, supplies may be limited or seasonal, it may be expensive to harvest and treat, and there can be sometimes be operational issues when gasified.

Combining coal and biomass via cogasification can be beneficial. Cogasifying biomass in large coal gasifiers can achieve high efficiencies and improve process economics through the greater economies of scale that can be tapped into, and it can help smooth out fluctuations in biomass availability and variable properties. On the emissions front, adding biomass may help a coal plant to obtain credits for the use of a renewable fuel and, when combining the two, some useful catalytic and synergetic effects (such as lower activation energies) have been observed. Thus, combining biomass and coal in this way can be useful, both environmentally and economically, as it may be possible to capitalise on some of the advantages of each feedstock, and overcome some of their individual disadvantages.

Cogasification has been undertaken on a commercial scale and several coal-fuelled IGCC plants in operation have at least trialled combining biomass with their coal feed; a number of proposed commercial plants aim to do likewise. To date, useful operational experience of cogasification has been gained. All the major gasifier variants (entrained flow, fluidised bed, and fixed bed) have been used successfully with a range of biomass and waste materials.

Studies undertaken by the IEA and others suggest that, in view of the limited degree of industrialisation so far achieved with dedicated biomass gasification, at least in the near to medium term, the best way to achieve an industrial process route involving biomass is via its introduction as a blend feed to the more mature, commercially proven, coal gasification technologies that currently dominate the world market.

The use of cogasification as the starting point for producing liquid fuels has been examined. This has long been an area of interest to oil-consuming countries that possess significant coal reserves. Gasification is the foundation for converting coal and other feedstocks to gasoline, diesel and jet fuel. Two main processes have been demonstrated at full commercial scale for coal-to-liquids, namely Fischer-Tropsch (FT) and methanol-to-gasoline (MTG). Both start with coal gasification and follow this with further downstream processing, although the spread of products from each is quite different. There are currently several commercial projects under development or operating in China and the USA, although these use only coal – at the moment, there is no biomass component. To date, no mature biomass gasification technology is available for large-scale biomass-to-liquids production.

The global potential for producing liquid fuels from coal and biomass combinations is substantial, and various studies have examined the possible scale of manufacture for different countries. Most conclude that producing transport fuels from coal and biomass is best achieved by cogasifying, followed by either FT or MTG synthesis – these two appear to offer the most viable and economic options. There are a number of major programmes, in for instance the USA and Europe, actively investigating these routes. It is widely considered that the biomass input to such processes should take the form of agricultural and forestry residues, as most are readily available and do not require additional land cultivation or compete with food requirements (OECD/IEA, 2010).

A major aim of this report was to examine different systems that combine coal use with various other technologies to create efficient and clean energy-producing systems. In a number of countries, hybrid concepts for the production of SNG, electricity and/or heat, and liquid transport fuels have either been proposed or are in the process of being developed or trialled. A number are based on the cogasification of coal and biomass in various ways. However, as well as incorporating biomass, some propose to take this a step further by adding yet another element of renewable energy to the system, generally by incorporating electricity generated by intermittent renewables (such as wind and solar power).

A major drawback with wind and solar power is their intermittency. Consequently, times of peak output may not correspond with periods of high electricity demand, and vice versa. At times, there can be significant amounts of surplus unwanted energy available, particularly from wind farms. This can be quite a widespread phenomenon, and the usual solution is to take wind turbines off line. However, rather than waste this electricity, it would clearly be beneficial to put it to good use. One way would be to use it to electrolyse water, producing hydrogen and oxygen. Both gases have the potential to be component parts of such hybrid systems, and there are various schemes where the hydrogen could be fed into the syngas from a gasification system, used in fuel cells, used directly as a transport fuel, or stored for later combustion in gas turbines to generate electricity. Similarly, oxygen could be used for a number of industrial applications, or fed to a coal/biomass gasifier or an oxyfuel combustion plant to generate electricity. Different concepts and schemes combining gasification, intermittent renewables and electrolysis are currently being examined. If the economics can be made to work, several look promising.

In some locations, there may be inadequate 'surplus' electricity available from intermittent sources to make electrolysis economically viable. If insufficient, electrolysers would stand idle with low a load factor, so even though electricity was cost-free, hydrogen (and oxygen) produced would be expensive. Electrolysers are currently an expensive option for hydrogen production, although compared to a decade ago, ongoing developments have significantly reduced operating and capital costs; further reductions are expected in the future as ongoing R&D continues to drive costs down. In the current situation, for small-scale niche applications such as hydrogen refuelling stations for road vehicles, it would probably be less expensive to use grid electricity (Davison, 2013).

There is a growing number of coal/renewables hybrid systems proposed – some also incorporate forms of carbon capture and storage. For example, an ongoing project in Germany is combining coal-based power generation with aspects of carbon capture and wind-generated electricity with trials of advanced electrolyser technology. Success could encourage increased uptake of, for instance, advanced electrolysis, as a component part of different coal/renewables systems. Examples of promising technologies and their current status are discussed in the report.

Some hybrid systems are at early stages in their development or have been undertaken at a very small size, hence extrapolating to commercial scale and obtaining firm process costs remains problematic. For a variety of reasons, not all schemes proposed are considered to be technically and/or economically viable. However, from the former standpoint, some appear to be much more robust. Ongoing improvements in, for instance, gasifier and electrolyser design could encourage further development of such systems for energy production. Where hydrogen and/or oxygen production forms part of such schemes, reductions in the cost of electricity supplied by renewable energy sources (such as wind and solar) would also be beneficial in making electrolysis more cost effective.

A number of projects are further advanced than others, with development programmes well under way. Some component parts (such as the cogasification stage) have now been well established, and others are under development or being trialled (such as the commercial-scale demonstration of hydrogen production from wind power, and testing of advanced electrolysers). A co-ordinated approach involving a consortium of organisations can be beneficial in drawing together specialist expertise from a number of fields. In this respect, the approach being adopted for the CRL-led developments in New Zealand is a good example. This cogasification/electrolysis concept combines input from several organisations and shows particular promise, certainly within a New Zealand context. A number of such proposed hybrid systems show potential although in the medium term, assuming outstanding technical and economic issues can be resolved fully, most seem likely to be applied initially to niche markets, or to find application under specific, favourable circumstances. For instance, New Zealand has coal, biomass and plentiful wind power resources potentially available for such a system, making deployment particularly attractive.

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