PERGAMON

Renewable and Sustainable Energy Reviews
6 (2002) 181–248

RENEWABLE
& SUSTAINABLE
ENERGY REVIEWS

www.elsevier.com/locate/rser

A techno-economic comparison of power production by biomass fast pyrolysis with gasification and combustion

A.V. Bridgwater*, A.J. Toft, J.G. Brammer

Bio-Energy Research Group, Aston University, Birmingham B4 7ET, UK

Abstract

This paper presents an assessment of the technical and economic performance of thermal processes to generate electricity from a wood chip feedstock by combustion, gasification and fast pyrolysis. The scope of the work begins with the delivery of a wood chip feedstock at a conversion plant and ends with the supply of electricity to the grid, incorporating wood chip preparation, thermal conversion, and electricity generation in dual fuel diesel engines. Net generating capacities of 1–20 MW_e are evaluated.

The techno-economic assessment is achieved through the development of a suite of models that are combined to give cost and performance data for the integrated system. The models include feed pretreatment, combustion, atmospheric and pressure gasification, fast pyrolysis with pyrolysis liquid storage and transport (an optional step in de-coupled systems) and diesel engine or turbine power generation. The models calculate system efficiencies, capital costs and production costs. An identical methodology is applied in the development of all the models so that all of the results are directly comparable.

The electricity production costs have been calculated for 10th plant systems, indicating the costs that are achievable in the medium term after the high initial costs associated with novel technologies have reduced. The costs converge at the larger scale with the mean electricity price paid in the EU by a large consumer, and there is therefore potential for fast pyrolysis and diesel engine systems to sell electricity directly to large consumers or for on-site generation. However, competition will be fierce at all capacities since electricity production costs vary only slightly between the four biomass to electricity systems that are evaluated.

Systems de-coupling is one way that the fast pyrolysis and diesel engine system can distinguish itself from the other conversion technologies. Evaluations in this work show that situations requiring several remote generators are much better served by a large fast pyrolysis

* Corresponding author. tel.: +44-0121-359-3611x4647.
E-mail address: a.v.bridgwater@aston.ac.uk (A.V. Bridgwater).

PII: S1364-0321(01)00010-7

plant that supplies fuel to de-coupled diesel engines than by constructing an entire close-coupled system at each generating site. Another advantage of de-coupling is that the fast pyrolysis conversion step and the diesel engine generation step can operate independently, with intermediate storage of the fast pyrolysis liquid fuel, increasing overall reliability. Peak load or seasonal power requirements would also benefit from de-coupling since a small fast pyrolysis plant could operate continuously to produce fuel that is stored for use in the engine on demand.

Current electricity production costs for a fast pyrolysis and diesel engine system are 0.091 € /kWh at 20 MW_e and 0.199 €/kWh at 1 MW_e in the base case studied here reducing to 0.073 € /kWh at 20 MW_e and to 0.146 €/kWh at 1 MW_e when learning effects are included. These systems are handicapped by the typical characteristics of a novel technology: high capital cost, high labour, and low reliability. As such the more established combustion and steam cycle produces lower cost electricity under current conditions.The fast pyrolysis and diesel engine system is a low capital cost option but it also suffers from relatively low system efficiency particularly at high capacities. This low efficiency is the result of a low conversion efficiency of feed energy into the pyrolysis liquid, because of the energy in the char by-product. A sensitivity analysis has highlighted the high impact on electricity production costs of the fast pyrolysis liquids yield. The liquids yield should be set realistically during design, and it should be maintained in practice by careful attention to plant operation and feed quality. Another problem is the high power consumption during feedstock grinding. Efficiencies may be enhanced in ablative fast pyrolysis which can tolerate a chipped feedstock. This has yet to be demonstrated at commercial scale.

In summary, the fast pyrolysis and diesel engine system has great potential to generate electricity at a profit in the long term, and at a lower cost than any other biomass to electricity system at small scale. This future viability can only be achieved through the construction of early plant that could, in the short term, be more expensive than the combustion alternative. Profitability in the short term can best be achieved by exploiting niches in the market place and specific features of fast pyrolysis. These include:

- countries or regions with fiscal incentives for renewable energy such as premium electricity prices or capital grants;
- locations with high electricity prices so that electricity can be sold direct to large consumers or generated on-site by companies who wish to reduce their consumption from the grid;
- waste disposal opportunities where feedstocks can attract a gate fee rather than incur a cost;
- the ability to store fast pyrolysis liquids as a buffer against shutdowns or as a fuel for peak-load generating plant;
- de-coupling opportunities where a large, single pyrolysis plant supplies fuel to several small and remote generators;
- small-scale combined heat and power opportunities;
- sales of the excess char, although a market has yet to be established for this by-product; and
- potential co-production of speciality chemicals and fuel for power generation in fast pyrolysis systems.

Contents

1. Introduction

In recent years public and political sensitivities to environmental issues and energy security have led to the promotion of indigenous renewable energy resources [1,2]. Biomass is one of the renewable resources that could play a substantial role in a more diverse and sustainable energy mix. Biomass may be defined as any renewable source of fixed carbon. The term is generally used to describe plant material such as wood, wood residues, agricultural crops and their residues. Industrial and municipal wastes are often also considered as biomass due to their high percentages of food waste and fibre.

Electricity generation is considered the most lucrative opportunity for commercial exploitation of biomass, by virtue of the high value of electricity [3]. Biomass to electricity schemes already provide over 9 GW_e of world-wide generating capacity [4]. These systems burn various biomass and wastes (mainly wood) in boilers to raise steam that is used to drive a steam turbine. This technology is established but far from ideal for biomass fuels. Generating capacities are constrained by the local availability of feedstock and at low plant sizes steam turbine plant are inefficient generators with high capital costs [5,6].

Increased efficiencies and decreased capital costs may be possible if the solid biomass feedstock is first converted to an intermediate liquid or gaseous fuel that may then be used in gas turbines or engines [7]. The integration of sustained feed production, feed conversion and high efficiency electricity generation as shown in Fig. 1 may be the key to generating electricity from biomass at a lower cost than is currently possible.

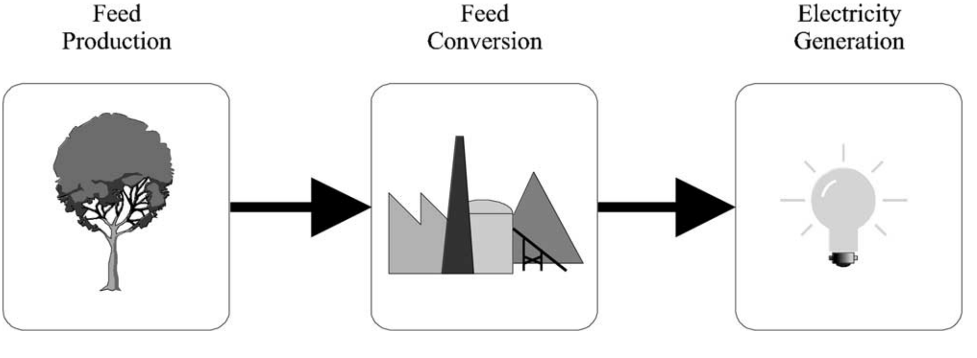

Fig. 1. Basic stages in a complete integrated biomass to electricity system.

This section presents an overview of the technologies. Section 1.1 discusses fast pyrolysis and its applications, the main focus of this work. Section 1.2 summarises combustion systems, the established approach to electricity generation from biomass. Section 1.3 describes gasification and its use in electricity generation since this is an emerging technology that is expected to be a key competitor with fast pyrolysis. Section 1.4 introduces systems de-coupling, an option that is only possible with fast pyrolysis and that could offer significant advantages for this technology.

1.1. Fast pyrolysis applications

Pyrolysis is the thermal degradation of biomass in the absence of an oxidising agent whereby the volatile components of a solid carbonaceous feedstock are vaporised in primary reactions by heating, leaving a residue consisting of char and ash. Pyrolysis always produces a gas, vapour that can be collected as a liquid and a solid char. Fast pyrolysis processes are designed and operated to maximise the liquid fraction at up to 75% wt on a dry biomass feed basis [8]. The char may be sold or used internally to provide heat for the process. The gas has a medium heating value and can be used internally to provide process heat, re-circulated as an inert carrier gas or exported for example for feed drying [9]. The liquid is an homogenous mixture of organic compounds and water in a single phase with the fuel properties that are summarised in Table 1.

Fast pyrolysis requires rapid heating of the feedstock to moderate temperatures of typically around 500°C and rapid quenching of the pyrolysis vapours to minimise secondary reactions. A wide range of fast pyrolysis processes has been investigated, covering a variety of different reactor configurations and methods of achieving the necessary reaction conditions [10]. Fluid bed configurations have been the most popular reactors, mostly as bubbling beds, but also as circulating beds and trans-

Table 1
Comparison of pyrolysis liquid and conventional fuel oil characteristics

		Pyrolysis liquid	Diesel	Heavy fuel oil
Density	kg/m^3 at 15°C	1220	854	963
Typical composition	%C	48.5	86.3	86.1
	%H	6.4	12.8	11.8
	%O	42.5	–	–
	%S	–	0.9	2.1
Viscosity	cSt at 50°C	13	2.5	351
Flash point	°C	66	70	100
Pour point	°C	−27	−20	21
Ash	%wt	0.13	<0.01	0.03
Sulphur	%wt	0	0.15	2.5
Water	%wt	20.5	0.1	0.1
LHV	MJ/kg	17.5	42.9	40.7
Acidity	pH	3	–	–

ported beds. have been scaled up to commercial capacities (see reviews in [8,10]). These reactors use the excellent heat transfer characteristics of fluid beds to rapidly heat the feedstock to the reaction temperature. Vacuum pyrolysis (e.g.[11]) also gives high yields of liquids of up to 60% wt on dry feed, but although the vapour residence time is short as in conventional fast pyrolysis systems, the solid heating rates are low and the solid residence time is also very high.

Most fast pyrolysis processes demand a finely divided, substantially dry feed and some feed pretreatment is therefore usual before the reactor. Exceptions are ablative and vacuum pyrolysis both of which have the advantage of tolerating much larger feed sizes. In most reactor configurations particle size is constrained by a need to limit secondary reactions of the primary pyrolysis vapours with char formed at the particle surface since this char catalyses secondary reactions that reduce the liquids yield. Bubbling fluid beds are limited to particle sizes of less than 2 mm and circulating fluid beds or transport reactors can tolerate up to 5 mm particles.

Most feedstocks must also be dried before entering the reactor. As all the feed water and pyrolysis reaction water reports to the liquid product, feed moisture content must be limited to improve liquid product yield and quality, although some moisture enhances fuel properties such as viscosity. A maximum feed moisture content of 10% is usually specified, while a 7% moisture content is preferred.

There are a wide range of potential opportunities for fast pyrolysis liquids in heat, chemicals, fuels and electricity applications, as indicated by Fig. 2. Most development for electricity generation is focused on the use of raw pyrolysis liquids in gas turbine or diesel engine applications.

Combustion for heat production has been well demonstrated at large scales of operation including supplemental firing in power stations. Diesel engine operation on pyrolysis liquids has been successfully carried out. Large scale development of diesel engine systems is ongoing through the work of Ormrod Diesels in the UK [12] and Wärtsilä Diesels in Finland [13]. Pyrolysis liquids are very different to

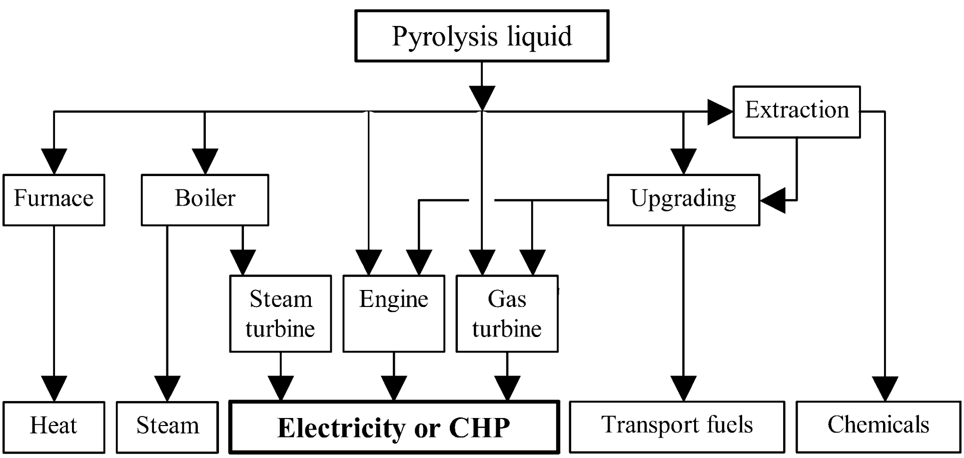

Fig. 2. Fast pyrolysis applications.

conventional diesel fuels (as shown in Table 1) but it has been shown that crude pyrolysis oil burns well in engines. Ignition is difficult but pilot-ignition engines, which use a small amount of an auxiliary fuel to ignite the main fuel solve this problem.

Less development work has been carried out on the use of gas turbines with fast pyrolysis. Early tests on a combustor rig designed to simulate a slurry-fed gas turbine highlighted problems including entrained char in the bio-oil which blocked fuel injection systems; ash fouling downstream of the gas turbine; corrosion to turbine components; and increased smoke emissions [14]. More recent tests at Orenda in Canada [15] have evaluating the firing of a 2.5 MW_e industrial gas turbine with more promising results. The turbine has been run successfully for several hours on 100% pyrolysis liquids [16] while flame tunnel tests are examining the long-term resistance of turbine parts to corrosive attack from alkali metals in the ashes entrained in pyrolysis liquids.

Chemical recovery is seen as a more commercially exciting short term opportunity due to the higher value of chemicals, but as in fuel applications, the opportunities are more likely to lie in niche markets [8].

1.2. Combustion applications

The combustion of solid biomass is fully established and already widely used in biomass applications [17–19]. The combustion properties of biomass are well understood [20]. The most popular combustors for 100% biomass applications are either stoker-fired and fluid bed designs [21], although in recent years the option to co-fire small proportions of biomass with coal in large suspension-fired furnaces has attracted widespread interest [22]. In stoker-fired combustors the feed burns as it moves through the furnace while resting on a stationary or moving grate. Fluid bed designs burn the feed in a turbulent bed of inert material that is fluidised by combustion air flowing through it from underneath. Although grate-fired combustors are the norm for older biomass-fired plant [23], fluid bed combustors are rapidly becoming the preferred technology for biomass combustion because of their low NO_x emissions [24–26].

Fluid bed boilers have been commercially available for over 20 yr [24] at capacities ranging from 15 to 715 MW_{th} input. Bubbling fluid beds tend to be limited to the lower size range, while circulating fluid beds are reported over the entire capacity range. Over 110 fluid beds are operating or are planned for operation in the US [27], all with performance guarantees from the vendor. La Nauze [28] lists over 50 commercial installations that operate on biomass with capacities of 2.5–94 MW_{th}.

There are a number of ways of generating electricity using the heat produced in combustion, including the steam turbine, the reciprocating steam engine, Stirling engines, indirect fired gas turbines and direct fired gas turbines. These options have been reviewed in a recent IEA evaluation [29] that showed that the steam turbine is the only established generating technology. The other options had efficiency advantages but were not available commercially and most were confined to small scale applications.

The basic steam turbine Rankine cycle is bound by thermodynamic and materials limitations to modest efficiencies of around 35% [30]. Such cycles are optimised through the use of high pressure, highly superheated steam combined with complex steam generation, reheat and regeneration options. This extra complexity and the materials demands imposed by high pressure steam increase capital costs dramatically at small scale, with only minor increases in system efficiency. As a result, most steam cycles at the small scale are relatively simple and consequently inefficient.

1.3. Gasification applications

Thermochemical gasification is the conversion by partial oxidation at elevated temperature of a carbonaceous feedstock into a gaseous energy carrier consisting of permanent, non-condensable gases. Development of gasification technology dates back to the end of the 18th century when hot gases from coal and coke furnaces were used in boiler and lighting applications [31]. Gasification of coal is now well-established, and biomass gasification has benefited from activity in this sector and is developing rapidly [32]. However the two technologies are not directly comparable due to differences between the feedstocks (e.g. char reactivity, proximate composition, ash composition, moisture content, density).

Gasifiers have been designed in various configurations, with the main options shown in Fig. 3. Other less established designs are the twin fluid bed and the entrained bed. Detailed reviews of gasifier options are available [33,34].

Although many biomass gasification processes have been developed commercially [35], only the fluid bed configurations are being considered in applications that generate over 1 MW_e [36,37]. Fluid bed gasifiers are available from a number of manufacturers in thermal capacities ranging from 2.5 to 150 MW_{th} for operation at atmospheric or elevated pressures. Atmospheric bubbling bed gasifier manufacturers include EPI, PRM Energy Systems, Foster Wheeler, and TPS. Pressurised bubbling bed systems are being developed by Enviropower and IGT. Atmospheric circulating

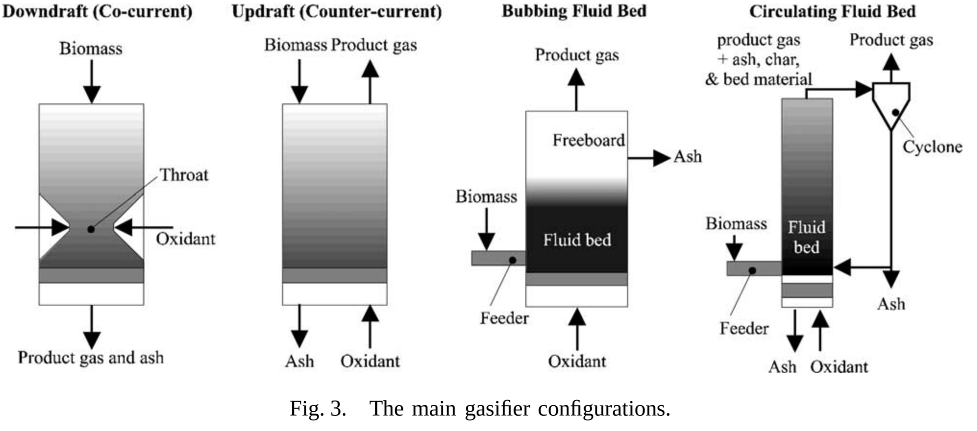

Fig. 3. The main gasifier configurations.

fluid bed suppliers include TPS, Foster Wheeler, Battelle and Lurgi. Foster Wheeler have also developed a pressurised circulating fluid bed system.

Ideally, the process produces only a non-condensable gas and an ash residue. In reality, incomplete gasification of char and the pyrolysis tars will produce a gas containing varying levels of the contaminants such as particulate, tars, alkali metals, fuel-bound nitrogen compounds [38] and an ash residue containing some char. The composition of the gas and the level of contamination varies with the feedstock, reactor type and operating parameters, and typical gas characteristics are shown in Table 2 [39].

Biomass gasification can be used to produce heat, steam, bulk chemicals or electricity. Electricity generation could be accomplished in a variety of ways but the most interesting near term opportunities involve internal combustion engines or gas turbines.

1.3.1. Gasification with gas turbines

Gas turbines are noted for their high efficiency; low specific capital cost, especially at small scale; short lead times by virtue of modular construction; low emissions; high reliability and simple operation [40,41]. Gas turbine integration with biomass gasification is not established but there are many demonstration projects active with capacities of 0.2–27 MW_e [42,43]. Gas turbine tests on biomass fuel gases are underway by a number of organisations to support these projects [44–46].

There are several issues that must be resolved in the integration of gas turbines with biomass gasification, including:

- The reliable and environmentally sound operation of gas turbines with low heating value gases;
- The selection of gasification operating pressure (atmospheric or elevated) and the consequent integration of the air flow to the gasifier and fuel gas flow to the gas turbine combustor with the rest of the system;
- Fuel gas cleaning and cooling; and
- The selection of the gas turbine cycle, although generally combined cycles are preferred.

Table 2
Gasifier product gas characteristics

	Gas composition, %v/v dry					HHV, MJ/Nm^3	Gas quality	
	H_2	CO	CO_2	CH_4	N_2		Tars	Dust
Fluid bed air-blown	9	14	20	7	50	5.4	Fair	Poor
Updraft, air-blown	11	24	9	3	53	5.5	Poor	Good
Downdraft, air-blown	17	21	13	1	48	5.7	Good	Fair
Downdraft, oxygen-blown	32	48	15	2	3	10.4	Good	Good
Multi-solid fluid bed	15	47	15	23	0	16.1	Fair	Poor
Twin fluidised bed gasification	31	48	0	21	0	17.4	Fair	Poor

Of these issues, it is fuel gas cleaning that is the cause of most concern. Gas turbines are highly sensitive to fuel gas quality, and the fuel gas must be treated to remove contaminants. Two basic gas treatment methods have been proposed [47]: hot gas filtration and wet gas scrubbing.

In hot gas filtration the gases are partially cooled to around 500°C to condense alkali metal vapours onto particulate in the gas. Gas cooling is followed by a hot gas filter that removes both the particulate and the condensed alkali metals. The gas is delivered to the gas turbine at relatively high temperatures of around 450°C that allow tars in the gas to be retained as vapours. Hot gas filters are currently the subject of a great deal of research and development activity [48,49], and are perceived to be the better solution if their technical problems can be overcome because the tars and sensible heat in the product gas are retained and the effluent stream that would be produced in wet gas scrubbing is avoided (wet gas scrubbing is described below).

1.3.2. Gasification with engines

The operation of diesel and spark-ignition engines using a variety of low heating value gases is an established practice [50–53]. Both dual fuel diesel and spark ignition engines for operation using low heating value gases may be regarded as fully developed, although integration of a biomass gasifier and engine is not fully established.

Again the main issue that must be resolved is the effective treatment of the fuel gas to cool and clean it to the specifications demanded by the engine [54,55]. The fuel gas must be cool at injection to the engine and therefore wet scrubbing is the preferred gas treatment method. In this approach the gases are cooled to under 150°C and then passed through a wet gas scrubber. This removes particulate, alkali metals, tars and soluble nitrogen compounds such as ammonia. Wet gas scrubbing is considered an established gas cleaning technology although there is little experience of its application with biomass gasification gases. If wet scrubbing is used then it is usual to incorporate thermal or catalytic cracking of the tars before gas clean-up to produce non-condensable hydrocarbon gases and so retain the chemical energy of the fuel gas [56].

1.4. Systems de-coupling

De-coupling is the separation in time or space of the conversion and generation stages of the biomass to electricity system. De-coupling is only available for fast pyrolysis systems where it is viable to store and transport the intermediate energy carrier since it is a liquid. Conversely the steam produced in a combustion system must be used immediately in the steam turbine and a low heating value fuel gas cannot be stored or transported for long distances economically. Combustion and gasification systems must therefore be used in close-coupled configurations where the conversion and generating stages occur concurrently and at the same site.

De-coupling offers several potential system configurations, with the four main options shown in Fig. 4. In each case there is an interaction between transport costs and capital costs that could result in a lower production cost for the electricity. Since

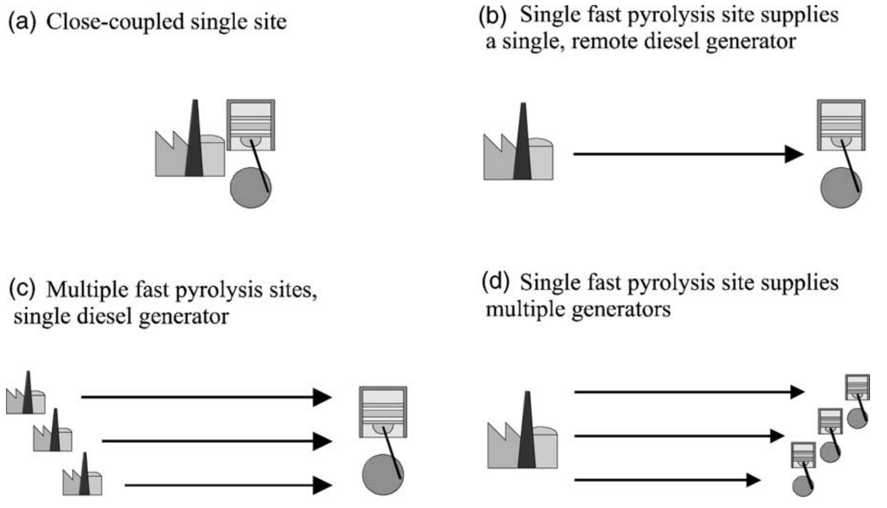

Fig. 4. System de-coupling options for fast pyrolysis systems.

these four options are not available in combustion or gasification based-systems, de-coupled fast pyrolysis systems may be more cost-effective than the alternative technologies in particular circumstances.

2. Methodology

2.1. Systems to be evaluated

The primary aim of this project is to evaluate the costs and performance of systems that generate electricity using fast pyrolysis and diesel engines. In addition, the costs and performance of these systems are compared using a consistent methodology with several alternatives. Four systems were selected for evaluation, as follows (an abbreviated name for each system is given in brackets):

1. Fast pyrolysis and diesel engine (PyrEng);
2. Combustion in a boiler followed by a steam cycle, as the established alternative technology (Combust);
3. Atmospheric gasification and dual-fuel diesel engine, as an emerging alternative for small scale applications (GasEng); and
4. Pressurised gasification and gas turbine combined cycle, as an emerging alternative for large scale applications (IGCC).

2.2. Scope of the evaluations

The four systems have been broken down into modules for modelling convenience. Each module calculates the cost and performance of a discrete part of the system and combinations of modules are used to evaluate whole systems. Some of the modules are common to all of the systems so that the entire range of systems can be modelled using the modules listed in Table 3 and shown in Fig. 5.

2.3. System performance calculations

System performance is measured in terms of its ability to convert the energy in the delivered feedstock into power supplied to the grid. The two dual fuel engines use an auxiliary fuel in electricity generation and this is included as an additional energy input to the system. All thermal energy flows are measured on an lower heating value (LHV) basis. Net system efficiency is calculated using Eq. (1):

$$\text{Net system efficiency, } \eta_{\mathrm{e,net}} = \frac{E_{\mathrm{e,net}}}{E_{\mathrm{th,del}} + E_{\mathrm{th,aux}}} \qquad (1)$$

where

$E_{\mathrm{e,net}}$ net annual electricity output to the grid, GJ/yr;
$E_{\mathrm{th,conv}}$ annual energy value of the conversion technology product, GJ/yr;
$E_{\mathrm{th,aux}}$ annual energy value of the auxiliary diesel fuel if used, GJ/yr.

Other useful efficiencies that can be used to compare system performance are the gross system efficiency (Eq. (2)), the conversion efficiency (Eq. (3)) and the generation efficiency (Eq. (4)). The gross system efficiency excludes internal power consumption. The conversion and generation efficiencies are gross, in that they are based purely on the energy in the feed or fuel and ignore power consumption.

$$\text{Gross system efficiency, } \eta_{\mathrm{e,gross}} = \frac{E_{\mathrm{e,gross}}}{E_{\mathrm{th,del}} + E_{\mathrm{th,aux}}} \qquad (2)$$

Table 3
Location of module descriptions within this report

Module	Used in	Described in
Feed pretreatment	All systems	Section 4
Combustion	Combust	Section 6.1
Fast pyrolysis	PyrEng	Section 5.1
Atmospheric gasification	GasEng	Section 7.1
Pressurised gasification	IGCC	Section 8.1
Steam cycles	Combust	Section 6.2
Dual-fuel diesel engine (liquid-fired)	PyrEng	Section 5.3
Dual-fuel diesel engine (gas-fired)	GasEng	Section 7.2
Gas turbine combined cycle	GTCC	Section 8.2
Grid connection	All systems	Section 5.4
Pyrolysis liquid transport	PyrEng	Section 5.2

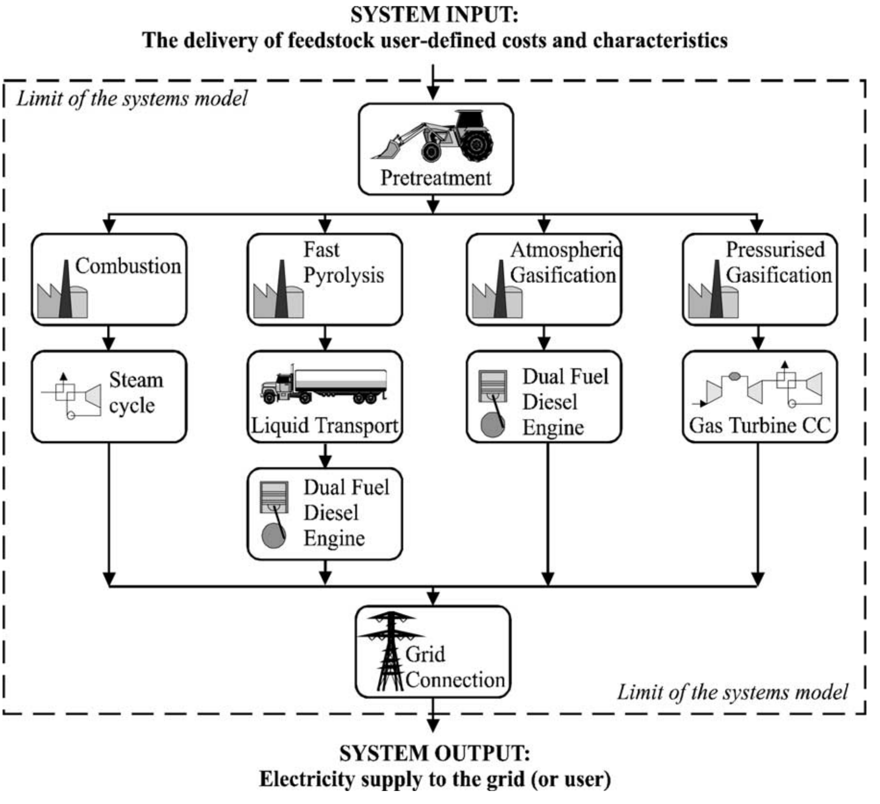

Fig. 5. The structure of the model in terms of modules.

$$\text{Conversion efficiency, } \eta_{\text{conv}} = \frac{E_{\text{th,conv}}}{E_{\text{th,pret}}} \tag{3}$$

$$\text{Generation efficiency, } \eta_{\text{gen}} = \frac{E_{\text{e,gross}}}{E_{\text{th,conv}} + E_{\text{th,aux}}} \tag{4}$$

2.4. System cost calculations

2.4.1. Currency, year and location

All cost data have been updated and converted as necessary to give costs in €, 2000 basis using international cost indices from the Chemical Engineer [57] and OECD international exchange rates for 2000 [58].

2.4.2. Capital costs

All capital costs are presented as total plant costs. As such they include the costs of the basic equipment plus costs for erection, piping, instruments, electrical, civils, and buildings to give a direct plant cost. This is converted to total plant cost using the factors given in Table 4. Total plant costs are used so that realistic estimates of the total cost of constructing a working system can be calculated.

2.4.3. Production costs

The unit electricity production cost is calculated by dividing the total annual production cost by the annual electricity output. No profit element has been included. Annual production costs are the sum of:

- Delivered feedstock cost;
- Capital amortisation;
- Materials costs (mainly diesel fuel and catalyst in the GasEng system);
- Labour cost (operator requirements are calculated by system capacity, with four shifts in rotation and an average salary of 25000 €/yr);
- Utility costs (boiler feed water, cooling water and electricity when required);
- Plant maintenance costs at 2.5% of TPC; and
- Plant overheads costs at 2.0% of TPC.

All production costs are calculated in real terms and are assumed to be constant in real terms over the life of the project. Capital is amortised over 20 yr at a nominal interest rate of 10% per annum. Since capital amortisation is a constant charge in

Table 4
Components of capital cost estimates

Cost component	Usual range		Factor used here
Major equipment items cost			
+ erection			
+ piping			
+ instruments			
+ electrical			
+ civils			
+ structures and buildings			
+ lagging			
	Direct Plant Cost (DPC)		
Engineering, design, supervision		10–20% DPC	15% DPC
Management overheads		5–20% DPC	10% DPC
	Installed Plant Cost (IPC)		=125% DPC
Commissioning		1–10% IPC	5% IPC
Contingency		0–50% IPC	10% IPC
Contractors' fees		5–15% IPC	10% IPC
Interest during commission		7–15% IPC	10% IPC
Total Plant Cost (TPC)			=135% IPC =169% DPC

nominal terms, a real cost is estimated by averaging the real cost for each year of the project using an annual inflation rate of 5%.

2.5. Learning effects

This project will examine both the current and the future costs of electricity generated using the four systems by applying learning effects. It is widely accepted that the costs of a process reduce as more units are built and experience accumulates [59]. A learning factor may be observed, which is a fixed percentage reduction in cost per doubling of cumulative production [60]. Since doubling of number of plants built is more rapid during the construction of the first few plant, cost reductions are quickly realised during the early development of a technology, as shown in Fig. 6.

The impact of learning on future capital costs depends on two factors: the learning factor and the status of the current costs.

- For this analysis, a learning factor of 20% has been assumed. This corresponds to the estimates suggested by Elliott and Booth for the GEF Brazilian IGCC plant [3] and will result in a 50% reduction in capital costs after 10 installations of a novel process.
- Only the fast pyrolysis and gasification technologies are considered novel. The current capital costs associated with these modules are assumed to refer to the costs of the first plant constructed. All the other modules are based on established equipment and their current capital costs are assumed to be 100th plant costs.

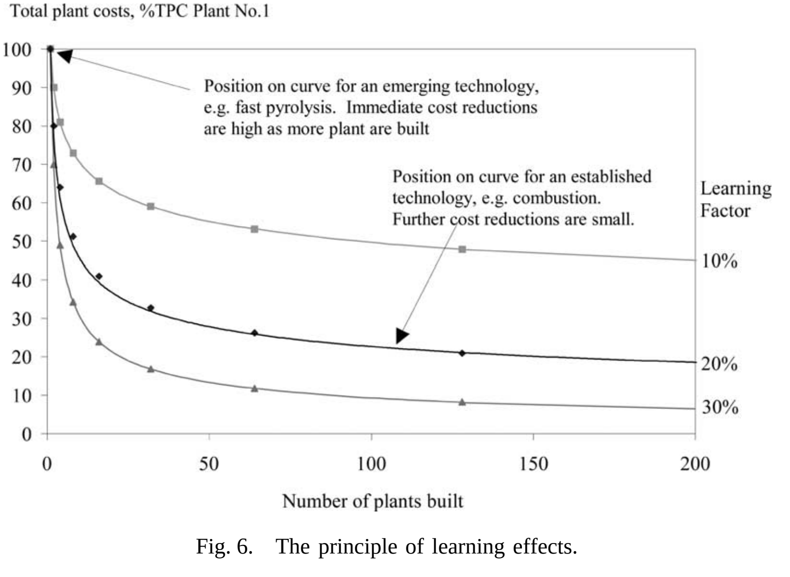

Fig. 6. The principle of learning effects.

3. Feedstock characteristics

3.1. Feed selection

The term biomass can be applied to a very diverse range of feedstocks, although the predominant biomass feedstock for electricity generation is currently wood. There is far more information available about wood production, handling and processing than any other feedstock. For these reasons this work will focus exclusively on wood feedstocks. Details of wood production methods, characteristics and costs have been compiled in a report written by the Wood Supply research Group at the University of Aberdeen [61].

3.2. Feed characteristics

Table 5 summarises the values that have been used in the evaluations on the basis of [61] and other data in the literature.

3.3. Delivered feed costs

Feed costs for short rotation forestry wood and conventional forestry wood have been reported by Aberdeen University [61] and also by Kaltschmitt [63] for various European countries. The costs vary widely by country, ranging from 10–20 €/odt through to over 160 €/odt. Mean costs are 70 €/odt. The evaluations presented later will not use this average since it is unlikely that a novel technology would be demonstrated in an area where feed costs are high. Thus a feed cost of 40 €/odt is used as

Table 5
Feedstock characteristics used in the modelling[a]

Characteristic	Value used	Source
Moisture content, based on wet mass	50% if fresh 25% after long term storage	[62]
Size distribution	3–45 mm	[62]
Bark content, short rotation forestry	30%	[62]
Bark content, residues	40%	[62]
Bark content, stem wood	20%	[62]
Ultimate analysis, %dry basis	C—51.8% H—5.7% O—40.9% N—0.1% S—0%	[62]
Lower heating value at 0% moisture	19.3 GJ/odt[a]	[62]
Ash content, %dry basis	1.1%	[62]
Bulk density	0.150 odt/m^3	[62]

[a] The unit oven dry tonne (odt) is used throughout this report to denote the mass of feedstock at zero moisture content; if a feedstock property is measured on a wet tonne basis then the unit ‘t’ is used.

a standard in the evaluations, supported by an analysis of the effect of feed cost on the electricity production cost to show the impact of the wide range of feed costs reported in [61,63].

4. The feed pretreatment module

4.1. Pretreatment requirements

The characteristics of wood feedstocks as they are found at harvest or collection are often very different from the feed characteristics demanded by the conversion reactor, and steps are usually required to match the feedstock to the process. The key requirements of the feed pretreatment system are:

- The reception and storage of incoming feed until it is required by the conversion step. The logistics of ensuring a constant feed supply must be considered carefully, especially when some feedstocks are only available on a seasonal basis (such as short rotation coppice). In such cases continuous operation of the conversion facility will require either extensive long term storage of the feedstock or a feed reactor and pretreatment system that is flexible enough to accommodate multiple feedstocks.
- The screening of the feedstock to keep particle sizes within appropriate limits and prevent contamination of the feedstock by metal or rocks.
- The drying of the feedstock to a moisture content suitable for the conversion technology.
- The comminution of the feedstock to an appropriate particle size.
- The buffer storage of prepared feed immediately prior to the reactor.

4.2. Pretreatment module construction

The pretreatment module has itself been broken down into a number of steps to produce the flexibility required to cope with the range of feed constraints and system capacities studied in this report. These steps are modelled in isolation and the overall pretreatment requirements are met by a sequence of steps, shown schematically in Fig. 7. Transfer between steps is always included in the upstream step of the two steps.

Capital costs for each step are calculated from the main equipment items required to suit the feed conditions and step capacity. Equipment costs are available in the literature and manufacturers' brochures since the equipment is already established in other industries. Labour and power requirements are also considered for each step. It is inappropriate to present details of these calculations given the complexities introduced by the number of steps and the equipment options within each step. Further details are available in previous work by Toft [64].

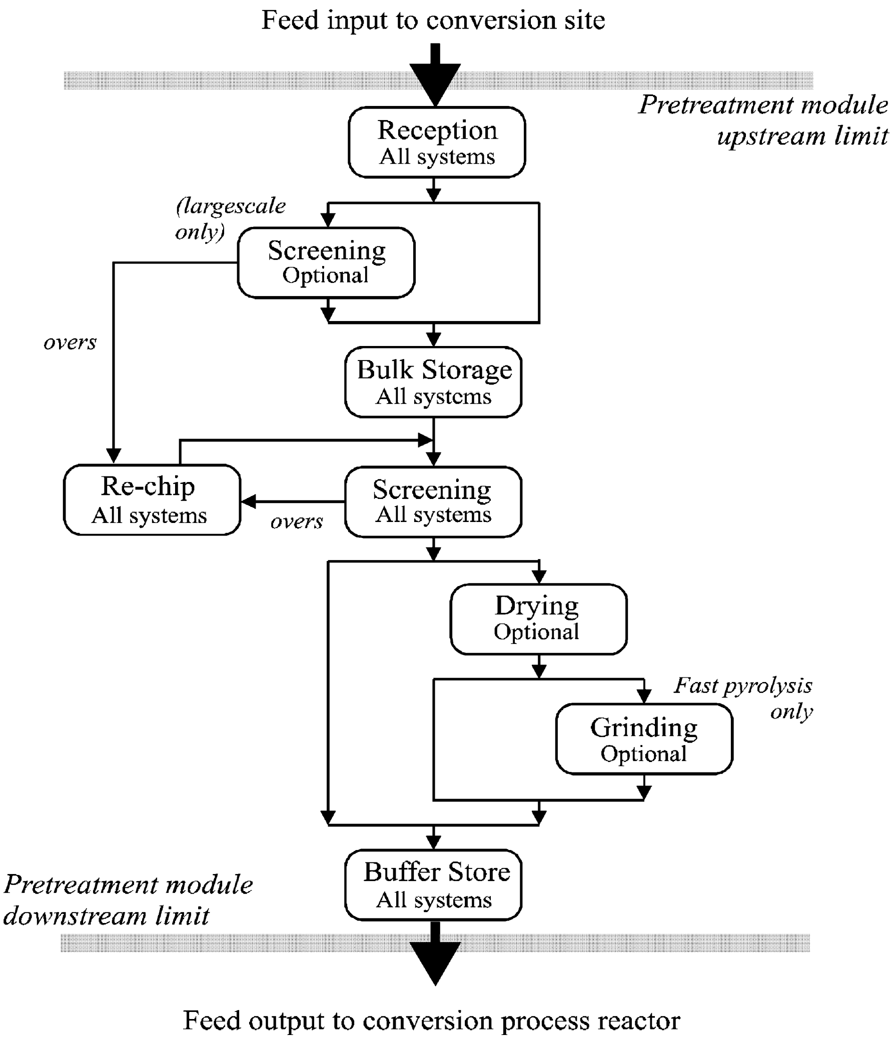

Fig. 7. Steps in the pretreatment module.

5. Modelling the fast pyrolysis and diesel engine

5.1. The fast pyrolysis module

5.1.1. Module limits

This module calculates the cost and performance of converting the prepared wood feedstock to a pyrolysis liquid in a fast pyrolysis reactor. The starting point of the module is the entry of the prepared feedstock into the reactor feeding system. The end point of the module is the storage of the pyrolysis liquid product.

5.1.2. Feed constraints

In the base case it is assumed that the reactor requires a particle size of less than 2 mm. Later the results will examine the impact of a larger feed particle size on pretreatment costs. A feed moisture content of 7% is specified and the feed is dried by the flue gas dryers modelled in the feed pretreatment module. The availability of waste heat for drying has been studied by Beckman et al. [65] and Cottam [9]. Both studies have concluded that there is ample heat available for drying the feedstock to a 7% moisture content in the flue gases produced when burning the off-gas and char to heat the reactor.

5.1.3. Performance

The performance of the fast pyrolysis process is measured here by its ability to convert the chemical energy in the feed into chemical energy in the pyrolysis liquid. The energy in the pyrolysis liquid is established by calculating the pyrolysis liquid yield and its lower heating value.

The current approach to fast pyrolysis process design for fuels is maximisation of liquid product yield, even though this liquid may not be the optimum quality. More specifically, the aim is to maximise the organic fraction of the liquid product since it is this fraction that carries the energy. The default yields used in the module were derived from the results of experimental data from bench scale tests of fluid bed pyrolysis reactors using clean wood samples. When plotted against temperature, yields of the four characteristics products of fast pyrolysis vary as exemplified in Figs. 8 and 9 [66–70].

Assuming the conditions for peak liquid organics yield, the yields shown in Table 6 can be predicted. The initial results gave a closure of 97.4%, which was adjusted

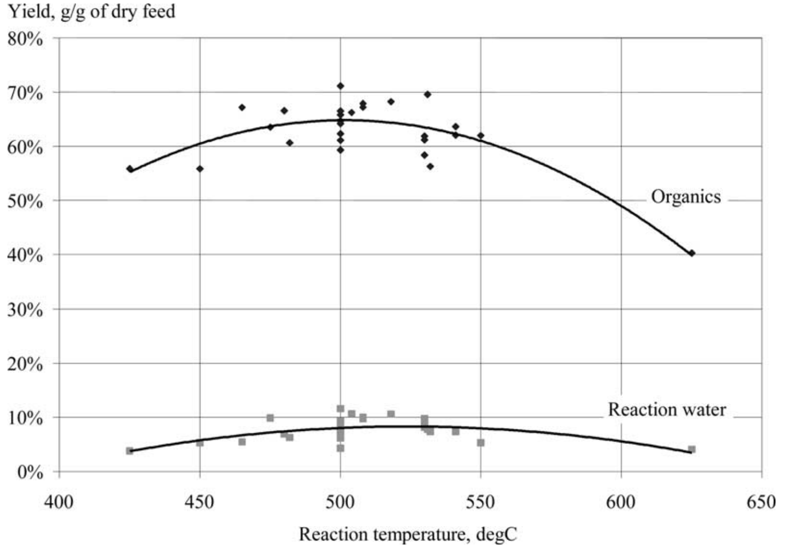

Fig. 8. Organics and water yields, fluid bed fast pyrolysis of wood.

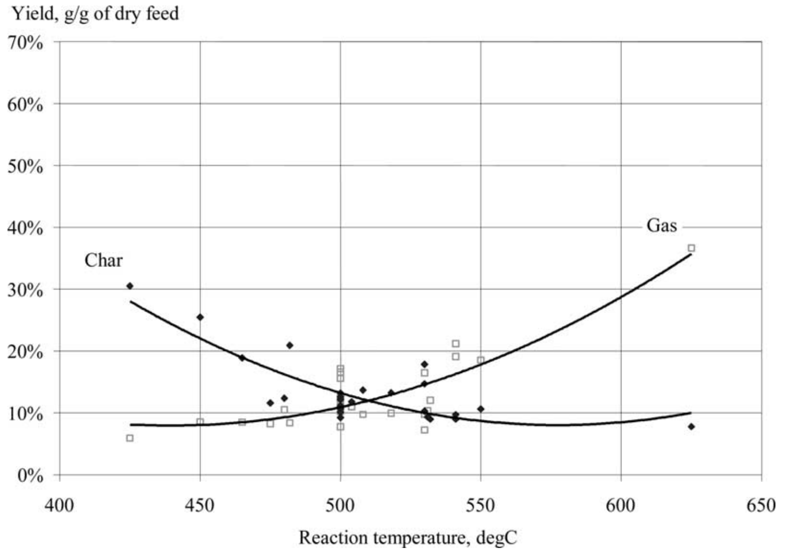

Fig. 9. Char and gas yields, fluid bed fast pyrolysis of wood.

Table 6
Fast pyrolysis yields for maximum organics production

Product	Yield, g/g dry feed Small scale	Small scale, normalised	Commercial scale, predicted
Organics	64.9%	64.9%	59.9%
Reaction Water	8.1%	10.8%	10.8%
Char	13.2%	13.2%	16.2%
Gas	11.1%	11.1%	13.1%
Total	94.4%	100.0%	100.0%

to 100% by increasing the yield of reaction water from 8.1% to a more reasonable 10.8% [9].

Pyrolysis process designers face many problems when moving from the bench to commercial scale in achieving high, controlled heat rates; the correct reaction temperature; a low gas-vapour residence time at a moderate temperature; rapid removal of char as it forms and effective liquids recovery. After careful consideration it was decided that these problems are not insurmountable and there is no reason to assume that the results achieved at bench scale cannot be achieved at larger capacities.

One factor that will affect the yield is the feed material. The ideal yields are based on clean wood but such material would not be available in bulk quantities for energy since it could attract much higher prices as a pulping feedstock. Thus the feed considered here is a whole tree feedstock of much lower value and contaminated by bark. High ash levels in the bark catalyse reactions in the primary pyrolysis vapours to produce more char and gas [67,71], as shown in experimental data using poplar containing 15–20% bark [72]. On this evidence it is assumed that the level of bark contamination in the feedstock reduces the yield from pure wood feedstocks by 4–5 percentage points. This adjustment gives the default yields used in the model that are shown in the last column of Table 6.

The heating value of many pyrolysis liquids have been found in the literature and are plotted in Fig. 10 against the moisture content of the pyrolysis liquid [73–77]. The heating values were generally given on a higher heating value basis, since this is much easier to determine experimentally. A variety of feedstocks are represented in this chart, since the non-wood feedstocks such as bagasse showed no deviation from the results for wood. The lower line on the chart is a regression on the lower heating values that were calculated from the recorded higher heating values. The equation for this line (Eq. (5)) is used to calculate the lower heating value of a feedstock as a function of its moisture content.

$$LHV_x = 21.20 - 25.31(x_l) \tag{5}$$

where

LHV_x = Lower heating value at x_l, GJ/t
x_l = Moisture content of the pyrolysis liquid, %wet basis

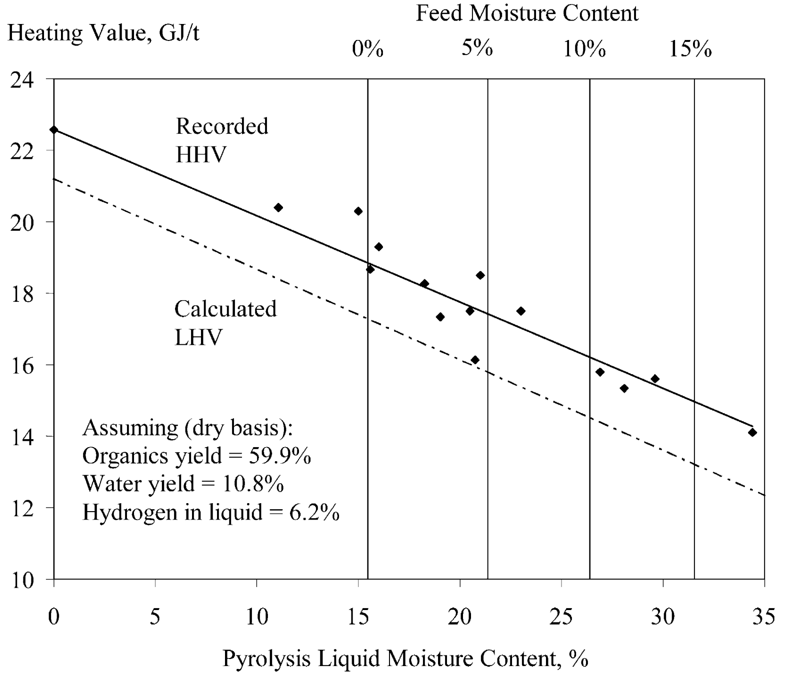

Fig. 10. Pyrolysis liquids heating values, wet basis.

5.1.4. Capital costs

Bridgwater has compiled normalised plant costs for a number of fast pyrolysis and gasification systems [35] to give the same equipment and financial scope. These data were used by the IEA Pyrolysis Activity [78] and have since been updated by Bridgwater with new information [79]. Some of the data were proprietary and cannot be reproduced but a regression on the 14 data points for the fast pyrolysis module is shown in Fig. 11. Eq. (6) is taken from this chart and is used to calculate the cost of the fast pyrolysis reactor, feeding system and liquids recovery. The cost data used are for systems based on novel technology and it is assumed that the costs are 1st plant costs.

$$\mathrm{TPC_{conv,pyr}, ECU_{2000}} = 40.8 \times (Q_{\mathrm{h,pret,dry}} \times 1000)^{0.6194} \quad (6)$$

where

$\mathrm{TPC_{conv,pyr}}$ = the total plant cost of the pyrolysis reactor system, $€_{2000}$
$Q_{\mathrm{h,pret,dry}}$ = the mass flow rate of prepared wood feed into the reactor, odt/h

A buffer of pyrolysis liquid product is stored at the fast pyrolysis facility to allow for unplanned shutdowns of the fast pyrolysis system. This will allow the supply of pyrolysis liquid to the engine generators to continue through short interruptions in pyrolysis liquid production and this could give fast pyrolysis an advantage by increasing the reliability of the overall system. The cost of the pyrolysis liquid storage tanks and transfer pumps have been taken from equipment costs in Garrett [80] and Eq. (7) has been derived after for the total plant cost of pyrolysis liquids storage.

$$\mathrm{TPC_{Storage}} = 119 \times (Q_{\mathrm{h,conv}})^{0.4045} \quad (7)$$

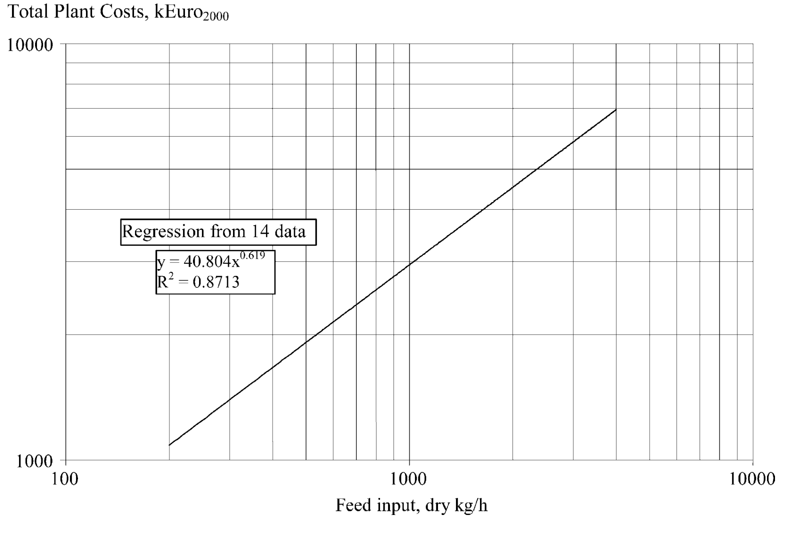

Fig. 11. Fast pyrolysis total plant costs.

where

$\mathrm{TPC}_{\mathrm{storage}}$ = The total plant cost of liquids storage, €$_{2000}$
$Q_{\mathrm{h,conv}}$ = The output flow rate of the pyrolysis liquid conversion product, t/h

5.1.5. Operating costs

Labour requirements are calculated from Eq. (8) which is based on the estimates given by Beckman and Graham [81] for the operation of an Ensyn transported bed fast pyrolysis plant:

$$\mathrm{Labour}_{\mathrm{conv,pyr}} = 1.04\times(Q_{\mathrm{h,pret,dry}})^{0.475} \tag{8}$$

where

$Q_{\mathrm{h,pret,dry}}$ = The input flow rate of prepared feed, odt/h

Power requirements have been estimated in work by Cottam [9], Beckman [81] Black [82] and Diebold [83]. From these estimates it is assumed that the fast pyrolysis module will consume 40 kWh/odt. The same authors suggest various rates for cooling water consumption and an average of 18.5 m^3/odt of feedstock is used here.

Heat for the process is supplied by combustion of the char and off-gas in an external combustor [9]. While this simplifies the economic analysis, the system could be more cost-effective if the char is sold as a by-product and another energy source is used in the process and future work could consider the various options available.

5.2. The pyrolysis liquid transport module

5.2.1. Module limits

This module calculates the cost of transporting the pyrolysis liquid in de-coupled systems where the pyrolysis process and electricity generation are at separate sites. The starting point of the module is the loading of liquid fuel tankers at the pyrolysis site(s) and the downstream limit is the unloading of pyrolysis liquid ready for storage at the generating site(s).

5.2.2. Assumptions used

A full analysis of transport distances can only be performed on a case by case basis, taking account of actual feed production areas, local topography, the road network and other case-specific features. This work requires a more generic approach and the following assumptions have been made:

1. Feed production is evenly distributed over a circular feed supply area.
2. Where there is more than one feed conversion facility, each conversion facility is identical. The total feed supply area is split into identical sectors and each sector supplies feed to a single site.
3. Each feed conversion facility is located at that point in its feed supply area that

minimises the total direct distance from all of the feed sources to the conversion facility.

4. The road network is regular and symmetrical such that a single ‘winding factor’ can be used to convert the direct distance between source and conversion facility into an actual road distance.
5. Either conversion or generation must take place at a single site located at the centre of the feed supply area.

The size of the feed supply area is derived from Eq. (9). The actual land used only in feed production is adjusted to give the total area required for all uses by application of a land area limitation which is the percentage of the total area that is used in feed production. This work assumes a default yield of 10 odt/ha/yr and a default land area limitation of 5% in accordance with previous work [84]. Given the feed area, the radius of the feed area can be found by simple geometry.

$$A = \frac{Q_{\mathrm{del}}}{Y} \times \frac{1}{\mathrm{LAL}} \tag{9}$$

where

Q_{del} = the amount of feedstock required by all conversion facilities, odt/yr
Y = the wood production yield, odt/ha/yr
LAL = the land area limitation, %

Where multiple conversion units are used, an analogy with 1st moments of area has been used to show that the location of each conversion facility will be the centroid of the sector that supplies it with feed [85].

For multiple sites the distance from the centre of the total feed supply area to the centroid of a sector can be calculated using standard sector geometry. The average distance from any element in the sector to its centroid is given by double integration. These distances were calculated for systems with 1–10 conversion units and the results have been combined by regression analysis to give Eq. (10).

$$\text{Mean direct transport distance, km} = \text{R, km} \times 0.6747 \times (\text{No. sites})^{-0.4647} \tag{10}$$

The actual distance travelled between the feed source at the conversion facility is higher than the direct distance because the transport vehicles must follow the existing road network. To allow for this a winding factor has been applied where the actual distance travelled is the product of the direct distance and a winding factor. A winding factor of $\sqrt{2}$ was used on the basis that the actual route taken between a feed source and the feed conversion facility in a grid of roads would run along two sides of a right-angled isosceles triangle.

5.2.3. Pyrolysis liquid transport costs

No data were available in the literature for pyrolysis liquid transportation. Instead, tanker haulage transport charges for fuel oil distribution in the UK are used. Two costs were obtained, as shown in Table 7. The variation in fixed charge is notable: the Shell data were composite data for the whole oil industry and includes the fixed cost burden of the distribution centres; Linkman on the other hand reported that the fixed cost would be negligible since it is simply the cost of pumping the liquid. The latter case has been assumed here. No account has been made for the special properties of the pyrolysis liquid because data were unavailable. The default transport cost for liquids is calculated using the fixed and variable charges shown in Eq. (11).

$$\text{Liquid transport cost, ECU/t} = 0.40\text{ECU/t/km}\times L_r,\text{km} \tag{11}$$

5.3. *The liquid-fired dual fuel engine module*

5.3.1. *Module limits*

The upstream limit of this module in close-coupled systems is the pyrolysis liquid day tank in the dual-fuel engine fuel injection system. In a de-coupled system where feed conversion and electricity generation are at different sites then the upstream limit of the module is the bulk storage of pyrolysis liquid in storage tanks at the generating site. The downstream limit is the generator terminals. The module includes the engine fuel injection system, auxiliary fuel storage, diesel engine and generator. Multiple engines are used as required. The power output from this module is the gross power output. The net power output is calculated by the grid connection module, which is described in Section 5.4.

5.3.2. *Performance*

The pyrolysis liquid fuel is supplemented by an auxiliary diesel fuel that ignites the main charge, required because the pyrolysis liquid ignition characteristics are poor. The level of diesel pilot fuel required has not been established. This module will assume that 7.5% of the total energy supplied to the engine is provided by the diesel pilot fuel, based on initial test results [88].

The use of pyrolysis liquids at elevated temperatures could result in char deposits in the fuel injection system and for this reason the injection system is flushed by a solvent at the beginning and end of engine runs. A suitable solvent is methanol [88]. The use of this solvent will add to the complexity of the fuel storage and injection system.

It is assumed that the engines are used in multiples since their capital costs are virtually independent of scale and because engines with capacities larger than 40 MW_e are rare [89]. In the systems evaluations the maximum capacity of a single

Table 7
Fuel oil transport costs

Payload, t	Fixed cost, €/t	Variable cost, €/t/km	Source
30.5	4.29	0.039	Shell UK [86]
24.0	None	0.043	Linkman Tankers [87]

engine is 5 MW_e for total capacities up to 10 MW_e; 7.5 MW_e for capacities up to 20 MW_e; and 10 MW_e for larger total capacities. In a real system there would probably be spare engines as well but engine redundancy has not been included in this study since it would unfairly penalise the engine based systems during the comparisons with the Combust and IGCC options.

Efficiency data for diesel engines have been collected from the literature and is presented in Fig. 12 [90–92]. Diesel engine efficiency is not significantly affected by operation in dual fuel mode when using natural gas [93] and it is assumed in the absence of operational data that the dual fuel operation with a pyrolysis liquid will also have minimal impact on efficiency.

The data in Fig. 12 yielded the efficiency relationship presented as Eq. (12).

$$\eta_{\mathrm{gen,peng}} = -0.002329(E_{\mathrm{th,conv}} + E_{\mathrm{th,aux}})^2 + 0.313(E_{\mathrm{th,conv}} + E_{\mathrm{th,aux}}) + 38.6 \tag{12}$$

where

$\eta_{\mathrm{gen,peng}}$ = Gross electrical efficiency, % LHV basis
$E_{\mathrm{th,conv}}$ = Energy supplied by the pyrolysis liquid, MW_{th} LHV basis
$E_{\mathrm{th,aux}}$ = Energy supplied by the diesel pilot fuel, MW_{th} LHV basis

5.3.3. Capital costs

Dual fuel diesel engine and generator investment costs were taken from the literature and discussions with manufacturers. Costs vary widely according to the speed and build quality of the engine: low speed, heavy duty engines tend to have higher initial costs offset by lower maintenance costs. Low speed, heavy duty engines were selected where possible because they are more adaptable to unconventional fuels.

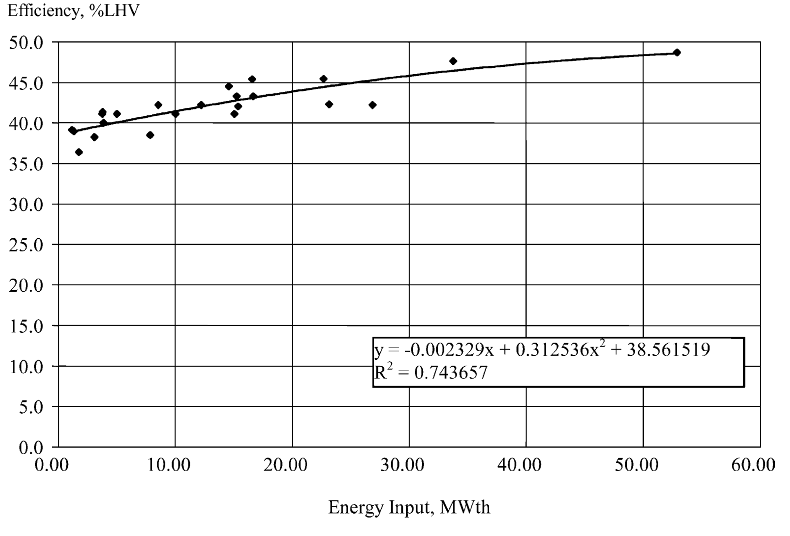

Fig. 12. Diesel engine generating efficiencies.

The capital costs that were identified have been adjusted to give the total plant costs in €$_{2000}$ and the results are shown in Fig. 13 [88,93–96].

A nominal additional cost of 10% has been included to allow for:

1. the storage of the pyrolysis liquid in a day tank; and
2. the extra complexity imposed by the methanol flush and the probable requirement for special materials and fuel pre-heating to resist corrosive attack from the pyrolysis liquid and lower viscosity [71].

This adjustment gives Eq. (13).

$$TPC_{gen,peng}, kECU_{2000} = [821(P_{e,gross})^{0.954}] \times 1.10 \tag{13}$$

where

$P_{e,gross}$ Gross generator output, MW_e

If multiple engines are used it is assumed that plant replication and shared plant items will offer some capital cost savings. Therefore the total plant cost for all engines is given by Eq. (14) where n is the number of engines used.

$$TPC_{gen,peng}, kECU_{2000} = TPC_{engine} \times n^{0.9} \tag{14}$$

De-coupled systems include the bulk storage of pyrolysis liquid at the generating site. The additional capital cost is calculated using Eq. (7), the same relationship that applies when storing pyrolysis liquid at the pyrolysis site.

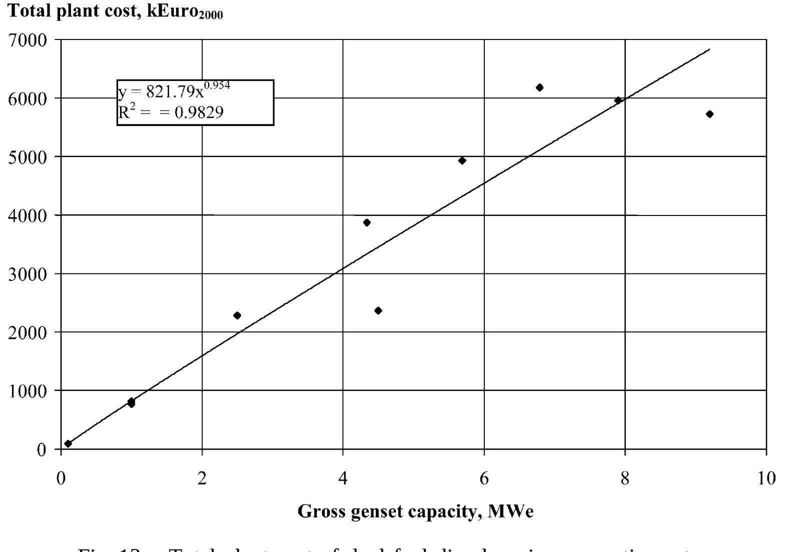

Fig. 13. Total plant cost of dual fuel diesel engine generating sets.

5.3.4. Operating costs

Diesel oil is charged at a rate of 12.7 €/GJ [97]. Methanol costs have not been included because the amount used is negligible.

Some of the gross power output from the engine(s) is used in the plant for auxiliaries such as fan motors, the lubrication oil pumps, fuel injection pumps and the control equipment. A factor of 3.0% of the gross power output is used to calculate this internal power consumption [88].

Labour requirements for diesel engine gensets were given by Solantausta [78]. Eq. (15) has been derived from that data.

$$\text{Labour}_{\text{peng}},\text{operators/shift} = 0.4847(P_{\text{e,gross}} - P_{\text{e,gen}})^{0.483} \tag{15}$$

where

$P_{\text{e,gross}}$ = Total gross electricity output of all engines, MW_e
$P_{\text{e,gen}}$ = Internal power required by the engines, MW_e

A total maintenance cost of 0.01 €/kWh is assumed, based on operating data in the literature [91]. This cost is independent of capacity and includes lubricating oil.

5.4. The grid connection module

5.4.1. Module limits

This module calculates a net system capacity in MW_e and a net system output in MWh/yr. The two figures are not directly related because some of the pretreatment equipment does not operate continuously.

5.4.2. Performance

The net capacity is calculated by subtracted the sum of the power requirements in MW_e of the pretreatment, conversion and generation stages from the gross power output. In de-coupled fast pyrolysis systems the pretreatment and conversion stages may be separated from the generator, and so only the generator internal power requirement is subtracted from the gross power output. The power requirement for the pretreatment and fast pyrolysis systems is supplied by the grid.

The net electricity output to the grid is calculated in a similar way to the net power output, except that this time the electricity actually consumed is subtracted from the gross output.

5.4.3. Capital costs

The connection of the system to the grid must be safe and meet the requirements of the utility in terms of protection for both the grid and the electricity supplier [98]. Grid connection equipment includes electrical control, protection equipment, transformers and switchgear. The costs of grid connection are very case-specific since they are a function of location, the size of plant and the grid voltage at the connection [99]. There is therefore some uncertainty associated with these capital costs. Equipment costs [88,99,124] have been converted to total plant costs and analysed to give

Eq. (16). Although there is uncertainty about grid connection costs, their proportion of the total system capital costs is small and they should not have a significant impact on the overall system.

$$\mathrm{TPC}_{\mathrm{Grid}},\mathrm{kECU}_{2000} = 282\times(P_{\mathrm{e,net}})^{0.537} \tag{16}$$

where

$\mathrm{TPC}_{\mathrm{Grid}}$ = Total plant cost of the grid connection equipment, $\mathrm{k€}_{2000}$
$P_{\mathrm{e,net}}$ = Power supplied to the grid, $\mathrm{MW_e}$

5.4.4. Operating costs

There are no operating costs associated with this module apart from maintenance and overheads which are calculated as percentages of the total plant cost.

6. Modelling the combustion and steam cycle modules

6.1. The combustion module

6.1.1. Module limits

The upstream limit of this module is the entry of a prepared feedstock into the combustor feeding mechanism. The downstream limit is the supply of superheated, high pressure steam ready for expansion in the steam turbine. The module includes the combustor feeding mechanism, combustor, boiler, superheater and flue gas stack.

6.1.2. Feed constraints

Fluid bed combustors will accept a wide range of particle sizes up to 50 mm [28] and no size control other than screening to remove over-size material should be necessary on the basis of the feed size distribution suggested in [61].

Low moisture content feedstocks are preferred because they increase combustion efficiency; they reduce flue gas volumes and hence the capital cost of flue gas equipment; they reduce carbon carry-over and particulate emissions; they raise the dew point in the stack and allow more control over the combustion process. However, drying the feedstock will mean additional capital costs for the dryer and changes to the system to make heat available for drying. In this work it is assumed that the feedstock is dried to a moisture content of 35%, which is considered a reasonable compromise between enhanced system performance and the increased capital costs [100].

6.1.3. Performance

Energy efficiency is calculated here by considering the mass and energy flows into and out of the combustor. The energy flows have been simplified by including the air preheater within the limits of the sub-system and assuming that all the energy required to preheat the air comes from the flue gases. The energy added to the feed water to produce superheated steam is found by difference, after accounting for all other energy fluxes, a standard approach to calculating combustion efficiency [101].

In the mass balance the excess air during combustion is assumed to be 46.6% on the basis of performance data for five fluid bed plants in California [102]. The burn out rate is 99%, typical for fluid bed and circulating fluid bed combustors [21,24,27,103]. Reactor heat losses are 5% of the energy input in a small combustor with a feed input of 1 odt/h, and the calculations assume that these losses reduce exponentially to 1% in a 50 odt/h reactor [101]. Useful energy is recovered from the flue gases down to 175ºC and after this the remaining sensible heat is very low quality and is used only for feed drying.

The energy efficiencies for a range of feed moisture contents (after drying) and capacities have been calculated using the above assumptions to give the curves shown in Fig. 14. The curves can be represented by a combination of Eqs. (17) and (18).

$$\eta_{\mathrm{conv,comb}} = (-1.335x_f^4 + 1.24x_f^3 - 0.4567x_f^2 + 0.0096x_f + 0.9)\times f(Q_{\mathrm{h,pret,dry}}) \quad (17)$$

$$f(Q_{\mathrm{h,pret,dry}}) = 0.00019(Q_{\mathrm{h,pret,dry}})^2 + 0.00194(Q_{\mathrm{h,pret,dry}}) + 0.934 \quad (18)$$

where

x_f = Moisture content of the prepared feedstock, %
$Q_{\mathrm{h,pret,dry}}$ = Dry feed input to the combustor, odt/h

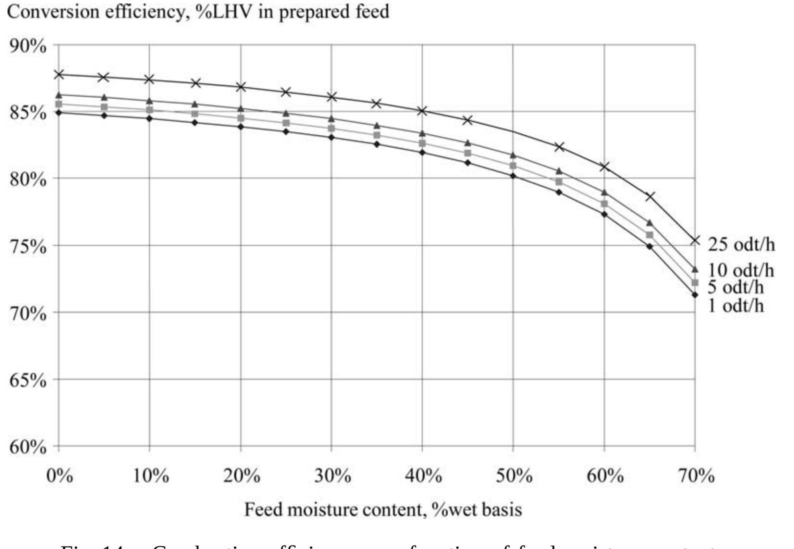

Fig. 14. Combustion efficiency as a function of feed moisture content.

6.1.4. Capital costs

Reported capital costs of bubbling and circulating fluid bed combustors and boilers have been normalised to a total plant cost basis and the results are shown in Fig. 15 [5,21,27,104]. The best regression curve is shown on the graph and total plant costs for the combustion module are calculated using Eq. (19).

$$\mathrm{TPC}_{\mathrm{conv,comb}},\mathrm{kECU}_{2000} = 481(E_{\mathrm{th,pret}})^{0.80} \tag{19}$$

where

$E_{\mathrm{th,pret}}$ the energy in the prepared feedstock, $\mathrm{MW_{th}}$ LHV

6.1.5. Operating costs

Labour requirements are derived from reported data in the literature [19,21,104,106]. Given the basic data for a whole system, the labour requirements for the pretreatment and steam cycle sections have been extracted since these are added in other modules. It was assumed that 66% of the labour in a small scale facility (1 $\mathrm{MW_e}$) is required for pretreatment of the wood chips, reducing logarithmically to 33% at 100 $\mathrm{MW_e}$. This allows for the high manual handling during reception, storage and handling in small scale systems and the more automated processing in larger facilities. The remaining labour has been split equally between the conversion and generating step. The results of this analysis are shown in Fig. 16, assuming a constant generating efficiency of 25% when converting from the original plant data to an energy input basis. The data are represented in the module by two curves, where Eq. (20) is used at scales below 140 $\mathrm{MW_{th}}$ input and Eq. (21) is used at higher capacities.

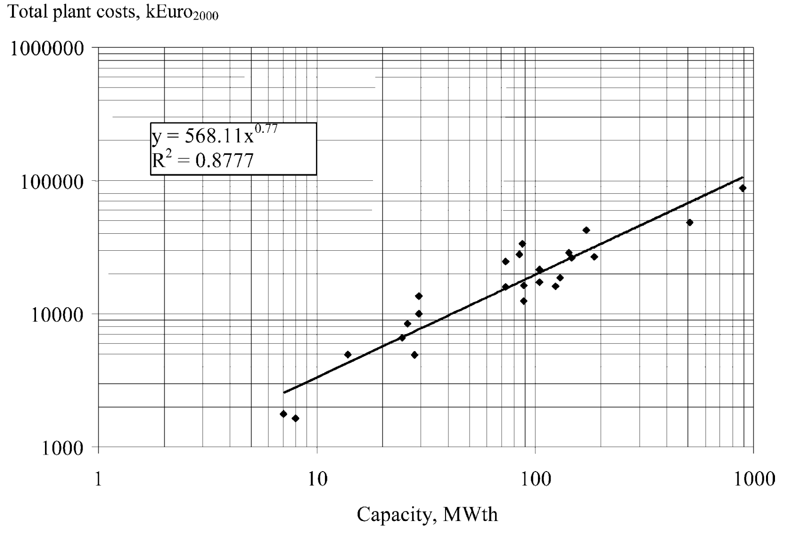

Fig. 15. Fluid bed combustion capital cost.

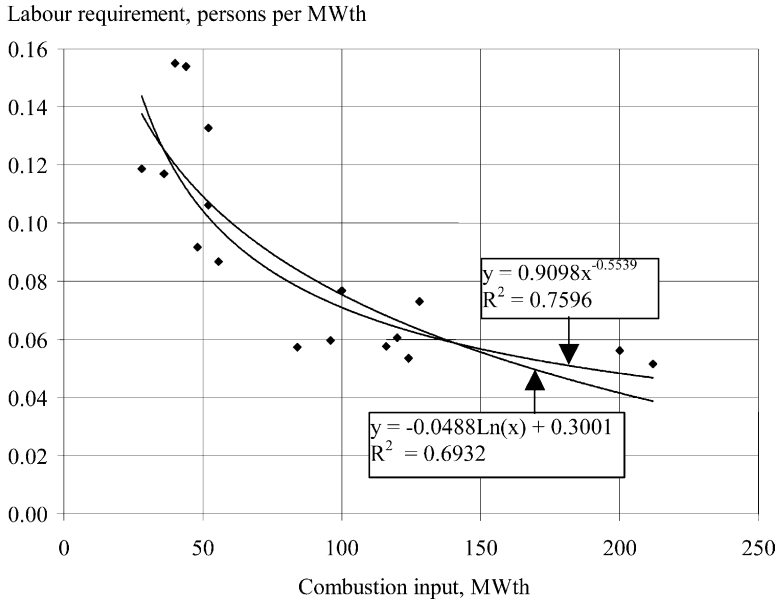

Fig. 16. Specific labour requirements, combustion module.

$$\text{Labour}_{\text{combustion}} = (-0.0488\ln(E_{\text{th,pret}}) + 0.3001)\times E_{\text{th,pret}} \tag{20}$$

$$\text{Labour}_{\text{combustion}} = (0.9098(E_{\text{th,pret}})^{-0.5539})\times E_{\text{th,pret}} \tag{21}$$

where

$E_{\text{pret,MWth}}$ Energy available in the prepared feedstock, MW_{th}

The only utility that is considered here is the internal power consumption. Boiler feed water and cooling feed water requirements of the steam cycle are calculated in the steam cycle module. Reports of the auxiliary power consumption for fluid bed combustion plant rarely consider the combustor alone and it has been difficult to estimate the power consumption for the module. A survey of five Californian fluid bed and circulating fluidised bed combustion plant [102] showed power consumption for the whole combustion and generating system of between 10.6 and 17.7% of the gross power output for net capacities of between 18.6 and 31.9 MW_e. The average internal power consumption was 13.6% of the gross power output, which was approximately 4% of the energy input. Evald [105] showed that the power consumption (excluding the heating system) in 30 Danish wood combustion plant was 1.6–2.4% of the thermal input in MW_{th} (the average value was 1.9%). On the basis of this limited data, a value of 2% of the thermal input is used as a default in the module.

6.2. The steam cycle module

6.2.1. Module limits

The upstream limit of this module is the entry of high pressure superheated steam into a steam turbine. The downstream limit is the generator terminals. The module includes the steam turbine, generator, condenser, water treatment system and boiler feed water pumps. The cost of the boiler and superheater are not included (they form part of the combustion module). The power output is the gross power output; net power output is calculated by the grid connection module, which is described in Section 5.4.

6.2.2. Performance

The steam cycle module assumes that a basic Rankine steam cycle with superheat is used since cycle enhancements are not usually cost effective at small scale [27]. Full expansion of steam is assumed since power generation only is required and condensing steam turbines offer the maximum power output and generating efficiency.

The cycle efficiency has been derived by calculating the ideal cycle efficiency for a given set of steam conditions and adjusting the steam properties at exit to the steam turbine to allow for isentropic losses. Steam conditions at turbine inlet are taken from examples in the literature over a wide range of capacities [21,24,106–108]. The steam conditions at exit from the steam turbine are fixed at a relatively modest 0.1 bar, again a reflection of the low system capacity [109]. The losses in the steam turbine have been assigned based on data published by Guinn and are a function of the steam pressure and the generating capacity [23].

The steam cycle analyses produced the data in Fig. 17, presented as a graph of cycle efficiency against thermal input in the superheated steam. A best fit regression curve to the data is used to give the relationship between steam cycle efficiency and the energy supplied to the steam at the boiler resulting in Eq. (22).

$$\eta_{\mathrm{gen,stream}} = 0.0516\ln(E_{\mathrm{th,conv}}) + 0.0794 \qquad (22)$$

where

$\eta_{\mathrm{gen,steam}}$ gross generating efficiency before internal consumption, %
$E_{\mathrm{th,conv}}$ the energy supplied by the boiler, MW_{th}

6.2.3. Capital costs

Steam cycle capital costs have been extracted from total combustion plant cost data [21,104,106] where the data have split the total costs into pretreatment costs, boiler costs, steam plant and emissions control equipment. These data were converted to total plant costs using the ratios method and used to produce Fig. 18. A regression on the data gives Eq. (23). These capital costs are for established equipment and the learning effect that may be applied to them is minimal. They are assumed to be 100th plant costs.

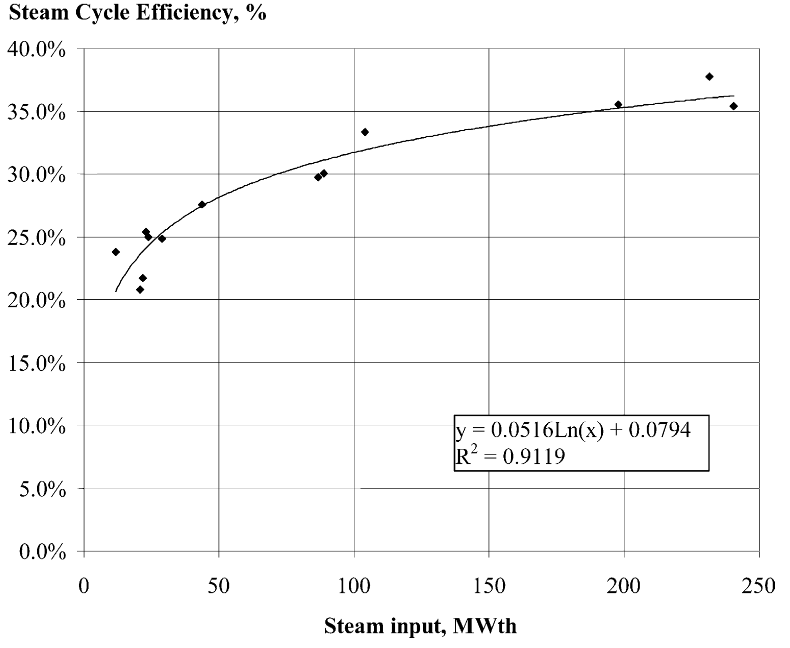

Fig. 17. Steam cycle efficiency as a function of boiler energy input.

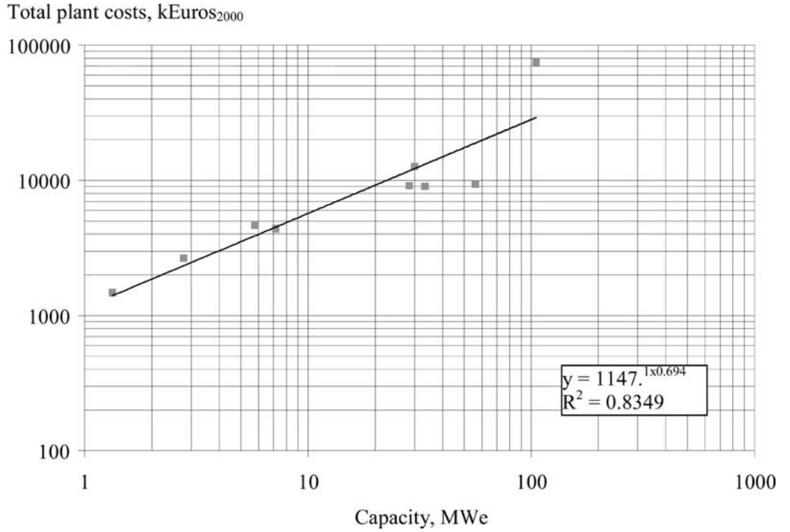

Fig. 18. Steam cycle capital cost as a function of gross power output.

$$\mathrm{TPC_{gen,steam},kECU_{1996}} = 1147(E_{\mathrm{e,gross}})^{0.695} \quad (23)$$

where

$E_{\mathrm{e,gross}}$ Gross generator output, MW_e

6.2.4. Operating costs

The internal power consumption of the cycles found in the literature varied between 5 and 18% of the gross power output [21,102,104,106]. Higher internal power consumption rates are due to the extra fan requirements for fluid bed combustors. Given that the pretreatment system internal power consumption and the combustor internal power consumption are accounted for separately, the internal power consumption of the steam cycle is set at 4% of the gross power output.

Labour requirements in the literature for combustion and steam cycle plant were analysed in Section 6.1.5. Using the data given in that earlier discussion, the specific labour is calculated using Eq. (24) for capacities up to 35 MW_e and Eq. (25) above that capacity.

$$\mathrm{Labour_{steam}} = [-0.1951\ln(P_{\mathrm{e,gross}}) + 0.9298]\times P_{\mathrm{e,gross}} \quad (24)$$

$$\mathrm{Labour_{steam}} = [1.6887(P_{\mathrm{e,gross}})^{-0.5539}]\times P_{\mathrm{e,gross}} \quad (25)$$

where

$P_{\mathrm{e,gross}}$ Power output from the steam turbine, MW_e.

Cooling water is required at a rate of 5 t/MWh and is charged at a rate of 1.5 € /t [110]. This has been estimated from an estimate of 5000 t/h cooling water consumption for a 1000 MWe coal combustion plant [111]. This is a considerable extrapolation but the impact of cooling water consumption is very low and any error is insignificant. Make-up water is required at a rate of 1.5 t/MWh produced (based on an average of data given by Golobic [104] and Tewksbury [106]), at a cost of 0.84 € /t [112].

Maintenance costs of steam cycles are reported to be 4% of installed capital costs or equivalent to 0.002–0.004 €/kWh [23]. A default value of 0.004 €/kWh is used in the module.

7. Atmospheric gasification and diesel engine

7.1. The atmospheric gasification module

7.1.1. Module limits

The upstream limit of this module is the entry of a prepared feedstock into the gasifier feeding mechanism. The downstream limit is the supply of a clean low heating value fuel gas at ambient temperature to the dual fuel engine fuel injection system. The module includes the gasifier feeding mechanism, the gasifier, a catalytic tars cracker, wet gas scrubbing and the clean-up of the scrubbing effluent.

7.1.2. Feed constraints

Fluid beds are fairly tolerant of variations in feed size up to 25–30 mm and can be expected to operate with a chipped feedstock [38,113–115]. Only the minimum of processing to remove over-size pieces and contaminants such as rocks is required. Some drying of the feedstock is required to raise the conversion efficiency and maintain the heating value of the product gas. This module assumes a feed moisture content of 15% which corresponds to a 10–20% range found in the literature [114–117].

7.1.3. Performance

Gasification is a complex process that is influenced by many interdependent variables including the amount of oxidant present; the feedstock composition, morphology and moisture content; reactor temperature and reactor geometry. Many models have been developed to aid developers (e.g. Chern [118], Belleville [119], Shand [120], Maniatis [121]) but these rely on a detailed specification of the operating conditions. Such details are beyond the scope of this work. In this work the energy efficiency of the gasifier has been simplified to a basic mass and energy balance across the gasifier and cracker, consistent with the approach used in the combustion module.

The mass balance requires the definition of an air factor, which is the ratio of the actual oxidant flow rate to the stoichiometric oxidant flow rate. This was assumed to be 0.3, based on the data produced by Maniatis in his study of the effects of the air factor on gasifier performance [122,123]. It is assumed that the ash produced contains 33%wt of char, which is equivalent to a carbon conversion efficiency of 99.5% [39]. The dolomite fluid bed catalytic tar cracker ensures that the virtually all tars are cracked and the mass balance assumes that only 0.1%wt of the feedstock emerges as tar [35,113]. The reactor losses are assumed to vary logarithmically between 7% at 1 odt/h and 2% at 50 odt/h [35,39]. The energy in the dry fuel gas is found by difference after all the other energy outputs are determined. This energy is the total chemical energy and sensible energy in the gas at exit from the catalytic cracker at 900°C.

Given the energy output from the gasifier and tar cracker, the next stage is to calculate the sensible and latent heat losses that are incurred during gas cooling and cleaning. A gas cooler will cool the gas to around 150°C. This is high grade heat that could be used elsewhere in the system. Some of this heat is used to preheat gasifier air, the rest could be used in feed drying. The wet scrubber will cool the gas further as well as condensing out most of the water in the gas. It is assumed that the gas leaves the wet gas scrubber saturated with water vapour and is reheated slightly to 40°C to produce a gas with a maximum humidity of 80% at entry to the engine [124].

The results of the mass and energy balance procedure were used to derive a relationship for efficiency as a function of system capacity, shown as Eq. (26). The efficiencies that are predicted compare well with data in the literature. The gasifier survey by Bridgwater [35] quotes efficiencies of 67.8% (excluding 10% energy in tars) for the TPS system at Greve in Chianti and 79% for the Foster Wheeler atmospheric CFB gasifier. Chern [118] has calculated a cold gas efficiency for a fluid bed of 72% from his modelling work. Maniatis [123] estimates that a cold gas efficiency of 60–70% would be attainable in a commercial gasifier, but this assumes that the chemical energy in tars is lost.

$$\eta_{\mathrm{conv,agas}} = [-0.00006(Q_{\mathrm{h,pret,dry}})^2 + 0.0347(Q_{\mathrm{h,pret,dry}}) + 71.10]/1000 \qquad (26)$$

where

$\eta_{\mathrm{conv,agas}}$ the conversion efficiency of the atmospheric gasification module, %
$Q_{\mathrm{h,dry}}$ the dry flow rate of feed into the reactor, odt/h

7.1.4. Capital costs

Capital costs are taken from the same source used for the fast pyrolysis module (see Section 5.1.4). This data produces the lower of the lines shown in Fig. 19, which is assumed to show 1st plant costs. The curve only gives the costs for the gasifier feeding mechanism, the gasifier and the gas cleaning system. It does not include the cost of the tar cracker and so the costs must be adjusted. The original costs were normalised on the basis that the relative costs of the gasifier and the gas treatment train were 100 and 40 respectively. It can be assumed that the catalytic cracker costs the same as the gasifier on the basis that both are fluid beds. However the gasifier cost includes the biomass feeder, the air blower and many other items that would be only be required once in a two reactor system. Thus it is assumed that the tar cracker adds another 50% to the gasifier cost, or (50/140)% of the total costs. This

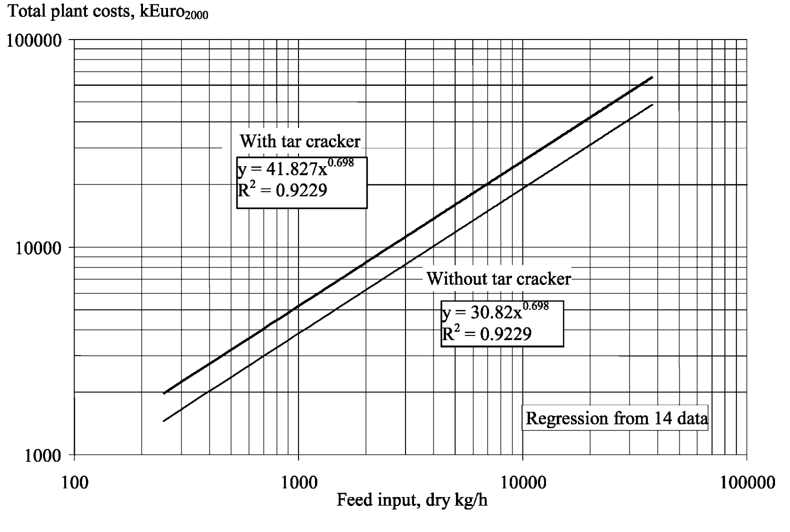

Fig. 19. Atmospheric gasification total plant costs.

means that the cost of a system incorporating a tar cracker is (190/140)% of the original cost and thus the total plant costs are based on the upper line shown in Fig. 19 which yields Eq. (27).

$$TPC_{conv,agas} = [30.82\times(Q_{h,pret,dry}\times1000)^{0.6983}]\times\frac{190}{140} \tag{27}$$

where

$TPC_{conv,agas}$ total plant cost of the atmospheric gasification module, k€$_{2000}$
$Q_{h,pret,dry}$ the mass flow rate of prepared wood feed into the reactor, odt/h

7.1.5. Operating costs

The labour requirement for the atmospheric gasification system is calculated using the same relationship used for the fast pyrolysis module (Eq. (8)). The equipment required in both systems is very similar. The atmospheric gasification system is complicated by the addition of the tar cracker, but is simplified by the fact that its heat requirement is generated internally, so precluding the external char combustor used in the fast pyrolysis system.

The internal power requirement is also comparable with the fast pyrolysis case. The gasification system must supply more fluidising gas than fast pyrolysis, and has the pressure drop in two reactors to overcome. Conversely, the fast pyrolysis module must meet the extra power requirement of the external combustor, and the two requirements will tend to cancel out. It is assumed that the atmospheric gasifier requires 40 kWh/odt, the same amount of power as the fast pyrolysis module.

The cooling water requirement is unlikely to be significant since the make-up water can be taken from the condensate in the scrubber. The treatment method and costs of disposal of the wet scrubber effluent is highly uncertain. One possibility is that most of the scrubber water is recirculated with a bleed to maintain a maximum concentration of tars in the water. The bleed water would be disposed of by incineration, at a significant energy cost [125]. Given that the tars yield could be lower and the tars concentration in the scrubbing water could be higher, the uncertainty surrounding this option is very high and the costs of effluent treatment has been excluded from the calculations.

A final utility requirement is catalyst for the cracker. Dolomite consumption is calculated at 0.68 t/odt feed input and a cost of 30 €/t [126].

7.2. The gas-fired dual fuel diesel engine module

7.2.1. Module limits

The upstream limit of this module is the entry of cool, clean fuel gas into the engine fuel injection system. The downstream limit is the generator terminals. The module includes the engine fuel injection system, auxiliary fuel storage, diesel engine and generator. The power output is the gross power output. The net power output is calculated by the grid connection module, which is described in Section 5.4.

This module uses many of the relationships defined in Section 5.3, including those for:

- the maximum size of engines;
- diesel fuel charges;
- utilities requirements;
- labour requirements; and
- maintenance and overheads charges.

7.2.2. Performance

In the gas dual fuel engine generator two fuels are required: the fuel gas and a diesel pilot to ignite the main gaseous fuel. There is more experience of dual fuel operation with low heating value gases than with pyrolysis liquid and the amount of diesel fuel required is can be fixed at 5% of the total energy input [51,93,127].

The generating efficiency of this module uses the same basic relationship developed for the pyrolysis liquid fuelled engine, but only 90% of the efficiency given by Eq. (13) is attained because the engine is operating with a low heating value gas [127].

7.2.3. Capital costs

The capital costs are based on the relationship developed for the liquid-fired dual fuel engine module in Section 5.3.3 with the following changes:

1. The factor of 10% is not required because the engine injection system does not include methanol or pyrolysis liquid storage.
2. Engine power output is de-rated when operating on low heating value gases. De-rating of engine outputs of between 6% and 50% have been reported, with most engines de-rated by around 20% [50,54,127,128]. Given a de-rating of 20%, an engine must be 25% bigger (i.e.100/80%) to give the required power output when fired by a low heating value gas.

These two changes give Eq. (28) that is used to calculate the total plant cost of a single engine genset using low heating value gas.

$$\mathrm{TPC}_{\mathrm{gen,geng}},\$\mathrm{k}_{2000} = 1008(P_{\mathrm{e,gross}}\times 1.25)^{0.96} \tag{28}$$

where

$P_{\mathrm{e,gross}}$ Gross generator output for a single engine, $\mathrm{MW_e}$

7.2.4. Operating costs

Operating costs are calculated using the same data and relationships given in Section 5.3.4.

8. Pressurised gasification and gas turbine combined cycle

8.1. The pressurised gasification module

8.1.1. Module limits

The upstream limit of this module is the entry of a prepared feedstock into the gasifier feeding mechanism. The downstream limit is the supply of a clean low heating value fuel gas at 450°C and elevated pressure to the gas turbine fuel injection system. The module includes the gasifier feeding mechanism, the gasifier, moderate gas cooling and hot gas filtration. The fuel gas from the gasifier is burned in a gas turbine and does not need to be cooled to ambient temperatures; any tars are maintained as vapours and can be burned in the gas turbine with the fuel gas [38].

8.1.2. Feed constraints

Feed constraints are exactly the same as those specified for the atmospheric gasifier module in Section 7.1.

8.1.3. Performance

The procedure used to define the pressurised gasifier performance is the same as that used in Section 7.1.3 to define the atmospheric gasifier efficiency with the following exceptions:

1. There is no tar cracker and the tar yield is 1% of the dry feed input.
2. The output conditions at the gasifier are 900°C and 25 bar, based on the operating conditions of the Värnamo plant [114].
3. The fuel gas enters the gas turbine at 450°C after gas cooling and hot gas filtration. At these conditions the water vapour in the raw fuel gas is still a vapour and the enthalpy of the water vapour is included in the output stream of the conversion process.

The analysis produced Eq. (29).

$$\eta_{\mathrm{conv,pgas}} = [-0.00006(Q_{\mathrm{h,pret,dry}})^2 + 0.0347(Q_{\mathrm{h,pret,dry}}) + 85.50]/100 \qquad (29)$$

where

$\eta_{\mathrm{conv,pgas}}$ the conversion efficiency of the pressurised gasification module, %
$Q_{\mathrm{h,pret,dry}}$ the dry flow rate of feed into the reactor, odt/h

8.1.4. Capital costs

Total plant costs are based on the data already described in Section 5.1.4. This source produced the line shown in Fig. 20 and Eq. (30). Given that this regression is based on only four data points, there is more uncertainty about capital costs for this module than for the other modules. The four data points used are for novel, 1st plant and the costs for this module are assumed to be 1st plant costs.

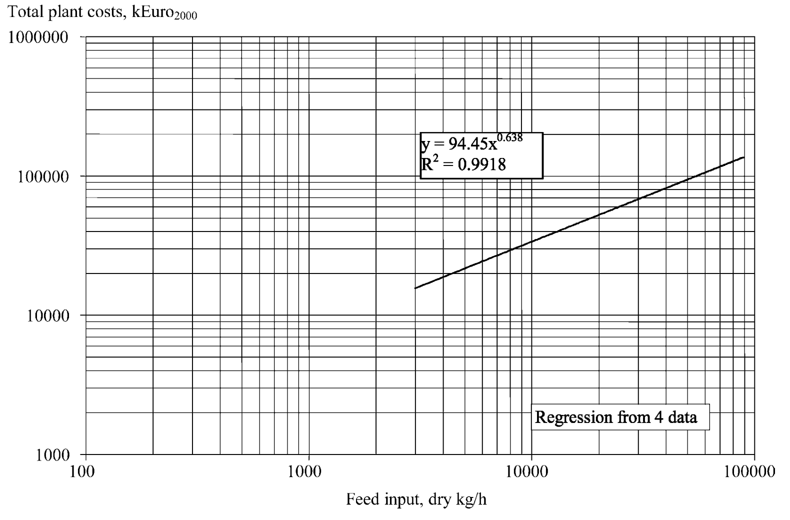

Fig. 20. Pressurised gasification total plant costs.

$$\mathrm{TPC}_{\mathrm{conv,pgas}} = 94.5\times(Q_{\mathrm{h,pret,dry}}\times 1000)^{0.6384} \tag{30}$$

where

$\mathrm{TPC}_{\mathrm{conv,pgas}}$ total plant cost of the atmospheric gasification module, k€$_{2000}$
$Q_{\mathrm{h,pret,dry}}$ the mass flow rate of prepared wood feed into the reactor, odt/h

8.1.5. Operating costs

The labour requirement for the pressurised gasification module is assumed to be the same as the labour requirement for the atmospheric gasification module, since the equipment required in both are similar. The hot gas filtration used in the pressurised system is likely to require more attention than wet gas scrubbing given its novelty, compensating for the lack of a tar cracker.

The internal power consumption has been estimated by comparison with the power consumed in the other modules. The main consumer of power is the booster compressor that raises bleed air from the gas turbine compressor to a pressure sufficient to overcome the pressure drop in the fluid bed, the gas filtration system and fuel gas injection to the gas turbine. It is difficult to estimate this requirement since the gas turbine pressure will change with each machine, but it is likely to be significantly more than the fan power requirement for the atmospheric gasifier. The feeding system could also consume substantial power if a lock hopper system is used by virtue of the need to compress the inert gas purge. This power consumption and the expense of the purge (probably nitrogen) has discredited lock hopper systems and it is assumed that a screw feeder is used instead. The gas cleaning systems in both the gasification modules will require power, the former for pumping scrubbing water and the latter in terms of the pressure drop (already noted) and the flushing mechanism required to periodically clean the filters. In summary it will be assumed that the compressor work increases the amount of power required in this module by 50%, and a value of 60 kWh/odt is used.

There are no other utility requirements for this module.

8.2. The gas turbine combined cycle module

8.2.1. Module limits

The upstream limit of this module is the entry of hot, clean fuel gas into the gas turbine fuel injection system. The downstream limit is the generator terminals. The module includes the gas turbine, heat recovery steam generator, steam cycle and stack. The power output is the gross power output. The net power output is calculated by the grid connection module, which is described in Section 5.4.

8.2.2. Performance

There are many issues that must be considered if a gas turbine is to be adapted for operation with a low heating value gas, including the air and fuel mix required to give the correct turbine inlet temperatures, the control and operation of the gas turbine compressor, any emissions limitations, injection system limitations and possible redesign of the early gas turbine stages to meet the increased flow rates that will arise when firing low heating value gases [129,130]. Such analyses are beyond the scope of this study and the approach here is more general.

One key simplification is that the energy output from the gasification module is the fuel input to the gas turbine. Strictly, the fuel input to the gas turbine is only the dry fuel gas and the tar vapours, and should not include the enthalpy of the steam. The gas turbine is effectively operating in a partial STIG cycle because of the high steam content of the fuel gas [130]. In this respect, the steam displaces part of the fuel that would have been required to give a specific output, and therefore in this generic analysis it is reasonable to consider the fuel energy and sensible energy of the total fuel gas stream as a single fuel input.

Generating efficiency is calculated using a methodology developed by Maude [30] during the early evaluation of coal IGCC systems. This used a basic flow diagram as shown in Fig. 21.

The gas turbine efficiency is set by regression from performance data for aeroderivative gas turbines taken from data published in Modern Power Systems [131]. In fact there are currently very few gas turbines that are available for operation on low heating value gases and IGCC system outputs rise in steps that correspond to the capacities of these few machines [115]. The regression curve used here is an approximation required to allow the continuous range of capacities required by this work.

Using the gas turbine efficiency relationship and the steam cycle efficiency relationship given in Section 6.2.2, the gas turbine combined cycle efficiency was calculated for a range of capacities as shown in Fig. 22. A regression analysis on this data gives the gas turbine combined cycle efficiency that is used in the module, Eq. (31).

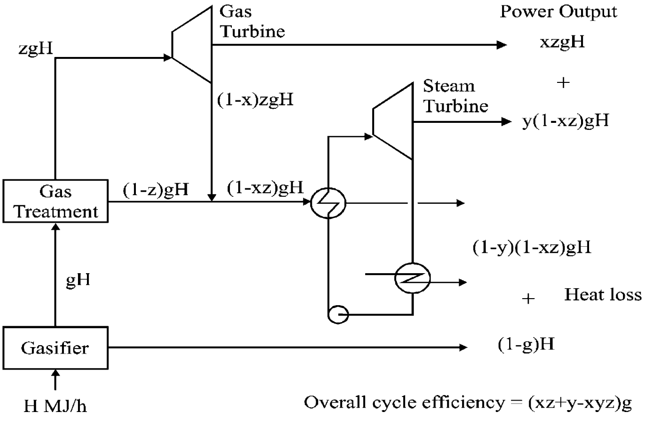

Fig. 21. Methodology for calculating the efficiency of the GTCC.

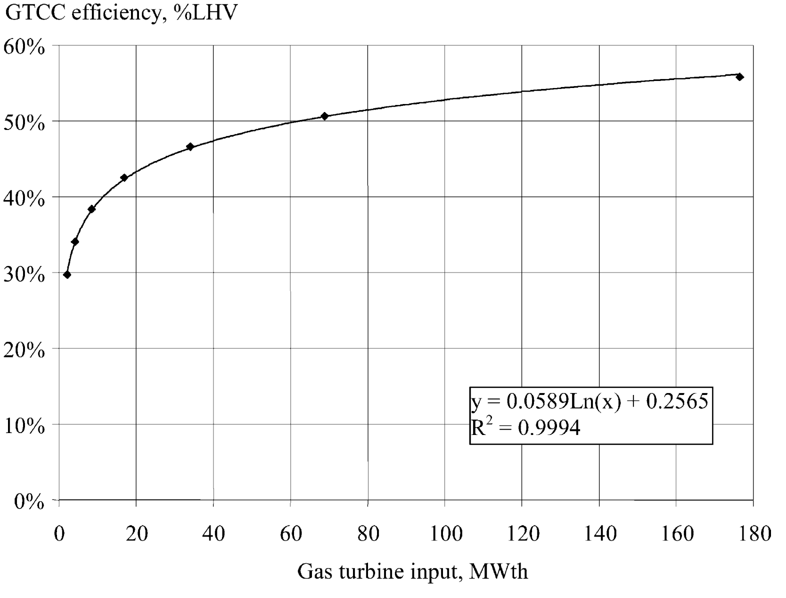

Fig. 22. Gas turbine combined cycle generating efficiencies.

$$\eta_{\mathrm{gen,gtcc}} = 0.0589\ln(E_{\mathrm{th,conv}}) + 0.2565 \tag{31}$$

where

$\eta_{\mathrm{gen,gtcc}}$ The gross generating efficiency of the gas turbine combined cycle, %
$E_{\mathrm{th,conv}}$ The lower heating value of the conversion energy product, MW_{th}

8.2.3. Capital costs

Capital costs have been taken from the literature for natural gas-fired gas turbine combined cycles [132–134]. Some gas turbine modifications may be required to adapt the fuel and air injection systems, the combustion chambers and the turbine blading to low heating value gas operation. Gas turbine modification costs have not be included but they are expected to only be a small percentage of the gas turbine, which is in itself only part of the combined cycle. The cost data was adjusted to total plant costs using the ratios method and adjusted to $€_{2000}$. The results are shown in Fig. 23, which gives Eq. (32). These capital costs are based on established equipment and the learning effect that they will experience is minimal. They are assumed to be 100th plant costs.

$$\mathrm{TPC}_{\mathrm{gen,gtcc}}, kECU_{2000} = 2157\times(P_{\mathrm{e,gross}})^{0.85} \tag{32}$$

where

$\mathrm{TPC}_{\mathrm{gen,gtcc}}$ Total plant cost of the GTCC module, $k€_{2000}$
$P_{\mathrm{e,gross}}$ The total gross power output, MW_e

8.2.4. Operating costs

Bressan [135] reports internal power consumption for several gas turbine combined cycles rated at between 42 and 63 MW_e and operated on natural gas. Power consumption for the six cycles ranged from 2.5% to 3.6% of the gross power output, with an average value of 3%, which is used here.

Cooling water and boiler feed water requirements are calculated using the data for the steam cycle given in Section 6.2.4. Since the steam turbine only contributes

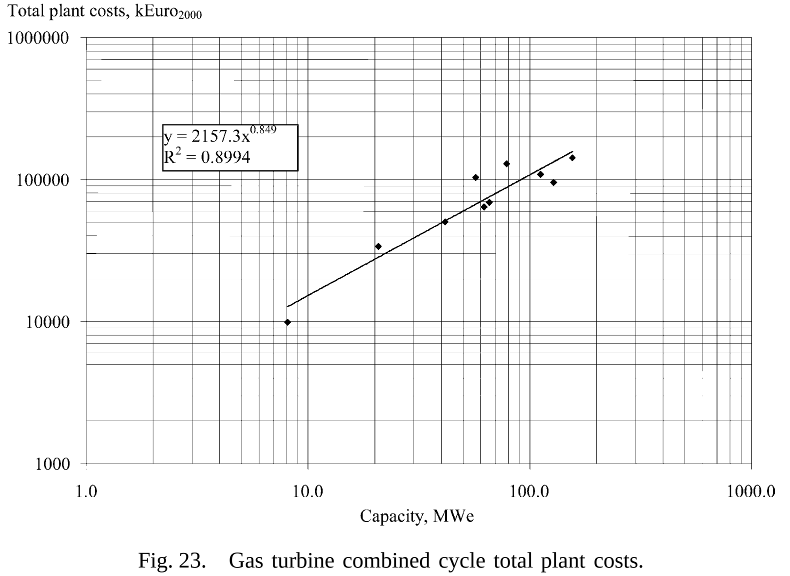

Fig. 23. Gas turbine combined cycle total plant costs.

about a 1/3 of the total power produced by the module, the consumption figures have been divided by 3 to give a cooling water requirement of 1.6 t/MWh and a boiler feed water requirement of 0.5 t/MWh.

It can be expected that the labour required is higher than the labour for the steam cycle since the GTCC is more complex than the steam cycle. It is also reasonable to expect the labour required in the engine based cycles to be greater than the GTCC since multiple engines are used. On the basis of this evidence, the labour for the gas turbine combined cycle is based on the relationships for the steam cycle (Eqs. (24) and (25)), with an additional 25% to account for the extra complexity.

Reported maintenance costs for gas turbine combined cycles range from 0.0065–0.009 €/kWh [132,136]. Given the novel application, a high maintenance cost is likely because of the potential for damage to the gas turbine by contaminants in the gas. Thus the maintenance cost for the gas turbine combined cycle is set at 0.009 €/kWh.

9. Results

9.1. Overview

Comparing the economics of any novel system with established systems is difficult to achieve fairly. Novel systems are easily prejudiced by their high initial if current costs are used since the established systems have the benefit of learning effects. However, it is also dangerous to use estimates of future costs when comparing systems because developers can lose faith in technologies that fail to meet long term economic claims in early demonstrations.

With this in mind, the results section is structured as follows:

- Future costs of the four generating systems are compared to indicate the long-term potential of the fast pyrolysis and diesel engine system in relation to alternative biomass to electricity systems and the wider electricity market.
- Present costs of the four generating systems are compared to show the immediate potential of fast pyrolysis and diesel engine systems, again with reference to the alternative systems and the existing electricity market.
- De-coupled systems are evaluated to assess the opportunities offered by this unique feature of fast pyrolysis-based systems.
- Sensitivities on key variables are examined for the fast pyrolysis and diesel engine system to indicate the uncertainties within the model and the areas to focus on in system application.

9.2. Potential costs for the fast pyrolysis and alternative systems

This first analysis uses the theory described earlier in Section 2.5 by applying a 20% learning factor to the 1st plant capital costs calculated in the fast pyrolysis and gasification models. All other models (i.e. pretreatment, combustion and steam cycle) models are unaffected. Production costs for the 10th plant in each of the novel systems are compared with the production costs for the established combustion system (which is already assumed to be 100th plant and therefore has virtually constant capital costs).

Future systems should also benefit from:

- reductions in feed cost through improvements in silvicultural practices;
- better reliability and hence higher availability; and
- reduced labour requirements through optimised operator practices and increases in automation.

It is difficult to quantify these improvements but conservative estimates are made for this evaluation and the characteristics of each system are summarised in Table 8.

The results of this evaluation are shown in Fig. 24. These results are compared with three benchmarks:

1. the UK pool price, which fluctuates around 0.035 €/kWh.
2. the mean EU price for electricity that is paid by large consumers (0.075 €/kWh [97]). This represents the price that could be viable if generated electricity was sold directly to a consumer or used internally on-site.
3. The UK NFFO 3 price for biomass gasification projects (0.117 €/kWh). This represents a price that could be available for electricity produced from a renewable resource such as biomass.

It must be noted that the benchmarks are electricity prices and the calculations give electricity production costs that exclude any profit element. Hence, these reference points are intended only as a general guide to the viability of the systems.

It can be seen from the potential electricity production costs in Fig. 24 that the fast pyrolysis and diesel engine system is the most economic in small scale systems up to 5 MW_e. However the future production costs are very similar for all systems and with so little difference between the electricity production costs it is clear that the biomass to electricity market will be extremely competitive.

The electricity production costs should also be compared with the three benchmarks given in Fig. 24. None of the systems show the potential to converge with the UK pool price, which can be expected given the much larger capacity of conventional generators and thus their significant scale economies. The systems compare favourably at all but the smallest capacities with the current NFFO3 price that is paid for biomass-based IGCC projects in the UK. This result must treated with caution because such elevated prices for renewable electricity rely on political support. Incentive schemes are a useful way of establishing the technology but, in the long term a viable system should be capable of meeting the electricity consumer price. A comparison with the mean EU electricity price for large consumers shows that the systems meet this target at around 12–14 MW_e but that only the IGCC and Combustion systems significantly undercut the benchmark. It may seem from this that the chances

Table 8
Assumptions used when comparing the systems under future conditions

System name	PyrEng	Combustion	GasEng	IGCC
Feedstock	Whole tree wood chips, 25 mm particle size, 50% moisture			
Feedstock cost	30 €/odt including transport (odt=oven dry tonne)			
Pretreatment requirements	Reception of the feed, storage, screening, drying, grinding (if fines required), buffer storage			
Moisture content as fed	7%	35%	15%	15%
Feed particle size as fed	Fines, <2 mm	Chips	Chips	Chips
Conversion process	Fast pyrolysis	Combustion	Atmospheric gasification	Pressurised gasification
Intermediate energy carrier	Pyrolysis liquid	Superheated steam	Cold, clean fuel gas	Hot, clean fuel gas
Generating cycle	Dual fuel diesel engine	Superheated steam in a condensing steam turbine	Dual fuel diesel engine	Integrated gas turbine combined cycle
Overall availability	90%[a]	90%	85%	85%
Labour requirement	Default* 75%	Default	Default* 75%	Default* 75%
Configuration	All systems are close-coupled			
Status of capital cost				
Pretreatment	All assumed 100th plant			
Conversion	10th plant	100th plant	10th plant	10th plant
Generation	All assumed 100th plant			

[a] This assumes that a buffer storage of pyrolysis liquid limits unplanned generation shutdowns.

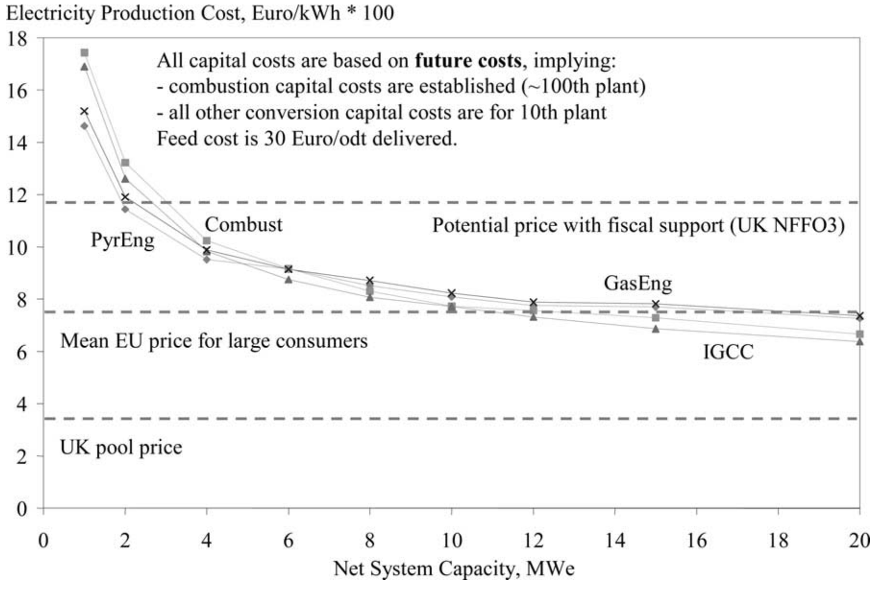

Fig. 24. Potential electricity production costs using future system conditions. (System parameters are as shown in Table 8.)

for viable fast pyrolysis and diesel engine systems are small, but it must be remembered that the benchmark is a mean price: the fast pyrolysis and diesel engine system is likely to be viable in locations where the electricity price paid by large consumers is relatively high.

The potential for fast pyrolysis and diesel engine systems after learning effects can be summarised as follows:

- The fast pyrolysis and diesel engine system produces the lowest electricity production costs at scales up to 5 MW_e.
- All of the biomass to electricity systems will produce similar electricity production costs in the future. For the fast pyrolysis system these costs range from 0.146 € /kWh at 1 MW_e to 0.073 €/kWh at 20 MW_e.
- Biomass to electricity systems could supply large consumers in niche markets where the price paid by the consumer is higher than the EU mean price.
- Biomass to electricity systems cannot supply the grid without fiscal incentive schemes.

9.3. Current costs for the fast pyrolysis and alternative systems

9.3.1. Comparison of the four biomass to electricity systems

In this and all subsequent evaluations current cost and performance criteria are used as specified in Table 9 (variations to the conditions in this table will be noted explicitly).

Table 9
Assumptions used when comparing the systems under future conditions

System name	PyrEng	Combustion	GasEng	IGCC
Feedstock	Whole tree wood chips, 25 mm particle size, 50% moisture			
Feedstock cost	40 €/odt including transport (odt=oven dry tonne)			
Pretreatment requirements	Reception of the feed, storage, screening, drying, grinding (if fines required), buffer storage			
Moisture content as fed	7%	35%	15%	15%
Feed particle size as fed	Fines, <2 mm	Chips	Chips	Chips
Conversion process	Fast pyrolysis	Combustion	Atmospheric gasification	Pressurised gasification
Intermediate energy carrier	Pyrolysis liquid	Superheated steam	Cold, clean fuel gas	Hot, clean fuel gas
Generating cycle	Dual fuel diesel engine	Superheated steam in a condensing steam turbine	Dual fuel diesel engine	Integrated gas turbine combined cycle
Overall availability	85%[a]	95%	80%	80%
Configuration	All systems are close-coupled			
Current status of capital cost				
Pretreatment	All assumed 100th plant			
Conversion	1st plant	100th plant	1st plant	1st plant
Generation	All assumed 100th plant			

[a] This assumes that a buffer storage of pyrolysis liquid limits unplanned generation shutdowns.

Fig. 25 gives a comparison of the electricity production costs that are calculated for the four biomass to electricity systems at capacities from 1 to 20 MW_e. From this figure it can be seen that none of the novel systems produce lower cost electricity than the established combustion system. However, the fast pyrolysis and diesel engine system is clearly the most economic of the novel systems at scales up to 15 MW_e.

The key reasons for the variations in electricity production cost can be seen in the breakdown of costs shown in Fig. 26. In Fig. 26 it can be seen that the feed expenditure in the combustion systems is the highest of the systems at any capacity, a result of the low system efficiencies shown in Fig. 27. This high feedstock expenditure is countered by low capital expenditure as a result of the low total plant costs shown in Fig. 28. Low capital amortisation costs are combined with low overheads and maintenance charges that are also functions of total plant costs. The other advantage that the combustion system has is its lower labour costs. Both low capital costs and low labour requirements are results of the experience gained from building many combustion and steam cycles. It must be emphasised that the poor competitiveness of the fast pyrolysis and gasification-based systems is largely due to lack of this experience, as the results in Section 9.2 have shown.

9.3.2. Fast pyrolysis and diesel engine system efficiencies

From Fig. 27 it can be seen that the net system efficiency is poor compared with the other novel systems (GasEng and IGCC) but better than the efficiency of the conventional combustion and steam cycle. The curve is not smooth; fluctuations are caused by changes in the number of engines that are used. Net system efficiencies

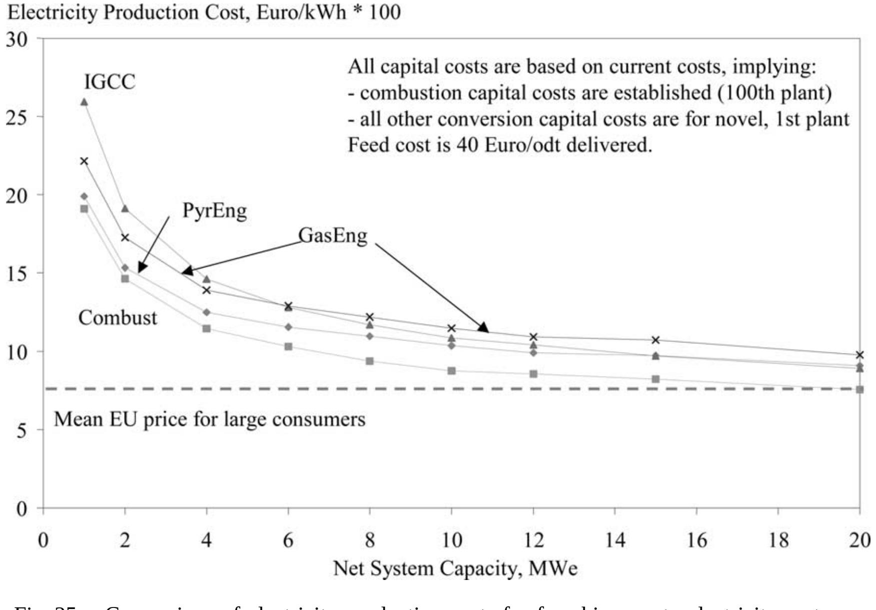

Fig. 25. Comparison of electricity production costs for four biomass to electricity systems.

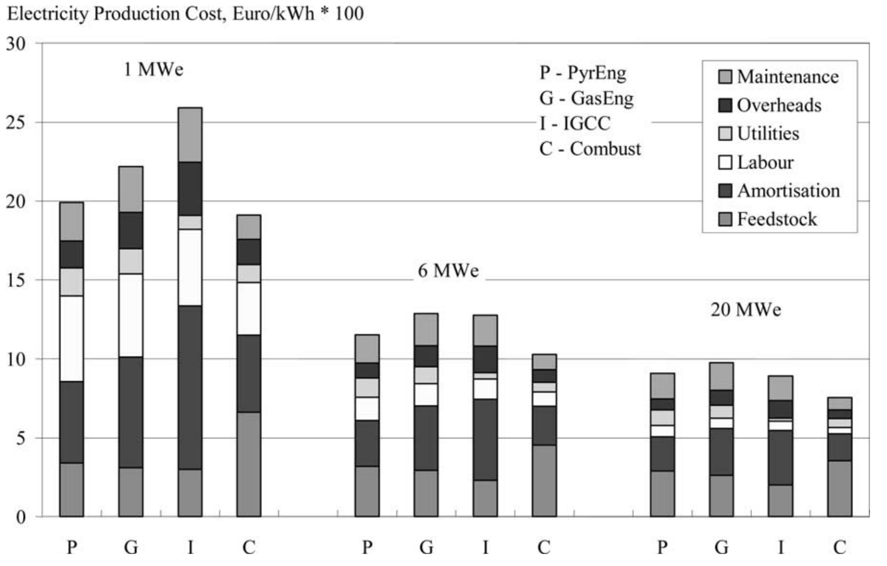

Fig. 26. Breakdowns of electricity production costs by cost sector for four biomass to electricity systems.

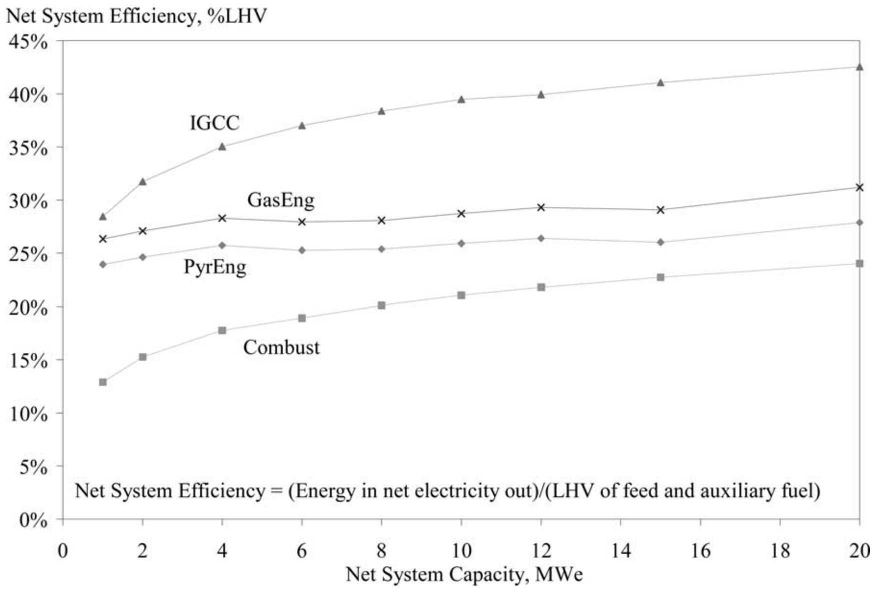

Fig. 27. Comparison of efficiencies for four biomass to electricity systems.

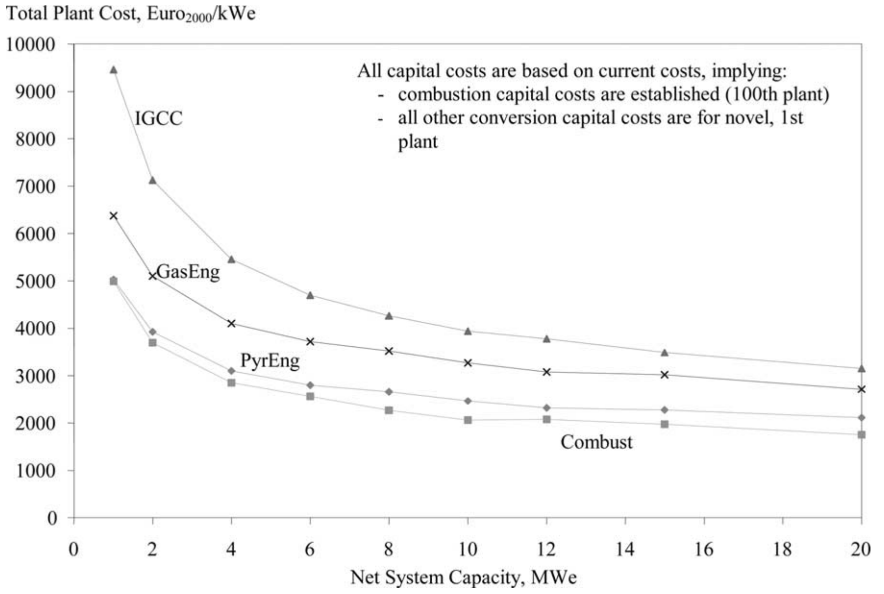

Fig. 28. Comparison of total plant costs for four biomass to electricity systems.

change very little over the capacity range, with a minimum efficiency at 1 MW_e of 23.9% and a maximum efficiency at 20 MW_e of 27.9%.

A breakdown of the energy fluxes in the fast pyrolysis and diesel engine system at three system capacities is given in Table 10. This table demonstrates the high internal losses caused by parasitic power consumption. Parasitic loads use approximately 15% of the gross power output and result in an overall drop in efficiency of 4–5 percentage points. Most of the parasitic load is consumed when grinding the feedstock to the $<$2 mm particle size specification and the impact of less severe pretreatment is examined in Section 9.5.3.

Another interesting point that arises from Table 10 is that the available energy in the feedstock rises during pretreatment as the feedstock is dried. The energy for drying have not been examined in this work but previous work has shown that there is sufficient heat of adequate quality for feed drying if the waste heat from the engine exhaust gases is used [64]. However, the system would have to be evaluated in more detail if this energy was not available, as in the case of cogeneration or in de-coupled systems for example.

9.3.3. Fast pyrolysis and diesel engine system capital costs

A breakdown of the current total plant costs for the fast pyrolysis and diesel engine system is presented in Fig. 29. This highlights the scale economies that can be gained in the fast pyrolysis step. The diesel engine capital costs are insensitive to scale due mainly to the use of multiple engines that restricts the range of engine sizes used. The pretreatment capital costs are relatively low, although they are significant at 1–2 MW_e. At these very small scales the high fixed costs for plant items such as front

Table 10
Mass and energy flows in the base case system

System capacity	MW_e	1	6	20
Mass flows				
Feed delivered	odt/yr	6291	35,742	107,963
Feed from storage	odt/yr	6260	35,563	107,423
Pyrolysis liquid	t/yr	4897	27,820	84,034
Energy flows				
Feed delivered	GJ/yr	105,980	602,103	1,818,747
Feed from storage	GJ/yr	105,450	599,092	1,809,653
Feed at reactor	GJ/yr	119,655	679,795	2,053,428
Energy intermediate	GJ/yr	74,775	424,819	1,283,232
Supplementary diesel	GJ/yr	6063	34,445	104,046
Gross electricity out	GJ/yr	31,949	188,805	626,216
Net electricity out	GJ/yr	26,807	160,833	536,130
Efficiencies				
Conversion efficiency	%LHV	62.5%	62.5%	62.5%
Generating efficiency	%LHV	39.5%	41.1%	45.1%
Overall gross system efficiency	%LHV	28.5%	29.7%	32.6%
Overall net system efficiency	%LHV	23.9%	25.3%	27.9%
Power and electricity				
Gross capacity	MW_e	1.192	7.043	23.362
Pretreatment parasitic load	MW_e	0.122	0.641	2.083
Conversion parasitic load	MW_e	0.034	0.191	0.577
Generation parasitic load	MW_e	0.036	0.211	0.701
Net capacity	MW_e	1.000	6.000	20.001
Gross output	MWh/yr	8875	52,446	173,949
Parasitic consumption	MWh/yr	1429	7770	25,024
Net output	MWh/yr	7446	44,676	148,925
Parasitic consumption	%gross output	16.1%	14.8%	14.4%

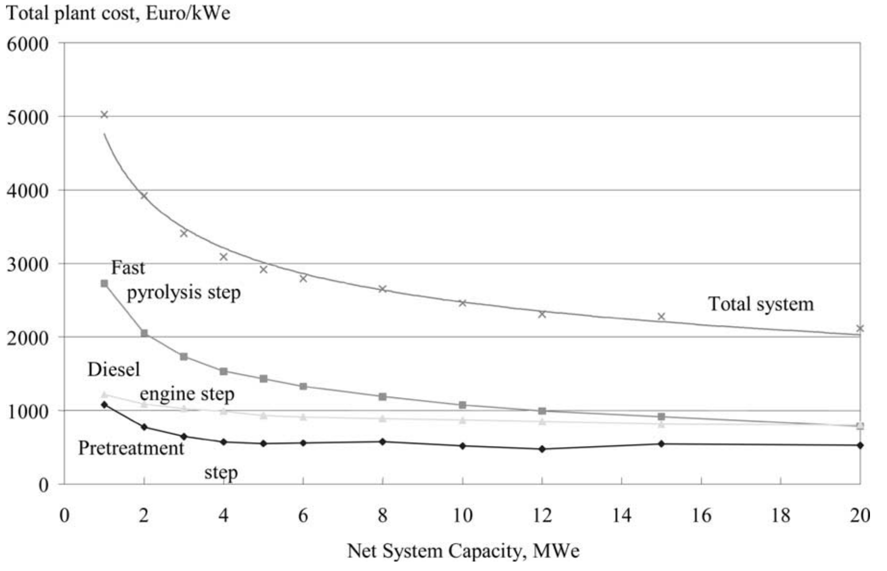

Fig. 29. Total plant costs under current conditions.

end loaders are not recouped by system output, producing the high specific capital costs shown. At higher system capacities the pretreatment capital costs are kept relatively constant by the addition of extra grinders.

A regression analysis on the total system capital costs gives Eq. (33). This equation can be used to approximate the investment required for a system with a specific net power output, but only under base case conditions.

$$TPC_{\mathrm{system}},kECU_{2000} = 4757\times(\mathrm{NetMW}_e\mathrm{output})^{0.72} \tag{33}$$

9.3.4. *Fast pyrolysis and diesel engine system production costs*

The production costs under the system conditions specified in Table 9 vary from 0.199 €/kWh at 1 MW_e net output to 0.0909 €/kWh at 20 MW_e. The components of these production costs have already been presented in Fig. 26, which is supported by the data given in Table 11. These results show that the main constituents of the production costs are feedstock costs and capital amortisation, with significant labour costs at the small scale.

It can be seen that feedstock costs would have to be significantly lower to make the system viable. It should also be noted that almost constant system efficiencies result in specific feedstock costs that are independent of system capacity. By contrast, specific capital amortisation charges and labour costs are significantly reduced by increasing plant size. As a result the feedstock cost becomes much more important at large scale. Maintenance costs are also almost independent of scale due to the fixed costs of maintenance for the diesel engine (0.01 €/kWh).

Table 11
Production costs under base case conditions

Net system output	MW_e MWh/yr	1 7884	6 47,304	20 157,685
Production costs by system step				
Feed production	k€/yr	252	1430	4319
Feed transport	k€/yr	0	0	0
Pretreatment	k€/yr	413	772	1773
Conversion	k€/yr	468	1293	2488
Liquids transport		0	0	0
Generation		351	1665	4958
Total		1483	5159	13537
Production costs by cost centre				
Feed supply and transport	k€/yr	252	1430	4319
Capital amortisation	k€/yr	386	1289	3252
Labour	k€/yr	405	663	1051
Utilities	k€/yr	130	553	1473
Overheads	k€/yr	126	419	1058
Maintenance	k€/yr	183	804	2386
Total	k€/yr	1483	5159	13,537
	€/kWh*100	19.91	11.55	9.09

The labour costs are very high in the 1 MW_e system. This is to be expected as there is likely to be a minimum labour requirement to operate the systems that may result in poor productivity in the very small systems. Even allowing for this the labour requirements presented in Table 12 are high. This is a result of considering each step in the system in isolation. In very small scale systems it is very probable that the total labour required could be reduced by sharing labour between the steps. There is also likely to be scope for lesser savings as system capacity increases. For this work the current labour requirements are left at their original values because labour costs are likely to be higher in early demonstration plants but the labour costs in established plant are likely to be lower (as assumed in the future costs calculated in Section 9.2).

Table 12
Labour requirements under base case conditions

Net system output	MW_e	1	6	20
Pretreatment	/shift	1.8	2.0	2.7
Conversion	/shift	1.0	2.2	3.7
Generation	/shift	0.5	1.2	2.1
Total	/shift	3.2	5.3	8.4

9.4. Evaluation of systems de-coupling

The systems comparisons in Section 9.3 have shown that under current conditions the fast pyrolysis and diesel engine system has no economic advantage over combustion and steam engine systems. These latter systems are more established and therefore present a lower risk to potential developers of biomass to electricity systems. Risk is often a very important factor is system selection and would tend to favour the combustion option.

In future systems, as demonstrated in Section 1.4, fast pyrolysis has only a slight advantage over the gasification and combustion options, especially at small scales. Thus in both current and future systems the fast pyrolysis option can be expected to face stiff competition from alternative systems.

However, all the evaluations thus far have considered only close-coupled systems. Systems de-coupling, introduced in Section 1.4, is only possible in fast pyrolysis systems where the liquid fuel that is produced in fast pyrolysis can be stored and transported. It may be possible to use this unique feature of the fast pyrolysis option to give it a significant advantage over the competition in certain circumstances.

The three de-coupled options shown in Fig. 4 were each evaluated for this section but only the option of combining a large fast pyrolysis plant with several small generators gives any significant advantage. This assumes a situation where electricity is required at a number of remote sites. Under such circumstances a close-coupled system could be constructed at each location. Alternatively a single large fast pyrolysis plant could be constructed and the pyrolysis liquid that is produced could be distributed to generators located at each site where power is required. The advantage of such a system is that scale economies can be harnessed in the construction and operation of the fast pyrolysis plant.

Fig. 30 demonstrates the possibilities of this arrangement. The systems assume the conditions presented in Table 9 for each close-coupled options with each option generating a total of 20 MW_e at four 5 MW_e generating sites. An alternative de-coupled fast pyrolysis option uses a single fast pyrolysis site to supply pyrolysis liquid to four remote 5 MW_e generators, with average liquid transport distances of 50 km. The savings produced in the second case are clearly demonstrated. It can be seen that the de-coupled fast pyrolysis option has a significant cost advantage in this scenario, even before learning effects.

9.5. System sensitivities

9.5.1. Overall sensitivity analysis

This section examines the effects on production costs of changing any of the user-editable system parameters by 10% of their default value. The system evaluated is a 6 MW_e fast pyrolysis and diesel engine system, set up as presented in Table 9. It should be noted that the sensitivity of each variable will vary with the system configuration and capacity and so a sensitivity analysis is only relevant to a particular case.

Each variable was examined in turn by multiplying the default value by either

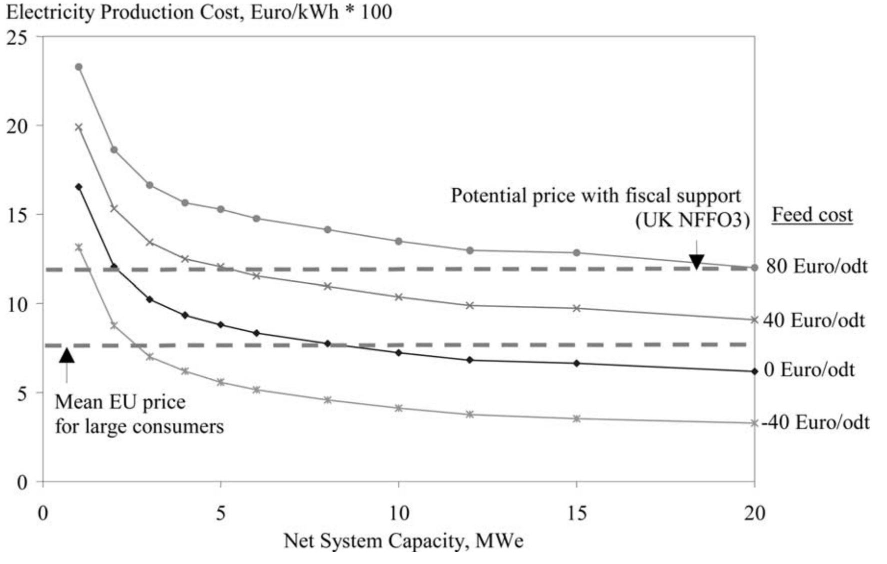

Fig. 30. Electricity production costs with varying feedstock costs.

110% or 90%, with the factor selected that would produce a rise in the system electricity production cost. 55% variables in all were tested, and most had an insignificant impact on the electricity production cost. The 15 most sensitive parameters are presented in Table 13.

The sensitivity analysis shows that the engine and pyrolysis efficiencies have a high impact. The performance of diesel engines in general is established but there is scant experience of diesel engine operation using pyrolysis liquids. The efficiency used as a default is a reasonable estimate and the low efficiency used in the sensitivity analysis is unlikely. The sensitivity of the system to the fast pyrolysis organics yield is a much greater concern. This is one of the least certain variables in the model since it has been derived from bench scale tests and there are very few examples of fast pyrolysis yields at demonstration scale. Moreover, the organics yield is highly dependent on the feedstock. Thus the sensitivity of the model to this variable increases the uncertainty of the overall results tremendously. Future studies should take care to evaluate the effect on the system economics of changing this variable to assess fully the financial risks associated with the study.

The system availability is the next most sensitive variable, which is a reflection of the large fixed costs associated with the system. At the small scales typical of biomass to electricity plant the scale economies are poor and consequently specific capital costs are very high, raising capital amortisation, overheads and maintenance costs. Under these circumstances it is vital to the system viability that the plant operating hours are as high as possible to maximise annual production and bring down unit production costs. Fast pyrolysis systems have an inherent advantage in this respect, since a buffer of fast pyrolysis liquid can be stored in case of shutdowns in the fast pyrolysis process. The 85% default availability selected by the model is

Table 13
Most sensitive variations to the base case conditions at 6 MW_e

	Default value	Value after change by 10%	Electricity production cost, €/kWh
Base case			0.1155
Diesel engine efficiency, %	41.10%	36.99%	0.1268
Pyrolysis organics yield, %dry input	59.90%	53.91%	0.1267
Pyrolysis availability, %	85%	77%	0.1223
Overall system TPC, k€	16779	18457	0.1199
Delivered feed moisture content, %	50%	55%	0.1193
Engine operating cost, k€/yr	1665	1832	0.1192
Delivered feed cost, €/odt	40.00	44.00	0.1187
Delivery days, d/week	5	5	0.1187
Delivery weeks, weeks/yr	52	47	0.1187
Pyrolysis operating cost, k€/yr	1293	1422	0.1184
Life of project, yr	20	18	0.1178
Pyrolysis TPC, k€	7965	8762	0.1177
Interest rate, %	10	11	0.1175
Pretreatment operating cost, k€/yr	774	851	0.1172
Mean salary, €/yr	25,000	27,500	0.1170

a reasonable estimate, but situations can occur such as seasonal demand or feedstock availability where this variable must be carefully set to prevent serious errors in the calculated electricity production cost.

The impact of the overall total plant cost is high, as expected by virtue of the low scale economies that have already been noted. Here there is some uncertainty regarding the calculated figure, inevitable in study estimates of this type. Errors of ±30% are typical, and increased accuracy can only be achieved through very detailed and expensive analysis of the particular case study. System developers should always be aware of potential inaccuracies in predicted capital costs and test scenarios with elevated total plant costs to see whether possible errors can be tolerated.

The sensitivity of the system to feed moisture content when delivered is an interesting result. This reflects the extra cost of feedstock drying and handling as the feedstock gets wetter (and therefore heavier). This is a relatively easy variable to predict accurately, once the feedstock is known. Again, care should be taken in systems evaluations to set this figure accurately and later, if a plant is constructed, to ensure that the feedstock is of the required quality.

The operating costs of parts of the system appear three times in Table 13. This tells little about the system sensitivities since each figure is a combination of many components of operating costs that are individually tested in the sensitivity analysis (such as labour).

System sensitivity to the delivered feedstock cost is often cited in biomass to electricity system studies. The ranking of delivered feedstock cost in Table 13 belies its significance; this cost can vary enormously, and certainly well outside the 10% limit tested here. Section 9.5.2 examines feed cost variations in more detail.

The impact of changes to the delivery schedule is interesting and was not expected. Subsequent evaluations showed that the small changes made in the variables produced step changes in the equipment required during feed reception and storage. Such dramatic changes are not realistic, and are a result of the necessary limitations in the model. In changes to delivery schedules could be accommodated by subtle changes to the equipment specification or working practices.

Finally, the system is sensitive to the project life and interest rate chosen, which both impact on the annual repayments on capital borrowed. The life of the project is largely within the control of the developer (barring major incidents) and can be planned for. Interest rates can also be controlled by agreeing fixed rates with the lenders. Thus the uncertainty associated with these variables can be minimised.

9.5.2. Sensitivity to feed costs

The sensitivity of biomass system to feedstock costs is well known. The base case analyses used a feedstock cost of 40 €/odt. The impact of changes to the feedstock cost is demonstrated by Fig. 30.

The very low cost feedstock options produce low cost electricity and would provide excellent opportunities for early demonstrations of the system. In reality, supplies of free or negative cost feedstocks are likely to be scarce or sporadic. For example, as the fast pyrolysis systems demonstrate an economic use for wastes then the feedstocks will become valuable. Low cost feedstocks can be used as a short term way of reducing the overall costs in early systems. The experience gained can lead to the long term reductions in costs through learning effects so that future systems are viable even with more usual feed costs.

9.5.3. Variations to the feed particle size

In Section 1.1 it was noted that the feed particle size required by the fast pyrolysis reactor varies with the type of reactor. Fluid bed reactors (assumed in the base case) are most demanding and require a <2 mm feed particle size while circulating fluid beds or transport reactors require a 5 mm particle size. Ablative fast pyrolysis could operate with chips, although a demonstration plant has yet to be constructed. In this exercise comminution is varied to match each of the cases above. No changes are made to the rest of the system: fast pyrolysis costs and yields are kept constant since there are insufficient data at this time to discern between reactor types. Thus this analysis only gives an indication of the savings that could be made through reducing comminution requirements and it must be remembered that other changes to the system as a result of changing reactor type could reduce or accentuate the impacts shown here.

The results in Fig. 31 show that changes in the comminution requirement has a small but significant impact on the overall production costs. On this evidence it would be worth developing the analysis of ablative reactor systems further to see

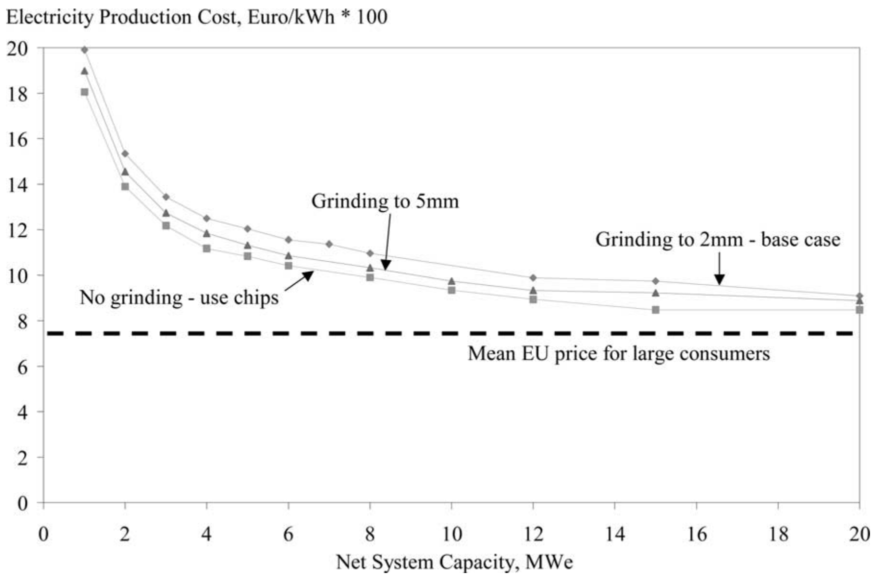

Fig. 31. Effects of comminution costs and performance on production costs.

whether the improvements brought about by removing the grinding step will still stand when the changes to the reactor are also considered.

10. Conclusions

The electricity production costs for fast pyrolysis and diesel engine generating systems have been calculated for 10th plant systems, indicating the costs that are achievable in the medium term after the high initial costs associated with novel technologies have reduced. The calculated costs for such systems are 0.073 €/kWh at 20 MW_e rising to 0.146 €/kWh at 1 MW_e. These costs converge at the larger scale with the mean electricity price paid in the EU by a large consumer, and there is therefore potential for fast pyrolysis and diesel engine systems to sell electricity directly to large consumers or for on-site generation. Profitability in this sector would be greatly enhanced by carefully selecting opportunities where the local electricity price is higher than average. Other means of reducing costs to increase profitability are summarised later.

In the comparison of four biomass to electricity systems based on future costs and performance, the fast pyrolysis and diesel option is the least expensive option up to 5 MW_e. However, competition will be fierce at all capacities since electricity production costs vary only slightly between systems.

Given that there is little to choose between the four system options, systems decoupling is one way that the fast pyrolysis and diesel engine system can distinguish itself from the competition. Evaluations in this work show that situations requiring several remote generators are much better served by a large fast pyrolysis plant that supplies fuel to de-coupled diesel engines than by constructing an entire close-coupled system at each generating site. Production costs in the de-coupled system are much lower than those in the close-coupled systems by virtue of the scale economies in the large, single fast pyrolysis plant.

The other advantage of de-coupling is that the fast pyrolysis conversion step and the diesel engine generation step can operate independently, with intermediate storage of the fast pyrolysis liquid fuel. In this work this ability has been recognised by setting a higher system availability for the fast pyrolysis system than for the novel gasification systems. Peak load or seasonal power requirements would also benefit from de-coupling since a small fast pyrolysis plant could operate continuously to produce fuel that is stored for use in the engine on demand.

Current electricity production costs for a fast pyrolysis and diesel engine system are 0.091 €/kWh at 20 MW_e and 0.199 €/kWh at 1 MW_e in the base case studied here. These systems are handicapped by the typical characteristics of a novel technology: high capital cost, high labour, and low reliability. As such the more established combustion and steam cycle produces lower cost electricity under current conditions and this may prove a barrier to the early development of the fast pyrolysis and diesel engine system.

Given the promise of lower costs in the future, developers must take a long term view and continue to exploit emerging technologies such as fast pyrolysis. Governments can help this by promoting specific technologies through fiscal incentives such as subsidised high electricity prices or capital grants. Political aid is not a long term solution, however, and other opportunities must be sought. For example, sales of waste heat and by-product char or the co-production of speciality chemicals are promising ways of reducing the electricity production cost.

One area of particular interest is waste disposal, where the feedstock may actually attract a disposal fee from industrial or municipal suppliers. Feedstock would then become a revenue stream rather than an operating cost and in these circumstances the system may be viable without any artificial support.

The fast pyrolysis and diesel engine system is a low capital cost option but it also suffers from relatively low system efficiency particularly at high capacities. This low efficiency is the result of a low conversion efficiency of feed energy into the pyrolysis liquid, because of the energy in the char by-product. A sensitivity analysis has highlighted the high impact on electricity production costs of the fast pyrolysis liquids yield. The liquids yield should be set realistically during design, and it should be maintained in practice by careful attention to plant operation and feed quality. Another problem is the high power consumption during feedstock grinding. Efficiencies may be enhanced in ablative fast pyrolysis which can tolerate a chipped feedstock. This has yet to be demonstrated at commercial scale and further effort should be made to develop this configuration.

In summary, the fast pyrolysis and diesel engine system has great potential to generate electricity at a profit in the long term, and at a lower cost than any other biomass to electricity system at small scale. This future viability can only be achieved through the construction of early plant that could, in the short term, be more expensive than the combustion alternative. Profitability in the short term can best be achieved by exploiting niches in the market place and specific features of fast pyrolysis. These include:

- locations with high electricity prices so that electricity can be sold direct to large consumers or generated on-site by companies who wish to reduce their consumption from the grid;
- waste disposal opportunities where feedstocks can attract a gate fee rather than incur a cost;
- the ability to store fast pyrolysis liquids as a buffer against shutdowns or as a fuel for peak-load generating plant;
- de-coupling opportunities where a large, single pyrolysis plant supplies fuel to several small and remote generators;
- small-scale combined heat and power opportunities;
- sales of the excess char, although a market has yet to be established for this by-product; and
- potential co-production of speciality chemicals and fuel for power generation.

References

[1] IPCC. Climate change: the IPCC 1990 and 1992 assessments. Washington DC: Island Press, 1991.
[2] UK Royal Commission on Environmental Protection. Energy—the changing climate. In: 22nd Report of the RCEP; 2000.
[3] Elliott P. Biomass energy overview in the context of Brazilian biomass-power demonstration. Bioresource Technol 1993;46:13–22.
[4] Klass DL. Biomass for renewable energy, fuels and chemicals. New York: Academic Press, 1998.
[5] US Department of Energy. Electricity from biomass—national biomass power program five year plan (FY1994–1998); April 1993.
[6] Larson ED, Williams RH. Biomass-gasifier steam injected gas turbine cogeneration. J. Engng Gas Turb. Pow 1990;112:157–63.
[7] Solantausta Y. PhD thesis, Aston University, UK; 2000.
[8] Bridgwater AV, Czernik S, Piskorz J. An overview of fast pyrolysis technology. In: Bridgwater AV, editor. Progress in thermochemical biomass conversion, Oxford: Blackwell; 2001.
[9] Cottam M-L. Technical and economic simulation of biomass pyrolysis processes for fuels and electricity. PhD thesis, Aston University, Birmingham; 1995.
[10] Bridgwater AV, Peacocke GVC. Fast pyrolysis processes for biomass. Renew. Sustain. Energy Rev 2000;4:1–73.
[11] Yang J, Blanchette D, de Caumia B, Roy C. Modelling, scale-up and demonstration of a vacuum pyrolysis reactor. In: Bridgwater AV, editor. Progress in thermochemical biomass conversion, Oxford: Blackwell; 2001.
[12] Leech J, Bridgwater AV. Development of an internal combustion engine for use with crude bio-oil and evaluation of associated processes. Presented at 1st EC APAS Contractors' Meeting, Venice, Italy; November 1995.
[13] Gros S. Pyrolysis oil as diesel fuel. In: Power Production from Biomass II, VTT Symposium 164, Espoo: VTT; 1995:225–38.
[14] Kasper JM, Jasas GB, Trauth RL. Use of pyrolysis-derived fuel in a gas turbine engine. ASME paper no. 83-GT-96; 1983.
[15] Andrews RG, Patnaik PC. Feasibility of utilising a biomass derived fuel for industrial gas turbine

applications. In: Bridgwater AV, Hogan EN, editors. Bio-oil production and utilisation. Newbury, UK: CPL Press; 1996. p. 236–45.
[16] Bridgwater AV. Biomass fast pyrolysis and applications in Europe. In: Kaltschmitt M, Bridgwater AV, editors. Biomass gasification and pyrolysis, CPL Press; 1997.
[17] Toupin K. Modern wood fired boiler designs—history and technology changes. Presented at 2nd Biomass Conference of the Americas, Portland, Oregon; 21–24 August 1995.
[18] Strub A. The Commission of the European Communities R&D programme: energy from biomass. In: Bridgwater AV, editor. Thermochemical processing of biomass, London: Butterworths; 1984:1–10.
[19] Easterley JL, Burnham M. Overview of biomass and waste fuel resources for power production. Biomass Bioen 1996;10(2–3):79–92.
[20] Jenkins BM, Baxter LL, Miles Jr. TR, Miles TR. Combustion properties of biomass. Biomass Bioen 1998;54(1–3):17–46.
[21] van den Broek R, Faaij A, van Wijk A. Biomass combustion power generation technologies. Report no. 95029, Utrecht University; 1995.
[22] Tillman DA. Biomass cofiring: the technology, the experience, the combustion consequences. Biomass Bioen 2000;19(6):365–84.
[23] Guinn GR. Design manual for small steam turbines. Alabama: Tennessee Valley Authority, 1990.
[24] Murphy ML. Integrated recycling, resource recovery and energy facility: the experience at Louisville, Kentucky. In: Klass DL, editor. Energy from biomass and wastes XVI, Chicago: IGT; 1992.
[25] Bronson LF. Transportation and handling of wood for fuel from the forest to the utilisation facility. Report to IEA/BA Task IX Activity 6; February 1994.
[26] Malinen HO, Helynen SA. Possibilities for increasing power production with biofuels in the Finnish forest industry—present and future technologies and their effects on emissions. In: Chartier P, Beenackers AACM, Grassi G editors. Biomass for energy, environment, agriculture and industry, 1. Oxford: Pergamon Press; 1995:779–92.
[27] FBT Inc. Fluidised bed combustion and gasification: a guide for biomass waste generators. Report prepared for the Southeastern Regional Biomass Energy Program, Tennessee Valley Authority, Alabama; July 1994.
[28] La Nauze RD. A review of the fluidised bed combustion of biomass. J. Inst. Energy 1987;443:66–76.
[29] Hustad JE, Skreiberg Ø, Sønju OK. Biomass combustion research and utilisation in IEA countries. Biomass Bioen 1995;9(1–5):235–56.
[30] Maude CW, Jones DM. Practical approaches to power generation from low grade fuels. Chem Eng, 1974;285:298–303.
[31] Buekens AG, Maniatis K, Bridgwater AV. Introduction. In: Buekens AG, Bridgwater AV, Ferrero G-L, Maniatis K, editors. Commercial and marketing aspects of gasifiers, Brussels: Commission of the European Communities; 1990:8–12.
[32] Maniatis K. Progress in biomass gasification: an overview. In: Bridgwater AV, editor. Progress in thermochemical biomass conversion, Oxford: Blackwell; 2001.
[33] Bridgwater AV. Review of thermochemical biomass conversion. ETSU report no. ETSU B 1202, Energy Technology Support Unit, Harwell; 1991.
[34] van Swaaij WPM, van den Aarsen FG, Bridgwater AV, Heesink ABM. A review of biomass gasification. Report to the EC DGXII JOULE Program; April 1994.
[35] Reed TB, Gaur S. A survey of biomass gasification 2000. Biomass Energy Foundation report, USA; 1999.
[36] Overend RP, Rivard CJ. Thermal and biological gasification. In: First Biomass Conference of the Americas, Golden Colorado: National Renewable Energy Laboratory; 1993:47–497.
[37] Palonen J, Lundqvist RG, Ståhl K. IGCC technology and demonstration. In: Power Production from Biomass II, VTT Symposium 164, Espoo: VTT; 1995:41–54.
[38] Bridgwater AV. The technical and economic feasibility of biomass gasification for power generation. Fuel 1995;74(5):631–53.
[39] Bridgwater AV, Maniatis K, Masson HA. Gasification technology. In: Buekens AG, Bridgwater

AV, Ferrero G-L, Maniatis K, editors. Commercial and marketing aspects of gasifiers, Luxembourg: CEC; 1990:41–65.
[40] Gainey BW. Natural gas for power generation. Shell Selected Papers; November 1991.
[41] Brander JA, Chase DL. Repowering application considerations. Trans. ASME A J. Engng Gas Turb. Power 1992;114:643–52.
[42] Babu SP, Bain RL, Craig K. Thermal gasification of biomass technology development in USA. In: Sipilä K, Korhonen M, editors. Power Production from Biomass II with Special Emphasis on Gasification and Pyrolysis, VTT Symposium 164, Espoo: VTT; 1996.
[43] Beenackers AACM, Maniatis K. Gasification technologies for heat and power from biomass. In: Kaltschmitt M, Bridgwater AV, editors. Biomass gasification and pyrolysis, CPL Press; 1997.
[44] Karlsson G, Ekstrom C, Liinanki L. The development of a biomass IGCC process for power and heat. In: Chartier P, Beenackers AACM, Grassi G editors. Biomass for energy, environment, agriculture and industry, vol. 2. Oxford: Pergamon Press; 1995:1538–49.
[45] Haselbacher H. Gas turbines for electricity production from LCV gas. In: Kaltschmitt M, Bridgwater AV, editors. Biomass gasification and pyrolysis: state of the art and future prospects, CPL Press; 1997.
[46] Najewicz DJ, Furman AH. Pilot scale testing of biomass feedstocks for use in gasification/gas turbine based power generation systems. In: First Biomass Conference of the Americas, Golden Colorado: National Renewable Energy Laboratory; 1993:498–512.
[47] Kurkela E, Ståhlberg P, Laatikainen J, Simell P. Development of simplified IGCC processes for biofuels—supporting gasification research at VTT. Bioresource Technol 1993;46(1–2):37–48.
[48] Wiant BC, Carty RH, Horazak DA, Ruel RH. Biomass gasification hot gas cleanup for power generation. In: First Biomass Conference of the Americas, Golden Colorado: National Renewable Energy Laboratory; 1993:571–82.
[49] Newby RA, Lippert TE, Alvin MA, Burck GJ, Sanjana ZN. Status of Westinghouse hot gas filters for coal and biomass power systems. J. Engng Gas Turb. Power Trans. ASME 1999;121(3):401–8.
[50] Nolting E, Leuchs M. The use of gas from biomass in engines. Muich: M.A.N.-Neue Technologies, 1995.
[51] Daugas M. Pielstick tests on afb biogas diesels give promising results. Mod. Pow. Sys 1983;February:43–5.
[52] Vielhaber K. The use of process gases as sources of heat and power using spark ignition gas engines. In: Proceedings of the Institution of Diesel and Gas Turbine Engineers INPOWER 96 Conference, London; 1996.
[53] Tschalamoff T. Wood gas operation of spark ignited gas engines in the power range 100–2000 kW. In: Proceedings of the International Energy Agency Seminar: IC Engines for LCV Gas from Biomass Gasifiers, Zurich; 1997.
[54] Van de Welde J, Buekens A, Maniatis K. Product gas utilisation. In: Buekens AG, Bridgwater AV, Ferrero G-L, Maniatis K, editors. Commercial and marketing aspects of gasifiers, Luxembourg: CEC; 1990:90–114.
[55] Stassen H, Koele HJ. The use of LCV-gas from biomass gasifiers in internal combustion engines. In: Kaltschmitt M, Bridgwater AV, editors. Biomass gasification and pyrolysis: state of the art and future prospects, CPL Press; 1997.
[56] Simell P, Kurkela E, Ståhlberg P, Hepola J. Development of catalytic gas cleaning in biomass gasification. In: Sipilä K, Korhonen M, editors. Power Production from Biomass II with Special Emphasis on Gasification and Pyrolysis, VTT Symposium 164, Espoo: VTT; 1996.
[57] Gerrard AM, editor. A guide to capital cost estimating, London: UK Institution of Chemical Engineers; 2000.
[58] OECD. Main economic indicators, 1986–2000. Paris: OECD, 2000.
[59] Jelen FC. Cost and optimisation engineering. New York: McGraw-Hill, 1970.
[60] Taylor JH, Craven PJ. Experience curves for chemicals. Process Econ. Int 1979;1(1):13–28.
[61] Mitchell CP, Hudson JB, Gardner DNA, Storry PGS, Gray IM. Wood fuel supply strategies—volume 1: the report. Energy Technology Support Unit report ETSU B 1176-P1.
[62] Maniatis K, Buekens A. Fuel properties of biomass. In: Buekens AG, Bridgwater AV, Ferrero G-

L, Maniatis K, editors. Commercial and marketing aspects of gasifiers, Luxembourg: CEC; 1990:13–29.
[63] Kaltschmitt M, Rosch C, Dinkelbach L (Eds). Biomass gasification in Europe. European Commission report AIR3-CT-94-2284; 1998.
[64] Toft AJ. A comparison of integrated biomass to electricity systems. PhD thesis, Aston University; October 1996.
[65] Beckman et al. Techno-economic assessment of selected biomass liquefaction processes. VTT research report no. 697, VTT, Espoo, Finland; 1990.
[66] Scott DS, Piskorz J. The continuous flash pyrolysis of biomass. Can. J. Chem. Engng 1984;62:404–12.
[67] Scott DS, Piskorz J, Radlein D. Liquid products from the continuous fast pyrolysis pyrolysis of biomass. I&EC Process Des. Devel 1985;24:581–8.
[68] Agblevor FA, Besler-Guran S, Wiselogel AE. Plant variability and bio-oil properties. In: 2nd Biomass Conference of the Americas; 1995:1099–1110.
[69] Bridgwater AV, Peacocke GVC. Preliminary report of the fast pyrolysis of pine bark. Report to the New Zealand Forest Research Institute; 20 November 1995.
[70] Palm M, Piskorz J, Peacocke C, Scott DS, Bridgwater AV. Fast pyrolysis of sweet sorghum bagasse in a fluid bed. In: First Biomass Conference of the Americas, Golden Colorado: National Renewable Energy Laboratory; 1993:947–63.
[71] Bridgwater AV, Peacocke GVC. Biomass fast pyrolysis. In: Proceedings of the Second Biomass Conference of the Americas, NREL; 1995:1037–47.
[72] Liden AG, Berruti F, Scott DS. A kinetic model for the production of liquids from the flash pyrolysis of biomass. Chem. Engng Commun. 1988;65:207–21.
[73] Cuevas A, Reinoso C, Lamas J. Advances and developments at the Union Fenosa pyrolysis plant. In: Chartier P, Beenackers AACM, Grassi G editors. Biomass for energy, environment, agriculture and industry, 2. Oxford: Pergamon Press; 1995:1506–12.
[74] Czernik S, Scahill J, Diebold J. The production of liquid fuel by fast pyrolysis of biomass. Transactions of the ASME. J. Solar Energy Engng 1995;117:2–6.
[75] Elliott DC, Hart TR, Neuenschwander GG, McKinney MD, Norton MV, Abrams CW. Environmental impacts of thermochemical biomass conversion. Report no. NREL/TP-433-7867, National Renewable Energy Laboratory, Golden Colorado; 1995.
[76] Kuester JL. Diesel fuel via indirect liquefaction. In: Lowenstein MZ, editor. Energy applications of biomass, Amsterdam: Elsevier; 1984:263–73.
[77] Bridge SA. Flash pyrolysis of biomass for liquid fuels. M.Phil. thesis, The University of Aston in Birmingham; 1990.
[78] Solantausta Y, Bridgwater T, Beckman D. Electricity production by advanced biomass power systems. VTT research notes no. 1729, VTT, Espoo; 1996.
[79] Bridgwater AV. Capital costs of gasification and fast pyrolysis systems. Personal communication; June 1996.
[80] Garrett DE. Chemical engineering economics. New York: Van Nostrand Reinhold, 1989.
[81] Beckman D, Graham R. Economic assessment of a wood fast pyrolysis plant. In: Bridgwater AV, editor. Advances in thermochemical biomass conversion, Glasgow: Blackie Academic and Professional; 1993:1314–24.
[82] Black JW. Preliminary evaluation of the Waterloo fast pyrolysis process. Report to the University of Waterloo; June 1986.
[83] Diebold JP et al. IEA Techno-economic analysis of the thermochemcal conversion of biomass to gasoline by the NREL process. In: Bridgwater AV, editor. Advances in thermochemical biomass conversion, Glasgow: Blackie Academic and Professional; 1993:1325–42.
[84] Mitchell CP, Bridgwater AV, Stevens DJ, Toft AJ, Watters MP. Technoeconomic assessment of biomass to energy. Biomass Bioen 1995;9(1–5):205–26.
[85] Meriam JL, Kraige LG. Engineering mechanics, vol. 1. Chichester: Wiley, 1987.
[86] Morris S. Shell UK oil distribution. Personal communication; August 1996.
[87] Gilroy T. Linkman Tankers. Personal communication; August 1996.
[88] Leech J. Ormrod Diesels. Personal communication; 12 April 1996.

[89] McCullogh D. W H Allen. Personal communication; 2 March 1993.
[90] Verneau A, Sulle C. Flourinol turbine boosts diesel engine output by 10%. Mod. Power Sys 1995;September:45–9.
[91] Anon. Working cost and operations report, 1992. Trans. Inst. Dies. Gas Turb. Eng 1992;June:3–13.
[92] Vuorinen A. Competitive analysis of diesel power plant and gas turbine power plant. Wärtsilä Diesel Sales Conference 1992, Singapore; 28–29 October 1992.
[93] Hausermann WB. Electric power systems for small, new, or incremental-capacity addition in remote or underdeveloped areas. Report no. 95-EERC-08-04, University of North Dakota; September 1995.
[94] Zoellner S. ECNZ. Personal communication; 8 March 1996.
[95] Scott DH. Advanced power generation from fuel cells—implications for coal. IEA Coal research report IEACR/59, IEA Coal Research, London; 1993.
[96] Ismail A, Quick R. Advances in biomass fuel preparation, combustion and pollution abatement technologies. In: Klass DL, editor. Energy from biomass and wastes XV, Institute of Gas Technology, Chicago, USA 1991:1063–1100.
[97] International Energy Agency, Energy Prices and Taxes, 4th Quarter; 1998.
[98] TVA Generating Group. Biomass design manual. Alabama: US Southeastern Regional Biomass Program, 1991.
[99] Breag GR. Decentralised production of electricity from biomass. Presented at the Joule Contractors' Meeting, Athens; June 1993.
[100] Bloomfield RB. Wood and wood fuel handling. In: Elliott TC, editor. Standard handbook of power engineering, McGraw-Hill, New York, USA 1989:3.73–3.115.
[101] Prasad SB. Biomass-fired steam power cogeneration system: a theoretical study. Energy Conver. Manage 1995;36(1):65–77.
[102] Grass SW, Jenkins BM. Biomass fueled fluidised bed combustion: atmospheric emissions, emission control devices and environmental regulations. Biomass Bioen 1994;6(4):243–60.
[103] Institute of Waste Management. Report on fluidised bed technology as applied to waste incineration. IWM Business Services, Northampton; 1995.
[104] Golobic P, Shervill P, Ivey WP. Design and operation of a 7.2 MW_e wood waste cogeneration plant—a case history. In: Klass D, editor. Eelctricity from biomass and wastes XII, Chicago: Institute of Gas Technology; 1989:651–72.
[105] Evald A, Jakobsen HH. Experiences from 30 wood chip fired district heating plants in Denmark. In: Chartier P, Beenackers AACM, Grassi G, editors. Biomass for Energy, Environment, Agriculture and Industry 8th EC Conference, Oxford: Pergamon; 1994:1055–61.
[106] Tewksbury C. Wood combustion and NOx formation control. In: Klass DL, editor. Energy from biomass and wastes XV, Chicago: Institute of Gas Technology; 1991:95–128.
[107] McBurney B. A case study of a large scale wood waste power generating plant. Biologue 1995;1:5–11.
[108] Meridian Corporation. Case studies of biomass energy facilities in the southeastern US. Alabama: Tennessee Valley Authority, 1986.
[109] Staff Editors, Power Magazine. Steam turbine fundamentals. In: Elliot TC, editor. Standard handbook of powerplant engineering, New York: McGraw-Hill; 1989. pp. 2.3.
[110] Environmental Agency. Annual abstraction charges 1996–1997. HMSO, 1996.
[111] Takematsu T, Maude C. Coal gasification for IGCC power generation. IEA Coal Research; 1991.
[112] Personal communication. Severn Trent Water; July 1996.
[113] Blackadder WH, Lundberg H, Rensfelt E, Waldheim L. Heat and power production via gasification in the range 5–50 MW_e. In: Bridgwater AV, editor. Advances in thermochemical biomass conversion, Amsterdam: Elsevier; 1994:449–75.
[114] Ståhl K, Lundqvist R. Combined power and heat production based on thermal gasification of wood chips at Värnamo, Sweden. In: Chartier P, Beenackers AACM, Grassi G, editors. Biomass for energy, environment, agriculture and industry, Oxford: Pergamon Press; 1995:831–40.
[115] Herbert PK, Baguss I, Loeffler JC. Low Btu gas from bark and waste via CFB gasification. In: Klass D, editor. Electricity from biomass and wastes XII, Chicago: Institute of Gas Technology; 1989:731–52.
[116] Lindman N, Andersson CG, Liinanki L, Horvath A, Sala K. Integrated pressurised wood-gasifi-

cation combined cycle power generation. Presented at IGT Conference on Energy from Biomass and Wastes, Orlando, USA; 1992.
[117] Herbert PK, Baguss I, Loeffler JC. Low Btu gas from bark and waste via CFB gasification. In: Klass D, editor. Electricity from biomass and wastes XII, Chicago: Institute of Gas Technology; 1989:731–52.
[118] Chern SM, Walawender WP, Fan LT. Mass and energy balance analyses of a downdraft gasifier. Biomass 1989;18:127–51.
[119] Belleville P, Capart R. A model for predicting outlet gas concentrations from a wood gasifier. In: Bridgwater AV, editor. Thermochemical processing of biomass, London: Butterworths; 1984:217–28.
[120] Shand RN, Bridgwater AV. Fuel gas from biomass: status and new modelling approaches. In: Bridgwater AV, editor. Thermochemical processing of biomass, London: Butterworths; 1984:229–54.
[121] Maniatis K, Buekens AG. An empirical model for the design of fluidised bed gasifiers for biomass. In: Bridgwater AV, editor. Thermochemical processing of biomass, London: Butterworths; 1984:267–76.
[122] Buekens AG, Schoeters JG. Mathematical modelling in gasification. In: Bridgwater AV, editor. Thermochemical processing of biomass, London: Butterworths; 1984:177–200.
[123] Maniatis K. Fluidised bed gasification of biomass. PhD thesis, Aston University, UK; 1986.
[124] Anon. Development of standard procedures for gas quality in biomass gasifier/power generation systems. NOVEM report no.9608; 1995.
[125] Bridgwater AV, Elliott DC, Fagernäs L, Gifford JS, Mackie KL, Toft AJ. The nature and control of solid, liquid and gaseous emissions from the thermochemical processing of biomass. Biomass Bioen 1995;9(1–5):325–41.
[126] Faaij A, van Ree R, Oudhuis A. Gasification of biomass wastes and residues for electricity production. Report no. 95035, ECN, Utrecht University; June 1995.
[127] Anon. Low-Btu gas from wood to fuel 20-MW_e diesel CHP power plant. Cogeneration 1986;Sept–Oct:18–20.
[128] Walsh JL, Ross CC, Smith MS, Harper SR, Wilkins WA. Biogas utilization handbook. Atlanta: Georgia Institute of Technology, 1988.
[129] Moses CA, Bernstein H. Impact study on the use of biomass-derived fuels in gas turbines for power generation. NREL report no. NREL/TP-430-6085; January 1994.
[130] Palmer CA, Erbes MR. LM2500 fired on low Btu fuels. Final report to VTT, Menlo Park: Enter Software; 1992.
[131] Product guide part 3: aero-derivative. Mod Power Sys 1991;September:85–91.
[132] Personal communication from Y Solantausta, March 1994.
[133] Mesko JE. Economic evaluation of various cogeneration systems for a large university campus. ASME Cogen-Turbo 1991;6:87–94.
[134] Hurd PJ. Ruston Gas Turbines Ltd. Personal communication; 7 May 1991.
[135] Bressan L, Domenichini R, Trucco E. The 50 MW combined cycle of Fiat Progetto Energia. ASME Cogen-Turbo 1991;6:145–51.
[136] Polsky MP. Cogeneration. In: Elliot TC, editor. Standard handbook of powerplant engineering, New York: McGraw-Hill; 1989. pp. 2.195.