Review of the Potential for Large Bio-energy Plants

Report Number: 2006/TR3

Date: September 2006

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IEA Greenhouse Gas R&D Programme (IEA GHG), "Review of the Potential for Large Bio-energy Plants, 2006/TR3, September 2006".

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REVIEW OF THE POTENTIAL FOR LARGE BIO-ENERGY PLANTS

Background

IEA GHG is considering carrying out a study to assess the performance, costs and potential for bio-energy plants with CO_2 capture and storage (CCS). Such plants can be considered to have negative net emissions of CO_2. IEA GHG is also considering assessing the relative merits of a broad range of greenhouse gas abatement options, including bio-energy plants with and without CCS.

One of the key issues in studies on bio-energy is the plant size. It has been suggested that CCS may be economically unattractive for relatively small scale biomass plants because of high costs of CO_2 transportation. However, some of the authors of the IPCC Special Report on CCS (SRCCS) indicated that plants using 1000 MW_{th} or more of purpose grown biomass could be feasible. This scale of bio-energy plant is much larger than the 30-70 MW_e plants considered appropriate for Spain in an earlier study by IEA GHG.

The aim of this report is to provide a critical review and comparison of the key technical and economic assumptions presented in published papers on bio-energy plants, principally those referenced in the IPCC SRCCS.

Results and Discussion

As the capacity of a biomass energy conversion plant increases, the specific capital cost decreases due to economies of scale but the biomass costs generally rise as a result of increased transportation costs, as larger amounts of biomass have to be gathered from a wider area around the plant. This review has shown that the optimum scale of a bio-energy plant is site specific as it depends on how these costs vary with scale. Around the optimum capacity, however, there is a wide range over which the change in costs is small.

The key disparities in the referenced papers were assumptions made regarding the availability of the biomass fuel, in terms of the biomass yields and collection area around the conversion plant. The papers covered three broad scenarios. For locations where biomass density is low (e.g. due to low yields, land limitations, use of agricultural/forestry residues) the appropriate scale for a biomass energy plant was relatively small. For locations where most of the land around the conversion facility can be dedicated to biomass planting and/or biomass yields are relatively high, the optimum scale is reported to be higher, typically around 115 to 150 MW_e for power generation or around 600 MW_{th} for liquid biofuel production, for those references which take into account the effects of distance on biomass transportation costs. For the third scenario, where biomass by-products are generated from industrial processes, the economic optimum scale for the conversion plant will be dependent on the amount of biomass by-product available (i.e. the scale of the primary process) and alternative uses for the by-product. For example, modern pulp mills could fuel around 100 MW_e of power generation.

Differences in assumptions made regarding the costs of biomass collection and transportation and capital costs of the conversion plant were also shown to impact on the optimum biomass plant capacity. Lower capital cost estimates led to a lower cost of energy production and approached a minimum cost of energy at smaller plant capacities. Reducing the rate of increase in the transportation cost component with increasing plant scale resulted in higher optimum capacities.

Several studies used projections for future scenarios in which advanced bio-energy conversion technologies are commercially mature and operating on a large scale, and biomass yields are significantly higher than at present. In addition, a number of studies did not consider the impact of increased conversion plant size on the costs of biomass transportation. Both these assumptions lead to a higher estimate of the optimum biomass plant capacity.

Conclusions

The optimum size of bio-energy plants depends on the fraction of land around the plant which is devoted to biomass production, biomass yields per hectare, the relationship between biomass transportation distance and costs, and costs and economies of scale in the bio-energy conversion plant. The optimum size therefore depends on the characteristics of the site and the level of technology development.

A wide range of assumptions have been made in published bio-energy studies, resulting in different optimum plant sizes. Some of the studies which focused on particularly large plant sizes did not take into account the effects on costs of increased biomass transportation distances.

The addition of CO_2 capture and transportation will increase capital costs and is likely to increase the economic optimum plant size.

Recommendations

Any future studies by IEA GHG on the relative merits of GHG abatement options should include assessment of bio-energy plants at a range of different sites worldwide. The studies also need to be based on a clearly defined timeframe and assumptions regarding future technological improvements.

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Final Report
September 2006

Prepared for

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GLOSSARY

BCL:	Battelle Columbus Institute of Gas Technology
BCL/FERCO:	Battelle Columbus Laboratory/Future Energy Resource Company
BIGCC:	biomass integrated gasification combined cycle
BIG-GT:	biomass integrated gasification – gas turbine
CBP:	consolidated bio-processing
CCRs:	capital charge rates
CFB:	circulating fluidised bed
CHP:	combined heat and power
COA:	cost of alcohol
COA_{min}:	minimum cost of alcohol
COE:	cost of electricity
COE_{min}:	minimum COE
FB:	fluidised bed
GE:	General Electric
GEF:	Global Environmental Facility
GIS:	geographic information system
HHV:	higher heating value
IGCC:	integrated gasification combined cycle
IGT:	Institute of Gas Technology
IPCC:	Intergovernmental Panel on Climate Change
IPPM:	integrated pulp and paper mill
LCV:	lower calorific value
MPM:	market pulp mill
NC:	north central
NREL:	National Renewable Energy Laboratory
O&M:	operations and maintenance
ORECCL:	Oak Ridge National Laboratory database
R&D:	research and development
RDF:	refuse-derived fuel
SE:	south east
SMR:	steam methane reforming of natural gas
SRC:	short-rotation woody crops
UN:	United Nations

REVIEW OF THE POTENTIAL FOR LARGE BIO-ENERGY PLANTS

1 INTRODUCTION

There is considerable interest in many regions of the world in the use of biomass to produce energy and biofuels, either in dedicated plants or in combination with fossil fuels. Although many dedicated biomass energy systems are currently less economically attractive compared to their fossil fuel counterparts, they offer benefits such as greenhouse gas mitigation, saving of fossil fuel, local economic development and waste reduction. There is also interest in biomass energy plants with CO_2 capture and storage (CCS), as these offer the prospect of generating electricity with a net 'negative emission' of CO_2.

A number of different thermal conversion technologies are available or are being developed for utilisation of biomass to produce energy, in the form of electricity, heat or biofuels (such as ethanol and methanol). For large scale systems these largely involve technologies based on integrated gasification combined cycle or fluidised bed combustion.

A key issue posed by biomass energy production is that of scale. Current biomass energy production plants are much smaller than fossil fuel power plants; typical plant capacities are about 30 MW_e compared to coal fired of several hundred MW_e. Most biomass energy production plants are considered to be located in the area where the biomass is produced and the scale of the facility depends largely on the availability of these supplies. Agricultural and forestry residues tend to be dispersed in nature and must be gathered from a wide area around the energy production facility. However, locations with concentrated biomass sources, such as pulp mills and sugar processing plants or high density dedicated biomass plantations, could favour larger plant capacities.

Previous work by the IEA Greenhouse Gas R&D Programme surveyed 28 favoured sites in Spain using woody biomass crops and concluded that the average appropriate scale for a biomass energy plant would be in the range 30 to 70 MW_e[1]. This figure is based on the fact that transport distances longer than the assumed maximum of 40 km would render larger plants uneconomic. A recent IPCC Special Report on carbon dioxide capture and storage, however, referenced a number of studies which inferred that biomass plant capacities of up to 1,000 MW_{th} could be technically and economically feasible.

This report provides a critical review and comparison of the key technical and economic assumptions presented in the papers referenced[2,3,4,5,6,7,8] in the IPCC Special report[9], in order to assess the potential for large scale biomass energy plants. Section 2 of the report gives a review of current major commercial and demonstration biomass energy projects undertaken to-date. A critical review of assumptions and findings of the IPCC referenced studies is shown in Section 3, whilst comparisons between the studies are made and discussed in Section 4.

2 REVIEW OF MAJOR BIOMASS ENERGY PLANT

The main biomass conversion systems for large scale generation of heat and power are based on direct-fired gasification, combustion and indirect firing of biomass in an existing power plant. Although biomass can also be co-fired with coal in an existing power plant furnace, this option does not involve a dedicated biomass conversion plant and is not discussed in this report. Large scale biomass conversion plants can also be used to generate liquid fuels, such as ethanol.

2.1 Gasification

For electricity generation, gasification of biomass typically involves reacting biomass in a gasifier with air or oxygen to produce a fuel gas (also known as syngas). The fuel gas is subsequently cleaned and fired in a gas turbine to generate power. The hot exhaust gas is recovered and used in a heat recovery boiler to produce steam for the steam turbine which generates further power. The overall system is known as a biomass integrated gasification combined cycle (BIGCC).

Biomass is very reactive and often has a high moisture content and there are several gasifiers that have been developed particularly for biomass. Fluidised bed gasification tends to be the preferred technology; often operating at atmospheric pressure, which makes feeding the biomass into the gasifier easier.

BIGCC offers the means for higher power generation efficiency. However, although there are several coal fuelled integrated gasification combined cycle (IGCC) facilities operating at a commercial-scale, some of which co-gasify biomass/MSW components, there are no dedicated biomass fuelled IGCC facilities operating commercially. The development and implementation of BIGCC systems is complex as it involves all components from fuel production to power generation.

During the past 20 years a significant research and technology development and demonstration effort has been launched in Europe and North America. The European Union, through the THERMIE energy program, has been supporting commercial scale IGCC demonstration systems fuelled by biomass (Arbre and Bioelettrica) and at least three projects were undertaken in the US which had varying degrees of success. The key large scale BIGCC demonstration that ran for any significant length of time, and was widely recognised for its technical success, was at Värnamo, Sweden between 1996 and 2000.

The major IGCC demonstration projects undertaken to date are listed in Table 2-1. The majority of these demonstration plant are small in scale, i.e. <32 MW_e. The only large scale project (75-100 MW_e) was located at Granite Falls, USA, in an area with a dedicated, high planting density of biomass. However, the project was cancelled when key financing partners withdrew from the project because of uncertainties with fuel supply and biomass gasification technology at this scale.

Table 2-1 Examples of biomass IGCC plant

Name	Location	Output MW_e	Fuel	Gasifier	Status	Achievement	Year
Arbre	Yorkshire UK	9	Wood	CFB, TPS with tar cracker	Cancelled due to managerial & financial issues	Gasifier & GT operational	1998 - 2002
BIG-GT	Brazil	32	Wood, Bagasse	TPS CFB	Cancelled due to high project cost	Design of 32 MW_e plant	~2004
Bioelettrica	Italy	14	Wood, biomass residues	Pressurised CFB	Cancelled due to technical & non-technical problems		2003
Burlington	Vermont, USA	(200 t/d)	Wood	Battelle dual FB	Cancelled due to funding issues	Successful demonstration of commercial scale gasifier	2003
Granite Falls	USA	75-100	Alfalfa stems	GTI pressurised FB	Cancelled due to funding issues	Biomass supply agreements	1999
Maui	Hawaii, USA	(100 t/d)	Bagasse	Pressurised FB	Cancelled due to fuel feeding problems	Gasifier operational	1997
Värnamo	Sweden	6	Wood wastes	Pressurised CFB, Foster Wheeler	Mothballed – economic reasons	Demonstration successful	1993-2000

Two of the key biomass IGCC demonstration projects are described below, namely the BIG-GT and Värnamo projects, whilst details of the other existing and recently proposed projects are given in Annex I.

BIG-GT, Brazil

Development funds for the Brazilian Biomass Integrated Gasification-Gas Turbine Project (BIG-GT) demonstration plant located in Bahia, North-Eastern Brazil, were provided by the World Bank and the UN through a program called Global Environmental Facility (GEF). The project aimed to construct and operate a 32 MW_e biomass-fuelled, integrated, combined-cycle power station fuelled by eucalyptus wood. Around $8 million was granted to do all preliminary development work including fuel resource study, environmental impacts, plant component specification and selection and final design.

The TPS gasification process and a GE gas turbine were selected. The facility used wood as the primary fuel, collected from a short rotation cultivation operation that was part of the project. In the process schematic shown in Figure 2-1[10], the wood feed is chipped and dried (using waste heat) on-site. The dried wood chips are gasified in the air-blown fluidized bed gasifier (1.8 bar). The product gas is cleaned to remove tars, ammonia and particulates and burned in a gas turbine. Hot flue gas from the gas turbine is led into a heat recovery boiler producing steam that is in turn led into a steam turbine.

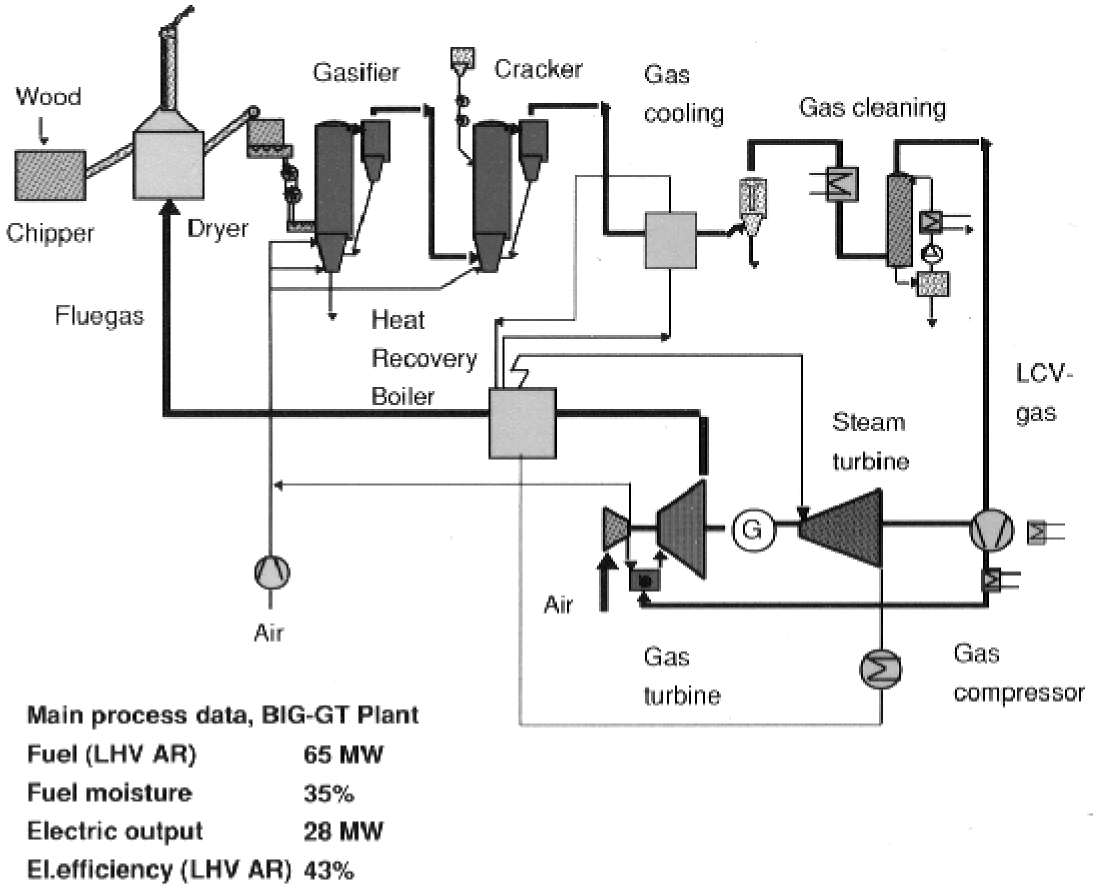

Figure 2-1. Process Schematic of TPS Termiska Atmospheric Pressure BIG-GT Demonstration Project (Reference 10)

Phase II of the project involved an economic and risk evaluation of the Brazil BIG-GT project[10]. The projected cost breakdown of producing the wood fuel is outlined in Table 2-2.

The total plant cost was estimated to range from $1830/kW to $2180/kW. From the planning and design phases, the plant installation cost was estimated at $112 million (including land costs and short rotation crop operation). The project has not proceeded beyond the design stage. Apparently the high cost of the project and a downturn in the economy contributed to a decision not to continue.

Table 2-2. Projected cost of wood stumpage, harvesting, transport, and in-plant handling and chipping (Reference 10)

Cost Item	US \$/m ton (0% m)	US \$/GJ	US \$/MBtu	% of Total
Price of Wood on the Stump	13.75	0.70	0.74	35.6%
Price of Cutting	6.19	0.31	0.33	16.0%
Price of in Field Transport	5.57	0.28	0.30	14.4%
Price of Loading	4.02	0.20	0.22	10.4%
Price of Freight	4.33	0.22	0.23	11.2%
Social Tax	0.8	0.04	0.05	2.3%
Price of in Plant Wood Handling	0.89	0.05	0.05	2.3%
Price of Wood Chipping	2.96	0.15	0.16	7.7%
Total Price of Wood Delivered to Dryer	**\$38.60**	**\$1.96**	**\$2.07**	**100.0%**

Värnamo, Sweden

The Värnamo plant was the world's first biomass-fuelled IGCC plant that operated successfully for extended periods of time. This demonstration facility produced power and heat (6 MW_e, 9 MW_{th}) and was developed by Sydkraft AB and Foster Wheeler International. The gasifier was a pressurized air-blown circulating fluid bed reactor that operated at pressures of 18-22 bar. The facility used finely ground, dried wood and bark feedstock (10 to 20% moisture content) delivered to the power generation site from an adjacent preparation facility.

The gas cleaning system consisted of a cyclone separator, followed by heat exchanger to cool the gas to about 350ºC (from around 900ºC) thereby condensing alkali vapours on particulate matter. The partially cooled gas was passed through a barrier filter (ceramic and/or sintered metal 'candle' filters). The tar and alkali contents in the filtered gas were less than 5 $g.m^{-3}$, and 0.1 ppm (by weight) respectively. The filtered gas was then fired in a gas turbine (European Gas Turbines Ltd). To handle the low calorific value fuel gas, the natural gas turbine burners and their enclosing cans were enlarged in size. The exhaust gases from the gas turbine (at 450°C) passed through an Ahlstrom heat recovery steam generator to produce superheated steam. A Nadrowski steam turbine was used to generate electricity. The turbine air compressor produced 10-12 bar air, which was compressed further in a booster compressor to produce gasification air at 20 bar pressure. The gas turbine generated around 4 MW_e, and the steam bottoming cycle produced an additional 2 MW_e.

The Värnamo gasification system has more operational experience than any other biomass fired gas turbine system. By 1999, the accumulated operating experience at the plant amounted to about 8,500 hours of gasification runs and 3,600 hours of operation as a fully integrated plant. The test runs were successful and the plant was operated on different wood fuels as well as straw and refuse-derived fuel (RDF). The demonstration programme was concluded in 2000 and the plant has been mothballed since then as it is not economical to operate given the commercial conditions prevailing in Sweden. The facility was built as a near-commercial demonstration and was not intended to provide long-term power generation on a commercial basis.

2.2 Direct-Fired Combustion

Most of today's biomass power plants are direct-fired systems that are similar to most fossil-fuel fired power plants. The biomass fuel is burned in a boiler to produce high-pressure steam for the steam turbine which generates electricity.

While steam generation technology is very dependable and proven, its efficiency is limited. Biomass power boilers are typically in the 20-50 MW_e range, compared to coal-fired plants in the 100 to over 600 MW_e range[11]. The smaller capacity plants tend to be lower in efficiency because of economic trade-offs; efficiency-enhancing equipment cannot pay for itself in small plants.

Although techniques exist to push biomass steam generation efficiency over 40%, actual plant efficiencies are in the low 20% range.

A number of different combustion technologies are available for biomass, however, fluidised bed combustion plant are typically selected for large scale applications (normally exceeding 30 MW_{th}). For smaller plants, fixed bed systems are usually more cost-effective. The combustion installation needs to be properly designed for the specific fuel type in order to guarantee adequate combustion quality and low emissions.

An example of a biomass heat and power boiler is the Brista Kraft 122 MW biomass CFB plant (with a power output of 44 MW and heat output of 75 MW) located in the area around Stockholm, Sweden. The boiler is a compact second-generation CFB from Foster Wheeler Energia Oy, Finland, and the steam turbine is from ABB in Stal, Sweden. Wood chips are used as the main fuel, and peat is the support fuel. The plant is designed to burn 250 million to 300 million kilograms of wood waste annually.

2.3 Indirect co-firing of biomass

Indirect co-firing of biomass involves either (a) pre-gasifying the biomass in a separate plant and firing the syngas produced in a conventional boiler or (b) firing the biomass in a separate combustor and routing the steam to the main turbine. The technology has a major advantage over direct co-firing in that the coal ash is not contaminated by any constituent of the biomass fuel and that these constituents cannot cause corrosion or slagging in the main plant. Furthermore the total biomass fuel capacity is not limited by existing constraints imposed by installed hardware and any problems with the biomass plant will not result in the whole power plant being shut down. However, the major disadvantage of indirect firing is that installation costs are very much higher than for direct firing.

There are currently a number of projects in Europe and North America in which small scale, biomass fired gasifiers or combustors are built alongside existing stations to partially repower the existing boiler. The major indirect co-firing projects are listed in Table 2-3[12,13]. Biomass plant capacities based on gasification technologies range from around 4 MW_e to 30 MW_e, whereas biomass energy conversion plant based on combustion technologies are typically larger ranging from 40 to 70 MW_e. The Lahti project is described below, whilst details of other commercial and demonstration projects are given in Annex 1.

Lahti

In 1997-98, the Lahden Lämpövoima Oy, installed a 60 MW_{th} atmospheric pressure Foster Wheeler CFB biomass gasifier at its 200 MW_e fossil fuel fired power station in Lahti, Finland. The aim of the project was to demonstrate commercial scale gasification of a wet biofuel and the use of hot, raw, low calorific gas directly in an existing coal-fired boiler which currently produces 167 MW_e and 240 MW_{th} of district heating. The biomass gasification plant was installed primarily to use locally available fuels and waste materials; these include biofuels such as bark, wood chips, saw dust and recycled fuel (e.g. plastics) from households, offices etc.

The gasifier is of the atmospheric circulating fluidised bed type and is a single gasifier vessel with a cyclone and an air preheater for heating the gasification air to approximately 400°C. The LCV gas is cooled from approximately 830-850°C to 700°C before it is transported in a pipeline to the boiler. The raw gas has no adverse effect on the performance of the boiler. Emissions are reduced and the heating surfaces in the boiler stay relatively clean.

The present breakdown of fuels in the boiler is approximately: 11% LCV fuel gas from the gasifier, 69% coal, 15% natural gas to boiler and 5% natural gas to gas turbine. The annual average total efficiency is approximately 80% and the fuel to power efficiency with the gas turbine in operation is 35%. The gas turbine has increased the efficiency by 4% points. The gasifier output varies between 35 and 70 MW_{th}.

Table 2-3. Examples of indirect co-firing plant

Name	Location	Output	Fuel	Biomass Conversion Technology	Status	Year
Energy Farm	Italy	12 MW_e	Short rotation forestry	Lurgi CFB gasifier	Construction	2000
Lahti	Finland	35-70 MW_{th}	Wood wastes	Gasifier	Operational	1998
McNeal	USA	~15 MW_{th}	Wood chips	Gasifier	Operational	1997
New Bern	USA	<60 MW_{th}	Black liquor	Gasifier	Operational	1997
Ruien	Belgium	50 MW_{th}	Wood wastes	Gasifier	Operational	2003
Vermont	USA	42 MW_{th}	Wood	Gasifier	Demonstration finished	2000- 2004
Zeltweg	Austria	10 MW_{th}	Biomass/ wastes	Gasifier	Shut down	1997 - 2001
Aabenraa	Denmark	40 MW_e	Wood chips/ straw	Combustor	Operational	1998
Avedøre 2	Denmark	40 MW_e	Wood chips/ straw	Combustor	Operational	2002
Västerås	Sweden	70 MW_e	Biomass	Combustor	Operational	2000

2.4 Biofuel Production

At present, the most common biofuels are ethanol, ethyl tertiary-butyl ether (ETBE) derived from ethanol, and biodiesel. Ethanol, the most widely-used biofuel, is currently produced by fermentation of grain or sugar crops. In the future, ethanol may also be produced from lignocellulosic biomass such as woody or herbaceous crops. Ethanol is used extensively in North America and Brazil where it is typically used to supplement rather than replace gasoline. ETBE is produced by catalytically reacting ethanol with petroleum derivatives. ETBE is used primarily in parts of Europe where it is typically blended in motor gasoline. Biodiesel is produced from the esterification of vegetable oils or waste fats. Biodiesel is typically used in both North America and Europe and can be mixed with or replace diesel fuel.

In addition to the interest in biological conversion of biomass to ethanol, there is also substantial current interest in the thermal conversion of this resource to ethanol. Thermal conversion technologies offer the potential of high conversion efficiencies because they utilize all the major components of the biomass resource. In the thermo-chemical conversion process, biomass would be gasified to form a synthesis gas composed primarily of carbon monoxide, carbon dioxide and hydrogen. Biomass thermal gasification technologies for synthesis gas have been under development for several years, and several demonstration facilities are operating.

The synthesis gas produced by biomass gasification would subsequently be used to produce ethanol, using either a catalytic or biological process, or a combination of both. The catalytic process would be similar to those used in the petrochemical industry to produce chemicals such as methanol. As an alternative, the synthesis gas could potentially be converted to ethanol using micro-organisms.

Basic research is being conducted on biological conversion of synthesis gases at several locations. Several small-scale proof-of-concept facilities relating to thermal ethanol production are being built or are operating in North America. Bioresource Engineering Inc. has developed synthesis gas fermentation technology that can be used to produce ethanol from cellulosic wastes with high yields and rates[14]. A gasification/biocatalytic process developed for BRI Energy enables the co-production of electricity and ethanol (and/or hydrogen) from biomass. The BRI process utilizes a culture of acetogenic bacteria (*Clostridium ljungdahlii*) that ingests synthesis gas from the gasified biomass (or waste) and generates ethanol at a yield of some 75 gallons or more per dry ton of biomass[15]. Syntec Biofuel Inc. ("Syntec"), has also developed a Gasification-Catalytic Synthesis process to convert biomass into ethanol[16].

3 NEW DATA ON ECONOMICS OF LARGE SCALE BIOMASS ENERGY PLANT

A critical review of studies referenced in the IPCC Special Report on carbon dioxide capture and storage, which inferred that biomass plant capacities of up to 1,000 MW_{th} could be technically and economically feasible, is given below. The key technical and economic assumptions which lead to the referenced study conclusions regarding economic viability of large scale biomass power plant are summarised. Where possible, the papers were followed up to major primary data source studies and/or the author was contacted to obtain the necessary information. The references reviewed are shown below in alphabetical order (by the primary author's name)[i]. A number of the papers examine a range of potential biomass to energy conversion technologies. To allow comparisons between these papers, this review has focussed on BIGCC and fluidised bed combustion technologies for power generation. Technologies reviewed for biofuel production are based on gasification and/or enzymatic hydrolysis. Comparisons of the key assumptions and results of the studies are discussed in Section 4.

3.1 Audus and Freund, IEA GHG, UK (Reference 1)

The IEA GHG paper titled "Climate change mitigation by biomass gasification combined with CO_2 capture and storage" considers the application of CO_2 capture and permanent storage to the production of electricity by biomass gasification. Combining CO_2 capture and permanent storage with biomass conversion to energy would result in a net removal of CO_2 from the atmosphere. The potential CO_2 reduction for a processing scheme based on the production of electricity from short-rotation woody crops (SRC) grown in a sustainable manner is assessed. The SRC is converted into electricity in an integrated gasification combined cycle (BIGCC). The study was based on previous work on such schemes and reports on the emissions, technology and cost implications if the process is altered to include the addition of CO_2 capture and permanent storage.

The main focus of the paper was on the use of purpose-grown biomass crop in a 'stand-alone' context, i.e. the source of fuel, power plant and CO_2 storage are all local and not integrated into larger schemes. The paper also considered the use of biomass by-products, i.e. the source of fuel is a residue from a commercial activity.

In previous IEA GHG reports[17,18] infrastructure requirements, such as land availability, accessibility to water, roads, distance to the electricity grid etc., were evaluated and used to derive optimum power plant sizes for 28 potential sites in Spain. The size of the plant was determined according to two main criteria. The biomass plantations had to be located inside a circle of 40 km radius around the power plant, and the total land needed for each plant was a maximum of 10% of the available non-irrigated arable land (assumed to be a minimum of 700 km^2) in that circle.

Biomass Production and Costs

Short-rotation woody crops (SRC), such as acacia and eucalyptus were selected for the study. The harvesting was carried out in short rotation, 3 year intervals with 5 harvests per cycle; 2 cycles of

[i] *Costs and weights in this report are given as US dollars and metric tonnes. Costs quoted in euros in the referenced papers have been converted to US dollars assuming an exchange rate of 1.25€ to the dollar and have not been escalated from the reference figures. Weights given in short US tons were converted to metric tonnes (1 short US ton = 0.907 metric tonnes).*

planting, harvesting and clearance would be needed to cover the life of the biomass power plant (30 years). The average biomass harvested per km^2 was calculated to be 1,330 tonnes (dry material) per year.

A simple approach was assumed regarding the ownership along the fuel cycle: a single utility company, the 'Power Company', would be the owner of the biomass power plant. The Power Company would assume the costs associated with the production of the biomass fuel, i.e. it would manage and pay for nurseries, farming, harvesting, transportation and storage of biomass. It was also the tenant of the land rented from the farmers. The price of the land was assumed to be similar to the current land devoted to cereal and sunflower crops. The land rented also included the area required for nurseries, plantations, threshing floors, specialised machinery hangers, power plants and silos. The Power Company also accepts the commitment to return the land to the farmers, once the lifetime of the power plants has ended, in the same conditions as they were at the beginning of the project. On average, the cost of land contributed 22% to the cost of the biomass fuel and about 10% to the cost of electricity. There was little correlation between the land price and the cost of electricity, mainly because the more expensive (better) land gives higher yields of biomass.

The assumed planting density was 100 plants per km^2. The plantation area was assumed to be 10% of the cultivated land within the maximum radius of 40 km and estimated to be around 118 km^2 [(ii)]. The net yield of biomass averaged about 133,000 tonnes of dry matter/yr[(ii)] (i.e. around 1,130 $t/km^2/y$); the availability of water was the main criteria used to assess potential yield. Around 50% of the cost of the biomass was attributed to transport and harvesting.

The total cost of producing the SRC was 54 \$/dry tonne and comprised of costs for activities associated with implanting, growth, harvesting, transport, stumping, land rent and capital costs. The main contributors to biomass costs were transport, harvesting and land rent, which correspond to around 28%, 19% and 22% of the total crop production costs respectively.

Transportation of the harvested biomass to the power plant involved:

a) In areas closest to the power plant (5/12 of the plantation area), the biomass was harvested using a chipper and the chips loaded onto trailers and transported by tractor directly to the power plant. The costs for transporting the chips were based on total time taken and the price per hour for loading and transport by tractor and trailer (i.e. 26.9 \$/h). The maximum distance travelled was around 12.5 km and the average distance 8.8 km[(ii)]. The total time taken for transporting the production of one square kilometre was estimated to be around 1,210 hours[(ii)]. The moisture content at the moment of harvesting was assumed to be 50% by weight.

b) For longer distances (the other 7/12), the biomass stems were collected and transported to a store, where they were dried and chipped. The chips were then taken to the power station by means of 24 tonne lorries. Costs for transporting the stems to the store were based on the time taken to collect, transport and unload the stems (26.9 \$/h for an average transport time of 950 hours per km^2). Costs for transporting the chips were based on the distance travelled. Transportation costs for the first 10 km was assumed to be \$2.3 per tonne of the lorry (using a 24 tonne lorry). For distances greater than this, the price per km rises at \$0.03 per tonne of weight of the lorry. The moisture content of the SRC (chips) to be transported was assumed to have stabilised at 27% of dry weight.

The maximum distance (one-way) travelled was estimated to be 31.3 km and the average distance 22.1 km[(ii)]. Total transport costs were estimated to be 15 \$/dry tonne.

Biomass Conversion

The focus of the referenced study[1] was biomass gasification integrated in a combined cycle (BIGCC). Based on the above assumptions regarding biomass availability in a 40 km radius, the

[ii] *Average data used for sites 27 and 28 in Reference 18.*

optimum average plant size was rated at 36 MW_e. The 30 MW_e plant was used as the basis for comparisons in this paper. A future efficiency of 40% (LHV) was assumed, which included parasitic consumption of the plant. The calorific value of the SRC used for the study was 18.3 MJ/dry tonne, LHV.

Economic Evaluation

The capital cost of the 30 MW_e BIGCC plant was estimated to be 56 million US$. This equates to a specific cost of $1870/kW[1]. A scaling cost exponent of 0.7 was used for the evaluation.

The levelised cost of electricity (COE) was 8.1 cents/kWh at a 10% discount rate over a 30 year lifetime (which coincides with 2 plantation-cycles of 15 years; assuming a more standard year lifetime makes little difference to the cost of electricity). The load factor was assumed to be 85% of rated capacity, i.e. 7,500 hours per year. The COE breakdown was fuel 50.7%, O&M 21.1% and capital costs 28.2%.

Potential By-Products Options

The possibility of introducing BIGCC with capture and storage of CO_2 into paper pulp mills and sugar cane processing was also considered. The study focuses on the additional costs and benefits of adding CO_2 capture and storage. This was done by applying the costs of treating syngas to capture CO_2 (for a free-standing power station) to the biomass by-product derived syngas. The optimum size of the BIGCC plant will be dependent on the scale of the primary process (i.e. the quality and quantity of the biomass by-product) and alternative uses for the by-product.

Summary

The study by Audus and Freund examines the potential CO_2 reduction for a processing scheme based on the production of electricity from short-rotation woody crops (SRC) grown in a sustainable manner. The study is based on previous work on such schemes which involved a detailed evaluation of the biomass production and infrastructure requirements for 28 potential sites in Spain. The optimum average plant size was rated at 36 MW_e based on predictions for biomass productivity of 1,130 dry tonnes per km^2 per year, i.e. the plantation area was assumed to be 10% of the cultivated land within the maximum radius of 40 km and the net yield of biomass averaged about 133,000 tonnes of dry matter per year. The average cost of biomass ($54 per dry tonne) was comparable to biomass cost estimates for other studies in this report. Typical transport costs were $15 per tonne (over an average two-way distance of 44 km). The scaling exponent for capital costs of a BIGCC plant was 0.7.

3.2 Dornburg and Faaij, University of Utrecht, The Netherlands (Reference 2)

The work reported by Dornburg and Faaij on "Efficiency and economy of wood-fired biomass energy systems in relation to scale regarding heat and power generation using combustion and gasification technologies" is a study of a variety of biomass conversion options with different performance characteristics to identify optimal systems[2]. To allow comparison with the other referenced work in this report, data and assumptions for the atmospheric pressure fluidised bed combustion and BIGCC systems using clean wood as a fuel were investigated. The study was carried out for Dutch conditions.

Methodology

The economic and energetic performance of biomass energy systems is dependent on many variables, such as costs of logistics, scaling effects and the degree of heat utilisation. In this study, different biomass energy systems were analysed to establish their efficiency and economic performance related to fossil fuel primary energy savings. The biomass energy systems considered produce different energy carriers, namely heat and/or power. Fossil primary energy savings were chosen as the functional unit to which costs and energy efficiencies of the biomass energy systems were related (referred to as primary energy savings). The performance of the systems was expressed as a function of scale. This was done by applying generic functions to describe plant efficiencies and specific investment costs and by comparing the electrical and heat output and costs from the biomass plant with a coal fired plant of comparable scale.

Biomass Production and Costs

The study uses clean wood (forestry residues) as the biomass fuel and the cost was assumed to be 4.75 \$/GJ (LHV); based on typical costs quoted for Europe. This price covered production costs and was based on a study of conditions prevailing in The Netherlands; the transport cost component of the biomass fuel was considered separately[19].

To investigate the influence of fuel on the total costs, the utilisation of waste wood (industrial waste wood, demolition wood and wood products) was also considered. It was noted that the use of waste wood is more feasible in larger systems due to additional gas cleaning requirements. The cost of the waste wood was assumed to be 0 \$/GJ at the plant gate[2].

It was assumed that the distribution of biomass over the production area was constant. The biomass distribution density in tonnes per km^2 was assumed to be 46 for clean wood and 24 for waste wood[iii].

The transport distance was assumed to be the radius of a circle in which the biomass is spread. Two transfer operations are assumed to take place, both by road in multiple loads of 28 tonnes[iv]. The biomass was harvested and transported (by road) to a transfer point and transported (by road) to the conversion unit[20]. The conversion plant was assumed to be located outside the biomass plantation. The minimum distance for the first transfer (to the transfer point) was 20 km and for the second (to the conversion unit) 100 km. The specific transport costs (\$ per tonne km) were assumed to be 7.25 x (transport distance in km)$^{-0.6}$ and the costs of transfer were given as 0.35 \$/tonne[v].

From the data given by the authors it was calculated that a 100 MW_{th} BIGCC plant using wood chips (20 MJ/kg HHV) operating for 8,000 hours per year will require around 144,000 tonnes of wood per year. Assuming a biomass yield of 1,200 dry tonnes/km^2/y and that the percentage of land used for energy farming around the plant is 20%[iii], the collection area will be 600 km^2. By comparison, a 300 MW_{th} plant will require around 432,000 tonnes of wood per year and the collection area will be 1,800 km^2.

Biomass Conversion

The referenced study investigates a broad variety of combustion and gasification technologies producing heat, CHP or power at different scales. This report focused on the atmospheric pressure fluidised bed gasification system using a combined cycle (BIGCC) and atmospheric pressure fluidised combustion system using a steam cycle (FBC). Generic data on these processes and economic performances of these technologies were collated from a range of referenced work.

Economic Evaluation

For power generation, BIGCC and FBC system plant capacities of 10 to 300 $MW_{th\text{-}input}$ and 10 to 200 $MW_{th\text{-}input}$ respectively were investigated. Power generation was calculated with a full-load operation time of 7,000 hours per year. The operating costs were assumed to be 4% of the total capital (investment) costs, the rate of real interest was 4% and life span of the plant was 25 years.

[iii] *This value was assumed be to on a per year basis but appears to refer to the average distribution density over The Netherlands (Ref. 19). A further reference by the same authors clarified that the assumed average annual biomass yield was 1,200 dry tonne per km² and a percentage of land used for energy farming around the plant was 20% (Ref.20).*
[iv] *The referenced NOVEM report detailing further information on transfer operations was written in Dutch. The author of this report was unable to obtain a copy in English.*
[v] *This value equates to an average total transport distance of around 155 km. A further reference by the authors clarified that the total logistic costs were in the order of 16 \$ per dry tonne biomass (Ref.20).*

Scale effects for capital costs and efficiencies are calculated as a power function. In this study, trendlines of efficiencies and investment costs were composed by regression techniques, mainly based on real plant data. Details of power values used were not specified but, from the data provided, calculated to be an average of 0.7 for specific investment costs and around 0.1 for electrical efficiency (η). For the BIGCC system, this equated to a value of 41% for η at the 100 MW_{th} scale compared to 46% at 300 MW_{th}. The electrical efficiency of a 200 MW_{th} FBC system was estimated to be 33%. Specific capital costs for a 100 MW_{th} BIGCC plant were 1,250 $/kW_{th}$ compared to 870 $/kW_{th}$ at the 300 MW_{th} scale (€ to US$ exchange rate was assumed to 1.25). This compared with a specific capital cost of 870 $/kW_{th}$ for the 200 MWth FBC plant.

The plant electrical efficiency for the Dutch coal fired heat and power case was assumed to be 43% (LHV) and the thermal efficiency 90% (LHV).

The study assumes that the heat and power generated by the biomass fired plants was sold at current Dutch prices (i.e. cost of electricity = 8.1 $/GJ and cost of heat = 4.5 $/GJ) and the performance was calculated relative to the average efficiency of current fossil fuel heat and power plants. A reimbursement for installed power generating capacity of 119 $/kW_e$, paid by Dutch government, was also taken into account. The electricity price and the reimbursement, together with the assumed operational time, resulted in an electricity revenue of around 12.9 $/GJ or 0.045 cents/kWh.

The economic performances of both the biomass fired BIGCC and FBC systems were shown to improve with increasing scales from 10 to 300 MW_{th} and from 10 to 200 MW_{th} respectively; i.e. with the assumptions made within the report, scale effects of decreasing specific investment costs and higher revenues from power sales due to increasing efficiencies, prevail over the increasing costs for logistics. The costs per unit of primary energy saved with clean wood firing as a function of scale showed an exponential trend in Figure 3-1.

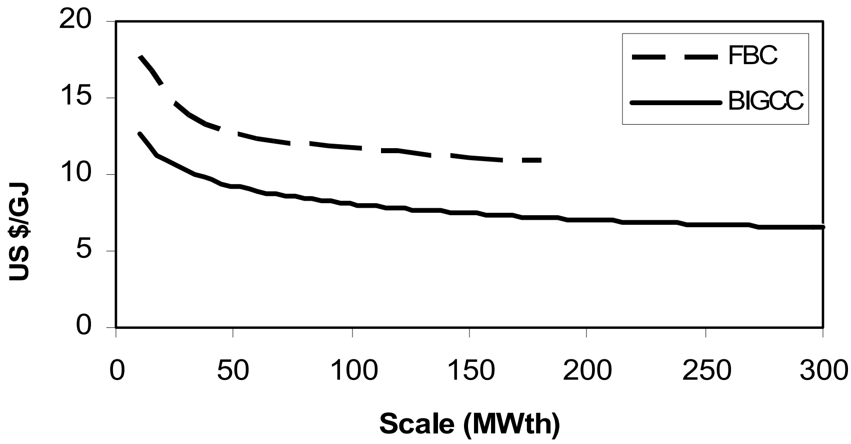

Figure 3-1. Costs per unit of primary energy saved with 'clean' wood firing for the BIGCC and FBC cases (Reference 2)

The economic performance of firing waste wood was significantly better than that for clean wood due to the assumption that the delivered cost of the waste wood was zero.

Sensitivity studies showed that the most important parameters with respect to process economics were biomass costs, annuity (rent and lifetime), investment costs, lower heating values, plant efficiency, transport costs and electricity prices (for the Dutch case).

Further Information

Contact by e-mail with the author, Andre Faaij, revealed that a recent study on the development of an optimisation tool which optimises a biomass and waste treatment system for a given amount of biomass and/or waste has been undertaken by the University of Utrecht[21,22]. This optimal system is characterised by scale, location and type of technology and important aspects that are taken into account include biomass transportation and economies of scale. Combinations of 16 different conversion technologies and 22 different biomass or waste streams were included in the study.

For the BIGCC case scales of 20 to 1,000 MW_{th} were considered. The electrical efficiency, η, was assumed to be: $\eta = 0.045 \times \ln(P) + 0.312$, where P is the scale of the installation in MW_{th}[21]. Investment costs ($\$10^6/MW_{th}$) were calculated: $-0.385 \times \ln(P) + 2.95$. A spatial distribution of biomass with an average density of 1,200 tonne per km^2 was assumed. The biomass was harvested and transported (by road) to a transfer point and transported (by road) to the conversion unit. The transport costs were assumed to be: $\$7.24 \times s^{-0.64}$ per tonne km, where s is the average distance transported in km in a 28 tonne truck. The transfer cost was also reported as being $0.35 per tonne.

The costs per unit of primary energy savings show a similar exponential trend of improved economic performance with increasing plant scale from 20 to 1,000 MW_{th}. These improvements, from increased efficiencies and decreased investment costs per unit of installed capacity, are usually described by logarithmic functions and approach a limit at larger scales.

An earlier report by Faaij, Meuleman and van Ree on modelling of costs of electricity for future advanced BIGCC systems also showed that the economies of scale can offset the increased costs of biomass transport up to capacities of several hundreds of MW_{th}[20]. The results (Figure 3-2) illustrate that, for the assumptions used, the cost component for logistics only shows a modest increase with increasing capacity. On the other hand, the impact of increasing plant scale on capital investment and O&M costs is significant.

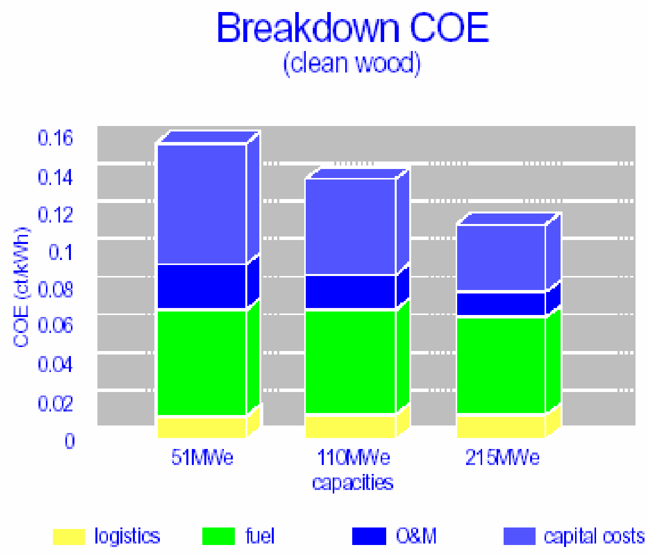

Figure 3-2 Cost of electricity for future advanced BIG/CC systems (Reference 20)[vi]

The study assumes that the biomass (wood) has a yield of 1,200 dry tonnes per km^2 per year. The biomass is harvested and transported by road to a transfer point. The land available for energy farming was assumed to be 20%. For the 51 MW_e plant the average distance to the transfer point was 10.6 km (one way) and for the 215 MW_e plant 20.8 km. The wood was then transported by road to the BIGCC plant over a constant distance of 75 km (one way). The total logistic costs for a 51 MW_e and 215 MW_e plant were $7.8 and $9 per tonne of wet fuel respectively. The moisture content of the transported fuel was assumed to be 50%. The logistic costs contributed around 18 to 20% of the total fuel costs. As in the above study, scaling factors for the costs of system

[vi] *The fuel cost component of the COE decreases with plant capacity due to the higher conversion efficiencies assumed for the larger scale plant.*

components were used, as opposed to a global scaling exponent. The operational costs were around 4.5% of the total installed investment. The efficiencies for the 51 MW_e and 215 MW_e BIGCC cases were 54% and 59% (LHV) respectively[vii].

Summary

The work reported by Dornburg and Faaij is a study of a variety of biomass conversion options with different performance characteristics to identify optimal systems for Dutch conditions. The price for forestry residues of 4.75$/GJ, excludes transportation costs, and is significantly higher than the costs for other biomass fuels quoted in this report. The annual biomass productivity (1,200 dry tonnes per km^2 per year) is comparable to that assumed by Audus[1] and Marrison[6], however, the total transportation distances are significantly higher. This is mainly due to the longer (fixed) distance from the transfer point to the conversion plant (which is located outside the biomass plantation area) and also in part due to the larger scale of plant studied. Other data from the authors reported that the average transport distance (two way) for biomass required to fuel a 51 MW_e plant was 170 km compared to 192 km for a 215 MW_e plant; the corresponding incremental increase in logistic costs was around $2 per dry tonne. This rate of increase of logistic costs with biomass transport distance is around 100% lower than that estimated in studies by Marrison[6] and NREL[35].

The economic performances of the BIGCC and FBC systems were shown to improve with increasing scales (from 10 to 300 MW_{th} and from 10 to 200 MW_{th} respectively) due to decreasing specific investment costs and higher revenues from power sales (due to assumed increasing efficiencies with scale) which prevailed over the increasing costs for biomass transportation. The costs per unit of primary energy saved with clean wood firing as a function of scale showed an exponential trend which begins to level out around 100 $MW_{th\text{-}input}$.

3.3 Greene, Natural Resources Defence Council, USA (Reference 3)

The report by Greene entitled “Growing energy: how biofuels can help end America’s growing oil dependence” offers a plan for reducing America’s oil dependence through the use of biofuels. The report is based on the work of agricultural, engineering and environmental experts and evaluates the sustainable potential for biofuels and the environmental benefits. The findings show more cost-effective potential than do previous studies largely because the report focuses on what bio-energy technologies will be able to achieve in 2050 when they are commercially mature and operating on a large scale.

Biomass Production and Costs

The model energy crop considered was switchgrass. Typical yields for different regions in North America were around 5 dry tons per acre per year (ranging from 3.5 to 6 dry ton/acre/yr). Following an aggressive breeding programme (not using genetically modified plants), future yields for 2025 and 2050 were projected to average 8 and 12.5 dry tons per acre per year respectively.

The author did not investigate the impact of increased transport costs for larger scale plant, however, assumptions were made regarding the mode of transport. For moderately sized biomass conversion processes (e.g. requiring less than 5,000 tons per day), the feedstock is likely to be transported to the plant by truck. The economics of truck based transportation will favour higher density near the plant to reduce transportation costs. For larger scale plants, requiring more than 5,000 tons of biomass per day, the crops will need to come from further away and it is likely the feedstock will be transported by train. With train-based transportation, the costs become a function of weight and density rather than distance and there is less incentive for crops to be densely planted around the facility.

To meet the needs of plants using 5,000 and 20,000 tons per day from within a 50 mile radius would require between roughly 3 and 11 percent of the land to be planted with a crop such as

[vii] *Predicted efficiencies of 54% and 59% are significantly higher than those assumed for the other referenced studies; see Table 4-1.*

switchgrass (Table 3-1). It should be noted that land coverage requirements are based on the 2050 projected yield of 12.5 tons per acre per year which is 2.5 times higher than current biomass yields. Assuming the biomass has a calorific value of 20 MJ/kg, 500 and 20,000 tons per day equate to a 105 MW_{th} and 4,200 MW_{th} plant respectively.

Table 3-1. Land coverage required to serve different size plants (Reference 3)

Feedstock collection radius (miles)	Plant size (tons/day)				
	500	1,000	5,000	10,000	20,000
10	6.5%	13.1%	65.5%	131.0%	261.9%
20	1.6%	3.3%	16.4%	32.7%	65.5%
30	0.7%	1.5%	7.3%	14.6%	29.1%
40	0.4%	0.8%	4.1%	8.2%	16.4%
50	0.3%	0.5%	2.6%	5.2%	10.5%
60	0.2%	0.4%	1.8%	3.6%	7.3%
70	0.1%	0.3%	1.3%	2.7%	5.3%

Assumes 12.5 tons/acre and that the plant operates at 90% capacity annually.

The study assumed a constant price for switchgrass of $44 per dry tonne ($40 per short ton) for all plant sizes and did not take into account the impact of increased transportation costs for the larger scale plants[viii,23].

Biomass Conversion

Two of the most promising methods for processing biomass were considered, namely biological and thermochemical processing.

The mature technology scenarios considered in the study for biological processing of cellulosic biomass were based on consolidated bio-processing (CBP). CBP was selected as being the most promising technology that can be developed into the lowest-cost commercially mature option by 2015. This approach involves pre-treatment followed by direct fermentation of carbohydrates to ethanol by micro-organisms without added enzymes. Both the pre-treatment process and development of CBP-enabling micro-organisms are not mature technologies and will require a concerted R&D, demonstration and deployment effort.

Pressurised, oxygen-blown gasification was identified as being the most efficient thermochemical conversion technology for biomass in the year 2050. The study assumed that the three remaining challenges to biomass gasification have been overcome; namely that pressurised, oxygen-blown gasification processes, technologies for feeding biomass into a pressurised gasifier without penalising overall plant performance and hot gas cleaning technologies are all commercially proven and available.

Economic Evaluation

Analysis of the different biofuel options involved production of detailed engineering designs which were validated using ASPEN Plus. The economic assessment of the processes used an equipment costing database and economic model to evaluate the economic competitiveness of the different biofuels technologies on a dollar per gallon basis. The report provided an overview of the results; details of the cost breakdowns were not provided or referenced.

Based on the study analysis, advanced biofuel facilities should be able to produce cellulosic ethanol at a cost between 0.39 and 0.69 $ per gallon at the plant gate, depending on the scale of the facility

[viii] *Correspondence with the author revealed the assumption was based on a review by Charles Wyman (ref. 23) which suggested that transportation costs are more than off set by economies of scale benefits of biorefineries up to scales of 50,000 dry tonnes/day. That said, Oakridge National Laboratory are currently in the process of performing an extensive analysis of switchgrass production and supply chain logistics with the aim of arriving at a more definitive picture.*

and the other products that the facility co-produces. The analysis focused on facilities that use 5,000 to 20,000 tons of biomass per day. The author commented that the low density of switchgrass would present logistical hurdles at these scales; however, based on discussions with experts in this field, considered that cellulosic biofuels plants larger than 5,000 to 20,000 dry tons per day would be feasible. Assuming the biomass has a calorific value of 20 MJ/kg, 5,000 and 20,000 tons per day equate to a 1,050 MW_{th} and 4,200 MW_{th} plant respectively.

The author acknowledges that larger plant sizes will pay more on average for biomass than small plants, due to higher transportation distances (biomass and transportation costs were fixed for all scales of plant in this study). However, work by Marrison and Larson[24] was referenced as an example that prior analyses have shown that increased biomass costs that accompany increased scale are more than compensated for by decreased unit capital costs that accompany increasing plant size, giving the net result of lower product cost for very large plant sizes.

Cost estimates for generated electricity from switchgrass using a pressurised oxygen blown BIGCC were $0.046 and $0.039 for the 5,000 tons per day and 20,000 tons per day plants respectively. The key financial parameters on which these numbers are based include debit/equity ratio of 40/60; loan rate of 7.5%; return on equity of 15%; discount rate of 12% and economic life of 25 years.

Summary

The report focuses on the potential performance of advanced bio-energy conversion technologies in 2050 when they are commercially mature, operating on a large scale and biomass yields are significantly enhanced. The plant sizes considered in the study ranged from 1,050 to 4,200 MW_{th}, however, a key assumption made was that the costs of biomass and biomass transportation are constant for all plant sizes. This leads to an exaggerated result of decreasing costs of ethanol production with increasing plant size.

3.4 Hamelinck and Faaij, University of Utrecht, The Netherlands (Reference 4)

The paper entitled "Future prospects for production of methanol and hydrogen from biomass" by Hamelinck and Faaij[4] evaluates the technical and economic prospects of the future production of methanol and hydrogen from biomass. The conversion concepts incorporated improved or new technologies for gas processing and synthesis and were selected on potential low cost or high efficiency. Some concepts co-produce power to exploit the high efficiencies of once through conversion. Six methanol and five hydrogen production plants were modelled using the Aspen+ flowsheeting programme and were optimised towards internal heat demand and supply; surplus heat was converted to electricity. The models were used to analyse the technical performance of the methanol production plant concepts and the results used for the economic evaluations. The paper provides a detailed description of the technical and economic performance calculations for the conversion technologies. A range of plant scales (80 to 2,000 MW_{th}) were investigated for a Latin/North American situation where biomass is available for all scales of plant at a fixed price. An overview of the key assumptions and economics of the methanol production concepts is given below.

Biomass Conversion

The Institute of Gas Technology (IGT) pressurised direct oxygen fired fluidised bed gasifier, in normal and maximised H_2 option, and the BCL (Battelle Columbus) atmospheric indirectly fired fluidised gasifier were selected for synthesis gas production. Both produce medium calorific gas, undiluted by N_2 and cover a broad range of gas compositions. The overall conversion concepts included conventional and advanced systems for gas cleaning, and different reforming, methanol synthesis processes (to optimise H_2:CO) and powering options (steam turbine or combined cycle). Available process units were logically combined so the supplied gas composition of a unit matched the demands of the subsequent unit and, where possible, temperature variations were avoided. The author noted that some of the technologies considered in the study were not yet fully proven/commercially available.

The base case for all concepts modelled was a 430 MW_{th} input HHV (80 dry tonnes per hour) biomass plant. The net electrical efficiency was assumed to be 45% HHV in an advanced BIGCC and the net efficiency for the different methanol conversion concepts was estimated to range from 52-59%. The different concepts also produced variations in the methanol and electrical generation capacities. The methanol and electricity outputs ranged from 113MW_{fuel}/105MW_e to 255MW_{fuel}/–17MW_e (all HHV basis). In the latter case, the internal electrical requirement exceeded that generated by the steam turbine.

With regards to overall plant efficiency, concepts which co-produced power performed better than concepts aiming at methanol only production. Also hot gas cleaning generally showed a better performance. The author noted that at larger scales, conversion and power systems (especially combined cycle) may have higher efficiencies, but this has not been researched in depth.

Biomass Production and Costs

For the economic evaluation, a range of plant capacities were considered from 80 to 2,000 MW_{th}. The larger scale production facilities, of 1,000 to 2,000 MW_{th}, require very large volumes of feedstock, e.g. 200 to 400 dry tonnes biomass per hour or 1.6 to 3.2 dry million tonnes per year. Hamelinck and Faaij acknowledge that biomass availability will be a limitation for most locations for such large scale production facilities, especially in the shorter term. In the longer term (2010-2030), however, if biomass production systems become commonplace, this can change. Various large scale sugar/ethanol plants in Brazil have a biomass throughput of 1 to 3 million tonnes of sugarcane per year; while the production season covers less than half a year. Also large paper and pulp complexes have comparable capacities. For many European countries, large scale plants would require large biomass import. Long distance biomass transport will influence the biomass price and overall process economics.

The report assumes that biomass is available for all scales of plant at a delivered price of \$2/GJ. Hamelinck and Faaij note that this is a reasonable price for Latin and North American conditions. Costs of cultivated energy crops in the Netherlands amount approximately to \$4/GJ, whilst biomass imported from Sweden on a large-scale is expected to cost \$7/GJ. On the other hand, biomass grown on Brazilian plantations could be delivered to local conversion facilities at \$1.6-1.7/GJ.

Details of the type, production, transport or preparation of the biomass were not given.

Economic Evaluation

The production costs were calculated by dividing the total annual costs of a system by the produced amount of methanol. Unit sizes of 80, 400, 1,000 and 2,000 MW_{th} HHV, resulting from the plant modelling, were used to evaluate overall costs for the concepts considered; the base case chosen was 400 MW_{th}.

The scaling factor for the costs of system components ranged from 0.6 to 1. Operational costs were taken as a single overall percentage (4%) of the total installed investment. The interest rate was 10%, the economic lifetime was 15 years and the plant lifetime was 25 years. The electricity supplied to or demanded from the grid was assumed to cost \$0.03/kWh and the annual load was assumed to be 8,000 hours.

The 400 MW_{th} conversion plant concepts deliver methanol at \$8.6 to \$12 per GJ. The lowest methanol production prices were found for concepts having the lower investment costs (using the BCL gasifier with little or no power co-production).

The interest rate has a large influence on fuel production costs, e.g. at a rate of 5%, methanol production costs decrease around 20%.

Increasing the scale of methanol production to 1,000 MW_{th} and 2,000 MW_{th} led to a reduction in delivered methanol costs, as shown in Table 3-2; due to lower capital costs per unit of methanol produced for large scale plant.

Feedstock costs account for between 35 to 41% of the fuel costs (excluding cost/income from power) for the selected methanol production technologies. If a biomass price of \$1.6-1.7/GJ could be realised (which Hamelinck and Faaij claim is a realistic price for biomass grown on Brazilian plantations delivered to local conversion facilities), methanol production costs would become $8 to $11 per GJ for the 400 MW_{th} concepts. On the other hand, when biomass costs increase to $3/GJ (short term Europe) the cost of methanol production would increase to $10 to $16 per GJ.

Table 3-2 Delivered methanol costs for a range of production plant capacities (Reference 4)

Production plant capacity, MW_{th}	***Cost of methanol, $/GJ***
80	12.3 – 19.7
400	8.6 – 12.2
1,000	7.6 – 10.5
2,000	7.1 – 9.5

Summary

Technical and economic prospects of the future production of methanol from biomass were evaluated. A range of conversion concepts were considered, including future advanced components, at scales of 80 to 2,000 MW_{th}. The 2,000 MW_{th} production facility will require 3.2 dry million tonnes of biomass per year which, for many European countries, would require large biomass import. This scale of plant would only be feasible at locations with concentrated biomass sources, such as sugar processing plants or paper pulp mills. It was assumed that enough biomass would be available for all scales of plant at a fixed delivered cost of $2/GJ. Production costs of methanol from biomass were lowest for the largest scale modelled (2,000 MW_{th}) due to economies of scale of capital items, however, no allowance was made for an increase in the transportation cost component for the larger scale plant.

3.5 Makihira, Barreto and Riahi, Tokyo Electric Power Company, Japan (Reference 5)

The report by Makihira, Barreto and Riahi entitled "Assessment of alternative hydrogen pathways: Natural gas and biomass" looks at the future potential of hydrogen production from biomass, with a view to using the H_2 generated in fuel cells. The findings were compared with hydrogen production from natural gas and their potential for carbon mitigation via carbon capture and storage is also examined.

Biomass Conversion

Technologies for hydrogen production from biomass are currently not commercially available. A few demonstration facilities exist, however, a number of technical and economic issues still have to be solved.

Biomass gasification is a promising option for H_2 generation. A typical biomass gasification scheme for H_2 production involves gasifying dried biomass with steam or oxygen to generate a syngas containing CO, H_2, CH_4, CO_2 and some higher hydrocarbons. This is followed by steam reforming (to convert hydrocarbons in the syngas to H_2); a water gas shift reaction step (to convert H_2O to H_2) and a final H_2 purification step to produce the required purity of H_2.

The indirectly heated gasifier developed at the Battelle Columbus Laboratories (BCL) was selected as the representative technology. The hydrogen production efficiency was assumed to be 53%.

Biomass Production and Costs

The author provides estimates of biomass production worldwide and outlines factors which affect their exploitation; such as technological progress, economic incentives, other land uses, development of dedicated fuel supply systems and logistic issues. No information was given on biomass feedstock type, production, transportation or preparation. Feedstock costs were assumed to be $3.9/GJ based on representative values[25].

Economic Evaluation

Hydrogen production costs are based on the work in published literature[26,27,28,29,30]. An annual discount rate of 5%, a plant lifetime of 20 years and a plant utilisation factor of 90% were assumed. The results of the evaluation are shown as a graph in Figure 3-3.

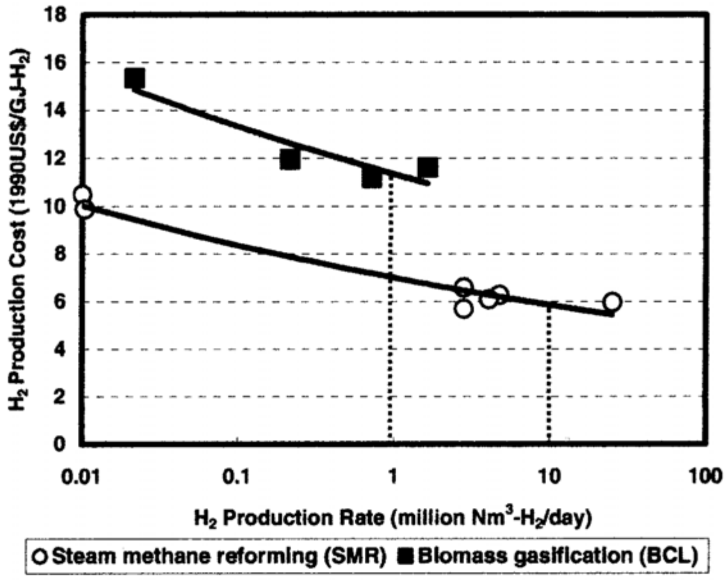

Figure 3-3 Hydrogen production costs via steam methane reforming of natural gas (SMR) and biomass gasification (BCL) (Reference 5).

The figure shows that there is a potential economy of scale for the biomass gasification plant ((BCL) with H_2 production capacities less than 0.2 million Nm^3/day). The economic benefits of scale are less apparent for high capacities. The hydrogen capacity of 1 million Nm^3/d can be considered as equal to generating around 80 MW_e from a hydrogen fuel cell power plant. It should be noted that data was taken from a range of studies and that the delivered cost of biomass fuel remained constant for all scales of plant. The authors comment that in practice the plant size of the BCL is constrained by the logistics involved in handling enormously large flows of biomass fuel required for the operation of very large BCL plants.

The total hydrogen production costs for a 1 million Nm^3/day plant (excluding H_2 transportation costs) were \$11.2/GJ-H_2; capital and O&M cost were \$7.3/GJ-H_2 and feedstock costs \$3.9/GJ-H_2.

Summary

The report by Makihira, Barreto and Riahi examines the future potential of hydrogen production from biomass, with a view to using the H_2 generated in fuel cells. The delivered cost of biomass fuel was assumed to remain constant for all scales of plant (\$3.9/GJ). No information was given on biomass feedstock type, production, transportation or preparation. The results show that there is a potential economy of scale for biomass gasification plant generating around 16 MW_e from a hydrogen fuel cell power plant. The economic benefits of scale are less apparent for high capacities.

3.6 Marrison and Larson, Princeton University, USA (Reference 6)

The paper by Marrison and Larson entitled "Cost vs scale for advanced plantation-based biomass energy systems in the USA and Brazil" examines the effects of scale on the prospective costs of electricity in the North Central (NC) and Southeast (SE) regions of the USA and in Bahia state, Brazil.

Biomass Production and Costs

A specific site in Iowa, USA was selected initially to provide case study variations in soil quality and transportation distances. The total area was around 5,100 km^2, of which 94% was used for growing crops. Soil type and road maps of the region were digitised and loaded into a geographic information system (GIS). The GIS system was used to calculate road transport distances from each acre in the region to a central processing facility that was assumed to be located near the centre of the region.

As detailed below, the cost of growing biomass on each acre (dependent primarily on soil type) was then calculated and added to the transport cost associated with the distance between the growing site and the conversion facility. The characteristics of the Iowa site were then used to represent a typical agricultural area in the NC and SE regions.

Switchgrass was selected as the energy crop for the NC and SE regions of the USA. Switchgrass yield and cost projections made by the Oak Ridge National Laboratory provided the basis for the biomass production costs. These production costs included estimates of the acreage, projected switchgrass yield, projected first year establishment costs and yields, post harvest losses, projected annual plantation maintenance costs (incurred in ensuing nine years, after which it is assumed that replanting is required) and estimated annual land rents.

Transport costs were calculated from: Cost (\$/t) = A + TC x TD; where TD is the one way distance travelled in km from the harvest site to the conversion facility; A is the fixed cost for truck loading/unloading and was assumed to be \$3/dry tonne; TC is the variable transport cost assumed to be 0.18 \$/dry tonne-km. The area analysed was not circular but the greatest transport distance was limited in the analysis to the minimum distance between the conversion facility and the outer border of the area. This defined a circle of a radius of about 32km. The moisture content of the field dried switchgrass was assumed to be 15%.

For the NC region in 2000, biomass costs were estimated to start at \$71/dry tonne or \$3.9/GJ (switchgrass HHV was 18.44 GJ/t dry). The maximum production within a radius of about 32 km was 1.7 million dry tonnes/year; with an average cost of \$77/tonne. Biomass costs were considerably lower in the SE region starting at around \$40/tonne (year 2000). This was due to the higher production yields for switchgrass in the SE region, i.e. 1,430 dry tonnes/km^2/y for the SE compared to 990 dt/km^2/y for the NC. These yields excluded post harvest losses which were assumed to be 10%. Average steady state production costs were \$35,600/km^2/yr for the SE region and \$49,500/km^2/yr for the NC. Using projections for the year 2020, average biomass costs in the NC region were \$3.3/GJ and the maximum production was 2.4 million dry tonnes/year.

A simplified approach was also developed for developing biomass supply curves to avoid data-intensive, time consuming GIS analysis. The results of the two approaches were shown to agree well.

The simplified approach was applied for the analysis of data collected at the Brazil site. At the site, eucalyptus is harvested in a six year rotation, with maximum planting density of 0.8. Assuming a 10% discount rate, the levelised cost of production was \$30.1/ dry tonne (\$1.6/GJ). The higher heating value of the eucalyptus was 19.34 GJ/dry tonne. Harvesting plus fixed transport costs were \$4.4/dry tonne, chipping costs were \$5.5/dry tonne, the variable transport cost (TC) was \$0.2/dry tonne-km and the fixed cost for truck loading/unloading (A) was assumed to be \$1.3/dry tonne.

Biomass Conversion

A number of conversion technologies were considered. For electricity production, these included a commercial steam rankine cycle and a nearing commercial status technology, the gasifier/gas turbine combined cycle (BIGCC). Two alcohol fuel production technologies were also considered, namely methanol via thermochemical gasification and ethanol via enzymatic hydrolysis. Both of these alcohol production processes could be commercially ready early in the twenty first century.

Economic Evaluation

Estimates of installed capital costs for all of these conversion systems were based on published sources. The total installed capital cost per unit of output for each technology was assumed to vary with capacity as follows:

Unit cost = $C + D \times (\text{capacity})^E$;

where C, D & E are constants for a given technology. E is a negative number (unit cost falls with increasing capacity), therefore C corresponds to the unit cost for a very large facility. The specific capital cost of the BIGCC plant was estimated to be 2,577 $/kW_e$ and 1,288 $/kW_e$ for the 10 MW_e and 60 MW_e capacities respectively. This compared with 3,510 $/kW_e$ and 1,647 $/kW_e$ for the 10 MW_e and 50 MW_e steam rankine cycles. The estimated specific capital costs for the 811 GJ/h methanol plant and 1,355 GJ/h ethanol plant were 317 $/MJ/h and 151 $/MJ/h respectively.

To convert capital costs to annualised costs, capital charge rates (CCRs) of 0.101 for electricity and 0.151 for alcohol production plants were assumed. The electricity CCR assumes utility financing, whereas for alcohol production, the CCR is based on average financial parameters. The generating and production efficiencies were assumed to be 37% (HHV) for BIGCC; 20% for the 10 MW_e steam rankine cycle; 60% for methanol production and 50% for ethanol production. O&M costs per unit of output were assumed fixed regardless of scale for each technology, at 0.008 $/kWh for the BIGCC system, 0.0125 $/kWh for the steam rankine cycle, and 2.61 $/GJ and 2.18 $/GJ for the methanol and ethanol production plants respectively.

The results for the estimated COE and COA versus scale for USA for the year 2000 and 2020 are shown in Figure 3-4.

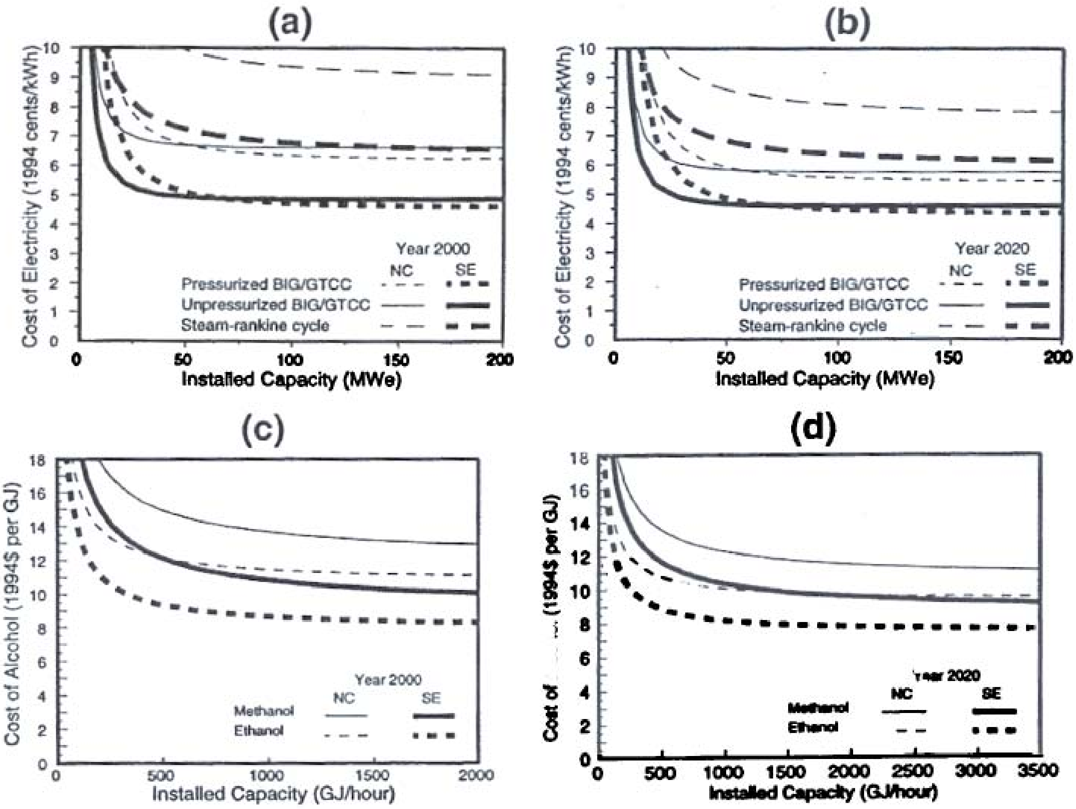

Figure 3-4 (a) and (b) Total levelised cost of electricity production as a function of installed capacity for the selected site in the NC and SE regions of USA in 2000 and 2020. (c) and (d) Total levelised cost of methanol and ethanol production as a function of capacity (Reference 6).

Electricity production

For small capacities, falling specific capital costs with scale for the conversion systems more than offset increasing biomass costs that arise from increased transportation costs. The total COE reached a minimum COE (COE_{min}) at the capacity at which the rate of decrease in specific capital costs equalled the rate of increase in the transport costs. At capacities larger than this, there was a very gradual rise in the COE as the transport costs become increasingly more important. For a given technology, lower biomass costs led to lower COE_{min} and higher installed capacities at which at which these minima were reached.

In all the USA cases, the capacity at which the COE_{min} was achieved was relatively large, i.e. around 120 MW_e for the atmospheric pressure BIGCC and up to 500 MW_e for the steam rankine cycle[6]. However, the rate of decrease of COE with increasing capacity levelled out (i.e. approaches COE_{min}) at much smaller capacities. For the atmospheric pressure BIGCC, the capacity at which the COE was within 1% and 5% of the minimum COE was around 60 MW_e and 32 MW_e respectively. Therefore for biomass energy plants greater than 30 MW_e the optimum plant size is very dependent on the rate of increase in biomass costs, i.e. transportation costs and planting density.

If lower planting densities and higher transport costs are assumed, the capacity at which the minimum COE (COE_{min}) is reached is lower. For example, at the Brazilian site, the lower assumed planting density (0.8 compared to 0.94 for USA), led to a greater weighting of transport costs and the capacity at which COE_{min} was reached was smaller than at the USA sites.

The pressurised BIGCC is more efficient than the low pressure version, but is more costly below a certain capacity range. The capacity at which COE_{min} was achieved was around 280 MW_e.

For the steam rankine cycle, the capacities for being within 5% of the minimum COE (85 to 111 MW_e) are larger than existing biomass-fired steam rankine power plants. Most such plants reply on low cost biomass (e.g. by-products of industrial processing) and their scales are set by the availability of feedstock, rather than by economies of scale.

The COE_{min} with BIGCC plants are approached at much smaller capacities than with the steam rankine cycles because most of the scale economy gains in capital cost occur at smaller capacities.

Using 2020 projections for the pressurised BIGCC in the NC region, the optimum capacity was 290 MW_e (this compares to a year 2000 optimum capacity for this technology of 269 MW_e). The projected cost for electricity in 2020 was 5.4 c/kWh compared to 6.2 c/kWh in 2000.

Alcohol fuel production

Similar patterns were observed as seen for the electricity costs, with one major difference for the USA sites; the capital costs of the alcohol production facilities dominated the total costs for capacities up to those which can be supported by biomass supplied from the entire site used for the study (area of 3,215km^2 with a 94% planting density). For the US site, even at capacities requiring transport from the 32 km limit, capital costs were falling at a faster rate than the biomass transport costs were rising. The optimum cost of alcohol (COA_{min}) was not reached within the limits of the capacity scales in Figure 3-4.

In general, where biomass costs are relatively low, plant capacities that give minimum COAs were larger.

Methanol production costs reached 5% of the minimum COA at capacities of around 1,320 and 2,020 GJ/h for the NC and SE in 2000 respectively. These capacities are comparable to those of the largest existing industrial biomass processing facilities or methanol-from-natural gas plants.

Ethanol production costs approached a minimum at smaller plant capacities than for methanol due to the lower assumed capital costs of ethanol plants. Capacities for a COA within 5% of the minimum ranged from 650 to 1,470 GJ/h.

Using projections for the year 2020, the optimum capacity (within 1% of the minimum cost of alcohol) for an ethanol production plant in the NC region, was 2,270 GJ/h and the projected cost for ethanol was 0.26 $/litre.

Further Information

Another paper by the same authors[31] examined the impact of planting density, variable transport costs, yield and annual land rent on the COE_{min} and the capacity at which COE_{min} is reached. The base case values of parameters shown in Table 3-3 are for the SE region for the year 2020 and projected yields were assumed to be around 2,050 dry t/ km^2/y. This parameter value is significantly higher than that used for the year 2000 (yields for SE and NC regions ranged from 990 to 1,430 dry t/ km^2/y), hence the lower COE_{min} and the higher corresponding capacity. The table, however, provides information on the impact of key parameters on the COE_{min} capacity.

Table 3-3 Results of sensitivity analysis for South East Region in 2020 showing impact on minimum energy production cost for each technology and capacity at which the minimum is reached (Reference 31)

	Atmospheric BIGCC		Steam Rankine Cycle		Methanol		Ethanol	
	COE_{min} c/kWh	Cap. MW_e	COE_{min} c/kWh	Cap. MW_e	COA_{min} $/GJ	Cap. GJ/h	COA_{min} $/GJ	Cap. GJ/h
BASE CASE	4.57	142	6.05	520	10.1	>5,500	8.6	>4,500
Variable transport = $0.09/t-km	4.48	183	5.85	691	9.8	>5,500	8.3	>4,500
Variable transport = $0.36/t-km	4.71	100	6.39	304	10.7	>5,500	9.3	3,800
Planting density = 47%	4.62	127	6.16	362	10.7	>2,700	9.0	>2,300
Planting density = 9.4%	4.76	87	6.8	75	13.9	>400	11.2	>300
Yield = +25% (dry t/ km^2/y)	4.24	147	5.57	525	9.3	>7,000	7.8	>5,700
Yield = -25% (dry t/ km^2/y)	5.10	123	6.83	447	11.3	>4,100	10.0	>3,400
Land rent +$12,300/$km^2$/y	5.00	142	6.66	520	13.4	>3,800	12.4	>3,200
Land rent -$12,300/$km^2$/y	4.13	142	5.43	520	9.4	>5,500	7.8	>4,600

The base case values of parameters examined in this table are:- variable transport cost = $0.18/dry tonne-km; planting density = 94%; average yield = 2,050 dry t/ km^2/y; land rent = $7,100/ km^2/y.

Table 3-3 shows that the planting density and variable transport costs have a significant impact on the capacity at which COE_{min} is reached.

Reducing the planting density raises transport costs. For locations where planting density is 9.4%, the capacity that gives COE_{min} / COA_{min} is reduced by around 40% for BIGCC systems, by 85% for steam-rankine systems and by 90% for the methanol and ethanol production. The difference in results for electricity and alcohol production is due the greater flatness of the alcohol cost curves around the minimum[31].

Raising the variable transport cost from $0.18 to $0.36/t-km lowered the capacity at which COE_{min} was reached by 30%.

Changing the biomass yield assumption (+/- 25% dry t/ha/y compared to the base case) had a small effect on the capacities at which minimum COE or COA was reached, but a much larger impact on the value of COE_{min} and COA_{min}. With higher yields, more biomass is available within a smaller radius, thereby lowering the costs of both production and transportation per tonne. Both these costs impact on the value of COE_{min} and COA_{min}, whilst only the increased transportation costs reduce the capacity required to achieve the minimum costs.

Modified input assumptions which change the unit cost of producing biomass by a fixed amount (regardless of capacity) shift the COE or COA curves up or down, but will not change the capacity at which minimum production costs are achieved; one such cost is the land rent.

Summary

Marrison and Larson examined the effects of scale on the prospective costs of electricity from switchgrass in the North Central (NC) and Southeast (SE) regions of the USA and from eucalyptus in Bahia state, Brazil.

Conversion technologies considered included a commercial steam rankine cycle, a nearing commercial status electric generating technology, the gasifier/gas turbine combined cycle (BIGCC) and two alcohol fuel production technologies, based on thermochemical gasification (methanol) and enzymatic hydrolysis (ethanol). Both of the alcohol production processes could be commercially ready within the next 20 years. Estimates of installed capital costs for all technologies were based on data published sources.

Biomass cost-supply analyses were determined for the USA sites for the year 2000 and 2020 using estimates for switchgrass yields and costs. A geographic information system was used to analyse soil quality (and yield) distributions and road transport distances. The total agricultural area around the conversion plant was 5,100 km^2, of which 94% was used for growing crops.

The available land at the selected site is similar to that assumed for the Spanish study by Audus and Freund. However, due to the difference in plantation areas and planting density, the amount of biomass produced annually for the US sites was estimated to be around 5,500,000 tonnes biomass per year compared to 133,000 tonnes per year for the Spanish sites. For the USA conditions, biomass transportation costs will increase less rapidly with increasing plant capacity and will lead to a minimum cost of energy at larger plant capacities than for the Spanish conditions.

In all the USA cases, the capacity at which the COE_{min} is achieved is relatively large, e.g. around 120 MW_e for the atmospheric pressure BIGCC and up to 500 MW_e for the steam rankine cycle. However, the capacity at which the COE is within 5% of the minimum COE is much lower; namely around 32 MW_e for the BIGCC and around 100 MW_e for the steam rankine cycle. The smaller COE_{min} capacities for BIGCC plants is because most of the scale economy gains in capital cost occur at smaller capacities than for steam rankine cycles. It was estimated that when the planting density is reduced to 9.4%, the capacity that gives COE_{min} is around 60 MW_e for the atmospheric pressure BIGCC system.

Similar patterns were observed for alcohol fuel production costs, with one major difference for the USA sites: the capital costs of the alcohol production facilities dominate the total costs. For the US site, even at capacities requiring transport from the 32 km limit, capital costs are falling at a faster rate than the biomass transport costs are rising. The optimum cost of alcohol (COA_{min}) was estimated to be >2,200 GJ/h for ethanol and >2,700 GJ/h for methanol.

3.7 Möllersten, Yan, and Moreira, Luleå University, Sweden (Reference 7)

The paper by Möllersten, Yan, and Moreira, entitled “Potential market niches for biomass energy with CO_2 capture and storage - opportunities for energy supply with negative CO_2 emissions”, presents an analysis of biomass energy with CO_2 capture and storage in industrial applications. Sugar cane-based ethanol mills and chemical pulp mills are identified as potential market niches whereby the waste biomass material generated from these processes is used to generate heat and power to meet process demands or liquid fuels as a by-product.

Biomass Production

Pulp and Paper mills

Pulp mills can generate two forms of biomass energy; a woody residue produced during feed preparation (bark) and a black liquor (caustic solution containing lignin) produced during the extraction of cellulose. Slightly more than half of the biomass entering a pulp mill is dissolved in the black liquor. This black liquor stream is currently burnt in recovery boilers which recover important pulping chemicals and feed steam to the mill CHP system. In modern pulp mills, the fuel requirement for the CHP system is typically covered by the black liquor and internally generated bark, whereas integrated pulp and paper mills need to import fuels to satisfy the process demand for medium- and low-pressure steam. Most pulp mills and all integrated mills rely on electricity import to cover part of their electricity demand.

In existing pulp mills (with modern CHP systems based on recovery and biomass boilers), the electrical efficiencies are low (up to 15%). Significantly improved overall energy efficiency and increased electrical efficiency could be accomplished by the introduction of black liquor integrated gasification with combined cycles (currently not a commercially available technology). Increasing the electrical efficiency of CHP systems often leads to a reduction in steam production. This could be overcome through the introduction of modern pulp and paper mill processes with lower process steam demand or by importing additional biomass fuel.

A modern pulp mill generates 1.7–1.8 tonnes of black liquor (dry solids) per tonne of pulp. In Finland and Sweden, modern pulp mills typically produce over 1,500 adt (air dry tonne) per day of pulp and generate over 2,600 tonnes of black liquor per day (around 10.5 PJ/year).

Sugar Cane processing

In commercial sugar production from sugar cane not all the sucrose is used due to economic and technical reasons, related respectively to the large amount of energy required to extract the lowest fraction of sucrose and to the presence of C12 sugars not suitable for production of commercial sugar. Typically 15% of the initial sucrose is contained in the by-product molasses which has a low-commercial value and is used for ethanol production (or to feed animals). Plants dedicated exclusively to ethanol production with sugar cane as feedstock are also in operation. Typically, sugar cane processing takes place in large scale industrial units. In Brazil, average-size plants dedicated to ethanol production can process 0.5 million litres/day, with the largest approaching capacities near 5 million litres/day.

It is important to note that converting sugar plant (or starch, or cellulose) to ethanol is very energy intensive. Currently, almost all the sugar cane bagasse is burned to produce electricity, mechanical power and steam for the process, making the units self-sufficient in energy.

Biomass Conversion

Three conversion technologies were selected for study; namely (a) black liquor recovery and bark boilers, (b) black liquor BIGCC and (c) sugar cane-based ethanol production.

The main emphasis of the paper was on the assessment of the potential for further CO_2 reduction through biomass-based energy conversion with CO_2 capture and storage. Technical and economic details of the conversion systems were not provided in the paper, however, other papers by Möllersten and Yan provide supplementary details for the pulp and paper mill systems[32,33].

The modelling of pulp and paper mill CHP systems was carried out for two different mill environments, a market pulp mill (MPM) and an integrated pulp and paper mill (IPPM). Various configurations were modelled.

Cases MPM3 and IPPM3 were based on pressurised high-temperature, oxygen-blown gasification technology, without CO_2 capture. For the MPM3 case, the fuel input was assumed to be 338MW_{th} black liquor, the net electrical efficiency (LHV) and the total efficiency were 31% and 76% respectively[32]. In addition to a fuel input of 338MW_{th} black liquor, the IPPM3 case required an additional 97 MW_{th} which was generated from bark and woody biomass using a supplementary BIGCC. The net electrical efficiency was assumed to be 26% and a total efficiency of 80%[32].

Cases MPM1 and IPPM1 were based on boiler technology with back pressure steam turbines without CO_2 capture. The black liquor fuel inputs were 338 MW_{th} for both cases; the IPPM1 case also required an additional 80 MW_{th} which was generated from bark and woody biomass using a supplementary boiler. The net electrical efficiencies of the MPM1 and IPPM1 cases were 16% and 14% respectively; the total efficiencies were 60% and 70% respectively.

The ethanol production plant consumes around 11,000 tonnes of sugar cane per day and around 1,500 tonnes of bagasse per day (dry weight) is used as fuel to generate power and steam for the process. Ethanol production is 1 million litres per day.

Economic Evaluation

A simple economic analysis was carried out to provide information of the costs of CO_2 capture in pulp and paper mills. Capital cost estimates for the system components were taken from other referenced work and the results were presented as estimated incremental capital costs for the CO_2 capture systems relative to the base cases without CO_2 capture. A scaling factor of 0.7 was used to adjust capital costs for size. Detailed of the base case costs, without CO_2 capture, were not provided.

Summary

Waste biomass material generated from pulp and paper mills and sugar cane-based ethanol mills can be used to generate heat and power to meet process demands or liquid fuels as a by-product. Unlike, purpose grown biomass conversion systems, the optimal economic scale for the conversion plant will be dependent on the amount of waste biomass available from pulp and paper or sugar mill processes and the demand for heat and power from the mill CHP system.

3.8 Rhodes and Keith, Carnegie Mellon University, USA (Reference 8)

The paper by Rhodes and Keith, "Biomass Energy with Geological Sequestration of CO_2: Two for the Price of One?" investigates the technical feasibility and economic implications of combining biomass energy systems with carbon capture and sequestration technology. Two potential conversion systems were investigated, based on BIGCC and bio-ethanol technologies.

Biomass Production and Costs

Details of biomass production and costs were provided in a referenced paper by Wooley et al, National Renewable Energy Laboratory (NREL) in 1999[34]. The analyses were carried out to provide a relative context for choosing plant size. Previous NREL process economics assumed a plant size of around 2,000 tonnes per day of biomass for a bio-ethanol production plant. The results of the simplified analysis of trade off between economies of scale and increased cost of delivering feedstock are outlined below and suggested that the selected plant scale was reasonable.

A brief internet search revealed that a more recent paper by NREL had been published on the same topic. In 2002, Aden et al (NREL) repeated the analysis in a more rigorous way to see if a plant size of 2,000 tonnes per day is appropriate in the current design for a bio-ethanol production plant[35]. The results of this paper are also outlined below.

Wooley et al, 1999[34]

In this paper, two potential feedstocks were considered, switchgrass and corn stover, which comprises stalks, leaves, cobs and husks. Corn stover was identified as being the more promising feedstock material in terms of its availability in high volume as a by-product from corn farmers.

The Oak Ridge National Laboratory database, known as ORECCL, was used to provide county-level data on land availability and rents, energy crop yields, and production costs. An analysis was carried for corn stover collection, using data from an ongoing corn stover collection project in Harlan, Iowa. The yield of corn stover was estimated to be around 1.67 tonnes per acre (413 tonnes/km^2/year). It was assumed that 50% of the land around a Midwest facility would be dedicated to corn, and that the remaining 50% would be used for soybean production. This reflects the common practice of corn and soybean crop rotation. Seventy-five percent of the land surrounding the plant was assumed to be actual farmland and available for planting; the other 25% was used for infrastructure.

Biomass collection costs comprise the cost of harvesting and baling and the cost of transportation from the farm to the plant gate. Only transportation costs are directly affected by the size of the plant. The analysis showed that a 2,000 tonnes/day plant using corn stover would require a collection radius of 37 km (23 mile) to meet its feedstock needs. Doubling the size of the plant to 4,000 tonnes per day would extend the collection radius by only 16 km (10 miles). If plant size doubled from 1,000 to 2,000 tonnes per day, feedstock costs would rise by \$2.11/tonne of switchgrass and only \$1.21/tonne of corn stover[ix]. Doubling again from 2,000 to 4,000 tonnes per day would result in added costs of \$1.63/tonne of switchgrass and \$0.93/tonne of corn stover.

Aden et al, 2002[35]

In 2002, further work carried out at NREL on the economics of bio-ethanol production reported that the 50% scenario was not very realistic because the corn-soybean rotations are not likely to permit sustainable collection at a level of 2 tonnes per acre[35]. The authors stated that in the near term, the 10% availability scenario is closer to reality. A geographic information system (GIS) model was used to estimate energy demands, environmental flows and costs for collection and transportation of corn stover in the state of Iowa, US (this model was also used in the work by Marrison[6] in Section 3.6). Figure 3-5 shows the radius of collection around the plant for different levels of access to acres for collection, assuming a maximum yield of 2 tonnes per acre (494 t/km^2).

For the 10% availability scenario, a 2,000 tonnes/day plant using corn stover would require a collection radius of 72 km (45 mile) to meet its feedstock needs.

The transport costs were estimated to be around 23% of the overall biomass costs[35]. Baling and staging, at \$29 per dry tonne represented almost half the cost of delivered feedstock. The analysis also included a payment of a premium to farmers of \$11 per dry tonne (a profit of \$22 per acre) to cover for the risk and additional work of collecting and selling their residue. Added fertilizer costs amounted to around \$8 per dry tonne. Published costs for transporting corn stover were used to show hauler costs as a function of radial distance from the plant (Figure 3-6).

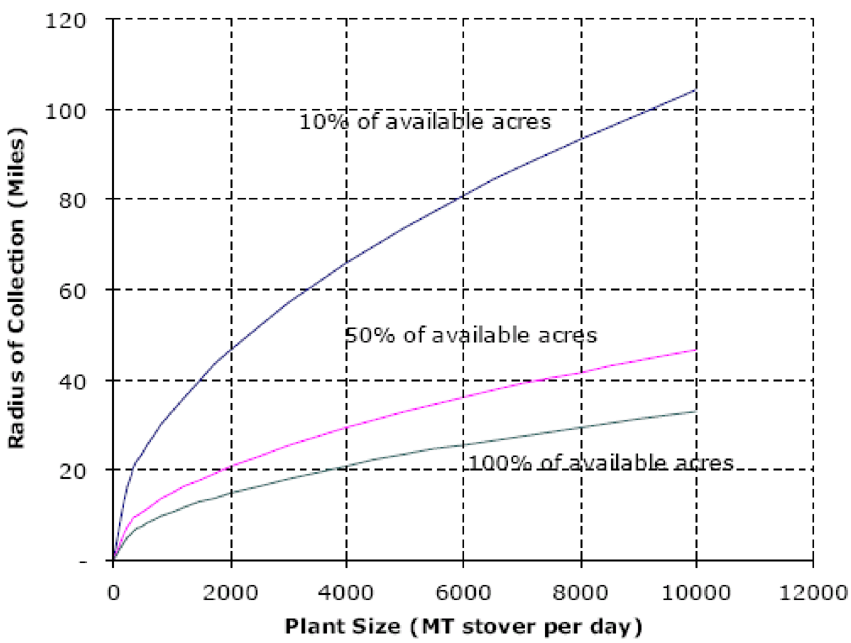

Figure 3-5 Collection distance as a function of plant size for corn stover[x] (Reference 35)

[ix] *Assumed to be dry tonnage. The moisture content of the biomass was not given.*
[x] *MT =metric tonnes*

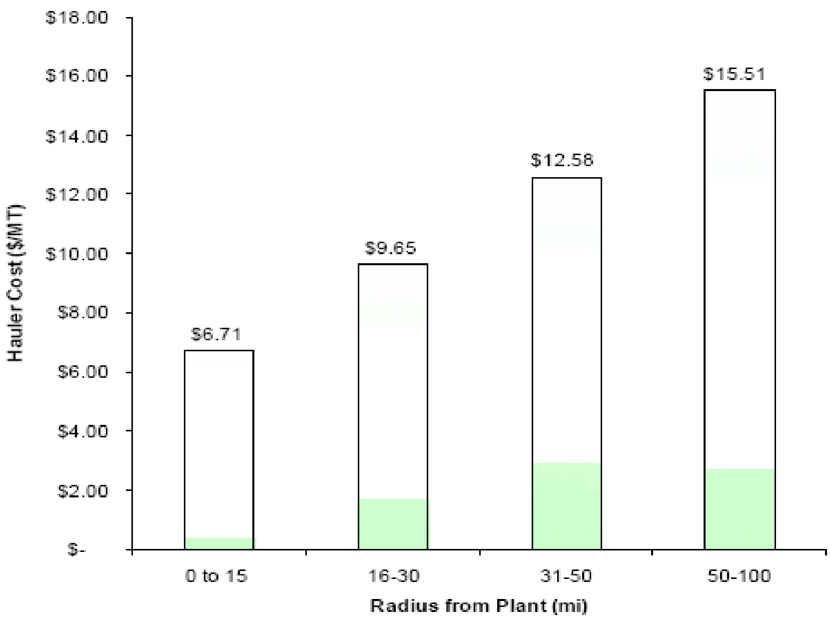

Figure 3-6 Haulage charges for corn stover as a function of distance (Reference 35)

The linear relationship between cost and distance was used to predict a total cost of delivered corn stover that is a function of distance from the plant. The effects of plant size on the capital costs were estimated using a capital cost scaling exponent of 0.7. Figure 3-7 shows the minimum selling price for ethanol as a function of plant size for the scenario of collecting stover from 10% of the corn acres around the conversion facility.

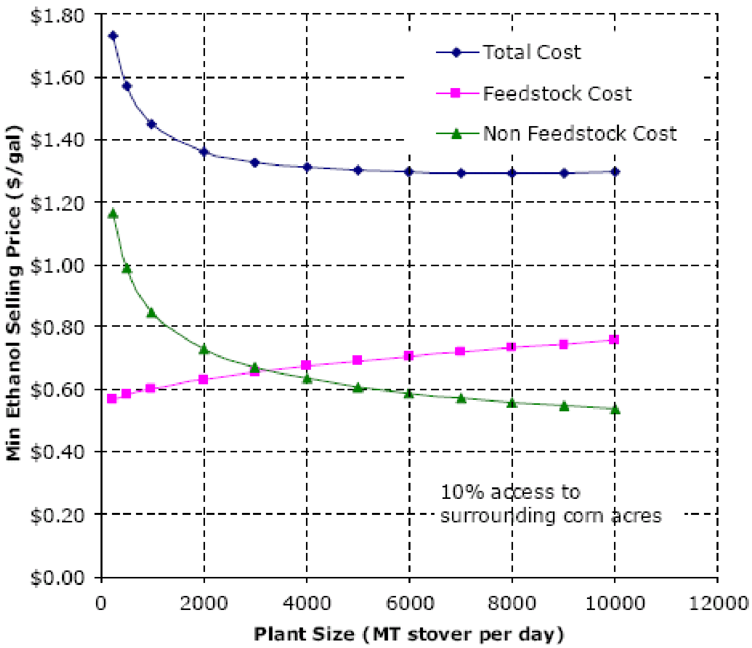

Figure 3-7 Ethanol costs as a function of plant size for 10% availability of corn acres (Reference 35)

An increase in plant size from 2,000 to 10,000 tonnes (MT) per day reduces non-feedstock costs by 0.19 $/gallon but the increased cost of feedstock eliminates $0.13 of these savings. For the assumptions made in the analysis, the optimal minimum plant size is around 2,000 to 4,000 tonnes per day. Factors which will affect the optimal plant size were:-

- availability of land for biomass production around the conversion facility; as more land becomes available the optimal plant size will increase.
- cost of delivered feedstock in terms of cost per ton-mile. Lower bulk density of the biomass and poor road infrastructure will increase the cost of delivered feedstock. A 100% increase in hauling cost per tone-mile reduces the optimum plant size and higher plant sizes can actually see significant increases in minimum ethanol selling price (Figure 3-8).

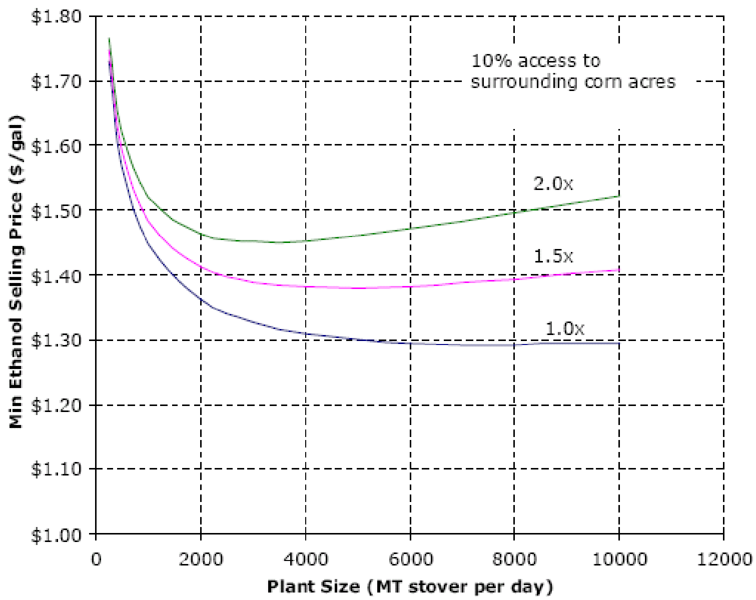

Figure 3-8 Ethanol price as a function of plant size and hauling cost (Reference 35)

Biomass Conversion

Models for two potential systems based on BIGCC and bio-ethanol technologies were developed.

BIGCC

The Battelle Columbus Laboratory/Future Energy Resource Company (BCL/FERCO) technology was selected for the biomass gasifier. It uses steam-blown gasification and provides heat for gasification by burning residual char in separate reaction vessels. Steam gasification by indirect heating avoids dilution of the syngas by atmospheric nitrogen. Carbon conversion efficiency was around 70%; the remaining 30% being burnt in the char combustor. BCL/FERCO technology is still in development for large scale applications although it should be available with 10 years.

The BIGCC model was based on pre-existing ASPEN simulations and component cost estimates. One key reference was the work by Mann on a study of hydrogen production by using the Battelle indirectly heated biomass gasifier[29].

Bio-ethanol production

The biomass-to-ethanol process uses co-current dilute acid pre-hydrolysis of the lignocellulosic biomass with simultaneous enzymatic saccharification of the remaining cellulose and co-fermentation of the resulting glucose and xylose to ethanol. The biomass is treated with dilute sulphuric acid catalyst at a high temperature, liberating the hemicellulose sugars and other compounds. After separation and detoxification, simultaneous enzymatic saccharification and co-fermentation of the detoxified hydrolyzate slurry is carried out. After several days, most of the cellulose and xylose will have been converted to ethanol. The resulting solution is sent to product recovery, which consists of distilling the ethanol away from the water and residual solids, followed by purification to 100% ethanol. The solids from distillation, the concentrated syrup from the evaporator, and biogas from anaerobic digestion are combusted in a fluidized bed combustor to raise steam for process heat. Generally, the process produces excess steam that is converted to electricity for use in the plant and for sale to the grid.

An existing engineering-economic model of bio-ethanol production was modified to incorporate capture and sequestration of CO_2 off-gases from fermentation; based on the work by Wooley et al[34].

Economic Evaluation

Based on the above feedstock production analyses and previous studies, a plant size of around 2,000 tonnes/day of biomass was selected as the study plant size[29,35]. The economic analysis was based on predicted costs for the year 2000. Capital costs were amortized over twenty years at 10% interest. Annual O&M was defined as a fraction of total capital costs; 6% for BIGCC and 2.75% for bio-ethanol technologies. Biomass fuel costs were fixed at \$2.7 per gigajoule. The type of biomass was not specified[8].

BIGCC

The total capacity of the BIGCC plant was 1,814 dry tonnes per day, the net conversion efficiency (HHV) 34% and total output 141MW_e. The results of the economic analysis showed that the total capital cost was \$171 million and the specific capital costs were \$1,210 per kWh. Non-fuel O&M costs were estimated to be \$11.4 million per year and electricity generation costs were 5.92 cents/kWh[8].

Bio-ethanol production

For the ethanol production case the total plant capacity was assumed to be 2,000 dry tonnes per day, the net conversion efficiency (HHV) 40% and the total output 235 million litres per year. Total capital costs were \$234 million, specific capital costs were \$1,270/kWh, and non-fuel O&M costs \$7.3 million/year. The cost of bio-ethanol production was estimated to be \$ 0.35 per litre[8].

Summary

The paper by Rhodes and Keith examines the technical and economic implications of using biomass energy systems with carbon capture and sequestration technology. Selection of a 2,000 tonne per day facility as the appropriate scale for the biomass conversion plant was based on referenced studies for potential sites in Iowa, USA. The more recent work assumed that 10% of the land around the conversion facility was dedicated to corn production and the yield of corn stover was assumed to be around 500 tonnes per km^2. It was estimated that a 2,000 tonnes/day plant using corn stover would require a collection radius of 72 km to meet its feedstock needs. A linear relationship between cost and distance was used to predict a total cost of delivered corn stover that is a function of distance from the plant; the transport costs were estimated to be around 23% of the overall biomass costs. The effects of plant size on the capital costs were estimated using a capital cost scaling exponent of 0.7. The results of the simplified analysis of trade off between economies of scale and increased cost of delivering feedstock suggested that the 2,000 tonnes per day plant scale was reasonable. Comparison of results from earlier work, however, demonstrated that the costs of biomass collection are very dependent on assumptions made regarding availability of arable land, collection distance, biomass yields etc.

4 DISCUSSION

The optimum scale of a biomass energy conversion system is the capacity at which the lowest cost of energy production is achieved. This optimum scale is site specific as it is dependent on the assumed costs for the delivered biomass and the conversion to energy, and how these costs vary with scale.

As the scale of a biomass energy conversion plant increases, the specific capital costs decrease due to economies of scale but the biomass production costs generally rise as a result of increased transportation costs, as larger amounts of biomass have to be gathered from a wider radius around the plant. For a given location and conversion technology, the optimum size of biomass energy plant is the capacity at which the rate of decrease in specific capital costs equals the rate of increase in the biomass costs.

Many biomass energy conversion technologies have not yet been commercially demonstrated and overall cost and performance characteristics have not been proven. Therefore, capital cost estimates are typically based on equipment costing databases, economic models and published data. Capital costs for process components typically increase exponentially as a function of size or throughput and are adjusted using a scaling exponent. Lower capital costs lead to a lower cost of energy production and approach a minimum cost of energy at smaller plant capacities.

The total biomass cost comprises costs for production, collection, storage and transport of the biomass to the conversion facility. For a given conversion technology, lower biomass costs lead to a lower cost of energy production and higher optimum capacities.

The logistic cost component is influenced by the energy content and density of the biomass, production (net yield) per square kilometre, the collection area and the resulting transport distances. The number of transfer steps, the mode of transport and the road infrastructure can also impact on the transport costs. Reducing the rate of increase in the transportation cost component with increasing plant scale leads to a minimum cost of energy at larger plant capacities.

With respect to biomass availability, the referenced papers basically cover three scenarios for biomass energy conversion systems, namely:-

1) *Low density biomass:* energy conversion systems using (a) dedicated energy crops in locations were land available for biomass plantations is limited and/or biomass yields (tonnes/km^2/year) are relatively low or (b) agricultural or forestry residues which tend to be dispersed in nature.
2) *High density biomass:* energy conversion systems using dedicated energy crops in locations were most of the land around the conversion facility can be dedicated to biomass planting and/or biomass yields (tonnes/km^2/year) are relatively high.
3) *Biomass by-products:* large commercial activities generating biomass by-products, such as the sugarcane or paper and pulp industries.

A comparison of the performance and key assumptions of the referenced biomass fuelled IGCC, combustion and alcohol production plants is given Tables 4-1, 4-2 and 4-3 respectively and discussed below.

Total Biomass Costs

The biomass types covered in the study included dedicated energy crops (such as switchgrass, acacia and eucalyptus), agricultural or forestry residues and biomass by-products from industrial processes.

The total cost for production, collection, storage and transport of a dry tonne of purpose grown biomass to the conversion plant ranged from $40 to $77 (2.2 to 4.2 $/GJ, LHV); the majority ranging from $40 to $55 per tonne (Table 4-1). The wide range of biomass costs quoted for Marrison[6] was attributed to differences in the production yields.

Costs quoted for clean wood were higher. For The Netherlands case, the cost of forestry residues (excluding transportation costs) was reported to be 4.75$/GJ.

Biomass by-products generated from pulp and paper mills and sugar cane-based ethanol mills can be used to generate heat and power to meet process demands. The energy conversion systems are typically located on the industrial process site and the biomass by-product is considered to be zero cost. Some systems require supplementary fuels (imported at market price) to meet the process demand for steam and/or electricity.

Table 4-1 Comparison of performance and key assumptions of biomass-fired IGCC plants

Reference	**Audus & Freund[1]**	**Dornburg & Faaij[2]**		**Greene[3]**	**Marrison & Larson[6]**		**Möllersten et al[7]**	**Rhodes & Keith[8]**
Reference year	2001	1999		2050	2000			2000
Biomass type	Acacia/ Eucalyptus	Forestry residues		Switchgrass	Switchgrass		Black liquor	Corn stover
Study country	Spain	The Netherlands		USA	USA		Sweden	USA
Conversion Technology:								
Biomass technology	FBG	FBG		Pressurised O_2 blown	FBG		Pressurised O_2 blown	Indirect heated FBG
Power cycle	combined	combined		combined	combined		combined	combined
Optimum plant size [a], MW$_e$	36	138		n.d.	114 - 130		n.d.	n.d.
Study plant size, MW$_e$	**30**	**41**	**138**	**470 – 1,890**[b],[c]	**10**	**60**	**95**	**141**
Biomass Cycle Management:								
Area covered, km^2	5,024	n.d.		n.d.	5,100		Waste biomass source from pulp and paper mill	4,300[g]
Agricultural land, km^2	1,180[e]	600 – 1,800[f]		n.d.	5,100			3,225[g]
Plantation area, km^2	118[e]	120 – 360[f]		n.d.	4,600			1,610[g]
Planting density, %	10	20[f]		n.d.	94			50[g]
Productivity, dt/km^2/y (dry)[d]	1,130[e]	1,200[f]		2,830[c]	890 – 1,290			350[h]
Biomass production, kt/y	133[e]	144 – 432[f]		n.d.	5,500		512	560
Biomass demand, kt/y	121[e]	144[i]	432[i]	n.d.	37	222	512	560
Biomass Costs:								
Cost of land rent, \$/km^2/year	15,415	n.d.		n.d.	n.d.		n.a.	5,436[l]
Total biomass cost, \$/dt [j]	54	85[k]		44[c]	40 - 77		n.a.	49[m]
Biomass HHV, MJ/kg	19.6	20		n.d.	18.4		n.d.	n.d.
Biomass cost, \$/GJ (LHV) [j]	2.97	4.75[k]		n.d.	2.2 – 4.2		n.d.	2.7[n]
Logistics:								
Means	Road	Road		Delivered biomass costs constant for all plant scales	Road		n.a. – integrated mill &CHP plant	Road [g]
Max. Distance, km	31 [e]	n.d.			32			72[p]
Average distance, km	22 [e]	n.d.			n.d.			n.d.
Moisture content, % dry wt	27 / 50[o]	n.d.			15			n.d.
Power Plant Efficiency (LHV), %	40	41	46	n.d.	37[q]	37[q]	26 - 31	34[q]
Plant Costs:								
Capital cost, million \$	56[r]	125	315	n.d.	26	77	n.d.	171
Specific cost, \$/kW$_e$	1,870	3,050	2,300	n.d.	2,580	1,290	n.d.	1,210
O&M, % total costs	20	~14	~12	n.d.	12	12	n.d.	20[s]
Scaling exponent	0.7	0.7	0.7	n.d.	~0.7	~0.7	0.7	0.7
Levelised cost of electricity, c/kWh	8.1	n.d.	n.d.	3.9 - 4.6	6 - 8	5 - 7	n.a.	5.9

n.d. = no details
n.a. = not applicable
dt = dry tonnes
HHV = higher heating value
LHV = lower heating value
FBG = fluidised bed gasification

(a) optimum plant size quoted by author
(b) calculated from 5,000 and 20,000 tons/day; assuming biomass CV = 20 MJ/kg, plant efficiency = 45%.
(c) 1 tonne = 0.907 US ton.
(d) productivity = annual net yield in plantation area (delivered to power plant), dry tonnes per km^2 per year
(e) average data for sites 27 and 28 in Reference 18.
(f) based on values taken from References 12 and 20
(g) Wooley et al Reference 34
(h) assuming harvested corn stover contained 15% moisture
(i) calculated assuming plant operating 8,000 hours/year and biomass 20 MJ/kg (HHV)
(j) total cost for production, collection, storage and transport of a tonne of biomass to the power plant.
(k) costs exclude transportation costs; total biomass cost calculated from assumed LHV$_{dry}$ value of 18 MJ/kg.
(l) premium paid to farmers to cover for the risk and additional work of collecting and selling their residue
(m) calculated assuming the calorific value of corn stover is 18 MJ/kg (LHV)
(n) assumed to be LHV basis
(o) 27% moisture in chips and 50% moisture in stems
(p) Aden et al Reference 35
(q) hhv basis
(r) authors note that this value low & has not fully taken into account the cost of providing a clean syngas.
(s) O&M costs 6% of capital costs. Capital costs assumed to be 30% of total cost.

Table 4-2 Comparison of performance and key assumptions of biomass-fired combustion plants

Reference	Dornburg & Faaij[2]	Marrison & Larson[6]		Möllersten et al[7]
Reference year	1999	2000		2000
Biomass type	Forestry residues	Switchgrass		Black liquor
Study country	The Netherlands	USA		Sweden
Conversion Technology:				
Biomass technology	FBC	n.d.		n.d
Power cycle	steam	steam		steam
Optimum plant size [a], MW_e	66	366 - 424		n.d.
Study plant size, MW_e	**66**	**10**	**50**	**55**
Biomass Cycle Management:				
Area covered, km^2	n.d.	5,100		Waste biomass source from pulp and paper mill
Agricultural land, km^2	600 – 1,800[c]	5,100		
Plantation area, km^2	120 – 360[c]	4,600		
Planting density, %	20[c]	94		
Productivity, $dt/km^2/y$ (dry)[b]	1,200[c]	890 – 1,290		
Biomass production, kt/y	288[c]	5,500		512
Biomass demand, kt/y	288[d]	68	253	512
Biomass Costs:				
Cost of land rent, $\$/km^2/year$	n.d.	n.d.		n.a.
Total biomass cost, \$/dt [e]	85[f]	40 - 77		n.a.
Biomass HHV, MJ/kg	20	18.4		n.d.
Biomass cost, \$/GJ (LHV) [e]	4.75[f]	2.2 – 4.2		n.d.
Logistics:				
Means	Road	Road		n.a. – integrated mill &CHP plant
Max. Distance, km	n.d.	32		
Average distance, km	n.d.	n.d.		
Moisture content, % dry wt	n.d.	15		
Power Plant Efficiency (LHV), %	33	20[g]	27[g]	14 - 16
Plant Costs:				
Capital cost, million \$	152	35	82	n.d.
Specific cost, $\$/kW_e$	2,300	3,510	1,650	n.d.
O&M, % total costs	n.d.	16	16	n.d.
Scaling exponent	0.7	~0.7	~0.7	0.7
Levelised cost of electricity, c/kWh	n.d.	>9[h]	~7.5[h]	n.a.

n.d. = no details
n.a. = not applicable
dt = dry tonnes
HHV = higher heating value
LHV = lower heating value
FBC = fluidised bed combustion

(a) optimum plant size quoted by author
(b) productivity = annual net yield in plantation area (delivered to power plant), dry tonnes per km^2 per year
(c) based on values taken from References 12 and 20
(d) calculated assuming plant operating 8,000 hours/year and biomass 20 MJ/kg (HHV)
(e) total cost for production, collection, storage and transport of a tonne of biomass to the power plant.
(f) costs exclude transportation costs; total biomass cost calculated from assumed LHV_{dry} value of 18 MJ/kg.
(g) hhv basis
(h) in the SE region of the USA for the year 2000

Table 4-3 Comparison of performance and key assumptions of referenced biomass fuelled alcohol production plants

Reference	Greene[3]	Hamelinck & Faaij[4]	Marrison & Larson[6]		Möllersten, Yan & Moreira[7]	Rhodes & Keith[8]
Reference year	2050	2001	2000		2000	2000
Biomass type	Switchgrass	n.d.	Switchgrass		Molasses	Corn stover
Study country	USA	USA	USA		Brazil	USA
Conversion Technology						
Biomass technology	Biological	Gasification	Thermo-chemical gasification	Enzymatic hydrolysis		Enzymatic hydrolysis
Alcohol	Ethanol	Methanol	Ethanol	Methanol	Ethanol	Ethanol
Optimum plant capacity[(a)], GJ/h		7,200	>2,200	>2,700	~2,000	n.d.
Study plant capacity, GJ/h [(b)]	**3,780–15,120**	**1,538**	**1,355**	**811**	**950**	**715**[(c)]
Biomass Cycle Management						
Area covered, km^2	n.d.	n.d.	5,100		Waste biomass source from sugar production	4,300[(f),(g)]
Agricultural land, km^2	n.d.	n.d.	5,100			3,225[(f)]
Plantation area, km^2	n.d.	n.d.	4,600			1,610[(f)]
Planting density, %	n.d.	n.d.	94			50[(f)]
Productivity, dt/km^2/y (dry) [(d)]	2,830 [(e)]	n.d.	890 – 1,290			350[(f),(h)]
Biomass production, 1,000 dt/y	n.d.	n.d.	5,500		1,980	560
Biomass demand, 1,000 dt/y	n.d.	640	~510 – 1,030		1,980	560
Biomass Costs						
Cost of land rent, \$/km^2/year	n.d.	n.d.	n.d.		n.a.	5,436 [(j)]
Total biomass cost, \$/dt [(i)]	44[(e)]	~36	40 - 77		n.a.	49 [(k)]
Biomass HHV, MJ/kg	n.d.	~18	18.44		n.d.	n.d.
Biomass cost, \$/GJ (LHV) [(i)]	n.d.	2	2.2 – 4.2		n.d.	2.7 [(l)]
Logistics	Delivered biomass costs constant for all plant scales					
Means		n.d.	Road		n.d.	Road [(f)]
Max. Distance, km		n.d.	32		n.d.	72 [(m)]
Average distance, km		n.d.	n.d.		n.d.	n.d.
Moisture content, % dry wt		n.d.	15		n.d.	n.d.
Net conversion efficiency (HHV), %	n.d.	50 - 57	50	60	n.d.	40
Plant Costs						
Capital cost, million \$	n.d.	225 - 283	205	257	n.d.	234
Specific cost, \$/$(MJ/h)_{output}$	n.d.	145 – 185	151	317	n.d.	328
Scaling exponent	n.d.	0.6 -1	~0.3	~0.3	0.7	0.7
Cost breakdown, %						
Capital	n.d.	44	n.d.	n.d.	n.d.	n.d.
O&M	n.d.	15	20	21	n.d.	6 [(n)]
Fuel	n.d.	41	n.d.	n.d.	n.d.	n.d.
Cost of alcohol, \$/litre	0.16-0.2	0.15 – 0.22	0.23-0.32	0.23 – 0.29	n.d.	0.35

n.d. = no details
dt = dry tonnes
HHV = higher heating value
LHV = lower heating value

(a) optimum plant size quoted by author
(b) GJ/h to litres/h conversion: divide by the appropriate HHV: 0.0181 GJ/litre for methanol and 0.0228 GJ/litre for hydrous ethanol (95% ethanol, 5% water)
(c) assuming 312 operational days per year
(d) productivity = annual net yield in plantation area (delivered to alcohol production plant), dry tonnes per km^2 per year
(e) 1 tonne = 0.907 US ton.
(f) Wooley et al, Reference 34
(g) calculated assuming area covered is a circle of radius 37 km.
(h) assuming harvested corn stover contained 15% moisture.
(i) total cost for production, collection, storage and transport of a tonne of biomass to the alcohol production plant.
(j) premium paid to farmers to cover for the risk and additional work of collecting and selling their residue
(k) calculated assuming the calorific value of corn stover is 18 MJ/kg (LHV)
(l) assumed to be LHV basis
(m) Aden et al Reference 35
(n) O&M costs 2.75% of capital costs. Capital costs assumed to be 45% of total costs.

Logistic Cost Component

The logistic costs of biomass are dependent on assumptions made regarding the distances travelled and/or time taken to collect the biomass and transport it to the conversion facility, and the resulting costs.

Transport distances and duration

The approach for estimating transportation distances varied. Marrison[6] and Rhodes[xi] carried out a detailed geographic investigation to calculate transport distances for a specific location. The work by Audus[1] and Dornburg[2] assumed that the biomass plantation area was circular and the transport distances were calculated from assumptions made regarding the location of the conversion plant, transfer points and the biomass distribution density. Whereas, the studies by Greene[3], Hamelinck[4] and Makihira[5] assumed a constant price for biomass for all scales of plant and did not take into account the impact of increased transportation distances (i.e. costs) for larger scale plant.

The biomass productivity, in terms of net yield per km^2, impacts on the transport distance per tonne biomass; higher yields lead to lower biomass transportation costs. The collection area is dependent on the availability of arable land around the conversion facility and the proportion of that arable land which can be dedicated to the biomass plantation; as the collection area increases, transportation and overall biomass production costs will increase. The moisture and energy content of the biomass will influence the number of trips needed to deliver the biomass; biomass with a higher gross calorific value will require fewer trips and subsequently transport costs will be lower.

The biomass productivity, in terms of annual net yield in plantation area, ranged from 350 to 2,830 dry tonnes per km^2 per year and the planting densities between 10 and 94% (Tables 4-1 and 4-2). In general, higher planting densities were assumed for biomass conversion plants located in USA compared to those in Europe. For example, the study undertaken by Marrison and Larson[6], the available land around the conversion facility at the US sites is similar to that assumed for the Spanish study by Audus and Freund[1]. However, the assumed biomass plantation areas and planting densities, and hence annual biomass yields, are very different. The USA case assumed that all the selected area (5,100 km^2) was agricultural land, of which 94% was available for the biomass plantation. The Spanish case assumed that around 1,180 km^2 of the 5,000 km^2 was arable land of which 10% was available for the biomass plantation. The amount of biomass produced annually for the USA sites was estimated to be around 5,500,000 tonnes compared to 133,000 tonnes per year for the Spanish sites. For the Spanish conditions, biomass transportation costs will increase more rapidly with increasing plant capacity and will lead to a minimum cost of energy at smaller plant capacities than for the USA conditions.

Similar high biomass planting densities were assumed for the USA situation referenced by Rhodes and Keith[8]. For this case, 75% of the land surrounding the conversion facility (4,300 km^2) was assumed to be available for planting, of which 50% was dedicated to biomass feedstock production (1,610 km^2). The annual production yields of biomass were estimated to be around 560,000 tonnes.

The conditions prevailing in The Netherlands are similar to those for the Spanish situation. Dornburg[2] assumed a biomass yield of 1,200 dry tonnes/km/y and the percentage of land used for energy farming of 20%. A 41 MW_e conversion facility would require 144,000 dry tonnes of wood per year from a collection area of 600 km^2.

Transportation Costs

Various approaches were used for estimating the logistic costs of transporting the harvested biomass to the conversion plant. The transportation cost parameters for key references are summarised in Table 4-4 and discussed below.

[xi] Details of the approach for estimating the transport distance were not given in the NREL[34] paper referenced by Rhodes[8], however, more recent work by NREL used a GIS system[35].

Table 4-4 Comparison of logistic costs for referenced biomass fuelled plants

Reference	Transportation Cost Parameters		Two-way Distance, km	Plant Size, MW_e	Transport Costs, $/dry tonne-km*	% Total Fuel Cost
Audus[1]	Time	26.9 $/h	44	30	0.34	28
	Distance	0-10km: $2.3/tonne of lorry wt >10 km: $0.03/km-tonne of lorry wt				
Dornburg & Faaij[2]	Distance	7.25 x (distance in km)$^{-0.6}$ ($/t-km)	155	41	0.10	18-20
	Transfer	0.35 $/tonne				
Marrison & Larson[6]	Cost ($/t) = A + TC x TD ; where A = fixed cost of $3 per dry tonne, TD = one way distance (km), TC = variable transport cost of 0.18 $ per dry tonne-km		64	60	0.135	11-22
Rhodes & Keith[8]	15.5 $ per dry tonne		72	141	0.22	31

** Transport costs estimated for the given plant size.*

The transport cost component (for biomass delivered to the power and alcohol production plants referenced in Table 4-4) ranged from 0.1 to 0.34 $ per dry tonne-km and contributed to around 11 to 31% of the total fuel cost.

The paper by Audus and Freund[1] referenced a detailed study for specific sites in Spain. Transport costs were based on a detailed analysis of both the distance travelled and time taken. For areas closest to the conversion plant, the biomass was harvested and transported directly to the plant and transport costs were based on time taken. For longer distances, harvested biomass was transported to a store (time taken cost basis), chipped and subsequently transported to the conversion plant (distance cost basis). The distance based cost component assumed 2.3$ per tonne for the first 10 km and for further distances, the price per km rose at 0.03 $ per tonne of weight of lorry (using a 24 tonne lorry). Costs were on a gross basis and the moisture content of the biomass during the second transfer operation was assumed to be 27%. The plantation area was assumed to be 10% of the cultivated land within a maximum radius of 40 km.

Dornburg and Faaij[2] assumed that two transfer operations took place; the biomass was harvested and transported to a transfer point and subsequently transported to the conversion plant. The transfer point was located in the centre of the biomass plantation. The distance the biomass was transported to the transfer point was variable, depending on the plant fuel requirements (i.e. capacity). The conversion plant was assumed to be located outside the biomass plantation, some 50 km from the transfer point. Transport distances involved were longer than those considered in the other referenced studies, which assumed that the conversion plant was located near the centre of the biomass plantation. Other data from the authors reported that the average transport distance (two way) for biomass required to fuel a 51 MW_e plant was 170 km compared to 192 km for a 215 MW_e plant; the corresponding incremental increase in logistic costs was around $2 per dry tonne (i.e. around 0.1 $ per dry tonne-km). This rate of increase of logistic costs with biomass transport distance is around 100% lower than that estimated in studies by Marrison[6] and Rhodes[xi].

Marrison and Larson[6] used a geographic information system to analyse soil quality distributions and road transport distances for sites in USA. Transportation costs were also based on a fixed transfer cost and a variable transportation cost. The variable transport cost was assumed to be 0.18 $ per dry tonne-km and the furthest transport distance was 32 km.

Rhodes and Keith[8] referenced a NREL report which used a linear correlation between cost and distance to predict the total cost of biomass as a function of collection distance from the plant. More recent papers by NREL[35] showed that a 2,000 tonnes per day biomass conversion plant required a collection radius of 72 km to meet its feedstock needs. Haulage charges for this distance were predicted to be around 15.5 $ per dry tonne (i.e. 0.22 $ per dry tonne-km).

Conversion Plant Costs

As discussed above, capital cost estimates for the conversion technologies were typically based on equipment costing databases, economic models and published data, using exponential scaling factors. The scaling exponent used for most referenced studies was around 0.7.

The specific capital costs predicted for BIGCC technology ranged from 1,210 to 3,050 $/kW_e$ whilst costs of electricity typically ranged from 6 to 8 c/kWh (Table 4-1). Capital cost estimates reported by Dornburg[2] were significantly higher than others quoted for similar scale plant. Comparable specific capital costs were also reported for biomass fuelled combustion plant; ranging from 1,650 to 3,500 $/kW_e$.

The capital cost of the alcohol fuel production facility is a major cost component of the total cost of alcohol. Capital costs for alcohol production plants ranged from 205 to 283 million dollars, whilst specific capital costs ranged from \$145 to \$330 per MJ/h output (Table 4-2). High capital costs were generally assumed for enzymatic hydrolysis conversion technologies; specific capital costs for conversion processes based on gasification ranged from \$150 to \$185 per MJ/h output.

Plant electrical efficiencies for BIGCC technologies were generally based on predicted future efficiencies for coal fired plant and ranged from around 26% to 46% (LHV). The lower efficiencies were predicted for the biomass combustion plant and alcohol production plant fuelled by pulp and paper by-products. The work by Dornburg[2] also assumed that the electrical efficiency of the BIGCC plant will increase as a function of scale. Scale effects were calculated as an exponential function (0.1 for BIGCC). Net conversion efficiencies for alcohol production plants ranged from 40 to 60% (HHV).

Optimum Scale

A number of the referenced assessments of biomass-based power generation technology have focussed on larger units due to the economies of scale. However, capital costs only contribute around 30% to the overall cost of electricity. The capital cost component of the overall cost of alcohol is slightly higher at around 45%. It is also important to consider the impact of increasing the size of conversion plants on infrastructure requirements, such as water and land availability, biomass yields, adequate roads etc. For example, most thermal power plants use large volumes of water, which may not be available where the biomass is produced. Electricity transmission and demand may also be an issue.

The optimum scale of a biomass energy system is dependent on the assumed biomass cost (delivered) and conversion facility cost and how these costs vary with plant size. A number of referenced papers have investigated the effect of plant scale on cost of electricity/alcohol[2,3,6,8] and show:-

1) For small scale facilities, biomass transport costs will be relatively low, but capital costs per unit of output will be relatively high. For these facilities, the rate of decrease in unit capital cost outweighs the increasing costs for logistics.
2) As the scale of the plant increases, biomass transport costs will become increasing more important but specific capital costs will decrease. The total cost of energy or biofuel production should reach a minimum at the capacity at which the rate of decrease in specific capital costs equals the rate of increase in the transport costs (i.e. the optimum capacity). *However, around the optimum capacity there is a wide range over which costs change very little.*
3) At capacities larger than this there is a plateau or a very gradual rise in the cost of electricity or alcohol as the transport costs become increasingly important.

As discussed above, the capacities at which the above changes occur are dependent on assumptions made regarding the biomass cost, capital cost and the impact of scale on these costs.

For locations where biomass density is low (e.g. due to low yields, land limitations, use of agricultural/forestry residues) the appropriate scale for a biomass energy plant is relatively small. Audus[1] concluded that for the Spanish situation the optimum plant size was 36 MW_e. For conditions prevailing in The Netherlands, Dornburg[2] predicted a higher optimum capacity of 138 MW_e. Key disparities between the two studies are the capital cost estimates, biomass costs and how the biomass costs vary with plant capacity. The higher capital costs and lower rate of increase in logistic costs estimated for The Netherlands conditions leads to a larger optimum plant capacity. Conversely, the higher biomass costs assumed for the Dutch forestry residues reduces the optimum capacity.

Studies located in areas of high density biomass only show a modest rate of increase of biomass transportation costs with increasing scale. For these locations, where most of the land around the conversion facility can be dedicated to biomass planting and/or biomass yields (tonnes/km^2/year) is relatively high, the optimum scale for an energy conversion plant is reported to be around 115 to 150 MW_e for a power plant based on BIGCC technology[2,6]. This equates to a power plant throughput of 1,035 to 1,350 GJ/h of biomass[xii]. For an ethanol or methanol production plant the reported optimum capacities were high; greater than 2,000 GJ/h[4,6]. These capacities are comparable to those of the largest existing industrial methanol-from-natural gas plants. Alcohol production costs approached a minimum at comparatively high plant capacities due to the high capital cost component of the total cost of alcohol.

Biomass by-products generated from pulp and paper mills and sugar cane-based ethanol mills can be used to generate heat and power to meet process demands or produce liquid fuels. Unlike, purpose grown biomass conversion systems, the optimal economic scale for the conversion plant will be dependent on the amount of biomass by-product available (i.e. the scale of the primary process) and alternative uses for the by-product. The paper by Mollersten et al[7] suggested that modern pulp mills can generate around 10.5 PJ black liquor per year which could fuel a 95MW_e power plant based on pressurised BIGCC technology.

Further work by Marrison and Larson[31] quantified the impact of planting density, transport costs (mileage) and yield on the optimum plant capacity. The paper suggested that (a) raising the transport cost (mileage component) from \$0.18 to \$0.36 per tonne-km lowered the optimum capacity by 30%, (b) reducing the planting density from 94% to 9.4% lead to a reduction in the optimum capacity by around 40% for BIGCC systems and by 90% for alcohol production schemes[xiii] and (c) reducing the biomass yield assumption by 25% lead to a 20% reduction in the optimum capacity. It can be inferred that the optimum scale of an energy conversion system can vary significantly, in certain scenarios by over 90%, depending on assumptions made regarding biomass production and transport costs.

The major stand alone biomass IGCC demonstration projects undertaken to date are small in scale, i.e. <32 MW_e. The only large scale project (75-100 MW_e) was located at Granite Falls, USA, in an area with a dedicated, high planting density of biomass. However, the project was cancelled when key financing partners withdrew from the project because of uncertainties with fuel supply and biomass gasification technology at this scale.

Future Performance

The work by Greene[3] and Marrison[6] considered the potential performance of advanced bio-energy conversion technologies when they are commercially mature, operating on a large scale and biomass yields are significantly enhanced. Their work was based on future energy scenarios and assumed improved agricultural practices could increase crops yields by factors of 1.4 and 2.5, in years 2020 and 2050 respectively, from current yields. As discussed above, increasing the planting density and biomass yields effectively reduces the biomass transportation costs and hence reduces the total biomass costs for a given capacity of conversion plant. Using projections for 2020, delivered biomass costs within a radius of 32 km around the conversion plant were around 25%

[xii] *Assuming a plant efficiency of 40% (HHV)*
[xiii] *The difference in results for electricity and alcohol production is due to the greater flatness of the alcohol cost curves around the minimum (Section 3.6)*

lower than year 2000 costs (e.g. around \$4.2/GJ for year 2000 compared to around \$3.3/GJ for year 2020) [6].

Pressurised, oxygen-blown BIGCC technologies were identified as being the most efficient way of generating power from biomass. Combined cycle technologies are commercially established for use with natural gas and, to a lesser extent, with synthesis gas generated from a coal fired gasifier. For biomass gasification, however, further development work is required; namely the pressurised, oxygen-blown gasification process, technologies for feeding biomass into a pressurised gasifier without penalising overall plant performance and hot gas cleaning technologies all need to be commercially proven and available. The work by Greene[3] and Marrison[6] assumes that these three remaining challenges have been overcome.

For ethanol production, Greene[3] considered consolidated bio-processing, where pre-treated biomass is fermented directly by cellulolytic micro-organisms, to be the most promising technology that can be developed into the lowest cost commercially mature option by 2015. Marrison[6] considered enzymatic hydrolysis ethanol production, for which advanced designs are currently undergoing pilot-scale testing and development in the USA[36].

In both studies, the lower biomass costs and higher conversion efficiencies projected for future energy scenarios led to significantly lower costs of electricity/alcohol and higher optimum capacities for the conversion plant. Marrison[6] assumed year 2020 biomass production yields and estimated that the optimum capacity of a pressurised BIGCC system was 290 MW_e (this compares to a year 2000 optimum capacity for this technology of 269 MW_e). The projected cost for electricity in 2020 was 5.4 c/kWh compared to 6.2 c/kWh in 2000. For an ethanol production plant the optimum capacity (within 1% of the minimum cost of alcohol) was 2,270 GJ/h for year 2020 compared to 1,530 GJ/h for year 2000. The projected cost for ethanol in 2020 was 0.26 \$/litre compared to 0.3 \$/litre in 2000.

Greene[3] considered pressurised BIGCC systems ranging from around 470 to 1,900 MW_e, ethanol production plants from 3,800 to 15,000 GJ/h and assumed year 2050 biomass production yields. The estimated costs of electricity and ethanol ranged from 3.9 to 4.6 c/kWh and 0.16 to 0.2 \$/litre respectively. A key assumption made by Greene, however, was that the costs of biomass and biomass transportation were constant for all plant sizes (i.e. fixed biomass cost of \$44/dt). This led to an exaggerated result of decreasing costs of electricity and ethanol production with increasing plant size.

5 CONCLUSIONS

1. This paper provides a critical review and compares the key assumptions presented in selected studies which inferred that large scale biomass plant capacities could be technically and economically feasible. The results of the studies are based on assumed biomass production and conversion technologies, many of which have not been commercially demonstrated.
2. The appropriate capacity of a biomass energy conversion system is site specific as it is dependent on assumptions made regarding costs for the delivered biomass and conversion facility, and how these costs vary with scale.
3. The key disparities in the referenced papers were assumptions made regarding the availability of the biomass fuel, in terms of the biomass yields and collection area around the conversion plant. The biomass productivity ranged from 350 to 2,830 dry tonnes per km^2 per year and the planting densities between 10 and 94%. In general, higher planting densities were assumed for biomass conversion plants located in USA compared to those in Europe.
4. Differences in assumptions made regarding the logistic costs of the biomass fuel and capital costs of the conversion plant were also shown to impact on the optimum biomass plant capacity. Lower capital cost estimates led to a lower cost of energy production and approached a minimum cost of energy at smaller plant capacities. Reducing the rate of

increase in the transportation cost component with increasing plant scale resulted in higher optimum capacities.

5. Various approaches were used for estimating biomass transportation costs. A number of studies carried out a detailed analysis to calculate transport distances and costs for a specific location to the conversion plant. Others, however, assumed a constant price of biomass for all scales of plant and did not take into account the impact of increased transportation distances for larger scale plant. The transport cost component ranged from 0.1 to 0.34 $ per dry tonne-km and contributed to around 11 to 31% of the total fuel cost.

6. The total costs for delivered, purpose grown, biomass ranged from $40 to $77 per dry tonne; the majority ranging from $40 to $55 per tonne. Biomass by-products, for example from pulp and paper mills, were typically considered to be zero cost.

7. The specific capital costs predicted for BIGCC technology ranged from 1,210 to 3,050 $/kW$_e$ and were comparable to those reported for biomass fuelled combustion plant. The cost of electricity was typically lower for BIGCC (ranging from 4 to 8 c/kWh) due to the higher conversion efficiencies predicted for these systems. The capital cost of the alcohol fuel production facility is a major cost component of the total cost of alcohol; specific capital costs ranged from $145 to $330 per MJ/h output. High capital costs were generally assumed for enzymatic hydrolysis conversion technologies.

8. The referenced papers covered three broad scenarios. For locations where biomass density is low (e.g. due to low yields, land limitations, use of agricultural/forestry residues) the appropriate scale for a biomass energy plant was relatively small. For locations where most of the land around the conversion facility can be dedicated to biomass planting and/or biomass yields are relatively high, the optimum scale is reported to be higher, typically around 115 to 150 MW$_e$ (power generation) or 2,000 to 7,200 GJ/h (biofuel production). For the third scenario, where biomass by-products are generated from industrial processes, the optimum economic scale for the conversion plant will be dependent on the amount of biomass by-product available (i.e. the scale of the primary process) and alternative uses for the by-product.

9. An important consideration, with regards to selection of the optimum capacity of a biomass conversion facility, is the impact on infrastructure requirements, such as water and land availability, biomass yields, adequate roads etc., and how these impacts vary with scale.

10. Future energy scenarios, when advanced, more efficient, bio-energy conversion technologies are commercially mature and operating on a large scale, and biomass yields are significantly enhanced, projected that the costs of electricity and alcohol would be significantly lower and the optimum capacity for the conversion plant would increase.

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ANNEX 1: SUPPLEMENTARY INFORMATION ON MAJOR BIOMASS ENERGY PLANT

A1 BIOMASS INTEGRATED GASIFICATION COMBINED CYCLE

A1.1 Current Commercial and Demonstration Projects

Arbre, UK

A state-of-the-art wood-fuelled gasification combined cycle plant, Project ARBRE, was constructed at Eggborough, North Yorkshire, UK. The plant, which was the first of its kind, contained an atmospheric pressure circulating fluidised bed gasifier of TPS technology coupled to a tar-cracking vessel. After cooling and cleaning in conventional equipment, the energy-rich gas was compressed and fired in a Typhoon gas turbine to produce 8 MW_e.

A contract was set up with local farmers to cultivate, harvest and transport short rotation coppice (SRC) to the generating plant. The wood was delivered in chipped form to the plant by truck. The fuel supply, preparation and feeding system consisted of a weigh-bridge, a reception pit, an A-frame storage building (providing three days bulk storage), a dryer (which dries the fuel to around 10% moisture content with flue gases leaving the waste heat boiler) plus travelling screws, screws and elevator and conveyors interconnecting these latter three units and also leading to the two gasifier fuel feed silos.

The plant was to consume 43,000 dry tonnes of wood per year and its net electrical efficiency was projected to be c. 30%. This relatively low efficiency was a result of the requirement of eligibility for the EU grant that net generation must reach 8 MW_e, which after selecting the technically proven Typhoon gas turbine of 4.5 MW_e, could only be achieved by increasing the contribution of the steam turbine cycle to the overall output by firing a third of the gas produced directly into the HRSG, thereby bypassing the gas turbine, such that the plant configuration was not an example of a typical generic combined cycle.

The gasifier operated smoothly for a total period of more than 1,000 hours over ten test periods, each of varying duration. The fuels gasified included many different wood species, including that from several of the SRC plantings. The gas quality data collected from the tar cracker, from the short periods when operating reasonably close to design conditions, indicated that expected LCV and quality could be met. At the beginning of 2002, the gas compressor and gas turbine were operated on LCV gas (~5.7 MJ/Nm^3), the gas turbine operating on 70% product gas at 80% load for a number of hours at 3.6 MW_e. Emissions were as expected.

Starting with plant commissioning in 2001, several design and operational problems were encountered[1]. Due to certain design inadequacies in detailed engineering and related operational issues, the primary raw gas heat exchanger overheated and promoted plugging with carry-over solids. Hence, the plant could not be operated for extended periods. The problems were compounded when financial pressures resulting from change of ownership, etc., did not provide the support needed to remedy the design and operational issues. When the project was terminated during the latter part of 2002, the plant operations provided valuable insight into project management, engineering design, and operational issues. The energy crop part of the project has been a success and farmers are actively looking to grow more material to supply the co-firing market.

Bioelettrica, Italy

The Thermie Energy Farm (TEF) Project at Cascina, near Pisa, Italy, by Bioelettrica SpA has faced many technical and non-technical problems. This is another selection by the EC THERMIE demonstration program. The selected atmospheric gasification technology of Lurgi (sized for 43

MW_{th} fuel input) was changed to the pressurized gasification technology of Carbona to generate 14 MW_e (33% efficiency). The design fuel was wood chips, and olive and grape pomace residues. The plant was supposed to be operational in 2002 but the project was terminated in 2003[2].

Burlington, Vermont, USA

A Battelle (commercialized by FERCO) gasifier sized for 200 tonnes per day wood chips was installed next to the boiler at the McNeil Generating Station in Burlington Vermont. The McNeil facility is a 50 MW_e Rankine steam cycle biomass fired plant. The project consisted of scaling up the Battelle dual-fluidized bed gasifier to produce gas for co-firing in the McNeil boiler initially, followed by staged implementation of gas cleaning systems and a gas turbine to be operated on the producer gas as an IGCC. The gasifier uses steam and hot sand to gasify the biomass. The char and sand from the first fluidized bed is shuttled to a second fluidized bed reactor and the char combusted to heat the sand which is recirculated to the first reactor. Steam is used as the fluidizing and gasification agent in the first reactor, avoiding dilution with nitrogen in air and producing a higher quality gas for use in the IGCC. It operates at near atmospheric pressure. The project successfully demonstrated that Battelle gasifier at a commercial scale and was successful in co-firing the producer gas in the McNeil boiler. Federal funding in support of full IGCC implementation did not occur and testing beyond gas co-firing to the solid fuel boiler was not conducted.

Granite Falls, USA

A growers' cooperative (Minnesota Valley Alfalfa Producers or MnVAP), electric utility, university, private partners and state agencies formed a group to site a biomass power station. US DOE sponsored the program as well. The concept was to strip the leaves from the growers' cooperative alfalfa harvest (2000 growers, 180,000 acres) and use them for creating high quality animal feed. The low protein stems were to be used for the biomass fuel. A 75-100 MW_e plant based on the GTI pressurized oxygen enriched airblown gasifier (licensed to Carbona) supplying an IGCC system was specified. Expected required feed rate of alfalfa stems was 1,100 tonnes per day. The DOE was providing up to £25 million of the £78 - £112 million cost for construction of the plant and associated facilities. Significant milestones accomplished by 1999 included:

- Purchase of existing alfalfa-processing plant and development of stem and leaf separation technology
- Formulate agreements with farmers to buy shares in the cooperative and making them future co-owners of the power facility
- Obtaining a loan guarantee and 100 acres of land donated by the city of Granite Falls, Minnesota, for the power facility

However, in 1999, key financing partners withdrew from the project because of uncertainties with fuel supply and the unproven technology (biomass IGCC) at this scale.

Maui, Hawaii

In cooperation with the Hawaii Commercial and Sugar Company, the state of Hawaii, Gas Technology Institute (GTI, a merger of the former Gas Research Institute (GRI) and the Institute of Gas Technology (IGT)), Westinghouse Electric and others, DOE provided cost-shared funding to scale up a GTI gasifier (developed by IGT) to a demonstration scale that would consume 100 tonnes per day of bagasse (sugar cane residue). The demonstration was to include hot producer gas clean-up technology that could create a producer gas suitably clean for firing in a gas turbine. The gasifier was designed to operate with air or oxygen up to pressures of 20 bar. The unit operated for short periods at a fuel feed rate of about 50 tonnes per day and a pressure of 10 bar but creating a producer gas that was flared. There were significant problems feeding the biomass to the pressurized reactor which were not solved with a re-design of the feed system. Funds were not available to continue the project after the second feeding system proved inadequate[3].

A1.2 New Demonstration Projects

Carbona and FERCO Enterprises report new projects are being developed.

Carbona

Carbona which licensed the Renugas technology from GTI has constructed and tested a 15 MW_{th} high-pressure (20 bar) Renugas pilot plant in Tampere, Finland. Around 1993, Carbona successfully operated the pressurised gasifier for over 2,000 hours with a variety of biomass wastes and also evaluated hot-gas filtration for IGCC application. In October 2004, Carbona reported that ground had been broken for building a 5.4 MW_e capacity low pressure, Renugas demonstration project in Skive, Denmark. The project will start its operations with pelletised wood.

Carbona is also reported to be supplying the gasifier and gas cleaning system for an IGCC project in India[2]. It is proposed to consume wood waste and cashew and coconut shell. Fuel feed rate is planned for 200 tonnes per day and should net 12 MW_e. The project cost is £12.5 million. Project initiation is awaiting final decision from financing partners.

FERCO Enterprises

An energy firm in the UK (Peninsula Power) is planning to build a 23 MW_e (net) BIGCC facility using the FERCO gasifier and a Siemens Cyclone gas turbine. Fuel will come from a consortium of energy crop growers (short rotation willow coppice and miscanthus) and local forestry operation wastes. The project cost is reported to be £39 million of which £11 million is a renewable energy grant award from the government. The project is in the permitting stage.

A2 INDIRECT CO-FIRING OF BIOMASS

A2.1 Current Commercial and Demonstration Projects

Aabernraa

At Aabenraa in Denmark, a biomass boiler has been installed in parallel with an existing unit of the Enstedværket coal-fired plant. The two boilers are only connected via a common feedwater pipe from the condenser and a common steam pipe leading to a high pressure steam turbine. The biomass boiler consumes 120,000 tonnes of straw and 30,000 tonnes of wood chips per year and supplies steam corresponding to 40 MW_e and the coal-fired unit has an output of 660 MW_e. The biomass plant was fully operational in August 1998 but has incurred problems with corrosion which necessitated overlay welding the entire furnace in 2000.

Avedøre 2

Avedøre 2 consists of a parallel powered combined cycle arrangement with a coal/natural gas/oil USC boiler, a biomass combustion unit able to burn wood chips or straw and an aeroderivative gas turbine running in an integrated cycle. The plant has the capacity at full load of 570 MW_e or 485 MW_e plus 570 MJ/s of district heating. The main unit is a 380 MW_e ultra-supercritical boiler. The primary fuel was intended to be natural gas constituting about 85% of total fuel consumption with biomass accounting for 10% but since then the spot price of electricity has fallen and the price of natural gas has risen hence in 2002 the main boiler will be converted to use highwood pellets. The biomass boiler is a once-through Benson type boiler consuming 26.5 tonnes of straw per hour and producing 40 MW_e and 60 MJ/s heat. It has been designed for 100% straw firing or mixed firing with straw and wood chips. The USC boiler started operating in late 2001 and the biomass boiler was fired in January 2002.

New Bern

A commercial gasifier based on Chemrec™ technology has been in operation at the Weyerhauser New Bern pulp mill in North Carolina, USA since 1997. The Chemrec gasifier is an atmospheric pressure entrained flow reactor and gasifies around 300 tonnes of black liquor (dry solids basis) per day. Problems reported include excessive carry over of ash into the boiler and corrosion and thermal stress in the gasifier at the interface with the quench. The former was rectified by the optimisation of a venturi scrubber downstream of the gasifier and the latter by modification of the refractory lining.

Ruien

The Biopower Ruien project of Electrabel in Belgium is the site of a biomass gasification partial repowering project. In this project, pulverised wood is gasified in an atmospheric pressure circulating fluidised bed gasifier supplied by Foster Wheeler and the gas produced is used to partly replace coal in an existing coal-fired boiler. In the first phase of the project a 8.5 t/h plant was used to gasify 40,000 tons per year of clean wood to generate 14 MW_e. After reconstruction, the second phase commercial operations commenced in May 2003, generating 17 MW_e (50 MW_{th}) from 100,000 tonnes per year of clean and waste wood. Generation capacity at project completion is estimated to be 31MW_e.

Västerås

A new boiler has been constructed at the Västerås CHP plant in Sweden to fire biomass. The biomass boiler is a CFB boiler with natural circulation. It connects to the turbine, condensate and feed water systems of the existing coal-fired Unit 4 which is a once-through boiler generating 180 MW_e or 155 MW_e and 250 MWdh. The biomass boiler will increase the production to 250 MW_e or 220 MW_e and 350 MWdh. The biomass boiler was started up in October 2000 and is in commercial operation.

Vermont

The McNeil generating station in Burlington, Vermont is an existing 50MW_e unit fuelled by wood chips. A Battelle gasifier has been retrofitted to convert a part of the wood feed into gas which is then fired directly into the existing boiler. The gasifier uses around 200 tonnes per day of pre-dried wood chips. The low pressure Battelle gasification process consists of two physically separate reactors:

- a gasification reactor in which the biomass is converted into a medium calorific value (MCV) gas and residual char at a temperature of 850°C, and
- a combustion reactor that burns the residual char to provide heat for gasification.

Heat transfer between reactors is accomplished by circulating sand between the gasifier and combustor. Since the gasification reactions are supported by indirect heating, the primary fuel gas is a MCV fuel gas (~ 17.75 MJ/Nm^3). The gasifier was commissioned in 1997, however, problems were encountered during initial operation which lead to modifying the fuel drying and gas cleaning processes. In late 2000, continuous operation of the plant was demonstrated with feed rates up to 320 tonnes per day.

The Vermont project is seen as a development towards an IGCC plant and FERCO is actively pursuing commercialisation of the process[1].

Zeltweg

The Austrian utility Verbund has installed a biomass gasifier at its 137 MW_e coal-fired plant in Zeltweg. The project, which is known as BioCoComb, involves gasifying bark and wood chips in a CFB gasifier and feeding the product gas into the existing boiler to generate 10 MW_{th}. The first gasification took place in December 1997 and by October 2000, 5000 tonnes of biomass and supplementary fuels had been gasified. For economic and strategic reasons the main power station was shut down in April 2001 but by then the project had demonstrated that the BioCoComb process was technically sound and that the generation costs were competitive for electricity production from biomass.

A2.2 New Demonstration Project

Lurgi has scaled-up their CFB gasifier design to an 85 MW_{th} biomass plant built for Essent /AMER in Geertruidenberg, the Netherlands. This co-firing (in a pulverised coal (PC) boiler with a total capacity of 600 MW_e) project has been reactivated after some modifications to the downstream heat-exchanger to test and evaluate gasification of demolition wood. One of the operational modifications was to maintain the raw gas handling temperature at 400 to 450°C to minimise condensation in the downstream heat-exchanger. Under these conditions, most of the heavy metals (e.g., Pb and Zn) and alkali compounds condense on the entrained solids which are subsequently removed in a cyclone separator. The cyclone separator is estimated to operate at 65 to 70% efficiency.

The Lurgi CFB gasifier uses 150,000 tonnes per year of construction and waste wood and has an output equivalent to 29 MW_e or 26 MW_e and 15 MW_{th}. Chipped wood is delivered by ship and truck and stored in a silo. Since drying is not required the wood fuel is directly conveyed to the gasifier and gasified at a temperature of 850°C. The raw gas leaving the gasifier is cooled in a gas cooler producing superheated steam at 55 bar. Downstream of the gas cooler is a bag-house filter installed dedusting the gas to a final dust content of less than 5 mg/m^3. The dedusted gas is then routed to a wet scrubbing stage where it is quenched and ammonia removed to the specified level. The clean gas is reheated and sent to the power station where it is combusted. The wash water is stripped of ammonia which is recycled to the gasifier. The stripped wash water is also sent to the boiler for combustion.

A3 REFERENCES

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(3) Williams R, and Vincent B, Project 1.1: *Technology assessment for biomass power Generation*, SMUD ReGEN Program, Contract 500-00-034, October, 2004.