Eidgenössische Technische Hochschule Zürich
Swiss Federal Institute of Technology Zurich

PAUL SCHERRER INSTITUT

Cost outlook for the production of biofuels

A cost comparison assessment of the future production of biofuels

Martin Ragettli

February 2007
Diploma Thesis, Environmental Sciences ETH

Cover picture:

hybrid poplar plantation, United States Department of Agriculture (USDA).

Cost outlook for the production of biofuels

A cost comparison assessment of the future production of biofuels

Diploma Thesis, Environmental Sciences ETH

February 2007

Author:
Martin Ragettli
Via Fischeisch 15
CH-7017 Flims Dorf
phone: +41 79 407 85 22
mail: martirag@student.ethz.ch

Supervision:
Timur Gül & Leonardo Barreto
Energy Economics Group
Laboratory for Energy Systems Analysis (LEA)
Paul Scherrer Institute (PSI)
CH-5232 Villigen
phone: +41 56 310 25 98
mail: leonardo.barreto@psi.ch, timur.guel@psi.ch

Co-Supervision:
Alexander Wokaun
General Energy Research Department (ENE)
Paul Scherrer Institute (PSI)
CH-5232 Villigen
phone: +41 56 310 27 51
mail: alexander.wokaun@psi.ch

"When the wind of change starts blowing there are people who build walls, and there are others, building windmills" [150].

Preface

This thesis is a result of my work at the General Energy Research Department (ENE) of the Paul Scherrer Institute (PSI). For me it has been a privilege to be a member of the PSI Energy Economics Group (EEG) for the past six months. First of all I would like to thank my supervisors Leonardo Barreto and Timur Gül for their advices and support, and their always open ears for my questions and concerns. The work was fascinating and boosted my passion to learn more about energy systems in the future.
I am sincerely thankful to Alexander Wokaun for accepting me as a master student and for enabling the link between the Department of Environmental Sciences and the Paul Scherrer Institute. To Warren Schenler, Samuel Stucki and Remo Felder I want to express my thanks for the helpful inputs they provided. I am also grateful to Ernst Stäuble for looking through this text as for the language.
In addition I would like to thank the whole Energy Economics Group for the coffee breaks and lunch times we spent together, not only discussing about the serious things in life. The spirit within the group let me feel welcome and comfortable.
I would like to thank my parents for their strong support during my studies and all my friends with whom I could spend my time in the nature, either kidding and hoaxing or just remaining with me in awe of its beauty. Particularly I want to thank my girlfriend Michèle for her understanding and love.

Abstract

Keywords: global energy demand, transport sector, greenhouse gases, biofuels, biomass supply potential, biofuels production costs, feedstock costs, truck transport costs, distribution costs, plant gate costs, fueling station gate costs, Latin America, Western Europe

Global demand for energy and the energy use in the transport sector are projected to increase drastically until 2030. A variety of problems are going along with the present energy supply system, such as: depletion of fossil energy sources, a security risk of supply, or local, regional and global environmental problems, including the emission of greenhouse gases influencing the earth's climate system.

Biofuels can contribute together with other technologies to abate these problems and are therefore promoted in several countries worldwide. Production of biofuels is expected to grow substantially, particularly in Brazil, Europe and the USA.

Whereas the use of starch and oil crops for the production of biofuels is on a reasonable high level already, big attention is being paid to future development of cellulosic and lignocellulosic biomass-to-biofuels production technologies because the growing of latter plants is not affecting the food production and can be realized on minor quality land with cheap feedstocks.

The global biomass supply potential for 2050 is calculated to range between 33 EJ and 1344 EJ per annum. Compared to the transport sector which is projected to consume 36.2 EJ in 2030, it is obvious that a big part of fossil fuels can potentially be replaced with biofuels, at least on a technical potential level, not considering the costs. It has to be considered though that in this case biomass or biofuels have to be imported from regions with high biomass supply potential to regions with low supply potential. Biggest potential is found to be in Latin America, Eastern Europe (Ukraine, Former Soviet Union), Southeast Asia, China and Sub-Saharan Africa.

A cost comparison assessment of biofuel production has been conducted in order to analyze the competitiveness of biofuels compared to fossil fuels. Subject of the analysis was the production of ethanol, biodiesel (FAME, FAEE), synthetic natural gas, FT-diesel, methanol and dimethyl ether from various feedstocks and production pathways.

The costs of fifty individual processes found in literature have been reviewed, out of which ten representative pathways have been selected for further analysis. The subsequent system components have been considered within the cost analysis: producer prices of the feedstock, truck transport from the farm to the conversion plant, biomass-to-biofuel conversion costs, and distribution costs from the conversion plant to the fueling station. In addition a cost comparison between Western Europe and a world region with high biomass supply potential, namely Latin America has been carried out.

Biofuels production costs vary widely between different fuel types and production pathways. Considering the cost at the fueling station gate, in LAFM, SNG from anaerobic digestion is the most costly biofuel, in WEUR it is ethanol from sugar. The relative cost rankings of the other biofuels remain yet quite identical between the two regions. Though as a rule of thumb, one can say that the total production costs (production & distribution) in Latin America are reduced by some 2-5 $/GJ biofuel, compared to Western Europe. Ethanol from sugar costs can even be reduced by 17 $/GJ, mainly due to lower feedstock costs.

In a low cost production region like Latin America, the biofuel with the lowest production and fueling station gate cost is methanol from wood gasification, followed by biodiesel from esterification, biodiesel from pyrolysis, and FT-diesel from wood gasification. These biofuels can be produced and delivered at costs of some 11.5-14.5 $/GJ. Ethanol from starch, sugar or cellulosic biomass, synthetic natural gas from wood gasification, synthetic natural gas from anaerobic digestion, and dimethyl ether from wood gasification cost about 18.5-22.89 $/GJ. Feedstock costs are one of the main contributors to total production costs and can contribute up to 83% to total production costs.

For synthetic natural gas, FT-diesel, methanol and dimethyl ether, the investment costs in process equipment are relatively high and can contribute up to 65% to total costs. The distribution costs of the final fuel are another significant contribution to total costs. For gaseous biofuels these costs are higher than for liquid fuels. Synthetic natural gas distribution accounts for about 40% of the total fueling station gate costs. For the other fuels, distribution accounts for about 20% of the total costs.

If one considers the present fueling station gate cost of 11 $/GJ for fossil fuels (costs for Switzerland) excluding taxes, only methanol from wood gasification produced in Latin America, is nearly competitive with costs of 11.48 $/GJ. If the plant gate costs of the biofuels are compared with the plant gate cost of 7 $/GJ for today's fossil fuels, methanol from wood gasification in Latin America is competitive at costs of 5.42 $/GJ. Biodiesel from wood pyrolysis produced in Latin America and methanol from wood gasification in Western Europe are just slightly more expensive with total plant gate costs of 9.96 $/GJ and 8.33 $/GJ, respectively.

Taxes on fossil fuels however, as for example a CO_2 tax, could make future biofuel wholesale costs competitive to their fossil counterparts.

As literature data about the environmental influences of the biofuel production are highly controversial, it is recommended to carry out a multi criteria analysis, dealing not only with the costs but also with ecological, economical and social sustainability. Doing so one could establish a useful tool in affecting which biofuels should be subject to subsidies, or how high taxes on different fuels should be.

Table of contents

List of figures

List of tables

1 Introduction

According to the International Energy Agency, total final world energy consumption in 2004 amounted to 90.7 EJ, compared to 54.6 EJ in 1973 [89]. In the IEA Reference Scenario[1], global primary energy demand is projected to increase by 60% between 2002 and 2030, resulting in an average annual growth rate of 1.7% and a final consumption of 140.2 EJ (Figure 1).

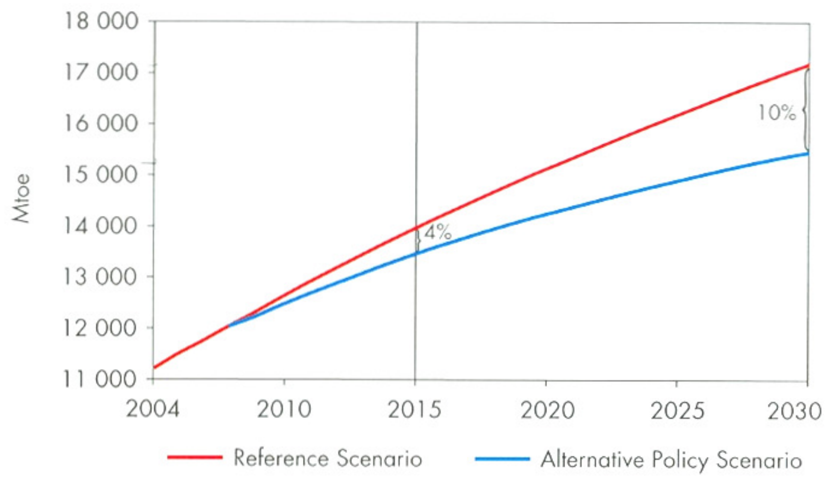

Figure 1: Global primary energy demand in the „Alternative Policy Scenario" and in the „Reference Scenario" from the IEA. The biggest savings in the "Alternative Policy Scenario" are caused by fossil fuels reductions [92].

The "Alternative Policy Scenario[2]" results in some 10% less total energy demand, mainly caused by fossil fuels reductions. In both scenarios of the "World Energy Outlook" fossil fuels will remain the dominant source for energy until 2030. Over 70% of the increase in primary energy demand is expected to come from developing countries, with China alone accounting for 30% [92].

The energy consumption of the transport sector[3] rose from 11.4 EJ in 1973 to 23.4 EJ in 2004. In percentages of total final energy consumption this means an increase from 20.8% in 1973 to 25.8% in 2004 [89]. Road transport is expected to grow between 1.2% and 1.7%[4] annually until 2030. In other words, the energy share of the transport sector to total energy consumption remains on the actual level of about 25% and is projected to be around 35 EJ in 2030 [92].

In 2004 22.1 EJ or 85.6% of the energy consumed in the transport sector was derived from petroleum products, this corresponds to 57.7% of world oil consumption [89]. Thus, the oil dependence problem is a transport problem [86]. From an emission point of view, the transport sector is responsible for 23% of

[1] The "Reference Scenario" takes into account government policies and measures until mid 2006. Possible, potential or even likely future policy actions are excluded [92].

[2] The "Alternative Policy Scenario" analyses how the global energy market could evolve if countries were to adopt all of the policies they are currently considering related to energy security and energy related CO_2 emissions.

[3] The Transport sector includes all fuels for transport except international marine bunkers. It includes transport in the industry sector and covers road, railway, aviation, domestic navigation, fuels used for transport of materials by pipeline and non-specified transport.

[4] This corresponds to the "Reference Scenario" and the "Alternative Policy Scenario", respectively, from WEO, 2006 [92].

the total global carbon dioxide (CO_2) emissions [89]. Light duty vehicles[5] and other passenger and freight transport modes on roads contribute up to 90% of energy consumption to the entire transport sector [88, 91].

The number of light-duty vehicles[5] in use worldwide, is expected to double, from 650 million in 2005 to 1.4 billion in 2030 [92],[86]. Although the technical efficiency of light duty vehicles steadily increased over time, this gain is outweighed by the consumer preference for heavier, larger vehicles and more powerful engines [91].

High oil prices and the introduction of fuel standards have been the most effective drivers for the development and use of energy saving technologies in the transport sector [88]. One of these technologies for the future could be biofuels, helping to reduce fossil oil consumption in the transport sector.

The scope of this study is to give an overview of the future production costs for biofuels from a variety of feedstocks (starch crops, sugar crops, wood, agricultural residues, organic waste). Namely considered are ethanol, biodiesel, FT-Diesel[6], SNG[7], DME[8] and methanol derived through different conversion pathways.

The cost estimate starts with the feedstock prices adding a truck transport cost for the feedstock transportation to the plant where the biomass is converted to the biofuel. After conversion, the biofuel is distributed to the fueling station which adds another cost factor. The result of the study is an economic comparison assessment of future biofuels production and distribution.

The main goal of the study is the breakdown of the biomass-to-biofuel conversion costs in investment costs, fixed O & M costs, variable O & M costs, energy input costs and feedstock costs. An additional target is to compare wholesale biofuel production costs from a low cost world region with big biomass supply potential to Western Europe. Therefore a division of the world in different world regions is conducted. As a next step the world region incorporating the biggest biomass production potentials for the respective biofuel conversion pathway is selected. As far as possible the mentioned cost elements (feedstock prices, conversion costs, transport and distribution) are then adapted if feasible to the respective world region. At the end of the study the following questions should be answered:

- What are the expected production costs for biofuels in the future with the main focus on biomass–to-biofuel conversion costs?
- Are biofuels fueling station gate costs and plant gate costs competitive to conventional fossil fuels?
- How big is the biofuel production cost difference between a world region with high biomass supply potential and Western Europe?
- What factors have the biggest influence on the total costs of various biofuels at the fueling station?

[5] passenger cars and other light duty vehicles
[6] Fischer Tropsch diesel
[7] synthetic natural gas
[8] dimethyl ether

The cost comparison is embedded in a wider context, in which sustainability aspects, the global biomass potentials and national programs and targets for the promotion of biofuels are briefly analyzed. These aspects are discussed in the subsequent chapters (Chapter 2-5).

As a next step the different technologies for the production of biofuels found in literature are described in Chapter 6. In Chapter 7, the main assumptions for the cost calculation are described, the system is outlined spatially and chronologically and the different system components and variables are defined. In the next chapter these system components are described and discussed in order to carry out a consistent economic analysis and a regional cost approach (Chapter 7). The regional approach procedure is outlined in Chapter 9, and the results of this approach are presented in Chapter 10, followed by the discussion and conclusions in Chapter 11 and Chapter 12.

Further information about the national targets and programs for the promotion of biofuels can be found in Chapter 15, Appendix 1, a detailed technology description can be read in Chapter 16, Appendix 2. The whole set of reviewed biomass-to-biofuels conversion pathways and their parameters can be found in Chapter 17, Appendix 3. Chapter 19, Appendix 5 shows additional details about the selected pathways for the regional approach.

2 Biofuels in the context of sustainability and renewable energy[9]

A variety of problems are going along with the present energy supply system: depletion of fossil energy sources, a security risk of supply, local, regional and global environmental problems, including the emission of greenhouse gases influencing the earth's climate system.

Moreover, 2 billion people have no access to modern energy carriers. According to Jefferson, solving these problems requires a new thinking about energy that considers the impacts of energy use at local and global scale and the development of a wider portfolio of energy resources and cleaner technologies. The future energy system should offer wider access and cover our present needs as well as the wellbeing of future generations [96].

The third assessment report of the Intergovernmental Panel on Climate Change (IPCC) provides the strongest evidence that global warming is largely due to human activity, especially the emission of carbon dioxide (CO_2), caused by the burning of fossil fuels [93]. The United Nations Framework Convention on Climate Change (UN 1992, article 2) calls for a …"stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interferences with the climate system… ". But unless major changes are made in the manner fossil energy is used to provide energy, carbon dioxide (CO_2) in the atmosphere will continue to rise [81].

Biomass has the potential to become one of the major global primary energy sources during this century, and future bioenergy systems are suggested to be important contributors to future sustainable energy systems and to sustainable development in industrialized countries as well as in developing countries, serving as a key option to mitigate greenhouse gas emissions, to substitute fossil fuels and provide energy security [67-69, 92, 99, 196]. In addition air pollutants can be reduced through using biofuels in combustion engines[10] [86]. Oil could better be used for the production of chemicals and materials which profit from the unique complexity of the oil, instead of burning it to carbon dioxide (CO_2) and water (H_2O) [198].

Only biomass offers the possibility to produce liquid, carbon neutral, transportation fuels [169] causing even better engine performance than normal fuels[11] [86]. Nevertheless it can be converted into modern energy carriers that can be used for heat and electricity production, as well as for transportation [145, 173, 189]. Summarizing the latter aspects one can see that large scale introduction of biomass energy could make a contribution to sustainable development on several aspects, environmentally, socially, and economically [145, 148, 178].

---

[9] For further information see also [37, 55, 128, 131].

[10] The emission of certain pollutants may also increase. E. g.: Ethanol blends benefit from reductions in CO, SO_2 and particulate matter (PM), biodiesel benefits additionally from lower hydrocarbon emissions. In addition biofuels are in general less toxic than conventional fuels. On the other hand, ethanol use leads to higher aldehyde and evaporative hydrocarbon emissions, and both ethanol and biodiesel can cause higher NO_x emissions, especially on a well-to-wheels basis. Net benefits could be biggest in cities with high PM emissions, as for example in developing countries [86].

[11] Biodiesel has a slightly higher cetane number and better lubricity than conventional diesel, thus burns more efficiently and reduces wear of engine components [134]. Ethanol has a higher octane number than gasoline and can be added as an oxidant to conventional gasoline. Its oxygen content improves the combustion process, leading to a decreased level of tail-pipe emissions [43]. In Europe most ethanol is converted to ethyl-tertiary-butyl-ether (ETBE) which has a lower volatility than ethanol [86].

Sustainable growth of energy crops can improve soil quality by sequestering carbon and restoring erosion damage [145, 173, 189]. Plantations could create local employment in rural areas, and stimulate economic growth [92]. At the same time solid wastes can be reduced, which results in a clear social benefit [86].

However, it is not clear and insufficiently analyzed yet what consequences a rise in bioenergy production would have on biodiversity and nature conservation [17]. Other authors say that one would preferably promote the use of lighter, more efficient vehicles instead of biofuels. In addition it would be more efficient to generate electricity with biofuels instead of burning them in a low efficient combustion engine for transport purposes [32-34, 79, 161].

Estimating the net impacts of using biofuels on oil use and GHG[12] emissions is very complex and requires comprehension about the full fuel cycle, from biomass feedstock production to final fuel consumption [86]. The net environmental and emissions impact of replacing conventional fuels with biofuels depends on the type of crops, yields, the amount and type of energy used for fertilizer production, the harvesting method, transportation mode and distance, alternative land uses, energy intensity of the conversion process, water use and utilization of by-products [92]. Therefore in literature one can find an enormous variation in net emission and energy savings using biofuels in modern combustion engines (Figure 2).

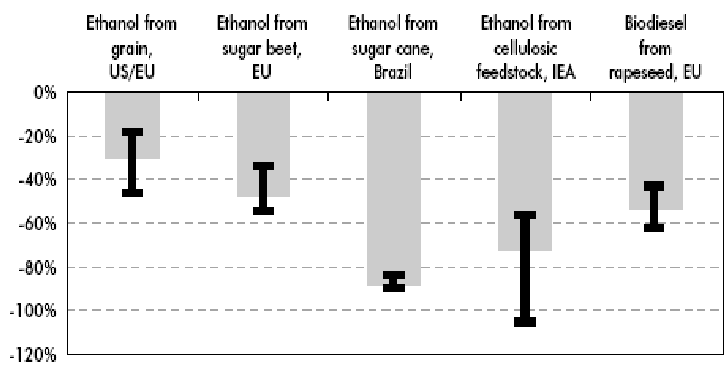

Figure 2: Range of estimated greenhouse gas reductions from different ethanol production pathways[13] [86].

For ethanol from wood the much disputed [130] study of Pimentel finds a net energy input which is 57% higher than the net energy content of the biofuel itself. For ethanol from corn the net energy input is still 29% higher than the output [140].

Farrel instead shows a net energy saving of 20% for ethanol from corn in the USA, compared to conventional fuel production [48]. The European commission estimates that conventional ethanol production can result in a net energy saving of up to 23% of the energy required for gasoline or a saving of over 30% in greenhouse gas emissions. Sugar beet to ethanol and rape to biodiesel in Europe can yield reductions in well-to-wheels emissions of typically 20%-60% [40]. For cellulosic derived ethanol, the IEA

[12] greenhouse-gas emissions

[13] This figure shows reductions in well-to-wheels CO_2-equivalent GHG emissions per kilometer from various biofuel/feedstock combinations, compared to conventional-fuelled vehicles. Ethanol is compared to gasoline vehicles and biodiesel to diesel vehicles respectively. Blends provide proportional reductions; e.g. a 10% ethanol blend would provide reductions of one-tenthof those shown here. Vertical black lines indicate range of estimates [86].

reports greenhouse gas reductions of up to 80% (Figure 2) [86]. These examples shall just give an idea of the bandwidth of possible emissions reductions. Estimating this potential is not subject of this thesis though[14].

The most important operating disadvantage of some biofuels in comparison with fossil fuels is its much lower energy content on volumetric basis[15]. This increases fuel consumption when biofuel is used (either in pure form or in blended one) in comparison with application of pure fossil fuels, proportionally to the share of the biofuel content. This increase in fuel consumption is augmenting in addition the overall cost of the application of biofuel as an alternative to fossil fuels [43].

[14] Detailed life cycle analysis of different biofuels is carried out by the CONCAWE studies [40]. Felder and Dones carried out an analysis of the ecological impacts of synthetic natural gas from wood used in current car systems [49]. For further details of environmental impacts from the production and use of biofuels see also [37, 55, 128, 131].

[15] e. g.: ethanol: 21.28 MJ/l, gasoline: 32.18 MJ/l [40]

3 Markets, targets and programs for the promotion of biofuels[16]

Considering the above mentioned fact that the transport sector is currently responsible for some 25% of the total global energy consumption one can see that a big fossil fuel reduction potential in this sector is possible. Therefore several nations have adopted different programs and targets to effect a more intense production and utilization of biofuels. The production of biofuels is mainly promoted through tax incentives.

At present though, agricultural policies often have more significant influence on biofuels production policies than climate protection interests. A better understanding is still needed of how policies in these two areas interact, and how they could be optimally designed in this regard [86].

Almost all biofuels produced today are either ethanol or esters[17]. Most important biofuels production and utilization is located in the USA, Brazil and the EU. In the USA mainly ethanol from corn is produced, in Brazil ethanol from sugar cane and in Europe biodiesel from oilseeds. Biofuel use in other regions is rather modest.

Global production of biofuels in 2005 amounted to 20 Mtoe, which is equal to 1% of total road transport fuel consumption in energy terms. In 2004, only in Sweden, Brazil and Cuba, total biofuel demand exceeded 2%. But with new production capacity coming on line this share is steadily growing in several countries [92].

For a detailed description of the national strategies and programs planned or in place see also Chapter 15, Appendix 1.

[16] The selection of countries and/or regions is arbitrary and does reflect the availability of data in literature. The most important biofuels producers are though USA, Europe and Brazil [92].

[17] commonly referred to as biodiesel

4 Different types of biomass for the production of biofuels

Biofuels can be produced from a great variety of feedstocks such as agricultural crops, organic waste, wood, residues emerging from forestry or other industries, (e.g.: black liquor[18] from the paper industry) [12], oil seed crops (e. g.: soy[19], rapeseed[20], sunflower, oil palm), or animal fats (beef tallow, poultry fat, pork lard) [86].

In general, the following biomass groups for the production of biofuels can be identified: cellulosic[21], lignocellulosic[22], starch[23], sugar[24] and oil containing[25] feedstocks. For the production of ethanol from starch, both corn and wheat are used most commonly [4, 74, 192]. For ethanol from sugar, sweet sorghum, sugar cane and sugar beet are commonly processed [86, 92]. Rapeseed, sunflower, oil palm and soybean are widely used for the production of biodiesel [98]. For the production of biofuels from cellulosic feedstocks, stover and switch grass are most popular. For the biofuels production from lignocellulosic feedstocks, forest residues, and poplar or willow from plantations are commonly used [71, 73, 122, 182]. Biogas is mainly received from organic waste [98].

Theoretically every plant can be processed into some biofuel. Most important criteria for the selection of a suitable plant for the production of biofuels are yield, growth rate, water content, alkali content, as well as energy needed for the cultivation, harvesting, transport and pretreatment [122].

---

[18] Black liquor is the liquid material remaining from pulpwood cooking in the soda or sulfate paper-making process [26, 76]. Black liquor is not considered in this study because no feedstock prices have been found in literature.

[19] In Europe soy is generally called soya [86].

[20] often called rape or canola [86].

[21] "Cellulose is a polymer of up to about 10,000 glucose molecules joined by beta 1-4 linkages in long, straight cellulose chains that can align parallel to one another and joined by hydrogen bonds in crystalline regions that typically contain much of the cellulose. About 40 to 50% of the structural portions of plants is cellulose" [198].

[22] "Lignin is a complex phenylpropanoic acid polymer that is chemically linked with hemicellulose to cement cellulose together. Lignin represents about 15% to 20% of the dry weight of cellulosic biomass and is not fermentable at an appreciable rate" [198].

[23] "a polymer of glucose molecules joined predominately by alpha 1-4 linkages" [198].

[24] "a family of simple, often sweet, compounds consisting of carbon, hydrogen, and oxygen obtained in the juice of many plants and particularly from sugarcane and sugar beets. Also refers specifically to sucrose, a particular type of sugar. Other sugars typically contained in biomass include arabinose, galactose, glucose, mannose, and xylose [198].

[25] In this case "containing" refers to as "high concentrations" of the particulate content, so that the energy used per unit of biofuel produced is as small as possible" [198].

5 Global biomass supply potentials

Biomass is abundant in most parts of the world [148]. Even though some world regions have a much larger biomass production potential than others due to good soil quality, low population densities and extensive agriculture [83].

The present use of biomass covers 9%-14% of the global energy demand. Most of this use is for traditional, low-tech cooking and heating in developing countries [68, 173]. Production of modern energy carriers contributes about 7 EJ to global energy use [173].

The estimated biomass supply potentials are highly dependent on the variables, land availability (e.g.: land use choice) and crop yields on various land types. As these variables can vary extremely between different regions, assumptions on biomass supply are highly uncertain [17]. Other important factors influencing the bioenergy potential are population growth, food demand, economic development, food production efficiency and competing biomaterial products [70, 83].

Potentials can be distinguished in the theoretically available potential[26], the geographical potential[27], the technical potential[28], the economic potential[29] and the implementation potential[30] [82]. In literature the geographical potential is described most widespread [17, 29, 47, 82, 83, 157]. As an approximation, the technical potential, which means the theoretically producible amount of biofuels, can be derived from dividing the geographical potential by a factor of two, [86].

Furthermore it can be distinguished between demand driven assessments and resource focused assessments. The latter one focuses on the total bioenergy resource and the competition between different uses of the resource. The demand driven assessment estimates the competitiveness of biomass compared to other energy carriers, or the amount of biomass required to meet exogenous targets on climate neutral energy supply [17]. In this study resource-focused assessments are being considered.

Net food demand is projected to decrease from an annual growth rate of 2.2% per year during the last 30 years to 1.5% in 2030. A lack of land is not forecasted for the time period until 2030. Overall FAO estimates conclude that suitable land for rain fed crop production is nearly three times larger (4152 million ha) than currently used capacities (1608 million ha) [47]. Another study finds a total available agricultural land for bioenergy production of 700-3600 ha for the year 2050, depending on the demand for pasture and crop land. This is equal to 14%-70% of the present total agricultural land in use [157].

In energy terms this assumption leads to a geographical potential of 215-1272 EJ per year in 2050, the utilization of residues adding another 58-72 EJ per year. Without other land use, 1807 EJ for a low level of technology and 4435 EJ for a high level of technology are projected to be available by then [157].

Berndes carried out a review of 17 studies in which the contribution of biomass in the future global energy supply varies between below 100 EJ [13] and 400 EJ [51] in 2050 [17]. Hoogwijk finds a geographical "biomass-for-energy" potential ranging from 33 EJ to 1135 EJ per year for 2050 [83].

---

[26] The theoretical upper limit of primary biomass; e.g.: Net Primary Production of biomass produced at the total earth surface by the process of photosynthesis [82].

[27] The theoretical potential at land area level for energy production from biomass [82].

[28] The geographical potential reduced by losses due to agricultural conversion efficiency and technology [82].

[29] The technical potential that can be realized at profitable levels [82].

[30] The maximum amount of the economic potential that can be implemented within a certain timeframe, taking institutional constraints and incentives into account [82].

Most important plant categories for the production of bioenergy are generally expected to be crops on surplus cropland, energy crops on degraded land, residues, manure and waste [83]. Berndes outlines that biomass from plantations, especially wood, are the most important contributors to a future global bioenergy system [17]. In Hoogwijks study, biomass from energy plantations on surplus agricultural land has the largest potential contribution to total biomass for energy[31] [82, 83].

[31] 130-988 $EJyr^{-1}$ in 2050 [82, 83]

6 Biofuels production technologies

Biomass can be processed into a variety of liquid, solid and gaseous fuels using different processing technologies which can be grouped into three categories: biological, thermochemical and mechanical [98].

Before the actual biofuels production, the biomass undergoes a pretreatment step (e.g.: cleaning, chipping, milling). Eventually, the biomass has then to be converted in order to enable the biofuel processing step (e. g.: starch has to be hydrolyzed before fermentation). As a next step the actual biofuel processing can take place (e. g.: fermentation, gasification). The resulting product may be liquid or gaseous hydrocarbons (syngas, bio-oil, ethanol) which then have to be further processed and/or refined/upgraded (e. g.: syngas processing, esterification of bio-oil to biodiesel, distillation of ethanol) in order to obtain a biofuel which can be burned in modern combustion engines[32] (Figure 3).

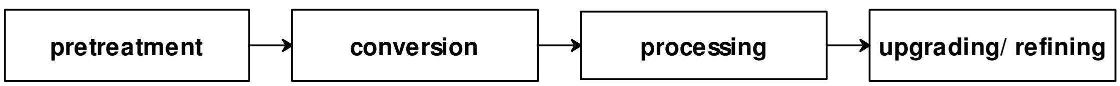

Figure 3: Exemplary biofuels production pathway. Single pathway steps and composition may differ between different biofuels production modes.

Using biological methods (e.g.: fermentation), the raw material is hydrolyzed[33] after which the carbohydrate fraction can be converted into fermentation products such as ethanol and methane [114, 172].

A thermochemical method is pyrolysis which converts biomass into oil, charcoal, and other products by heating it in the absence of air to some 475°C [147]. Biomass gasification at high temperatures (800-1100°C) is another thermochemical process and produces a mixture of hydrogen (H_2), carbon monoxide (CO), methane (CH_4), and carbon dioxide (CO_2). The resulting product gas or syngas can be reformed, whereby hydrocarbons are converted to carbon monoxide (CO) and hydrogen (H_2). The syngas can then be synthesized into a variety of fuels (e.g.: FT-Diesel[34], DME[35], methanol, hydrogen, SNG[36]) [123].

Other thermochemical processes include supercritical fluid extraction, in which biomass is liquefied using chemicals as carbon dioxide (CO_2), ammonia (NH_4^+), and methanol (CH_3OH) under supercritical conditions [30]. In hydrothermal upgrading (HTU), cellulosic materials are first dissolved in water under high pressure and relatively low temperatures to be converted into a biocrude liquid which can then be upgraded to diesel fuel in a hydrothermal upgrading unit [88]. Another thermochemical method is transesterification, a low temperature (20-60°C) reaction of oil[37] with an added alcohol in order to form an ester and glycerol which can be used in the pharma industry for example [40, 104, 117].

---

[32] In the subsequent part of the study the steps pretreatment, conversion, processing and upgrading/ refining are referred to as biomass-to-biofuel conversion or biofuels production.

[33] Lignocellulosic and starch crops need to be hydrolyzed. Sugar crops contain sugar already and therefore do not need to undergo hydrolysis (Chapter 16, Appendix 2).

[34] Fischer Tropsch diesel

[35] dimethyl ether

[36] synthetic natural gas

[37] animal fat, bio-oil, used oil and fat from the food industry

Mechanical methods for the production of biofuels are for example pelletization and briquetting. These methods can be used to increase the bulk density and enhance the heating value of the biomass [62, 109, 165, 200]. Another mechanical process is the mechanical extraction of oil from oil crops by pressing. This is usually the preliminary step of the transesterification [40, 104]. Figure 4 gives an overview of the processes considered in this study.

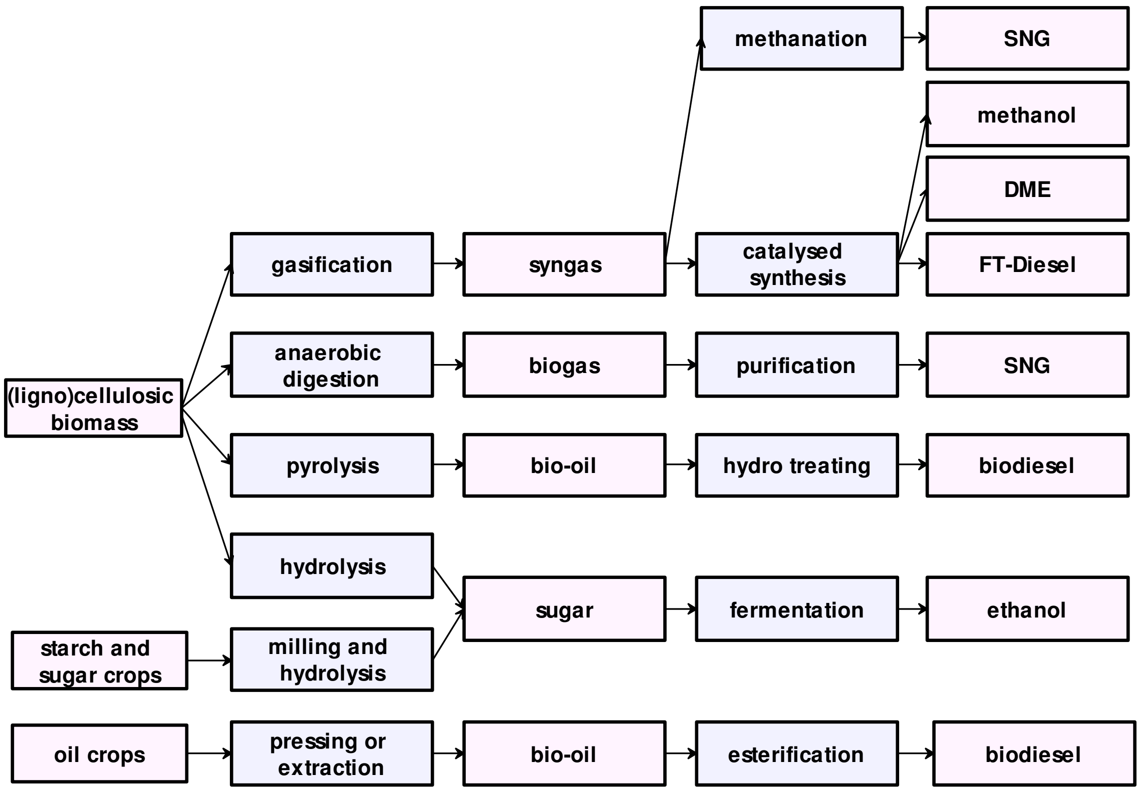

Figure 4: Biofuels production pathways analyzed in this study. Flowchart modified from Hamelinck [71]. For anaerobic digestion lignocellulosic biomass refers to as cellulosic biomass only. For hydrolysis, gasification and pyrolysis both cellulosic and lignocellulosic biomass can be used.

Excess heat and syngas can be recycled within the process or used for the co-generation of electricity. Non utilizable products (e. g.: bagasse, lignin fraction of biomass) can be burned as well in order to generate heat and electricity, and therewith increase overall process efficiency and decrease production costs [4, 35, 40, 115, 120].

Other by-products can be converted to chemicals (e. g.: glycerol from esterification of bio-oil) [7] or sold as animal feed (DDG[38]) [40]. As a result the net energy requirement and production costs of the conversion plant decrease [4, 40, 115].

Ethanol from starch and sugar fermentation, biodiesel from mechanical extraction and esterification, and SNG from anaerobic digestion are well established, commercially produced transportation fuels [23, 59, 85, 86]. A big hurdle for widespread use of gaseous fuels (SNG, DME), though, is the necessity for a new fueling station infrastructure whereas for the other above mentioned fuels, the existing

[38] Distillers Dried Grains (DDG) is a protein rich by-product which can be sold as animal feed.

infrastructure can be used with minor modifications [71]. Because of their widespread use and the production at a commercial level, these fuels are called 1st generation biofuels.

Methanol, DME and FT-diesel are arguably produced at a commercial level, but exclusively from natural gas or coal. These processes are called CTL or GTL which stands for coal-to-liquids and gas-to-liquids respectively [156].

Worldwide no commercial plants exist for the production of transportation fuels from lignocellulosic or cellulosic feedstocks. However various demonstration plants are in use or under construction around the globe [88, 92]. Biofuels derived from lignocellulosic or cellulosic feedstocks are generally called 2nd generation biofuels, regarded to be more competitive than 1st generation biofuels due to cheaper feedstock production costs, lower well-to-wheels greenhouse gas emissions, as well as less conflicts with the food producing industry [86] due to the fact that lignocellulosic feedstocks can be cultivated on minor quality or "set-aside[39]" land [47].

A more detailed process description of the different biofuels production pathways under analysis can be found in the Chapter 16: Appendix 2.

[39] land which is not in agricultural use

7 Methodology

In order to analyze the costs of different pathways of biofuels production, a spreadsheet with detailed cost components of the different production routes has been generated with data found in literature. These spreadsheets can be found in Chapter 17, Appendix 3. Moreover, feedstock costs, biomass truck transport costs, and distribution costs of the final fuel have been analyzed, resulting in an overall fueling station gate cost for various biofuels.

A regional cost approach was used in order to obtain a comparison of the biofuels production costs between Europe and a region with high biomass supply potential and low production costs. For this reason two different scenarios were set up with data obtained from literature.

The subsequent section is going to deal with the outline of these scenarios and the whole system. It describes the approach to the general cost calculation and deals with the fundamental assumptions and specifics of the cost assessment.

7.1 System outline

In this section the system structure and boundaries are presented. The time frame for the analyzed studies is discussed and the geographical allocation of the system is described. Subsequently, the system components and variables are highlighted.

7.1.1 Time frame

For the analysis of the whole cost chain of biofuels production for the future, a major constraint is the availability of data in literature. Normally one can say that technology forecasts get more optimistic (in the case of a cost analysis "optimistic" refers to as "less cost intensive") over time [169]. This makes clear that technology prospects for different time frames (e.g.: short term, long term) may differ. As it is virtually impossible to align the whole assemblage of reviewed production pathways described in literature on the same time frame, the biomass-to-biofuels conversion processes were defined to be just in the future, i.e. not distinguishing between short term and long term, and not limiting the upper timeframe of the forecast.

If a more exact time frame or starting point of the technology needs to be assumed in order to use such data for other studies, a time frame between 2010 and 2020 is considered to be most appropriate. For the other system components (feedstock costs, transport and distribution) present costs were used, this mainly due to the lack of cost predictions available in literature.

7.1.2 Geographical system outline

In order to accomplish a regional cost comparison a division of the world in 8 world regions was applied similar to the Global Markal Model[40] (GMM) (Energy Economics Group (EEG) at the Paul Scherrer Institute (PSI)) [143].

[40] The MARKAL model is a "bottom-up" energy-systems optimization model which allows a detailed representation of different energy technologies [143, 155]. This model is currently used at the Energy Economics Group at the Paul Scherrer Institute (PSI-EEG).

GMM contains 6 regions: Western Europe (EU25, Norway, Ireland, Bulgaria, Romania)(=WEUR), North-America (USA, Canada, Alaska)(=NAM), Latin America (Latin America incl. Mexico), Middle East and Africa (=LAFM), Former Soviet Union (=EEFSU), Asia (=ASIA) and Pacific OECD (Oceania, Australia, New Zealand und Greenland)(=OOECD). For the purpose of this study China (=CHN) and India (=IND) have also been considered as separate regions (Figure 5).

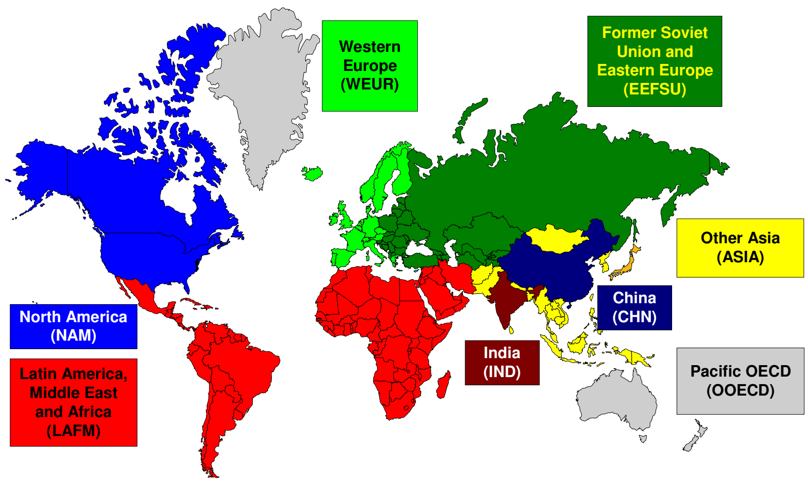

Figure 5: The 8 world regions according to the Global Markal Model (GMM) (Energy Economics Group (EEG) at the Paul Scherrer Institute (PSI)).

7.1.3 System components and variables

Within the study four different system components are considered in order to calculate the costs of a particular biofuel at the fueling station: feedstock costs, transport costs of the biomass to the production facility, production costs of the biofuel, and its distribution costs to the fueling station.
Each system component, except truck transport, has different options for determining the structure of a pathway. In Table 1 the system components and the corresponding options are presented.

Table 1: Different system components for the cost calculation and the corresponding options in this study.

system components	options
feedstock costs	different types of biomass
biomass transport costs to the facility	truck transport
biofuels production costs	different biofuels production pathways
biofuel distribution costs to the fueling station	different types of biofuels

Based on a defined set of variables the costs for each system component can be calculated, whereas each variable is influencing the cost calculation of a particular system component to a different extent (Table 2).
For the calculation of the feedstock costs, the producer prices in different world regions represent the only variable, thus reducing the complexity of the agricultural supply chain. As the costs are quoted in

dollars per energy content of the respective matter (e. g.: \$/GJ[41] biomass), and the efficiencies are calculated on an energy basis as well, the heating value[42] of the biomass and the biofuel respectively, have an influence on the system as well. For the calculation of the biomass transport costs, the heating value and the transport distance to the plant are considered. The production costs of the biofuels were analyzed in very detail, considering as much parameters as available. The distribution costs are assumed as average costs (Table 2). In Chapter 8 the different components are discussed in detail.

Table 2: Different system components for the cost calculation and the corresponding variables.

system components	variables
feedstock costs	producer prices in different world regions biomass heating value
biomass transport costs to the facility	biomass heating value distance
biofuels production costs	availability factor by-product credits biomass heating value discount rate efficiency energy prices feedstock costs fixed operation & maintenance costs investment costs lifetime transport costs of the biomass variable operation & maintenance costs world region
biofuel distribution costs to the fueling station	average costs (depending on biofuel)

Figure 6 gives a structural overview of the different options for the system components considered in this study.

[41] for details of the economic calculations see section 7.2.1

[42] all values on LHV basis

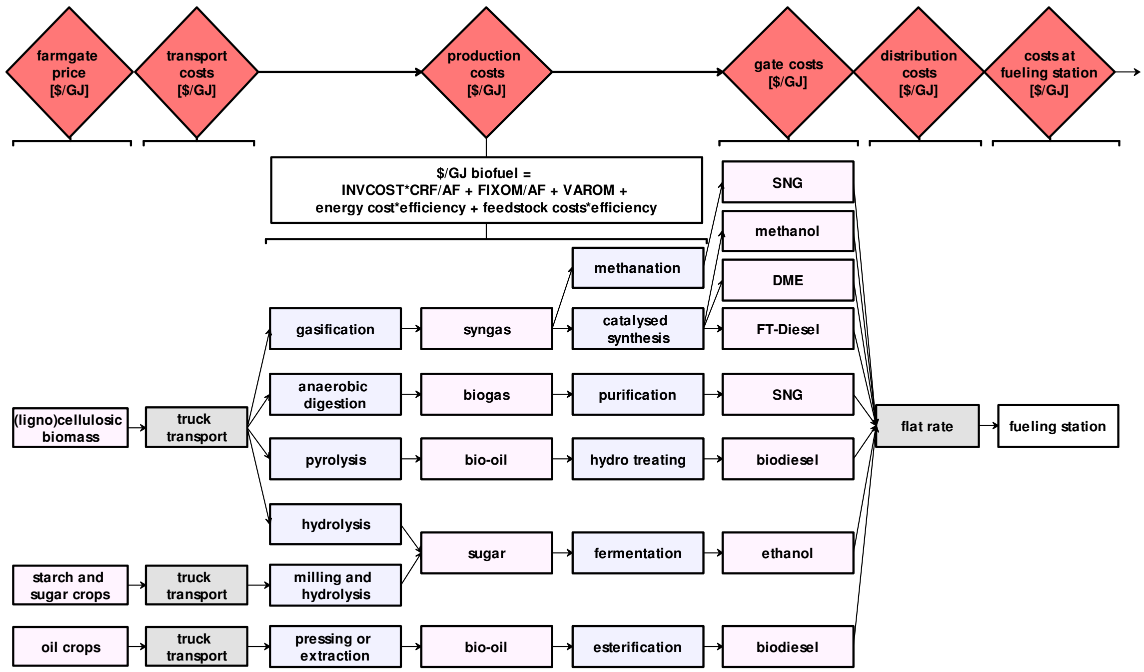

Figure 6: Schematic overview of the different system component options.

7.2 System assumptions

This section presents the methodology for the calculation of the biofuels production costs (biomass-to-biofuel conversion), as well as the definition of the energy prices needed for the calculations and the cost comparison of fossil fuels with biofuels.

7.2.1 Economic calculations

For the economic calculations all values are indicated in US$2000, computed with the inflator calculator of the U. S. Department for Labor, Bureau of Labor Statistics [174]. Currency conversions are calculated with the yearly currency exchange average from the corresponding year with FXHistory, one of the largest foreign exchange databases on the Internet [135].

For the calculation of the levelized costs of biofuels production (in this study the terms biomass-to-biofuel conversion costs or production costs are used) the following equations are adopted (equations (1) and (2)). Levelized means that the costs per energy content of the biofuel are calculated on a yearly basis.

*(1) PRODCOST= INVCOST*CRF/AF+FIXOM/AF+VAROM+energyprice*efficiency+feedstock costs*efficiency*

PRODCOST	:	*levelized biofuel production cost; [$/GJ]*
INVCOST	:	*total capital investment[43]; [$/GJ]*
CRF	:	*capital recovery factor; [ ]*
FIXOM	:	*fixed operating & maintenance costs[44]; [$/GJ]*

[43] TCI

[44] fixed O & M

AF	:	*availability factor of the plant; [ ]*
VAROM	:	*variable operating & maintenance costs[45] [$/GJ]*
energy price	:	*price for natural gas, electricity or steam; [$/GJ]*
efficiency	:	*input [GJ]/ biofuel output [GJ]; [ ]*
feedstock costs	:	*costs of biomass at the plant gate; [$/GJ]*

Production cost refers to biofuel plant gate costs excluding fuel taxes and value added tax. Total capital investment includes all materials for the construction of the facility plus auxiliary equipment and installation labor, engineering and contingencies. The capital recovery factor is calculated with the discount rate and the life time of the plant whereas it is assumed that the total capital investment is amortized over life time (2). The discount rates and life times found in literature are presented in Chapter 8.3.

$$CRF = i(1+i)^n/((1+i)^n-1) \tag{2}$$

i	:	*discount rate*
n	:	*life time*

Operating and maintenance costs (O & M) consist of fixed and variable costs. Fixed O & M costs are labor, overhead, maintenance, insurance and taxes. Variable O & M costs are consumables (e. g.: chemicals) and disposal (e. g.: waste water) costs [74]. The availability factor expresses the time in which the production plant is able to produce biofuels and is not shut down due to maintenance or repairing[46] [74]. Energy price means the price for which one GJ of the needed process energy is bought (see chapter 7.2.4). This price is multiplied by the efficiency in order to get the energy costs per GJ biofuel. If different energy types are used for the production of the biofuel, one has to calculate multiple efficiencies[47]. By-product credits are accounted to the variable O & M costs.

7.2.2 Accounting for by-products

As seen in Chapter 6, many biomass-to-biofuel conversion processes produce not only the desired product, but also other streams of so-called by-products. The margins generated by the selling of these products are accounted to the variable O & M costs.

In the regional cost approach, the region specific cost index or multiplier for the variable O & M costs is applied to these credits as well (Chapter 9). This methodology is mainly explained with the lack of data on by-product selling prices in different world regions.

[45] variable O & M

[46] e. g.: if a plant produces biofuels on 328.5 days a year, the availability factor is 0.9

[47] e. g.: (feedstock input [GJ]/ biofuel output [GJ])*(feedstock costs [$/GJ])+(electricity input [GJ]/ biofuel output [GJ])*(electricity cost [$/GJ])

7.2.3 Energy use

For electricity, only net energy in-, or outputs are indicated. As a consequence one cannot see how much total energy is needed for the process if excess electricity is sold to the grid. In this case only the net energy excess amount is realized.

Other energy carriers (e. g.: excess syngas) are always used for electricity generation and not sold in its original form. Therefore other energy input than electricity is understood to be gross input.

Hence the different processes cannot be compared on a gross energy input basis, as literature data was not detailed enough for this purpose.

7.2.4 Energy prices

The need for purchasing energy is common to several biofuel production pathways. Generally natural gas and/ or electricity are used for the processes. In some literature steam is additionally listed with a purchasing price. Electricity and natural gas are internationally traded commodities and therefore the macroeconomic cost is equal to its price on the international market. For electricity the purchase and selling price is assumed to be identical. For this study the energy price projections for the year 2010 from EIA's[48] Annual Energy Outlook (AEO) are used (Table 3) [41].

Table 3: Energy price projections for 2010 from EIA's AEO 2005, high A case [41].

energy prices	[$/GJ]
industrial natural gas	4.55
industrial electricity	13.75
steam	7.5

7.2.5 Gasoline and diesel price composition

For the cost comparison of biofuels with conventional fossil fuels, refinery gate costs and fueling station gate prices were used.

According to the IEA the refinery gate costs for fossil fuels range between 4.86 $/GJ and 6.75 $/GJ [86]. According to Hamelinck, the gasoline and diesel refinery gate costs are 6.16 $/GJ and 7.04 $/GJ respectively, at a crude oil price of 38 $/bbl [71]. For this study a value of 7 $/GJ was assumed for both diesel and gasoline. For a cost comparison of the fueling station gate costs, gasoline and diesel price compositions from Switzerland are applied. As the values between diesel and gasoline are similar, 11 $/GJ is assumed to be appropriate for diesel and gasoline. A detailed price composition is listed in Table 4 [77].

[48] Energy Information Administration

Table 4: Gasoline and diesel price composition in Switzerland. December 5, 2006 [77].

price composition (1 December 5, 2006	**gasoline [CHF2006/l]**	**diesel**	**gasoline [US$2000/l]**	**diesel**	**gasoline [US$2000/GJ](2**	**diesel**
cargo & purchase	0.5187	0.6031	0.3521	0.4094	10.9396	11.4160
fuel taxes	0.7312	0.7587	0.4963	0.5150	15.4214	14.3614
value-added tax (7.6%)	0.1098	0.1222	0.0745	0.0829	2.3157	2.3131
margin	0.1920	0.2400	0.1303	0.1629	4.0494	4.5429
fueling station gate price	1.5550	1.7300	1.0555	1.1743	32.7957	32.7470

1) 1 CHF2006=0.79856 USD2006, 1 USD2006=0.85 USD2000 [135, 174].
2) LHV basis, LHV gasoline=32.184 MJ/l, LHV diesel=35.8592 MJ/l [40]

8 System components

This section provides a detailed description of the various system components and discusses the assumptions and considerations which have been made regarding the data available in literature. The data found in literature is presented in order to facilitate the understanding for the regional cost approach of the subsequent chapter where the system components are added to each other.

8.1 Feedstock costs and properties

As shown in Chapter 4, various feedstocks can be used for the production of biofuels. Cost and properties vary widely amongst regions and feedstocks.

8.1.1 Feedstock properties

Biomass is a carbonaceous material of biological origin, derived from a wide variety of feedstocks or plants respectively [12]. In comparison to coal, biomass has a 30%-40% lower heating value, a lower mass density and higher initial moisture content. In addition it is dispersed on a much wider land area than fossil fuels are.

Biomass ash does not contain toxic metals and is free from other potentially hazardous materials which for example, can make the disposal of coal ash difficult. In contrast, biomass ash is even used as a fertilizer for nutrient restoring. Another important difference between coal and biomass is the much higher volatile fraction in biomass. This makes biomass much more reactive than coal (e. g.: easier to gasify, lower process temperatures) [12, 100].

The heating value (or calorific value) is used for the definition of the amount of heat released during the combustion of a fuel or biomass. It is measured in units of energy per amount of material. Heating values may be reported as Btu/m³, kcal/kg, GJ/t, J/mol, or a variety of other combinations of units. The quantity known as higher heating value (HHV, also named gross calorific value or gross energy) is determined by bringing all the products of combustion back to the original pre-combustion temperature. The quantity known as lower heating value (LHV, or net calorific value) is determined by subtracting the heat of vaporization of the water in the by-product from the higher heating value results.

The lower heating value is what is typically used for vehicle engine analysis [89, 188]. It is also used in most studies on biomass or biofuels and therefore in this study as well [4, 40, 72-74, 192].

The energy content of most organic feedstocks is in a range of 17-21 GJ_{LHV}/t [122]. Biomass properties[49] (e. g.: heating values) vary enormously amongst different regions and depend on growing conditions (e. g.: sunlight, fertilizer, soil quality, precipitation, temperature), type of biomass and pretreatment methods (e. g.: chipping, drying) [40, 149, 165, 198]. In Table 5 the lower heating values of different feedstocks found in literature are presented.

[49] For details on biomass properties see McKendry, 2002, p. 41 [122].

Table 5: Lower heating values for various feedstocks suited for the production of biofuels.

feedstock type	LHV [GJ/t]	moisture content [%]	source
barley	15.95	0	ECN-Biomass, 2006
biomass in general	17.60	0	Hamelinck, 2002
black liquor	12.10	0	Harvey. 2004
cattle manure, fresh	16.20	0	ECN-Biomass, 2006
cellulosic biomass	16.54	0	Wyman, 2004
corn grain	18.53	0	BIOBIB, 2006
corn stover	16.56	0	ECN-Biomass, 2006
farmed wood	18.00	0	Edwards, 2006
oil palm fruit kernel	18.50	0	Geurds, 2006
oilseeds	23.00	0	assumed value
organic domestic waste, Holland	15.00	0	ECN-Biomass, 2006
poplar chips	14.35	0	ECN-Biomass, 2006
poplar wood	18.10	0	U. S. Department for Energy, 2006
rape seed	23.80	10	Edwards, 2006
sorghum	15.07	0	assumed value
sorghum stalks	15.07	0	Junfeng, 2005
soybean	23.00	0	assumed value
sugar beet	3.80	77	Edwards, 2006
sugar beet	15.77	0	ECN-Biomass, 2006
sugar cane bagasse	16.16	0	IEA, 2006
sugar cane stems	16.50	0	BIOBIB, 2006
sunflower seeds	23.80	10	Edwards, 2006
switch grass	17.88	0	ECN-Biomass, 2006
waste wood, wood residues	18.00	0	Edwards, 2006
wheat grain	14.80	13	Edwards, 2006
wheat straw	15.65	0	ECN-Biomass, 2006

8.1.2 FAOSTAT producer prices, 2000-2003

The costs for the production of these feedstocks depend strongly on growing, harvesting, handling and storing methods (or rather costs), which depend again on climatic conditions, soil quality and landscape. Climatic conditions and soil quality influence the harvest window[50], which has an effect on the operation window[51]. Yields differ as a matter of soil conditions and climatic conditions, directly affecting the feedstock costs.

In a mountainous region feedstock growing, harvesting and handling are more complex and costly than in a plane area. Eventually the load factors of machines may also influence the cost of the biomass. In addition the costs for labor, goods and machines as well as interest rates differ widely between the world regions and countries. [9, 50, 110, 138, 165, 171, 202].

[50] In temperate regions multiple harvest windows are feasible (e. g.: sugar cane in brazil) [86].

[51] The operation window depends on the biomass harvest or supply window. Machines can be in operation only if biomass supply is active. It is of high importance to keep the system's operation window as wide as possible, possibly by combining multiple biomass chains with the use of the same capital [165].

For this study producer prices from the FAOSTAT[52] database were derived for all available countries [46]. Additional data was derived from other authors [4, 61, 70, 107, 158]. As it is typical for agricultural products that margins are relatively low, prices and costs are assumed to be identical.

It is assumed that all cost factors previously discussed (growing, harvesting, handling, transportation to storage and storage) are comprised in this producer price and that biomass is available at the corresponding price at a storage facility 365 days a year (supply window=365 days). Further on, the feedstock is supposed to be already in a form suitable for transportation (e. g.: logs, bales)[53].

During storage, the biomass gets drier and drier due to evaporation. Moisture content depends on biomass and on the period it is stored [165]. Producer prices in the FAOSTAT database are given in [$/t]. In order to receive [$/GJ] the heating value of the various feedstocks is necessary for the unit conversion. For most feedstocks lower heating values (LHV) on dry biomass basis were used (see chapter 8.1.1 for details on LHV) [19, 39, 40, 58]. For rapeseed, sunflower and sugar beet LHV's on fresh biomass basis could be found in literature. For sorghum, oilseeds and soybean no LHV's have been found in literature. For these feedstocks similar LHV's as for other feedstocks in the same category (sugar crops, starch crops, cellulosic biomass, and lignocellulosic biomass) have been assumed.

As a result, feedstock prices in [$/GJ] on dry biomass basis are somewhat lower than if calculated on the basis of wet or fresh biomass. The prices are weighted averages for the years 2000-2003. Weighted average means that countries with producer prices far above the regional average and low production potential have not been considered for the price estimate. As data for the biomass production potential on a country level was not available, personal judgment was applied.

Sugar cane average costs in LAFM are as cheap as 1.31 $/GJ [46]. Corn grains in NAM cost 4.45 $/GJ and rapeseed in WEUR costs 8.02 $/GJ on average [46]. Corn stover and switch grass in NAM, both cellulosic feedstocks, cost 1.5 $/GJ each [61, 158]. On average, wood residues are cheapest in LAFM and EEFSU were one GJ costs 1.31 $ and 1.37 $ respectively [46]. Oil palm fruits and oilseeds in ASIA can be as cheap as 3.71 $/GJ and 3.44 $/GJ respectively [46]. Producer prices within the world regions vary strongly. This can be seen on the basis of the minimum and maximum values in Table 6.

Future feedstock prices are generally expected to decrease, due to improved agricultural methods [17, 29, 74]. Jaeger mentions though that biomass costs could slightly increase for larger scale production due to higher logistic costs [95]. In addition competition for biomass and land use may increase biomass costs as well [40].

Hamelinck expects best estimate feedstock price projections for the production of 2nd generation biofuels to be between 1.76 $/GJ and 2.65 $/GJ [74]. De Vries projects biomass costs between 7 $/GJ and 23.6 $/GJ for 2050 [29].

According to the FAOSTAT producer prices, these prices are already reality or even undercut in some world regions like for example in LAFM [46]. Costs for starch and sugar containing crops are most likely to increase in future, due to the increased demand for food and ethanol production [40, 181]. For details about the world regions see section 7.1.2.

[52] For U. S. crop prices the US Department of Agriculture (USDA) database can be recommended [177].

[53] Suurs found that pellets and logs are most suited for the transport of biomass, as the energy density is relatively high [165].

Table 6: Producer prices of sugar crops, starch crops, oil crops, agricultural residues & cellulosic biomass and wood in the eight world regions [4, 46, 61, 70, 107, 158].

producer prices, average 2000-2003, LHV basis [US2000$/GJ] If not mentioned otherwise, data is derived from FAOSTAT		sugar crops			starch crops			oil crops					agricultural residues & cellulosic biomass		wood	
		sorghum (2	sugar beet (3	sugar cane (4	barley (5	corn gains (6	wheat (7	oil palm fruit (8	oilseeds (9	rapeseed (10	soybean (11	sunflower grain (12	corn stover (13	switchgrass (18	hard wood chips (19	wood residues (21
North-America (USA, Canada, Alaska)	min	4.25	9.73	1.64	4.52	3.61	5.46	n. a.	10.97	8.24	8.04	10.47	1.23	1.5 (17	n. a.	6.92
	max	4.25	10.25	1.64	6.90	5.29	7.39	n. a.	10.97	9.38	8.35	11.45	1.8 (14	1.5 (17	n. a.	6.92
	w. a. (1	4.25	9.99	1.64	5.71	4.45	6.42	n. a.	10.97	8.81	8.19	10.96	1.5 (15	1.5 (17	n. a.	6.92
Latin America (incl. Mexico), Middle East and Africa	min	2.83	1.82	0.52	5.31	3.74	6.57	2.33	2.82	6.83	3.39	6.05	n. a.	n. a.	3.6 (20	1.12
	max	21.18	47.81	30.28	45.39	123.53	49.12	34.04	17.99	15.35	33.48	75.36	n. a.	n. a.	3.6 (20	32.97
	w. a.	7.35	6.90	1.31	7.48	6.00	10.43	5.87	4.63	7.83	7.47	8.24	n. a.	n. a.	3.6 (20	1.12
China	min	6.75	9.12	1.60	5.85	5.71	8.16	8.27	6.66	8.87	10.70	8.70	7.24 (16	n. a.	n. a.	5.49
	max	6.75	9.12	1.60	5.85	5.71	8.16	8.27	6.66	8.87	10.70	8.70	7.24 (16	n. a.	n. a.	5.49
	w. a.	6.75	9.12	1.60	5.85	5.71	8.16	8.27	6.66	8.87	10.70	8.70	7.24 (16	n. a.	n. a.	5.49
India	min	7.51	n. a.	1.06	7.80	6.15	9.67	n. a.	11.22	11.30	9.13	17.79	n. a.	n. a.	n. a.	n. a.
	max	7.51	n. a.	1.06	7.80	6.15	9.67	n. a.	11.22	11.30	9.13	17.79	n. a.	n. a.	n. a.	n. a.
	w. a.	7.51	n. a.	1.06	7.80	6.15	9.67	n. a.	11.22	11.30	9.13	17.79	n. a.	n. a.	n. a.	n. a.
Other Asia	min	4.90	5.07	0.63	5.98	5.09	6.84	3.29	1.91	11.45	9.81	13.15	n. a.	n. a.	n. a.	3.24
	max	21.26	5.07	1.87	9.05	9.75	9.72	13.02	12.64	35.83	18.62	13.15	n. a.	n. a.	n. a.	4.92
	w. a.	6.89	5.07	1.05	6.68	6.12	7.67	3.71	3.44	11.75	11.40	13.15	n. a.	n. a.	n. a.	4.08
Pacific OECD (also Australia, Newseeland und Greenland)	min	5.95	37.75	0.88	7.12	5.78	8.44	n. a.	10.90	5.68	10.05	12.93	n. a.	n. a.	n. a.	7.49
	max	48.66	37.75	0.88	42.23	57.97	90.97	n. a.	52.66	66.22	85.73	12.93	n. a.	n. a.	n. a.	7.49
	w. a.	5.95	37.75	0.88	7.19	6.34	8.68	n. a.	10.90	7.07	10.05	12.93	n. a.	n. a.	n. a.	7.49
Former Soviet Union	min	3.64	4.64	n. a.	2.89	4.14	4.73	n. a.	5.59	3.44	2.66	6.12	n. a.	n. a.	n. a.	1.09
	max	10.24	66.91	n. a.	28.98	62.85	40.83	n. a.	27.50	16.07	19.48	21.18	n. a.	n. a.	n. a.	1.82
	w. a.	5.32	7.10	n. a.	4.49	5.45	6.03	n. a.	7.75	6.68	5.26	7.10	n. a.	n. a.	n. a.	1.37
Western Europe (EU25, Norway, Ireland, Bulgaria, Romania)	min	5.95	5.92	0.88	5.23	4.80	5.96	n. a.	2.04	5.49	7.26	8.38	n. a.	n. a.	n. a.	n. a.
	max	19.18	48.83	2.22	8.49	15.35	31.16	n. a.	51.31	23.56	14.15	35.24	n. a.	n. a.	n. a.	n. a.
	w. a.	7.77	9.69	1.50	7.01	6.17	7.79	n. a.	12.52	8.02	8.27	9.83	n. a.	n. a.	n. a.	2.55 (22

1) weighted average: countries with outstanding high producer prices and low production potential were removed; 2) LHV=15.07 MJ/kg, 0% moisture (assumed value); 3) LHV=3.8 MJ/kg, 77% moisture (Edwards, 2006); 4) LHV=16.5 MJ/kg, 0% moisture (BIOBIB, 2006); 5) LHV=15.95 MJ/kg, 0% moisture (ECN-Biomass, 2006); 6) LHV=18.53 MJ/kg, 0% moisture (BIOBIB, 2006); 7) LHV=14.8 MJ/kg, 0% moisture (Edwards, 2006); 8) LHV=18.5 MJ/kg, 0% moisture (Geurds, 2006); 9) LHV=23 MJ/kg, 0% moisture (assumed value); 10) LHV=23.8 MJ/kg, 10% moisture (Edwards, 2006); 11) LHV=23 MJ/kg, 0% moisture (assumed value); 12) LHV=23.8, 10% moisture (Edwards, 2006); 13) LHV=16.56, 0% moisture (ECN-Biomass, 2006); 14) Aden, 2002; 15) Sokhansanj, 2002; 16) Larson, 1999; 17) Graham, 2000; 18) LHV=17.88 MJ/kg, 0% moisture (ECN-Biomass, 2006); 19) LHV=14.35 MJ/kg, 0% moisture (ECN-Biomass, 2006); 20) Hamelinck, 2004; 21) LHV=18 MJ/kg, 0% moisture (farmed wood from (Edwards, 2006)); 22) Edwards, 2006

8.2 Feedstock transportation costs to the biofuels plant

As a next step, the transportation of the biomass to the biofuel production facility is analyzed. Biomass can be transported in different ways as by rail, truck or ship [165]. Even pipeline transport of biomass is reported in literature [105].

The cheapest way to transport biomass is by ship, making even biomass transport from Latin America to Europe economically feasible [165, 169].

For the transportation of sugar cane from the fields to the sugar plant, railways are an attractive option [101]. For relatively short transport distances, truck transport is suited as well [165]. Therefore the mean of transport considered in this study is truck transport. Variables influencing the transport costs are the transport distance and the LHV of the biomass.

8.2.1 Transport distance to the plant

Depending on the biomass density for the production of biofuels in a certain growing and harvesting area, and the production plant capacity, the average catchment radius, or transport distance to the plant can be calculated [40]. With increasing transport distances the transport costs increase, whereas biofuel production costs decrease with larger scale processing facilities. For this trade-off, the optimum balance has to be figured out for each individual case. NREL calculated an ideal production capacity of 2000-4000 t/day (~400-800 MW_{th}) for corn stover in the USA considering the latter trade-off [4]. The resulting transport distance can now be assumed from literature data.

In literature one can find transport distances from the farm gate to the processing plant, i.e. anything from 10 km to almost 200 km. The first represents theoretical calculations of the radius needed to grow sufficient crop to feed the factory. The second represents the actual trucking distance for some existing plants [40].

NREL calculates an average transport distance of 80 km for a 2000 t/day (~400 MW_{th}) corn stover to ethanol plant, with a land availability of 10%. If the land availability is 50%, the average transport distance would be reduced to 35 km [4]. For corn stover, the CONCAWE study assumes that a transport distance of 25 km is sufficient for a plant of 200 MW_{th} [40]. It is calculated, that for farmed crops in general, an average transport distance of 50 km is suitable for running a 200 MW_{th} facility, with a land availability of 4% only [40]. Wyman calculates that for a 5'000 t/d (~1000 MW_{th}) plant with a land availability of 20%, a transport distance of 50 km would be suitable [197]. Wood residues are more scattered though and would require sea transport over longer distances (400 km, typical of the Baltic Sea) when fed to a large plant [40].

Considering additionally that a biofuel production plant is economically feasible only if its capacity is bigger than 100 MW_{th}-200 MW_{th} [40], a transport distance of 50 km seems reasonable and is therefore assumed in the present study.

8.2.2 Transport costs

For the calculation of transport costs by truck important factors are: loading/ unloading time, transfer time or distance, speed, cargo capacity, bulk density of the freight, loading factor of the truck (depends on supply window of biomass or other cargo types for transport), as well as investment costs and operating & maintenance costs[54] [40, 165].

Because of the relatively low bulk densities the limiting factor in transporting biomass is usually volume rather than weight [165]. In literature though most truck transport costs for 50 km are indicated on weight basis ranging from 9.4 $/t-12.6 $/t depending on biomass types [4, 132, 165] (Table 8).

Table 7: Truck transport costs for various biomass types found in literature. Transport distance 50 km.

Feedstock type	costs [US$2000/t]	moisture content [%]	LHV [GJ/t]	source
switch grass bales	10.5	n.a.	15.0	Noon, 1996
corn stover bales	12.6	n.a.	16.0	Aden, 2002
wood bundles	9.4	45%	17.0	Suurs, 2002
wood chips	10.5	<10%	18.0	Suurs, 2002

Table 8: Truck transport costs for a distance of 50 km from the farm gate to the biofuels production plant.

feedstock type	LHV [GJ/t]	moisture content [%]	truck transport cost, 50 km [$/GJ]
barley	15.95	0	0.63
biomass in general	17.60	0	0.57
black liquor	12.10	0	0.83
cattle manure, fresh	16.20	0	0.62
cellulosic biomass	16.54	0	0.60
corn grain	18.534	0	0.54
corn stover dry	16.563	0	0.60
farmed wood	18.00	0	0.56
oil palm fruit kernel	18.50	0	0.54
oilseeds	23.00	0	0.43
organic domestic waste, Holland	15.00	0	0.67
poplar chips	14.35	0	0.70
poplar wood	18.10	0	0.55
rape seed	23.80	10	0.42
sorghum	15.07	0	0.66
sorghum stalks	15.07	0	0.66
soybean	23.00	0	0.43
sugar beet	3.80	77	2.63
sugar beet	15.77	0	0.63
sugar cane bagasse	16.16	0	0.62
sugar cane stems	16.50	0	0.61
sunflower seeds	23.80	10	0.42
switch grass	17.88	0	0.56
waste wood, wood residues	18.00	0	0.56
wheat grain	14.80	13	0.68
wheat straw	15.65	0	0.64

[54] For further details see Suurs, 2002, p. 31 [165].

Because of the lack of data for bulk densities and transport costs on volume basis in literature, a cost approach on weight basis was fulfilled in this study. A transport cost of 10 $/t for 50 km was assumed with the help of some sparse literature data (Table 7) [4, 132, 165]. This cost includes the return of the truck to the farm gate. Effective travel distance for the truck is therefore 100 km. This cost was then divided by the different lower heating values from Table 5 in order to derive a transport cost in $\$/GJ_{LHV}$ (Table 8).

The average transport cost over 50 km is about 0.67 $/GJ biomass (Table 8). As no data for a regional cost approach could be found, the transport costs are assumed to be independent from different world regions.

Because transport costs are unlikely to change much over time[55], and considering that cost variability between countries may be bigger than an eventual change in transport costs over time anyways, no cost change over time is assumed [85].

8.3 Biomass-to-biofuel conversion costs

As explained in Chapter 6, various biofuels can be produced from biomass. Figure 4 gives an overview of the processes analyzed in this study (see also Chapter 17: Appendix 3). The production costs are calculated according to equation (1) and (2) in Section 7.2.1. In cases without an indication of the world region the country of the origin of the study is assumed as location for the production plant.

Some 50 different processes were found in literature, which vary widely in methods and units used for energy and cost calculations. Therefore, the main challenge was to make all these processes consistent and eventually comparable. Economies of scale and technological learning are often considered in the cost calculations and therefore discussed below. But often, it is not clearly visible how these concepts are applied within the studies. There are all possible realizations, from simple flat-rate cost reductions due to technological learning and scaling [40] to very detailed calculations [73, 74, 169].

8.3.1 Economies of scale

The plant capacities considered in this study range from 3 MW_{th} to 2000 MW_{th} mostly lie between 100 MW_{th} and 400 MW_{th} however. As often in the process industry, capital costs increase with increasing plant capacity (see equation (3)). The exponent n is normally about 0.6. An exponent of 1 would describe a linear scaling, an exponent smaller than 1 would mean that the capital costs per unit decrease with increasing size of the installation [4]. This concept is generally known as economies of scale [72].

$$\text{new costs} = \text{original costs} \cdot (\text{new size}/\text{original size})^n \tag{3}$$

If a unit has reached its maximum feasible size, the number of units has to be increased, rather than the capacity of one single unit. In this case, the effect of the economies of scale disappears [72].

[55] Due to the fact that transport is at a big scale already and demand for transport is increasing, costs are unlikely to decrease [85].

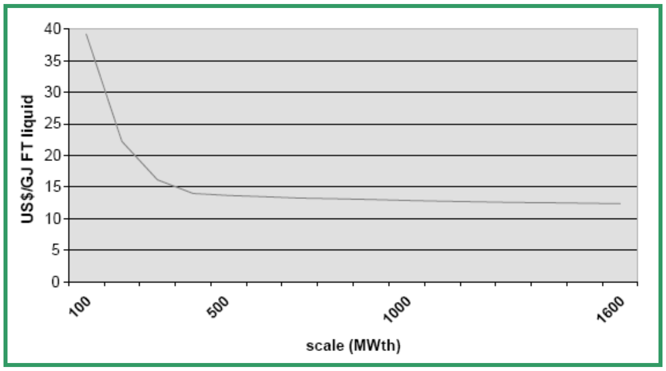

Figure 7: The effect of increasing scale on the production costs of FT-liquids. At 400 MW_{th} production costs of 14 US$/GJ are assumed [72]. Biomass feedstock costs are assumed constant here, whereas in practice biomass costs could slightly increase for larger scales due to higher logistic costs [95].

As an example for the economies of scale the FT-process can be mentioned. The costs for the produced biofuel decrease strongly if the capacity of the plant increases from 80 MW_{th} to 400 MW_{th} (4-6 $/GJ). If the plant scale increases further on, from 400 MW_{th} to 2000 MW_{th}, biofuel production costs decrease just slowly (1-2 $/GJ) (Figure 7) [72]. Whims calculated a capital cost reduction of 40%, and an O & M cost reduction of 15-20% for a starch to ethanol plant, if plant scale is going to triple [187].

8.3.2 Technological learning

Another possibility for the reduction of the biofuel production costs is technological learning. This means on the one hand, that by constructing and running a facility, the knowledge about the process is likely to improve, which ultimately will result in decreasing costs for the construction of other facilities. On the other hand specific costs of the components decrease with an increasing number of produced facilities[56]. Until 2020, Hamelinck foresees a 15% reduction of capital costs for the production of methanol due to technological learning [72].

8.3.3 Fuel properties

For the calculations of the biomass-to-biofuel conversion costs not only biomass properties play an important role. In order to derive cost data on a $/GJ basis it was necessary in various cases to have knowledge about the LHV's or the densities of the fuels themselves. In the following tables an overview of the parameters used for this study is given [40, 147, 182].

[56] For further information on technological learning see also Mc Donald, 2001 and Junginger, 2005 [97, 121]

Table 9: Diesel, gasoline, crude oil and natural gas LHV's and densities.

fuel properties	LHV [GJ/t]	LHV [MJ/l]	density [kg/m3]	source
crude oil	42.00	34.44	820.00	Edwards, 2006
diesel	43.10	35.86	832.00	Edwards, 2006
gasoline	43.20	32.18	745.00	Edwards, 2006
natural gas (EU-mix)	45.10	0.04	0.79	Edwards, 2006

Table 10: Biofuels properties

fuel type (1	LHV [GJ/t]	LHV [MJ/l]	density [kg/m3]	source
biogas	50.00	0.04	0.72	Edwards, 2006
biooil (pyrolysis)	18.00	21.64	1202.00	Ringer, 2006
DME	28.40	19.03	670.00	Edwards, 2006
ETBE	36.30	27.23	750.00	Edwards, 2006
ethanol	26.80	21.28	794.00	Edwards, 2006
methanol	19.90	15.78	793.00	Edwards, 2006
MTBE	35.10	26.15	745.00	Edwards, 2006
rape-EE	37.90	33.73	890.00	Edwards, 2006
rape-ME	37.20	32.74	880.00	Edwards, 2006
sunflower-ME	33.50	29.65	885.00	Vasudevan, 2005
syn diesel	44.00	34.32	780.00	Edwards, 2006

1) EE refers to as ethyl ester, ME to as methyl-ester

8.3.4 Efficiency of the conversion processes

The efficiencies of the different conversion processes found in literature can be seen in Table 11. It needs to be noted though that some of the processes found in literature, i. e.: FT-diesel, DME, methanol, are co-production facilities producing both, biofuels and electricity. Therefore, efficiencies for the production of 2nd generation biofuels seem relatively low (low=high value) compared to conventional biofuels production. This is partly due to the fact that 2nd generation biofuels production often includes the co-generation of electricity. Therefore more biomass is needed for the whole process. As a rule of thumb one can assume that one GJ biofuel can be made out of two GJ of biomass [40].

Table 11: Biomass-to-biofuels conversion efficiencies of different production pathways. Values expressed in [GJ biomass/GJ biofuel].

fuel type	conversion efficiency ranges [GJ biomass/GJ biofuel]	sources
biodiesel from mechanical extraction	1.61-1.73	Edwards, 2006, Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996
biodiesel from pyrolysis	1.42	Ringer, 2006
SNG from anaerobic digestion	1.94	Edwards, 2006
SNG from wood gasification	1.83	Schulz, 2005, Felder, 2006
ethanol from starch	1.85-2.29	Mc Aloon, 2000, Kwiatkowski, 2006, Edwards, 2006
ethanol from sugar	1.84	Edwards, 2006, USDA, 2006
ethanol from cellulosic biomass	1.84-2.9	Hamelinck, 2005, Wooley, 1999, Aden, 2002, Wymann, 2004, Edwards, 2006
FT-diesel from biomass gasification	1.85-4.94	Tijmensen, 2002, Edwards, 2006
methanol from biomass gasification	1.51-3.45	Hamelinck, 2002, Edwards, 2006
DME from biomass gasification	1.47-2	Edwards, 2006

8.3.5 Biomass-to-biofuels conversion costs

In a first step the original literature data was analyzed. Feedstock and energy prices were left unchanged. If not available from the study, energy prices from the EIA were adopted [41].

Modifications to the original data were inevitable in order to express all currencies in US$2000 and all costs and energy units in $/GJ and GJ respectively. Therefore the inflator calculator from the U. S. Department for labor, the FX history from OANDA [135, 174] and the above discussed LHV's were used.
50 processes have been analyzed from literature, resulting in the below presented portfolio of biofuels production costs and economic parameters (see also Chapter 17, Appendix 3, Table 12 and Table 13) [4, 36, 40, 57, 60, 63, 72, 74, 100, 104, 106, 107, 120, 136, 147, 151, 155, 169, 176, 191, 192, 198]. Biofuel plant gate costs are defined as the costs per GJ of biofuel at the plant gate, before distribution.

Table 12: Biofuel plant gate costs found in literature.

fuel type	biofuel gate costs [$/GJ]	sources
biodiesel from mechanical extraction	13-14.5	Edwards, 2006, Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996
biodiesel from pyrolysis	9.5	Ringer, 2006, Fortenbery, 2005
SNG from anaerobic digestion	14-19.5	Edwards, 2006
SNG from wood gasification	17	Schulz, 2005, Felder, 2006
ethanol from starch	11.5-17	Mc Aloon, 2000, Kwiatkowski, 2006, Edwards, 2006
ethanol from sugar	14.5-15	Edwards, 2006, USDA, 2006
ethanol from cellulosic biomass	9.5-22.5	Hamelinck, 2005, Wooley, 1999, Aden, 2002, Wymann, 2004, Edwards, 2006
FT-diesel from biomass gasification	12.5-23	Tijmensen, 2002, Edwards, 2006
methanol from biomass gasification	7-16.5	Hamelinck, 2002, Edwards, 2006
DME from biomass gasification	7-17.5	Edwards, 2006

Due to vast uncertainties regarding the cost of technologies still at an R & D[57] stage, it turns out that the production costs for 2nd generation biofuels vary more than those of the better described 1st generation biofuels. DME, methanol and FT-diesel costs from biomass gasification vary about 10 $/GJ each. So does ethanol from cellulosic biomass.
Ethanol from starch and SNG from anaerobic digestion vary about 5 $/GJ. Ethanol from sugar and biodiesel from mechanical extraction vary just about 1 $/GJ. For SNG from wood gasification and biodiesel from pyrolysis just one study each was found in literature, explaining the lack of variability. With the intention of elaborating a relative production cost ranking, one process per biofuel production pathway will be chosen in the regional approach (Chapter 9).

[57] research and development

Table 13 presents the range of parameters for the economic calculation of different biomass-to-biofuels conversion costs found in literature. The different parameters are varying widely amongst the different biofuels.

Table 13: Range of parameters for the economic calculations of different biomass-to-biofuels conversion processes.

process (1	INVCOST	FIXOM	VAROM (without feedstock)	credits	net energy costs	AF	discount rate	lifetime
	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[-]	[-]	[yr]
biodiesel from wood pyrolysis	21.98	1.89	1.58	0.12	0.32	0.91	0.10	20
DME from wood gasification	18.36-49.93	0.83-2.25	0.08-0.23	0.00	0-0.58	0.90	0.10	25
ethanol from starch	11.74-34.18	0.77-1.53	1.3-1.61	2.76-5.97	3.09-4.52	0.9-0.91	0.10	10-25
ethanol from sugar	19.89-32.45	0.63-0.94	0.46	1.85-2.39	0-1.29	0.90	0.10	25
ethanol from cellulosic biomass	20.8-62.15	0.91-1.99	0-7.44	0-6.25	0-1.56	0.41-0.91	0.07-0.1	20-25
FAME, FAEE from oil crops	6.7-6.8	0.21-0.22	0.19-0.4	3.24-3.75	0.46-0.69	0.90	0.10	25
FT-diesel from wood gasification	48.66-125.46	2.19-4.97	0.31-0.48	0-16.98	0-0.57	0.9-0.91	0.10	20-25
methanol from wood gasification	16.83-62.92	0.75-2.03	0.08-0.69	0-11.15	0-0.8	0.9-0.91	0.10	25
SNG from anaerobic digestion	48.62-69.46	4.86-6.95	2.20	2.26-2.51	0.00	0.90	0.10	25
SNG from wood gasification	49.69	1.74	0.01	0.00	0.11	0.91	0.10	25

Generally one can see that 2nd generation biofuels require higher capital investment than 1st generation biofuels. Biodiesel from wood pyrolysis requires similar capital investment as 1st generation biofuels though. Fixed O & M costs are highest for FT-diesel and SNG from anaerobic digestion and lowest for biodiesel from oil crops. Variable O & M costs are highest for ethanol from cellulosic biomass and for SNG from anaerobic digestion. Contributions of capital investment to total costs are much bigger than fixed and variable O & M costs, which are just about 1%-10% of capital investment.

Most of the processes found in literature produce electricity, animal feed or glycerine as a by-product, resulting in credits of a few dollars to as much as 17 $/GJ biofuel for FT-diesel. As a consequence, net energy costs are low, as electricity is co generated from excess syngas, heat or biomass.

The biofuel plants are available at about 90% of the time, shut downs are caused due to repair and maintenance. The lifetime of virtually all processing plants is indicated with 20-25 years. Discount rates on investment are in a range of 7%-10%. Further insight in the different processes found in literature is given in Chapter 17, Appendix 3.

8.4 Distribution costs

Fuel distribution costs relate principally to volume rather than weight. It is understood as to be the costs from the plant gate to the fueling station gate, including the following cost components: sea, road or rail transport from the refinery gate or plant to the depot, depot storage, administration and handling in wholesale trade, transport from depot to filling station, filling station storage, administration and handling in retail trade, emergency and strategic storage, and interest on working capital.

Due to lack of data in literature about this topic, flat-rate costs incorporating average distribution costs including the above mentioned components, were applied from the IEA [85].

Results are presented in Table 14 [85]. By using these distribution costs, it is assumed that the biofuel can virtually be transported from a region with high biomass supply potential to Europe or within Europe.

Table 14: Distribution costs for various fuels. Included costs are: Sea, road or rail transport from the refinery gate to the depot, depot storage, administration and handling in wholesale trade, transport from depot to filling station, filling station storage, administration and handling in retail trade, emergency and strategic storage, and interest on working capital [85].

fuel type	distribution costs [$/GJ]
biodiesel (1	3.49
diesel	3.61
DME	8.40
ethanol	5.27
gasoline	3.97
methanol	6.06
SNG (2	8.40

1) biodiesel refers to as FT-diesel, FAME, FAEE and biodiesel from pyrolysis
2) costs are assumed to be the same as for DME

9 Regional approach

In the regional approach a set of representative pathways is selected in order to provide a detailed overview of the production costs and a regional comparison.

The biomass producer prices, transport costs, distribution costs and energy prices from literature are applied to the set of chosen production pathways, leading to a consistent and comparable economic analysis.

As a subsequent step, the analysis compares production costs in the world region with biggest biomass supply potential with those in WEUR.

9.1.1 Choice of a representative set of production pathways

With the intention of providing a better overview and a comparable dataset, a representative set of production pathways is selected from some 50 processes found in literature. As the studies of NREL, Hamelinck and Tjimensen are conducted in very detail, they are preferably considered for further analysis.

In order to have a scale matching 50 km truck transport distance to the plant, a maximum scale of 400 MW_{th} was considered. This capacity corresponds to the lower optimum value, calculated by the NREL for the ethanol production from corn stover (see Chapter 8.2.1) [4]. Except for ethanol from lignocellulosic biomass this is the biggest scale found in literature anyway.

Within the range of 3 MW_{th}-400 MW_{th}, preferably the biggest possible scale is chosen due to the above discussed effects of the economies of scale. The selected pathways are marked with an asterisk in Chapter 17, Appendix 3. For details of the selected pathways see Section 9.1.3.

9.1.2 Regional biomass supply potentials

In literature one can find various studies estimating the global biomass supply potential (see Chapter 5), regional data are sparse however. Generally Latin America, Eastern Europe (Ukraine, Former Soviet Union), Southeast Asia, China and Sub-Saharan Africa are seen as the most potential suppliers for future biomass based energy systems [17, 29, 44, 70, 111]. De Vries estimates the biggest potential at cheapest prices in South America [29].

For this study the biomass supply potentials from the IEA and oil crops production data from Mattson are used. From Mattson the amount of oil crops for the top world producers were derived and assumed to be equal to the biomass supply potential. The amount of oil crops used for food production is not subtracted from this amount though.

Generally, projections reveal that future potentials are far bigger than current production though. Therefore it can be assumed that the data from Mattson lead to an underestimation of the oil crop potentials. But as it is just important to see relative differences in supply potentials between the world regions rather than absolute estimates, this assumption fulfills its purpose. For the conversion of Mt/yr to PJ/yr the LHV's from Table 5 were applied [119]. Other supply potentials for different biomass categories were derived from the IEA [90].

Originally IEA's biomass supply potential is divided into 12 categories (see Chapter 18, Appendix 4) [90]. For the present study more aggregated categories were obtained by adding some of the IEA categories (Table 15).

Resulting categories are: *Lignocellulosic biomass* (production of solid biomass for biofuel (existing)+production of fuel wood (existing)+additional recovery potential from forests+new supply of solid biomass-plantanations on arable land+new supply of solid biomass-plantanations on permanent pasture land), *residues, straw and waste* (production of wastes and residues (additional)+production of straw and other agricultural residues), *municipal and industrial waste* (production of industrial wastes+production of municipal wastes (biomass content only)), *production of cellulosic and starch biomass for ethanol* (production of cellulosic and starch biomass for ethanol) [90], *oilseeds* (soybean+sunflower+rapeseed+oil palm) [119], and *sugar from cane and baggase* (bagasse production (sugar by-product only)+production of sugarcane for ethanol) [90].

Unfortunately waste and cellulosic biomass is included in two categories, making it hard to distinguish the potentials for individual biofuels production pathways relying on these categories. Additionally cellulosic and starch for ethanol are indicated as an aggregated potential. If this data is used for other studies it is recommended to consider the latter potential as starch for ethanol only. Cellulosic biomass is included already in other categories.

Results are presented in Table 15. The world region with biggest supply potential is highlighted in dark grey; subsequent regions with big supply potential as well are highlighted in light grey. With 83'161 PJ/yr, the LAFM region has by far the biggest overall potential, followed by NAM (25'223 PJ/yr), ASIA (21'989 PJ/yr), EEFSU (21'931), CHIN (17'210 PJ/yr), IND (13'216 PJ/yr), WEUR (8'185 PJ/yr) and OOECD (7'141 PJ/yr).

Except for municipal and industrial waste the LAFM region has as well biggest potential for each single category (Table 15) and is therefore chosen for further analysis. The overall global biomass supply potential of the used data is some 194 EJ/yr.

Table 15: Biomass supply potentials by world region[58] [90]. The region with the biggest supply potential is highlighted in dark grey, subsequent ones in light grey.

biomass supply potential by world region [PJ/yr]		NAM	LAFM	CHN	IND	ASIA	OOECD	EEFSU	WEUR	timeframe	source
lignocellulosic biomass		9859	50229	9582	5581	11935	3489	10246	2298	2050	IEA, 2005
residues, straw, waste		9410	14481	3188	3120	3024	2550	9990	4180	2050	IEA, 2005
municipial and industrial waste (biomass content only)		2040	530	254	70	522	234	415	980	2050	IEA, 2005
production of cellulosic and starch biomass for ethanol		1682	3253	1141	1294	834	347	1066	603	2050	IEA, 2005
oilseeds (canola, sunflower, sojabean, oilpalm), top producers (1	soybean (2	1918	2689	460	n. a.	n. a.	n. a.	n. a.	n. a.	2010	Mattson, 2004
	sunflower (3	38	129	n. a.	n. a.	n. a.	n. a.	214	n. a.	2010	Mattson, 2004
	rapeseed (4	121.3	n. a.	362	102	n. a.	n. a.	n. a.	124	2010	Mattson, 2004
	oilpalm (5	n. a.	14	n. a.	n. a.	364	n. a.	n. a.	n. a.	2003	Mattson, 2004
suger from cane and bagasse		155	11836	2223	3049	5310	521	n. a.	n. a.	2050	IEA, 2005

1) Data from the top producers in [Mt/yr] is transformed to [PJ/yr] for the corresponding world region with the following LHV's: Soybean= 23 GJ/t (assumed), sunflower = 23.8 GJ/t (Edwards, 2006), rapeseed = 23.8 GJ/t (Edwards, 2006), oilpalm kernels = 18.5 GJ/t (Geurds, 2006). Crops for food production is not substracted from total produced amount.

2) top producers are: USA = 83.4 Mt/yr, Brazil =67.7 Mt/yr, Argentina = 49.3 Mt/yr, China = 20 Mt/yr

3) top producers are: USA = 1.6 Mt/yr, Argentina =5.4 Mt/yr, Russia = 4.4 Mt/yr, Ukraine = 4.5 Mt/yr

4) top producers are: Canada = 5.1 Mt/yr, China = 15.2 Mt/yr, India = 4.3 Mt/yr, Germany = 5.2 Mt/yr

5) top producers are: Nigeria = 0.75 Mt/yr, Malaysia = 11.17 Mt/yr, India = 8 Mt/yr

[58] For further information see IEA, 2005, p. 216 [90].

9.1.3 Feedstock costs for the LAFM and WEUR region

The selected pathways process wood, stover, rapeseed, domestic waste, sugar cane, and corn grains into biofuels. In order to compare the region of the biggest biomass supply potential (LAFM) with Europe, dedicated producer prices for each region are selected. For LAFM the producer price for soybean instead of rapeseed is used. For WEUR sugar beet producer prices instead of sugar cane were applied. This mainly due to the fact that these crops are cultivated at big production levels already within these regions. If available, the producer prices from Brazil (average of the years 2000-2003) were used, assuming that Brazil is representative for the LAFM region. Other prices are weighted averages from the years 2000-2003 (Table 16). For further details about the producer prices see also section 8.1.2.

Table 16: Weighted average producer prices (2000-2003), matching the selected biofuels production pathways.

weighted average producer prices 2000-2003 for the selected pathways for WEUR and LAFM [$/GJ] (1	WEUR	LAFM
wood residues (LHV = 18 GJ/t)	2.55 (2	1.12 (3
domestic waste (LHV = 15 GJ/t)	1.5 (4	1 (5
corn grains (LHV = 18.53 GJ/t)	6.17	3.74 (6
corn stover (LHV = 16.56 GJ/t)	1.5 (7	1 (8
sugar beet/ sugar cane (LHV = 3.8 GJ/t, 16.5 GJ/t))	9.69	0.57 (9
rapeseed/ soybean (LHV = 23.8 GJ/t, 23 GJ/t)	8.02	5.83 (10

1) FAOSTAT, 2) Edwards, 2006, 3) price for South America, 4) source: Edwards, 2006, 5) assumed price, 6) price for Brazil, 7) price for the USA, 8) assumed price, 9) price for Brazil, 10) price for Brazil

9.1.4 Regional cost index for the biomass-to-biofuel conversion costs

The costs for the biomass-to-biofuel conversion vary considerably between different world regions, due to local circumstances such as availability of infrastructure (loading docks, local manufacturing shops, airports, housing, water and power supplies, etc.), availability, costs and productivity of imported and local skilled labor, as well as taxes and duties, etc..

A Sasol-Chevron Engineer mentioned in an interview that costs for building a GTL plant in two different world regions can vary by a factor of two [84]. According to the IEA cost differences between two regions are typically between 20% and 50% whereas O & M costs vary less then investment costs (Table 17). The cost multipliers presented below are applied for the production of biofuels in LAFM and WEUR in the ongoing analysis.

As by-product credits are assumed to be part of the variable O & M costs, the regional cost index is applied as well to them. Discount rates are left unchanged.

Table 17: Region specific cost multipliers for the construction and operation costs of biofuel plants [90].

region specific cost multipliers	investment costs	fixed O&M	variable O&M
Africa	125	90	85
Australia	125	90	90
Canada	100	100	100
Central and South America	125	90	85
China	90	80	80
Eastern Europe	100	90	85
Former Soviet Union	125	90	85
India	90	80	80
Japan	140	100	100
Mexico	100	90	90
Middle East	125	90	85
Other developing Asia	125	80	80
South Korea	100	90	90
USA	100	100	100
Western Europe	110	100	95

10 Results

In the following chapter the core results of the cost analysis are presented. The parameters from Chapter 8 and Chapter 9 are applied to the chosen set of production pathways, leading to a consistent and comparable analysis. The world regions chosen for comparison are LAFM and WEUR.

10.1 Costs of biodiesel from wood pyrolysis

Biodiesel from wood pyrolysis costs differ by 2.47 $/GJ between LAFM and WEUR, whereas LAFM offers more competitive total costs. Total costs at the fueling station gate are 13.45 $/GJ for LAFM and 15.92 $/GJ for WEUR respectively. Most important cost contributions to total costs are capital investment, distribution costs, and feedstock costs. The main reason for lower total costs in LAFM are lower feedstock costs of 1.12 $/GJ in LAFM compared to 2.55 $/GJ in WEUR (Figure 8).

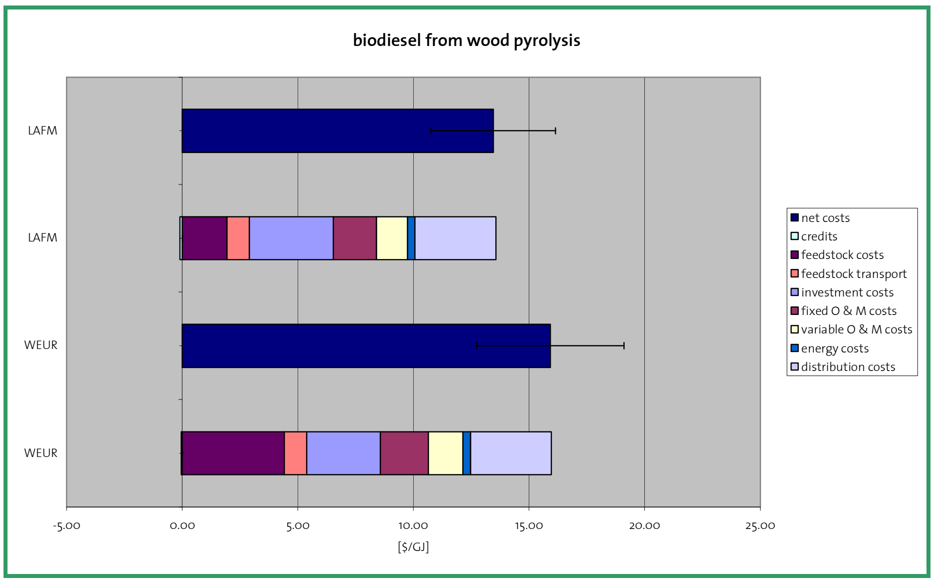

Figure 8: Biodiesel from wood pyrolysis. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%. The bars in single color indicate net total costs at the fueling station gate. The multi-color bars highlight the cost breakdown of the total costs into its components. The difference between the two bar types is caused by the subtraction of the by-product credits from the total costs.

10.2 Costs of DME from wood gasification

Fueling station gate costs for DME are 21.81 $/GJ for LAFM and 24.11 $/GJ for WEUR respectively. Distribution costs are by far the biggest contributors to total fueling station gate costs, followed by not much lower investment costs. Feedstock prices in LAFM are only 1.43 $/GJ cheaper than in WEUR resulting though in a doubling of total feedstock costs per GJ biofuel for WEUR compared to LAFM. Variable O & M costs are in both cases less then one percent of total costs (Figure 9).

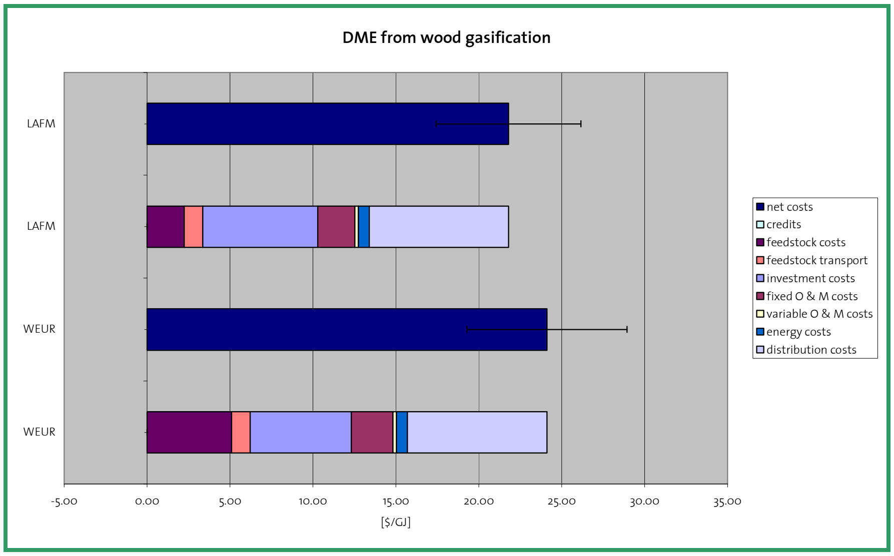

Figure 9: DME from wood gasification. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.3 Costs of ethanol from cellulosic biomass

Total fueling station gate costs for ethanol from cellulosic biomass are 18.63 $/GJ for LAFM and 19.67 $/GJ for WEUR respectively. Distribution costs are the biggest single contributor to total costs, followed by investment costs and variable O & M costs. Feedstock costs in LAFM contribute only less than 5% decrease of total costs. Although some excess electricity can be sold from the integrated power generation system, there is additional need for natural gas as an energy input (Figure 10).

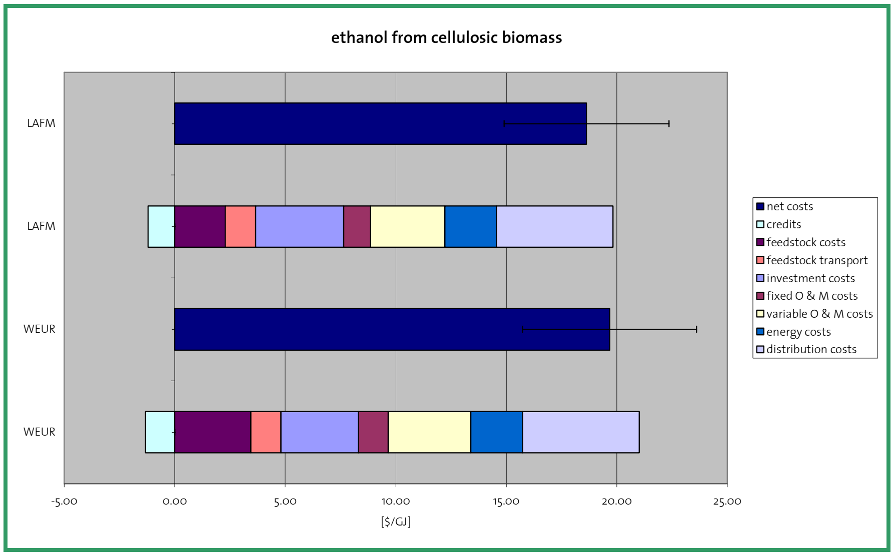

Figure 10: Ethanol from cellulosic biomass. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.4 Costs of ethanol from starch

Ethanol from starch can be produced at costs of 21.84 $/GJ for LAFM and 26.95 $/GJ for WEUR respectively. In WEUR feedstock costs contribute as much as 51.9 % to the total ethanol fueling station gate costs. In LAFM this share is reduced to 38.8 %, though still being relatively high. Distribution and energy costs are other significant cost contributors. Animal feed as a by-product can reduce total costs by some 3 $/GJ biofuel (Figure 11).

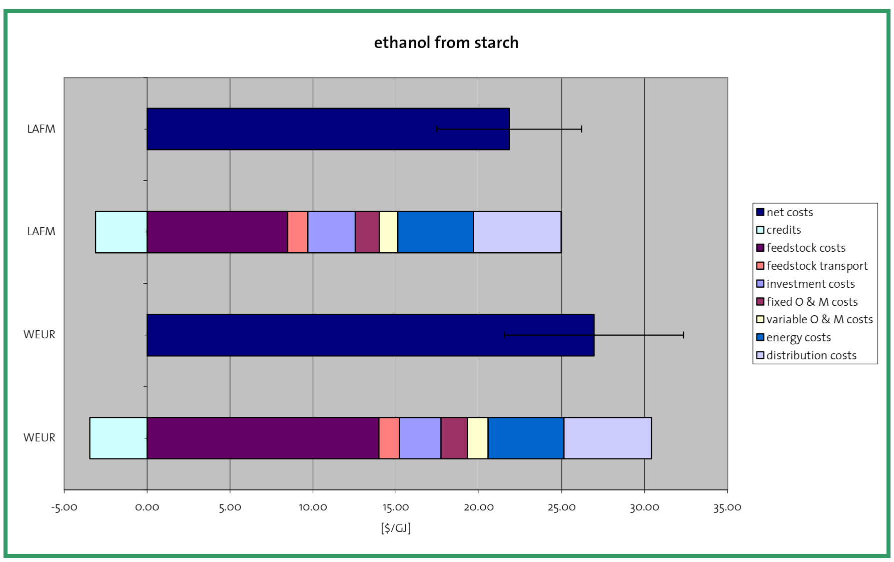

Figure 11: Ethanol from starch. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.5 Costs of ethanol from sugar

Ethanol from sugar varies extremely between LAFM and WEUR, due to feedstock cost differences of 9.1 $/GJ of the corresponding biomass. In LAFM ethanol is produced mainly from sugar cane, in WEUR it is derived from sugar beet. In LAFM ethanol can be produced at costs of 19.45 $/GJ, whereas in WEUR 36.73 $/GJ are needed. Fixed O & M costs are second biggest influence factors on total costs, followed by distribution and energy input costs (Figure 12).

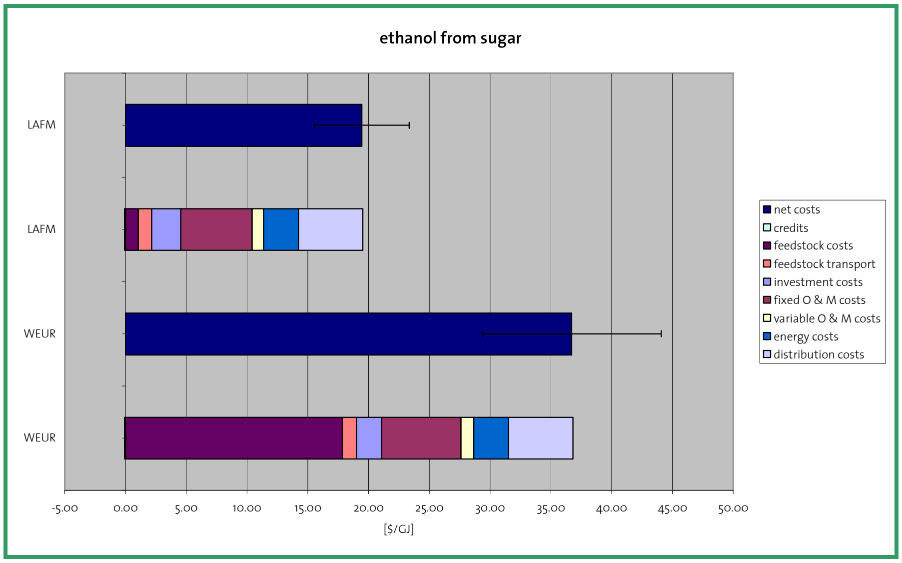

Figure 12: Ethanol from sugar. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.6 Costs of FAEE from oil crops

Biodiesel from oil crops can be produced at costs of 12.23 $/GJ for LAFM and 15.33 $/GJ for WEUR respectively. Feedstock costs are representing about 80% of total production costs. Distribution is another important contributor to the total costs, fixed and variable O & M costs are relatively low though. Credits from animal feed by-products decrease total costs by about 3 $/GJ biofuel (Figure 13).

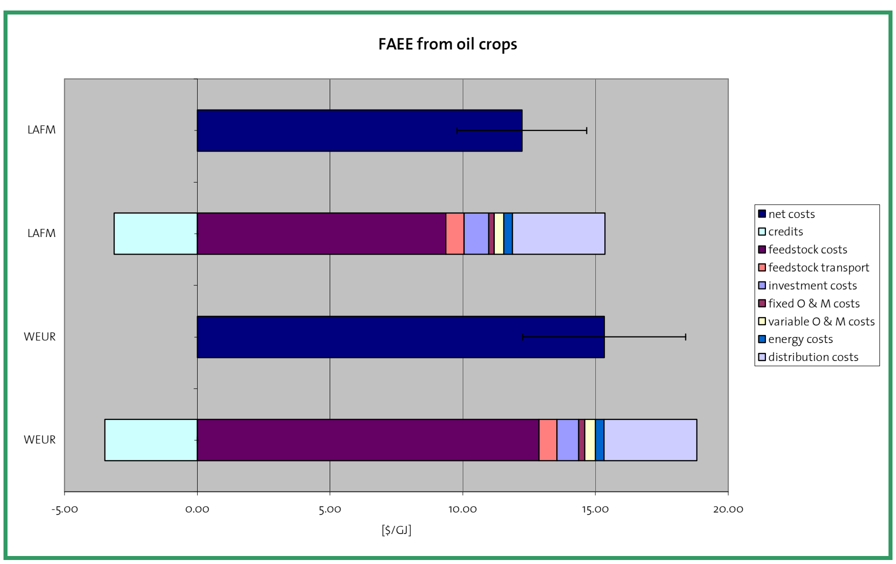

Figure 13: FAEE from oil crops. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.7 Costs of FT-diesel from wood gasification

FT-diesel can be produced at costs of 14.84 $/GJ for LAFM and 16.86 $/GJ for WEUR respectively. The selling of excess electricity lowers total costs by about 10 $/GJ biofuel. Investment costs are extremely high, reaching 11 $/GJ and 12.5 $/GJ biofuel respectively. Yet variable O & M costs are low (Figure 14).

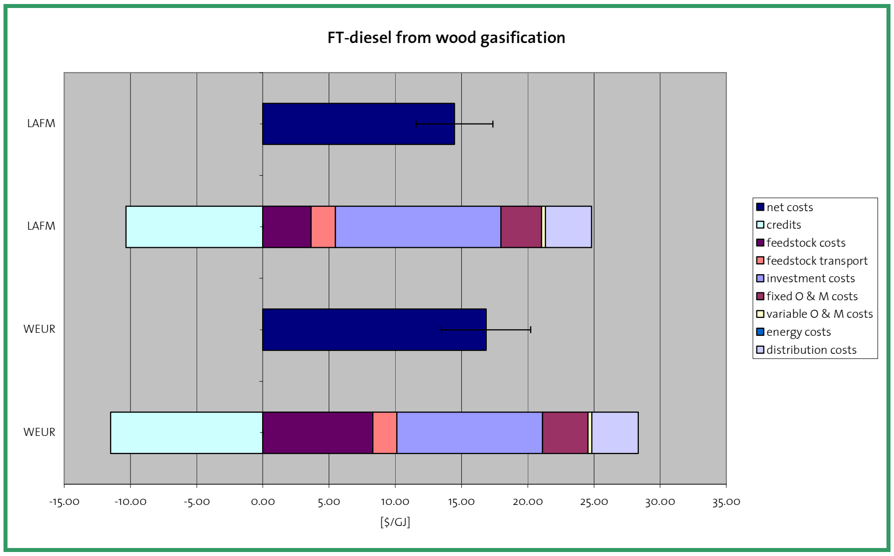

Figure 14: FT-diesel from wood gasification. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.8 Costs of methanol from wood gasification

Methanol from wood production cost break down is similar to FT-diesel, mainly due to a similar technology used for the process (Figure 15).

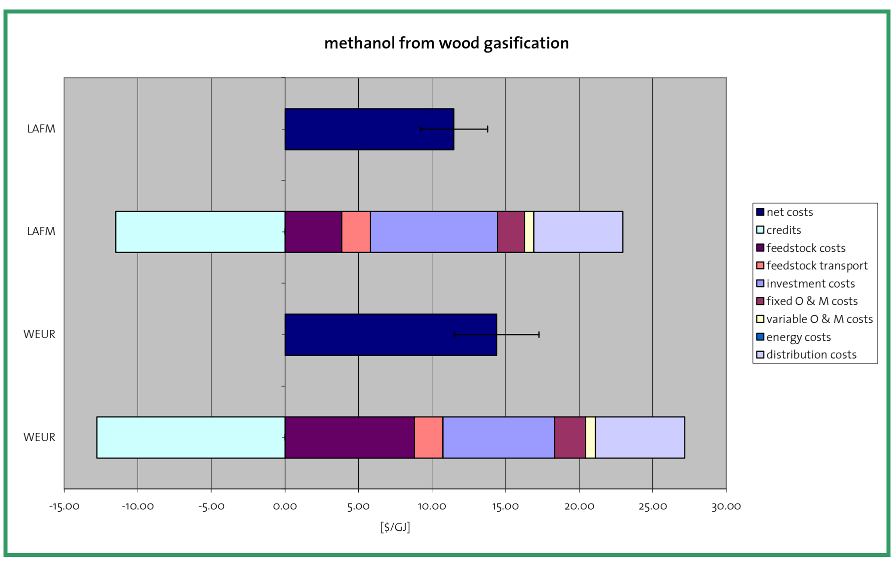

Figure 15: Methanol from wood gasification. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

The methanol production technology results as well in high investment costs and relatively low variable O & M costs. Total costs amount to 11.48 $/GJ for LAFM and 14.39 $/GJ for WEUR respectively (Figure 15).

10.9 Costs of SNG from anaerobic digestion

SNG from anaerobic digestion costs 22.89 $/GJ for LAFM and 23.55 $/GJ at a WEUR fueling station respectively. Investment and distribution costs make about 30% of total costs each. Fixed O & M costs are relatively high, contributing about 20% to the total fuel costs. Distribution costs with 8.4 $/GJ are relatively high due to the fact that SNG is not a liquid and has therefore a lower energy content per volume than liquid fuels. Costs for domestic waste are only 0.5 $/GJ lower in LAFM than in WEUR, leading to similar total feedstock costs for these two regions (Figure 16).

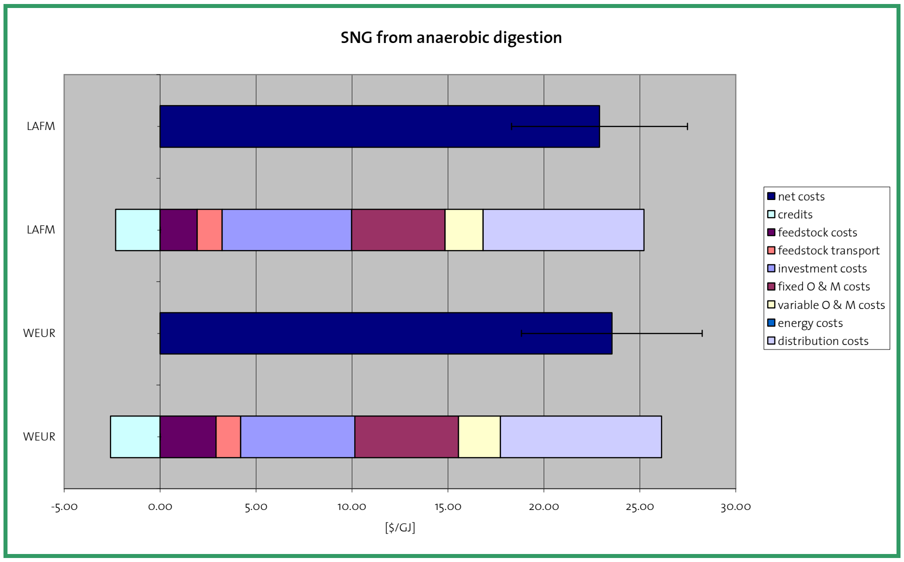

Figure 16: SNG from anaerobic digestion. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.10 Costs of SNG from wood gasification

SNG from wood gasification costs 20.16 $/GJ for LAFM and 22.16 $/GJ for WEUR respectively. Mainly this difference results from the differences in feedstock costs between these two regions. Because of the gaseous state of the biofuel here again, distribution costs are relatively high compared to liquid fuels. Variable O & M costs are very low contributing less than 1% to total production costs (Figure 17).

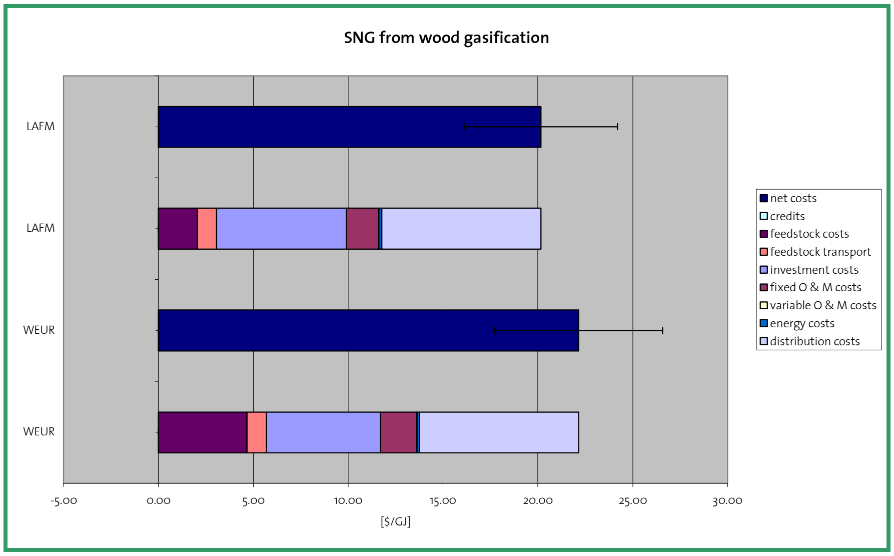

Figure 17: SNG from wood gasification. Breakdown of fueling station gate costs for the world regions LAFM and WEUR. Uncertainty range is assumed to be 20%.

10.11 Summary and comparison of results

As outlined in the above section, total biofuels production costs vary significantly between different fuel types, world regions and production modes. In LAFM, SNG from anaerobic digestion is the most costly biofuel, in WEUR it is ethanol from sugar (Figure 18, Figure 19 and Table 18). The relative cost rankings of the other biofuels remain yet quite identical between the two regions. The biomass-to-biofuel efficiencies of the selected pathways are in a range of 1.61-3.45 (Table 19).

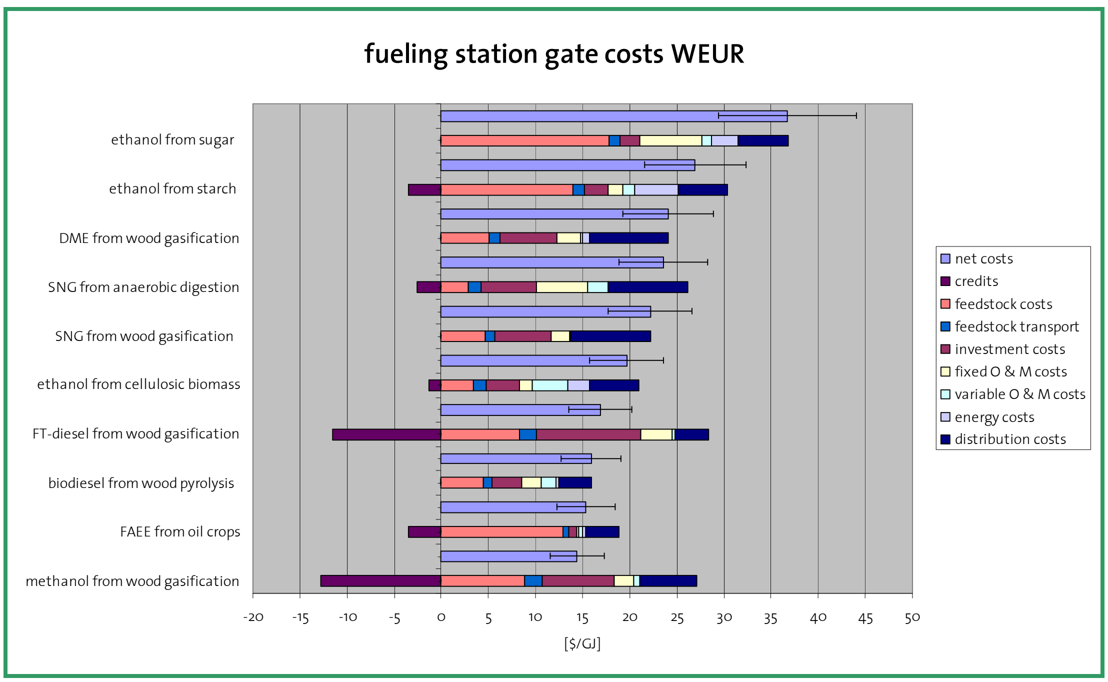

Figure 18: Summary of fueling station gate costs in WEUR in [$/GJ]. The first bar expresses the net costs at the fueling station and the second bar represents a cost breakdown of the wholesale costs into its components.

In LAFM as a rule of thumb, one can say that total production costs are reduced by some 2-5 $/GJ biofuel compared to WEUR. Ethanol from sugar costs can even be reduced by 17 $/GJ. This is mainly due to lower feedstock costs in LAFM.

Fixed and variable O & M costs are as well lower in LAFM, mainly due to lower material and labor costs. Investment costs however are though higher than in WEUR because of the lack of infrastructure on the construction site (see also section 9.1.4).

In a low cost production region as LAFM, the biofuel with the lowest production cost is methanol from wood gasification, followed by FAEE from oil crops, biodiesel from pyrolysis, and FT-diesel from wood gasification (Figure 19). These biofuels can be produced at costs of some 11.5-14.5 $/GJ. Ethanol from starch, sugar or cellulosic biomass, SNG from wood gasification, SNG from anaerobic digestion, and DME from syngas cost about 18.5-22.89 $/GJ. Feedstock costs are one of the main contributors to total production costs and can contribute up to 83% to the total production costs in the case of FAEE from rapeseed in WEUR. This can be explained with the relatively high feedstock prices of rapeseed (8.02 $/GJ) in this region. However, for SNG from waste, feedstock costs contribute with just about 8.46% to the total costs in LAFM.

Feedstock costs per GJ biofuel are on one hand influenced by the producer prices for a particular feedstock and on the other hand by the efficiency of the conversion process (amount of biomass per biofuel output). 2nd generation biofuels need in general more biomass input per biofuel output (Table 19). This is outweighed though with the selling of excess electricity produced within the process, and relatively low feedstock prices for lignocellulosic biomass.

For SNG, FT-diesel, methanol and DME investment costs are relatively high. The latter costs for FT-diesel and methanol can be as high as 11 $/GJ and 7.6 $/GJ respectively. This corresponds to 65% and 53% of total production costs of the biofuel. Fixed O & M costs vary between 1.5% and 22.5% of total costs.

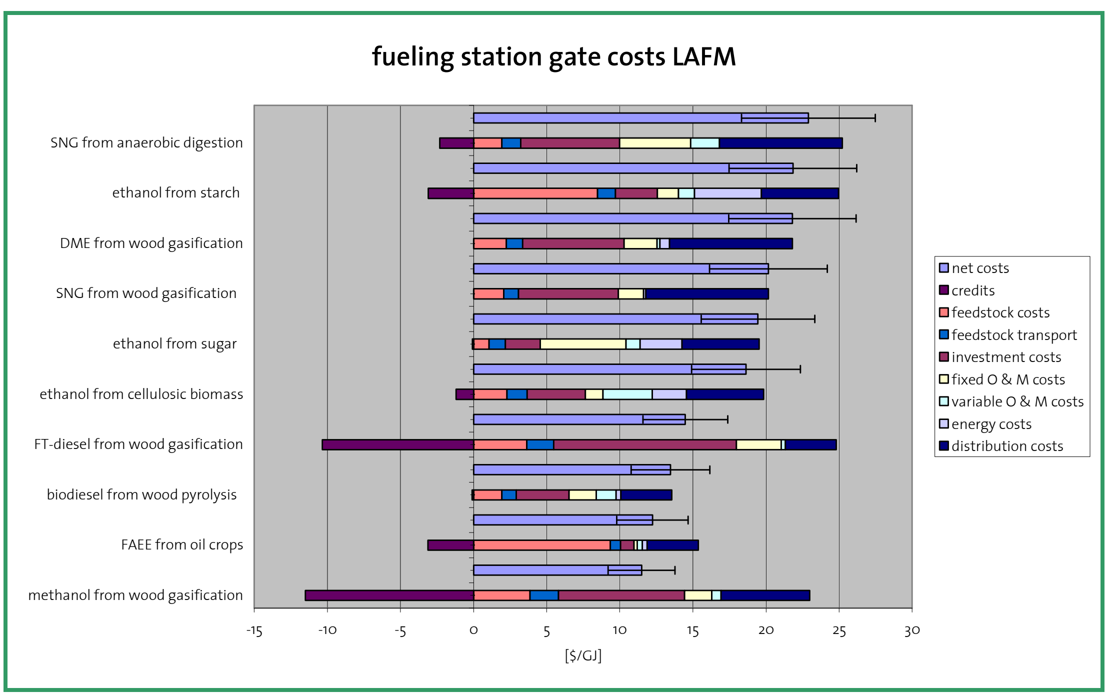

Figure 19: Summary of fueling station gate costs in the LAFM region in [$/GJ]. The first bar expresses the net costs at the fueling station and the second bar represents a cost breakdown of the wholesale costs into its components.

SNG from anaerobic digestion and ethanol from starch have the highest fixed O & M costs, followed by FT-diesel production.

Variable O & M costs are highest for ethanol from cellulosic biomass in WEUR, being as high as 3.74 $/GJ which is equal to 19% of total costs. Generally the variable O & M costs contribute around 1%-2% to the total production costs.

In most of the reviewed processes electricity is produced and sold as a by-product leading on the one hand to a somewhat higher capital investment because of the power generation system (e. g.: gas turbine), but on the other hand reducing total production costs. Considerable additional energy inputs are needed only for the ethanol production pathways, contributing 2.3 $/GJ-4.5 $/GJ (12.6%-20.9% of total costs) to the total costs.

The truck transport costs are in the range of 1 $/GJ-2 $/GJ biofuel, making only a small part of total production costs. Transport costs in this study depend on the LHV of the corresponding biomass.

The distribution costs of the final fuel are another significant contribution to total costs. For gaseous biofuels these costs are higher than for liquid fuels. For methanol the contribution of the distribution costs to total costs is as high as 52% in LAFM. As the distribution costs are assumed as flat-rate costs, being constant between different regions, the relative contribution to the total costs is higher in a low cost production country as LAFM. SNG distribution accounts to between 35.7% and 41.7% of the fueling station gate costs. For the other fuels the distribution is about 20% of the total costs.

Throughout the studies the uncertainties are not always indicated, but generally assumed to be between 20% and 40%. For the present results the lower of this uncertainty boundary has been chosen (Figure 18 and Figure 19). For detailed cost numbers and parameters of the LAFM and WEUR regions, see also Chapter 20, Appendix 6.

Table 18: Fueling station gate costs of the analyzed biofuels in the WEUR and LAFM world regions.

WEUR	fueling station gate costs [$/GJ]	LAFM	fueling station gate costs [$/GJ]
biodiesel from wood pyrolysis	15.92	biodiesel from wood pyrolysis	13.45
DME from wood gasification	24.11	DME from wood gasification	21.81
ethanol from cellulosic biomass	19.69	ethanol from cellulosic biomass	18.64
ethanol from starch	26.95	ethanol from starch	21.84
ethanol from sugar	36.73	ethanol from sugar	19.45
FAEE from oil crops	15.33	FAEE from oil crops	12.23
FT-diesel from wood gasification	16.86	FT-diesel from wood gasification	14.48
methanol from wood gasification	14.39	methanol from wood gasification	11.49
SNG from anaerobic digestion	23.55	SNG from anaerobic digestion	22.89
SNG from wood gasification	22.14	SNG from wood gasification	20.14

Table 19: Biomass-to-biofuel conversion efficiencies of selected pathways.

fuel type	conversion efficiency [GJ biomass/GJ biofuel]
biodiesel from wood pyrolysis	1.73
DME from wood gasification	2.00
ethanol from cellulosic biomass	2.29
ethanol from starch	2.27
ethanol from sugar	1.84
FAEE from oil crops	1.61
FT-diesel from wood gasification	3.25
methanol from wood gasification	3.45
SNG from anaerobic digestion	1.94
SNG from wood gasification	1.83

11 Discussion

In this chapter the results of the economic analysis are discussed and critical parameters and system assumptions are highlighted and weighted.

11.1 Economic analysis discussion

For the economic analysis a literature review has lead to a consistent set of comparable biofuel production routes. Considered are the production and distribution of ethanol, methanol, DME, FT-diesel, SNG, and biodiesel (FAEE, FAME).

This set has been selected out of fifty different biomass-to-biofuel conversion pathways found in literature. Due to a lack of data, a scenario with one optimum supply chain option has been developed. This cost scenario was then adapted to Western Europe and Brazil as a representative for the LAFM region, a world region with high biomass supply potential and low production costs.

Four different system components have been investigated, leading to a fueling station gate price excluding taxes. The variables influencing these components are constrained by the availability of literature data. The system components considered in this study are: producer prices of the feedstock, truck transport costs to the plant, costs of the biomass-to-biofuel conversion, and distribution costs of the resulting biofuel.

All system components but conversion have been calculated as a single cost factor. The conversion costs though, are split into investment costs, fixed O & M costs, energy costs, variable O & M costs, feedstock costs, and by-product credits. On the one hand, this allows a detailed discussion on cost reduction potentials for the biomass-to-biofuel conversion step. For the rest of the system components it reveals on the other hand, that a detailed cost reduction approach turns out to be impossible, as the latter components could theoretically be split in different cost contributors as well. In the case of the system component “distribution” for example, it can not be seen which individual component (transport, storage, capital investment, etc.) contributes most to the total distribution costs. However, it can be said how much each system component contributes to the fueling station gate costs of the final fuel.

If one considers a fueling station gate cost of 11 $/GJ (costs for Switzerland) [77] without taxes for fossil fuels, only methanol from wood gasification in the LAFM region is almost competitive to corresponding costs of 11.48 $/GJ (Figure 20).

If the plant gate costs of the biofuels are compared with a plant gate cost of 7 $/GJ [85] for fossil fuels, methanol from wood gasification in LAFM is competitive with costs of 5.42 $/GJ (Figure 21). Biodiesel from wood pyrolysis in LAFM and methanol from wood gasification in WEUR are just slightly more expensive with total plant gate costs of 9.96 $/GJ and 8.33 $/GJ respectively.

The difference of the calculated fueling station gate cost between LAFM and WEUR is just some 1-5 $/GJ for all but one of the considered biofuels. For ethanol from starch this difference is 17 $/GJ. This is mainly due to a feedstock cost difference of 9 $/GJ, as for WEUR sugar beet was chosen as a feedstock and for LAFM sugar cane prices were adopted.

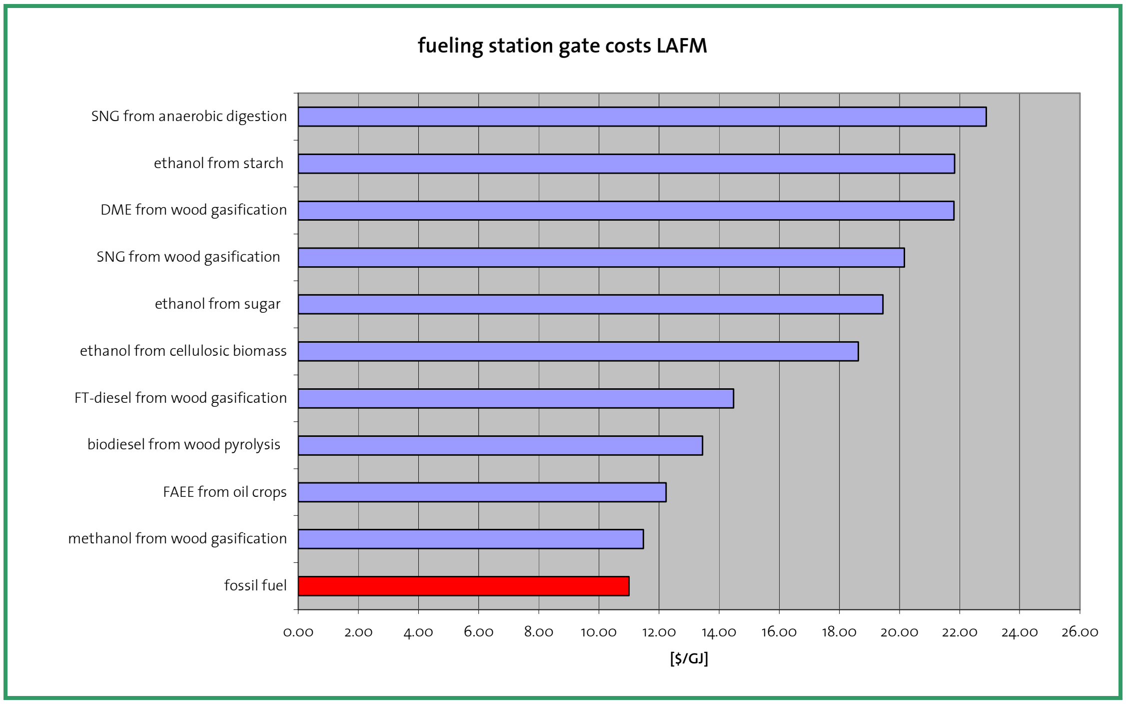

Figure 20: Fueling station gate costs in LAFM compared with fossil fuels in Switzerland. Source for fossil fuel costs: [77] It is not distinguished between diesel and gasoline costs. Just one single cost for latter two fuels is assumed.

In general, it can be said that the production costs of 2nd generation biofuels between WEUR and LAFM vary less than 1st generation biofuel costs due to smaller differences between the matching feedstock prices.

A further analysis of fueling station gate costs reveals that in LAFM, SNG from anaerobic digestion is the most costly option with 22.89 $/GJ, followed by ethanol from starch with 21.84 $/GJ and DME from wood gasification with 21.81 $/GJ. In WEUR ethanol from sugar is the most cost intensive biofuel resulting in a fueling station gate cost of 36.75 $/GJ, followed by ethanol from starch with 26.95 $/GJ and DME from wood gasification with 24.11 $/GJ.

In WEUR just FAEE from oil crops can be cost competitive with 2nd generation biofuels, namely with biodiesel from wood pyrolysis and methanol from wood gasification, with costs around 15 $/GJ. FT-diesel is just slightly more expensive with 16.86 $/GJ. In LAFM this relation is affirmed, too. Fueling station gate costs for SNG and DME are above 20 $/GJ in both regions analyzed, being comparable with ethanol from starch and ethanol from sugar costs in WEUR. This is mainly due to more expensive distribution costs, resulting from the lower energy content of the gas and the requirement for more sophisticated technical equipment for transport and storage.

Feedstock costs are one of the main contributors to total production costs. But due to the fact that feedstock prices are unlikely to get below the applied producer prices for this study, no significant cost reduction potential is expected here. If the conversion efficiencies are improved though, lower overall conversion costs can be expected. However, these efficiencies are already best estimates which are unlikely to further improve.

Another possibility would be the reduction of the investment costs which is another big contributor to the total costs. This could take place due to technological learning and economies of scale. But economies of scale are already considered as optimized in most of the studies and do therefore not offer much further cost reduction potential. According to experts it is unlikely, due to logistical problems, that future biomass-to-biofuel plants will exceed 400 MW. This scale is considered as a maximum scale in this study.

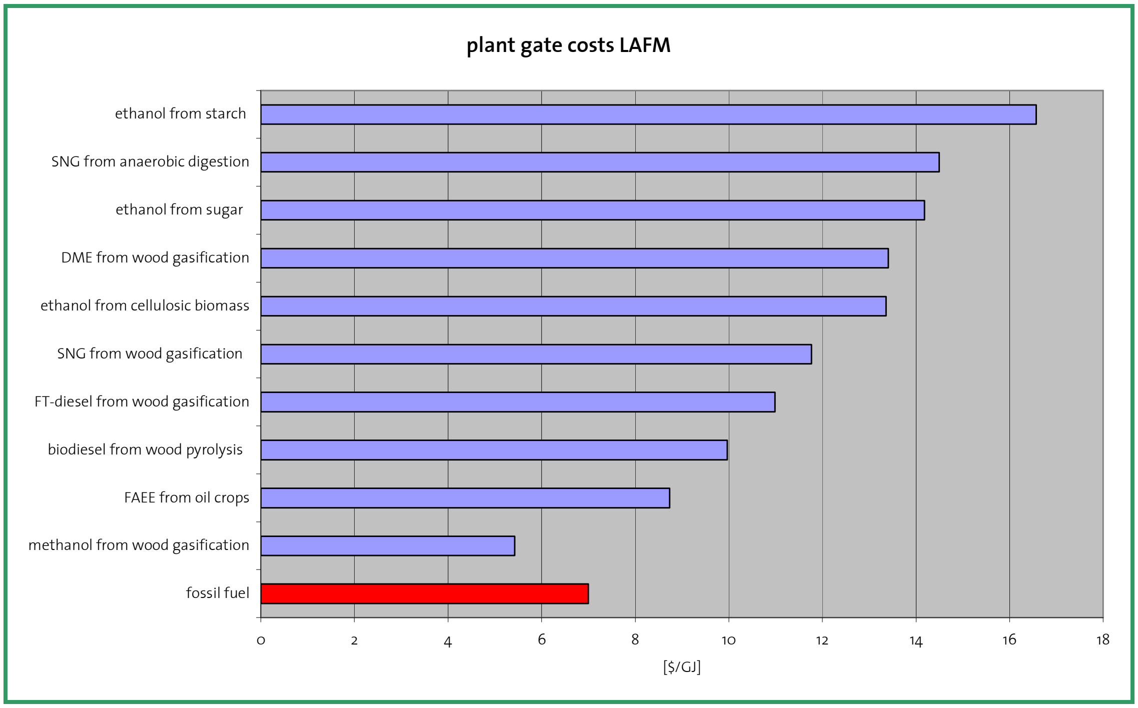

Figure 21: Plant gate costs in LAFM compared with refinery gate costs for fossil fuels. Source for fossil fuel costs: [86] It is not distinguished between diesel and gasoline costs. Just one single cost for latter two fuels is assumed.

As O & M costs are generally not very high, a cost reduction will not bring a big reduction in total costs. Global transport is already practiced at big scale, and demand for transport is steadily increasing. As a consequence, a decrease in transport costs over time is not expected either.

The only way to further reduce total production costs is seen by selling the by-products, in particular electricity and heat. It can be seen that the selling of electricity can reduce total costs by 10$ per GJ of biofuels in some cases. It is yet unclear how much the optimum amount of such electricity production should be in order to allow a still sufficient and efficient biofuels production, and at the same time reduce total costs as much as possible.

11.2 Critical parameter discussion

Biomass energy systems are highly variable and uncertain. Therefore several assumptions had to be made in order to make an analysis feasible. The overall uncertainty level is assumed to be between 20% and 40%. In the following section, critical aspects and assumptions of each system component are discussed.

11.2.1 Producer prices

Producer prices are expected to be prices paid to the farmer at the farm gate. These prices include the margin for the farmer and are therefore higher than actual costs. As discussed above, it is assumed that prices and costs for agricultural goods are identical.

In most of the cases the moisture content of the feedstock was assumed to be zero, as corresponding heating values in literature are described widespread with a moisture content of zero. In reality the moisture content of the feedstock will be higher, because the biomass is handled in a fresh condition. This assumption may lead to somewhat lower producer prices per GJ as the feedstock prices given in $/tons are divided by a LHV which is bigger at low moisture contents, leading to a lower price per GJ biomass. It is not known though, in which form and with which moisture content the feedstock is delivered.

Another aspect is the weighting of the producer prices. The producer prices are derived from every country available per world region from 2000-2003. Very high producer prices from countries with probably low supply potential were excluded from the calculations. As supply potentials were not available for all countries and as such work would have exceeded the time limit for this thesis, the corresponding countries were excluded according to the judgment of the author. It is not expected though, that this methodology tampers the results of the assessment.

Further on, it was assumed that all required biomass can be delivered at the producer prices found in literature. In reality prices may increase with increasing demand for these feedstocks. Especially the prices for wood residues in WEUR may be too low for the necessary amount of biomass required for a biofuel production at big scales.

Producer prices for domestic waste and stover for the LAFM region were assumed on the basis of data from other regions and are therefore uncertain.

Summarizing the above discussion it can be said that feedstock prices are highly variable amongst the world regions but in general the used prices for biomass are similar to other biomass prices found in literature and are therefore classified as realistic.

11.2.2 Truck transport to the plant

Truck transport costs in this study are based on cost per weight. In reality though this cost may be influenced more by volume than by weight. But in order to get cost data in the form of $/GJ out of $/m^3, bulk densities for different biomass types would have been essential. As this data could not be found in literature solely an approach on weight basis was applied.

Another point to mention is the fact that transport costs vary extremely between the world regions, this mainly due to differences in wages. In this study transport costs between different world regions are assumed to be constant. This may lead to a somewhat too high cost estimate for the LAFM region, as original cost data calculations come from Europe or the USA. But these costs are low compared to the other cost components, wherefore this discrepancy can be neglected.

In order to derive truck transport costs for the different types of biomass on a $/GJ basis, the LHV's of the different feedstocks had to be applied. Mostly, the LHV of dried biomass was used, leading to a too low cost estimate. But it turned out to be impossible to find out the real moisture content of the various types of biomass before transport, and their corresponding LHV. If for example sugar cane is transported in a dry condition the truck transport will decrease 2 $/GJ compared to a moisture content of 77%.

11.2.3 Biomass-to-biofuel conversion

Biomass-to-biofuel conversion processes are described in most detail compared to other system components. In many studies though it is not clear for which world region the calculations are made. As a consequence it is assumed that the calculations represent the world region of origin of the study. In order to get a comparable set of data between the world regions, the region specific costs indices for the production of biofuels from the IEA are applied. This is a quite approximate approach, but other possibilities turned out not to be feasible.

Another problem was that often it was unclear what exact type of biomass, what LHV and energy inputs are assumed within the different studies. Assumptions had to be completed on this aspect as well. The LHV's used in this study may differ from the LHV's used in the original studies, leading to uncertainties in the biomass-to-biofuel efficiencies.

In addition, most studies did not distinguish between fixed and variable O & M costs, so that a breakdown had to be approximated from other sources. In general though O & M costs are just a small part of total conversion costs and uncertainties can therefore be neglected.

Regarding the time frame and scale of the conversion facilities, it could not be avoided that different scales and time frames are compared to each other. If possible though, consistent data were chosen.

A last problem to be mentioned is the fact that some studies indicate uncertainties regarding capital investment of up to 40%. This makes clear how big actual uncertainties in estimating the costs of the conversion process might be.

For all these reasons the results in this study may differ from original data but compared to other studies, the cost data are still expected to be in a realistic range.

11.2.4 Distribution costs

Distribution costs are assumed as flat-rate costs or average costs per fuel type, as it turned out to be very difficult to find appropriate distribution cost data for all different fuels from literature. Distribution costs are assumed to be constant over the world regions and may not change in the future.

For the transport of a biofuel from South America to Europe the applied distribution costs may be appropriate, but for the distribution within Europe, if the biofuel is produced in Europe as well, these costs may be too high. But as all of latter cost components are predicted to change in a uniform way the relative comparison between the different biofuels is ensured.

However, it would be important to have more accurate cost data as regards distribution because latter costs are a major contributor to the biofuel fueling station gate costs.

12 Conclusions

Of the various possibilities in reducing energy consumption in the transport sector, biofuels are generally seen as an important contributor to achieve this aim. They have the potential to reduce global greenhouse gas emissions, provide energy security and substitute fossil fuels.

As a consequence of such arguments and under increasingly progressive energy policies in various countries, biofuel energy may play an important role in future energy systems. Namely in Europe, Brazil, and the USA biofuel production is going to be subject to significant increase in the near future.

The total regional potentials used in this study amount to about 194 EJ, which is at the lower end of the estimated range for the global supply potential of some 33 EJ–1344 EJ. Conversion of this biomass to the final biofuel will at least result in a division by a factor two, leading to a technical global biofuel potential of about 100 EJ.

The amount of biomass supply which can be produced in an economically feasible manner leads to a further reduction of the total supply potential. Even though if one assumes a maximum growth rate of the energy use in the transport sector of 1.7% per year until 2030, which is equal to 36.2 EJ, it is obvious that a part of fossil fuels can be replaced with biofuels without sacrifice on land for food cultivation.

Biofuels production makes sense especially in regions with high supply potential such as Latin America, Eastern Europe (Ukraine, Former Soviet Union), Southeast Asia, China and Sub-Saharan Africa, reducing the transport distance to the processing plant and allowing big plant capacities. Big capacities again are essential for an economic production of the biofuel.

For regions with relatively low biomass supply potential, as for example Western Europe, biomass or biofuel imports from regions with high supply potentials are coercive, if biofuels are to replace fossil fuels on a large scale.

Further studies are needed though, in order to ensure that increased biofuel production is compatible with sustainability and food security. If for example, the biofuels are produced on former rainforest area or cultivated under intensive agricultural conditions, it has to be analyzed whether the decrease of energy use and greenhouse gas emissions can outweigh the negative effects (e. g.: reducing biodiversity, degrading soils, influencing spatial landscape) on the ecosystem caused by the cultivation.

If the feedstock for the production of a certain biofuel is used for food production at the same time, one can assume that food prices are going to increase because of the increased demand for the feedstock. This may cause problems especially in developing countries were people depend on affordable staple foods. Therefore 2nd generation biofuels, using cellulosic or lignocellulosic biomass should be preferred to crops used for nutrition purposes as well.

If the net energy input for the production of a biofuel is even bigger than the energy content of the biofuel itself, as it is found for ethanol from corn and wood in the USA, it is highly questionable if the use of biofuels is sustainable. Therefore from an energy point of view, biofuels production should preferably be carried out in tropical countries were soils are naturally rich and sunshine is intensive. This would minimize energy use and GHG emissions emerging from the production.

If taxes on fossil fuels are implemented, as for example a CO_2 tax, future biofuels can be competitive with fossil fuels. In this case methanol from wood gasification, FAEE from oil crops, biodiesel from wood pyrolysis and FT-diesel from wood gasification are going to be the most cost competitive options. The fact that crude oil prices are going to increase in the future will make biofuels even more cost competitive. However it should be measured from case to case if the produced biofuels are sustainable, distinguishing between “good” and “bad” biofuels, in order not to promote ecologically critical pathways for biofuels production.

13 Recommendations for further research

As regards the cost assessment, it has to be said that further studies are required in order to examine more detailed cost differences of all system components between the world regions.

In addition, the different system components, mainly biomass transport should be the object of further research in order to make costs more sensitive to different types of biomass. It would be favorable as well to describe distribution costs in more detail than it is done in current literature, in order to analyze possible cost reduction potentials and distinctions between different world regions.

As seen, the co-generation of electricity and its selling can result in substantial overall cost reductions. In the reviewed studies it was not clear though which is the optimum ratio of electrical energy to be produced in a biofuels production facility. Future studies should focus on the optimization in by-products production and their sales, in order to better assess this cost reduction potential.

As literature data regarding the environmental influences of the biofuel production are highly controversial, it is recommended to carry out a multi criteria analysis dealing with ecological, economical and social sustainability. In doing so, a useful tool could be established for designating which biofuels should be subject to subsidies, or how high tax incentives should be.

14 References[59]

1. Abbott, J. and B. Crewdson, Gas heated reforming improves Fischer Tropsch process. Oil & Gas Journal, 2002. 100(16): p. 64-66, 68, 70.

2. Abengoa Bioenergy. The first commercial demonstration of Abengoa biomass ethanol technology in the world. 2006. Available from: http://www.abengoabioenergy.com/about/index.cfm?page=5&lang=1&headline=30.

3. Adachi, Y., et al., Effective utilization of remote coal through dimethyl ether synthesis. Fuel, 2000. 79: p. 229-234.

4. Aden, A., et al., Lignocellulosic biomass to ethanol process design and economics utilizing co-current dilute acid prehydrolyses and enzymatic hydrolyses for corn stover. 2002, National Renewable Energy Laboratory (NREL): Golden.

5. Aizpun, A.T., The action of the European Commission in the field of biofuels, in Unit D4. Clean Transport & Sustainable Development. 2006, European Commission: Brussels.

6. Akin, D.E., et al., Alterations in structure, chemistry, and biodegradability of grass lignocellulose treated with white rot fungi Ceriporiosis subvermispora and Cyathus stercoreus. Applied and Environmental Microbiology, 1995. 61: p. 1591-1598.

7. Amen-Chen, C.H.P. and C. Roy, Production of monomeric phenols by thermochemical conversion of biomass: A review. Bioresource Technology, 2001. 79(3): p. 277-299.

8. Archer Daniels Midland. ADM world. 2006. Available from: http://www.admworld.com/cgi-bin/search/euge/search.asp?Realm=Admworld_EUGE&Terms=biodiesel.

9. Atchinson, J.E. and J.R. Hettenhaus, Innovative methods for corn stover collecting, handling, storing and transporting. 2003, National Renewable Energy Laboratory (NREL): Golden.

10. Azuma, J.I. and T.K. Tanaka, Enhancement of enzymatic susceptibility of lignocellulosic wastes by microwave irradiation. Journal of Fermentation Technology, 1984. 62(4): p. 377.

11. Barnwal, B.K. and M.P. Sharma, Prospects of biodiesel production from vegetable oils in India. Renewable and Sustainable Energy Reviews, 2005. 9(4): p. 363-378.

12. Barranon, D.C.C., Methanol and Hydrogen production. 2006, Lulea University of Technology: Lulea.

13. Battjes, J.J., Global options for biofuels from plantations according to IMAGE simulations. 1994, Interfacultaire Vakgroep Energie en Milieukunde (IVEM): Groningen.

14. Baumgartner, J., DGMK-Projekt 645 Laboruntersuchungsprogramm zur Ethanolbeimischung zu Ottokraftstoffen, in Biogene und synthetische Treibstoffe; Praxis und Ausblick. 2006, Schweizerische Studiengesellschaft für Motorbetriebsstoffe: Luzern.

15. BBI. Peru plan aims to supply California with ethanol fuel. 2003. Available from: http://bbiethanol.com/news/view.cgi?article=724.

16. Berg, C. World fuel ethanol analysis and outlook. 2004. Available from: http://www.distill.com/World-Fuel-Ethanol-A&O-2004.html.

17. Berndes, G., M. Hoogwijk, and R. van den Broek, The contribution of biomass in the future global energy supply: a review of 17 studies. Biomass and Bioenergy, 2003. 25(1): p. 1-28.

18. Bhatt, B.L., et al., Liquid phase Methanol development. American Chemical Society, Division of Petroleum Chemistry, 1999. 44(1): p. 25-27.

[59] All cited internet sources were available, January 16, 2007.

19. BIOBIB. BIOBIB-database for biofuels. 2006. Available from: http://www.vt.tuwien.ac.at/biobib/biobib.html.

20. Bockey, D. and W. Von Schenk, Status report-biodiesel production and marketing in Germany 2005. 2005, Union zur Förderung von Öl- und Proteinpflanzen: Berlin.

21. Bridgwater, A.V., Renewable fuels and chemicals by thermal processing of biomass. Chemical Engineering Journal, 2003. 91(2-3): p. 87-102.

22. Bullis, K. Making ethanol from wood chips. MIT Technology Review. 2006. Available from: http://www.technologyreview.com/NanoTech/17799/.

23. Bundesministerium für Umwelt Naturschutz und Reaktorsicherheit (BMU), Erneuerbare Energien, Innovationen für die Zukunft. 2006, Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU): Berlin.

24. CEC, Costs and benefits of a biomass to ethanol production industry in California. 2001, California Energy Commission: Sacramento.

25. Celunol. Osaka Project. 2006. Available from: http://www.celunol.com/interior.html?redir=projects1.

26. Corrosion Source. Glossary. 2006. Available from: http://www.corrosionsource.com/handbook/glossary/b_glos.htm.

27. CPL Press. BEST - Bioethanol for Sustainable Transport. 2006. Available from: http://www.biomatnet.org/secure/FP6/S1993.htm.

28. Davenport, B., Methanol, in Chemical Economics Handbook Marketing Research Report. 2002, SRI International: Menlo Park.

29. De Vries, B.J.M., D.P. van Vuuren, and M.M. Hoogwijk, Renewable energy sources: Their global potential for the first-half of the 21st century at a global level: An integrated approach. Energy Policy, 2006. In Press, Corrected Proof.

30. Demirbas, A., Supercritical fluid extraction and chemicals from biomass with supercritical fluids. Energy Conversion and Management, 2001. 42: p. 279-294.

31. Desmet Ballestra. The plants are built by Desmet Ballestra. 2006. Available from: http://www.desmetballestraoleo.com/.

32. Die Süddeutsche Zeitung. Alternative Antriebe. 6. Nov. 2006. Available from: http://www.sueddeutsche.de/,trt1m2/automobil/special/132/66066/.

33. Die Zeit. Viel Mist gemacht. Die Zeit. 23. Nov. 2006. Available from: http://www.zeit.de/2006/48/U-Biofuels?page=all.

34. Diethelm, R., Potenzial der Biotreibstoffe ist begrenzt, in Tagesanzeiger. 8. Dez. 2006.

35. Dorado, M.P., et al., An approach to the economics of two vegetable oil-based biofuels in Spain. Renewable Energy, 2006. 31(8): p. 1231-1237.

36. Dreier, T., B. Geiger, and A. Saller, Ganzheitliche Prozeßkettenanalyse für die Erzeugung und Anwendung von biogenen Kraftstoffen; Studie im Auftrag der Daimler Benz AG, Stuttgart und des Bayerischen Zentrums für Angewandte Energieforschung e.V. (ZAE). 1998, Forschungsstelle für Energiewirtschaft (FfE): München.

37. Dry, M.E., Fischer-Tropsch reactions and the environment. Applied Catalysis A: General, 1999. 189(2): p. 185-190.

38. Dry, M.E., The Fischer Tropsch process 1950-2000. Catalysis Today, 2002. 71: p. 227-241.

39. ECN-Biomass. Phyllis, the composition of biomass and waste. 2006. Available from: http://www.ecn.nl/phyllis/.

40. Edwards, R., et al., Well to wheel analysis of future automotive fuels and power trains in the European context, well to wheel report, version 2b. 2006, CONCAWE, EUCAR, European Commission: Brussels

41. EIA, Annual Energy Outlook 2005. 2005, Energy Information Administration (EIA): Washington D.C..

42. EIA. Estimated numbers of alternative fueled vehicles in use in the USA. 2004. Available from: http://www.eia.doe.gov/cneaf/alternate/page/datatables/aft1-13_03.html.

43. Enguidanos, M., et al., Techno-economic analysis of Bio-alcohol production in the EU: a short summary for decision-makers. 2002, European Commission: Brussels.

44. Ericsson, K. and L.J. Nilsson, Assessment of the potential biomass supply in Europe using a resource-focused approach 2006. 30(1): p. 1-15.

45. Erzengin, M. and M.M. Kucuk, Liquefaction of sunflower stalks by using supercritical extraction. Energy Conversion and Management 1998. 39(1): p. 1203-1206.

46. FAO, FAOSTAT database. 2006, Available from: http://faostat.fao.org/site/336/DesktopDefault.aspx?PageID=336

47. FAO, World agriculture: Towards 2015/2030. 2002, Food and Agriculture Organization: Rome.

48. Farrel, A., et al., Ethanol can contribute to energy and environmental goals. Science, 2006. 311(5760): p. 506-508.

49. Felder, R. and R. Dones, Evaluation of ecological impacts of synthetic natural gas from wood used in current heating and car systems. Submitted for publication in Biomass and Bioenergy, 2006.

50. Fike, J.H., et al., Switchgrass production for the upper southeastern USA: Influence of cultivar and cutting frequency on biomass yields. Biomass and Bioenergy, 2006. 30(3): p. 207-213.

51. Fischer, G. and L. Schrattenholzer, Global bioenergy potentials through 2050. Biomass and Bioenergy, 2001. 20: p. 151-159.

52. Fleisch, T.H., et al., Dimethyl ether: A fuel for the 21st century. Fuel and Energy Abstracts, 1997. 38(6): p. 390.

53. Fleisch, T.H. and M.D. Sills, 2002-Emergence of the gas-to-liquids industry: A review of global GTL developments. Journal of Natural Gas Chemistry, 2002. 11: p. 1-14.

54. Fleisch, T.H., R.A. Sills, and M.D. Briscoe, 2002-Emerge of the gas to liquids industry: A review of global GTL developments. Journal of Natural Gas Chemistry, 2002. 11: p. 1-14.

55. Fleming, J.S., S. Habibi, and H.L. MacLean, Investigating the sustainability of lignocellulose-derived fuels for light-duty vehicles. Transportation Research Part D: Transport and Environment, 2006. 11(2): p. 146-159.

56. Fontes, S.A.M., Petrobras, in Assessing the Biofuels Option. 2005, IEA: Paris.

57. Fortenbery, T.R., Biodiesel feasibility study: An evaluation of biodiesel feasibility in Wisconsin. 2005, University of Wisconsin-Madison, Department of Agricultural & Applied Economies: Madison.

58. Geurds, M., Clean technologies for industries, biomass in Asean. 2006, Asia Pro Eco Programme: Brussels.

59. Gnansounou, E. and A. Dauriat, Ethanol fuel from biomass: A review. Journal of Scientific & Industrial Research, 2005. 64: p. 809-821

60. Gover, M.P., et al., Alternative road transport fuels - a preliminary life-cycle study for the UK. Vol. 2. 1996: East Tennessee State University: Johnson City.

61. Graham, R.L., B.C. English, and C.E. Noon, A Geographic Information System-based modeling system for evaluating the cost of delivered energy crop feedstock. Biomass and Bioenergy, 2000. 18(4): p. 309-329.

62. Granada, E., et al., Fuel lignocellulosic briquettes, die design and product study. Renewable Energy, 2002. 27: p. 561-573.

63. Gray, D. and G. Tomlinson, Mitretek Systems (MTS): Co production: A Green Coal Technology, Technical Report for the U.S. Department of Energy (DOE). 2001, Mitretek Systems: Falls Curch.

64. Green Car Congress. New DME plant in Iran will triple global production. 2004. Available from: http://www.greencarcongress.com/2004/06/new_dme_plant_i.html.

65. Green Car Congress. Sun Opta providing steam explosion technology for world's first cereal straw ethanol plant. 2005. Available from: http://www.greencarcongress.com/2005/08/sunopta_providi.html.

66. Grohmann, K., R. Torget, and M. Himmel, Optimization of dilute acid pretreatment of biomass. Biotechnology and Bioengineering Symposium 1985. 15: p. 59-80.

67. Hall, D.O., Biomass energy in industrialized countries - a view of the future. Forest Ecology and Management, 1997. 91: p. 17-45.

68. Hall, D.O., et al., Biomass for energy: supply prospects. Renewable Energy, Sources for Fuels and Electricity. 1993: Island Press: Washington, D. C..

69. Hall, D.O. and J.I. Scrase, Will biomass energy be the environmentally friendly fuel of the future? Biomass and Bioenergy, 1998. 15(4-5): p. 357-367.

70. Hamelinck, C.N., Outlook for advanced biofuels, in Faculteit Scheikunde. 2004, Universität Utrecht: Utrecht.

71. Hamelinck, C.N. and A.P.C. Faaij, Outlook for advanced biofuels. Energy Policy, 2006. 34: p. 3268-3283.

72. Hamelinck, C.N. and A.P.C. Faaij, Future prospects for production of methanol and hydrogen from biomass. System analysis of advanced conversion concepts by ASPEN-plus flow sheet modeling. Journal of Power Sources, 2002. 111: p. 1-22.

73. Hamelinck, C.N., et al., Production of FT transportation fuels from biomass; technical options, process analysis and optimization, and development potential. Energy, 2006. 29(11): p. 1743-1771.

74. Hamelinck, C.N., G.v. Hooijdonk, and A.P.C. Faaij, Ethanol from lignocellulosic biomass: techno-economic performance in short-, middle- and long-term. Biomass and Bioenergy, 2005. 28(4): p. 384-410.

75. Hansen, J.B., et al., Large-scale manufacture of dimethyl ether-a new alternative diesel fuel from natural gas. SAE Paper, 1995. 950063.

76. Harvey, S. and B. Facchini, Predicting black liquor gasification combined cycle powerhouse performance accounting for off-design gas turbine operation. Applied Thermal Engineering, 2004. 24(1): p. 111-126.

77. Heitzer, A., Personal Communication, 2006. Erdöl-Vereinigung: Zürich.

78. Heizer, A., Biogene und synthetische Treibstoffe, heutige Situation in der Schweiz und in Europa, in Biogene und synthetische Treibstoffe; Praxis und Ausblick. 2006, Schweizerische Studiengesellschaft für Motorbetriebsstoffe: Luzern.

79. Heywood, J.B., Fueling our transportation future. Scientific American, 2006. (special issue).

80. Hitachi. DME development Co., Ltd. launches 100t/d DME direct synthesis pilot plant project. 2002. Available from: http://www.power-hitachi.com/news/press_20020729.htm.

81. Hoffert, M.I., et al., Energy implications of future stabilization of atmospheric CO2 content. Nature, 1998. 395: p. 881-884.

82. Hoogwijk, M., et al., Potential of biomass energy out to 2100, for four IPCC SRES land-use scenarios. Biomass and Bioenergy, 2005. 29(4): p. 225-257.

83. Hoogwijk, M., et al., Exploration of the ranges of the global potential of biomass for energy. Biomass and Bioenergy, 2003. 25(2): p. 119-133.

84. House, K. DOE report on gas to liquids and coal to liquid technology & an interview with two Fischer-Tropsch Engineers. 2006. Available from: http://www.hcs.harvard.edu/~hejc/schedule.html.

85. IEA, Automotive fuels for the future, the search for alternatives. 1999, International Energy Agency (IEA): Paris.

86. IEA, Biofuels for transport. 2005, International Energy Agency (IEA): Paris.

87. IEA, Biogas production and utilization. 2005, International Energy Agency: Paris.

88. IEA, Energy technology perspectives. 2006, International Energy Agency (IEA): Paris.

89. IEA, Key World Energy Statistics. 2006, International Energy Agency (IEA): Paris.

90. IEA, Prospects for hydrogen and fuel cells. 2005, International Energy Agency (IEA): Paris.

91. IEA, Saving oil and reducing CO2 emissions in transport. 2001, International Energy Agency (IEA): Paris.

92. IEA, World Energy Outlook. 2006, International Energy Agency (IEA): Paris.

93. Intergovermental Panel on Climate Change (IPCC), Climate change 2001: the scientific basis. 2001, Cambridge University Press: Cambridge.

94. International Fuel Quality Center. Worldwide GTL projects. 2001. Available from: http://www.ifqc.org/member/Global-Topics/GTL/GTLDatabase110601.htm.

95. Jager, B., Developments in Fischer Tropsch technology. Dymmy, 1997: p. 219-224.

96. Jefferson, M., World Energy Assessment. 2000, United Nations Development Programme: New York.

97. Junginger, M., A. Faaij, and W.C. Turkenburg, Global experience curves for wind farms. Energy Policy, 2005. 33(2): p. 133-150.

98. Kaltschmitt, M. and H. Hartmann, Energie aus Biomasse, Grundlagen, Techniken, Verfahren. 2001, Springer: Berlin.

99. Kartha, S. and E.D. Larson, A bioenergy primer: Modernized biomass energy for sustainable development. 2000, United Nations Development Programme: New York.

100. Katofsky, R.E., The Production of Fluid Fuels from Biomass. 1993, The Center for Energy and Environmental Studies, Princeton University: Princeton.

101. Keef, A., Sugar cane railways : May still be the most economical haulage in the long run. International Sugar Journal 1996. 98(1170): p. 296.

102. Kilman, S. and J.J. Fialka. Big players join race to put farm waste into your gas tank. 2006. Available from: http://www.iogen.ca/news_events/cellulose_ethanol_news/2006_06_29.html.

103. Koullas, D.P., et al., Correlating the effect of pretreatment on the enzymatic hydrolysis of straw. Biotechnology and Bioengineering Symposium, 1992. 38: p. 113-116.

104. Kraus, K., G. Niklas, and M. Tappe, Deutschland: Aktuelle Bewertung des Einsatzes von Rapsöl/RME im Vergleich zu DK, in Texte. 1999, Umweltbundesamt (UBA): Dessau.

105. Kumar, A., J.B. Cameron, and P.C. Flynn, Pipeline transport and simultaneous saccharification of corn stover. Bioresource Technology, 2005. 96(7): p. 819-829.

106. Kwiatkowski, J.R., et al., Modeling the process and costs of fuel ethanol production by the corn dry-grind process. Industrial Crops and Products, 2006. 23(3): p. 288-296.

107. Larson, E.D. and H. Jin. A preliminary assessment of biomass conversion to Fischer-Tropsch cooking fuels for rural China in Proceedings of the 4th Biomass Conference of the Americas. 1999: Elsevier Science: New York.

108. Laser, M., et al., Comparison of hot liquid water and steam pretreatments of sugar cane bagasse for bioconversion to ethanol. Bioresource Technology, 2002. 81: p. 33-44.

109. Lehtikangas, P., Quality properties of pelletized sawdust, logging residues and bark. Biomass and Bioenergy, 2001. 20: p. 351-360.

110. Leinonen, A., Harvesting technology of forest residues for fuel in the USA and Finland. 2004, VTT Processes: Vuorimiehentie.

111. Licht, F.O., Biofuels and the international development agenda. F.O. Licht World Ethanol & Biofuels Report, 2005. 3(21).

112. Licht, F.O. F. O. Licht's World Distilleries Guide. 2005. Available from: http://www.agra-net.com/portal/home.jsp?pagetitle=showad&pubId=ag063.

113. Lusk, P., Methane recovery from animal manures. The current opportunities case book. 1998, National Renewable Energy Laboratory: Golden.

114. Lynd, L.R., Overview and evaluation of fuel ethanol from cellulosic biomass: technology, economics, the environment, and policy. Annual Reviews, Energy Environment, 1996. 21: p. 403-465.

115. Lynd, L.R., R.T. Elander, and C.E. Wyman, Likely features and costs of mature biomass ethanol technology. Applied Biochemistry and Technology, 1996. 57/58: p. 741-761.

116. Lynd, L.R., W.H. Weimer, and I.K. Van Zyl, Microbial cellulose utilization: Fundamentals and Biotechnology. Microbiology and Molecular Biology Reviews, 2002. 66(3): p. 506-577.

117. Ma, F. and M. Hanna, Biodiesel production: A review. Bioresource Technology, 1999. 70(1): p. 1-15.

118. Ma, F., D. Clements, and M.A. Hanna, The effect of mixing on transesterification of beef tallow Bioresource Technology, 1999.69(3): p. 289-293.

119. Mattson, J.W., C. Sun, and W.W. Koo, Analyses of the world oil crop markets. 2004, Center for Agricultural Policy and Trade Studies: Fargo.

120. Mc Aloon, A., F. Taylor, and W. Yee, Determining the cost of producing ethanol from corn starch and lignocellulosic feedstocks. 2000, National Renewable Energy Laboratory (NREL): Golden.

121. McDonald, A. and L. Schrattenholzer, Learning rates for energy technologies. Energy Policy, 2001. 29(4): p. 255-261.

122. McKendry, P., Energy production from biomass (part 1): overview of biomass. Bioresource Technology, 2002. 83(1): p. 37-46.

123. McKendry, P., Energy production from biomass (part 2): conversion technologies. Bioresource Technology, 2002. 83(1): p. 47-54.

124. McKendry, P., Energy production from biomass (part 3): gasification technologies. Bioresource Technology, 2002. 83(1): p. 55-63.

125. Methanol Institute. Methanol. 2006. Available from: http://www.methanol.org.

126. Milne, T.A., R.J. Evans, and N. Abatzoglou, Biomass gasifier tars: their nature formation and conversion. 1998, National Renewable Energy Laboratory: Golden.

127. Moreira, J.R. and J. Goldenberg, The alcohol program. Energy Policy, 1999. 27: p. 229-245.

128. Mortimer, N.D., et al., Evaluation of the comparative energy, global warming and socio-economic costs and benefits of biodiesel. 2003, School of environment and development, Sheffield Hallam University: Sheffield.

129. Naqvi, S., Dimethyl ether as an alternative fuel. 2002, SRI Consulting: Melno Park.

130. National Biodiesel Board. Response to David Pimentel's biodiesel Life Cycle Analysis. 2005. Available from: http://www.biodiesel.org/.

131. Niven, R.K., Ethanol in gasoline: environmental impacts and sustainability review article. Renewable and Sustainable Energy Reviews, 2005. 9(6): p. 535-555.

132. Noon, C.E., et al. Transport and site location analyses for regional integrated biomass assessment. The seventh National Bioenergy Conference: Partnerships to Develop and Apply Biomass Technologies, 1996. Nashville.

133. NOVEM, Ligno cellulosic ethanol. 2003, Netherlands Agency for Energy and Environment: Utrecht.

134. NREL, Biodiesel: the clean, green fuel for diesel engines. 2000, National Renewable Energy Laboratory: Golden.

135. OANDA. FX History: Historical currency exchange rates. 2006. Available from: http://www.oanda.com/convert/fxhistory.

136. Oelmühle Leer Connemann GmbH & Co., Biodiesel –Zentrale oder dezentrale Verarbeitung. 2000, Oelmühle Leer Connemann GmbH & Co: Hamburg.

137. Oukaci, R., Fischer Tropsch synthesis, in Second Annual GTL Summit. 2002: London.

138. Perlack, R.D. and A.F. Turhollow, Feedstock cost analysis of corn stover residues for further processing. Fuel and Energy Abstracts, 2004. 45(2): p. 106-106.

139. Petersen, K. Neue Wege. Sueddeutsche Zeitung. 2005. Available from: http://www.sueddeutsche.de/,trt1m2/automobil/special/132/66066/.

140. Pimentel, D. Cornell ecologist's study finds that producing ethanol and biodiesel from corn and other crops is not worth the energy. 2006. Available from: http://www.news.cornell.edu/stories/July05/ethanol.toocostly.ssl.html.

141. Rabe, S., T.B. Truong, and F. Vogel, Comparison of different noble metal catalysts for the low temperature catalytic partial oxidation of methane, in Internal report. 2006, Laboratory for Energy and Material Cycles: Villigen.

142. Radowitz, B. Revolution im Tank. Sueddeutsche Zeitung. 2006. Available from: http://www.sueddeutsche.de/,trt1m2/automobil/special/132/66066/.

143. Rafaj, P., Analysis of Policies Contributing to Sustainability of the Global Energy System Using the Global Multi-regional MARKAL Model (GMM). 2005, Swiss Federal Institute of Technology (ETH): Zurich.

144. Rahmim, I.I., Gas to liquid technologies: Recent advances, economics, prospects, in 26th IAEE Annual International Conference. 2003: Prag.

145. Ravindranath, N.H. and D.O. Hall, Biomass energy and environment, a developing country perspective from India. 1995, Oxford University Press: Oxford.

146. Renewable Fuels Association, From niche to nation-ethanol industry outlook 2006. 2006, Renewable Fuels Association: Washington, D.C..

147. Ringer, M., V. Putsche, and J. Scahill, Large-scale pyrolysis oil production: a technology assessment and economic analysis. 2006, National Renewable Energy Laboratory (NREL): Golden.

148. Rogner, H.H., Renewable energy technologies, in World Energy Assessment; Energy and the Challenge of Sustainability., J. Goldenberg, et al., Editors. 2000, United Nations Development Programme (UNDP): New York. p. 219-272.

149. Rosenberger, A., et al., Costs of bioethanol production from winter cereals: the effect of growing conditions and crop production intensity levels. Industrial Crops and Products, 2002. 15(2): p. 91-102.

150. Scheer, H., Speech at the Opening Session of the European Wind Energy Conference, in European Wind Energy Conference 2001: Copenhagen.

151. Schenler, W., Personal communication. 2006, Paul Scherrer Institute (PSI): Villigen.

152. Schmitd, A.S. and A.B. Thomsen, Optimization of wet oxidation pretreatment of wheat straw. Bioresource Technology, 1998. 64: p. 139-151.

153. Schmitz, N., Perspektiven der Bioethanolproduktion in Deutschland und der EU, in Bio - raffiniert! Neue Wege in der Nutzung biogener Rohstoffe, Fraunhofer Institut Umwelt-, Sicherheits-, Energietechnik UMSICHT. 2003, MEO Consulting Team: Oberhausen.

154. Schulz, H., Short history and present trends of Fischer-Tropsch synthesis. Applied Catalysis A: General, 1999. 186(1-2): p. 3-12.

155. Schulz, T.F., et al., Methane from wood-assessment of wood-based synthetic natural gas technologies with the Swiss MARKAL Model. 2005, Energy Economics Group and Laboratory for Energy and Materials Cycles, General Energy Research Department (ENE): VIlligen.

156. Shell. Gas-to-liquids. 2006. Available from: http://www.shell.com/home/Framework?siteId=shellgasandpower-en&FC2=/shellgasandpower-en/html/iwgen/leftnavs/zzz_lhn3_6_0.html&FC3=/shellgasandpower-en/html/iwgen/products_and_services/what_is_gtl/dir_what_is_gtl_1205.html.

157. Smeets, E., A.P.C. Faaij, and I. Lewandowski, A quickscan of global bioenergy potentials to 2050. 2004, NOVEM: Utrecht.

158. Sokhansanj, S. and A. Turhollow, F. , Baseline costs for corn stover collection. Applied Engineering in Agriculture, 2002. 18(5): p. 525-530.

159. Southern Chemical Corporation. Methanol Production. 2006. Available from: http://www.southernchemical.com/production.htm.

160. Spath, P.L. and D.C. Dayton, Preliminary screening-Technical and economic assessment of synthesis gas to fuels and chemicals with emphasis on the potential for biomass-derived syngas. 2003, National Renewable Energy Laboratory: Golden.

161. Spiegel Online. Kleiner, leichter, sparsamer. 30. Nov. 2006. Available from: http://www.spiegel.de/auto/aktuell/0,1518,451318,00.html.

162. Stucki, S., Internal report. 2006, Laboratory for Energy and Materials Cycles, Paul Scherrer Institute (PSI): Villigen.

163. Sun, Y. and J. Cheng, Hydrolysis of lignocellulosic materials for ethanol production: a review. Bioresource Technology, 2002. 83(1): p. 1-11.

164. Suppes, G.J., et al., Compression ignition fuel properties of Fischer-Tropsch syncrude. Industrial and Engineering Chemistry Research, 1998. 37: p. 2029-2038.

165. Suurs, R.A., Long distance bioenergy logistics, in Department of Science, Technology and Society. 2002, Utrecht University: Utrecht.

166. Taherzadeh, M.J., Ethanol from lignocellulose: Physiological effects of inhibitors and fermentation strategies in Department of Chemical Reaction Engineering. 1999, Chalmers University of Technology: Göteborg.

167. Teymouri, F., et al., Optimization of the ammonia fiber explosion (AFEX) treatment parameters for enzymatic hydrolysis of corn stover. Bioresource Technology, 2005. 96(18): p. 2014-2018.

168. Tijmensen, M.J.A., The production of Fischer Tropsch liquids and power through biomass gasification in Department of Science, Technology and Society. 2000, Utrecht University: Utrecht.

169. Tijmensen, M.J.A., et al., Exploration of the possibilities for production of Fischer Tropsch liquids and power via biomass gasification. Biomass and Bioenergy, 2002. 23(2): p. 129-152.

170. Toyo Engineering Corporation. Toyo Engineering Awarded Contract for Coal-based 2nd DME Plant in China. 2006. Available from: http://www.toyo-eng.co.jp/e/news/18/20060907.html.

171. Tuck, G., et al., The potential distribution of bioenergy crops in Europe under present and future climate. Biomass and Bioenergy, 2006. 30(3): p. 183-197.

172. Turick, C.E., et al., Methane fermentation of woody biomass. Bioresource Technology, 1991. 37(2): p. 141-147.

173. Turkenburg, W.C., Renewable energy technologies, in World Energy Assessment; Energy and the Challenge of Sustainability., J. Goldenberg, et al., Editors. 2000, United Nations Development Programme (UNDP): New York. p. 219-272.

174. U. S. Department for Labor. Inflation calculator. 2006. Available from: http://data.bls.gov/cgi-bin/cpicalc.pl.

175. United States Environmental Protection Agency. Renewable Fuel Standard Program. 2006. Available from: http://www.epa.gov/otaq/renewablefuels/.

176. USDA, The economic feasibility of ethanol production from sugar in the united states. 2006, U. S. Department of Agriculture: Washington D.C..

177. USDA, Feed grains database. 2005, US Department of Agriculture (USDA). 2006. Available from: http://www.ers.usda.gov/Data/FeedGrains/.

178. Van den Broek, R., Sustainability of biomass electricity systems in Department of Science Technology and Society. 2000, Utrecht University: Utrecht.

179. Van Kasteren, J.M.N. and A.P. Nisworo, A process model to estimate the cost of industrial scale biodiesel production from waste cooking oil by supercritical transesterification. Resources, Conservation and Recycling, 2006. In Press, Corrected Proof.

180. Van Nierop, P., H.H. Erasmus, and J.J. Van Zyl, Sasols achievements if the 20th century as a building block for the 21st. 2000, Technologies Council: San Francisco.

181. Van Walwijk, M., et al., Automotive Fuels Survey: Comparison and Selection. 1998, International Energy Agency: Paris.

182. Vasudevan, P., S. Sharma, and A. Kumar, Liquid fuel from biomass: An overview. Journal of Scientific & Industrial Research, 2005. 64: p. 822-831.

183. Verma, S., Anaerobic digestion of biodegradable organics in municipal solid wastes, in Department of Earth and Environmental Engineering. 2002, Columbia University: New York.

184. Volkswagen. Mobilität und Nachhaltigkeit. 2006. Available from: http://www.volkswagen-umwelt.de/buster/buster.asp?i=wissen_22658.asp.

185. Waldheim, L.E., Update on the progress of the Brazilian wood BIG-GT demonstration project. Journal of Engineering for Gas Turbines and Power, 2001. 123(525-536).

186. Warnecke, R., Gasification of biomass: comparison of fixed bed and fluidized bed gasifier. Biomass and Bioenergy, 2000. 18: p. 489-497.

187. Whims, J. Corn based ethanol costs and margins. 2002. Available from: www.agmrc.org/corn/info/ksueth1.pdf.

188. Wikipedia, Wikipedia die freie Enzyklopädie. 2006. Available from: http://www.wikipedia.org.

189. Williams, R.H., Roles for biomass energy in sustainable development in Industrial ecology and global change R. Socolow, et al., Editors. 1994, Cambridge University Press Oxford. p. 119-225.

190. Williams, R.H. and E.D. Larson, Biomass gasifier gas turbine power generating technology Biomass and Bioenergy, 1996. 10(2-3): p. 149-166.

191. Wooley, R., et al., Process design and costing of bioethanol technology: A tool for determining the status and direction of research and development. Biotechnology Process, 1999. 15: p. 794-803.

192. Wooley, R., et al., Lignocellulosic biomass to ethanol process design and economics utilizing co-current dilute acid prehydrolyses and enzymatic hydrolyses current and futuristic scenarios. 1999, National Renewable Energy Laboratory (NREL): Golden.

193. Wright, J.D., C.E. Wyman, and K. Grohmann, Ethanol from biomass by enzymatic hydrolysis. Chemical Engineering Progress 1988. 84: p. 62-74.

194. Wright, J.D., C.E. Wyman, and K. Grohmann, Simultaneous saccharification and fermentation of lignocellulose: process evaluation. Applied Biochemistry and Biotechnology 1988. 18: p. 75-89.

195. Wyman, C.E., Biomass ethanol: Technical progress, opportunities, and commercial challenges. Annual Reviews, Energy Environment, 1999. 24: p. 189-226.

196. Wyman, C.E., Ethanol from lignocellulosic biomass: Technology, economics, and opportunities. Bioresource Technology, 1994. 50(1): p. 3-15.

197. Wyman, C.E., Potential synergies and challenges in refining cellulosic biomass to fuels, chemicals, and power. Biotechnology progress, 2003. 19(2): p. 254-262.

198. Wyman, C.E. and J.C. Cutler, Ethanol Fuel, in Encyclopedia of Energy. 2004, Elsevier: New York.

199. Xu, M., D.W. Lunsford, and A.B. Goodman, Synthesis of dymethyl ether (DME) from Methanol over solid-acid catalysts. Applied Catalysis: A, 1997. 149: p. 289-301.

200. Yaman, S., et al., Production of fuel briquettes from olive refuse and paper mill wastes. Fuel Processing Technology, 2000. 68: p. 23-31.

201. Yokayo Biofuels. A history of biodiesel/ biofuels. 2006. Available from: http://www.ybiofuels.org/bio_fuels/history_biofuels.html.

202. Yoshioka, T., et al., A case study on the costs and the fuel consumption of harvesting, transporting, and chipping chains for logging residues in Japan. Biomass and Bioenergy, 2006. 30(4): p. 342-348.

15 Appendix 1: Markets targets and programs for the production of biofuels

15.1 United States of America

The Clean Air Act and its oxygenated fuel program were amended in 1990. As a consequence, gasoline that is sold in areas with too high carbon monoxide (CO) emissions must contain 2.7% oxygen. In the nine worst ozone non-attainment areas the Reformulated Gasoline Program (RGP) requires an oxygen content of 2% in gasoline [86].

In 2001 16 billion liters MTBE[60] and 6.63 billion liters ethanol in the form of ETBE[61] have been added for this purpose. But because MTBE often invaded in the groundwater where it persisted, nowadays more and more ETBE is used as an oxidant for gasoline. A Renewable Fuels Standard which prohibits the utilization of MTBE will probably be implemented by 2012 [198].

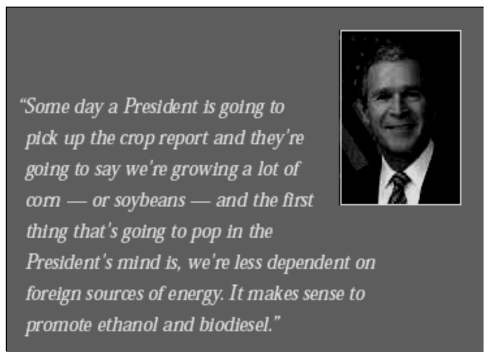

Figure 22: President George W. Bush, upon signing the RFS into law, August 8, 2005 [146].

In addition the 1992 Energy Policy Act encourages the use of renewable fuels. Fleets of vehicles from the US states and the fleets of alternative fuel providers were obligated to run one percentage of their vehicles on alternative fuels.

Under the Energy Policy Act of 2005, a national Renewable Fuels Program (also known as the Renewable Fuel Standard Program, or RFS Program) was signed (Figure 22). This program is going to increase the volume of renewable fuel required to be blended into gasoline, starting with 15.15 billion liters in 2006 and nearly doubling to 28.4 billion liters by 2012. The RFS program was developed in collaboration with refiners, renewable fuel producers, and many other stakeholders [175]. Strong promotion comes also from the Environmental Protection Agency (EPA).

Ethanol consumption rose some 2.5% per year in the 1990s. EPA's requirement for a phase out of MTBE (replacement with ETBE derived from ethanol) is an important driver for ethanol demand [106]. Some states have partial ethanol tax exemptions, mainly in ethanol producing areas [86]. In the year 2003

[60] methyl-tertiary-butyl-ether

[61] ethyl-tertiary-buthyl-ether

133'776 vehicles in the USA were running on E85[62], ethanol vehicles growing rates between 1995 and 2003 averaged on 78.8%. Most of them are light duty vehicles for federal fleets [42].

15.2 Canada

In its Climate Change Plan, the Canadian government recently encouraged the construction of new ethanol plants and development of cellulose based ethanol. The National Biomass Ethanol Program (NBEP) encourages firms to invest in the Canadian ethanol industry, as a partial compensation for the planned decrease of the excise tax reduction. In many provinces tax incentives do exist [86]. In 2001 Canada produced 238 million liters of ethanol, mainly from corn and wheat [198].

15.3 European Union

In the EU primarily biodiesel is produced, accounting for 87% of global biodiesel output [92]. The European Commission set a test-based emission target of 140 g of CO_2/km for average new vehicles sold in 2008-2009. As a consequence, carbon dioxide (CO_2) emissions from new cars in the EU-25 decreased by almost 12% between the years 1995 and 2005.

The current discussion focuses on a combination of biofuels and vehicle efficiency measures [88]. In 2003, two new indicative targets have been adopted. EU directive 2003/30/EC seeks to replace 20% of the liquid fossil fuels with biofuels, natural gas, hydrogen and other alternative fuels by 2020. Short term targets are to ensure that by 2010 5.75% of automotive fuels are derived from biofuels [86].

But according to the CONCAWE study, if no additional food imports are assumed and biofuels were produced with the EU surplus crops, this would allow a substitution of 4.2% gasoline and diesel, only [40].

The second directive namely 2003/96/EC addresses the tax treatment of biofuels. The EU proposes to adjust fuel excise duties to make tax reductions possible [86].

In 2005 the BEST program was started as a part of the EU sixth framework program[63]. Over the duration of this program, almost 9'000 biofuel vehicles and more than 150 fuelling stations are expected to emerge. The project will be able to show how the EU biofuels directive and the Kyoto Protocol can be met in a cost effective and sustainable way [27].

Other projects of the European Union are the BIOGASMAX and the CAP-CEB. BIOGASMAX fosters the distribution and use of biogas in the transport sector generated from a wide variety of feedstocks available in Europe. The CAP-CEP Project aims mainly on networking between the involved actors and monitoring the progress in the biofuels area [5].

Several countries have already adopted incentives for the use of biofuels. In Switzerland a contingent of 20 million annual liters are exempted from taxes by now. Future plans are to exempt bioethanol, biodiesel, biogas and animal fats entirely from taxations [78]. In Germany fuel tax exemptions for biofuels came into force in 2004 and are validated until 2009 [14].

Biodiesel sales at filling stations in the EU increased from 163.2 million liters in 2001 to 476.4 million liters in 2004 [20]. Spain is the momentary leader in EU ethanol production [86].

---

[62] refers to as a gasoline-ethanol blend with 85% ethanol

[63] The Sixth Framework Programme (FP6) is the current (2002-2006) Framework Programme for Research and Technological Development set up by the European Union (EU) in order to fund and promote European research and technological development.

At the moment, the price for bioethanol (E85) at the filling station is some 25% below the current gasoline prices in Sweden. In Germany bioethanol is some 10% cheaper than gasoline [142]. In compliance with the norms DIN EN 228 and DIN EN 590, which control the properties of fuels determined for internal combustion in Otto engines in the European Union, ethanol and biodiesel are allowed to be blended up to 5 vol.-% together with conventional fuels without any system modifications, ETBE even up to 15 vol.-% [14].
In Europe, the Saab 9-5 FFV[64] for ethanol is available for an additional charge of 1128.5 $[65] compared to the baseline vehicle. With ethanol combustion, the turbo engine power increases from 150 to 180 hp [139]. Ford's Focus C-max FFV for ethanol is available for an extra charge of some 380 $[65]. Volvo is preparing as well a FFV version of the V50 and the S40 for the Swedish market [139].

15.4 Eastern Europe

In 1991 a biodiesel program started in the Czech Republic and today most filling stations in the country offer biodiesel. Recently, the Czech Republic had a surplus of cereal crops with limited export possibilities, which eased biodiesel production [92]. In the Ukraine a rapid growth in ethanol industry is emerging. The Ukraine has 46 ethanol production facilities and a law which allows for a high octane oxygenate additive to be used [92].

15.5 Brazil

Due to an ideal climate for sugar cane growing, excellent soils, and relatively low labor and land costs, Brazil is the world's lowest-cost producer for sugar and therefore, ethanol. Its ethanol production exceeded 16 billion liters in 2005 (Figure 23).
Brazil's ethanol program dates back to the 70's. At this time the government launched the Pro Alcohol program in response to the oil price shock of this period [127]. The program first was intended to encourage ethanol production and use through a combination of subsidies, tax incentives and regulatory measures. During the 80's about 90% of all new cars sold in Brazil were running on ethanol [92].
In 1984 a total number of 1'800'000 cars, or 17% of the country's car fleet was running on pure ethanol. By the end of the 80's pure ethanol was used in 3-4 million vehicles; the rest of the fleet was using blends of 22%-26% [86].
An increase in sugar prices and decrease in oil prices at the same time caused a market break in ethanol production because sugar growers concentrated on exports. As a result, public confidence in the security of ethanol supply was lost and sales of dedicated ethanol fuelled cars almost dried up [92]. The share of pure ethanol vehicles declined from almost 100% of new car sales in 1988, to less than 1% by the mid 1990s [86]. At the same time, the Pro Alcohol program caused huge costs and therefore subsidies were removed by then [142].

---

[64] Using a flexible fuel vehicle (FFV), the driver can fuel all different mixtures of ethanol and gasoline from pure ethanol to pure gasoline. Sensors recognize the actual blend and adjust the motor management.
[65] Currency calculations from http://www.oanda.com/convert/fxhistory [135]. EUR to USD average from 01/01/2006-12/17/2006=1.25389

With the introduction of the first flexible fuel vehicles (FFV)[66] in the early 2000s, together with higher oil prices, the ethanol use in the transport sector experienced a revival. Rising demand for oxygenates geared up ethanol prices, boosting the profitability of ethanol production and stimulating investment in new sugar cane plantanations and biorefineries. FFV's now make up more than three-quarters of the vehicles sold in Brazil with prices equal to conventional gasoline cars.

The government of Brazil has set the target of augmenting the ethanol production by 40% between 2005 and 2010 [92]. The heart of the governmental program is a 10 year deal with Germany. Germany is going to purchase carbon credits as part of its Kyoto Protocol commitments and, in return, is going to help subsidizing Brazilian taxi drivers and car hire companies which are using ethanol cars.

Even though ethanol shortages do exist in Brazil, the government is hoping to strengthen the market by increasing exports. At the moment, a debate is running, negotiating with China, Japan, South Korea, the USA and Mexico which have shown interest in buying ethanol [86]. Currently, the price for ethanol in Brazil is about 45 US cents per liter, a bit more than half the price of gasoline [142].

In 2003, Volkswagen brought its first ethanol FFV to the Brazilian market. The enthusiasm of 184 million Brazilians to the introduction of the FFV set other car manufacturers under pressure. Meanwhile rather all manufacturers in Brazil have FFV's in their sales mix. In Brazil over 300'000 FFV's have been sold at mid year 2005. By June 2006 the number of FFV's sold exceeded other models selling for the first time, says Sergio Kakinoff, leading sales manager of Volkswagen Brazil [142].

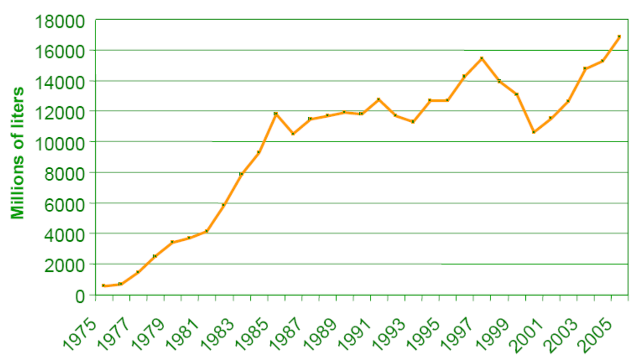

Figure 23: Ethanol production in Brazil. In 2005 production exceeded 16 billion liters [56].

15.6 Peru

Peru is well suited to produce ethanol and the government recently planned to export ethanol to the growing Californian market [86]. To do so, several sugar cane facilities have been constructed and some 1080 hectares of sugar cane feedstock have been planted in the central jungle [15].

[66] Using a flexible fuel vehicle, the driver can fuel all different mixtures of ethanol and gasoline from pure ethanol to pure gasoline. Sensors recognize the actual blend and adjust the motor management.

15.7 Japan

The target of the Japanese government is 10% ethanol blends as a standard by 2008. If all the gasoline consumed in Japan would be replaced with E10 its ethanol market would be around 6 billion liters [92].

15.8 Australia

At the moment, only about 0.2% of the total gasoline consumption in Australia is derived from biofuels. In 2001, the Australian government adopted a pro ethanol policy, including eliminating excise taxes.
After all, a big debate over the compatibility of ethanol mixes with gasoline and conventional vehicles aroused. As a consequence, Australia's oil refining industry and car makers have become reluctant to support ethanol.
In 2002, the government changed the policy, including setting a 10% limit to blends and re-instituting an excise tax on biofuels. Concurrently to the excise tax, a domestic production subsidy was implemented, which is equal to an import duty at the value of the excise tax. In 2003, the government set up an additional production subsidy for ethanol plants, accessible until a total domestic production of 350 million liters or by the end of 2006 [92].

15.9 China

In 2004, China approved new fuel-economy standards to reduce its dependence on imported oil and motivate foreign car constructors to introduce more fuel-efficient vehicles to the Chinese market. There is no effect visible yet, but an impact is likely to be seen in the ongoing years [88].
In China most ethanol is derived from corn, but experiments with cassava, sweet potato and sugar cane are in place as well [92]. Since the 1980s, China tries to encourage the cultivation of sweet sorghum[67] in collaboration with the United Nations Food and Agriculture Organization[68].
At the moment the development of latter technology is still on a demonstration stage though [59]. For the year 2002 China planned an ethanol production capacity of 380 million liters [198].

15.10 India

In 2000, India produced about 1.7 billion liters of ethanol, which is actually more than in the EU during the same time. In 2002, a number of projects started, involving blending ethanol with gasoline.
In 2003, about 220 retail outlets were selling ethanol. At the same time, a new program was implemented. In a first phase blending 5% ethanol to gasoline was initiated in nine states and four union territories. The second phase of this program will spread out nationally, meanwhile blends are augmented to 10%. In order to monitor the plan, a National Biofuel Development board was implemented. The government ensures a fixed price to sugar millers, representing a sizeable subsidy [92].

---

[67] Sweet sorghum is used for ethanol production

[68] FAO

15.11 Thailand

In the year 2000, the Thai government declared its intention to promote the utilization of biofuels derived from indigenous crops, such as sugar cane and tapioca. In 2000, the government declared to stimulate the production of 650 million liters ethanol per year in the near term. A package of tax incentives was introduced as well, including exemptions on machinery imports and an eight year corporate tax holiday. About 20 new plants are in application or approval process, one of them using a process with genetically modified bacteria [92]. In the near future Thailand aims at producing between 500 and 730 million liters of ethanol out of sugar cane, corn and tapioca [198].

15.12 Malaysia

Malaysia produces about half of the global palm oil, which at the same time is the vegetable oil with the biggest global production. It is also the oil plant with highest yields per hectare. As a result Malaysia has started exporting palm oil to produce biodiesel and is constructing biodiesel facilities within the country [92].

15.13 Africa

Africa is having the biggest share of biomass[69] in total energy consumption. Mostly firewood, agricultural residues, animal wastes and charcoal are burned within the countries. In 2004, a very small amount of biomass was converted to liquid fuels, although a lot of sugar cane plantations exist in the country. About 70% of this amount is produced in the Republic of South Africa, but mainly for industrial and pharmaceutical markets. The increasing prices for gasoline and the declining costs for ethanol production have created favorable economic conditions in Africa.

Ghana, Mali and other African countries have also been considering the production of biodiesel from oils extracted from Jatropha, which is very tolerant to poor soils and rainfall [92].

[69] 75% of total African final energy consumption is biomass, in OECD countries this amount is typically 3%.

16 Appendix 2: Description of the different biofuels production pathways

16.1 Thermochemical production of biofuels

The production of thermochemical fuels bases on five process steps: feedstock handling, gasification, gas cleaning, gas processing and fuel production (e. g.: DME, FT-Diesel, methanol, SNG). Depending on the desired biofuel, the syngas from biomass gasification is processed in different ways [123, 160]. In principle, various process configurations for the conversion of biomass to the above mentioned fuels are possible, depending on gasifier type, gas cleaning and whether electricity is co-generated [160].

16.1.1 Syngas from biomass gasification

General aspects

Gasification aims at the conversion of biomass in a gaseous energy carrier, which can be applied for energy consumption needs [98]. This process is generally called BTL which stands for biomass-to-liquids.

Because of the growing demand for electricity and the theoretically very high efficiency factor in the production of electricity from syngas derived from biomass, most of the produced syngas is used for power generation [98].

Over the years, various names were given to the syngas, such as producer gas, town gas or blue water gas [160]. Many of the syngas conversion processes were developed in Germany during the First and Second World War. In addition the political situation in South Africa (i. e. the international isolation during the Apartheid regime) and the abundance of local coal reserves in that country helped bring about the most successful commercial syngas industry in the world, based on syngas production from coal gasification. Sasol currently supplies diesel, gasoline, and other high-value hydrocarbons to local and global markets [160].

Wood gasification for the production of fuels is an established and well documented process as well. During the Second World War, the oil shortage caused the search for alternative fuels. The technology of choice was a fixed-bed wood gasifier which was fixed to the front of a car. Sweden developed biomass gasification even earlier in the 1920's [124]. In the 18th century coal gasification was used to produce light and heat.

Today's growing conscience for environmental problems and more stringent regulations put syngas in the ascent, compared to the fossil dominated energy market. The use of MTBE[70] for the raise in octane number and oxygen content in gasoline increased the demand for syngas conversion [160].

Process description

Before gasification, the biomass feedstock is typically screened, size-reduced, dried and metal debris are magnetically removed. For the gasification the moisture content should ideally be about 20% [124]. The

[70] methyl-tertiary-butyl-ether

size of the feedstock particles ranges in general between 20 mm and 80 mm, depending on the type of gasifier.

During the gasification the biomass is converted to a mixture of hydrogen (H_2), carbon monoxide (CO), methane (CH_4), carbon dioxide (CO_2), water (H_2O), and light hydrocarbons (e.g.: C_2H_4, C_2H_6). If air is used as a gasifier medium, considerable amounts of nitrogen (N_2) can emerge. In its purest form syngas compounds consist of carbon monoxide (CO) and hydrogen (H_2) only [160].

Gasification is an endothermic[71] reaction. Depending on the means of heat input one can differ between direct or autothermal[72] and indirect or allothermal[73] gasification [160]. In indirectly heated gasifiers, combustion and gasification are physically separated in two distinct chambers. For the heat transfer from one chamber to the other, different mechanisms are possible. These include direct contact with hot circulating sand, heat exchanger tubes, steam, recycled syngas or heat exchange through a wall common two both chambers [100]. Indirect heating enables the production of gas, undiluted by nitrogen without any costly need for the use of pure oxygen [107].

The gasification process can be further classified on the basis of gasifier types[74] and gas cleaning[75] modes. In addition, gasifiers vary in the following properties: contact medium between biomass[76] and oxidizer, heat generation[77], gasifier medium[78], pressure[79] and flow direction of the gasifier medium[80] [98]. Undesirable by-products are tars, condensates[81], ash and dust[82] [160]. When tars are condensing they can foul downstream equipment, coat surfaces and may clog filters and sorbents. To avoid these effects tar concentration has to be below condensation point at the pressure of the fuels synthesis. In addition, because tars contain a lot of carbon monoxide (CO) and hydrogen (H_2), they should be cracked into smaller hydrocarbons in order to increase gas yields [73].

Theoretically syngas can be processed from all hydrocarbons, such as natural gas, naphtha[83], residual oil, petroleum coke[84] or biomass. But the cheapest way to produce syngas is from remote[85] natural gas [160].

Directly heated gasifiers can be grouped into two types: fixed-bed and fluidized-bed, with variations within each group. In fixed-bed gasifiers the feedstock enters at the top of the reactor. Because the fixed-

---

[71] heat has to be added to the process

[72] heat input through partial oxidation of the feedstock.

[73] heat input with a heat exchanger or a circulating bed.

[74] see also Kaltschmitt, 2001, p. 432, for a Figure of gasifier types [98].

[75] one can distinguish between hot or dry gas cleaning and cold or wet gas cleaning.

[76] for further details see also Kaltschmitt, 2001, S. 432 [98].

[77] direct or indirect, see footer 72 and 73.

[78] air, oxygen or steam blown gasifier

[79] atmospheric pressure or high pressure

[80] updraft, downdraft, cross flow

[81] long chained organic compound

[82] Typical organic impurities are tars and BTX (benzene, toluene, and xylene), the inorganic impurities NH_3, HCN, H_2S, COS, and HCl, and furthermore volatile metals, dust, and soot [73].

[83] Naphtha is a group of various volatile flammable liquid hydrocarbon mixtures used primarily as feedstocks in refineries for the catalytic reforming process and in the petrochemical industry for the production of olefins in steam crackers [188].

[84] Coke is a solid carbonaceous leftover derived from destructive distillation of low-ash, low-sulfur bituminous coal [188].

[85] Natural gas that cannot be transported from the gas fields to the market economically, as reserves are very isolated. If the gas is liquefied, transport per energy content gets cheaper and more economic.

bed gasifier is working stationary different process steps, as drying, pyrolysis, char gasification and combustion, occur in distinct zones.

Depending on the direction of the gasifier medium flow relative to the feedstock movement, fixed-bed gasifiers are classified as updraft, downdraft or cross-flow [21, 124, 186]. Fixed-bed gasifiers have the advantage of a simple design, but they have also quite big disadvantages. Within the gasifier, a wide temperature distribution exists, resulting in hot spots causing ash fusion, formation of tars and oils and long heat up periods [100, 124, 186]. Because of the relatively high rate of tar formation, fixed-bed gasifiers are not very well suited for liquid fuels production, because much of the energy content cannot be recovered. Another disadvantage is the limited possibilities for a scale up. Downdraft gasifiers are limited to 1 MW_{th}, updraft gasifiers to 20 MW_{th}. Beyond these values, the gasifier diameter becomes unfeasibly large [185].

In fluidized-bed gasifiers, biomass normally enters through the side of the reactor where it is mixed onto a bed that helps cracking tars. There are three types of fluidized-bed gasifiers in use: bubbling, circulating and fast internally circulating fluidized-bed.

In bubbling fluidized-bed gasifiers air is introduced through a grate at the bottom of the gasifier. The biomass is pyrolysed in the hot bed to form char and high molecular weight gaseous compounds, which are then cracked by contact with the hot bed material. Ash, char and particulates are removed for disposal.

In circulating fluidized-bed gasifiers, the bed material circulates between a reaction vessel and a cyclone[86] separator, that removes the ash and returns the bed material and unreacted char to the reaction vessel [124, 160].

Fluidized-bed reactors have higher bed temperatures than fixed-bed gasifiers, resulting in higher throughput rates and larger operating scales. Another advantage is, that they can use a wider range of feedstock sizes and bulk densities [124].

As mentioned above the produced syngas contains tars, fine particles, alkalis and halogens which can clog filters, poison catalysts or corrode the gas turbine, in case of power generation. Two possible consequences for avoiding these problems are suitable: improve gasification so that minimal tar is produced or downstream removal of the tar. For downstream gas cleaning, low-temperature wet scrubbing and hot gas cleaning or dry scrubbing are two physical methods. In low-temperature gas cleaning, which is state of the art, the gas is cooled, filtered and scrubbed with water. Gaseous tar condenses as the stream is cooled and afterwards removed using wet scrubbing. Particulates are completely removed using a cyclone, in combination with a bag filter and a series of scrubbers. A final ZnO bed or solvent absorption reduces the sulfur concentration.

Moreover, hot gas cleaning is still being researched and developed [72]. This method removes particles and condensed tar using granular beds and ceramic filters. SO_x and NO_x are removed by sorbents. Alkalis are removed by physical adsorption or chemisorption, sulfur by chemisorption [126]. To better suit the further downstream processing (e. g.: FT-synthesis) requirements, the relative proportions of the syngas can now be adjusted.

[86] components are separated through centrifugal force

Steam methane reforming (SMR) converts methane and light hydrocarbons to carbon monoxide (CO) and hydrogen (H_2). Two alternatives to SMR are partial oxidation and carbon dioxide (CO_2) reforming, or autothermal reforming as a combination of partial oxidation and steam reforming.
Another syngas processing step is the water gas shift reaction which shifts the energy value of carbon monoxide (CO) to hydrogen (H_2) [1, 72, 100, 169]. Not converted syngas can be used for power and heat generation, excess electricity can be fed to the grid. Currently, steam turbines[87] are in use only, but BIG/GT[88] turbines would be more efficient [185, 190]. In Figure 24 the main gasification process steps are schematically drawn.

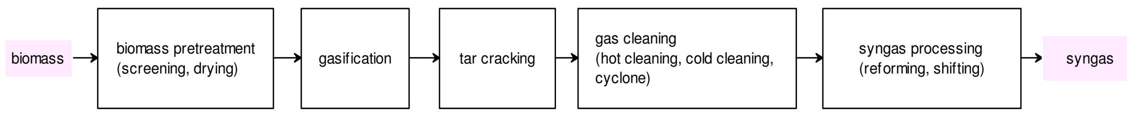

Figure 24: Simplified biomass to syngas process steps [72].

16.1.2 Methanol and dimethyl ether from syngas

General aspects

Methanol synthesis started in the 18th century with the isolation of wood alcohol from the pyrolysis of wood and is by now one of the top ten chemicals produced worldwide [160]. Currently, the majority of methanol is synthesized from syngas, produced via steam reforming of natural gas. Some methanol is produced as well from coal via coal gasification. World wide, there are about 150'000 tons DME produced per year [129].
Methanol is most commonly used as a chemical feedstock, solvent or extracant, and as a feedstock for producing the gasoline additive MTBE[89] [160]. It appears likely though that MTBE will be phased out due to groundwater contamination issues [88]. Methanol is used commercially as an aerosol propellant because of its environmentally benign properties [54, 125, 199], but would actually have premium fuel properties for compression ignition [52]. It has a very high octane number but in contrast to ethanol is not miscible with gasoline [88]. Some authors see big potential in an on-board reforming of methanol for the powering of fuel cells [90].
World-wide, more than 90 big scale methanol plants have the capacity to produce over 42 billion liters of methanol annually [28, 159], Methanex and SABIC being the biggest producers. BASF Germany started the first commercial methanol plant in 1923 [160].
Methanol can be converted into DME, which is physically similar to LPG[90]. It can be stored at temperatures as low as -25°C, or under low-pressure in liquid form. One of the main barriers for the market penetration of DME is the absence of a distribution infrastructure. As DME has to be handled and distributed under low pressure, special fueling stations are required [88].

[87] e. g.: rankine cycle
[88] BIG/GT: biomass integrated gasifier/gas turbine
[89] methyl-tertiary-butyl-ether
[90] liquefied petroleum gas

The leading producer of commercial DME plants is Halder Topsoe. Other important private developers are Air Products and Chemicals and NKK [3, 75]. DME Development Inc., a Japanese consortium of nine partners lead by NKK and Nippon Sanso operates a 100 t/d demonstration plant in Kushiro, Japan, producing DME from natural gas [80].
A 300 t/d DME from natural gas facility is situated in Sichuan, China, managed by Toyo Engineering [170]. Zagros Petrochemical, a subsidiary of the Iranian National Oil Company has built a 2'200 t/d DME from natural gas, in Iran, using Halder Topsoe synthesis technology [64].

Process description

The majority of methanol is produced via steam reforming or autothermal reforming of natural gas. The resulting syngas is fed to a reactor vessel where it reacts to methanol and water vapor with the help of a catalyst. Cu/ZnO/Al2O3 is primary used as catalyst components. The unreacted syngas is recycled and refed into the reactor, resulting in an overall efficiency of 99%. The crude methanol has to be distilled because it contains water, ethanol, higher alcohols, ketones and ethers.
One of the challenges associated with commercial methanol synthesis is removing the large excess heat from the reaction. Higher temperatures increase the efficiency of the methanol catalysis, but at the same time, enhance the formation of competing side products.
There are two main types of methanol reactors, adiabatic and isothermal ones. One of the most widely used isothermal methanol converters is the Lurgi Methanol Converter. The most used adiabatic methanol converter is the ICI Low Pressure Quench Converter. Other converters are developed by Halliburton, Halder Topsoe, Toyo Engineering Corporation, Chem Systems Inc., Air Products and Chemicals, Mitsubishi Gas Chemical Company Japan and Nihon Suiso Kogyo Japan.
Two other conversion principles are based on the idea that methanol is removed continuously from the gas phase by selective adsorption on a solid or in a liquid. The Gas-Solid-Solid Trickle Flow Reactor[91] uses SiO_2/Al_2O_3 to trap the produced methanol. In the reactor system with Interstage Product Removal[92] the produced methanol is adsorbed in a liquid [160].
The production of DME is adding another step to methanol synthesis. The syngas derived methanol is dehydrated in order to get DME [18]. Recently there have been developments towards direct synthesis of DME from syngas without methanol as an intermediate product (Figure 25) [88].

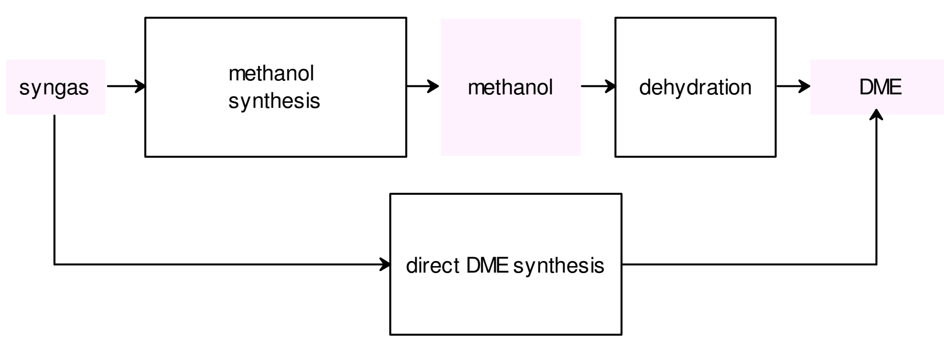

Figure 25: Simplified process steps in syngas to methanol and DME production [160].

[91] GSSTFR

[92] RSIPR

16.1.3 FT-diesel from syngas

General aspects

A lot of conversion processes were invented in Germany during the World Wars. Because natural resources were rare at this time, alternatives had to be found [160]. The production of liquid hydrocarbons from syngas was developed in 1923 by Fischer and Tropsch. In the year 1930 the FT-synthesis was commercially used for the first time [38].

The political situation in South Africa and the abundant coal reserves within the country helped establishing the most successful FT-industry. Since the 1990s the FT-synthesis gained new interest because a possibility was seen for the economic use of remote natural gas by the process [137, 144].

Fischer Tropsch (FT)-diesel production mainly aims to meet the fuel demand for low sulfur diesel, a growing market since exhaust gas emissions continue to be tightened. FT-liquids are mainly produced from coal and natural gas. At the moment, daily production amounts to 29 million liters. Until the year 2015, 117-234 million liters per day could be possible through new plants getting on stream [53]. After the success of Sasol 1 in South Africa, Sasol 2 and 3 were build in the years 1980 and 1982 respectively. In the 1990s, two other GTL plants came on-line, the Petro SA[93] plant in South Africa and the Shell Bintuli[94] plant in Malaysia. In Qatar the Oryx plant built by Qatar Petroleum, Chevron and Sasol was commissioned in 2006. In Australia, Syntroleum is constructing another FT-plant [160]. Other GTL facilities in a planning stage or under construction are the Shell QP Pearl project in Qatar, the Chevron project in Nigeria, the Sonatrach plant in Algeria, and the Exxon Mobil project in Qatar [92, 160].

A detailed overview of the current GTL projects is provided by the International Fuel Quality Center [94].

From 1995-1999, Sasol replaced some fluidized-bed reactors with fixed-bed reactors. These reactors are less expensive, more efficient and do have lower maintenance costs [38].

Meanwhile, Sasol has 97 Lurgi gasifiers in use which process 98'630 tons of coal per day [180]. Sasol delivers global and local markets with diesel, gasoline and other high value hydrocarbons and is now-with 17.6 million liters per day- the biggest single producer of FT-products [160].

Choren is the leading company in the production of synthetic diesel from biomass (BTL). Recently Volkswagen, Shell and Choren have signed a contract for the construction of two BTL plants in Germany for the production of a FT-diesel called Sunfuel.

Until the year 2007, a demonstration plant with a capacity of 15'000 tons of synthetic diesel per year will be constructed. If the operation turns out to be successful, a second facility with an annual capacity of 200'000 tons is going to be constructed by 2009 [184].

Process description

FT-synthesis involves the polymerization of syngas to produce a waxy syncrude, which contains largely paraffinic hydrocarbons with carbon numbers between 1 and 100 [168].

There are four main steps to produce FT-diesel: syngas generation, gas purification, FT-synthesis and product upgrading.

---

[93] GTL (gas to liquids), capacity: 1 million tons of FT products per year.

[94] GTL (gas to liquids), capacity: 500'000 tons FT products per year, using the Shell Middle Distillate process.

If natural gas is used as a feedstock, the technology of choice for the production of syngas is autothermal reforming in combination with steam reforming. If the feedstock is coal, the syngas is produced through high temperature gasification in the presence of oxygen. The production of a wide variety of hydrocarbons during the process is unavoidable [160].

The best option to maximize the gasoline fraction is the use of an iron catalyst and a high temperature fixed-bed reactor. For maximizing the diesel fraction a slurry-bed reactor with cobalt catalyst is the technology of choice [160].

The product selectivity is influenced by the type of the catalyst, syngas CO/ H_2 ratio, temperature, pressure and reactor type [168]. Light hydrocarbons are stripped away from the product without difficulty and recycled. Finally, the product consists of a mixture of C_4-C_{20} compounds, having excellent fuel properties for compression ignition.

About one third of the product will be wax (>C_{20}) and therefore tends to solidify at ambient temperatures [164]. To receive an automotive fuel, this fraction is typically hydro cracked and fractionated. In hydro cracking, hydrogen (H_2) is added in order to remove double bonds then the resulting liquids are cracked. The product contains diesel, naphtha and kerosene fractions, depending on process settings [38, 168]. Olefins (C_3-C_{11}) have to be passed through oligomerization, isomerization and hydrogenation in order to produce gasoline [160].

For the FT-synthesis, four types of reactors have been designed. The fixed-bed tubular reactor known as ARGE reactor, a high temperature fluidized bed reactor known as Synthol reactor (CFB), the Sasol Advanced Synthol Reactor, which is a fixed fluidized-bed reactor (FFB) and a low-temperature slurry reactor with a 3-phase reactor consisting of a solid catalyst suspended and dispersed in a high thermal capacity liquid (Figure 26)[154, 160].

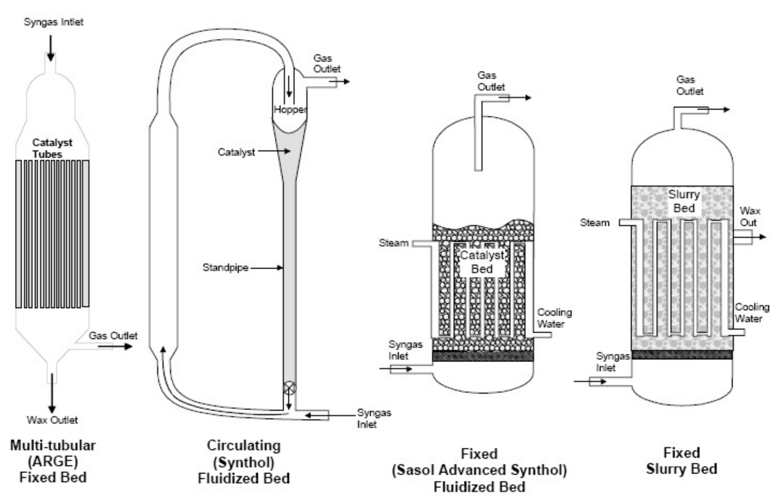

Figure 26: Four types of FT-synthesis reactors are used commercially [160].

For the production of the syngas, Choren uses its Carbo-V process in which the resulting syngas is converted to FT-diesel using the Shell Middle Distillate Process applied also in the GTL process in Bintulu [184]. Figure 27 presents the process steps of the FT-diesel and FT-gasoline production.

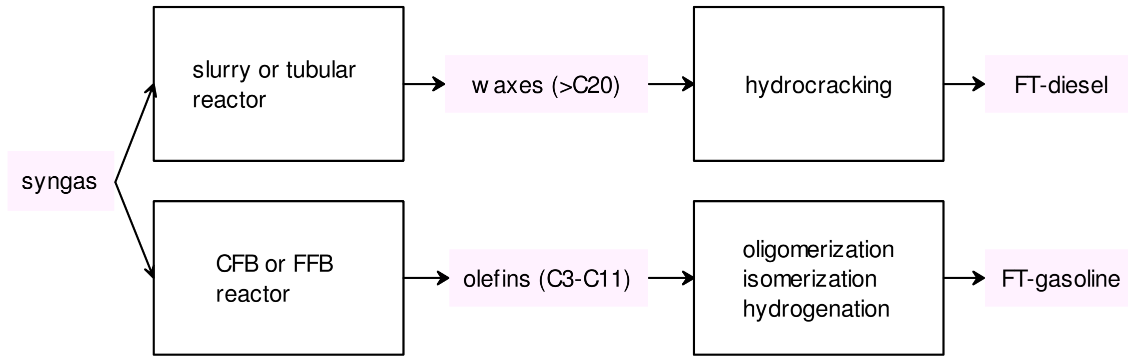

Figure 27: Simplified process steps in syngas to FT-diesel and FT-gasoline. CFB: High temperature fluidized bed reactor known as Synthol reactor. FFB: The Sasol Advanced Synthol Reactor, a fixed fluidized bed reactor [160].

16.1.4 SNG from wood gasification and methanation

General aspects

The Paul Scherrer Institute (PSI) participates in the sustainability program Novatlantis, which pursues new technologies for a sustainable future in conurbations. Within this program, PSI has investigated the use of gasified wood as a flexible and CO_2-neutral energy carrier [49] in its Laboratory for Energy and Materials Cycles (LEM), where methane from wood has been a project of central importance.

In 2003, a first link of a methanation reactor with an industrial scale gasifier was realized. The motivating results of this experiment led to the decision to get a 10 kW_{th} pilot plant ready for continuous operation in Güssing, Austria [162].

At the moment, syngas is mainly produced by steam reforming. But this reaction results in a gas too rich in hydrogen (H_2) for liquid fuels processing. In addition, it requires high temperatures and is strongly endothermic. Other possibilities for syngas processing are autothermal reforming and catalytic partial oxidation of methane, both of which however need high temperatures and thus require costly materials for safe and efficient operation.

The Low-Temperature wet Catalytic Partial Oxidation[95] of methane could be an alternative route for synthesis gas production. SNG from wood methanation is processed to a syngas with a more ideal stoichiometry for FT-diesel production, being at the same time a low cost solution [141, 162].

Process description

The production of methane from wood consists of two main processes. The first step is the gasification of wood, followed by a cleaning and conditioning processes.

The gasification is performed with a fast internally circulating fluidized-bed gasifier[96]. In the first gasifier section, biomass is gasified with steam. Unconverted biomass, namely char, is then transported together with the bed material olivine to the second section of the reactor, where it is combusted completely with air.

The resulting heat from combustion is transported with the bed material back to the first section of the reactor, where it keeps up steam gasification. The product gas is composed of about 30%-45% hydrogen

[95] LTCPO

[96] FICFB

(H_2), 20%-30% carbon monoxide (CO), 15%-25% carbon dioxide (CO_2), 8%-12% methane (CH_4) and 1%-3% nitrogen (N_2). Undesired by-products such as ammonium and dust are removed from the gas by scrubbers and fed back into the gasifier.
The resulting gas still contains traces of hydrosulfide (H_2S) which can be adsorbed by a ZnO-bed, adsorbing the sulphur (S) to form zinc sulfide (ZnS). The C-containing substances are transformed into methane (CH_4) and carbon dioxide (CO_2), whereas the methane (CH_4) yield rises with increasing pressure and falling temperature (Figure 28). Carbon dioxide (CO_2) is separated from the gas mixture using a membrane separation unit. The final composition of the syngas is 97.3 vol% methane (CH_4), 2.6 vol% carbon dioxide (CO_2) and 0.1 vol% water (H_2O) [49].

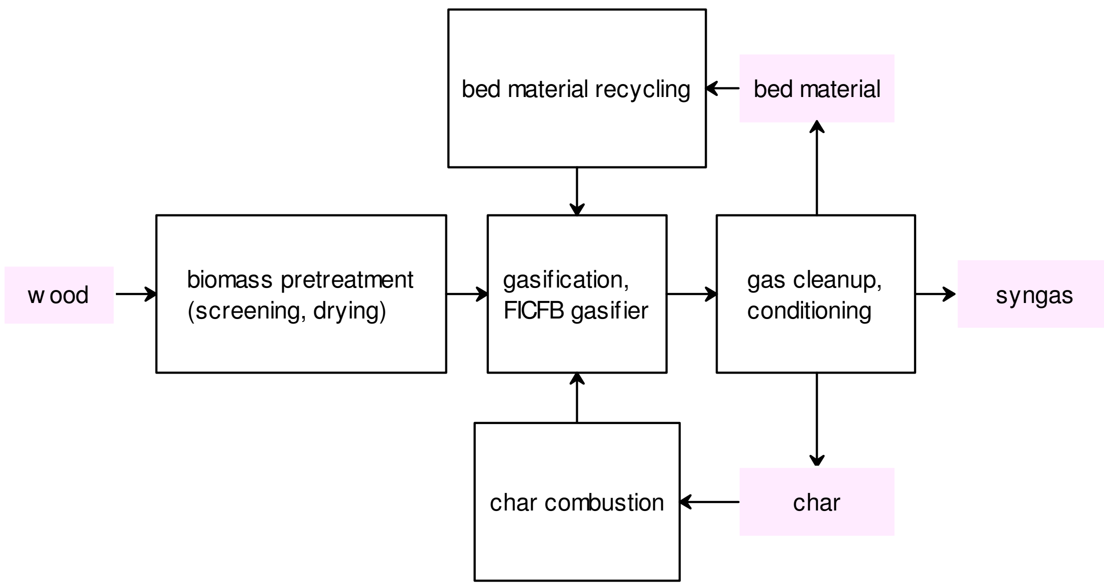

Figure 28: Simplified process steps in the wood methanation process.

16.1.5 Biodiesel from pyrolysis

General aspects

One refers to pyrolysis liquids with many names, including pyrolysis oil, bio-oil, bio-crude-oil, bio-fuel-oil, wood liquids, wood oil, liquid smoke, wood distillates, pyroligneous tar, pyroligneous acid, and liquid wood [21].
Pyrolysis of biomass has been practiced for thousands of years in the form of charcoal manufacture. This practice is in fact a form of slow pyrolysis in which heat is added at slow rates to the biomass. For fast pyrolysis, any form of biomass can be considered.
While most work has been carried out on wood pyrolysis due to its consistency and comparability between tests, many different biomass types have been tested too, ranging from agricultural wastes such as straw, olive pits and nut shells to energy crops such as miscanthus, sorghum and to solid wastes, such as sewage sludge and leather wastes [21, 147].
The process to synthesize bio-oils from fast pyrolysis is well established. According to Ringer, nine biomass pyrolysis plants are in operation worldwide [147].

The biggest plant is operated by Pyrovac in Canada processing 93 tons of biomass per day, followed by Red Arrow USA with plants of 40 tons and 45 tons biomass feed capacity. Other companies involved in biomass pyrolysis are DynaMotive, Wellman, RTI, VTT, BTG and Fortum [147].

Process description

Pyrolysis is a thermal decomposition occurring in the absence of oxygen. In combustion and gasification, pyrolysis is always the first step, followed by total or partial oxidation.

Low process temperatures and long vapor residence times increase the amount of charcoal produced during the process. If the temperature is high and residence times are short, the gas fraction in the product is increasing. Medium temperatures and residence times favor the production of liquids, which is of particular interest at the moment. Fast pyrolysis occurs in a few seconds or less.

From the pyrolysis of biomass, three primary products are obtained: char, permanent gases and vapors, which condense at ambient temperature to a dark brown viscous liquid. The distribution of products between liquid, char, and gas on a weight basis for charcoal production is 30%, 35% and 35% respectively. In fast pyrolysis this distribution undergoes a dramatic shift to 75%, 12% and 13%, respectively.

The critical process step is to bring the reacting biomass to the optimum process temperature in relatively short time and to minimize its exposure to lower temperatures, which favor the formation of charcoal. Therefore, small particle sizes (2 mm) are benign to maximize the surface of the reacting biomass.

Another possibility is to transfer heat very fast only to the particle surface that contacts the heat source.

Although fast pyrolysis is related to traditional pyrolysis for charcoal production, it is a process that needs careful controlling of all parameters in order to give high yields of liquids. Main aspects of the process are: very high heating and heat transfer rates at the reaction interface, carefully controlled reaction temperature of around 500°C, short vapor residence times of less than two seconds and rapid cooling of the pyrolysis vapors to receive the bio-oil.

The main product bio-oil is obtained in yields up to 75% on dry feed basis. Char and gas are used within the process, so that no waste streams other than flue gas and ash are produced. In order not to form too much water within the reactor, the biomass has to be dried to about 10% [21, 147].

In the past, a number of reactors have been developed, each meeting the heat transfers requirements noted above. Generally, the reactors can be categorized into the following groups: fluidized-bed reactors, transported-bed reactors, circulating fluidized-bed reactors, ablative (vortex) reactors, rotating cone reactors and vacuum reactors.

Bubbling fluidized-bed reactors have been in use in petroleum and chemical processing for over fifty years. Through the long history of service and very simple operating design, this type of reactor is supposed to be very reliable and virtually trouble free.

DynaMotive uses natural gas to heat their pilot reactor. But larger systems will need to integrate the combustion of char and gas in order to supply the necessary heat. Direct heating with gas is not recommended because it can end up in smaller oil yields due to oxidation from excess air in the flue gases. Particle sizes in this reactor typically are 2-3 mm with residence times from two to three seconds.

The circulating fluidized-bed reactor is another good candidate for fast pyrolysis, although it is a bit more complicated than the bubbling fluidized bed reactor because large quantities of sand have to be moved around and into different vessels. It also has high heat transfer rates and short vapor residence times. The recommended particle size is about 1-2 mm and residence times as short as 0.5-1.0 s.

The vortex or tubular reactor was developed from 1980-1996. Its design allows particle sizes of 20 mm in contrast to 2 mm particle size required by fluidized-bed reactors. Biomass particles are accelerated to very high velocities and than introduced to the vortex reactor. Under these conditions the particles are forced to slide along the inside surface of the reactor. The reactor wall is maintained at 625 °C, melting the particles in a similar manner as butter melting on a hot frying pan. Due to excessive material wear and uncertainties about scale up possibilities this design was abandoned in 1997.

A lower heat transfer reactor is the vacuum reactor. The process design is more complicated than other reactor designs, because the reactor feeding and conservation of the vacuum has to be fulfilled at the same time. Major drawbacks of the system are its relatively low yields and its water generation. However, the reactor can use particles of 2-5 cm and produces clean oil[97].

The rotating cone reactor has been developed at the University of Twente in The Netherlands since the early 1990s. The system is similar to the transported bed design in that it co-mingles hot sand with the biomass. The primary distinction is that centrifugal force from a rotating cone is used for this transport instead of a carrier gas. Biomass and sand are introduced at the base of the cone while spinning causes centrifugal force to move the solids upward to the lip of the cone (Figure 29). The process is complex though, and scale up is uncertain [147].

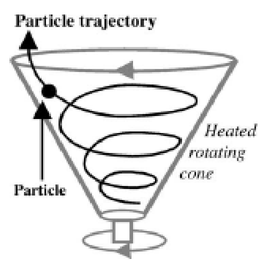

Figure 29: Principle of a rotating cone pyrolysis reactor

Once the pyrolysis vapors are generated in the reaction vessel, they have to be thermally quenched from the high reaction temperatures. This is necessary to preserve the bio-oil, otherwise many of the compounds will crack to permanent gases or polymerize to char [147]. Simple heat exchange can cause preferential deposition of lignin derived components leading to liquid fractionation and eventually blockage. Quenching in product oil or in an immiscible hydrocarbon solvent is widely practiced [21].

When cooling the pyrolysis vapors, aerosols are likely to form. This phenomenon is enhanced if large amounts of carrier gas are present with the oil vapors whilst condensation [147]. Another method for aerosol capture is electrostatic precipitation, which is currently the preferred method at smaller scales up to pilot plants [21].

Another problem is char, which reacts as a cracking catalyst and therefore has to be separated from the pyrolysed product. Cyclones are the usual method of char removal. Another method is hot vapor filtration, analogous to hot-gas filtration in gasification processes which gives a high-quality char free product, but reduces the liquid yield by about 10%–20%, due to the char accumulating on the filter surface that cracks the vapors [21].

[97] oil with low char content

The resulting bio-oil or bio crude is incompatible with conventional fuels and has to be upgraded. Main properties which make bio-oil incompatible to conventional fuels are: solids content, high viscosity, and chemical instability.

Chemical/catalytic upgrading processes for the production of hydrocarbon fuels that can be conventionally processed are more complex and costly than physical methods, but offer significant improvements, ranging from simple stabilization to high-quality fuel products. Fuel deoxygenating to high-grade products such as transportation fuels can be fulfilled by two main routes: hydro treating and catalytic vapor cracking over zeolites [21]. Figure 31 gives an overview of the fast pyrolysis process.

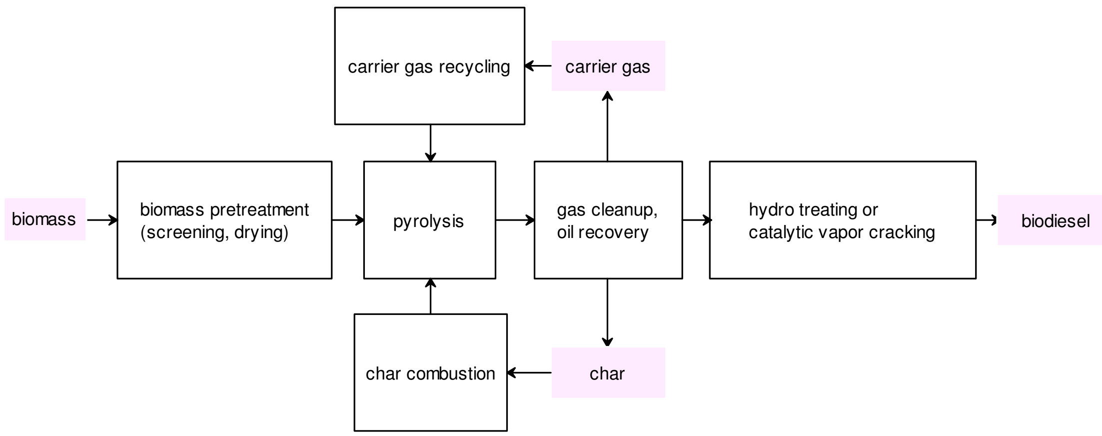

Figure 30: Simplified pyrolysis process steps [147].

16.2 Biochemical production of biofuels

16.2.1 Ethanol from fermentation

General aspects

Ethanol is the biofuel N°1 considering world production and diffusion. In 1908, ethanol was used already as an automotive fuel in Ford's T model [201].

Nowadays the ethanol market is experiencing a huge growth, especially in Brazil and the USA (see Table 20 for market review of different countries) [16, 59, 86, 111].

World ethanol production in 2005 was estimated to be 45'987 million liters (12'150 gallons) [111], biggest producers are Brazil, USA, China and India; 6% was produced in the EU25 [56].

Ethanol can be produced from any feedstock that contains sugar or materials that can be converted into sugar such as starch or cellulose. Corn, wheat and other cereals contain starch, trees and grasses contain cellulose and lignocellulose; though latter ones are more difficult to convert into sugar [86]. A wide variety of feedstocks can be used for ethanol production, e. g.: wood residues, agricultural residues, municipal and industrial waste, grasses, wood, starch and sugar crops [198].

Generally ethanol is produced from sugar fermentation by enzymes derived from yeasts. Lignocellulosic feedstocks can be hydrolyzed chemically, physically or biologically in order to make sugar. The organisms and enzymes for ethanol production from starch and sugar are available on a commercial scale already [40, 59, 86].

Corn and sugar cane are the dominant feedstocks for global ethanol production [59]. In the USA it is corn, in Brazil it is sugarcane, and in the EU25 mainly sugar beet and wheat are used for the production of ethanol [40, 86, 153]. 90% of the world ethanol production is derived from starch [166], whereof 67% is used as an automotive fuel, the rest of it is used in the food and beverage industry.

As ETBE[98] it is added to gasoline as an oxidant for cleaner combustion, having more benign environmental properties than the traditional additive MTBE[99] [92, 198].

Although the technology for ethanol production from starch and sugar is well developed, several drawbacks do exist. Sugar and starch containing plants have a higher value for food production than for ethanol production and relatively low yields compared with lignocellulosic biomass. Therefore, fermentation processes from lignocellulosic biomass are generally seen to have a bigger potential: there is a greater variety of possible feedstocks, and as a consequence bigger capacities at lower costs are feasible for biofuel production. In addition, minor quality or set-aside land can be used for the cultivation of the biomass [74].

Ethanol is more volatile than water, flammable and burns with a light blue flame. It is highly suitable for the combustion in spark ignition engines. The average octane number is 99, whereas normal gasoline has an octane number around 88. The energy content is about two third of the gasoline content. Therefore more ethanol is necessary to drive the same distance as a gasoline vehicle drives with the same fuel quantity.

[98] ethyl-tertiary-buthyl-ether

[99] methyl-tertiary-buthyl-ether

Table 20: World ethanol production per country in the years 2004 and 2005, in million gallons. Brazil and USA are the biggest producers [111].

World ethanol production [million gallons]		
Country	**2004**	**2005**
Brazil	3'989	4'227
U.S.	3'535	4'264
China	964	1'004
India	462	449
France	219	240
Russia	198	198
South Africa	110	103
U.K.	106	92
Saudi Arabia	79	32
Spain	79	93
Thailand	74	79
Germany	71	114
Ukraine	66	65
Canada	61	61
Poland	53	58
Indonesia	44	45
Argentina	42	44
Italy	40	40
Australia	33	33
Japan	31	30
Pakistan	26	24
Sweden	26	29
Philippines	22	22
South Korea	22	17
Guatemala	17	17
Cuba	16	12
Ecuador	12	14
Mexico	9	12
Nicaragua	8	7
Mauritius	6	3
Zimbabwe	6	5
Kenya	3	4
Swaziland	3	3
Others	338	710
Total	**10'770**	**12'150**

However, engine efficiency can be improved by compressing the fuel-mixture with higher pressures, leading though to higher NO_x emissions [198]. Main problems in the utilization as an automotive fuel are the higher vapor pressure of ethanol blends[100] compared to pure gasoline, corrosiveness[101] and water uptake of ethanol blends[102] [14, 139].

[100] All possible blends of gasoline and ethanol are feasible with minor technical adaptations. 85% ethanol is generally referred to as E85 [88].

[101] Ethanol has the tendency to oxidize into acetic acid. Therefore it is incompatible with some types of plastics, rubbers, elastomers and metals (alloy, aluminum, brass, zinc and lead) [88].

[102] With increasing EtOH content in the blend, the water uptake potential increases. If free water is present (phase separation) EtOH converts from the fuel phase to the water phase. This results in losses in RON and MON (RON=research octane number,

Ethanol from starch and ethanol from sugar process description

The core process for the ethanol production from biomass is alcoholic fermentation. Fermentation is the biochemical decomposition of carbohydrates by microbial enzymes under the exclusion of oxygen [98]. Starch is a carbohydrate, a polysaccharide which is composed mainly of glucose elements.

First of all the feedstock has to be pretreated. Normally, sugar containing plants are shredded, crushed, soaked or chemically treated. The kernels of starch containing crops are milled in order to increase the surface area for the following reactions.

Before milling, stones and other debris are removed from the biomass. Milling can be wet or dry, depending on whether the grain is soaked and broken down, before the starch is converted to sugar (wet) or during the conversion process (dry) [86].

Plants using wet milling have greater capacities, bigger investments and produce more different products than dry milling. The wet milling process converts corn into corn oil, animal feed products (corn gluten feed and corn gluten meal) and starch based products such as ethanol, corn syrups, or cornstarch.

The dry milling process generates two products only, namely ethanol and DDG[103]. Approximately 60% of the ethanol produced in the USA is derived from wet mills [106, 120]. Nowadays farmers favor dry mills since they require less capital, less operating staff, and since they tend to receive tax incentives due to smaller scale [120].

In order to be converted into sugar by yeasts, starch has to absorb water first. As a next step, starch is converted into sugar (glucose and maltose). This is generally conducted by amylases [98].

The mash or molasse is heated to about 110°C, than the amylases are added. After cooling to 60°C, yeasts and microbes which convert sugar into ethanol are added [120]. After fermentation, the solid residue is separated from the liquid solution and ethanol is distilled[104] and rectified[105] [88]. Molecular sieves or azeotropic distillation allow final ethanol concentrations of 100 vol.-% [98, 120].

Figure 31 gives an overview of the fermentation of sugar and starch to ethanol. For details of the distillers industry, F. O. Licht's World Distilleries Guide, which is listing over 4000 distilleries in 144 countries is recommended [112]. Novozymes is currently market leader in the production of enzymes for the conversion of starch into fermentable sugars. Genencor is working in the same area [133].

MON=motor octane number). A 5% blending results in a vapor pressure increase of 7kPa in summertime and 4kPa in wintertime. ETBE and MTBE reduce vapor pressure. The challenge is to produce a low vapor pressure gasoline to ensure that the final vapor pressure of the ethanol blend does not excess the critical value (60kPa for the EU) [139].

103 distiller's dried grain: residue after the digestion of the carbohydrates. DDG is protein rich (28%) and can be sold as animal feed [40].

104 removal of water

105 rectification is a multiple distillation [98].

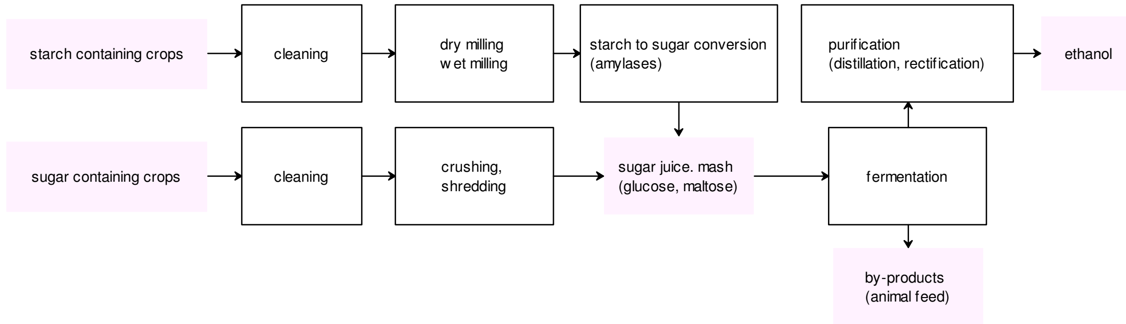

Figure 31: Simplified sugar and starch to ethanol process steps [120].

Ethanol from lignocellulosic biomass process description

Most plant matter is not sugar or starch, but cellulose, hemicellulose and lignin. Cellulose and hemicellulose can be converted into ethanol by first converting them into sugar. The lignin fraction cannot be converted. But the conversion of hemicellulose and cellulose to fermentable sugars is much more complicated than converting starch or sugar to ethanol [4, 86, 163].

Whilst starch to ethanol and sugar to ethanol are well established technologies modern lignocellulose to ethanol facilities are still at a development stage.

Companies working on the ethanol production from lignocellulosic feedstocks are Mascoma, Celunol, Sun Opta and Iogen [2, 22, 25, 65, 102]. Under license for Celunol, Marubeni Corporation will begin operating the company's first demonstration project in Osaka, Japan, in January 2007. The Osaka Project will utilize wood waste as a feedstock in producing up to 1.3 million liters of lignocellulosic ethanol annually [25]. Mascoma Corporation, based in the USA, is building demonstration facilities that will have the capacity to produce about 1.9-7.5 million liters of ethanol a year from waste biomass [22]. Iogen as well has a demonstration plant located in Canada, producing ethanol from straw [102].

The world's first commercial scale lignocellulosic biomass plant is currently being constructed by Abengoa Bioenergy to demonstrate its biomass-to-ethanol process technology using Sun Opta's steam explosion technology. Plant capacity is determined to be 5 million liters a year. Construction began in August 2005. The biomass conversion plant is located in Babilafuente, Spain [2, 65].

Other potential future ethanol from lignocellulosic biomass producers are Abengoa, Arkenol Inc., ADM Cargill and Staley and Nedalco [133][106].

Before processing, the biomass is washed and metal debris are removed [4, 192]. The second step within the process is pretreatment. In this step, biomass is broken down in order to separate the cellulose, hemicellulose and lignin fraction for further processing and to make the cellulosic fraction accessible to the biological conversion to ethanol [86].

The processes are mainly distinguished on the basis of hydrolysis and fermentation types [133]. These are as well the processes with the biggest development potential. The exact mechanism of the pretreatment is unknown, but through trial and error several processes have been developed. Theoretically the fermentation step is feasible without pretreatment but with much lower efficiencies (20% instead of 90% of the theoretical yields) [4].

[106] For further details see NOVEM, 2003, p. 16 [133].

There are three types of pretreatment: Physical pretreatment (e. g.: irradiation [10], mechanical, pyrolysis [163]), biological pretreatment (e. g.: fungi [6]) and chemical pretreatment (e. g.: steam, hot water [108], dilute acid [66], base [103], critical fluids [45], ozonlysis, oxidative delignification, organosolv process[107] [152, 163])[108].

In practice, a combination of biological and chemical pretreatment is commonly used, e. g.: steam explosion, CO_2-explosion or AFEX, which have big development potentials for the future [163, 167]. Steam explosion is a pretreatment of biomass with saturated steam at high pressure for the duration of several minutes. Then the pressure is released abruptly. This leads to the explosion of the biomass, which can then be further processed. With AFEX or Ammonia Fiber Explosion, the biomass is pretreated with liquid ammonium at pressures from 17-20 bars during 5 minutes [120]. CO_2-explosion works similarly, but with carbon dioxide (CO_2) instead of steam or ammonium [163].

Afterwards, hydrolysis with acids or alkalines and hydrolysis with enzymes can be used as a next processing step. Because acid hydrolysis is a more mature technology than enzymatic hydrolysis, the latter one has a bigger cost reduction potential. In addition, enzymes are more environment-friendly than are acids [74, 133, 195].

After the formation of cellulases, which hydrolyse cellulose to hexoses and pentoses, the fermentation of latter sugars can start. Available pretreatment technology for the production of ethanol from lignocellulose is based on acid or alkaline pre-hydrolysis [24, 74].

The processes cellulase formation, hydrolysis of the cellulose, hexose fermentation and pentose fermentation can be separated spatially and chronologically. Thus SHF (separate hydrolysis and fermentation), SSF (simultaneous saccharification and fermentation), SSCF (simultaneous saccharification and co-fermentation) and CBP (consolidated bioprocessing) are distinguished (Figure 32). According to Wright, SSF is less costly than SHF [193, 194]. SSCF is just a little less expensive then SSF [191]. Recently, SHF has gained interest because hydrolysis and fermentation can be adjusted separately. Lynd describes the SSF as state of the art. For the near term he sees big potential in the SSCF [114]. The biggest cost reduction potential though is seen with CBP [115, 198]. In the CBP process, hydrolysis and fermentation can potentially be conducted by a single microorganism or microorganism community. However though, such a microorganism has not yet been identified [116].

Mascoma is very active in this field of research. The company has arguably not achieved yet its ultimate goal of using a single genetically engineered organism to convert wood chips and other cellulosic raw materials into ethanol, but it has developed genetically modified bacteria that can speed up part of the process of producing ethanol [22].

[107] In the organosolv process, an organic or aqueous organic solvent mixture with inorganic acid catalysts is used to break the internal lignin and hemicellulose bonds [163].

[108] For further details see also Sun, 2002 [163].

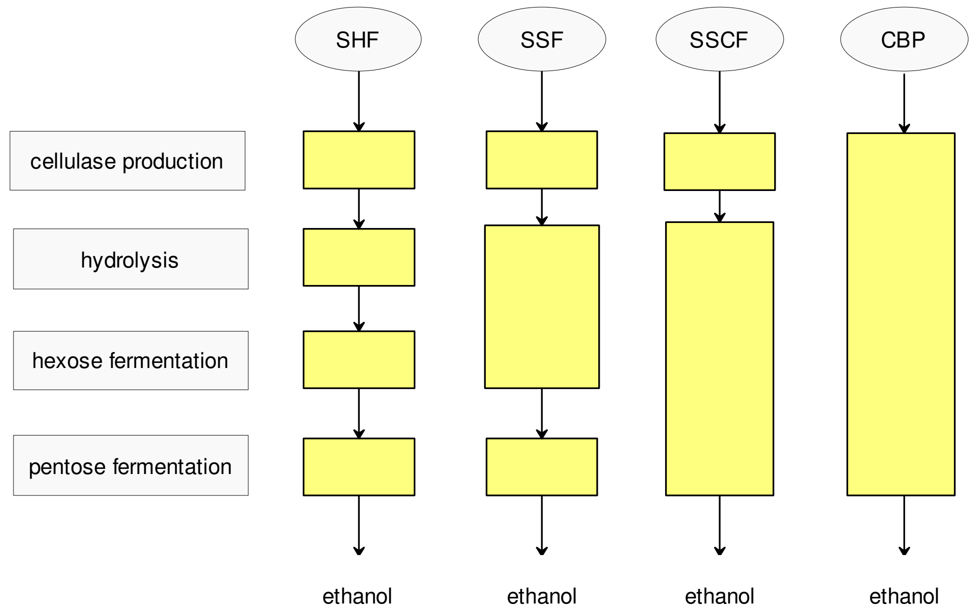

Figure 32: Spatial and chronological separation of the different fermentation processes. Each box incorporates a bio reactor. Scaling of the boxes does not correspond to the in fact size. For explanation of the terms SHF, SSF, SSCF, CBP see above text.

Distillation of ethanol is the final step of the whole process. It is identical with the distillation in the sugar and starch to ethanol process.

Figure 33 gives an overview of the lignocellulosic biomass to ethanol process.

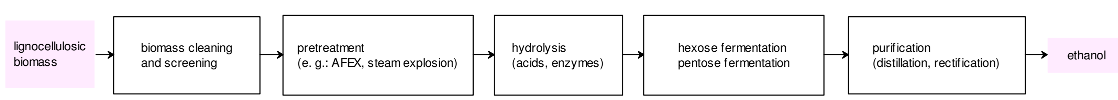

Figure 33: Simplified lignocellulosic biomass to ethanol process steps.

16.2.2 SNG from anaerobic digestion

General aspects

In evolutionary terms, anaerobic bacteria are very old, certainly much older than their aerobic counterparts. The anaerobic bacteria presumably first appeared before oxygen was a major part of the atmosphere. This accounts for their inability to process lignin, as woody plants had not yet evolved [87].

There is evidence that biogas was already used for heating in Assyria during the 10^{th} century and in Persia during the 16^{th} century. Jan Baptita Van Helmont first determined in the 17th century that flammable gases could evolve from organic matter.

In 1808, Sir Humphry Davy determined that methane was present in the gases produced during the anaerobic digestion of cattle manure. The first biogas production plant was built in Bombay in 1859.

In Europe the anaerobic digestion was used when energy supplies were reduced during and after the Second World War. By now some anaerobic digestion facilities in Europe have been in use for 20 years and more.

World-wide there are about 150 big anaerobic digestion plants in operation and another 35 under construction. Altogether these plants can process about 5 million tons of biomass per year [87]. In 2002, over 600 farm-based anaerobic digesters and 30 large centralized digesters were in use in Europe. About 250 of these systems had been installed alone in Germany over the past years [183].

Anaerobic digestion for the use of sewage sludge stabilization and as a pretreatment step for industrial waste water is well established and by now more than 2'500 systems are in operation or under construction. Mostly beverage, chemical, food, milk, pulp and paper and pharmaceutic industries are using anaerobic digestion [40].

As a feedstock, sewage sludge, agricultural waste, or municipal and industrial waste can be processed. Typically between 30% and 70% of sewage sludge is treated by anaerobic digestion depending on national legislation and priorities. Digestion of animal manure is probably the most widespread anaerobic digestion application worldwide [87]. It produces a valuable fertilizer as well as biogas.

Today, more and more organic industrial waste materials are added to the manure, which brings increased gas production and creates an additional income from the gate fee of the waste. In countries like Denmark, Austria and Germany, easily degradable wastes are becoming scarce and farmers are looking for alternative substrates (energy crops) such as corn, barley, rye or grass [87].

The EU has set the goal of reducing the amount of organic waste by 65% until 2014. Some countries have completely banned the disposal of untreated organic waste.

In the USA, especially in California, low emission cars are becoming an important issue. The project CalStart that is promoted in California, has rated biogas as the best alternative fuel before bio-ethanol and hydrogen for fuel cells.

World-wide more than 3 million natural gas vehicles are in operation and about 10'000 biogas driven cars and buses, demonstrating that the vehicle configuration is not a problem for the use of biogas as a vehicle fuel [87].

Most of the biogas though is used for electricity and heat generation [40]. The country with the vastest experience using large-scale digestion facilities is Denmark, where several large centralized plants are now in operation. In many cases these facilities co-digest manure, clean organic industrial wastes, and source separated municipal solid waste[109] [113].

Anaerobic digestion is considered to have positive environmental and socio-economic effects because waste can be used for the process and therefore, must not be disposed. Additionally to waste pollution prevention, it allows for energy, compost and nutrient recovery [87]. Thus, a disposal problem can be turned into a profitable business.

World leading companies in the construction of anaerobic digestion plants are Kruger (Denmark), BTA (Germany) and Kompogas (Switzerland) [183].

Process description

In the absence of oxygen, anaerobic bacteria can ferment biomass into methane (CH_4) and carbon dioxide (CO_2) at a ratio of 2:1 [98]. Anaerobic digestion is the result of a series of metabolic interactions between different types of microorganisms.

The resulting methane contains about 90% of the energy content of the biomass. This process is generally called anaerobic digestion. Naturally, this process occurs in the bottom sediments of lakes, ponds, swamps, hot springs and the sea. The abundance of methane bacteria over a wide temperature range demonstrates that anaerobic digestion can theoretically take place over a temperature range of 10°C to 100°C and a moisture range of 50% to over 99% [87].

In principle, the overall anaerobic digestion process can be divided into four individual steps: pretreatment, biomass digestion, gas recovery and residue treatment [183]. The actual anaerobic digestion occurs in three stages: hydrolysis/liquefaction, acidogenesis and methanogenesis. In the first step, microorganism enzymes hydrolyse the polymeric biomass structures to monomers such as glucose and amino acids. These are then converted to higher volatile fatty acids, hydrogen (H_2) and acetic acids by e.g. acetogenetic bacteria. Finally, methanogenetic bacteria convert hydrogen (H_2), carbon dioxide (CO_2) and acetate (AcO^-) to methane (CH_4) [183].

In the pretreatment step the digestible feedstock is separated and shredded. The separation makes sure that there are no undesirable materials such as metal, glass, stones etc. in the feedstock material. The feed is diluted in order to achieve desired solid content and rests in the digester for a certain retention time.

Water, sewage sludge or recycled process liquid can be used for the dilution. The mixture in the digester is kept at an optimum temperature and pH-value to maximize the efficiency. Digestion is eased by stirring the slurry. This makes the slurry homogeneous and intensifies the contact between the substrate and the bacteria. For the stirring either propellers, pumps, gas bubbling, external recirculation or paddles can be used [183].

In order to reinoculate the fresh feedstock with the bacteria from the digester, a small amount of the digested material has to be redirected to the feed [98]. Anaerobic digestion processes can be classified according to the total solids content of the slurry in the digester reactor. Low solid (less than 10%), medium solid (15%-20%) and high solid (22%-40%) mixtures are commonly distinguished.

[109] MSW

Another criterion is the number of reactors used for the digestion process. In single stage reactors, the three processes (hydrolysis/liquefaction, acidogenesis and methanogenesis) occur in one reactor, while multi stage reactors make use of two or more reactors.

Moreover, the flow of the slurry can be used to distinguish different reactor types. In batch reactors the slurry is loaded at the beginning of the reaction and the resulting products are discharged at the end of the cycle. For low solids slurries, the continuous flow reactor is used. Here the feedstock is continuously charged and discharged. As a consequence, the single stage and the multi stage systems can be further categorized as single stage low solids (SSLS), single stage high solids (SSHS), multi stage low solids (MSLS) and multi stage high solids (MSHS) [183].

Single stage low solids (SSLH) digestion processes are attractive because of their simplicity. They have been in operation for decades for the treatment of waste water and sludge. The most used reactor type is the continuously stirred tank reactor (CSTR). Feed is introduced at the same rates as effluent is removed whilst the slurry is continuously stirred.

Single stage high solid (SSHS) reactors are the DRANCO and Kompogas reactors. In the DRANCO reactor, feeding is conducted from the top of the reactor and the digested matter is extracted from the bottom. There is no additional mixing within the reactor.

The Kompogas reactor works similarly except that the feedstock flows in a horizontally disposed cylindrical reactor. An agitator mixes the materials in the reactor. On one hand, in SSHS reactor designs, the material to handle and transport high solid slurries has to be more robust. They are therefore more expensive than reactor designs of LS systems. On the other hand, HS systems can easily handle impurities (e. g.: wood, stones) that would have to be removed in LS process designs.

With the hope of improving digestion by having separate reactors for different stages of the digestion, the multi-stage anaerobic digestion processes were introduced. Typically two reactors are used: the first one for hydrolysis/liquefaction and acidogenesis and the second for methanogenesis. In the first reactor the process is limited by the rate of cellulose hydrolysis, in the second one by the growth of the microbes.

Multi-stage processes are also distinguished in multi-stage low solids (MMLS) and multi stage high solids (MMHS). An example for a multi stage process is the Biopercolat process. Its core component is a methanogenic Upflow Anaerobic Sludge Blanket reactor (UASB). Multi stage processes amount for just 10% of available treatment capacities [183].

There are three types of batch systems: Single stage batch, sequential batch and hybrid batch-UASB process. In the single-stage batch reactor the leachate is redirected to the top of the same reactor in contrast to the sequential batch process where the leachate from the first reactor is recirculated to the second reactor where the methanogenesis occurs. The hybrid batch-UASB process consists of a first reactor which is a batch reactor and a second reactor that is an upflow anaerobic sludge blanket (UASB) reactor.

Batch processes are technically simple, relatively cheap and robust but major drawbacks are that material is settling to the bottom, thus inhibiting digestion and involving the risk of explosion whilst unloading the reactor [183].

For the use of the biogas as an automotive fuel, the gas has to be upgraded [40]. The resulting biogas is scrubbed in a subsequent step to obtain high quality gas. The remaining biosolids are aerobically dried to convert them into a compost product. Upgrading is mainly referred to as hydrosulfide (H_2S) and carbon

dioxide (CO_2) removal. A common method for removing the hydrosulfide (H_2S) is the addition of small amounts of air into the reactor. Sulfobacter oxydans converts hydrosulfide (H_2S) into solid sulphur which can be collected on the surface of the fermented substrate.
Reactions with metal oxides or adsorption on active carbon are other methods. carbon dioxide (CO_2) removal is generally carried out with a pressurized water wash for which the gas needs to be compressed to 1 MPa [40]. Figure 34 gives an overview of the different process steps of anaerobic digestion.

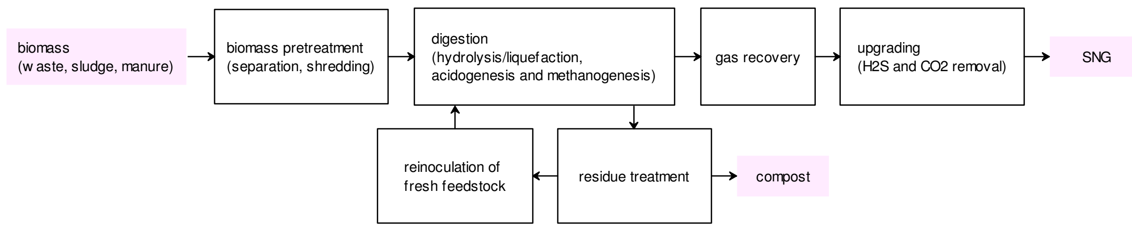

Figure 34: Simplified process steps of the anaerobic digestion.

16.2.3 Biodiesel from transesterification

General aspects

In 1898, Rudolph Diesel presented in Paris his compression ignition engine, running on peanut oil. Vegetable oils were used in diesel engines until the 1920s when a change was made to the engines, enabling the combustion of petroleum [201].
In the year 2003, world oilseed production was some 253.6 million tons, 21.8 million tons of which alone in India [11]. World biodiesel production capacity in 2002 was about 1'503 million liters, with emphasis in Europe[110] [86]
The expression biodiesel generally refers to as methyl or ethyl esters (fatty acid methyl esters (FAME) and fatty acid ethyl esters (FAEE)) from transesterification. The feedstock can be oil from oil seed crops as soy[111], sunflower, rapeseed[112], jatropha or oil palms[113], used oil as yellow grease from restaurants or animal fats as beef tallow, poultry fat and pork lard [11, 179]. Transesterification is a well established process which is in use since the mid 1800s. Originally it was used to distill out the glycerin needed for making soap. The by-products of this process are methyl and ethyl esters.
Archer Daniels Midland is one of the leading producers of biodiesel worldwide [8]. Caramuru, Granol, Novaol, Martifer, Vance Bioenergy and Bunge are just a few other major players in the biodiesel market [31]. Desmet Ballestra is one of the leaders in biodiesel production technology development [31].

[110] Germany: 625 million liters, France: 386 million liters, Italy: 239 million liters
[111] Effects of soy plantations on biodiversity are a major problem in these countries though.
[112] Fatty acid methyl esters from rape seed oil are commonly named RME.
[113] The jatropha tree is indigenous in South America but it is widely planted in Central America, Africa and Asia. It is adapted to marginal soils, low nutrients, high temperatures and drought. Palm oil offers the opportunity to expand biodiesel production in developing countries. Effects of plantations on biodiversity are though a major problem in these countries.

As a by-product, glycerol can be separated and used in cosmetics, medicine and food industry. This co-production as well as the cake from oil extraction improves the economies of biodiesel production [88]. For glycerol, markets are limited though. In Europe for example glycerol prices decreased in 2005 as a result of an increased glycerol production by the biodiesel industry. At the same time biodiesel production costs increased as a consequence [40].

Biodiesel is very suitable for the utilization in diesel engines. It can be used in its pure form or in all possible mixtures[114]. Biodiesel is sulphur free. As a result it reduces the overall sulphur content when blended to conventional diesel.

B100 acts as a mild solvent and is not compatible with certain elastomers and natural rubber compounds as it can degrade them over time. But its solvent properties can help keep engines clean and well running. Other properties are its high lubricity, helping engine parts to last longer. The energy content is about 10% lower than the energy content of conventional diesel [88].

Process description

Oilseed crops are first processed in an oil mill. The feedstock is crushed and the oil is extracted with steam and hexane. The by-product is a cake similar to DDG[103] which can be sold as a high value animal feed [40]. The next process step is purification, in which acidity is neutralized and water and contaminants are removed [88].

Feedstocks as used oil and animal fats can immediately be directed to this process step. The most mature technology for biodiesel production is the transesterification of vegetable oil, frying oil or animal fats [118]. Another approach is hydro cracking of bio-oils. This technology has reached demonstration stage, but its production potential is generally seen as limited [88].

Transesterification in this case is referred to as the reaction of organic acids with an alcohol. This is primarily conducted to make the fuel stable. Vegetable oil can be thought as three fatty acid “ribs” attached to a glycerol “backbone”. This quite big molecule is viscous and thermally unstable. During transesterification, the glycerol is replaced with three methanol or ethanol molecules, so that three fatty acid methyl esthers are formed from each bio-oil molecule [40]. During this process, sodium hydroxide, or potassium hydroxide usually act as a catalyst. As mentioned above, glycerol results as a by-product and can be sold to various industries [30]. Figure 35 gives an overview of the different process steps of the whole biodiesel production process.

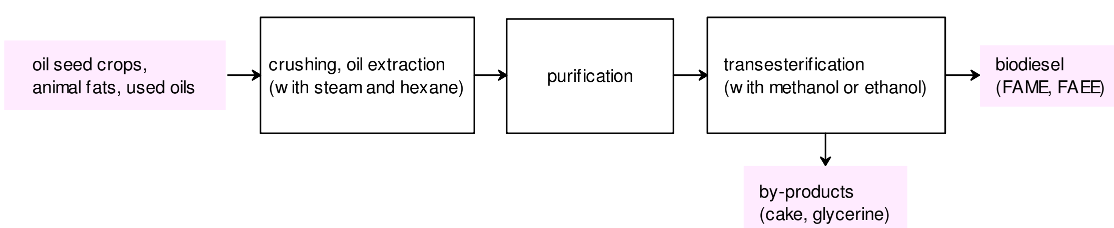

Figure 35: Simplified process steps of the transesterification process.

[114] pure biodiesel is generally named B100

17 Appendix 3: Unmodified biofuels plant gate costs[115]

17.1 Biodiesel from oil crops

	biodiesel from mechanical extraction (1 transesterification
costs [$/GJ]	**14.28**
biofuel	FAME
feedstock	rapeseed
capacity [MWth]	200.00
feedstock input [t/day]	734.25
LHV of feedstock [GJ/t]	23.80
by-products	cake, glycerin
by-products selling price [$/GJ]	5.13, 5.02
time period	short term
country	EU
electricity price [$/GJ]	0.00
natural gas price [$/GJ]	6.42
feedstock costs [$/GJ biomass]	9.13
source	CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**6'400'000.00**	**1.73**
net input power	electricity	0.00	0.00
	natural gas	397'507.79	0.11
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**6.85**
FIXOM		**0.22**
VAROM (without biomass)		0.19
	others	3.48
Net VAROM		**-3.29**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

115 If available from corresponding study, feedstock prices and energy prices are unmodified. For LHV sources see Table 5, p. 22. Capacity specifications in MW_{th} are just an approximation in order to facilitate the comprehension. Costs are plant gate costs. Feedstock costs include truck transport to theplant. Differences to original studies may be caused due to: different LHV of the feedstocks, different cost years, different currencies, cost uncertainties or feedstock type uncertainties. Pathways selected for further analysis are marked with an asterisk.

biodiesel from mechanical extraction (1	
	transesterification
costs [$/GJ]	**14.01**
biofuel	FAME
feedstock	rapeseed
capacity [MWth]	200.00
feedstock input [t/day]	734.25
LHV of feedstock [GJ/t]	23.80
by-products	cake, glycerin
by-products selling price [$/GJ]	5.13, 9.6
time period	short term
country	EU
electricity price [$/GJ]	0.00
natural gas price [$/GJ]	6.42
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	9.13

source: CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**6'400'000.00**	**1.73**
net input power	electricity	0.00	0.00
	natural gas	397'507.79	0.11
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**6.85**
FIXOM		**0.22**
VAROM (without biomass)		0.19
credits	electricity	0.00
	others	3.75
Net VAROM		**-3.56**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

biodiesel from mechanical extraction (1 transesterification

costs [$/GJ]	**14.72**
biofuel	FAME
feedstock	sunflower
capacity [MWth]	200.00
feedstock input [t/day]	682.20
LHV of feedstock [GJ/t]	23.80
by-products	cake, glycerin
by-products selling price [$/GJ]	5.13, 5.02
time period	short term
country	EU
electricity price [$/GJ]	0.00
natural gas price [$/GJ]	6.42
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	10.20

source: CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'900'000.00**	**1.59**
net input power	electricity	0.00	0.00
	natural gas	383'800.00	0.10
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**6.85**
FIXOM		**0.22**
VAROM (without biomass)		0.19
credits	electricity	0.00
	others	3.48
Net VAROM		**-3.29**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

biodiesel from mechanical extraction (1 transesterification

costs [$/GJ]	**14.72**
biofuel	FAME
feedstock	sunflower
capacity [MWth]	200.00
feedstock input [t/day]	682.20
LHV of feedstock [GJ/t]	23.80
by-products	cake, glycerin
by-products selling price [$/GJ]	5.13, 9.6
time period	short term
country	EU
electricity price [$/GJ]	0.00
natural gas price [$/GJ]	6.42
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	10.20

source CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'900'000.00**	**1.59**
net input power	electricity	0.00	0.00
	natural gas	383'800.00	0.10
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**6.85**
FIXOM		**0.22**
VAROM (without biomass)		0.19
credits	electricity	0.00
	others	3.48
Net VAROM		**-3.29**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

biodiesel from mechanical extraction (1

transesterification

costs [$/GJ]	**13.34**
biofuel	FAEE
feedstock	rapeseed
capacity [MWth]	200.00
feedstock input [t/day]	706.85
LHV of feedstock [GJ/t]	23.80
by-products	cake, glycerin
by-products selling price [$/GJ]	5.13, 5.02
time period	short term
country	EU
electricity price [$/GJ]	0.00
natural gas price [$/GJ]	6.42
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	9.13

source CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**6'100'000.00**	**1.61**
net input power	electricity	0.00	0.00
	natural gas	270'405.00	0.07
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**6.85**
FIXOM		**0.21**
VAROM (without biomass)		0.40
credits	electricity	0.00
	others	3.24
Net VAROM		**-2.84**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

*biodiesel from mechanical extraction (1 transesterification

costs [$/GJ]	**13.10**
biofuel	FAEE
feedstock	rapeseed
capacity [MWth]	200.00
feedstock input [t/day]	706.85
LHV of feedstock [GJ/t]	23.80
by-products	cake, glycerin
by-products selling price [$/GJ]	5.13, 9.6
time period	short term
country	EU
electricity price [$/GJ]	0.00
natural gas price [$/GJ]	6.42
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	9.13

source: CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		**[GJ/yr]**	**[GJ/GJ biofuel]**
input biomass	LHV basis	**6'100'000.00**	**1.61**
net input power	electricity	0.00	0.00
	natural gas	270'405.00	0.07
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'800'000.00**	1.00

costs		**[$/GJ biofuel]**
INVCOST		**6.85**
FIXOM		**0.21**
VAROM (without biomass)		0.40
credits	electricity	0.00
	others	3.48
Net VAROM		**-3.08**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

17.2 Biodiesel from pyrolysis

*biodiesel from pyrolysis (1 (2	
	bubbling fluidized bed
costs [$/GJ](3	**9.40**
biofuel	synthetic diesel
feedstock	wood
capacity [MWth]	100.00
feedstock input [t/day]	550.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	13.00
time period	short term
country	USA
electricity price [$/GJ]	13.00
natural gas price [$/GJ] (1	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.57

source: pyrolysis: Ringer, 2006, upgrading: Fortenbery, 2005, natural gas costs: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**3'613'500.00**	**1.73**
net input power	electricity	0.00	0.00
	natural gas	146'210.00	0.07
	others	0.00	0.00
net output power	electricity	18'435.00	0.01
output biofuel	LHV basis	**2'088'728.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**22.00**
FIXOM		**1.89**
VAROM (without biomass)		1.58
credits	electricity	0.13
	others	0.00
Net VAROM		**1.45**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) LHV bio-oil=18MJ/kg or 21.64MJ/l
2) Transesterification costs are added from Fortenbery, 2006. Scale differences between pyrolysis and transesterification are neglected. Natural gas costs 4.55 $/GJ (EIA, 2005).
3) costs excluding biodiesel upgrading are 5.92 $/GJ.

17.3 SNG from anaerobic digestion

SNG from anaerobic digestion (1

costs [$/GJ]	**19.52**
biofuel	synthetic natural gas
feedstock	manure
capacity [MWth]	3.00
feedstock input [t/day]	16.51
LHV of feedstock [GJ/t]	16.20
by-products	compost, heat & electricity
by-products selling price [$/GJ]	2, 12
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ] (1	0.00
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.88
source	CONCAWE, 2006, VAROM source: Schenler, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**97'600.00**	**1.94**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	9'492.00	0.19
output biofuel	LHV basis	**50'400.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**69.14**
FIXOM		**6.95**
VAROM (without biomass)		2.20
credits	electricity	2.26
	others	0.25
Net VAROM		**-0.31**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Outlet pressure=0.9MPa, TCI uncertainty range=+/-40%

*SNG from anaerobic digestion (1

costs [$/GJ]	**14.17**
biofuel	synthetic natural gas
feedstock	waste
capacity [MWth]	3.00
feedstock input [t/day]	17.82
LHV of feedstock [GJ/t]	15.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ] (1	0.00
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.50
source	CONCAWE, 2006, VAROM source: Schenler, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**97'600.00**	**1.94**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	9'492.00	0.19
output biofuel	LHV basis	**50'400.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**48.40**
FIXOM		**4.86**
VAROM (without biomass)		2.20
credits	electricity	2.26
	others	0.00
Net VAROM		**-0.06**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Outlet pressure=0.9MPa, TCI uncertainty range=+/-40%

17.4 SNG from wood gasification

*SNG from wood gasification (1	
	PSI process
costs [$/GJ]	**17.14**
biofuel	synthetic natural gas
feedstock	wood
capacity [MWth]	100.00
feedstock input [t/day]	477.48
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	13.00
time period	short term
country	CH
electricity price [$/GJ]	13.00
natural gas price [$/GJ]	0.00
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	5.00
source	Schulz, 2005, Felder, 2006, energy input: Schenler, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**3'153'600.00**	**1.83**
net input power	electricity	14'222.00	0.01
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**1'720'258.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**49.14**
FIXOM		**1.74**
VAROM (without biomass)		0.01
credits	electricity	0.00
	others	0.00
Net VAROM		**0.01**

discounted cash flow parameters (2	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) 0.82% of the produced gas are used for process power (predictions for 2030). This amount is equal to 14'222 GJ/yr.
2) assumed

17.5 Ethanol from starch

	*ethanol from starch (1
	dry milling
costs [$/GJ]	**16.31**
biofuel	ethanol
feedstock	corn grains
capacity [MWth]	150.00
feedstock input [t/day]	675.00
LHV of feedstock [GJ/t]	18.53
by-products	DDGS (2
by-products selling price [$/GJ]	5.13
time period	short term
country	USA
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	4.50

source: Mc Aloon, 2000, steam: Kwiatkowski, 2006, by-product selling price: CONCAWE, 2006, natural gas price, steam price: IEA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**4'566'204.00**	**2.27**
net input power	electricity	64'396.00	0.03
	natural gas	324'726.00	0.16
	steam	912'148.00	0.45
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'013'543.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**12.84**
FIXOM		**1.45**
VAROM (without biomass)		1.30
credits	electricity	0.00
	DDGS	3.64
Net VAROM		**-2.34**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	10.00
CRF	**0.16**

1) 1000 kg steam=15 $ (Kwiatkowski, 2006). (H) for 1kg vapor at 150 psi and 300°C=3050 kJ/kg ->1000 kg = 3 GJ (McAloon, 2000), cooling water is included in VAROM
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1	
	dry milling
costs [$/GJ]	**11.25**
biofuel	ethanol
feedstock	corn grains
capacity [MWth]	200.00
feedstock input [t/day]	981.46
LHV of feedstock [GJ/t]	18.53
by-products	DDGS (2
by-products selling price [$/GJ]	5.13
time period	short term
country	USA
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	3.25

source: Kwiatkowski, 2006, steam: Mc Aloon, 2000, natural gas price, steam price: EIA, 2005, VAROM and by-products selling price: CONCAWE, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**6'639'362.00**	**2.08**
net input power	electricity	75'928.00	0.02
	natural gas	502'810.00	0.16
	steam	1'113'085.00	0.35
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'191'880.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**11.74**
FIXOM		**0.77**
VAROM (without biomass)		1.36
credits	electricity	0.00
	DDGS	2.76
Net VAROM		**-1.40**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) 1000 kg steam=15 $ (Kwiatkowski, 2006). (H) for 1kg vapor at 150 psi and 300°C=3050 kJ/kg ->1000 kg = 3 GJ (McAloon, 2000), cooling water is included in VAROM
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1

dry milling, heat from conventional gas boiler

costs [$/GJ]	**16.73**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2
by-products selling price [$/GJ]	4.90
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90

source: CONCAWE, 2006, steam consumption: Kwiatkowski, 2006, natural gas consumption: Aden, 2002, Kwiatkowski, 2006, Mc Aloon, 2000, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	67'500.00	0.03
	natural gas	449'820.00	0.17
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**19.60**
FIXOM		**0.59**
VAROM (without biomass)		1.61
credits	electricity	0.00
	DDGS	2.98
Net VAROM		**-1.37**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1

natural gas fired gas turbine for heat and electricity

costs [$/GJ]	**14.53**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2, heat & electricity
by-products selling price [$/GJ]	4.9, 12
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90

source CONCAWE, 2006, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**25.50**
FIXOM		**0.77**
VAROM (without biomass)		1.61
credits	electricity	2.05
	DDGS	2.98
Net VAROM		**-3.42**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1

natural gas fired gas turbine for heat and electricity

costs [$/GJ]	**16.14**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2 for power generation
by-products selling price [$/GJ]	2.40
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90

source: CONCAWE, 2006, steam consumption: Kwiatkowski, 2006, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**25.50**
FIXOM		**0.85**
VAROM (without biomass)		1.61
credits	electricity	2.05
	DDGS	1.46
Net VAROM		**-1.90**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%

2) distillers dried grain with solubles, sold for power production

ethanol from starch (1

lignite boiler and back pressure turbo generator for power generation

costs [$/GJ]	**15.50**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2
by-products selling price [$/GJ]	4.90
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90

source CONCAWE, 2006, steam consumption: Kwiatkowski, 2006, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**34.40**
FIXOM		**1.53**
VAROM (without biomass)		1.61
credits	electricity	2.98
	DDGS	2.99
Net VAROM		**-4.36**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1

lignite boiler and back pressure turbo generator for power generation

costs [$/GJ]	**17.03**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2 for power generation
by-products selling price [$/GJ]	2.40
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90
source	CONCAWE, 2006, steam consumption: Kwiatkowski, 2006, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**34.40**
FIXOM		**1.53**
VAROM (without biomass)		1.61
credits	electricity	2.98
	DDGS	1.46
Net VAROM		**-2.83**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1

straw boiler and back pressure turbo generator for power generation

costs [$/GJ]	**15.85**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2
by-products selling price [$/GJ]	4.90
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90

source: CONCAWE, 2006, steam consumption: Kwiatkowski, 2006, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**34.40**
FIXOM		**1.53**
VAROM (without biomass)		1.61
credits	electricity	2.64
	DDGS	2.98
Net VAROM		**-4.01**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) distillers dried grain with solubles, sold as animal feed

ethanol from starch (1

straw boiler and back pressure turbo generator for power generation

costs [$/GJ]	**17.37**
biofuel	ethanol
feedstock	wheat grains
capacity [MWth]	150.00
feedstock input [t/day]	926.03
LHV of feedstock [GJ/t]	14.80
by-products	DDGS (2 for power generation
by-products selling price [$/GJ]	2.40
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	5.90

source: CONCAWE, 2006, steam consumption: Kwiatkowski, 2006, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'000'000.00**	**1.85**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'113'085.00	0.41
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'700'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**34.40**
FIXOM		**1.53**
VAROM (without biomass)		1.61
credits	electricity	2.64
	DDGS	1.46
Net VAROM		**-2.49**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) distillers dried grain with solubles

17.6 Ethanol from sugar

ethanol from sugar (1

costs [$/GJ]	**14.36**
biofuel	ethanol
feedstock	sugar beet
capacity [MWth]	50.00
feedstock input [t/day]	1'027.40
LHV of feedstock [GJ/t]	3.73
by-products	pulp & slop (2
by-products selling price [$/GJ]	5.13
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	6.16
source	CONCAWE, 2006, TCI source: Dreier, 1998, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**1'400'000.00**	**1.84**
net input power	electricity	0.00	0.00
	natural gas	215'451.00	0.28
	steam	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**760'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**20.00**
FIXOM		**0.63**
VAROM (without biomass)		0.46
credits	electricity	0.00
	pulp & slop	1.85
Net VAROM		**-1.39**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%
2) low protein animal feed

ethanol from sugar (1

costs [$/GJ]	**14.40**
biofuel	ethanol
feedstock	sugar beet
capacity [MWth]	50.00
feedstock input [t/day]	1'027.40
LHV of feedstock [GJ/t]	3.73
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	6.16

source CONCAWE, 2006, TCI source: Dreier, 1998, natural gas price, steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**1'400'000.00**	**1.84**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	0.00	0.00
net output power	electricity	151'079.00	0.20
output biofuel	LHV basis	**760'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**32.66**
FIXOM		**0.94**
VAROM (without biomass)		0.46
credits	electricity	2.39
	others	0.00
Net VAROM		**-1.93**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%

*ethanol from sugar

costs [$/GJ]	**15.03**
biofuel	ethanol
feedstock	sugar cane
capacity [MWth]	200.00
feedstock input [t/day]	5'620.00
LHV of feedstock [GJ/t]	2.88 (1
by-products	bagasse
by-products selling price [$/GJ]	0.35
time period	state of the art
country	USA
electricity price [$/GJ]	13.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.50

source: USDA, 2006, natural gas price, steam price: EIA, 2005, AF and CRF from CONCAWE, 2006

efficiencies		**[GJ/yr]**	**[GJ/GJ biofuel]**
input biomass	LHV basis	**5'914'168.00**	**1.84**
net input power	electricity	345'667.00	0.11
	natural gas	979'751.00	0.30
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'214'222.00**	1.00

costs		**[$/GJ biofuel]**
INVCOST		**15.70**
FIXOM		**5.87**
VAROM (without biomass)		1.13
credits	electricity	0.00
	bagasse	0.09
Net VAROM		**1.04**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) otherwise a LHV of 16.5 GJ/t is assumed from IEA, 2006

17.7 Ethanol from cellulosic biomass

ethanol from cellulosic biomass	
dilute acid pre-hydrolysis with saccharification and fermentation (SSF)	
costs [$/GJ]	**22.30**
biofuel	ethanol
feedstock	poplar wood
capacity [MWth]	400.00
feedstock input [t/day]	1'762.40
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.84
source	Hamelinck, 2005, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**11'578'741.00**	**2.86**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	411'045.00	0.10
output biofuel	LHV basis	**4'053'560.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**61.90**
FIXOM		**1.83**
VAROM (without biomass)		3.05
credits	electricity	1.22
	others	0.00
Net VAROM		**1.83**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

ethanol from cellulosic biomass

dilute acid pre-hydrolysis with saccharification and co-fermentation (SSCF)

costs [$/GJ]	**16.57**
biofuel	ethanol
feedstock	poplar wood
capacity [MWth]	400.00
feedstock input [t/day]	2'115.50
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	USA
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.87

source: Wooley, 1999, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**13'898'966.00**	**3.31**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	331'115.00	0.08
output biofuel	LHV basis	**4'204'281.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**57.12**
FIXOM		**1.83**
VAROM (without biomass)		2.44
credits	electricity	0.95
	others	0.00
Net VAROM		**1.49**

discounted cash flow parameters	
AF	**0.96**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

*ethanol from cellulosic biomass

dilute acid pre-hydrolysis with saccharification and co-fermentation (SSCF)

costs [$/GJ]	**13.89**
biofuel	ethanol
feedstock	corn stover
capacity [MWth]	400.00
feedstock input [t/day]	2'118.70
LHV of feedstock [GJ/t]	16.60
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	USA
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	1.81

source: Aden, 2002, electricity price: CONCAWE, 2006, natural gas price and steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'781'728.00**	**2.29**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'741'440.00	0.31
net output power	electricity	568'814.00	0.10
output biofuel	LHV basis	**5'581'541.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**33.95**
FIXOM		**1.29**
VAROM (without biomass)		3.94
credits	electricity	1.22
	others	0.00
Net VAROM		**2.72**

discounted cash flow parameters	
AF	**0.96**
interest rate	0.07
lifetime	20.00
CRF	**0.09**

ethanol from cellulosic biomass (10

dilute acid pre-hydrolysis with enzymatic simultaneous saccharification and fermentation (SSF)

costs [$/GJ]	**11.62**
biofuel	ethanol
feedstock	corn stover
capacity [MWth]	400.00
feedstock input [t/day]	2'205.00
LHV of feedstock [GJ/t]	16.60
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	2004
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	1.32

source: Wymann, 2004, electricity price, AF, CRF: CONCAWE, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'320'976.50**	**2.93**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	0.00	0.00
net output power	electricity	343'742.00	0.08
output biofuel	LHV basis	**4'204'730.40**	1.00

costs		[$/GJ biofuel]
INVCOST		**20.80**
FIXOM		**0.73**
VAROM (without biomass)		1.36
credits	electricity	0.98
	others	0.00
Net VAROM		**0.38**

discounted cash flow parameters	
AF	**0.41**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

10) Process details are not available, feedstock type, AF and CRF are assumed

ethanol from cellulosic biomass

steam explosion pre-hydrolysis with saccharification and co-fermentation (SSCF)

costs [$/GJ]	**16.24**
biofuel	ethanol
feedstock	poplar wood
capacity [MWth]	1'000.00
feedstock input [t/day]	5'525.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	mid term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.19

source: Hamelinck, 2005, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**28'946'853.76**	**2.50**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	5'248'065.00	0.45
output biofuel	LHV basis	**11'578'741.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**41.19**
FIXOM		**1.16**
VAROM (without biomass)		7.44
credits	electricity	5.44
	others	0.00
Net VAROM		**2.00**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

ethanol from cellulosic biomass

hot liquid water pre-hydrolysis with consolidated bio processing (CBP)

costs [$/GJ]	**9.52**
biofuel	ethanol
feedstock	poplar wood
capacity [MWth]	2'000.00
feedstock input [t/day]	11'049.70
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source Hamelinck, 2005, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**57'893'707.52**	**2.09**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	203'123.00	0.01
output biofuel	LHV basis	**27'728'980.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**26.41**
FIXOM		**0.91**
VAROM (without biomass)		0.87
credits	electricity	0.87
	others	0.00
Net VAROM		**0.00**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

ethanol from cellulosic biomass

saccharification and co-fermentation (SSCF)

costs [$/GJ]	**19.23**
biofuel	ethanol
feedstock	farmed wood
capacity [MWth]	400.00
feedstock input [t/day]	1'857.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.95
source	CONCAWE, 2006, natural gas price: EIA, 2005, TCI source: Wooley, 1999, VAROM source: Aden, 2004

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'200'000.00**	**2.90**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**4'200'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**43.28**
FIXOM		**1.93**
VAROM (without biomass)		0.40
credits	electricity	0.00
	others	0.00
Net VAROM		**0.40**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

ethanol from cellulosic biomass

saccharification and co-fermentation (SSCF)

costs [$/GJ]	**15.31**
biofuel	ethanol
feedstock	wood waste
capacity [MWth]	400.00
feedstock input [t/day]	1'857.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.60

source CONCAWE, 2006, natural gas price: EIA, 2005, TCI source: Wooley, 1999, VAROM source: Aden, 2004

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'200'000.00**	**2.90**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**4'200'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**43.28**
FIXOM		**1.93**
VAROM (without biomass)		0.40
credits	electricity	0.00
	others	0.00
Net VAROM		**0.40**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

ethanol from cellulosic biomass

IOGEN process with saccharification and co-fermentation (SSCF)

costs [$/GJ]	**9.43**
biofuel	ethanol
feedstock	wheat straw
capacity [MWth]	50.00
feedstock input [t/day]	245.00
LHV of feedstock [GJ/t]	15.65
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source: CONCAWE, 2006, natural gas price: EIA, 2005, TCI source: Wooley, 1999, VAROM source: Aden, 2004

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**1'399'830.00**	**1.84**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	395'683.00	0.52
output biofuel	LHV basis	**760'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**72.70**
FIXOM		**1.99**
VAROM (without biomass)		0.00
credits	electricity	6.25
	others	0.00
Net VAROM		**-6.25**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

17.8 FT-diesel from biomass gasification

*FT-diesel from biomass gasification	
80% conversion once trough, IGT gasifier (1	
costs [$/GJ]	**11.74**
biofuel	FT-diesel
feedstock	poplar wood
capacity [MWth]	450.00
feedstock input [t/day]	2'209.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.52
source	Tijmensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'512'971.76**	**3.25**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	2'971'530.97	0.67
output biofuel	LHV basis	**4'458'678.05**	1.00

costs		[$/GJ biofuel]
INVCOST		**66.33**
FIXOM		**2.48**
VAROM (without biomass)		0.25
credits	electricity	8.00
	others	0.00
Net VAROM		**-7.75**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) IGT=direct oxygen blown, pressurized gasifier from the Institute of Gas Technology (IGT), co-firing of the off gas with natural gas in a gas turbine, no tar cracking, wet gas cleaning, C5 Selectivity=83.5%

FT-diesel from biomass gasification

80% conversion once trough, EP gasifier (1

costs [$/GJ]	**11.78**
biofuel	FT-diesel
feedstock	poplar wood
capacity [MWth]	450.00
feedstock input [t/day]	2'209.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.52

source: Tijmensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'512'971.76**	**3.51**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	3'323'470.53	0.80
output biofuel	LHV basis	**4'140'201.04**	1.00

costs		[$/GJ biofuel]
INVCOST		**71.44**
FIXOM		**2.81**
VAROM (without biomass)		0.27
credits	electricity	9.63
	others	0.00
Net VAROM		**-9.36**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) EP=direct air blown, pressurized gasifier with tar cracker from Enviro Power (EP), co-firing of the off gas with natural gas in a gas turbine, with tar cracking, wet gas cleaning, C5 Selectivity=83.5%

FT-diesel from biomass gasification

40% conversion once trough, IGT gasifier (1

costs [$/GJ]	**11.98**
biofuel	FT-diesel
feedstock	poplar wood
capacity [MWth]	450.00
feedstock input [t/day]	2'209.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.52

source: Tijmensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'512'971.76**	**2.46**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	1'240'858.86	0.21
output biofuel	LHV basis	**5'910'023.25**	1.00

costs		[$/GJ biofuel]
INVCOST		**46.97**
FIXOM		**1.87**
VAROM (without biomass)		0.19
credits	electricity	2.52
	others	0.00
Net VAROM		**-2.33**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) IGT=direct oxygen blown, pressurized gasifier from the Institute of Gas Technology (IGT), co-firing of the off gas with natural gas in a gas turbine, no tar cracking, wet gas cleaning, C5 Selectivity=73.7%

FT-diesel from biomass gasification

40% conversion once trough, EP gasifier (1

costs [$/GJ]	**16.57**
biofuel	FT-diesel
feedstock	poplar wood
capacity [MWth]	450.00
feedstock input [t/day]	2'209.00
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.52

source: Tijmensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'512'971.76**	**4.94**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	3'298'072.83	1.12
output biofuel	LHV basis	**2'939'087.77**	1.00

costs		[$/GJ biofuel]
INVCOST		**99.70**
FIXOM		**3.96**
VAROM (without biomass)		0.38
credits	electricity	13.47
	others	0.00
Net VAROM		**-13.09**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) EP=Direct air blown, pressurized gasifier with tar cracker from Enviro Power (EP), co-firing of the off gas with natural gas in a gas turbine, with tar cracking, wet gas cleaning, C5 Selectivity=73.7%

FT-diesel from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**22.88**
biofuel	FT-diesel
feedstock	farmed wood
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.96

source CONCAWE, 2006, TCI and VAROM: Tijmensen, 2002, Gray, 2001, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.07**
net input power	electricity	134'160.00	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST (2		**81.80**
FIXOM		**3.50**
VAROM (without biomass)		0.35
credits	electricity	0.00
	others	0.00
Net VAROM		**0.35**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Battelle Columbus Laboratory (BCL) gasifier
2) TCI uncertainty range=+/-40%, VAROMS from Tijmensen, 2002: VAROM~FIXOM/11

FT-diesel from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**19.96**
biofuel	FT-diesel
feedstock	waste wood
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source: CONCAWE, 2006, TCI and VAROM: Tijmensen, 2002, Gray, 2001, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.07**
net input power	electricity	134'160.00	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST (2		**81.80**
FIXOM		**3.50**
VAROM (without biomass)		0.35
credits	electricity	0.00
	others	0.00
Net VAROM		**0.35**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Battelle Columbus Laboratory (BCL) gasifier
2) TCI uncertainty range=+/-40%, VAROMS from Tijmensen, 2002: VAROM~FIXOM/11

FT-diesel from biomass gasification

Choren process

costs [$/GJ]	**10.87**
biofuel	FT-diesel
feedstock	waste wood via black liquor
capacity [MWth]	450.00
feedstock input [t/day]	3'233.60
LHV of feedstock [GJ/t]	18.00
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55
source	CONCAWE, 2006, TCI and VAROM: Tijmensen, 2002, Gray, 2001, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'280'991.74**	**1.85**
net input power	electricity	134'160.00	0.02
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**7'735'537.19**	1.00

costs		[$/GJ biofuel]
INVCOST 1)		**32.92**
FIXOM		**1.47**
VAROM (without biomass)		0.35
credits	electricity	0.00
	others	0.00
Net VAROM		**0.35**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-40%, VAROMS from Tijmensen, 2002: VAROM~FIXOM/11

17.9 Methanol from biomass gasification

Methanol from biomass gasification

IGT gasifier-max H2, scrubber, liquid phase methanol reactor, combined cycle (1

costs [$/GJ]	**8.00**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock [GJ/t]	17.53
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.02
source	Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**2.42**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	1'671'408.00	0.33
output biofuel	LHV basis	**5'077'296.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**42.70**
FIXOM (2		**1.29**
VAROM (without biomass)		0.47
credits	electricity	3.95
	others	0.00
Net VAROM		**-3.48**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct oxygen blown pressurized fluidized bed gasifier from the Institute of Gas Technology (IGT). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

Methanol from biomass gasification

IGT gasifier, hot gas cleaning, auto thermal reformer, liquid phase methanol reactor with steam addition, combined cycle (1

costs [$/GJ]	**7.83**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock [GJ/t]	17.53
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.02

source Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**2.25**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	1'955'232.00	0.36
output biofuel	LHV basis	**5'455'728.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**45.95**
FIXOM (2		**1.38**
VAROM (without biomass)		0.50
credits	electricity	4.30
	others	0.00
Net VAROM		**-3.80**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct oxygen blown pressurized fluidized bed gasifier from the Institute of Gas Technology (IGT). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

*Methanol from biomass gasification

IGT gasifier, scrubber, auto thermal reformer, liquid phase methanol reactor with steam addition, combined cycle (1

costs [$/GJ]	**6.18**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock [GJ/t]	17.53
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.02
source	Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**3.45**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	3'311'280.00	0.93
output biofuel	LHV basis	**3'563'568.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**62.69**
FIXOM (2		**1.89**
VAROM (without biomass)		0.69
credits	electricity	11.15
	others	0.00
Net VAROM		**-10.46**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct oxygen blown pressurized fluidized bed gasifier from the Institute of Gas Technology (IGT). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

Methanol from biomass gasification

BCL gasifier, scrubber, steam reformer, liquid phase methanol reactor with steam addition and recycle, steam cycle (1

costs [$/GJ]	**7.43**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock [GJ/t]	17.53
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.02

source: Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**1.59**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**7'757'856.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**25.62**
FIXOM (2		**0.77**
VAROM (without biomass)		0.28
credits	electricity	0.00
	others	0.00
Net VAROM		**0.28**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct air blown atmospheric fluidized bed gasifier from the Battelle Columbus Laboratory (BCL). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

Methanol from biomass gasification

IGT gasifier, hot gas cleaning, auto thermal reformer, partial shift, conventional methanol reactor with recycle, steam turbine (1

costs [$/GJ]	**8.68**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock [GJ/t]	17.53
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.02

source: Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**1.76**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	473'040.00	0.07
output biofuel	LHV basis	**6'969'456.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**35.90**
FIXOM (2		**1.08**
VAROM (without biomass)		0.39
credits	electricity	0.81
	others	0.00
Net VAROM		**-0.42**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct oxygen blown pressurized fluidized bed gasifier from the Institute of Gas Technology (IGT). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

Methanol from biomass gasification

BCL gasifier, scrubber, steam reformer, partial shift, conventional methanol reactor with recycle, steam turbine (1

costs [$/GJ]	**8.22**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock [GJ/t]	17.53
by-products	heat & electricity
by-products selling price [$/GJ]	12.00
time period	long term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.02

source — Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**1.53**
net input power	electricity	536'112.00	0.07
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**8'041'680.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**26.18**
FIXOM (2		**0.79**
VAROM (without biomass)		0.29
credits	electricity	0.00
	others	0.00
Net VAROM		**0.29**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct air blown atmospheric fluidized bed gasifier from the Battelle Columbus Laboratory (BCL). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

Methanol from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**16.43**
biofuel	methanol
feedstock	farmed wood
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock [GJ/t]	18.00
by-products	-
by-products selling price [$/GJ]	-
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.96

source: CONCAWE, 2006, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.00**
net input power	electricity	130'522.67	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'900'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**45.06**
FIXOM (2		**2.03**
VAROM (without biomass)		0.20
credits	electricity	0.00
	others	0.00
Net VAROM		**0.20**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) O&M cost are given only. Assumption VAROM=FIXOM/11 (Tijmensen, 2002)

Methanol from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**13.61**
biofuel	methanol
feedstock	waste wood
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock [GJ/t]	18.00
by-products	-
by-products selling price [$/GJ]	-
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source: CONCAWE, 2006, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.00**
net input power	electricity	130'522.67	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'900'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**45.06**
FIXOM (2		**2.03**
VAROM (without biomass)		0.20
credits	electricity	0.00
	others	0.00
Net VAROM		**0.20**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) O&M cost are given only. Assumption VAROM=FIXOM/11 (Tijmensen, 2002)

Methanol from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**7.02**
biofuel	methanol
feedstock	waste wood via black liquor
capacity [MWth]	350.00
feedstock input [t/day]	2'671.80
LHV of feedstock [GJ/t]	18.00
by-products	-
by-products selling price [$/GJ]	-
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source: CONCAWE, 2006, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**11'800'000.00**	**1.51**
net input power	electricity	130'522.67	0.02
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**7'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**16.76**
FIXOM (2		**0.75**
VAROM (without biomass)		0.08
credits	electricity	0.00
	others	0.00
Net VAROM		**0.08**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) O&M cost are given only. Assumption VAROM=FIXOM/11 (Tijmensen, 2002)

17.10 DME from biomass gasification

DME from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**17.31**
biofuel	DME
feedstock	farmed wood
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock [GJ/t]	18.00
by-products	-
by-products selling price [$/GJ]	-
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.96

source: CONCAWE, 2006, Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.00**
net input power (2	electricity	139'577.93	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'900'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**49.70**
FIXOM		**2.25**
VAROM (without biomass)		0.23
credits	electricity	0.00
	others	0.00
Net VAROM		**0.23**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) "net energy and chemicals" assumed as electricity costs

*DME from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**14.49**
biofuel	DME
feedstock	wood waste
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock [GJ/t]	18.00
by-products	-
by-products selling price [$/GJ]	-
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source: CONCAWE, 2006, Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.00**
net input power (2	electricity	139'577.93	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'900'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**49.70**
FIXOM		**2.25**
VAROM (without biomass)		0.23
credits	electricity	0.00
	others	0.00
Net VAROM		**0.23**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) "net energy and chemicals" assumed as electricity costs

DME from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**7.22**
biofuel	DME
feedstock	wood waste via black liquor
capacity [MWth]	350.00
feedstock input [t/day]	2'603.80
LHV of feedstock [GJ/t]	18.00
by-products	-
by-products selling price [$/GJ]	-
time period	short term
country	EU
electricity price [$/GJ]	12.00
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.55

source CONCAWE, 2006, Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**11'500'000.00**	**1.47**
net input power (2	electricity	140'244.60	0.02
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**7'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**18.28**
FIXOM		**0.83**
VAROM (without biomass)		0.08
credits	electricity	0.00
	others	0.00
Net VAROM		**0.08**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) "net energy and chemicals" assumed as electricity costs

18 Appendix 4: IEA biomass supply potentials for 2050

Table 21: IEA biomass supply potentials for 2050.

IEA, biomass supply potential by region, 2050 [PJ/yr]	NAM	LAFM	CHN	IND	ASIA	OOECD	EEFSU	WEUR
additional recovery potential from forests	155	3836	623	1449	1310	121	0	0
bagasse production (sugar by-product only)	1110	450	234	50	502	116	375	400
new supply of solid biomass-plantanations on arable land	930	80	20	20	20	118	40	580
new supply of solid biomass-plantanations on permanent pasture land	240	569	0	0	0	0	0	25
production of cellulosic and starch biomass for ethanol	498	9133	2063	3246	8414	61	814	358
production of fuelwood (existing)	1110	451	234	50	502	116	375	400
production of industrial wastes	8300	13500	2700	3000	2000	2200	9200	2800
production of municipial wastes (biomass content only)	4993	15092	194	3	24	811	5885	702
production of solid biomass for biofuel (existing)	1893	5710	1925	2183	1407	755	1751	679
production of straw and other agricultural residues	2235	19725	5400	149	2090	1862	1796	534
production of sugarcane for ethanol	0	8000	1600	1600	4000	400	0	0
production of wastes and residues (additional)	1682	3253	1141	1294	834	347	1066	603
Black liquor	2079	568	4400	480	435	2427	385	835

19 Appendix 5: Selected biomass-to-biofuels conversion pathways

19.1 Selected biofuels pathways for WEUR

	biodiesel from mechanical extraction (1 transesterification
costs [$/GJ]	**11.84**
biofuel	FAEE
feedstock	rapeseed
capacity [MWth]	200.00
feedstock input [t/day]	706.85
LHV of feedstock	23.80
by-products	cake, glycerin
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	8.44
source	CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**6'100'000.00**	**1.61**
net input power	electricity	0.00	0.00
	natural gas	270'405.00	0.07
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**6.70**
FIXOM		**0.21**
VAROM (without biomass)		0.40
credits	electricity	0.00
	cake, glycerin	3.48
Net VAROM		**-3.08**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

biodiesel from pyrolysis (1 (2

bubbling fluidized bed

costs [$/GJ](3	**12.42**
biofuel	synthetic diesel
feedstock	wood
capacity [MWth]	100.00
feedstock input [t/day]	550.00
LHV of feedstock	18.00
by-products	heat & electricity
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ] (1	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.11

source pyrolysis: Ringer, 2006, upgrading: Fortenbery, 2005, natural gas costs: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**3'613'500.00**	**1.73**
net input power	electricity	0.00	0.00
	natural gas	146'210.00	0.07
	others	0.00	0.00
net output power	electricity	18'435.00	0.01
output biofuel	LHV basis	**2'088'728.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**24.18**
FIXOM		**1.89**
VAROM (without biomass)		1.50
credits	electricity	0.01
	heat	0.03
Net VAROM		**1.46**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) LHV bio-oil=18MJ/kg or 21.64MJ/l
2) Transesterification costs are added from Fortenbery, 2006. Scale differences between pyrolysis and transesterification are neglected. Natural gas costs 4.55 $/GJ (EIA, 2005).
3) costs excluding biodiesel upgrading are 5.92 $/GJ.

SNG from anaerobic digestion (1

costs [$/GJ]	**15.15**
biofuel	synthetic natural gas
feedstock	domestic waste
capacity [MWth]	3.00
feedstock input [t/day]	17.82
LHV of feedstock	15.00
by-products	heat & electricity
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ] (1	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	2.17
source	CONCAWE, 2006, VAROM source: Schenler, 2006

efficiencies		**[GJ/yr]**	**[GJ/GJ biofuel]**
input biomass	LHV basis	**97'600.00**	**1.94**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	9'492.00	0.19
output biofuel	LHV basis	**50'400.00**	1.00

costs		**[$/GJ biofuel]**
INVCOST		**48.62**
FIXOM		**4.86**
VAROM (without biomass)		2.20
credits	electricity	2.59
	others	0.00
Net VAROM		**-0.39**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Outlet pressure=0.9MPa, TCI uncertainty range=+/-40%

SNG from wood gasification (1

PSI process

costs [$/GJ]	**13.76**
biofuel	synthetic natural gas
feedstock	wood
capacity [MWth]	100.00
feedstock input [t/day]	477.48
LHV of feedstock	18.00
by-products	heat & electricity
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.11
source	Schulz, 2005, Felder, 2006, energy input: Schenler, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**3'153'600.00**	**1.83**
net input power	electricity	14'222.00	0.01
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**1'720'258.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**49.69**
FIXOM		**1.74**
VAROM (without biomass)		0.01
credits	electricity	0.00
	others	0.00
Net VAROM		**0.01**

discounted cash flow parameters (2	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) 0.82% of the produced gas are used for process power (predictions for 2030). This amount is equal to 14'222 GJ/yr.

2) assumed

ethanol from starch (1	
	dry milling
costs [$/GJ]	**21.68**
biofuel	ethanol
feedstock	corn grains
capacity [MWth]	150.00
feedstock input [t/day]	675.00
LHV of feedstock	18.53
by-products	DDGS (2
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	6.71
source	Mc Aloon, 2000, steam: Kwiatkowski, 2006, by-product selling price: CONCAWE, 2006, natural gas price, steam price: IEA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**4'566'204.00**	**2.27**
net input power	electricity	64'396.00	0.03
	natural gas	324'726.00	0.16
	steam	912'148.00	0.45
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'013'543.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**14.13**
FIXOM		**1.45**
VAROM (without biomass)		1.23
credits	electricity	0.00
	DDGS	3.46
Net VAROM		**-2.23**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	10.00
CRF	**0.16**

1) 1000 kg steam=15 $ (Kwiatkowski, 2006). (H) for 1kg vapor at 150 psi and 300°C=3050 kJ/kg ->1000 kg = 3 GJ (McAloon, 2000), cooling water is included in VAROM

2) distillers dried grain with solubles, sold as animal feed

ethanol from sugar

costs [$/GJ]	**31.47**
biofuel	ethanol
feedstock	sugar beet
capacity [MWth]	200.00
feedstock input [t/day]	5'620.00
LHV of feedstock	2.88 (1
by-products	bagasse
time period	state of the art
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	10.32

source USDA, 2006, natural gas price, steam price: EIA, 2005, AF and CRF from CONCAWE, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'914'168.00**	**1.84**
net input power	electricity	345'667.00	0.11
	natural gas	979'751.00	0.30
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'214'222.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**17.15**
FIXOM		**5.87**
VAROM (without biomass)		1.07
credits	electricity	0.00
	bagasse	0.08
Net VAROM		**0.99**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) otherwise a LHV of 16.5 GJ/t is assumed from IEA, 2006

ethanol from cellulosic biomass

dilute acid pre-hydrolysis with saccharification and co-fermentation (SSCF)

costs [$/GJ]	**14.39**
biofuel	ethanol
feedstock	corn stover
capacity [MWth]	400.00
feedstock input [t/day]	2'118.70
LHV of feedstock	16.60
by-products	heat & electricity
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	2.10

source — Aden, 2002, electricity price: CONCAWE, 2006, natural gas price and steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'781'728.00**	**2.29**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'741'440.00	0.31
net output power	electricity	568'814.00	0.10
output biofuel	LHV basis	**5'581'541.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**37.35**
FIXOM		**1.29**
VAROM (without biomass)		3.74
credits	electricity	1.33
	others	0.00
Net VAROM		**2.41**

discounted cash flow parameters	
AF	**0.96**
interest rate	0.07
lifetime	20.00
CRF	**0.09**

FT-diesel from biomass gasification

80% conversion once trough, IGT gasifier (1

costs [$/GJ]	**13.37**
biofuel	FT-diesel
feedstock	wood
capacity [MWth]	450.00
feedstock input [t/day]	2'209.00
LHV of feedstock	18.00
by-products	heat & electricity
time period	long term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.11

source Tijmensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'512'971.76**	**3.25**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	2'971'530.97	0.67
output biofuel	LHV basis	**4'458'678.05**	1.00

costs		[$/GJ biofuel]
INVCOST		**83.47**
FIXOM		**3.11**
VAROM (without biomass)		0.31
credits	electricity	11.49
	others	0.00
Net VAROM		**-11.18**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) IGT=direct oxygen blown, pressurized gasifier from the Institute of Gas Technology (IGT), co-firing of the off gas with natural gas in a gas turbine, no tar cracking, wet gas cleaning, C5 Selectivity=83.5%

Methanol from biomass gasification

IGT gasifier, scrubber, auto thermal reformer, liquid phase methanol reactor with steam addition, combined cycle (1

costs [$/GJ]	**8.34**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock	17.53
by-products	heat & electricity
time period	long term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.11

source: Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**3.45**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	3'311'280.00	0.93
output biofuel	LHV basis	**3'563'568.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**62.92**
FIXOM (2		**1.89**
VAROM (without biomass)		0.69
credits	electricity	12.78
	others	0.00
Net VAROM		**-12.09**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct oxygen blown pressurized fluidized bed gasifier from the Institute of Gas Technology (IGT). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

DME from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**15.72**
biofuel	DME
feedstock	wood waste
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock	18.00
by-products	-
time period	short term
country	WEUR
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	3.11

source CONCAWE, 2006, Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.00**
net input power (2	electricity	139'577.93	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'900'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**49.93**
FIXOM		**2.25**
VAROM (without biomass)		0.23
credits	electricity	0.00
	others	0.00
Net VAROM		**0.23**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.
2) "net energy and chemicals" assumed as electricity costs

19.2 Selected biofuels pathways for LAFM

biodiesel from mechanical extraction (1	
	transesterification
costs [$/GJ]	**8.74**
biofuel	FAEE
feedstock	rapeseed
capacity [MWth]	200.00
feedstock input [t/day]	706.85
LHV of feedstock	23.80
by-products	cake, glycerin
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	6.26
source	CONCAWE, 2006, TCI sources: Kraus, 1999, Ölmühle Leer Connemann GmbH & Co., 2000, Gover, 1996

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**6'100'000.00**	**1.61**
net input power	electricity	0.00	0.00
	natural gas	270'405.00	0.07
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'800'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**7.61**
FIXOM		**0.19**
VAROM (without biomass)		0.36
credits	electricity	0.00
	cake, glycerin	3.13
Net VAROM		**-2.77**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) TCI uncertainty range=+/-20%, energy consumed, assumed as natural gas.

biodiesel from pyrolysis (1 (2	
	bubbling fluidized bed
costs [$/GJ](3	**9.97**
biofuel	synthetic diesel
feedstock	wood
capacity [MWth]	100.00
feedstock input [t/day]	550.00
LHV of feedstock	18.00
by-products	heat & electricity
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ] (1	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.68
source	pyrolysis: Ringer, 2006, upgrading: Fortenbery, 2005, natural gas costs: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**3'613'500.00**	**1.73**
net input power	electricity	0.00	0.00
	natural gas	146'210.00	0.07
	others	0.00	0.00
net output power	electricity	18'435.00	0.01
output biofuel	LHV basis	**2'088'728.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**27.47**
FIXOM		**1.70**
VAROM (without biomass)		1.35
credits	electricity	0.08
	others	0.02
Net VAROM		**1.25**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) LHV bio-oil=18MJ/kg
2) Transesterification costs are added from Fortenbery, 2006. Scale differences between pyrolysis and transesterification are neglected. Natural gas costs 4.55 $/GJ (EIA, 2005).
3) costs excluding biodiesel upgrading are 5.92 $/GJ.

SNG from anaerobic digestion (1

costs [$/GJ]	**14.52**
biofuel	synthetic natural gas
feedstock	domestic waste
capacity [MWth]	3.00
feedstock input [t/day]	17.82
LHV of feedstock	15.00
by-products	heat & electricity
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ] (1	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.68

source CONCAWE, 2006, VAROM source: Schenler, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**97'600.00**	**1.94**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	9'492.00	0.19
output biofuel	LHV basis	**50'400.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**55.23**
FIXOM		**4.38**
VAROM (without biomass)		1.98
credits	electricity	2.33
	others	0.00
Net VAROM		**-0.35**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Outlet pressure=0.9MPa, TCI uncertainty range=+/-40%

SNG from wood gasification (1

PSI process

costs [$/GJ]	**11.77**
biofuel	synthetic natural gas
feedstock	wood
capacity [MWth]	100.00
feedstock input [t/day]	477.48
LHV of feedstock	18.00
by-products	heat & electricity
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other input costs [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.68

source Schulz, 2005, Felder, 2006, energy input: Schenler, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**3'153'600.00**	**1.83**
net input power	electricity	14'222.00	0.01
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**1'720'258.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**56.45**
FIXOM		**1.57**
VAROM (without biomass)		0.01
credits	electricity	0.00
	others	0.00
Net VAROM		**0.01**

discounted cash flow parameters (2	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) 0.82% of the produced gas are used for process power (predictions for 2030). This amount is equal to 14'222 GJ/yr.
2) assumed

ethanol from starch (1

dry milling

costs [$/GJ]	**16.57**
biofuel	ethanol
feedstock	corn grains
capacity [MWth]	150.00
feedstock input [t/day]	675.00
LHV of feedstock	18.53
by-products	DDGS (2
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	4.28

source: Mc Aloon, 2000, steam: Kwiatkowski, 2006, by-product selling price: CONCAWE, 2006, natural gas price, steam price: IEA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**4'566'204.00**	**2.27**
net input power	electricity	64'396.00	0.03
	natural gas	324'726.00	0.16
	steam	912'148.00	0.45
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'013'543.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**16.05**
FIXOM		**1.30**
VAROM (without biomass)		1.11
credits	electricity	0.00
	DDGS	3.11
Net VAROM		**-2.00**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	10.00
CRF	**0.16**

1) 1000 kg steam=15 $ (Kwiatkowski, 2006). (H) for 1kg vapor at 150 psi and 300°C=3050 kJ/kg ->1000 kg = 3 GJ (McAloon, 2000), cooling water is included in VAROM
2) distillers dried grain with solubles, sold as animal feed

ethanol from sugar

costs [$/GJ]	**14.19**
biofuel	ethanol
feedstock	sugar beet
capacity [MWth]	200.00
feedstock input [t/day]	5'620.00
LHV of feedstock	2.88 (1
by-products	bagasse
time period	state of the art
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.18

source USDA, 2006, natural gas price, steam price: EIA, 2005, AF and CRF from CONCAWE, 2006

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'914'168.00**	**1.84**
net input power	electricity	345'667.00	0.11
	natural gas	979'751.00	0.30
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**3'214'222.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**19.48**
FIXOM		**5.28**
VAROM (without biomass)		0.96
credits	electricity	0.00
	bagasse	0.07
Net VAROM		**0.89**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) otherwise a LHV of 16.5 GJ/t is assumed from IEA, 2006

ethanol from cellulosic biomass

dilute acid pre-hydrolysis with saccharification and co-fermentation (SSCF)

costs [$/GJ]	**13.35**
biofuel	ethanol
feedstock	corn stover
capacity [MWth]	400.00
feedstock input [t/day]	2'118.70
LHV of feedstock	16.60
by-products	heat & electricity
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
steam price [$/GJ]	7.50
feedstock costs [$/GJ biomass]	1.60

source: Aden, 2002, electricity price: CONCAWE, 2006, natural gas price and steam price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'781'728.00**	**2.29**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	steam	1'741'440.00	0.31
net output power	electricity	568'814.00	0.10
output biofuel	LHV basis	**5'581'541.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**42.43**
FIXOM		**1.16**
VAROM (without biomass)		3.37
credits	electricity	1.20
	others	0.00
Net VAROM		**2.17**

discounted cash flow parameters	
AF	**0.96**
interest rate	0.07
lifetime	20.00
CRF	**0.09**

FT-diesel from biomass gasification

80% conversion once trough, IGT gasifier (1

costs [$/GJ]	**10.99**
biofuel	FT-diesel
feedstock	wood
capacity [MWth]	450.00
feedstock input [t/day]	2'209.00
LHV of feedstock	18.00
by-products	heat & electricity
time period	long term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.68

source Tijmensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**14'512'971.76**	**3.25**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	2'971'530.97	0.67
output biofuel	LHV basis	**4'458'678.05**	1.00

costs		[$/GJ biofuel]
INVCOST		**94.82**
FIXOM		**2.80**
VAROM (without biomass)		0.28
credits	electricity	10.34
	others	0.00
Net VAROM		**-10.06**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	20.00
CRF	**0.12**

1) IGT=direct oxygen blown, pressurized gasifier from the Institute of Gas Technology (IGT), co-firing of the off gas with natural gas in a gas turbine, no tar cracking, wet gas cleaning, C5 Selectivity=83.5%

Methanol from biomass gasification

IGT gasifier, scrubber, auto thermal reformer, liquid phase methanol reactor with steam addition, combined cycle (1

costs [$/GJ]	**5.42**
biofuel	methanol
feedstock	biomass
capacity [MWth]	400.00
feedstock input [t/day]	1'920.00
LHV of feedstock	17.53
by-products	heat & electricity
time period	long term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.68

source: Hamelinck, 2002, VAROM: Tjimensen, 2002, TCI: Tjimensen, 2002, electricity price: CONCAWE, 2006, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**12'300'000.00**	**3.45**
net input power	electricity	0.00	0.00
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	3'311'280.00	0.93
output biofuel	LHV basis	**3'563'568.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**71.47**
FIXOM (2		**1.70**
VAROM (without biomass)		0.62
credits	electricity	11.50
	others	0.00
Net VAROM		**-10.88**

discounted cash flow parameters	
AF	**0.91**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) direct oxygen blown pressurized fluidized bed gasifier from the Institute of Gas Technology (IGT). Hamelinck assumes an uncertainty level of 30%.
2) O&M cost are given only. Assumption FIXOM=3%TCI (Tijmensen, 2002)

DME from biomass gasification

BCL gasifier, Choren process (1

costs [$/GJ]	**13.41**
biofuel	DME
feedstock	wood waste
capacity [MWth]	200.00
feedstock input [t/day]	882.80
LHV of feedstock	18.00
by-products	-
time period	short term
country	LAFM
electricity price [$/GJ]	13.75
natural gas price [$/GJ]	4.55
other energy price [$/GJ]	0.00
feedstock costs [$/GJ biomass]	1.68

source CONCAWE, 2006, Tjimensen, 2002, Gray 2001, Katofsky, 1993, Larson, 1998, natural gas price: EIA, 2005

efficiencies		[GJ/yr]	[GJ/GJ biofuel]
input biomass	LHV basis	**5'800'000.00**	**2.00**
net input power (2	electricity	139'577.93	0.05
	natural gas	0.00	0.00
	others	0.00	0.00
net output power	electricity	0.00	0.00
output biofuel	LHV basis	**2'900'000.00**	1.00

costs		[$/GJ biofuel]
INVCOST		**56.72**
FIXOM		**2.02**
VAROM (without biomass)		0.20
credits	electricity	0.00
	others	0.00
Net VAROM		**0.20**

discounted cash flow parameters	
AF	**0.90**
interest rate	0.10
lifetime	25.00
CRF	**0.11**

1) Gasifier from the Battelle Columbus Laboratory (BCL). TCI uncertainty range= +/- 40%.

2) "net energy and chemicals" assumed as electricity costs

20 Appendix 6: Cost details for LAFM and WEUR

Table 22: Cost breakdown for the LAFM and WEUR region.

process [1]	world region	biofuel plant gate costs	INVCOST	FIXOM	VAROM (without feedstock)	electricity credits	by product credits	net VAROM (without feedstock)	feedstock cost	feedstock transport costs (truck, 50 km)	total energy costs	feedstock input/biofuel output	AF	discount rate	lifetime	CRF
	[-]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[US$/GJ]	[GJ/GJ]	[-]	[-]	[yr]	[-]
biodiesel from wood pyrolysis	WEUR	12.43	24.18	1.89	1.50	0.01	0.03	1.47	4.41	0.97	0.32	1.73	0.91	0.10	20.00	0.12
DME from wood gasification	WEUR	15.71	49.93	2.25	0.23	0.00	0.00	0.23	5.10	1.12	0.66	2.00	0.90	0.10	25.00	0.11
ethanol from starch	WEUR	21.68	14.13	1.45	1.23	0.00	3.46	-2.23	13.99	1.22	4.57	2.27	0.90	0.10	10.00	0.16
ethanol from sugar	WEUR	31.46	17.15	5.87	1.07	0.00	0.08	0.99	17.83	1.16	2.87	1.84	0.90	0.10	25.00	0.11
ethanol from cellulosic biomass	WEUR	14.40	37.35	1.29	3.74	1.33	0.00	2.41	3.44	1.38	2.34	2.29	0.96	0.07	20.00	0.09
FAEE from oil crops	WEUR	11.84	6.70	0.21	0.40	0.00	3.48	-3.08	12.87	0.67	0.32	1.61	0.90	0.10	25.00	0.11
FT-diesel from wood gasification	WEUR	13.37	83.47	3.11	0.31	11.49	0.00	-11.18	8.30	1.82	0.00	3.25	0.91	0.10	20.00	0.12
methanol from wood gasification	WEUR	8.33	62.92	1.89	0.69	12.78	0.00	-12.09	8.80	1.93	0.00	3.45	0.91	0.10	25.00	0.11
SNG from anaerobic digestion	WEUR	15.15	48.62	4.86	2.20	2.59	0.00	-0.39	2.90	1.29	0.00	1.94	0.90	0.10	25.00	0.11
SNG from wood gasification	WEUR	13.76	49.69	1.74	0.01	0.00	0.00	0.01	4.67	1.03	0.14	1.83	0.91	0.10	25.00	0.11
biodiesel from wood pyrolysis	LAFM	9.96	27.47	1.70	1.35	0.08	0.02	1.25	1.94	0.97	0.32	1.73	0.91	0.10	20.00	0.12
DME from wood gasification	LAFM	13.41	56.72	2.02	0.20	0.00	0.00	0.20	2.24	1.12	0.66	2.00	0.90	0.10	25.00	0.11
ethanol from starch	LAFM	16.57	16.05	1.30	1.11	0.00	3.11	-2.01	8.48	1.22	4.57	2.27	0.90	0.10	10.00	0.16
ethanol from sugar	LAFM	14.18	19.48	5.28	0.96	0.00	0.07	0.89	1.05	1.12	2.87	1.84	0.90	0.10	25.00	0.11
ethanol from cellulosic biomass	LAFM	13.36	42.43	1.16	3.37	1.20	0.00	2.17	2.29	1.38	2.34	2.29	0.96	0.07	20.00	0.09
FAEE from oil crops	LAFM	8.74	7.61	0.19	0.36	0.00	3.13	-2.77	9.36	0.69	0.32	1.61	0.90	0.10	25.00	0.11
FT-diesel from wood gasification	LAFM	10.99	94.82	2.80	0.28	10.34	0.00	-10.06	3.65	1.82	0.00	3.25	0.91	0.10	20.00	0.12
methanol from wood gasification	LAFM	5.42	71.47	1.70	0.62	11.50	0.00	-10.88	3.86	1.93	0.00	3.45	0.91	0.10	25.00	0.11
SNG from anaerobic digestion	LAFM	14.49	55.23	4.38	1.98	2.33	0.00	-0.35	1.94	1.30	0.00	1.94	0.90	0.10	25.00	0.11
SNG from wood gasification	LAFM	11.76	56.45	1.57	0.01	0.00	0.00	0.01	2.05	1.03	0.13	1.83	0.91	0.10	25.00	0.11

1) all costs in US$2000/GJ biofuel