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Institute for Energy and Environment

Deliverable D 5.3.7 “Conversion Costs Calculation”

Project: RENEW – Renewable Fuels for Advanced Powertrains

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1. Introduction and Preface

1.1. Background

The paper at hand has been elaborated within the working package “micro-economics and socio-economical assessment” in the RENEW project (Renewable Fuels for Advanced Powertrains). This project – a European project, supported under the European Commission’s 6th Framework Programme and coordinated by Volkswagen – investigates different production routes for so called BtL-fuels.

Thereby, the aim of the SP 5 is the biofuel assessment. This includes – besides the analysis of the biomass potential, the life cycle assessment from well to tank and the technical assessment of available production routes for BtL fuels from lignocellulosic biomass – above all the analysis of economic, socio-economic and socio-political aspects of the different options of BtL-production (WP 5.3).

Within the economic assessment the conversion costs (biomass to liquid conversion at a future plant) are of main importance. Assessing these costs is task of Renew Del. 5.3.7. This Deliverable is focused on the concepts which are developed within SP 1-4. To produce reliable results for the different conversion technologies the conditions necessary for such an assessment have already been developed within the first 12 months of the Renew project (Del. 5.3.1-Method on Cost Calculation and Del. 5.4.1-Scenario and Boundary Conditions). Based on this consistent frame conditions, the following steps of conversion cost calculation (Del. 5.3.7) will be investigated:

* Integration of the technical data and information from WP 5.4 (efficiency, consumables etc.) based on the templates developed in cooperation with WP 5.4
* Investigation of the capital-related costs (cross checked based on SP1-4 data, literature data, aggregate manufactures and own calculations)
* Investigation of consumption-related costs (based on SP1-4 data and literature data)
* Investigation of operation-related costs (this will be based on literature data and experiences on commercial plants)

In preparation of these calculations of fuel production costs a pre-screening was carried to identify the most important influencing parameters (summarised in Del. 5.3.2). Based on these steps and the biomass costs free plant gate (derived from Del. 5.3.4 (biomass production costs) and 5.3.6 (biomass provision costs)) the biofuel production costs (free plant gate) will be calculated in this Del. 5.3.7 (Conversion costs).

1.2. Aim of this paper

Against this background the paper at hand aims to present the following work steps of conversion cost calculation to have a common discussion base within the Renew project:

* Calculation model (chapter 3)
* Description of the concepts to be considered (chapter 4)
* Original data of the cost calculation (chapter 5)
* Results on cost calculations including sensitivity analysis (chapter 6)

The first part describes the cost calculation model developed by IEE. It includes the presentation of the basics of cost calculation and the calculation method applied, but also calculation estimations.

In the second part the BtL-concepts are described via simplified flow charts from an economic point of view.

In the third part the original data which has been used for these cost calculations will be presented. This includes the general economic frame conditions and also biomass cost and investment costs. Thereby, the goal is to have a common and accepted basis for the final calculation in Del. 5.3.7.

Based on the model and the original data the results of cost calculation will be shown in the fourth part to give information on valid BtL production costs of the considered concepts in SP and S1 scenario. In the last part of the paper at hand a sensitivity analysis of the calculated costs is done. The aim is to clarify significantly influencing parameters on the cost calculation.

2. Procedure on Costs Calculation

Based on the previous mentioned objectives the assessment of biofuel production cost has to differ between two main aspects first of all:

* Regional specific biomass production
* Conversion of this biomass in defined European regions (WEST, EAST, NORTH, ALPINE, SOUTH, UK+IR, represented by reference countries referring to the SP 5 partners of the RENEW project)

The general approach for the cost calculation within the SP 5 of RENEW project is shown in Figure 2-1.

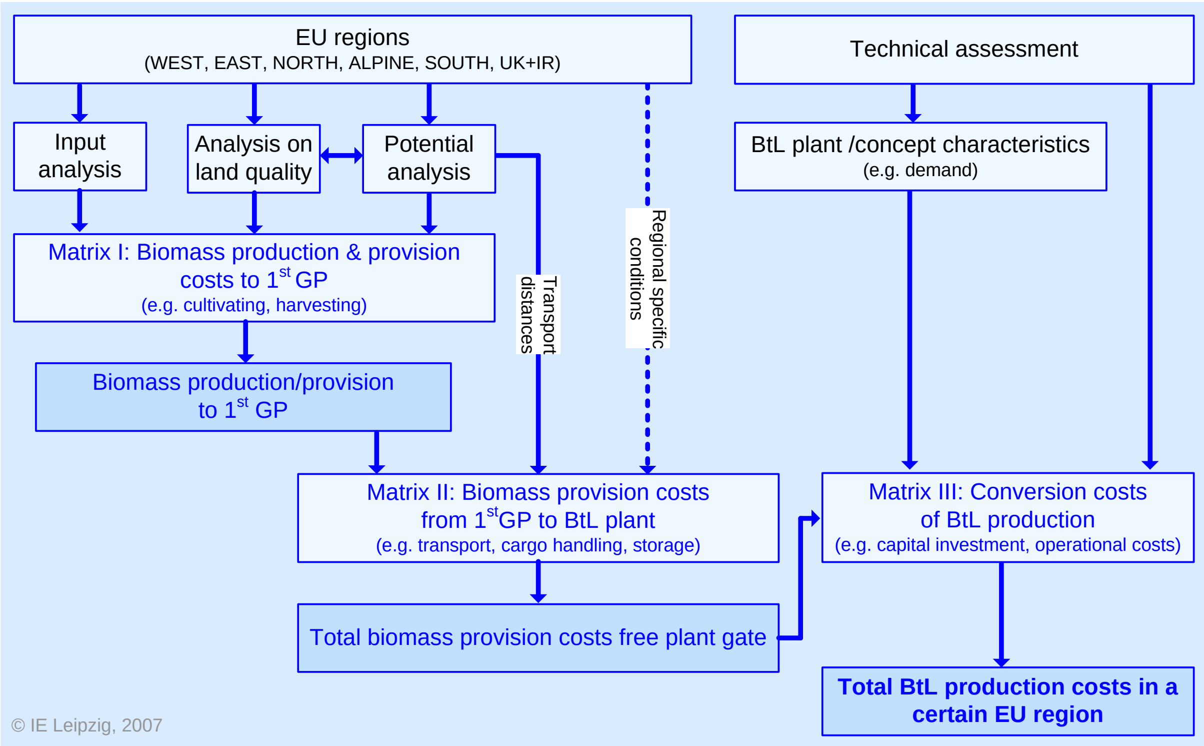


Figure 2-1: General approach of the economic assessment of biofuel production costs in certain regions

The calculation consists of three cost calculation matrixes:

* *Matrix I.* For the production of energy crops and their provision to the first GP LUND has elaborated a comprehensible cost calculation for different crop assortments and European regions taking into account e.g. costs for risk and land, establishment, fertilisation, harvesting, fields and road transports. The costs for the provision of agricultural and forestry residues have been calculated by ECBREC that developed a calculation tool that includes e.g. aspects of baling, bales collecting, forwarding, loading in, transport, loading out and storage. The provision costs to the 1st GP also took into account data and costs of the defined European regions.
* *Matrix II.* Based on the outcome of matrix I, biomass provision costs from the 1st GP to the BtL plant have been calculated by the IEE for the different biomass assortments,

European regions and BtL plant sizes as well as RENEW scenarios. Therefore, a cost calculation model has been developed further that considers regional specific aspects as well as required transport distances based on regional specific biomass potentials.

* *Matrix III.* Using the results of matrix II, best case biomass costs are compiled for each region and each biomass, both for SP and S1 scenario. These costs are used as biomass costs for the calculation of total BtL production costs which have been elaborated for the different BtL concept characteristics.

The total BtL production costs at free plant gate represent accumulated costs of the shown cost calculation matrixes.

Starting from this, typical distribution cost can be added to calculate the costs of biofuel free tank/free filling station (e. g. in €/GJ); this is foreseen in the scientific report based on typical distribution costs provided by the WTW study of EUCAR, CONCAWE & JRC/IES [WTW, 2006]. The planned procedure has been summarised detailed in D 5.3.1. ff.

With regard to the comprehensive results on total biomass provision costs at the BtL plant (cf. Deliverable 5.3.6, Appendix 2) BtL production costs are only calculated for the defined plant concept and scenarios specific biomass assortments (i.e. willow, straw, miscanthus) according to SP5-Scenario-Paper. These combinations, together with the relevant biomass input power, are compiled in Table 2-1. Exemplary sensitivity analysis based on biomass costs is given. With the cost results in Deliverable 5.3.6., using this analysis the reader will be able to carry out fundamental estimations for total BtL production costs by him-/herself.

Table 2-1: Considered plant concepts, biomass input power and biomass sources

Scenario	cEF-D	dEF-D	BLEF-DME	EF-E	CFB-D	ICFB-D	CFB-E
SP	500 MW	500 MW-P	500 MW	500 MW	500 MW	50 MW	500 MW
	SRC, STR	STR-P	SRC	SRC	SRC, STR	SRC, MIS	SRC
S1	500 MW	500 MW-P	500 MW	500 MW	500 MW	500 MW	500 MW
	SRC	STR-P	SRC	SRC	SRC, STR	SRC, MIS	SRC

STR – straw bales STR-P – straw pyrolysis slurry
SRC – willow chips MIS – miscanthus chips

3. The Cost Calculation Model

In the following chapter the basics of cost calculation are described (chapter 3.1). Based on this, the method applied for costs calculation in Renew is discussed (chapter 3.2.).

3.1. Basics of Cost Calculation

Basis of an economic assessment is the definition of a calculation model. Such models can be distinguished in models with one aim or models with several aims (compare [Götze, 2002]). Within this economic assessment it has been already decided which concepts/alternatives should be investigated. Thus, a "one-aim-model" is sufficient. Thereby economic numbers have to be determined and to be compared for these different concepts/alternatives.

As described (Del. 5.3.1, chapter 4.3.2), for such a calculation accepted dynamic[1] models are available. The most important calculation methods are compared in Table 3-1; detailed information on these methods and its calculation equations can be taken from [Wöhe, 1990], [Götze, 2002], [Schnitzer, 2001] and [Warnecke, 1996].

When comparing these methods the following conditions/assumptions are common:

* Availability of a (perfect) capital market; i.e. the interest rate is assumed as constant
* Calculation is based on receipts and expenditures in form of payments
* Payment level and payment time are considered as common (period start or end)
* The value of a payment depends on its time; payments of different times are converted into comparable payments by finance mathematic transformation (discounting or addition of accrued interest)

Independent of the common conditions/assumptions the following differences between these methods can be concluded:

* The method of capital value can be seen as the easiest method, since it is the basis for the other methods (internal interest rate and annuity).
* Interest rate and annuity lead to different aims as result of the calculation; thereby the annuity can be calculated as unique result and enables an easy interpretation (since it presents a average benefit).
* A principle ranking of the methods is not possible.

[1] Static calculation models are excluded since their inaccuracy is higher, the higher (i) the lifetime of an investment, (ii) the interest rate or the differences of payments in different periods. All aspects are of relevance when assessing large scale BtL-technologies.

Table 3-1: Advantages and disadvantages of investment appraisals [Götze, 2002]

Method	Advantages	Disadvantages
Capital value	- (necessary) pre-stage for annuity and internal interest rate - Low calculation effort - differentiated compilation of payments regarding time and amount	- no picture on rate of return; it shows only the overall result (over all periods) - low comparability between investments with different capital-related costs or different lifetimes
Annuity	- easy interpretation; annuity reflects an average benefit or average loss, i.e. period result	- no assignment of fluctuation payments to the periods (since they are average values)
Internal interest rate	- better interpretation compared to capital value: interest of bounded capital (profitability)	- calculation „only“ possible via interpolation - take-up of funds under internal interest rate are normally not meaningful. Thus, it should not be used for assessment of absolute advantage

3.2. Definition of the Calculation Method

Starting from the basics of cost calculation in the following chapter (i), the calculation model as well as (ii) the assumptions on cost development, and (iii) the parameter on sensitivity analysis will be described.

3.2.1. Calculation Model

An application oriented calculation model has been developed for the cost assessment. Thereby the calculation sequence follows accepted guidelines [VDI, 2000], [VDI, 1996].

This model determines annual costs of the period 0 by relevant cost factors (lifetime, interest rate etc.) and different cost types (capital-related, consumption-related, operation related and other costs). On the other hand annual revenues are considered (payments for main- and by-products). Figure 3-1 shows the calculation procedure of this model.

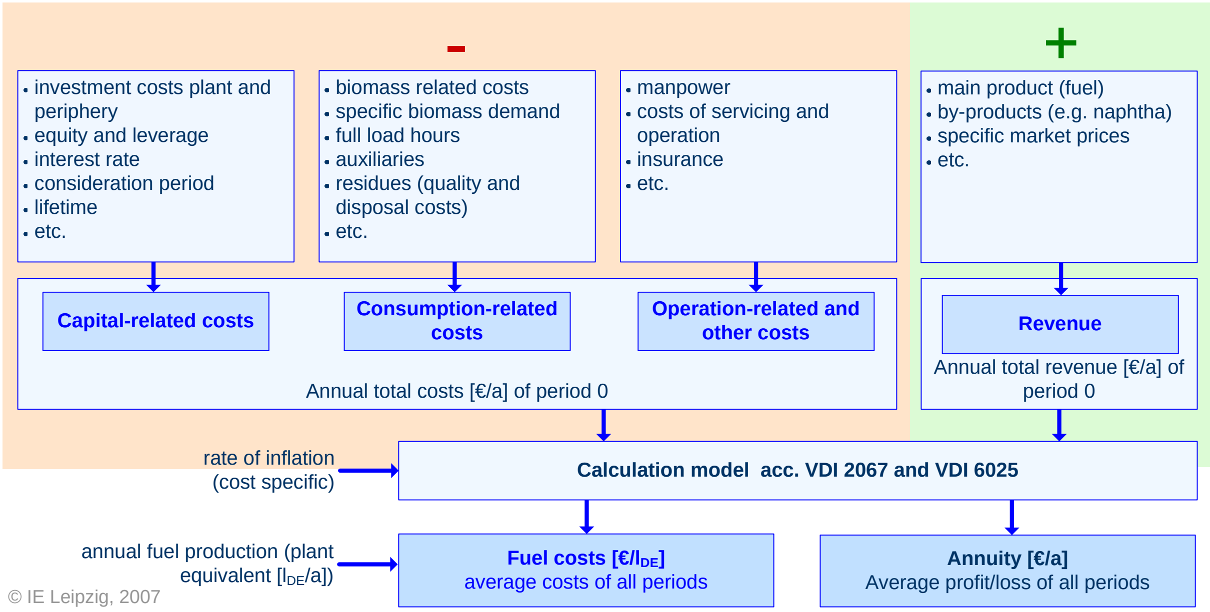


Figure 3-1: Cost calculation model

Based on this costs and revenues, the annuities of the different costs and revenues (and starting from this the overall-annuity [€/a], i.e. an average benefit or loss of all periods) can be calculated. The specific fuel production costs [€/l] or [€/GJ] can be calculated with regard to the annual production rate [l/a] or [GJ/a]. As a result of this calculation an assessment of the different concepts by both economic figures (annuity and fuel production costs) is possible.

3.2.2. Sensitivity Analysis

An option for analysing economic aspects under changing frame conditions is the so called sensitivity analysis. The aim of a sensitivity analysis is to check how sensible a decision-model reacts under changing frame conditions (like e. g. specific biomass costs). By applying this method, the dependence of economic figures and frame conditions and the range of potential results can be shown.

Therefore the following relevant parameters will be checked within the assessment of production costs:

* biomass provision costs free BtL plant gate
* BtL production capacity (economy of scale)
* investment costs (based on learning effects or price index)
* full load hours of the BtL plant
* applying future concepts: S1 technology

The prices of FT diesel, FT naphtha, heat, electricity and natural gas are influenced by the crude oil price. The oil price also has indirect but very strong impact on biomass provision costs. At the beginning of this project, it was chosen not to perform a sensitivity analysis for the different cost types, related to crude oil price. Instead, the calculation is based on a constant average oil price, founding on the price development as shown in Table 3-2.

Table 3-2: Development of spot crude oil price 2004 - 2006 [BP, 2007]

US-$/bbl	Dubai	Brent	Nigeria	West Texas	*Average*
2005	49.35	54.52	55.69	56.59	*54.04*
2006	61.50	65,14	67.07	66.02	*64.93*

Regarding a time frame from 2005 to 2006 for the cost calculation, a range of crude oil price from 55 to 65 US-$/Barrel can be assumed. This range is used to appreciate the product prices for naphtha, natural gas etc., which are summarised in chapter 5.1.

4. Short Description of the Concepts

At present the production of synthetic biofuels is under discussion for various options of biomass treatment, kind of gasification and gas cleaning up to the different options of synthesis and product-upgrading. Further on, it could be realised in different scales under usage of different types of solid biofuels. For all of these options also the scenarios defined in Del. 5.4.1 need to be considered. Starting from this variety the most relevant options of BtL-production will be assessed within Renew by seven different overall concepts. Figure 4-1 shows these options including the concept abbreviations and the partners responsible for data provision. Analysing these options in terms of economics the bandwidth of principle options of BtL-production will be assessed.

Concept	cEF-D	dEF-D	BLEF-DME	EF-E	CFB-D	ICFB-D	CFB-E
Scenario	SP MF SS	SP MF SS	SP MF SS	SP MF SS	SP MF SS	SP MF SS	SP MF SS
willow	eq.SP		eq.SP	eq.SP	eq.SP	eq.SS	eq.SP
straw	eq.SP	eq.SP			eq.SP		
miscantus						eq.SS	
Biomass input power [MW]	500	500	500	500	500	50	500
Pretreatment - mech. / thermal	drying	drying		drying	drying + pelletising	drying	drying
- thermochemical	carbonisation	pyrolysis	residue: black liquor (pulp mill)*	torrefaction	—	—	—
- location	plant	decentral	plant	plant	plant	plant	plant
Gasification	EF	EF	EF	EF	CFB	CFB	CFB
	chemical quench**	quench	quench	quench	autothermal	allothermal	allothermal
Gas cleaning / conditioning	conventional physical absorbtion:	conventional physical absorbtion:	conventional physical absorbtion:	conventional physical absorbtion:	dedicated technologies	dedicated technologies	conventional physical absorbtion:
	Selexol	Rectisol	Rectisol	Selexol			Selexol
Synthesis	TFBR, Co	SBCR, Co	MeOH, DME	no information	TFBR, Fe	SBCR, Fe	no information
Upgrading	Destillation, Hydrocracking	Destillation, Hydrocracking	Destillation	Destillation	external upgrading (refinery)	external upgrading (refinery)	Destillation
Plant product	FT-Diesel	FT-Diesel	DME	Ethanol	FT-raw-product	FT-raw-product	Ethanol
Data provision by	UET	FZK	CHEMREC	ABENGOA	CUTEC	TUV	ABENGOA

LEGEND

General
c central
d decentral
BL Black Liquor

Biomass input
willow
straw
miscantus

Synthesis
TFBR Turbular Fixed Bed Reactor
SBCR Slurry Bubble Column Reactor
MeOH, DME Methanol, DME Reactor
Fe, Co Ferrum - Iron, Cobalt

BtL output
DME Dimethylether
E Ethanol
FT-D / D Fischer-Tropsch Diesel
Fischer-Tropsch raw-product

Scenario
SP starting point
MF maximum biofuel
SS self sufficient
eq. equal

Gasification
EF Entrained Flow
CFB Circulating Fluidized Bed
ICFB Internally CFB

* no explicit thermochemical conversion step: residue of pulp mill
** temperature reduction via injection of char (primarily endothermal gasification reactions)

Figure 4-1: BtL-concepts considered within economic assessment

In the following these different concepts are described from an economic viewpoint. Thereby the description is based on the information provided by the respective Renew-partners (mentioned in Figure 4-1). For details and references see Del. 5.4.2.4.

4.1.1. Centralised Entrained Flow Gasification for FT-Diesel Production (cEF-D)

The production of FT-Diesel via entrained flow gasification of willow and straw is described by the cEF-D concept. Beside this main product also naphtha and electricity is produced. The biomass input power of this concept is 500 MW (over the fence of the overall plant). The information and data basis for this subsection was provided by UET (Choren Industries).

Concept Description – Scenario 'Starting Point'. In the starting point scenario, the biomass (willow salix or wheat straw) is converted into FT-Diesel without auxiliary energy. Thus, this scenario is equal to the self sufficient scenario. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pretreatment. The stored biomass is dried to the conditions of downstream processes by hot air (T ≈ 100 °C, air is preheated by low pressure steam) and fed to the lock hopper of the pyrolytic decomposition.

Thermochemical Pretreatment. A so called 'low-temperature gasifier' (NTV) is applied for pyrolytic decomposition of biomass. This aggregate, a horizontal cylindrical fixed bed reactor with rotating spindle (for mixing feedstock with hot material) is operated at 400 – 500 °C and under a gasification pressure of 35 bar. A hopper system ensures the feedstock pressurisation. To reach the decomposition temperature, biomass is partly oxidised by technical oxygen. As product, a so called low-temperature carbonisation gas (tar-containing) and char is feed to the downstream gasification.

Gasification. The carbonisation gas (with tar) is fed into the combustion chamber of a so called 'high-temperature gasifier' (an entrained flow reactor). Tar is reduced in the combustion chamber at high temperatures (T ≈ 1400 °C; p = 35 bar). The gasification agent is technical oxygen (produced at site by an air separation unit). A so called 'Chemical quenching' is done by blowing cooled and milled char into the hot gases downstream the combustion chamber. The endothermic gasification of the char causes a drop in gas temperature to 800 °C. The hot tar-free raw gas is then cooled in the heat exchanger producing high pressure steam (p = 40 – 45 bar) and low pressure steam (p = 5 bar) for power generation and other process parts. Ash particles and unconverted char are separated from the raw gas in the deduster. These are recycled back into the combustion chamber where it builds slag, which is removed from the bottom of the entrained flow reactor.

Gas Cleaning and Gas Conditioning. The main gas cleaning unit contains of two scrubbers. In the first scrubber, contaminants like chlorine and sulphur are washed out by acidic water. The second scrubber is a clear water scrubber, which is separating residual particles and washing agents (from first washer) from clean gas.

Adjusting the right H_2/CO-ratio is done by CO-conversion in the water-gas-shift reactor. The CO_2 in the clean gas is separated physically by a selexol washer. The fine gas cleaning (removal of O-, S- and Cl-traces) is ensured by a physical adsorption (e.g. ZnO), which is acting as a security guard for the synthesis reactor.

Further on, different gases from synthesis are looped back to the gas cleaning and gas conditioning unit; hydrogen is feed from this unit to synthesis and upgrading. For this conversion purpose, the upgrading technologies steam reforming (SMR) and pressure-swing-adsorption (PSA) are foreseen.

FT-Synthesis. A cobalt catalyst is applied in a Tubular-Fixed-Bed reactor (TFBR) for Fischer-Tropsch synthesis. Main products of the synthesis are long chain paraffins and wax for upgrading in the downstream hydrocracker. Beside this, naphtha (gasoline fraction of minor value) is produced as by product (for application as fuel, an additional isomerisation would be required). The reaction enthalpy of the synthesis is used for producing middle-pressure steam (p = 15 bar).

Upgrading. The long chain paraffins and waxes are cracked into smaller chains of the diesel fraction in a H_2-cracking process and simultaneously transformed into adequate isomers by isomerisation. The separation of the FT-raw products into the desired compositions is done in the distillation unit. The main product is FT-Diesel (BtL).

Utilities. The electrical consumption of the overall process is produced in an internal steam turbine. The steam is generated by superheating of unused process steam via surplus gas and small amounts of natural gas combustion (for optimized superheating). Surplus electricity is fed into the grid. Technical oxygen is produced by an air separation unit (ASU). Effluents of the process are handled in the water treatment and led into the sewage system. Surplus process water is used in the cooling tower to increase its cooling power. The different process steps are shown in Figure 4-2 for the starting point scenario.

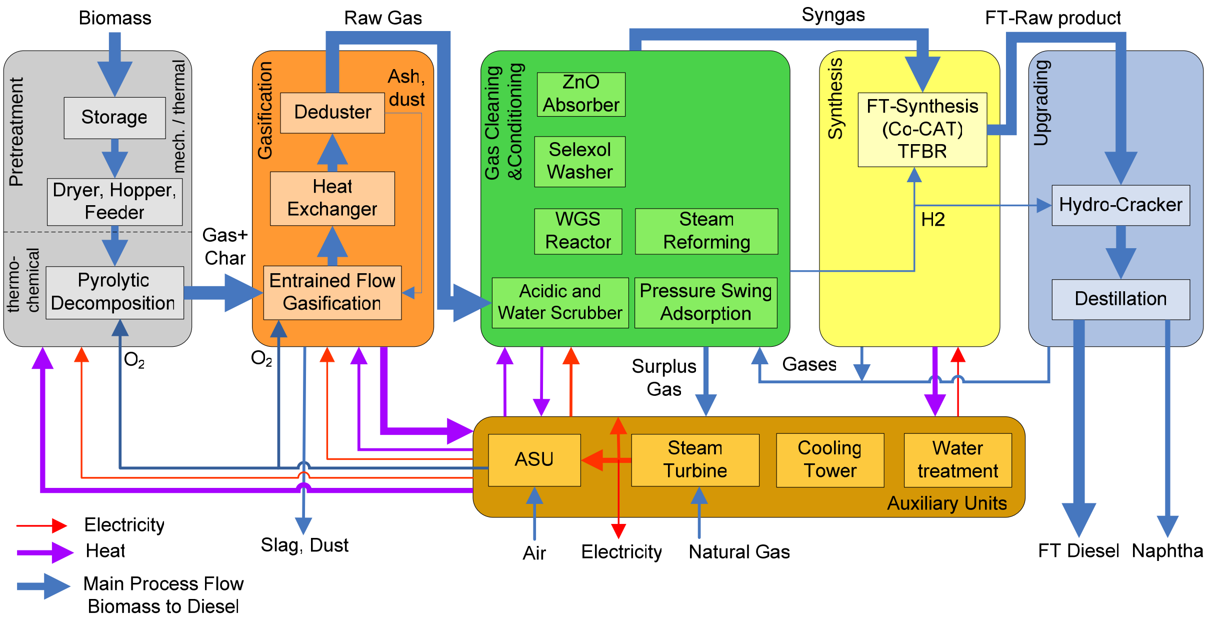


Figure 4-2: Simplified Process Flow of the cEF-D-Concept (SP)

In Figure 4-2, the main energy flows including heat transfer (steam, water, etc.) of the cEF-D-Concept (Scenario Starting Point, willow) are shown.

Process Description – Scenario 'Maximum Biofuel'. The biomass used in this scenario is willow salix. The process is the same as in the scenario 'Starting Point' except the following differences:

a) To achieve a higher carbon conversion and therewith higher fuel quantities, additional hydrogen is produced via electrolysis. The hydrogen is used in the synthesis unit and thus, no CO-Shift (WGS reactor) is required in the gas conditioning.

b) All CO_2 will be converted in the synthesis process. Hence, the selexol washer is not necessary.

c) The oxygen from electrolysis is used in the pretreatment and gasification units. Since the oxygen amount is sufficient for these processes, no air separation unit is needed. Surplus oxygen is foreseen for external use and credited as electricity for internal consumption in the assessment.

4.1.2. Decentralised Entrained Flow Gasification for FT-Diesel Production (dEF-D)

The production of FT-Diesel via entrained flow gasification of decentrally produced slurry (5×100 MW biomass input power) is described by the dEF-D concept. Beside this main product also naphtha and electricity is produced. The information and data basis for this subsection was provided by FZK (Forschungszentrum Karlsruhe).

Concept Description – Scenario 'Starting Point'. In the starting point scenario, the biomass (wheat straw) is converted into FT-Diesel without auxiliary energy. Thus, this scenario is equal to the self sufficient scenario. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pretreatment. The input material straw is pretreated decentralised at 5 pyrolysis plants with a biomass input of 100 MW. Therefore (after storing and drying by ventilation air), straw is crushed in a hammer mill and a chipper and fed to a conveyer dryer.

Thermochemical Pretreatment. A so called 'fast pyrolysis LR-mixer reactor' is applied for pyrolytic decomposition of biomass. This aggregate, a double-lead screw mixer reactor (for mixing feedstock with hot fluidized sand) is operated at 600 °C. Straw is thereby decomposed and char is separated from the 500 °C hot gas stream by a cyclone. The gas is split into pyrolysis oil and pyrolysis gas. After heat exchange, the gas is used in a gas burner to supply heat to the heat transfer medium (sand). Char, organic liquids and water form the so called 'slurry'; The water remains in the slurry (no phase separation occurs before supply free gasification plant gate).

Gasification. The slurry is taken from 5 fast pyrolysis plants and transported to one syngas plant, where it is mixed and preheated for gasification up to a temperature of 125 °C. The hot slurry is fed to an entrained flow gasifier (pressurised to p = 80 bar). The tar-content is limited by high gas temperatures (T ≈ 1200 °C). The gasification agent is technical oxygen (imported from outside 'over-the-fence'). The cooling of the raw gas is done via heat exchanger (producing steam of 600 °C) and a water quench.

Gas Cleaning and Gas Conditioning. Ash and particles are separated from the 500 °C hot raw gas in a water scrubber. A two-stage rectisol process is used for further gas cleaning and gas conditioning. In the first stage, impurities like H_2S and COS but also CO_2 are separated form the raw gas. In the second step, the clean gas stream is split: one part goes directly to synthesis; the other part is used for adjusting the right H_2/CO-ratio.

This is done by CO-Conversion in the water-gas-shift reactor. The resulting CO_2 in this second part of the clean gas is separated physically by the second-stage of the rectisol washer.

Further on, light hydrocarbons (C5) from the synthesis along with light ends from the distillation and from the hydrocracker are converted by an autothermal reforming process

(ATR) into CO and H_2. Hydrogen is separated by a pressure-swing-adsorption unit (PSA) and used in the synthesis and steam generation.

FT-Synthesis. A cobalt catalyst is applied in a low temperature slurry bubble column reactor (SBCR) for Fischer-Tropsch synthesis. Main products of the synthesis are long chain paraffins and wax for upgrading in the HPC-unit (a hydrocracker). Beside this, naphtha (gasoline fraction of minor value) is produced as by-product (for application as fuel, an additional isomerisation would be required). The reaction enthalpy of the synthesis is used for producing steam (T = 200 °C).

Upgrading. The light hydrocarbons (C5) are separated from the FT-raw product in the work-up rectification unit. The remaining raw product is left for upgrading.

Utilities. The electrical consumption of the overall process is produced in an internal steam turbine. The steam is generated by superheating of unused process steam via surplus gas from the PSA-unit. Surplus electricity is fed into the grid. Technical oxygen is imported from outside. Effluents of the process are handled in the water treatment and led into the sewage system.

The different process steps are shown in Figure 4-3 for the starting point scenario.

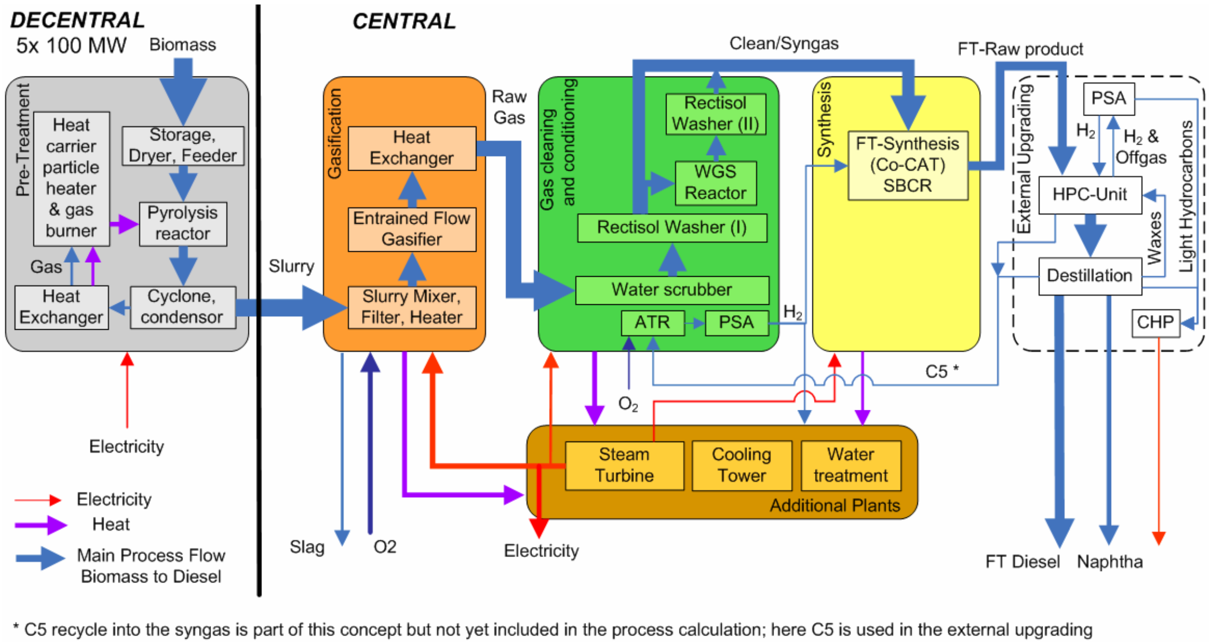


Figure 4-3: Simplified Process Flow of the dEF-D-Concept

In Figure 4-3 the main energy flows including heat transfer of the dEF-D-Concept (Starting Point, straw) are shown.

Process Description – Scenario ‘Maximum Biofuel’. The biomass used in this scenario is wheat straw. The process is the same as in the scenario ‘Starting Point’ except the following differences:

a) To achieve a higher carbon conversion and therewith higher fuel quantities, additional hydrogen is produced via electrolysis. The hydrogen is used in the synthesis unit and thus, no CO-Shift (WGS reactor) is required in the gas conditioning

b) All CO_2 will be converted in the synthesis process. Hence, the 2nd stage of the rectisol washer is not necessary
c) The oxygen from electrolysis is used in the gasification unit. Since the oxygen amount is sufficient for these processes. No external oxygen has to be imported over the fence, but surplus oxygen is foreseen for external use and credited as electricity for internal consumption in the assessment.

4.1.3. Entrained Flow Gasification of Black-liquor for DME Production (BLEF-DME)

The production of DME via entrained flow gasification of black liquor is described by the BLEF-DME concept. The biomass input power of this concept is 500 MW (over the fence of the overall plant). The information and data basis for this subsection was provided by Chemrec.

Concept Description – Scenario 'Starting Point'. In the starting point scenario the gasification of black liquor is combined with a DME(Di-Methyl-Ether)-synthesis. Thereby the black liquior is taken from a pulp mill; i. e. the DME-production is an additional process of this mill but integrated in the mass and energy flows: Instead of using black liquor in a boiler (like it is done in commercial pulp mills) it is gasified and green liquor is recirculated to the mill. The original heat and power production via the black liquor boiler is compensated via biomass combustion in two separate boilers. This power of the 'compensation boiler' corresponds to a power of 500 MW. Neither electricity nor district heat is imported or exported 'over the fence', i.e. the BtL-plant including pulp mill is self sufficient. Hence, this scenario is reflects also the self sufficient scenario. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pre-treatment. The stored biomass is dried and chopped to the conditions of combustion processes in a modern circulating fluidized bed boiler. Despite this feedstock for the boiler, the gasification media black liquor from the mill is filtered and heated up to a temperature of 120 °C for downstream gasification.

Gasification. Preheated black liquor is fed into four entrained flow gasifiers pressurised to p = 32 bar, with a capacity of each 167 MW (4 x 33 % = 133 % of full load). Necessary for this plant scale would be the usage of three reactors; one additional reactor is set up to increase the availability of the plant. Thus, if one reactor fails, a stand-still of the pulp mill can be avoided. The tar-content is limited by high flame temperatures in the entrained flow gasifier. The gasification agent is technical oxygen (produced at site by an air separation unit). Quenching is done by spraying condensate into a quench pipe tube, and after the quench smelt droplets and the raw gas are separated. The smelt droplets dissolve in the liquid forming green liquor, which is fed back to the pulp mill after cooling. The quench causes a drop in gas temperature to 220 °C.

Gas Cleaning and Gas Conditioning. The saturated raw gas is then cooled and cleaned in the 'combined cooling and washing system'. Particulates water and small amounts of organic material are removed from the raw gas via cooling the raw gas in a counter current condenser producing steam (pressure: p = 10 resp. 4 bar). This steam is feed to the pulp mill. The BLEF-

DME concept is considering a two-stage rectisol process. In the first stage traces of tars are removed followed by H_2S and COS but also CO_2. In the second step, the clean gas stream is split: one part goes directly to synthesis; the other part is used for adjusting the right H_2/CO-ratio.

This is done by CO-conversion in the water-gas-shift reactor. The resulting CO_2 in this second part of the clean gas is separated physically by the second-stage of the rectisol washer.

DME/Methanol-synthesis. DME is produced conventionally from the intermediate product Methanol. The syngas is compressed before entering the first reactor. Two reactors are used: a methanol reactor and a DME reactor. In the methanol reactor, CO_2 and H_2 are converted into MeOH and H_2O and the water-gas-shift reaction takes place. The DME raw product is produced preliminary from MeOH by separation of water in the DME-Reactor. The reaction enthalpy of the synthesis is used for producing high-pressure steam.

Upgrading. Dissolved light gases are separated from the DME raw product at low pressure in a separator. The distillation of the raw product is done in a three-stage distillation unit. The first separates the by-products and send it to the boiler. The second separates methanol for recycle and the third produces pure DME and process water (which is send to the waste water treatment plant).

Utilities. Biomass is imported to the mill site in order to produce steam and electricity to make the pulp mill and the BtL plant self-sustained. Technical oxygen is produced by an air separation unit. Effluents of the process are handled in the water treatment and led into the sewage system.

The different process steps are shown in Figure 4-4 for the starting point scenario.

In Figure 4-4 the main energy flows including heat transfer (steam, water, etc.) of the BLEF-DME Concept (Scenario Starting Point) are shown.

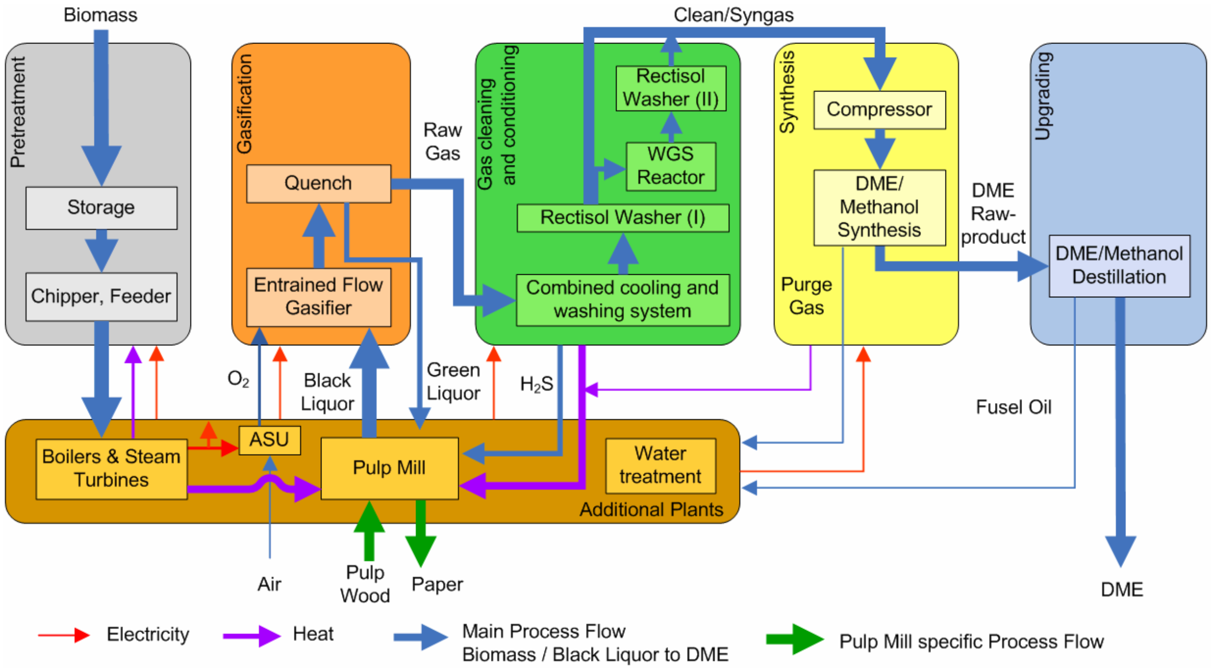


Figure 4-4: Simplified Process Flow of the BLEF-DME-Concept; Figures in MW

4.1.4. Centralised Entrained Flow Gasification for Ethanol Production (EF-E)

The production of Ethanol via entrained flow gasification of willow is described by the EF-E concept. Beside this main product, also methanol, propanol and electricity are produced. The biomass input power of this concept is 500 MW (over the fence of the overall plant). The information and data basis for this subsection was provided by Abengoa.

Concept Description – Scenario 'Starting Point'. In the starting point scenario, biomass (willow salix) is converted into Ethanol without auxiliary energy. Thus, this scenario is equal to the self sufficient scenario. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pretreatment. The stored biomass is dried to the conditions of downstream processes by a direct steam dryer (mid pressure steam; T= 309 °C; p = 12 bar).

Thermochemical Pretreatment. As part of the preparation for downstream gasification, the biomass is fed to a torrefaction unit and milled to char dust afterwards. A hopper system ensures the feedstock pressurisation (p = 40 bar). Compressed CO_2 inert gas is used for the pneumatic transport and feeding.

Gasification. The char dust is fed to an entrained flow reactor pressurised to p = 40 bar. The tar-content is limited by the high gas temperatures (T ≈ 1300 °C). The gasification agents are technical oxygen (produced at site by an air separation unit), CO_2 (from gas washing system) and high pressure steam (p = 40 bar).

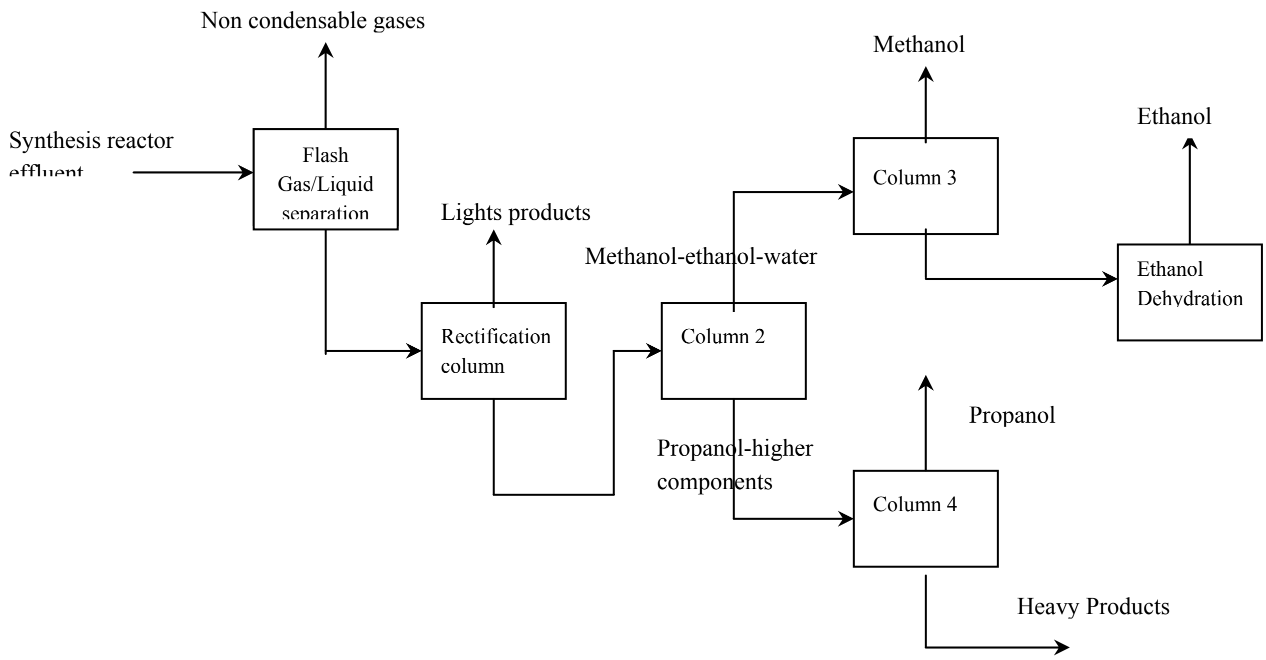
Gas Cleaning and Gas Conditioning. The hot tar-free raw gas is then cooled down to 65 °C in the heat exchanger producing high pressure steam (T = 537 °C; p = 55 bar) for power generation and other process parts. H_2S is separated from the raw gas in the so called LO-

CAT®-unit (unfortunately the data provider did not supply specific information about the function of this catalyst unit) and a ZnO-adsorber.

Adjusting the right H_2/CO-ratio is done by CO-conversion of a part of the raw gas stream in the water-gas-shift reactor. Downstream of the CO-Shift-reactor, the water is removed from the joint stream by reducing the temperature to 50 °C. Then, the gas is fed directly to the selexol washer for CO_2 removal. Before entering the synthesis reactor, the syngas is compressed to 70 bars which is the pressure required by the downstream synthesis reactions.

Ethanol-Synthesis. An alcohol synthesis reactor is used for syngas synthesis (T = 300 °C, p = 70 bar). The main product of the synthesis is ethanol. By-products are methanol, propanol, methane, ethane, butanol, pentanol, CO_2 and water. The reaction enthalpy of the synthesis is used for producing high pressure steam (p = 55 bar) from high pressure water.

Upgrading. A gas/liquid separator is used to separate reactants, CO_2 and light hydrocarbons (methane) from the raw product. Further, light products, methanol, propanol and heavy water are separated from ethanol in four rectification columns. Finally, water is separated from ethanol in a dehydration unit.



Utilities. The electrical consumption of the overall process is produced in an internal gas turbine by combustion a part of the gases from gas/liquid separation. The steam from the power generation unit is used within the process (e.g. for distillation). Surplus electricity is fed to the grid. Technical oxygen is produced by an air separation unit. Effluents of the process are handled in the water treatment and led into the sewage system. The concept provider did not specify in which processes the high pressure steam generated in the heat exchanger after the gasifier and the synthesis reactor is used.

The different process steps are shown in Figure 4-5 for the starting point scenario. Also, the main energy flows including heat transfer (steam, water, etc.) of the EF-E-Concept (Scenario Starting Point, Biomass input wood) are shown.

Process Description – Scenario 'Maximum Biofuel'. The biomass used in this scenario is willow salix. The process is the same as in the scenario 'Starting Point' except the following differences:

a) recycled syngas from ethanol synthesis is converted by a steam reforming process (SMR) into CO and H_2 and fed back to the clean gas
b) the heat for the steam reforming unit is supplied by natural gas
c) the electricity for compressing syngas, O_2 and CO_2 is taken from the grid, the gas turbine is not necessary

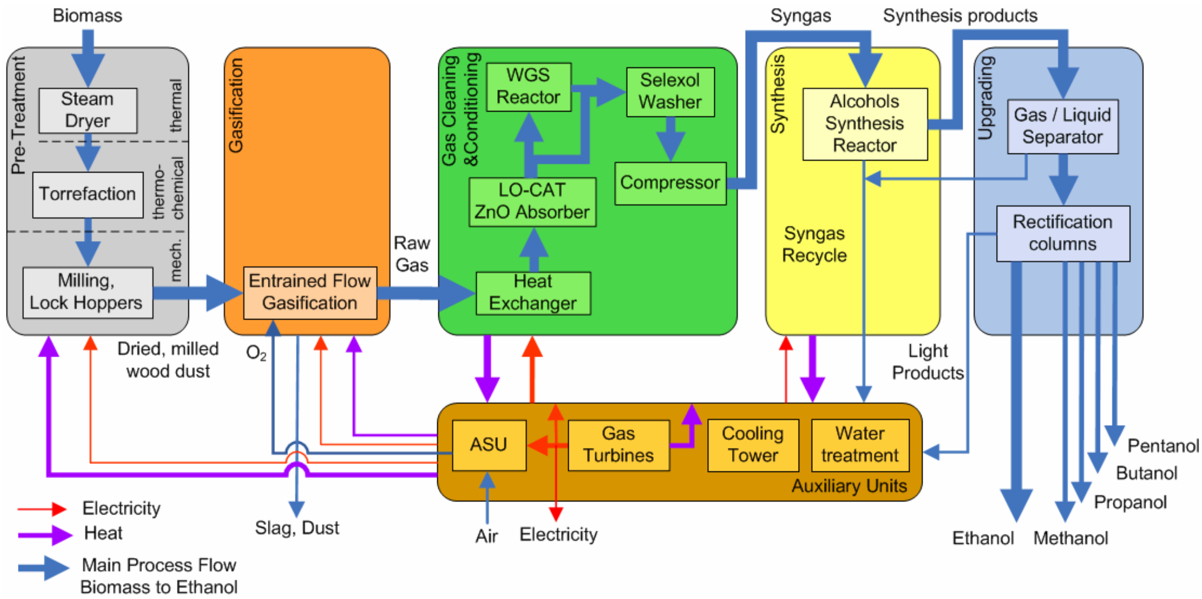


Figure 4-5: Simplified Process Flow of the EF-E-Concept (Starting Point)

4.1.5. Centralised Autothermal CFB-Gasification for FT-Diesel Production (CFB-D)

The production of FT-Diesel via CFB gasification of willow and straw is described by the CFB-D concept. Beside this main product also naphtha is produced. The biomass input power of this concept is 500 MW (over the fence of the overall plant). The information and data basis for this subsection was provided by the CUTEC-Institute.

Concept Description – Scenario 'Starting Point'. In the starting point scenario, the biomass (willow salix or wheat straw) is converted into FT-Diesel without auxiliary energy. Thus, this scenario is equal to the self sufficient scenario. In the scenario with willow salix as biomass input, surplus electricity is fed to the grid. In the scenario with wheat straw as biomass input, external electricity is imported 'over-the-fence'. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pretreatment. The delivered biomass is chipped and dried in a conveyer dryer. In case of wood as input material additionally metals are removed by the metal separation unit. Afterwards, the wood chips or straw are stored and fed to the gasifier.

Thermochemical Pretreatment. No thermochemical pretreatment is needed in this concept.

Gasification. The dry biomass is are fed to five circulating fluidized bed gasifier with a capacity of each 100 MW (5x20%), i.e. they are operated in parallel. The heat for gasification is supplied by oxidation of part of the biomass (autothermal concept). The gasifier works at temperatures of 950 °C and atmospheric pressure. The gasification agent consists of technical oxygen (produced at site by an air separation unit) and water steam (produced from treated waste water). The bed material is sand. At the exit of the gasifier (two phase stream of raw gas and sand) the solid material is separated from the raw gas in a cyclone and fed back to the gasifier.

Gas Cleaning and Gas Conditioning. A hot gas dedusting (by a battery of ceramic filters) is applied to remove particulates from the raw gas. To reduce the tar and adjust the H_2/CO-ratio a combined reactor is applied. This unit adjusts the right H_2/CO-ratio by CO-conversion in the water-gas-shift part; tar in the raw gas stream is removed by a Ni-catalyst. Afterwards, the raw gas is cooled down to 30 °C in a heat exchanger, producing low pressure steam at 110 °C. The removal of impurities like H_2S and NH_3 is done by absorption in a gas quench and water scrubber. Further tar impurities are dissolved and condensed at low temperature (6 °C) in a biodiesel scrubber. The tar-polluted biodiesel is partially discharged to the gasifier for combustion. The clean syngas is compressed to a pressure of 25 bar, which is necessary for FT-synthesis. The impurity carbonyl sulphide is catalytically converted with the help of hydrogen to CO and H_2S in a catalytical hydrogenation unit. Further, hydrogen sulphide is reduced to pure sulphide in a so called ‘oxidizing wash’ unit. The CO_2 in the clean gas is separated physically by a selexol washer. The fine gas cleaning (guard bed) is done in a ZnO-adsorber.

FT-Synthesis. A cobalt catalyst is applied in a Tubular-Fixed-Bed reactor (TFBR) for Fischer-Tropsch synthesis (T = 220 – 250 °C; p = 20 – 30 bars). Main products of the synthesis are long chain paraffins and waxes. The reaction enthalpy of the synthesis is used energetically in the process.

Upgrading. The light hydrocarbons (C1-C4) are separated from the FT-raw product in the work-up rectification unit and used within the gas turbine process. The remaining raw product is foreseen to be delivered for upgrading to a commercial refinery.

Utilities. The electrical consumption of the overall process is produced in a gas turbine. Surplus electricity is fed into the grid. Technical oxygen is produced by an air separation unit. Effluents of the process are handled in the water treatment and led into the sewage system. Surplus process water is used in the cooling tower to increase its cooling power.

The different process steps are shown in Figure 4-6 for the starting point scenario (willow salix; for straw electricity has to be imported from the grid).

In Figure 4-6 the main energy flows including heat transfer (steam, water, etc.) of the CFB-D-Concept (Scenario Starting Point, Biomass input wood) are shown.

Process Description – Scenario 'Maximum Biofuel'. The biomass used in this scenario is willow salix or wheat straw. The process is the same as in the scenario 'Starting Point' except the following differences:

a) To achieve a higher carbon conversion and therewith higher fuel quantities, additional hydrogen is produced via electrolysis. The hydrogen is used in the synthesis unit and thus, no CO-Shift (WGS reactor) is required in the gas conditioning

b) The oxygen from electrolysis is used in the gasification units. Since the oxygen amount is not sufficient for these processes, air separation unit is still required.

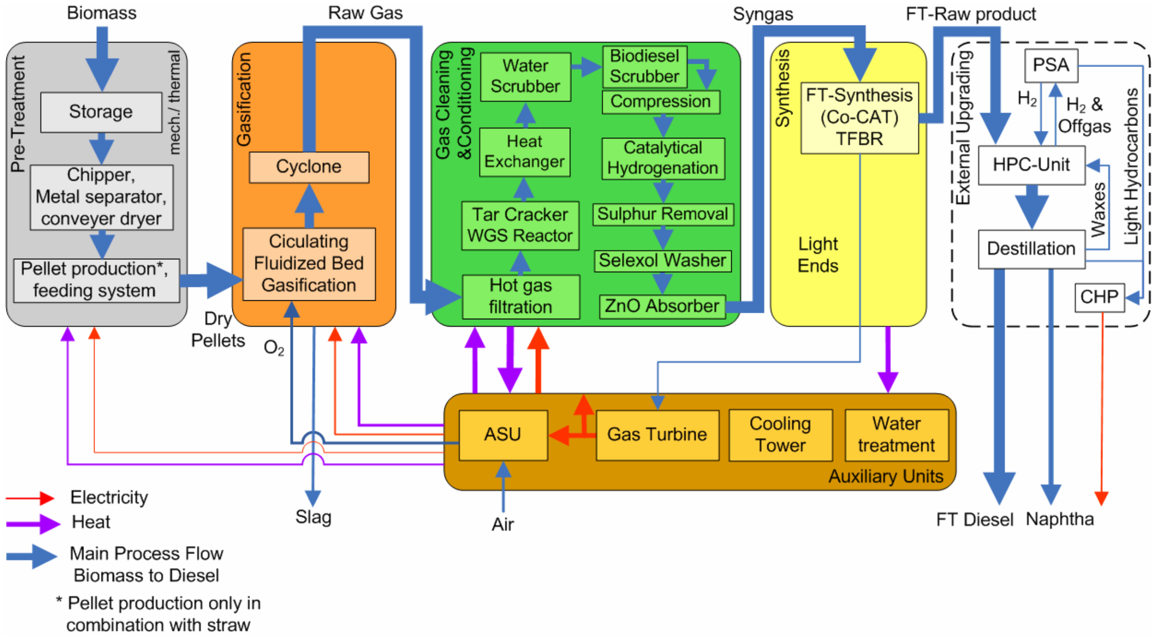


Figure 4-6: Simplified Process Flow of the CFB-D-Concept

4.1.6. Allothermal CFB-Gasification for FT-Diesel Production (ICFB-D)

The production of FT-Diesel via fast internally circulating fluidized bed gasification of willow and miscanthus is described by the ICFB-D concept. Beside this main product also naphtha, electricity and district heat (only in starting point scenario) is produced [TUV, 2006]. The biomass input power differs between the following concepts. The information and data basis for this subsection was provided by the Technical University of Vienna.

Concept Description – Scenario 'Starting Point'. In the starting point scenario, the biomass input power of 50 MW is taken for tri-generation of FT-Diesel, electricity and district heat. The concepts are based on willow salix and miscanthus. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pretreatment. Biomass is stored and chipped at site. The woody chips are dried in a drum dryer. Afterwards, the biomass is stored and fed to the gasifier.

Thermochemical Pretreatment. No thermochemical pretreatement is needed in this concept.

Gasification. A so called fast internal circulating fluidized bed gasifier (FICFB) is used in this concept. This reactor is divided into two fluidized beds, a gasification zone and a combustion zone. Between both zones, a circulation loop of bed material acts as heat carrier from the combustion to the gasification zone. Thus, the water steam (produced from treated waste water by waste heat) can be applied as gasification agent instead of oxygen. The bed material, together with some charcoal, circulates to the combustion zone. This zone is fluidized with air and the charcoal is partly burned. The exothermic reaction in the combustion zone provides the energy for the endothermic gasification with steam. The flue gas will be removed without coming in contact with the raw gas. Hence, the gas produced in the gasification zone (raw gas) is nearly free of nitrogen.

Gas Cleaning and Gas Conditioning. The gas cleaning unit contains of two lines: one for the raw gas cleaning and another for the flue gas cleaning. After the gasifier, dust is removed from the raw gas by a hot gas deduster (cyclone) and the gas is cooled by a heat exchanger. Around 30 % of tar is removed from the raw gas stream in fabric filters. Remaining tar is washed out in a biodiesel scrubber (RME). Residues of these gas cleaning units are recycled back to the combustion zone of the gasifier. After a booster compressor and a cooling and condensing unit, the gas is entering a 2-stage compressor, where it is pressurized 35 bars. The fine gas cleaning (removal of H_2S and HCl-traces) is ensured by a HDS-catalyst and a ZnO-absorber, which is acting as a security guard for the synthesis reactor.

Flue gas is treated in the second line of gas cleaning for post-combustion and heat generation. After the combustion zone, dust is separated from the flue gas steam via a cyclone. In the post-combustion, the combustible components of the flue gas are oxidized, generating heat, which is recovered by heat exchangers and used in the ORC plant and the drum dryer.

In this concept, no gas conditioning is considered.

FT-Synthesis. A cobalt catalyst is applied in a slurry bubble column reactor (SBCR) for Fischer-Tropsch synthesis. Main products of the synthesis are long chain paraffins and wax. The separation of the catalyst from the products is done in a sedimentation unit and a filtration unit. Both units are integrated into the FT-synthesis. The remaining raw product is foreseen to be delivered for upgrading to a commercial refinery.

Upgrading. The light hydrocarbons (C1-C4) are separated from the FT-raw product in the work-up rectification unit. The remaining raw product is foreseen to be delivered for upgrading to a commercial refinery

Utilities. The electrical consumption of the overall process is produced internally by a gas turbine (by combustion of recycled syngas) and an organic rankine cycle plant. The ORC plant uses the heat recovered by the heat exchanger in the process. The steam for gasification is generated via waste heat. Surplus electricity is fed into the grid. Surplus heat is used externally as district heat. Because of the scale, the ICFB-D concept is the only concept, which considers heat as output. Effluents of the process are handled in the water treatment and led into the sewage system.

The different process steps are shown in Figure 4-7 for the starting point scenario.

Process Description – Scenario 'Maximum Biofuel'. In the maximum biofuel scenario, the biomass (willow salix or miscanthus) is converted into FT-Diesel without auxiliary energy.

Thus, this scenario is equal to the self sufficient scenario. The process is the same as in the scenario ‘Starting Point’ except the following differences:

a) the biomass input fuel power is 500 MW
b) the aim of the concept is not tri-generation (like in the starting point scenario) but a maximised diesel production with self sufficiency, at this fuel optimised concept on large scale, district heat is not considered as output product
c) the gasifier is operated under pressure
d) the gas cleaning is different and additional conditioning is installed (e.g. steam reformer); thus, it will be described in the following
e) recycled syngas from FT-synthesis is converted by a steam reforming process (SMR) into CO and H_2 and fed back to the clean gas

Gas Cleaning and Gas Conditioning. After the gasifier, dust is removed from the raw gas. Then it is mixed with the recycled syngas from synthesis and converted by a steam reforming process (SMR) into CO and H_2. Now the gas is cooled and impurities are filtered out. A ZnO-absorber is applied for fine gas cleaning (removal of H_2S and HCl-traces). In this concept, no biodiesel scrubber is applied.

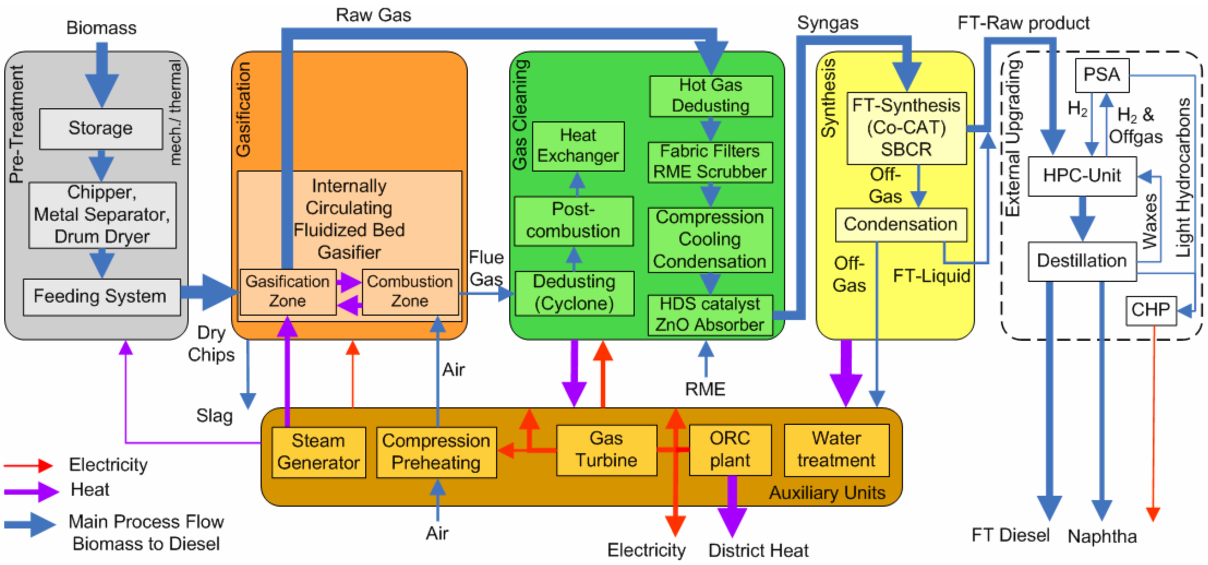


Figure 4-7: Simplified Process Flow of the ICFB-D-Concept

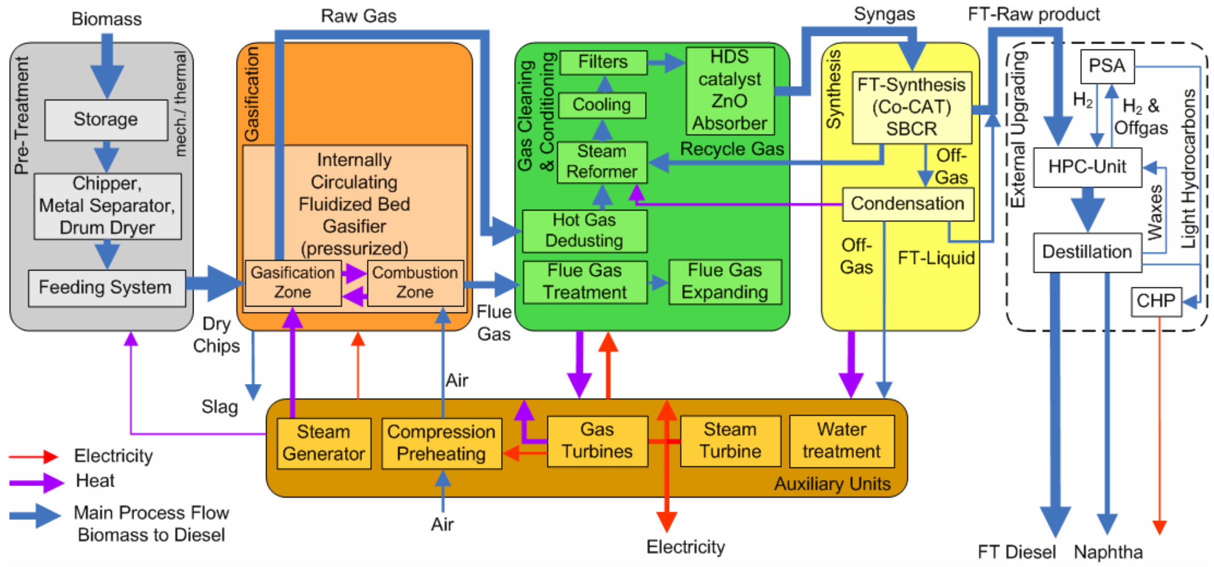


Figure 4-8: Simplified Process Flow of the ICFB-D-Concept (Maximum Biofuel, willow); Figures in MW

4.1.7. Allothermal CFB-Gasification for Ethanol Production (CFB-E)

The production of Ethanol via circulating fluidized bed gasification of willow is described by the CFB-E concept. Beside this main product, also methanol, propanol and electricity are produced. The biomass input power of this concept is 500 MW (over the fence of the overall plant). The information and data basis for this subsection was provided by Abengoa.

Concept Description – Scenario 'Starting Point'. In the starting point scenario, biomass (willow salix) is converted into Ethanol without auxiliary energy. Thus, this scenario is equal to the self sufficient scenario. In the following, the main steps of the conversion process are described.

Mechanical and Thermal Pretreatment. The stored wood is dried to the conditions of downstream processes by a direct steam dryer (mid pressure steam; T= 309 °C; p = 12 bar). A hammer mill decreases the wood size to the requirements of the fluidized bed gasification.

Thermochemical Pretreatment. No thermochemical pretreatment is needed in this concept.

Gasification. The dried and milled wood is fed to a circulating fluidized bed reactor. The reactor works at 850 °C and 2 bars. Mineral olivine (a magnesium iron silicate) is used as heat transfer media for the endothermic gasification reactions. It is heated by the combustion of unconverted char in an additional char combustor, which is fed with recycled syngas and air (see description of the ICFB-D-concepts). The gasification agent is mid pressure steam (p = 20 bar).

Gas Cleaning and Gas Conditioning. A catalytic tar reformer is applied for destroying methane and ammonia in the raw gas. It is powered by recycled syngas and operating at a temperature of 870 °C. The hot tar-free raw gas is then cooled down to 65 °C in the heat exchanger producing high pressure steam (T = 537 °C; p = 55 bar) for power generation and other process parts. H_2S is separated from the raw gas in the LO-CAT® (unfortunately the data provider did not supply specific information about the function of this catalyst unit) and a ZnO-adsorber.

Adjusting the right H_2/CO-ratio is done by CO-conversion of a part of the raw gas stream in the water-gas-shift reactor. Downstream of the CO-Shift-reactor the water is removed from the joint stream by reducing the temperature to 50 °C. Then the gas is fed directly to the Selexol washer for CO_2 removal.

Before entering the synthesis reactor, the syngas is compressed to 70 bars which is the pressure required by the downstream synthesis reactions.

Ethanol-Synthesis. An alcohol synthesis reactor is used for syngas synthesis (T = 300 °C, p = 70 bar). The main product of the synthesis is ethanol. By-products are methanol, propanol, methane, ethane, butanol and pentanol. The reaction enthalpy of the synthesis is used for producing high pressure steam (p = 55 bar) from high pressure water.

Upgrading. A gas/liquid separator is used to separate reactants, CO_2 and light hydrocarbons (methane) from the raw product. Further, light products, methanol, propanol and heavy water are separated from ethanol in four rectification columns. Finally, water is separated from ethanol in a dehydration unit.

Utilities. The electrical consumption of the overall process is produced in an internal gas turbine by combustion a part of the gases from gas/liquid separation. The steam from the power generation unit is used within the process (e.g. for distillation). Surplus electricity is fed to the grid. Effluents of the process are handled in the water treatment and led into the sewage system. The concept provider did not specify in which processes the high pressure steam generated in the heat exchanger after the gasifier and the synthesis reactor is used.

The different process steps are shown in Figure 4-9 for the starting point scenario.

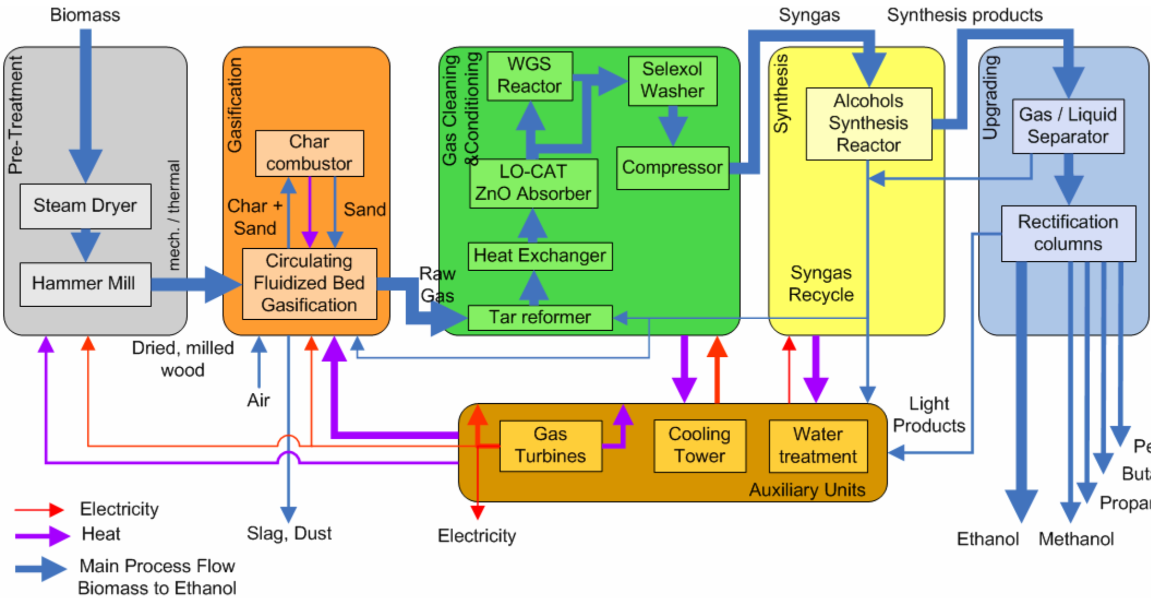


Figure 4-9: Simplified Process Flow of the CFB-E-Concept

5. Original Data

Within chapter 3 the cost calculation model has been described. Based on this, the original data used for the production cost calculation (including the bandwidths of the sensitivity analyses) will be shown in the following chapter. Thereby the data results from existing studies (like e.g. in the field of BtL-concepts or IGCC-plants) that allows a transmission on the frame conditions of the concepts described above was used.

Furthermore, it has been fixed not to consider taxes or subsidies. This applies also for declining balances.

Regarding the original data it is also of importance, that 1 US-$ is equivalent to 1 € , based on the exchange rate of the United States Dollar to the Euro in the time frame of January 2000 and April 2006 [IEA, 2003].

As described in chapter 3.2.2, the development crude oil price was not considered. Instead, a fixed bandwidth for this price was defined, using the spot oil prices of 2005 and 2006 (Table 3-2).

5.1. Economic Frame Conditions

The economic frame conditions required for the cost model have to be described in detail regarding (i) basic conditions, (ii) conditions of capital-related costs, (iii) conditions of consumption-related costs, (iii) conditions of operation-related costs, and (iv) conditions of other costs and revenues. These aspects are discussed in the following.

5.1.1. Basic conditions

Period under consideration:	20 years
Imputed interest:	10 %, based on leverage and equity of different studies [Consonni, 2003], [Ekbom, 2005]
Rate of inflation:	3 % for consumption- and operation-related costs, 2 % for capital-related, other costs and revenues [Consonni, 2003], [VDI, 2000].

Thereby it should be mentioned that these inflation rates are only considered for the period under consideration and are not distinguished between the different time horizons of the scenarios. This means that the economic data of the time frame 2004 (SP) and 2020 (S1) can be directly compared.

In some studies it is considered that new technologies need a higher effort on start-up within the first operation year. For example [Consonni, 2003] describes a rate of 80 % for the first year. Within Renew economic assessment the assumption is an efficiency of 100 % of the designed case and an operation under 100 % of full load hours of the designed case. Additional costs are implemented within the capital-related costs in order to achieve these values (see above).

5.1.2. Conditions of capital-related costs

Capital-related costs consist of investment costs and maintenance costs (compare VDI, 2000). They will be explained in the following. Costs for deconstruction and disposal after 20 years operation time are not included; costs for land and urbanisation are also not included.

Furthermore time related differences of investment cost data (like e.g. data from 1999 and data from 2001) are assumed as equalised by technical development.

Investment costs. The determination of overall investment costs is based on the method of additional/overhead costs. The aggregates costs required have been determined by up- or downscale of existing costs data for similar devices. Thereby for some components literature data is available; for some components (like e.g. pyrolysis) only rough estimations of technology developers exist. Furthermore, the investment costs could not be calculated on an equivalent basis between all Renew concepts because this would have required a much more detailed engineering type study, which was beyond the scope of Renew.

The investment cost figures given were calculated with references from literature dating from 2004 or before. Therefore the very sharp cost increase in the engineering and construction industries which has taken place since 2005 is not at all reflected in the Renew cost assessment. As a rough figure, an increase of 50 up to 100% could be expected for BtL type investment costs. Due to this, variations of the investment costs were considered within the sensitivity analysis in chapter 6.2.3.

Main components. The main components for the system components (pre-treatment, gasification, gas cleaning, gas conditioning, synthesis, up-grading) and the utilities (power generation, air separation unit etc.) can be determined based on the concepts defined above. For these components the relevant technical data (mass- and energy flows, scale factors, maximum scale) have been derived from the concept descriptions (delivered by SP1-4).

Installation factors. Based on the investment costs of the main components, the total cost of investment (TCI) can be determined via installation factors. Thereby direct or indirect single factors or overall factors from the literature have been used. When no information on installation factors was available, the TCI have been calculated according Table 5-1.

According to Faaij and Hamelinck; an overall installation factor of 1.54 (1.66) can be applied for a 500 MW (50 MW) BtL-plant. These factors result from 23 % (33 %) additional investment costs (direct auxiliary costs) of hardware and 25 % (25 %) indirect auxiliary costs of investment. 10 % have been applied for engineering costs [Hamelinck, 2004], [Faaij, 2001].

Table 5-1: Installation factors depending on the plant scale

Biomass power	500 MW	50 MW
direct costs		
measurement and control	2,50%	5,00%
buildings	1,40%	1,50%
power connexion	2,10%	5,00%
site preparation	0,50%	0,50%
civil works, property	9,20%	10,00%
Electronics	3,50%	7,00%
pipe work	4,00%	4,00%
installation factor (direct costs)	1,23	1,33
indirect costs		
Engineering	10,00%	10,00%
interest rate of construction time	10,00%	10,00%
start-up-costs	5,00%	5,00%
installation factor (indirect costs)	1,25	1,25
installation factor (total)	1,54	1,66

Most of the investment cost data is based on estimations with accuracy of ± 25 %, the influence of deviation will be analysed via sensitivity analysis. Thereby an adequate range has to be considered, for details see chapter 6.2.3.

Maintenance costs. According to VDI 2067 maintenance consists of “preserving and restoring the desired status and determining and assessing the actual status of a systems technical structure”. Therewith “maintenance includes servicing, inspection and repairs” [VDI, 2000].

As a result of lack of data on maintenance costs, this aspect can not be considered directly. Therefore higher costs for servicing (measures for preserving the desired status of a system technical structures) are foreseen (compare chapter 5.1.4).

Summary. Based on the frame conditions and its fluctuations the following data will be applied:

Table 5-2: Frame conditions of the capital-related costs

Parameter	Frame condition
Investment costs	Concept specific
Installation factor	1,54 (500 MW) 1,66 (50 MW)
Maintenance factor	-
Scale factor R (for TCI)	0,7

5.1.3. Conditions of consumption-related costs

The most important positions of consumption-related costs are the main inputs of biomass and electrical power. Beside these, costs on auxiliary energies or substances, residues, but also full load hours have an influence on economics and will be defined in the following.

Availability. Availability is important for calculating consumption-related costs. Different figures have been applied for calculating the cost of BtL-production; considering the background of the studies available and the experiences in other fields, 8000 h/a will be assumed as basis of the economic assessment. Variations of the availability are done within sensitivity analysis in chapter 6.2.4.

Main inputs. Main inputs are biomass, electrical power, natural gas and oxygen (if not generated via air separation unit).

Biomass. Biomass costs free plant gate are required for calculating fuel costs free plant gate. The assessment of biomass provision costs within the Renew project is documented in WP 5.3., Deliverable 5.3.6. For the calculation of the BtL production costs, standard biomasses were selected, as described in chapter 2 above. Considered biomass sources in SP and S1 scenario are:

- willow
- miscanthus
- straw

Electrical power. A large range of electrical power costs can be found in the literature depending on volume and voltage level [BMWi, 2006], [EC, 2003], [Bundesamt, 2006]. Within the SP scenario two of the concepts (dEF-D, CFB-D with biomass STR) require more electrical power than produced by operation. For its provision an electricity price of 0.06 €/kWh (electricity mix, same price as used for the electricity output of the other concepts) was assumed.

By the application of future plant concepts including electrolysis the costs for electrical power get a more significant influence. In this context different generation pathways and the resulting prices are considered, see chapter 6.2.5.

Natural gas. Natural gas cost of 40 €/MWh_{CH4} will be set contrary to the background of the price development during the last years.

Oxygen. Most of the concepts have foreseen the oxygen production via air separation. In case of concepts under oxygen feeding “over the fence” cost of 0.08 €/m^3 i.n. will be set [Henrich, 2005].

Auxiliaries and Residues. Beside the costs for the main feedstock, also those for auxiliaries (bed materials, water etc.) and residues (waste water, ash etc.) are of importance. A summary of the frame conditions on auxiliaries and residues is shown in the overview on consumption related costs (Table 5-3).

Table 5-3: Frame conditions of auxiliaries

Auxiliary	Costs	Source	Comment
RME	0,79 €/l		
NaOH	155 €/t	[IEA, 2003]	50 % NaOH
ZnO	10 €/l	[Renew, 2005]	
CaO	70 €/t	[Detering, 2004]	
Bed material	200 €/t	[Fraunhofer, 2005]	
Water	-		only waste water considered
Ash	30 €/t	[Detering, 2004]	
Fly ash	50 €/t	[Detering, 2004]	
Slag	60 ... 90 €/t	[IE, 2006]	
Waste water	2,16 €/m³	[Detering, 2004]	

5.1.4. Conditions of operation-related costs

Personnel costs. In principle, two options for personnel costs estimation exist. If number of operators are available or can be assumed, the personnel costs can be calculated based on an average personnel cost per employee and year. If no information on operators is available the personnel costs can be assumed based on the total investment costs of a conversion plant. Both options are shown in Table 5-4.

Costs for service and operation. Since no experiences on service costs for BtL-plants exists these factors also needs to be assumed. In most cases such an assessment is based on total investment costs but differs in a wide range. Thus, an average value of 3 % of the total investment cost will be applied in this study.

Table 5-4: Frame conditions of operation related costs [Air products, 1998], [Detering, 2004], [Hamelinck, 2004], [Borerrigter, 2003]

Parameter	Frame condition
Average specific personnel costs	50.000 €/a employee
Personnel costs (if no data of employee figures given)	0,5 % p.a. (of investment costs)
Costs for service and operation	3 % p.a. (of investment costs)

5.1.5. Conditions of other costs

Other costs include expenditures on insurances, administration or contingencies. These costs are also taken from literature and are summarised in Table 5-5.

Table 5-5: Frame conditions of other costs [Detering, 2004], [Hamelinck, 2004], [Borerrigter, 2003], [Tijmensen], [IEA, 2003]

Parameter	Frame condition
Insurance	1 % p. a. (of TCI)
Administration	0,5 % p. a. (of TCI)
Contingencies	1 % p. a. (of TCI)
Others	0,75 % p. a. (of TCI)

"Others" includes continuous costs, fees or testing costs

5.1.6. Conditions of revenues

Depending on the concept, different by-products can be sold. For large scale FT-Diesel production naphtha and electrical power need to be considered. When regarding small scale FT-production, also heat has to be considered, as it can be fed to a district heating grid for example. These by-products and their revenues are summarised in Table 5-6.

Further output materials like sulphur or ash/slag are not considered as by-products.

Table 5-6: Frame conditions of revenues [Riediger, 1971], [Westfalen, 2006], [Quartalsbericht, 2006], [Fachverband, 2006], [Kunststoff, 2006], [BASF, 2006]

Parameter	Frame condition	Source
Compensation for naphtha	400 €/t	[Riediger, 1971], [Westfalen, 2006], [Quartalsbericht, 2006], [Fachverband, 2006], [Kunststoff, 2006], [BASF, 2006]
Compensation for electricity	60 €/MWh_{el}	[EC, 2003], [Hamelinck, 2004], [Kalies, 2004], [Ekbom, 2005]
Compensation for heat	(30 €/MWh_{th})	[Detering, 2004], [Kalies, 2004], [Brennstoffspiegel, 2006]

5.2. Main components and overall investment costs

Based on the results of chapter 5.1.4 the following table shows the overall investment costs for all considered concepts, realising both SP and S1 technology. The detailed calculation of the investment costs can be found in Appendix A, both for SP and S1 technology. The main aim is the provision of cost-figures for the relative comparison of the different concepts; the absolute values of investment costs include the inaccuracies as described in chapter 5.1.4 above.

Table 5-7: Total capital investment in Million Euros, SP and S1 technology

[M€]	cEF-D	dEF-D	CFB-D	ICFB-D[2]	BLEF-DME	CFB-E	EF-E
SP	433,12	409,38	502,52	72,66	189,54	328,80	341,87
S1	956,17	896,14	656,71	403,81	189,54	381,96	371,87

In the diagrams below the share of the different system components on the total capital investment are shown both for the SP (Figure 5-1) and S1 scenario (Figure 5-2). It is obvious that in those concepts containing electrolysis components in S1 technology (cEF-D, dEF-D, CFB-D) a strong increase of the total capital investment in comparison to SP technology takes place. Therefore also compare Table 5-7. The investment for electrolysis equipment suitable for providing the necessary amounts of hydrogen constitute up to 45 % of the overall investment costs. Other correlations which can be deduced:

* "Economy of Scale" effect in case of the ICFB-D concept, visible regarding the investment cost for gas cleaning and conditioning; they decrease from app. 40 % in the SP scenario down to app. 10 % in the S1 scenario, rising the biomass input from 50 MW_{th} to 500 MW_{th}
* concepts with entrained flow gasification require additional investments concerning biomass treatment (esp. EF-E concept with its torrefaction unit), on the other hand the CFB concepts need more extensive gas cleaning devices
* a similar correlation can be found looking at the share of the product cleaning devices following FT synthesis

[2] Biomass input for the ICFB-D concept is 50 MW in SP, 500 MW in S1 scenario.

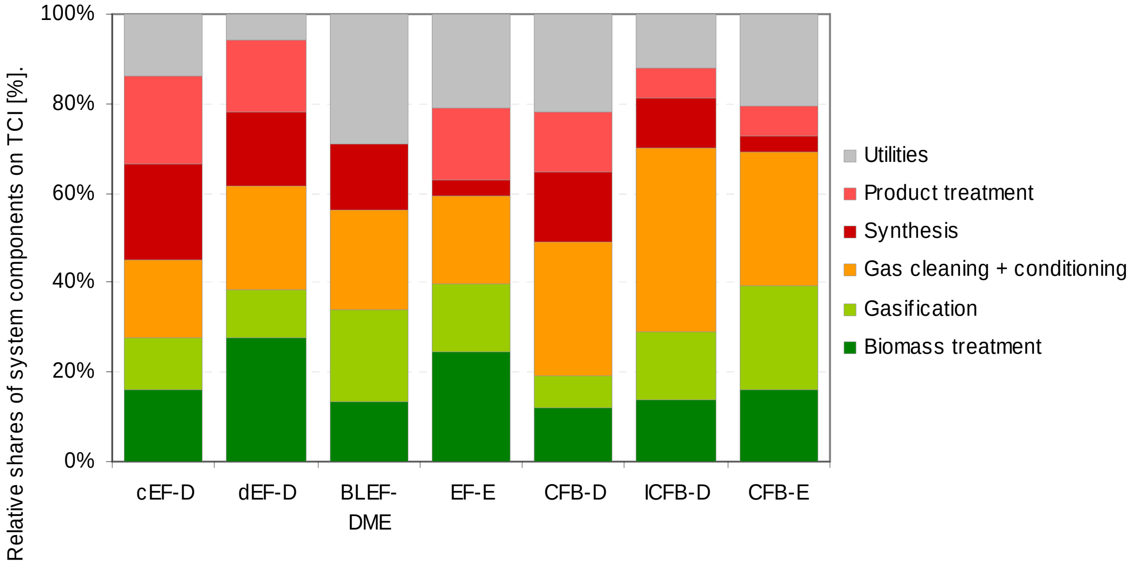


Figure 5-1: **Relative shares of system components on TCI for the BtL concepts, SP scenario**

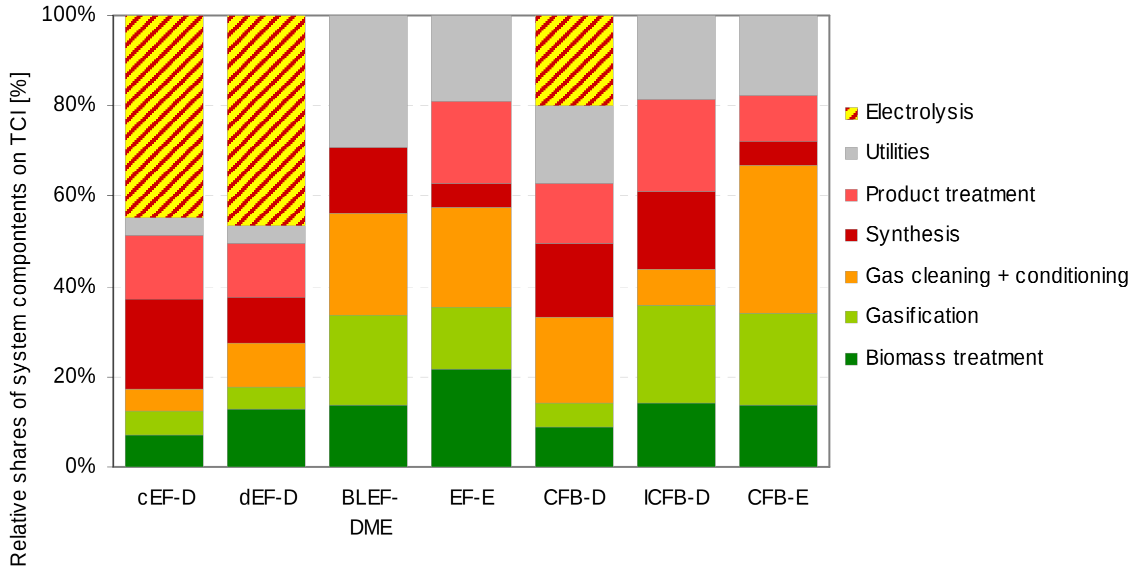


Figure 5-2: **Relative shares of system components on TCI for the BtL concepts, S1 scenario**

6. Results on cost calculation

In the following basic results as well as exemplary sensitivity analysis for total BtL production costs are considered.

6.1. Fuel production costs

6.1.1. Starting Point Technology

The BtL production costs using the technology of the starting point scenario were calculated based on biomass provision costs valid in SP and S1 scenario respectively. Biomass costs depend on the considered European region. For further information on biomass provision costs please see Del. 5.3.6.

For a first overview, according to the defined concepts and scenario specific biomass assortments (cf. SP5-Scenarios) the relevant biomass costs and the resulting total BtL production costs are summarised in Table 6-1. They are based on the most favourable biomass provision cost in SP and S1-scenario (cf. Appendix B); thereby in both cases SP technology for the production of synthetic biofuels has been considered. Those costs reach from app. 21 to 71 €/GJ BtL output. They are also used to define a bandwidth including the fuel distribution costs, therefore see chapter 6.3.

Table 6-1: Concept specific total BtL production costs (SP-technology, SP and S1-biomass costs for reference biomass assortments)

	cEF-D	dEF-D	CFB-D	ICFB-D[a]	BLEF-DME	CFB-E	EF-E
SP-SCENARIO							
Biomass costs – most favourable cost alternatives [€/GJ], region							
SRC (willow)	7.8 SOUTH	-	7.8 SOUTH	7.0 EAST	7.8 SOUTH	7.8 SOUTH	7.8 SOUTH
STR (straw)	4.5 EAST	4.4 EAST	4.5 EAST	-	-	-	-
MIS (miscanthus)	-	-	-	7.0 EAST	-	-	-
Total BtL production costs [€/GJ]							
based on SRC	34.04	-	52.36	62.49	21.00	58.48	71.26
based on STR	24.57	39.84	39.33	-	-	-	-
based on MIS	-	-	-	63.14	-	-	-
S1-SCENARIO							
Biomass costs – most favourable cost alternatives [€/GJ], region							
SRC (willow)	5.1 EAST	-	5.1 EAST	4.5 EAST	5.1 EAST	5.1 EAST	5.1 EAST
STR (straw)	5.0 EAST	5.1 EAST	5.0 EAST	-	-	-	-
MIS (miscanthus)	-	-	-	7.0 EAST	-	-	-
Total BtL production costs [€/GJ]							
based on SRC	26.46	-	41.16	30.02	16.13	40.88	45.89
based on STR	26.03	42.26	41.50	-	-	-	-
based on MIS	-	-	-	63.35	-	-	-

[a] plant size 50 MW_{th} in SP scenario (plant size of other concepts 500 MW_{th}, except dEF-D with 500 MW_{th} pyrolysis)

The biomass provision costs are in general lower in the S1 than in the SP scenario[3]. Lower provision costs result in lower consumption-related conversion costs. In both calculation variations SP technology is used, therefore all other cost components (operation-related and capital-related costs) and revenues (heat, electricity and naphtha) remain constant. Thus, BtL production fuels using SP technology are lower with S1 than SP biomass provision costs. As example, the production costs for the region WEST, together with the used biomass provision costs, are listed in Table 6-2. The particular cost shares can be found in Figure 6-1 and Figure 6-2.

[3] An exception is only straw in the regions SOUTH and UK+IR.

Table 6-2: Biomass provision costs (SP, S1) and resulting BtL production costs for region WEST, SP technology

[€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
SP biomass provision costs										
Biomass provision costs	8,46	5,24	6,15	8,46	8,46	8,46	5,24	7,59	8,23	8,46
Total BTL production costs	35,78	26,73	46,11	22,13	77,11	54,93	42,53	66,19	71,10	62,54
S1 biomass provision costs										
Biomass provision costs	6,13	5,08	5,77	6,13	6,13	6,13	5,08	6,13	7,72	6,13
Total BTL production costs	29,32	26,28	44,72	17,97	28,36	45,39	41,87	51,16	67,11	58,49

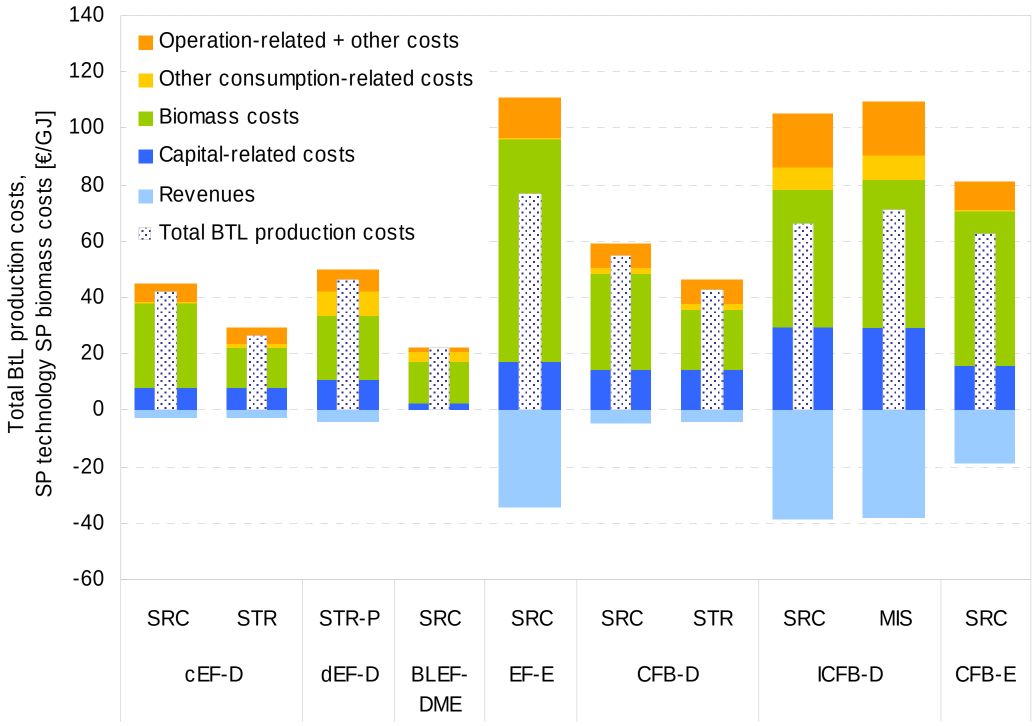


Figure 6-1: BtL production costs, region WEST, SP technology, SP biomass provision costs

Because of the high cost share, the applied biomass source has a strong influence on the BtL production costs. Thus, BtL fuel from residues has lower production costs then fuel from energy crops, if the same BtL concept is used. This can be found out for example by comparison of the cEF-D concept using SRC resp. STR in Figure 6-1.

Against the background of high biomass cost share, plant concepts with higher conversion efficiency, like BLEF-DME or cEF-D, turn out to have lower specific BtL production costs then other concepts, especially EF-E and CFB-E.

Among the rest of the concepts, the ICFB-D is a special design case because of the plant size of 50 MW_{th} biomass input and the focus on heat and power production. This leads to high specific production costs compared to the large scale concept, as shown by up-scaling ICFB-D in S1 scenario (see below).

The correlations described are valid also in all other defined European regions, for the accordant figures see Appendix B.

To clarify the influence of biomass provision costs and provide a good background for the comparison with S1 scenario, all BtL production costs were calculated with SP technology, and S1 biomass provision costs. The results can again be found in Table 6-2, and also in Figure 6-2.

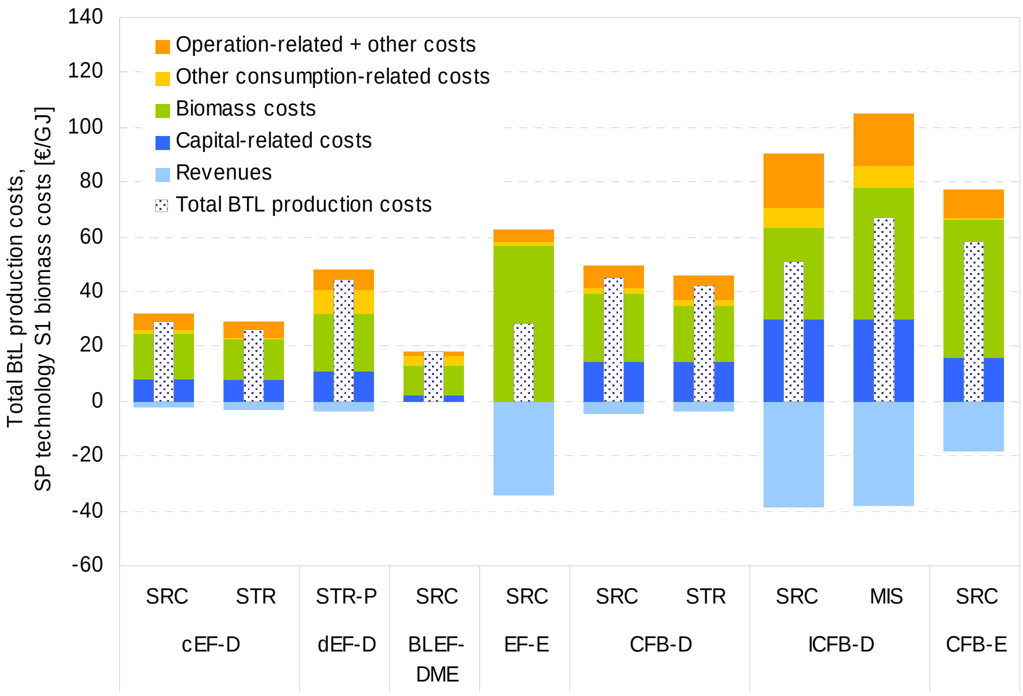


Figure 6-2: BtL production costs, region WEST, SP technology, S1 biomass provision costs

Because of the lower S1 biomass provision costs, of course the calculated BtL production costs are decreasing, too. This is valid in all regions, except STR in the regions SOUTH and UK+IR where its provision costs increase from SP to S1. For further data see Appendix B.

The cost share (biomass costs, operation-related costs, consumption-related costs and capital-related costs) differ between the technical concepts. Figure 6-3 gives a relative comparison of them using the example of SP-technology with equal biomass costs for all concepts, represented by willow in the region EAST, S1 scenario.

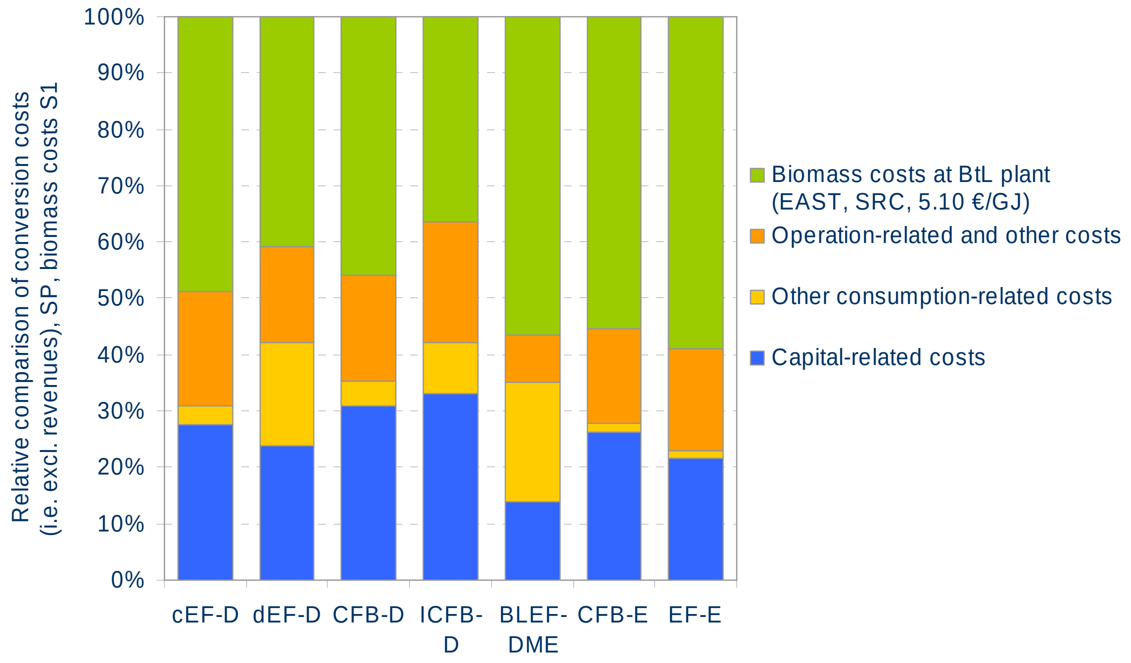


Figure 6-3: Relative comparison of concept specific BtL production costs in region EAST

It is obvious that the provision costs of biomass are the main influencing factor. Due to this, plant efficiency is most important. Furthermore an influential cost category is also built by the capital-related costs, in this relation full load hours and availability of the plant become relevant. A more detailed analysis of these determining factors will be done within sensitivity analysis in chapter 6.2.

6.1.2. Future Production Technology

For the calculation of future production costs, S1 technology and S1 best case biomass provision costs were used. The results can be found in Appendix B. As an example, Table 6-3 and Figure 6-4 show them for the region WEST.

Table 6-3: Biomass provision costs (S1) and resulting BtL production costs for region WEST, S1 technology

[€/GJ]	cEF-D SRC	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	6,13	5,77	6,13	6,13	6,13	5,08	6,13	7,72	6,13
Total BTL production costs	66,14	90,34	17,97	40,98	63,07	66,68	24,85	32,23	47,06

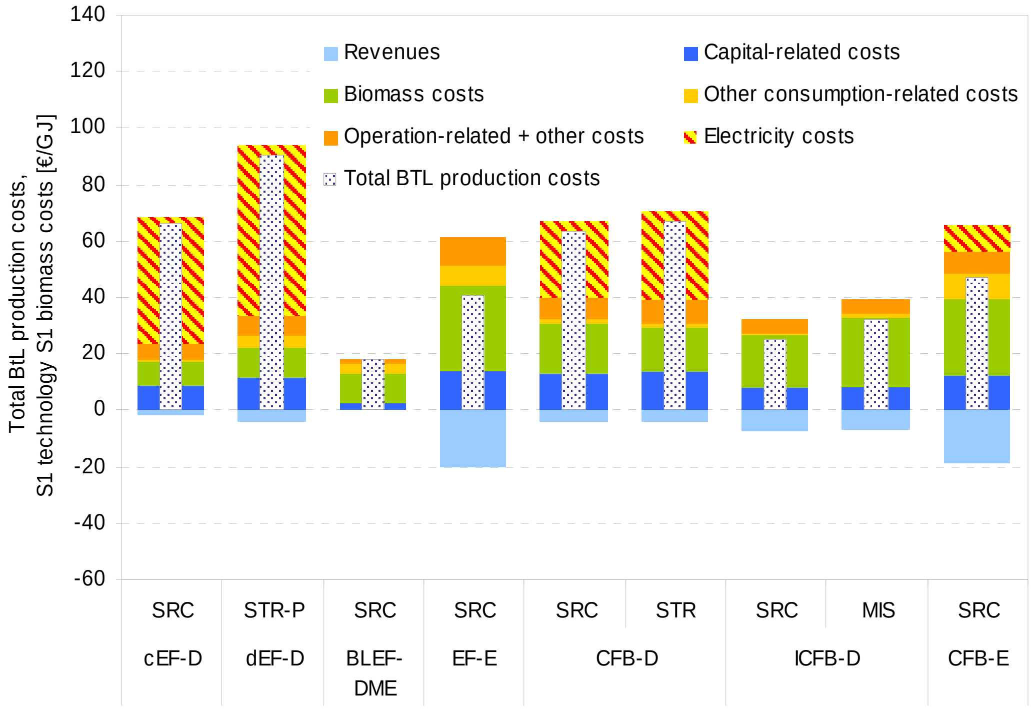


Figure 6-4: BTL production costs, region WEST, S1 technology, S1 biomass provision costs

The S1 technology of some plant concepts (cEF-D, dEF-D and CFB-D) is based on an external provision of hydrogen by electrolysis to maximise the FT-Diesel output. These large-scale electrolysis modules are leading to rising capital investments as mentioned above (Table 5-7). Furthermore, they need large amounts of electricity for operation, reaching up to 66.7 % of the total BTL production costs (dEF-D concept). For the calculations an electricity price of 0.12 €/kWh has been applied. This price is representative for the use of off-shore wind power. Other sources of electricity, together with their resulting prices, are discussed within the sensitivity analysis in chapter 6.2.5. Hence, the BTL production costs of those plant concepts containing electrolysis are significantly higher with S1 than with SP technology.

The BLEF-DME concept uses the same technology in SP and S1 scenario; therefore the BtL production costs have the same value. Considering all plant concepts without electrolysis (EF-E, ICFB-D, CFB-E), a reduction of BtL production costs can be asserted. This reduction has different causes, which will be discussed in the following passages:

Biomass provision costs. They decrease from SP to S1, thus the BtL production costs also lower. This effect could already be shown comparing the BtL production costs using SP technology and both SP and S1 biomass provision costs, as done in Table 6-2 for the example WEST.

Conversion efficiency. S1 technology is designed to produce higher yields of transportation fuels than SP technology, therefore the relative production costs without electrolysis per energy unit BtL are decreasing. This effect can be seen explicitly for the example region WEST comparing Figure 6-2 and Figure 6-4, which represent the BtL production costs for SP respectively S1 technology, but both S1 biomass provision costs. The cost reduction because of higher conversion efficiency is present at all concepts in general, but for those including electrolysis it is overlaid by the costs of electricity, which lead to a cost increase at all. The costs of the concepts EF-E and CFB-E are approaching to the other concepts' costs because of significantly higher S1 conversion efficiency.

Economy of scale. This effect in comparison with current and future technology is only appropriate concerning the ICFB-D concept. The plant size is 50 MW_{th} in SP, but 500 MW_{th} (biomass input) in S1 scenario. Together with a maximisation of the FT yield within the S1 concept, economy of scale effects (more detailed described in 6.2.2) lead to a cost reduction.

6.1.3. Comparative conclusion of SP and S1 technology

All described relations are valid not only in the WEST, but also under estimation of biomass costs of the defined European regions. For visualising, the BtL production costs in SP and S1 scenario for the cEF-D concept as example are compared in Figure 6-5.

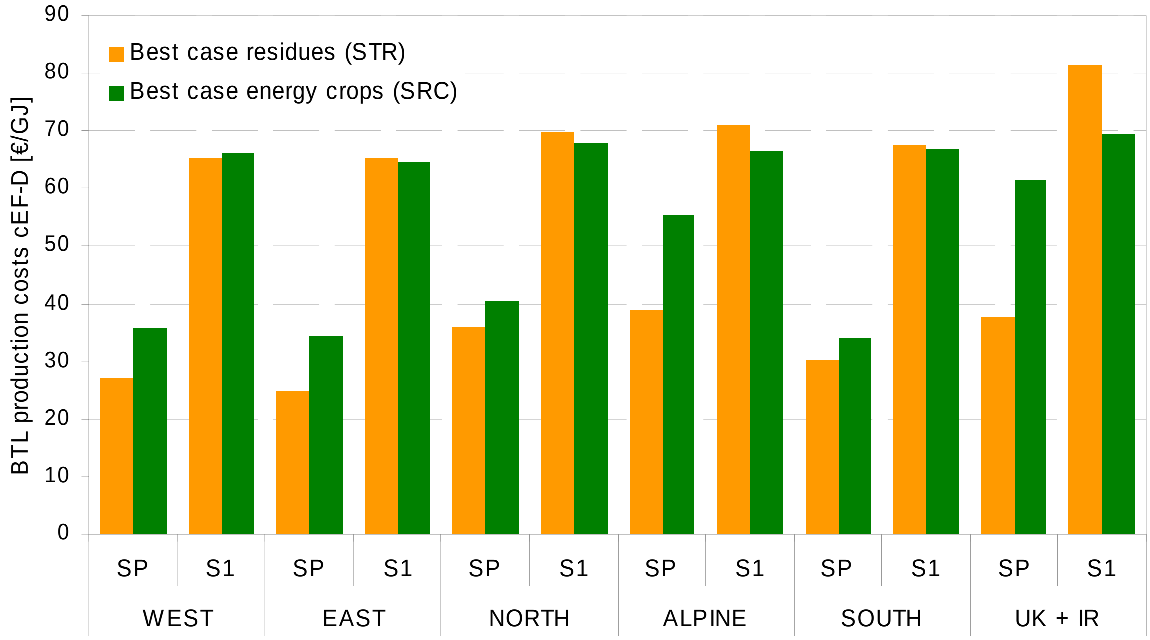


Figure 6-5: BtL production costs, cEF-D concept, SP and S1 scenario, all European regions

In Figure 6-5 for biomass sources STR (representative for residues, not included in cEF-D S1 standard biomasses) and SRC (representative for energy crops) were chosen. The biomass provision costs represent the best cases in the relevant region, for more details see Appendix B. Thereby the same conversion efficiencies for straw and willow chips were assumed. It can be found that the BtL production costs using residues respectively energy crops are approaching in the S1 scenario. There are two causes for this behaviour: First, the difference between straw and willow chips provision costs decreases in S1 compared to SP, in all regions. In some regions, e.g. UK+IR, straw is even getting more expensive than willow.

Second, cEF-D is a plant concept which uses electrolysis in S1. Electricity costs make up a large share on the whole BtL production costs (app. 60 %, also compare Figure 6-4), hence the influence of the applied biomass provision costs is getting lower, the difference between the BtL production costs using residues respectively energy crops decreases.

6.2. Sensitivity Analysis and Future Plant Concepts

Based on the discussion of open questions and comments (see chapter 6), the economics of the different concepts will be adapted and outstanding scenarios will be calculated.

These data will lead to the assessment of cost development (learning effects) and scale variations, but also sensitivities will be assessed for all scenarios within Del. 5.3.7 (biomass conversion costs).

6.2.1. Biomass costs

As shown Figure 6-6, BtL concepts with a high biomass conversion efficiency (e.g. BLEF-DME, cEF-D) will be able to produce BtL at favourable costs at a broader level of total biomass provision costs. To give an example: For producing BtL at a cost level of up to app. 30 €/GJ, the biomass provision costs for the concept cEF-D can be in a range of up to 6 €/GJ, for the concept CFB-D biomass should not cost more than 3 €/GJ.

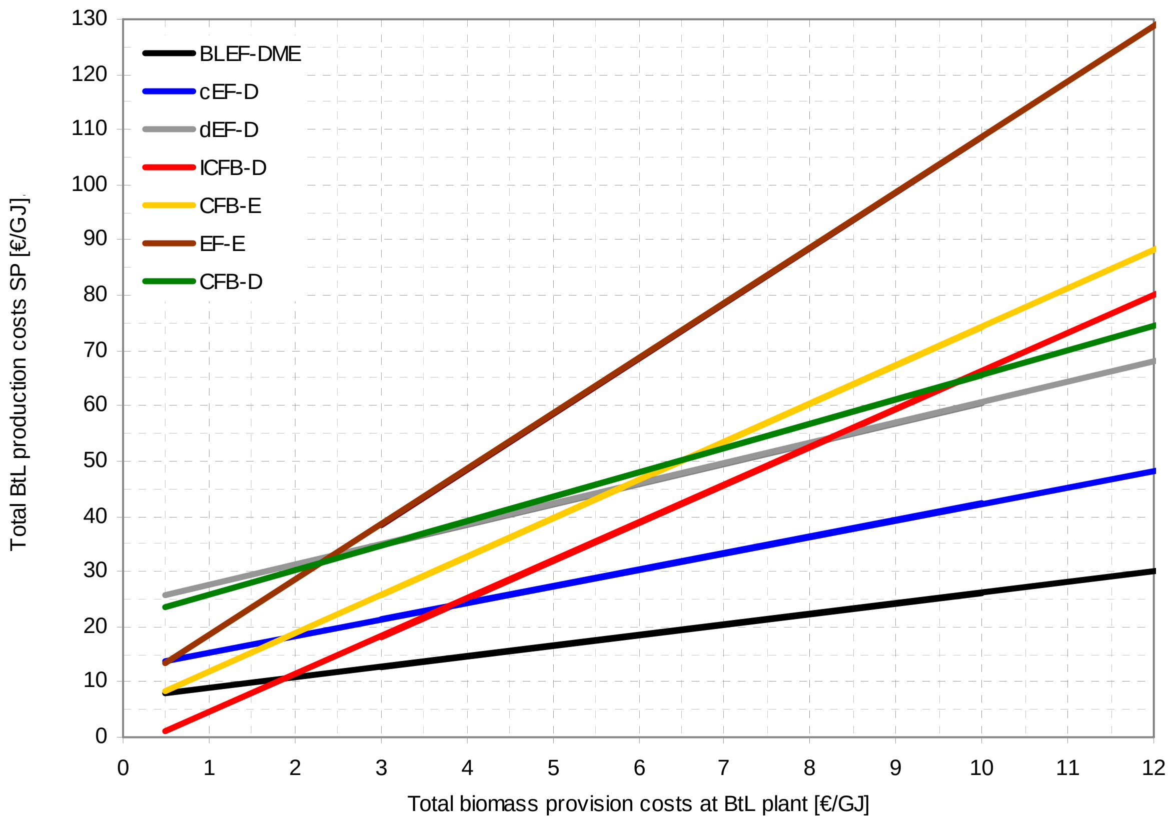


Figure 6-6: Influence of concept specific efficiency and role of biomass costs to the total BtL production costs (1 €/l_{DE}= 1 €/l / 0.0357 GJ/l_{DE}=28 €/GJ)

The change of provision costs also causes a variation in the structure of the conversion costs. With increasing biomass costs their share in the overall fuel production costs significantly increases. This behaviour is shown in Figure 6-7.

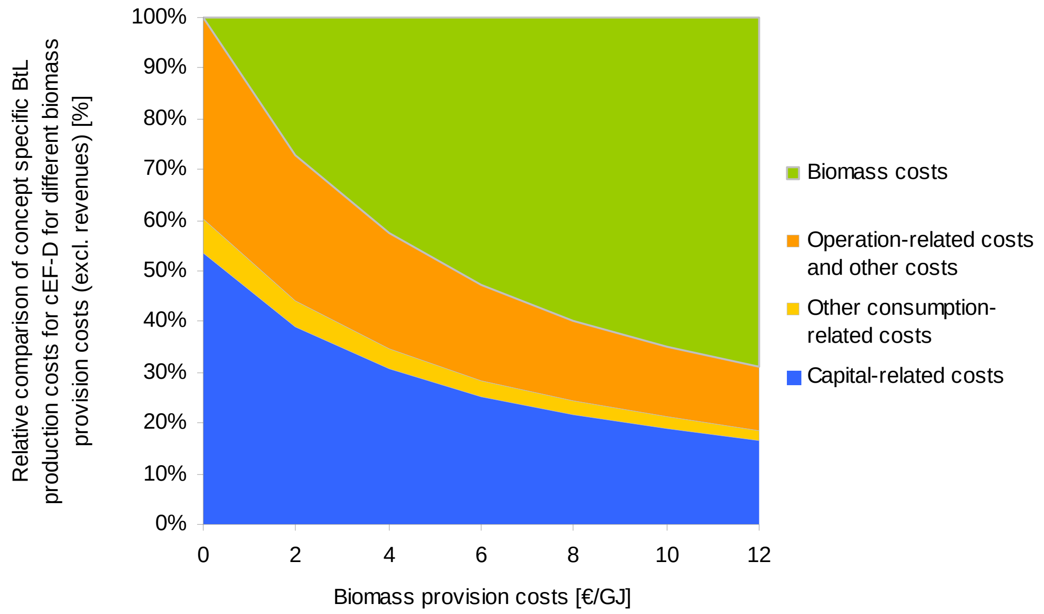


Figure 6-7 Correlation between biomass provision costs and the structure of cost categories (example cEF-D)

6.2.2. Up-scaling, Economy of scale

By up-scaling a plant, it is necessary to differ between direct provision of biomass (e.g. to a BtL plant that includes centralised pyrolysis such as cEF-D) and provision including de-centralised pyrolysis, e.g. dEF-D. The change of provision costs is exemplarily shown for STR and WC (both WEST, SP scenario) for different BtL plant sizes in Table 6-4.

Table 6-4: Correlation between plant size and biomass provision costs, cEF-D and dEF-D, WEST, SP scenario

	Total biomass provision costs [€/GJ]		
BtL plant size	500 MW_{th}	1.000 MW_{th}	2.000 MW_{th}
Direct provision (road-rail-road)			
STR	5.47	5.71	5.97
WC	8.46	9.02	9.54
Provision including pyrolysis (road-pyrolysis-rail-road)			
Slurry from STR	6.15	6.29	6.35
Slurry from WC	9.86	9.94	10.08

It can be found that – according to the specific assumptions within Renew – for the WEST region total biomass provision costs increase significantly with increasing plant sizes. In some regions, e.g. in ALPINE, this cost situation and thus the comparison between direct biomass provision and provision including pyrolysis may differ.

The second important factor considering the up-scaling of a plant is that as higher the capacity of a plant is, the lower the resulting specific investment cost will be. This effect of cost degression is called "Economies of scale ". Equation 1 is valid:

$$\frac{I_{02}}{I_{01}} = \left(\frac{P_2}{P_1}\right)^R \qquad \text{(equation 1)}$$

I_{01}/ I_{02} – investment costs (plant 1/ 2), P_1/ P_2 – scale (plant 1/ 2), R – plant specific scale exponent

Thereby the scale exponent R is a technique specific value between 0 and 1, but in most cases in the range of 0.7 [Hamelinck, 2004]. It may vary when scaling over a wide range. In this case a tenfold increase of capacity leads to a round about bisection of the specific investment costs.

In Figure 6-8 the production costs of cEF-D and dEF-D concept are exemplarily calculated for BtL plant sizes from 500 MW_{th} to 2 GW_{th} in WEST.

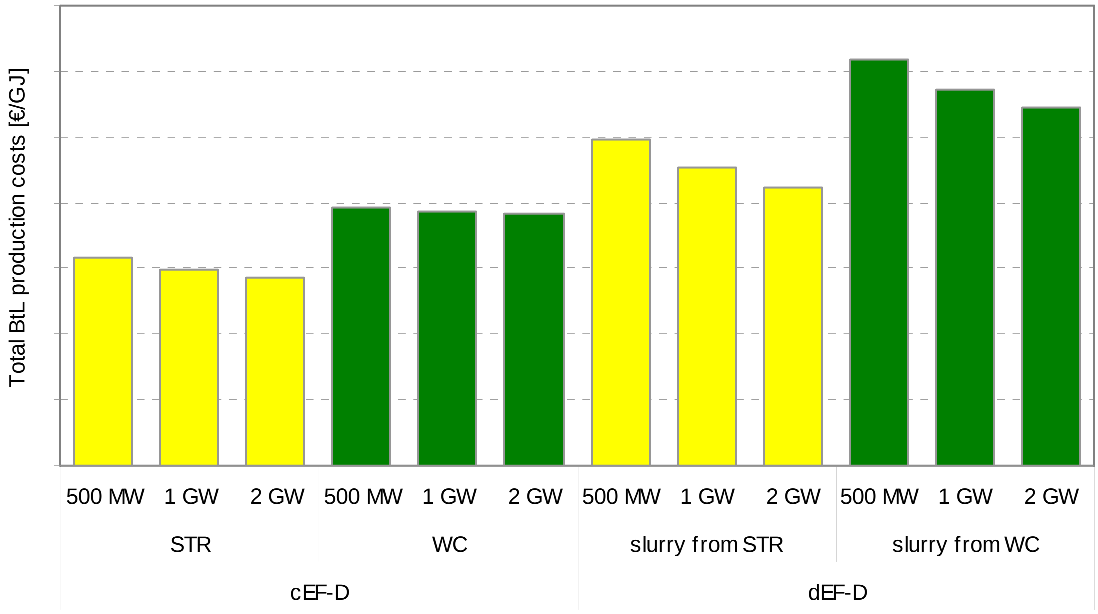


Figure 6-8 Effect of up-scaling – cEF-D versus dEF-D, SP, WEST

While total biomass provision costs increase with increasing BtL plant size, total BtL production costs will decrease. By up-scaling a plant, the BtL production costs can be reduced due to effects of economy of scale. The described correlation is valid both in the SP and S1 scenario.

6.2.3. Investment costs

By constructing several plants of one type, investment costs can be reduced due to technology learning. The calculation of this reduced investment costs is based on original overall investment costs I_1 of the respective BtL-concepts (as shown in Del. 5.3.1, chapter 4.2.1). Using equation 1, the changed costs I_2 are a function of the accumulated plant capacity at time 1 (C 1) and time 2 (C 2) and the degression factor f as well.

$$\frac{I_2}{I_1} = \left(\frac{C_2}{C_1}\right)^{-b} \text{ with } -b = \frac{\log f}{\log 2} \qquad \text{(equation 2)}$$

The costs change will be considered only for the overall BtL plant (no separation in system components or aggregates). The degression factor f depends on several variables, e.g. origin country of the technology, time frames etc. For the sensitivity calculation a factor of 0.9 was used, as example the cEF-D concept (SP) is considered. The results for 2, 4 and 8 plants are shown in Table 6-5.

Table 6-5: TCI considering technology learning for cEF-D, SP

Amount of plants		1	2	4	8
Accumulated plant capacity	MW	500	1000	2000	4000
Degression factor		0,9	0,9	0,9	0,9
TCI	M€	433,12	389,80	350,82	315,74

The figure corresponding to 8 accumulated cEF-D plants was used as *minimum value for the sensitivity analysis* concerning TCI. The *maximum value* should orientate on the price development of chemical plants and machinery. This index is commonly determined following the Kölbel-Schulze methodology, and is quarterly published in [CHEMIE TECHNIK]. The principle trend since 2000 is shown in Figure 6-9.

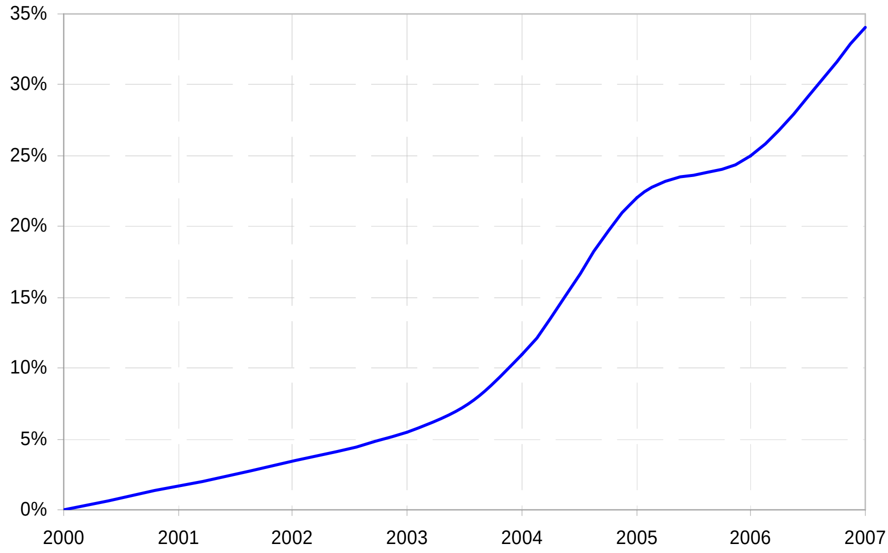


Figure 6-9: Development of TCI for chemical plants and machinery according to Kölbel-Schulze-Index, 2000 - 2007 [Chemie Technik]

It can be found that the TCI for chemical plants in the time frame from 2000 to 2007 increased by app. 35 %. This value was estimated to represent current conditions. To represent a "worst case", a doubling of TCI (as known from some GtL-engineering projects), this means a value of about 866.2 million Euros in case of the cEF-D concept, was assumed as maximum value.

The defined minimum and maximum TCI values as well as the assumed current value were set to calculate the resulting conversion costs for the cEF-D plant concept in SP scenario, with the biomass provision costs of SCR (willow chips) in the region WEST. The obtained correlation is visualised in Figure 6-10.

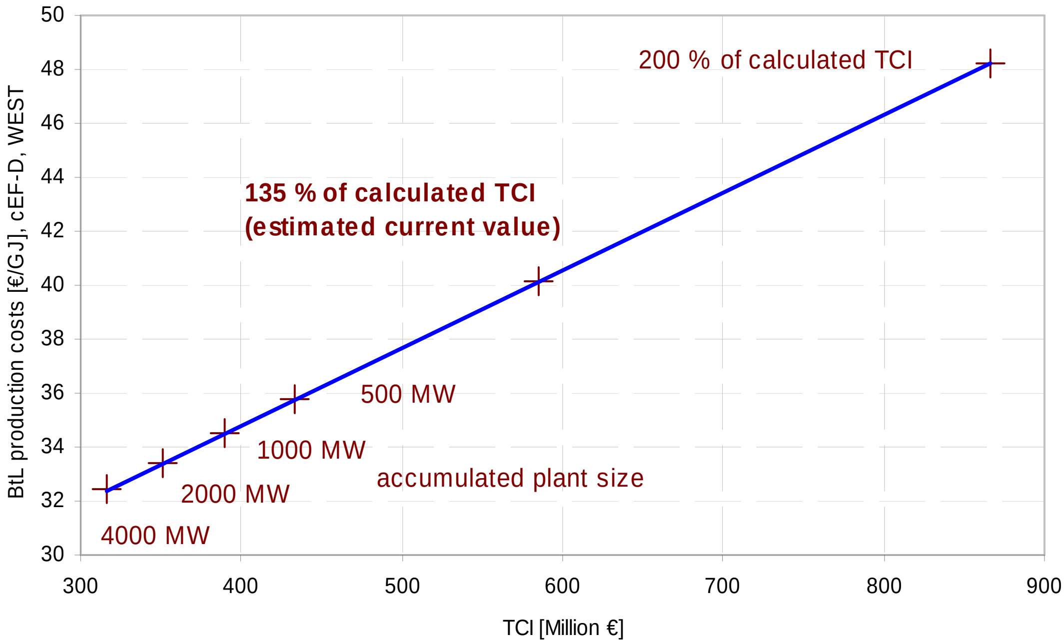


Figure 6-10: Correlation between reduced TCI (technology learning) resp. raised TCI and BtL production costs, cEF-D concept, SP, WEST

It can be found that by doubling the plant amount and the resulting reduction of TCI of app. 10 % (Table 6-5), the BtL production costs can be lowered about app. 1 €/GJ. This value is significantly lower than the reduction resulting out of the up-scaling of a single plant (see above). Otherwise, a doubling of TCI leads to an increase of the BtL costs of about 33 %. The estimated current level of 135 % compared to the TCI used for cost calculation leads to an increase of BtL production costs of about 11 %. This means that the current BtL production costs could be higher than the calculated values because of the rising TCI of chemical plants during the last 3 years.

6.2.4. Full load hours

All BtL cost calculation were done under the assumption of 8000 full load hours per year, this means a non-stop operation, except breaks for maintenance, reparation etc. To survey the influence of the full load hours on the production costs, they were varied in a range between 2000 and 8000 h/a for the cEF-D concept, using the biomass provision costs of region WEST. The result is shown in Figure 6-11:

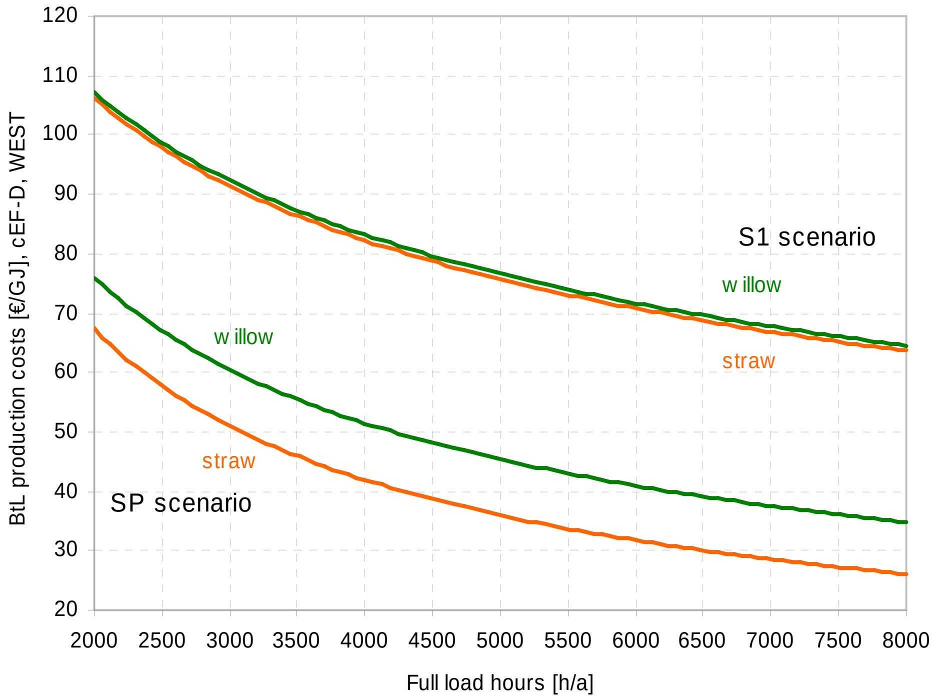


Figure 6-11: Correlation between full load hours and BtL production costs, cEF-D concept, region WEST

It can be found that the principle correlation between full load hours and BtL production costs is similar for SP and S1 technology and for the biomass sources willow (SRC) and straw (STR). Increasing full load hours lead to a linear increase of revenues and consumption-related costs. On the other hand, capital-related and operation-related costs stay unchanged. Thus, the BtL production cost decrease exponentially with increasing full load hours. To keep BtL costs on a moderate level, it is necessary to operate the BtL plant continuously, if possible.

6.2.5. Electricity price at future plant concepts

The BtL production costs of all S1 plants concepts are described above, see Figure 6-4. In case of external hydrogen provision, the price of electricity for hydrogen electrolysis has a significant influence on the BtL production cost. In the calculations above electricity price of 0.12 Euro/kWh$_{el}$ was assumed, which responds to an electricity provision by wind power. Other possible cases are the use of conventional provided electricity (0.05 Euro/kWh$_{el}$) or an electricity mix (0.07 Euro/kWh$_{el}$)

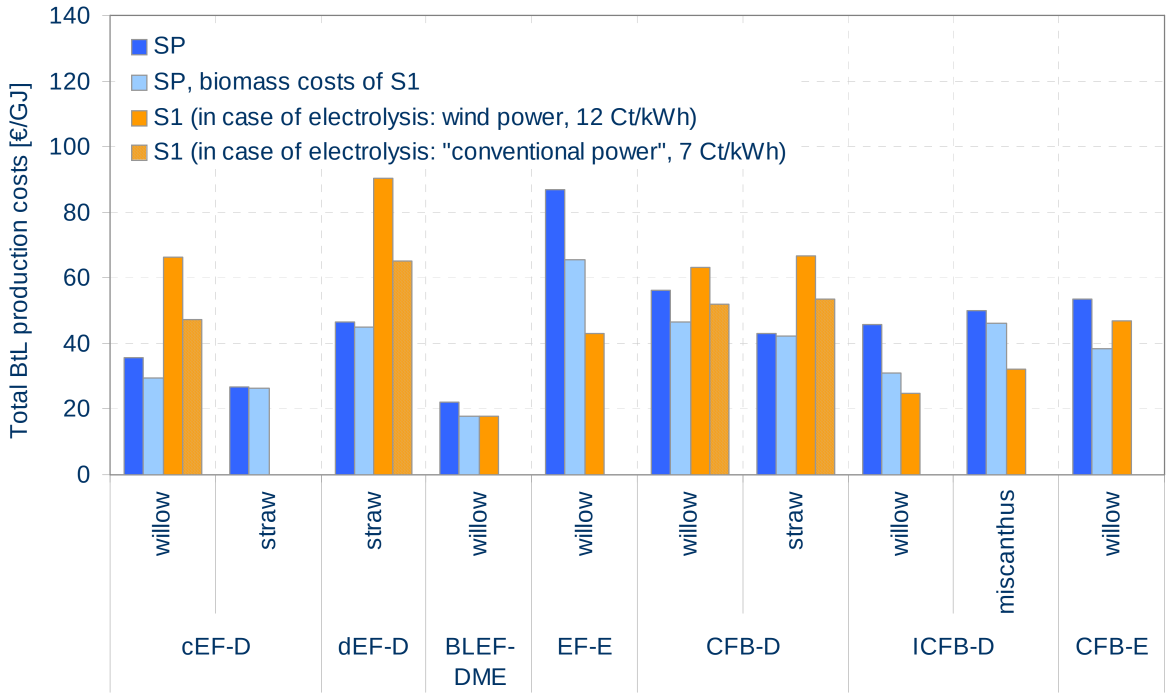
Table 6-6 gives an overview of the correlation between these prices and the BtL production costs, using the cEF-D concept with standard biomass (SRC) in the region WEST. “Base case” stands for the SP technology; the given relative changes correspond to this value.

Table 6-6: Correlation between price of electricity for hydrogen electrolysis and BtL production costs

	Base case [€/GJ]	Price of electricity for hydrogen electrolysis €ct/kWh$_{el}$]		
		5	7	12
Increase in total BtL production costs compared to base case	39.4	+ 12,1 %	+ 32,6 %	+ 84,8 %

It is quite evident that the price of electricity has a decisive influence on the BtL production costs of S1 concepts using electrolysis for external hydrogen provision. A price difference of 0.07 € is leading to an increase of BtL production costs of about 30 €/GJ. By lowering the electricity price, the large cost difference between SP and S1 scenario can be reduced. This is valid for all future concepts using electrolysis, as shown in Figure 6-12 for the region WEST and an electricity price of 0.07 or 0.12 €/kWh$_{el}$ respectively.

Figure 6-12: BtL production costs considering different prices of electricity, WEST



Source: DRAFT results calculated by IE Leipzig, 2007

Focusing on the CFB-D concept using willow as biomass source, it can be found that by the application of conventional power for electrolysis, the S1 BtL production costs can be lowered below the SP level. The price of electricity has no significant influence on plants without external hydrogen provision; therefore the second S1 column is not shown in the diagram.

6.3. Well-to-Tank costs

Using the conversion cost calculations described in the paper on hand, typical distribution cost can be added to calculate the costs of biofuel free tank/free filling station. This was done in the scientific report based on typical distribution costs provided by the WTW study of EUCAR, CONCAWE & JRC/IES [WTW, 2006]. There are figures determined for every type of fuel as shown in Table 6-7. If bandwidths are given, they result out of the consideration of small-scale and large-scale plants respectively.

Table 6-7: Typical distribution costs of biofuels [WTW, 2006]

Biofuel	FT-diesel	DME	Ethanol
distribution costs [€/GJ]	0.4 - 0.7	0.8 – 2.2	1.0

calculation based on an crude oil price of 50 US-$/bbl

For calculating a range of Well-to-Tank costs, for every plant concept the appropriate minimum resp. maximum distribution costs from Table 6-7 were added to the minimum resp. maximum BtL production costs of every plant concept. Thereby all European regions (Appendix B) were considered. The result is given in Figure 6-13.

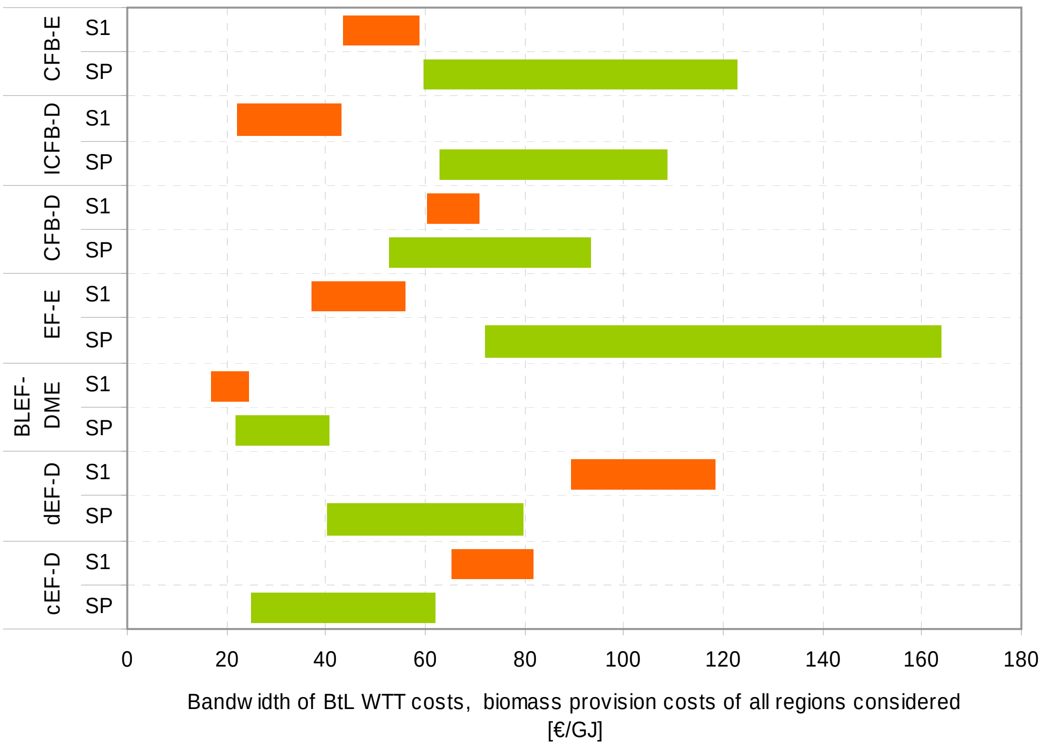


Figure 6-13: Bandwidth of BtL Well-To-Tank costs over all European regions

7. Summary and Future prospects

* BtL provision costs were calculated using plant-specific investment costs, region-specific standard biomass provision costs and consistent economic frame conditions. The calculation was done both for SP and S1 scenario. The production costs are within a wide range, reaching from app. 22 to 82 €/GJ for SP and 17 to 90 €/GJ for S1 scenario, respectively.
* The used biomass provision costs are specific for the considered European region (WEST, EAST, NORTH, ALPINE, SOUTH resp. UK+IR). They represent a broad share on the consumption-related costs, thus the BtL production costs differ significantly from region to region. They have their minimum value in region EAST with its low biomass provision costs, in regions with relatively high biomass provision costs like ALPINE and NORTH the BtL production costs are accordingly high.
* By comparing SP and S1 scenario, it can be asserted that the application of more efficient conversion technologies can reduce BtL production costs in principle. Indeed, in S1 concepts which include an external hydrogen provision, the costs of electricity for operating necessary electrolysis plants are significantly higher than those cost reductions. Hence, S1 production costs of plant concepts including external hydrogen provision are higher than the corresponding SP production costs.
* Rising biomass provision costs have a weaker influence on BtL concepts with a high biomass conversion efficiency, e.g. BLEF-DME, cEF-D. They can provide BtL at favourable costs at a broader level of total biomass provision costs.
* By up-scaling a plant, BtL production costs can be reduced due to "Economy of scale" effects, both in SP and S1 scenario. Rising biomass provision costs for larger plant sizes are considered.
* Technology learning by building up several plants of the same concept leads to a decrease of the total capital investment. The values of this reduction are present, but significantly lower than those which result out of the up-scaling of a single plant.
* Higher total capital investment costs, which could result due to the development of the investment costs of chemical plants and machinery during the last years, lead to a relevant increase of BtL production costs.
* To reach low BtL production costs, it is necessary to operate the production plant continuously if possible, because production costs increase exponentially with decreasing full load hours.
* The price of electricity has a decisive influence on the BtL production costs of S1 concepts using electrolysis for external hydrogen provision. For calculation, the electricity provision by wind power was assumed. The usage of electricity sources with lower prices leads to a significant decrease of the BtL costs of the concerned plant concepts.

For further research work, a feasibility study could be approved, which should include the following issues:

* precisely described locations of the BtL production plants
* current TCI with higher accuracy and more detailed implementation
* correlation of the calculation data with energy price scenarios (e.g. crude oil price development)

There is research work provided by several institutions which can give an orientation for the issues mentioned above.

The first one is a study dealing with the realisation of BtL plants in Germany by Deutsche Energie-Agentur [Dena, 2006]. It includes among others:

* calculation of biomass provision costs for 5 precisely described plant sites in Germany, reaching from 1.2 to 9.7 €/GJ
* consideration of crude oil prices in a range of 50 to 150 US-$/bbl within the calculations
* determination of the BtL production costs (and also estimated sales prices) for 5 plant concepts similar
* to those of the paper on hand, basing on TCI figures reaching from 525 to 650 million €

Not considered by the Dena study are plant sites in other European regions. The used TCI values were determined applying an uncertainty interval of ± 30 %.

Second, the IEC of the University of Freiberg did research work concerning one appointed BtL plant. Basing on a planning study which contains the technical conception of the conversion, cost determination and environmental aspects, an engineering study was done. It will be the basis for the construction of a BtL pilot plant [TUBAF, 2007]. By the realisation of this study in cooperation with several partner enterprises, a practical validation of calculated costs will be given. Otherwise, it has to be noted that the concept of the research project differs in general from those concerned in the Renew calculations.

Hence, the results of the paper at hand provide a good basis for the implementation of updated and specified frame conditions and calculation methods.

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Appendix A Total capital investment costs TCI

SP scenario

cEF-D, SP technology

Component	base costs M€	R -	base scale	installed scale	no.	costs M€	installation factor	overall costs M€	ref.	year
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	148 t_{feu}/h		3,05	1,54	4,69	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	148 t_{feu}/h		1,35	1,54	2,07	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	29,6 t_{feu}/h	5	38,50	1,54	59,19	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	148 t_{feu}/h		2,12	1,54	3,26	Boe	2002
Overall								**69,21**		
Gasification										
EF gasifier	25,50	0,7	250 MW_{th}	250 MW_{th}	2	51,00	1	51,00	Mun	2003
Overall								**51,00**		
Gas cleaning										
water scrubber ($Fe(OH_2)$)	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
water scrubber	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
Overall								**31,44**		
Gas conditioning										
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	5092 kmol/h ($CO+H_2$)		8,54	1,81	15,45	Boe	2002
selexol CO2 removal	63,00	0,7	9909 kmol/h (CO_2)	2130 kmol/h (CO_2)		21,48	1	21,48	Boe	2002
ZnO adsorber	0,13	1	367 MW_{BWL}	500 MW_{BWL}		0,18	1,54	0,27	Tij	1998
steam reformer	9,40	0,6	1390 kmol/h	113 kmol/h		2,08	1,54	3,20	Faa	2001
PSA	32,60	0,7	9600 kmol/h	113 kmol/h		1,45	1,69	2,45	Boe	2002
Overall								**42,86**		
Synthesis										
Solid bed gas phase FT	25,30	1	93,4 MW_FT	268 MW_{FT}		72,60	1,3	94,37	Boe	2003
Overall								**94,37**		
Upgrading										
rectification	5,00	0,7	20 t/h	22 t/h		5,31	1	5,31	Win	2006
hydrocracking	500,00	0,7	250 t/h	18,103 t/h		79,59	1	79,59	Rei	2006
Overall								**84,90**		
Utilities										
steam generation	3,38	0,8	47,5 t/h	159,4 t/h		8,90	1,54	13,69	Tij	1998
steam turbine	8,88	0,7	36,3 MW_{el}	36,3 MW_{el}		8,88	1	8,88	FNR	2005
ASU	45,70	0,5	76,6 t/h (O_2)	45,9 t/h (O_2)		35,37	1	35,37	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**59,34**		
Total capital investment								**433,12**		

dEF-D concept, SP technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	25,0 t_{feu}/h	5	4,80	1,54	7,37	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	25,0 t_{feu}/h	5	1,62	1,54	2,49	Boe	2002
chipper	0,48	0,6	33,50 t_{feu}/h	25,0 t_{feu}/h	5	2,01	1,54	3,10	Boe	2002
hammer mill	0,37	0,7	50,00 t_{feu}/h	25,0 t_{feu}/h	5	1,14	1	1,14	Ham	2003
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	25,0 t_{feu}/h	5	33,64	1,54	51,72	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	25,0 t_{feu}/h	5	1,79	1,54	2,75	Boe	2002
pyrolysis reactor					5			45,14	FZK	
Overall								**113,71**		
Gasification										
EF gasifier	44,06	0,7	432 MW_{th}	432 MW_{th}		44,06	1	44,06	Mun	2003
Overall								**44,06**		
Gas cleaning										
heat exchanger	8,10	0,6	138,1 MW_{th}	41,5 MW_{th}		3,94	1,54	6,05	Boe	2002
water scrubber	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
rectisol washing system I	24,00	0,7	132 t/h	132 t/h		24,00	1	24,00	Kos	2006
Overall								**45,77**		
Gas conditioning										
WGW reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	4899 kmol/h ($CO+H_2$)		8,33	1,81	15,07	Boe	2002
rectisol washing system II	24,00	0,7	132 t/h	66 t/h		14,77	1	14,77	Kos	2006
ATR	10,10	0,7	400 MW_{BWL}	500 MW_{BWL}		11,81	1,54	18,15	Tij	1998
Overall								**48,00**		
Synthesis										
slurry reactor	36,50	0,72	122,35 MW_{FT}	290,94 MW_{FT}		68,10	1	68,10	Boe	2003
Overall								**68,10**		
Upgrading										
rectification	5,00	0,7	20 t/h	17,80 t/h		4,61	1	4,61	Win	2006
hydrocracking	500,00	0,7	250 t/h	12,46 t/h		61,27	1	61,27	Rei	2006
Overall								**65,88**		
Utilities										
steam generation	3,38	0,8	47,5 t/h	159,4 t/h		8,90	1,54	13,69	Tij	1998
steam turbine	8,88	0,7	36,3 MW_{el}	36,3 MW_{el}		8,88	1	8,88	FNR	2005
waste water treatment	0,21	1	75 MW_{BWL}	455 MW_{BWL}		1,27	1	1,27	Ham	2004
Summe								**23,84**		
Total capital investment								**409,38**		

CFB-D concept, SP technology

Component	base costs M€	R -	base scale	installed scale	no.	costs M€	installation factor	overall costs M€	ref.	year
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	143,6 t_{feu}/h		2,99	1,54	4,59	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	143,6 t_{feu}/h		1,31	1,54	2,02	Boe	2002
chipper	0,48	0,6	33,50 t_{feu}/h	143,6 t_{feu}/h		1,15	1,54	1,77	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	143,6 t_{feu}/h		1,19	1,54	1,83	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	143,6 t_{feu}/h		27,23	1,54	41,87	Boe	2002
pelletising	2,60		10,00 t_{feu}/h	10,00 t_{feu}/h	15	39,00	1	39,00	Wac	2006
feeding system	0,48	1	33,50 t_{feu}/h	143,6 t_{feu}/h		2,06	1,54	3,16	Boe	2002
Overall								**94,24**		
Gasification										
CFB gasifier	13,50	0,7	500 MW_{th}	100 MW_{th}	5	21,88	1,54	33,64	CUT	2005
Overall								**33,64**		
Gas cleaning										
hot gas dedusting	14,30	0,7	400 MW_{th} H_o	537 MW_{th} H_o		17,57		17,57	Tij	1998
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	4365 kmol/h ($CO+H_2$)		7,72	1,81	13,98	Boe	2002
tar cracker	3,60	0,7	34,2 m³/s (Gas)	216,3 m³/s (Gas)		13,09	1,54	20,13	Boe	2002
heat exchanger	8,10	0,6	138,1 MW_{th}	12,5 MW_{th}		1,92	1,54	2,95	Boe	2002
water scrubber	3,00	0,7	12,1 m³/s (Gas)	69,89 m³/s (Gas)		10,24	1,54	15,74	Boe	2002
FAME scrubber	1,64	0,7	14,7 m³/s (Gas i. N.)	46,67 m³/s (Gas i. N.)		3,68	1	3,68	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	12,88 MW_{el}	2	25,27	1,54	38,85	Boe	2002
catalytical hydrogenation	3,60	0,7	34,2 m³/s (Gas)	50,0 m³/s (Gas)		4,70	1,54	7,23	Boe	2002
Overall								**120,14**		
Gas conditioning										
selexol washing system	63,00	0,7	9909 kmol/h (CO_2)	1587 kmol/h (CO_2)		17,48	1	17,48	Boe	2002
ZnO-adsorber	0,02	1	8 m³/s (Gas i. N.)	25 m³/s (Gas i. N.)		0,07	1,54	0,12	Boe	2002
Overall								**17,60**		
Synthesis										
Solid bed gas phase FT	25,30	1	93,4 MW_{FT}	206 MW_{FT}		55,80	1,3	72,54	Boe	2003
Overall								**72,54**		
Upgrading										
rectification	5,00	0,7	20 t/h	17 t/h		4,45	1	4,45	Win	2006
hydrocracking	500,00	0,7	250 t/h	11,838 t/h		59,12	1	59,12	Rei	2006
Overall								**63,56**		
Utilities										
gas turbine	22,00	0,7	26,3 MW_{el}	60,713 MW_{el}		39,51	1,54	60,75	Boe	2002
steam turbine	3,28	0,7	11,7 MW_{el}	8,121 MW_{el}		3,28	1	3,28	FNR	2005
ASU	45,70	0,5	76,6 t/h (O_2)	45,9 t/h (O_2)		35,37	1	35,37	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**100,80**		
Total capital investment								**502,52**		

ICFB-D concept, SP technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	15 t_{feu}/h		0,70	1,66	1,16	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	15 t_{feu}/h		0,22	1,66	0,37	Boe	2002
chipper	0,48	0,6	33,50 t_{feu}/h	15 t_{feu}/h		0,30	1,66	0,50	Boe	2002
dryer	8,50	0,8	33,50 t_{feu}/h	15 t_{feu}/h		4,56	1,66	7,59	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	15 t_{feu}/h		0,22	1,66	0,37	Boe	2002
Overall								**9,98**		
Gasification										
FICFB-gasifier	5,00	0,7	16,6 MW_{th}	52,7 MW_{th}		11,22	1	11,22	IE	2005
Overall								**11,22**		
Gas cleaning										
heat exchanger	8,10	0,6	138,1 MW_{th}	9,9 MW_{th}		1,66	1,66	2,76	Boe	2002
baghaouse filter	1,90	0,65	12,1 m³/s (Gas)	19,5 m³/s (Gas)		2,59	1,66	4,31	Boe	2002
FAME scrubber	1,64	0,7	14,7 m³/s (Gas i. N.)	3,4 m³/s (Gas i. N.)		0,59	1	0,59	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	2,5 MW_{el}	2	6,30	1,66	10,47	Boe	2002
ZnO adsorber	0,13	1	367 MW_{BWL}	50 MW_{BWL}		0,02	1,54	0,03	Tij	1998
hot gas dedusting	35,80	1	74,1 m³/s (Gas)	11,8 m³/s (Gas)		5,69	1,66	9,46	Boe	2002
heat exchanger	8,10	0,6	138,1 MW_{th}	6,7 MW_{th}		1,32	1,66	2,20	Boe	2002
Overall								**29,82**		
Gas conditioning										
-										
Synthesis										
slurry phase FT	36,50	0,72	122,35 MW_{FT}	14,837 MW_{FT}		7,99	1	7,99	Boe	2003
Overall								**7,99**		
Upgrading										
rectificatione	5,00	0,7	20 t/h	12 t/h		3,44	0,1	0,34	Win	2006
hydrocracking	500,00	0,7	250 t/h	8,204 t/h		45,73	0,1	4,57	Rei	2006
Overall								**4,92**		
Utilities										
gas turbine	7,70	0,7	25 MW_{el}	7,18 MW_{el}		3,22	1,66	5,35	Tij	1998
adjustment to LCV gas	0,26	0,7	52 MW_{BWL}	52 MW_{BWL}		0,26		0,26	Tij	1998
ORC	0,96	0,7	0,5 MW_{el}	2,53 MW_{el}		2,98	1	2,98	Ros	2005
waste water treatment	0,21	1	75 MW_{BWL}	52 MW_{BWL}		0,15	1	0,15	Ham	2004
Overall								**8,73**		
Total capital investment								**72,66**		

BLEF-DME concept, SP technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	148 t_{feu}/h		3,05	1,54	4,69	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	148 t_{feu}/h		1,35	1,54	2,07	Boe	2002
chipping	0,48	0,6	33,50 t_{feu}/h	148 t_{feu}/h		1,17	1,54	1,80	Boe	2002
conveyer drier	8,50	0,8	33,50 t_{feu}/h	148 t_{feu}/h		27,90	1,54	42,90	Boe	2002
feeding	0,48	1	33,50 t_{feu}/h	148 t_{feu}/h		2,12	1,54	3,26	Boe	2002
Overall								**54,72**		
Gasification										
entrained flow gasifier	20,40	0,7	200 MW_{th}	200 MW_{th}	4	81,60	1	81,60	Mun	2003
Overall								**81,60**		
Gas cleaning										
heat exchanger	6,99	0,6	39,2 kg/s (Dampf)	16 kg/s (steam)	4	16,33	1,54	25,11	Faa	2001
water scrubber	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
Rectisol I	24,00	0,7	132 t/h	132 t/h		24,00	1	24,00	Kos	2006
Overall								**64,83**		
gas cnditioning										
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	2613 kmol/h ($CO+H_2$)		5,53	1,81	10,01	Boe	2002
Rectisol II	24,00	0,7	132 t/h	66 t/h		14,77	1	14,77	Kos	2006
Overall								**24,79**		
Synthesis										
DME synthesis	47,80	0,7	25 t/h	34,3 t/h		59,65	1	59,65	STEM	2002
Overall								**59,65**		
Upgrading										
destillation*										
Utilities										
steam generation	56,90	0,7	500 MW_{th}	500 MW_{th}		56,90	1	56,90	Che	2005
steam turbine I	4,00	0,7	20 MW_{el}	54 MW_{el}		8,02	1	8,02	FNR	2005
steam turbine II	4,00	0,7	20 MW_{el}	126 MW_{el}		14,51	1	14,51	FNR	2005
ASU	45,70	0,5	76,6 t/h (O_2)	48,8 t/h (O_2)		36,48	1	36,48	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**117,31**		
sub-total								**343,24**		
reference plant										
BIL boiler								**-153,70**	Che	2005
Total capital investment								**189,54**		

*) included in DME synthesis

CFB-E concept, SP technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	133,8 t_{feu}/h		2,85	1,54	4,39	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	133,8 t_{feu}/h		1,24	1,54	1,91	Boe	2002
hammer mill	0,48	0,6	33,50 t_{feu}/h	133,8 t_{feu}/h		1,10	1,54	1,69	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	133,8 t_{feu}/h		1,13	1,54	1,74	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	133,8 t_{feu}/h		25,74	1,54	39,57	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	133,8 t_{feu}/h		1,92	1,54	2,95	Boe	2002
Overall								**52,25**		
Gasification										
FICFB gasifier	5,00	0,7	16,6 MW_{th}	452,0 MW_{th}		50,47	1,54	77,60	IE	2005
Overall								**77,60**		
Gas cleaning										
tar reformer	3,60	0,7	34,2 m^3/s (Gas)	63,5 m^3/s (Gas)		5,55	1,54	8,55	Boe	2002
tar cracker (LO-CAT)	3,60	0,7	34,2 m^3/s (Gas)	30,0 m^3/s (Gas)		3,28	1,54	5,05	Boe	2002
steam generation	8,10	0,6	138,1 MW_{th}	70,4 MW_th	3	16,22	1,54	24,94	Boe	2002
compressor	12,90	0,7	13,2 MW_el	0,5 MW_el		1,21	1,54	1,86	Boe	2002
ZnO adsorber	0,13	1	367 MW_{BWL}	500 MW_{BWL}		0,18	1,54	0,27	Boe	2002
Overall								**40,67**		
Gas conditioning										
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	5260 kmol/h ($CO+H_2$)		8,72	1,81	15,78	Boe	2002
selexol washing system	63,00	0,7	9909 kmol/h (CO_2)	412 kmol/h (CO_2)		6,80	1	6,80	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	25,20 MW_{el}		22,35	1,54	34,36	Boe	2002
Overall								**56,94**		
Synthesis										
ethanol synthesis	5,60	1	100 MW_{FT}	163 MW_{FT}		9,13	1,3	11,87	Ham	2004
Overall								**11,87**		
Upgrading										
rectification	5,00	0,7	20 t/h	23 t/h	4	21,95	1	21,95	Win	2006
Overall								**21,95**		
Utilities										
gas turbine	22,00	0,7	26,3 MW_{el}	68,521 MW_{el}		43,01	1,54	66,12	Boe	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**67,52**		
Total capital investment								**328,80**		

EF-E concept, SP technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	148,0 t_{feu}/h		3,05	1,54	4,69	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	148,0 t_{feu}/h		1,35	1,54	2,07	Boe	2002
mill	0,48	0,6	33,50 t_{feu}/h	148,0 t_{feu}/h		1,17	1,54	1,80	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	148,0 t_{feu}/h		1,22	1,54	1,87	Boe	2002
torrefaction	7,90	0,7	112,00 kt/a	834,0 kt/a		32,21	1,54	49,60	ECN	2007
bunker	1,16	0,6	33,50 t_{feu}/h	148,0 t_{feu}/h		2,83	1,54	4,35	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	148,0 t_{feu}/h		2,12	1,54	3,26	Boe	2002
Overall								**67,64**		
Gasification										
EF gasifier	44,06	0,7	432 MWth	407,0 MW_th		42,26	1,00	42,26	Mun	2003
Overall								**42,26**		
Gas cleaning										
heat exchanger	8,10	0,6	138,1 MW_{th}	68,4 MW_th		5,31	1,54	8,18	Boe	2002
tar cracker (LO-CAT)	3,60	0,7	34,2 m³/s (Gas)	72,9 m³/s (Gas)		6,11	1,54	9,41	Boe	2002
ZnO adsorber	0,13	1	367 MW_{BWL}	500 MW_{BWL}		0,18	1,54	0,27	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	0,39 MW_{el}		0,65	1,54	0,99	Boe	2002
Overall								**18,86**		
Gas conditioning										
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	3985 kmol/h ($CO+H_2$)		7,28	1,81	13,18	Boe	2002
selexol washing system	63,00	0,7	9909 kmol/h (CO_2)	1756 kmol/h (CO_2)		18,76	1	18,76	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	2,01 MW_{el}		2,61	1,54	4,01	Boe	2002
expansion turbine	5,9	0,7	10,3 MW_el	0,02 MW_el		0,07	1,54	0,11	Kal	?
Overall								**36,06**		
Synthesis										
ethanol synthesis	5,60	1	100 MW_{FT}	134 MW_{FT}		7,50	1,3	9,76	Ham	2004
Overall								**9,76**		
Upgrading										
rectification	5,00	0,7	20 t/h	37 t/h	4	30,76	1	30,76	Win	2006
Ethanol absolution	0,3245	1	250 l_EtOH/h	11246,6 l_EtOH/h		14,60	1	14,60	Wet	2005
Overall								**45,36**		
Utilities										
ASU	45,70	0,5	76,6 t/h (O_2)	54,3 t/h (O_2)		38,47	1	38,47	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
CO2 compressor	18,10	0,6	13,20 MWel	6,5 MWel		11,81	1,54	18,16	Kal	?
Overall								**58,03**		
Total capital investment								**277,98**		

S1 scenario

cEF-D concept, S1 technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	148 t_{feu}/h		3,04	1,54	4,68	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	148 t_{feu}/h		1,34	1,54	2,07	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	29,5 t_{feu}/h	5	38,42	1,54	59,07	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	148 t_{feu}/h		2,12	1,54	3,25	Boe	2002
Overall								**69,07**		
Gasification										
EF gasifier	25,50	0,7	250 MW_{th}	250 MW_{th}	2	51,00	1	51,00	Mun	2003
Overall								**51,00**		
Gas cleaning										
water scrubber ($Fe(OH_2)$)	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
water scrubber	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
Overall								**31,44**		
Gas conditioning										
selexol CO2 removal	63,00	0,7	9909 kmol/h (CO_2)	109 kmol/h (CO_2)		2,68	1	2,68	Boe	2002
ZnO adsorber	0,13	1	367 MW_{BWL}	500 MW_{BWL}		0,18	1,54	0,27	Tij	1998
steam reformer	9,40	0,6	1390 kmol/h	224 kmol/h		3,14	1,54	4,83	Faa	2001
PSA	32,60	0,7	9600 kmol/h	224 kmol/h		2,35	1,69	3,97	Boe	2002
Overall								**11,75**		
Electrolysis										
	3,30	1	4,3 MW	559 MW		429,23	1	**429,23**	(FML)	2004
Synthesis										
Solid bed gas phase FT	25,30	1	93,4 MW_FT	540 MW_{FT}		146,27	1,3	190,16	Boe	2003
Overall								**190,16**		
Upgrading										
rectification	5,00	0,7	20 t/h	44 t/h		8,71	1	8,71	Win	2006
hydrocracking	500,00	0,7	250 t/h	36,576 t/h		130,21	1	130,21	Rei	2006
Overall								**138,92**		
Utilities										
steam generation	3,38	0,8	47,5 t/h	272,7837 t/h		13,68	1,54	21,04	Tij	1998
steam turbine	8,88	0,7	36,3 MW_{el}	56,924 MW_{el}	1	12,16	1	12,16	FNR	2005
waste water treatment	0,21	1	75 MW_{BWL}	498,7525333 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**34,60**		
Total capital investment								**956,17**		

dEF-D concept, S1 technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	25,0 t_{feu}/h	5	4,80	1,54	7,37	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	25,0 t_{feu}/h	5	1,62	1,54	2,49	Boe	2002
chipper	0,48	0,6	33,50 t_{feu}/h	25,0 t_{feu}/h	5	2,01	1,54	3,10	Boe	2002
hammer mill	0,37	0,7	50,00 t_{feu}/h	25,0 t_{feu}/h	5	1,14	1	1,14	Ham	2003
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	25,0 t_{feu}/h	5	33,63	1,54	51,70	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	25,0 t_{feu}/h	5	1,79	1,54	2,75	Boe	2002
pyrolysis reactor					5			45,14	FZK	
Overall								**113,70**		
Gasification										
EF gasifier	44,06	0,7	432 MW_{th}	432 MW_{th}		44,06	1	44,06	Mun	2003
Overall								**44,06**		
Gas cleaning										
heat exchanger	8,10	0,6	138,1 MW_{th}	41,5 MW_{th}		3,94	1,54	6,05	Boe	2002
water scrubber	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
rectisol washing system I	24,00	0,7	132 t/h	132 t/h		24,00	1	24,00	Kos	2006
Overall								**45,77**		
Gas conditioning										
rectisol washing system II	24,00	0,7	132 t/h	66 t/h		14,77	1	14,77	Kos	2006
ATR	10,10	0,7	400 MW_{BWL}	904 MW_{BWL}		17,88	1,54	27,49	Tij	1998
Overall								**42,26**		
Electrolysis										
	3,30	1	4,3 MW	544,4595 MW		417,84	1	**417,84**	(FML)	2004
Synthesis										
slurry reactor	36,50	0,72	122,35 MW_{FT}	434,3304094 MW_{FT}		90,88	1	90,88	Boe	2003
Overall								**90,88**		
Upgrading										
rectification	5,00	0,7	20 t/h	35,60 t/h		7,49	1	7,49	Win	2006
hydrocracking	500,00	0,7	250 t/h	24,92 t/h		99,54	1	99,54	Rei	2006
Overall								**107,03**		
Utilities										
steam generation	3,38	0,8	47,5 t/h	272,78 t/h		13,68	1,54	21,04	Tij	1998
steam turbine	8,88	0,7	36,3 MW_{el}	56,9 MW_{el}		12,16	1	12,16	FNR	2005
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**34,60**		
Total capital investment								**896,14**		

CFB-D concept, S1 technology

Component	base costs M€	R -	base scale	installed scale	no.	costs M€	installation factor	overall costs M€	ref.	year
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	143,4 t_{feu}/h		2,98	1,54	4,59	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	143,4 t_{feu}/h		1,31	1,54	2,02	Boe	2002
chipper	0,48	0,6	33,50 t_{feu}/h	143,4 t_{feu}/h		1,15	1,54	1,77	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	143,4 t_{feu}/h		1,19	1,54	1,83	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	143,4 t_{feu}/h		27,20	1,54	41,82	Boe	2002
pelletising	2,60		10,00 t_{feu}/h	10,00 t_{feu}/h	15	39,00	1	39,00	Wac	2006
feeding system	0,48	1	33,50 t_{feu}/h	143,4 t_{feu}/h		2,05	1,54	3,16	Boe	2002
Overall								**94,18**		
Gasification										
CFB gasifier	13,50	0,7	500 MW_{th}	100 MW_{th}	5	21,88	1,54	33,64	CUT	2005
Overall								**33,64**		
Gas cleaning										
hot gas dedusting	14,30	0,7	400 MW_{th} H_o	536 MW_{th} H_o		17,55		17,55	Tij	1998
tar cracker	3,60	0,7	34,2 m³/s (Gas)	178,8 m³/s (Gas)		11,46	1,54	17,62	Boe	2002
heat exchanger	8,10	0,6	138,1 MW_{th}	9,5 MW_{th}		1,63	1,54	2,50	Boe	2002
water scrubber	3,00	0,7	12,1 m³/s (Gas)	58,65 m³/s (Gas)		9,06	1,54	13,92	Boe	2002
FAME scrubber	1,64	0,7	14,7 m³/s (Gas i. N.)	43,39 m³/s (Gas i. N.)		3,50	1	3,50	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	11,97 MW_{el}	2	23,73	1,54	36,49	Boe	2002
catalytical hydrogenation	3,60	0,7	34,2 m³/s (Gas)	50,0 m³/s (Gas)		4,70	1,54	7,23	Boe	2002
Overall								**98,82**		
Gas conditioning										
selexol washing system	63,00	0,7	9909 kmol/h (CO_2)	1475 kmol/h (CO_2)		16,60	1	16,60	Boe	2002
Zno adsorber	0,02	1	8 m³/s (Gas i. N.)	31 m³/s (Gas i. N.)		0,09	1,54	0,14	Boe	2002
Overall								**16,75**		
Electrolysis										
	3,30	1	4,3 MW	161 MW		123,56	1	**123,56**	(FML)	2004
Synthesis										
solid bed gas phase FT	25,30	1	93,4 MW_{FT}	292 MW_{FT}		79,10	1,3	102,83	Boe	2003
Overall								**102,83**		
Upgrading										
rectification	5,00	0,7	20 t/h	24 t/h		5,65	1	5,65	Win	2006
hydrocracking	500,00	0,7	250 t/h	16,668 t/h		75,12	1	75,12	Rei	2006
Overall								**80,76**		
Utilities										
gas turbine	22,00	0,7	26,3 MW_{el}	68,521 MW_{el}		43,01	1,54	66,12	Boe	2002
steam turbine	3,28	0,7	11,7 MW_{el}	11,7 MW_{el}		3,28	1	3,28	FNR	2005
ASU	45,70	0,5	76,6 t/h (O_2)	45,9 t/h (O_2)		35,37	1	35,37	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**106,17**		
Total capital investment								**656,71**		

ICFB-D concept, S1 technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	148,0 t_{feu}/h		3,05	1,54	4,69	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	148,0 t_{feu}/h		1,35	1,54	2,07	Boe	2002
chipper	0,48	0,6	33,50 t_{feu}/h	148,0 t_{feu}/h		1,17	1,54	1,80	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	148,0 t_{feu}/h		1,22	1,54	1,87	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	148,0 t_{feu}/h		27,90	1,54	42,90	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	148,0 t_{feu}/h		2,12	1,54	3,26	Boe	2002
Overall								**56,59**		
Gasification										
heat exchanger steam generation	6,99	1	39,2 kg steam/s	9,635555556 kg steam/s		1,72	1,54	2,65	Faa	2001
FICFB gasifier	5,00	0,7	16,6 MW_{th}	517 MW_{th}	1	55,45	1,54	85,25	CUT	2005
Overall								**87,90**		
Gas cleaning										
heat exchanger exhaust gas	8,10	0,6	138,1 MW_{th}	49,485 MW_{th}		4,38	1,54	6,73	Boe	2002
hot gas filter	30,00	1	74,1 m³ Gas/s	8,99 m³ Gas/s		3,64	1,72	6,26	Faa	2001
Overall								**12,99**		
Gas conditionin										
dust filter	1,90	0,65	12,1 m³/s (Gas)	9,88 m³/s (Gas)		1,67	1,54	2,56	Boe	2002
				181168			2,3	12,41		
steam reformer	1,02	0,85	25470 Nm³/h_Gas	Nm³/h_Gas		5,40			Faa	2001
product gas cooling	2,95	0,7	69,54 MW_th_LHV	20 MW_th_LHV		1,23	1,54	1,90	Tij	1998
catalytical hydrogenation	3,60	0,7	34,2 m³/s (Gas)	5,4 m³/s (Gas)		0,98	1,54	1,51	Boe	2002
ZnO adsorber	0,02	1	8 m³/s (Gas i. N.)	58 m³/s (Gas i. N.)		0,17	1,54	0,27	Boe	2002
Overall								**18,65**		
Synthesis										
slurry phase FT	36,50	0,72	122,35 MW_{FT}	300 MW_{FT}		69,62	1	69,62	Kal	?
Overall								**69,62**		
Upgrading										
rectification	5,00	0,7	20 t/h	24,615 t/h		5,78	1	5,78	Win	2006
hydrocracking	500,00	0,7	250 t/h	17 t/h		76,89	1	76,89	Rei	2006
Overall								**82,67**		
Utilities										
gas turbine	22,00	0,7	26,3 MW_{el}	27,981 MW_{el}		22,98	1,54	35,32	Boe	2002
gas turbine	22,00	0,7	26,3 MW_{el}	6,344 MW_{el}		8,13	1,54	12,52	Boe	2002
steam turbine incl. cycle	5,90	0,7	5,9 MW_el	28,773 MW_el		17,89	1,54	27,55	Kal	
Overall								**75,39**		
Total capital investment								**403,81**		

BLEF-DME concept, S1 technology

Component	base costs	R	base scale	installed scale	no.	costs	installation factor	overall costs	ref.	year
	M€	-				M€		M€		
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	148 t_{feu}/h		3,05	1,54	4,69	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	148 t_{feu}/h		1,35	1,54	2,07	Boe	2002
chipping	0,48	0,6	33,50 t_{feu}/h	148 t_{feu}/h		1,17	1,54	1,80	Boe	2002
conveyer drier	8,50	0,8	33,50 t_{feu}/h	148 t_{feu}/h		27,90	1,54	42,90	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	148 t_{feu}/h		2,12	1,54	3,26	Boe	2002
Overall								**54,72**		
Gasification										
EF gasifier	20,40	0,7	200 MW_{th}	200 MW_{th}	4	81,60	1	81,60	Mun	2003
Overall								**81,60**		
Gas cleaning										
heat exchanger	6,99	0,6	39,2 kg/s (Dampf)	16 kg/s (Dampf)	4	16,33	1,54	25,11	Faa	2001
water scrubber	2,57	0,7	69,54 MW_{BWL}	500 MW_{BWL}		10,22	1,54	15,72	Tij	1998
Rectisol I	24,00	0,7	132 t/h	132 t/h		24,00	1	24,00	Kos	2006
Overall								**64,83**		
Gas cnditioning										
WGS reactor	12,20	0,65	8819 kmol/h $(CO+H_2)$	2613 kmol/h $(CO+H_2)$		5,53	1,81	10,01	Boe	2002
Rectisol II	24,00	0,7	132 t/h	66 t/h		14,77	1	14,77	Kos	2006
Overall								**24,79**		
Synthesis										
DME synthesis	47,80	0,7	25 t/h	34,3 t/h		59,65	1	59,65	STEM	2002
Overall								**59,65**		
Upgrading										
destillation*										
Utilities										
steam generation	56,90	0,7	500 MW_{th}	500 MW_{th}		56,90	1	56,90	Che	2005
steam turbine I	4,00	0,7	20 MW_{el}	54 MW_{el}		8,02	1	8,02	FNR	2005
steam turbine II	4,00	0,7	20 MW_{el}	126 MW_{el}		14,51	1	14,51	FNR	2005
ASU	45,70	0,5	76,6 t/h (O_2)	48,8 t/h (O_2)		36,48	1	36,48	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**117,31**		
Sub-total								**343,24**		
Reference plant										
BIL boiler								**-153,70**	Che	2005
Total capital investment								**189,54**		

CFB-E concept, S1 technology

Component	base costs M€	R -	base scale	installed scale	no.	costs M€	installation factor	overall costs M€	ref.	year
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	133,9 t_{feu}/h		2,86	1,54	4,39	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	133,9 t_{feu}/h		1,24	1,54	1,91	Boe	2002
hammer mill	0,48	0,6	33,50 t_{feu}/h	133,9 t_{feu}/h		1,10	1,54	1,69	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	133,9 t_{feu}/h		1,13	1,54	1,74	Boe	2002
conveyer dryer	8,50	0,8	33,50 t_{feu}/h	133,9 t_{feu}/h		25,75	1,54	39,60	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	133,9 t_{feu}/h		1,92	1,54	2,95	Boe	2002
Overall								**52,29**		
Gasification										
FICFB gasifier	5,00	0,7	16,6 MW_{th}	452,0 MW_{th}		50,47	1,54	77,60	IE	2005
Overall								**77,60**		
Gas cleaning										
tar reformer	3,60	0,7	34,2 m³/s (Gas)	65,3 m³/s (Gas)		5,66	1,54	8,71	Boe	2002
tar cracker (LO-CAT)	3,60	0,7	34,2 m³/s (Gas)	30,3 m³/s (Gas)		3,31	1,54	5,09	Boe	2002
steam generation	8,10	0,6	138,1 MW_{th}	69,3 MW_th	3	16,07	1,54	24,70	Boe	2002
compressor	12,90	0,7	13,2 MW_el	0,4 MW_el		1,19	1,54	1,83	Boe	2002
ZnO adsorber	0,13	1	367 MW_{BWL}	500 MW_{BWL}		0,18	1,54	0,27	Boe	2002
Overall								**40,61**		
Gas conditioning										
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	5260 kmol/h ($CO+H_2$)		8,72	1,81	15,78	Boe	2002
selexol washing system	63,00	0,7	9909 kmol/h (CO_2)	410 kmol/h (CO_2)		6,78	1	6,78	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	51,38 MW_{el}		40,95	1,54	62,96	Boe	2002
Overall								**85,52**		
Synthesis										
ethanol synthesis	5,60	1	100 MW_{FT}	257 MW_{FT}		14,39	1,3	18,71	Ham	2004
Overall								**18,71**		
Upgrading										
rectification	5,00	0,7	20 t/h	53 t/h	4	39,71	1	39,71	Win	2006
Overall								**39,71**		
Utilities										
gas turbine	22,00	0,7	26,3 MW_{el}	68,521 MW_{el}		43,01	1,54	66,12	Boe	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
Overall								**67,52**		
Total capital investment								**381,96**		

EF-E concept, S1 technology

Component	base costs M€	R -	base scale	installed scale	no.	costs M€	installation factor	overall costs M€	ref.	year
Biomass treatment										
storage	1,16	0,65	33,50 t_{feu}/h	133,9 t_{feu}/h		2,86	1,54	4,39	Boe	2002
transport	0,41	0,8	33,50 t_{feu}/h	133,9 t_{feu}/h		1,24	1,54	1,91	Boe	2002
mill	0,48	0,6	33,50 t_{feu}/h	133,9 t_{feu}/h		1,10	1,54	1,69	Boe	2002
metal separation	0,43	0,7	33,50 t_{feu}/h	133,9 t_{feu}/h		1,13	1,54	1,74	Boe	2002
torrefaction	7,90	0,7	112,00 kt/a	834,0 kt/a		32,21	1,54	49,60	ECN	2005
bunker	1,16	0,6	33,50 t_{feu}/h	133,9 t_{feu}/h		2,66	1,54	4,10	Boe	2002
feeding system	0,48	1	33,50 t_{feu}/h	133,9 t_{feu}/h		1,92	1,54	2,95	Boe	2002
Overall								**66,39**		
Gasification										
EF gasifier	44,06	0,7	432 MWth	407,0 MW_th		42,26	1,00	42,26	Mun	2003
Overall								**42,26**		
Gas cleaning										
heat exchanger	8,10	0,6	138,1 MW_{th}	68,4 MW_th		5,31	1,54	8,18	Boe	2002
tar cracker (LO-CAT)	3,60	0,7	34,2 m³/s (Gas)	72,9 m³/s (Gas)			1,54		Boe	2002
						6,11		9,41		
ZnO adsorber	0,13	1	367 MW_{BWL}	500 MW_{BWL}		0,18	1,54	0,27	Boe	2002
Overall								**17,87**		
Gas conditioning										
WGS reactor	12,20	0,65	8819 kmol/h ($CO+H_2$)	6900 kmol/h ($CO+H_2$)		10,40	1,81	18,83	Boe	2002
selexol washing system	63,00	0,7	9909 kmol/h (CO_2)	2479 kmol/h (CO_2)		23,88	1	23,88	Boe	2002
compressor	12,90	0,85	13,2 MW_{el}	4,73 MW_{el}		5,39	1,54	8,29	Boe	2002
Overall								**51,00**		
Synthesis										
ethanol synthesis	5,60	1	100 MW_{FT}	226 MW_{FT}		12,66	1,3	16,45	Ham	2004
Overall								**16,45**		
Upgrading										
rectification	5,00	0,7	20 t/h	37 t/h	4	30,76	1	30,76	Win	2006
Ethanol absolution	0,3245	1	250 l_EtOH/h	19414,4 l_EtOH/h		25,20	1	25,20	Wet	2005
Overall								**55,96**		
Utilities										
ASU	45,70	0,5	76,6 t/h (O_2)	54,3 t/h (O_2)		38,47	1	38,47	Chi	2002
waste water treatment	0,21	1	75 MW_{BWL}	500 MW_{BWL}		1,40	1	1,40	Ham	2004
CO2 compressor	18,10	0,6	13,20 MWel	6,5 MWel		11,81	1,54	18,16	Kal	?
Overall								**58,03**		
Total capital investment								**307,97**		

Appendix B Btl production costs

SP technology, SP best case biomass provision costs

Note: Biomass provision costs are given in Euros per GJ biomass input, the conversion costs in Euros per GJ BTL fuel.

WEST [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	8,46	5,24	6,15	8,46	8,46	8,46	5,24	7,59	8,23	8,46
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	23,49	14,56	22,59	15,10	78,65	34,72	21,52	48,42	52,56	54,56
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,44	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	35,78	26,73	46,11	22,13	77,11	54,93	42,53	66,19	71,10	62,54

EAST [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	7,92	4,46	4,44	7,92	7,92	7,92	4,46	7,00	6,99	7,92
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	22,00	12,39	16,32	14,15	73,67	32,53	18,32	44,71	44,60	51,11
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	34,30	24,57	39,84	21,17	72,14	52,75	39,33	62,49	63,14	59,09

NORTH [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	10,13	8,50	9,55	10,13	10,13	10,13	8,50	7,78	11,00	10,13
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	28,13	23,61	35,07	18,09	94,19	41,59	34,91	49,65	70,18	65,35
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-3,40	-3,70	-3,67	0,00	-34,50	-4,42	-4,42	-38,97	-38,20	-18,60
Total BTL production costs	39,65	34,83	58,59	25,11	92,66	61,81	55,13	67,43	88,72	73,33

ALPINE [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	15,45	9,58	15,16	15,45	15,45	15,45	9,58	9,39	14,02	15,45
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	42,90	26,59	55,69	27,59	143,66	63,43	39,31	59,91	89,49	99,67
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	55,20	38,77	79,21	34,61	142,13	83,65	60,32	77,69	108,02	107,65

SOUTH	cEF-D		dEF-D	BLEF-DME	EF-E	CFB-D		ICFB-D		CFB-E
[€/GJ]	SRC	STR	STR-P	SRC	SRC	SRC	STR	SRC	MIS	SRC
Biomass provision costs	7,83	6,47	11,78	7,83	7,83	7,83	6,47	7,29	10,50	7,83
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	21,74	17,98	43,27	13,98	72,80	32,14	26,58	46,54	67,05	50,50
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	34,04	30,15	66,79	21,00	71,26	52,36	47,58	64,32	85,58	58,48

UK + IR	cEF-D		dEF-D	BLEF-DME	EF-E	CFB-D		ICFB-D		CFB-E
[€/GJ]	SRC	STR	STR-P	SRC	SRC	SRC	STR	SRC	MIS	SRC
Biomass provision costs	17,67	9,17	11,64	17,67	17,67	17,67	9,17	12,06	11,89	17,67
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	49,07	25,47	42,78	31,55	164,31	72,54	37,65	76,98	75,90	113,99
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	61,37	37,64	66,30	38,58	162,77	92,76	58,66	94,76	94,44	121,97

SP technology, S1 best case biomass provision costs

WEST	cEF-D		dEF-D	BLEF-DME	EF-E	CFB-D		ICFB-D		CFB-E
[€/GJ]	SRC	STR	STR-P	SRC	SRC	SRC	STR	SRC	MIS	SRC
Biomass provision costs	6,13	5,08	5,77	6,13	6,13	6,13	5,08	5,23	7,61	6,13
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	17,02	14,11	21,20	10,95	57,00	25,17	20,86	33,38	48,57	50,51
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	29,32	26,28	44,72	17,97	55,47	45,39	41,87	51,16	67,11	58,49

EAST	cEF-D		dEF-D	BLEF-DME	EF-E	CFB-D		ICFB-D		CFB-E
[€/GJ]	SRC	STR	STR-P	SRC	SRC	SRC	STR	SRC	MIS	SRC
Biomass provision costs	5,10	4,99	5,10	5,10	5,10	5,10	4,99	4,54	7,02	5,10
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	14,16	13,86	18,74	9,11	47,43	20,94	20,49	28,98	44,81	32,90
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-59,27	-38,20	-18,60
Total BTL production costs	26,46	26,03	42,26	16,13	45,89	41,16	41,50	26,45	63,35	40,88

NORTH	cEF-D		dEF-D	BLEF-DME	EF-E	CFB-D		ICFB-D		CFB-E
[€/GJ]	SRC	STR	STR-P	SRC	SRC	SRC	STR	SRC	MIS	SRC
Biomass provision costs	7,33	8,19	9,05	7,33	7,33	7,33	8,19	5,41	8,37	7,33
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	20,36	22,75	33,25	13,09	68,16	30,10	33,63	34,53	53,43	47,29
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	32,65	34,92	56,77	20,11	66,63	50,31	54,64	52,31	71,96	55,27

ALPINE [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	6,48	8,95	14,49	6,48	6,48	6,48	8,95	6,00	8,34	6,48
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	18,00	24,86	53,24	11,57	60,26	26,61	36,75	38,30	53,23	41,81
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	30,29	37,03	76,76	18,60	58,73	46,82	57,76	56,07	71,77	49,78

SOUTH [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	6,61	6,54	11,23	6,61	6,61	6,61	6,54	6,08	10,42	6,61
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	18,36	18,16	41,26	11,80	61,47	27,14	26,85	38,81	66,51	42,64
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	30,65	30,34	64,78	18,83	59,93	47,36	47,86	56,58	85,05	50,62

UK + IR [€/GJ]	cEF-D SRC	STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	8,54	15,85	20,62	8,54	8,54	8,54	15,85	6,09	7,32	8,54
Capital-related costs	8,01	8,01	10,98	2,25	17,42	14,13	14,13	29,64	29,64	15,59
Biomass costs	23,72	44,02	75,77	15,25	79,42	35,06	65,08	38,87	46,72	55,10
Other consumption-related costs	1,00	1,00	8,34	3,40	1,01	1,94	1,94	8,00	8,00	0,93
Operation-related + other costs	5,91	5,91	7,87	1,38	14,54	8,57	8,57	19,11	19,11	10,05
Revenues	-2,62	-2,74	-3,67	0,00	-34,50	-4,42	-3,63	-38,97	-38,20	-18,60
Total BTL production costs	36,01	56,19	99,29	22,27	77,88	55,28	86,09	56,65	65,26	63,07

S1 technology, S1 best case biomass provision costs

WEST [€/GJ]	cEF-D SRC	cEF-D STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	6,13	5,08	5,77	6,13	6,13	6,13	5,08	6,13	7,72	6,13
Capital-related costs	8,74	8,74	11,98	2,25	13,54	13,13	14,02	7,81	7,88	12,27
Biomass costs	8,42	7,51	10,57	10,95	30,37	17,85	15,15	18,44	25,33	26,78
Other consumption-related costs	45,55	45,55	63,90	3,40	7,17	27,77	32,68	0,88	0,89	18,89
Operation-related + other costs	5,59	5,59	7,55	1,38	10,40	7,96	8,50	5,03	5,08	7,91
Revenues	-2,15	-2,15	-3,66	0,00	-20,50	-3,65	-3,68	-7,30	-6,95	-18,78
Total BTL production costs	66,14	65,24	90,34	17,97	40,98	63,07	66,68	24,85	32,23	47,06

EAST [€/GJ]	cEF-D SRC	cEF-D STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	5,10	4,99	5,10	5,10	5,10	5,10	4,99	5,10	7,84	5,10
Capital-related costs	8,74	8,74	11,98	2,25	13,54	13,13	14,02	7,81	7,88	12,27
Biomass costs	7,00	7,38	9,34	9,11	25,26	14,85	14,88	15,34	25,72	22,28
Other consumption-related costs	45,55	43,40	63,90	3,40	7,17	27,77	32,68	0,88	0,89	18,89
Operation-related + other costs	5,59	2,13	7,55	1,38	10,40	7,96	8,50	5,03	5,08	7,91
Revenues	-2,15	3,46	-3,66	0,00	-20,50	-3,65	-3,68	-7,30	-6,95	-18,78
Total BTL production costs	64,73	65,11	89,11	16,13	35,88	60,07	66,41	21,75	32,62	42,57

NORTH [€/GJ]	cEF-D SRC	cEF-D STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	7,33	8,19	9,05	7,33	7,33	7,33	8,19	7,33	9,66	7,33
Capital-related costs	8,74	8,74	11,98	2,25	14,98	13,13	14,02	7,81	7,88	12,27
Biomass costs	10,06	12,11	16,57	13,09	36,31	21,35	24,42	22,05	31,69	32,02
Other consumption-related costs	45,55	43,40	63,90	3,40	7,17	27,77	32,68	0,88	0,89	18,89
Operation-related + other costs	5,59	2,13	7,55	1,38	11,20	7,96	8,50	5,03	5,08	7,91
Revenues	-2,15	3,46	-3,66	0,00	-20,50	-3,65	-3,68	-7,30	-6,95	-18,78
Total BTL production costs	67,79	69,84	96,35	20,11	49,17	66,56	75,95	28,46	38,59	52,31

ALPINE [€/GJ]	cEF-D SRC	cEF-D STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	6,48	8,95	14,49	6,48	6,48	6,48	8,95	6,48	8,78	6,48
Capital-related costs	8,74	8,74	11,98	2,25	14,98	13,13	14,02	7,81	7,88	12,27
Biomass costs	8,90	13,24	26,53	11,57	32,10	18,87	26,69	19,49	28,81	28,31
Other consumption-related costs	45,55	43,40	63,90	3,40	7,17	27,77	32,68	0,88	0,89	18,89
Operation-related + other costs	5,59	2,13	7,55	1,38	11,20	7,96	8,50	5,03	5,08	7,91
Revenues	-2,15	3,46	-3,66	0,00	-20,50	-3,65	-3,68	-7,30	-6,95	-18,78
Total BTL production costs	66,62	70,96	106,31	18,60	44,96	64,09	78,22	25,90	35,70	48,59

SOUTH [€/GJ]	cEF-D SRC	cEF-D STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	6,61	6,54	11,23	6,61	6,61	6,61	6,54	6,61	10,78	6,61
Capital-related costs	8,74	8,74	11,98	2,25	14,98	13,13	14,02	7,81	7,88	12,27
Biomass costs	9,08	9,67	20,56	11,80	32,74	19,25	19,50	19,88	35,37	28,88
Other consumption-related costs	45,55	43,40	63,90	3,40	7,17	27,77	32,68	0,88	0,89	18,89
Operation-related + other costs	5,59	2,13	7,55	1,38	11,20	7,96	8,50	5,03	5,08	7,91
Revenues	-2,15	3,46	-3,66	0,00	-20,50	-3,65	-3,68	-7,30	-6,95	-18,78
Total BTL production costs	66,80	67,40	100,34	18,83	45,60	64,47	71,03	26,29	42,27	49,16

UK + IR [€/GJ]	cEF-D SRC	cEF-D STR	dEF-D STR-P	BLEF-DME SRC	EF-E SRC	CFB-D SRC	STR	ICFB-D SRC	MIS	CFB-E SRC
Biomass provision costs	8,54	15,85	20,62	8,54	8,54	8,54	15,85	8,54	8,65	8,54
Capital-related costs	8,74	8,74	11,98	2,25	14,98	13,13	14,02	7,81	7,88	12,27
Biomass costs	11,73	23,45	37,76	15,25	42,31	24,87	47,26	25,69	28,38	37,31
Other consumption-related costs	45,55	43,40	63,90	3,40	7,17	27,77	32,68	0,88	0,89	18,89
Operation-related + other costs	5,59	2,13	7,55	1,38	11,20	7,96	8,50	5,03	5,08	7,91
Revenues	-2,15	3,46	-3,66	0,00	-20,50	-3,65	-3,68	-7,30	-6,95	-18,78
Total BTL production costs	69,45	81,17	117,53	22,27	55,16	70,09	98,79	32,10	35,28	57,59