OUI BIOMASSE

Fundamentals of Economics for Bioenergy

Responsible Partner: *Institute for Industrial Production (IIP)*
Authors: *Dr Bidart, Dr McKenna, Prof. Dr Fichtner*

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Coordinator:

Karlsruhe Institute of Technology (KIT)
Deutsch-Französisches Institut für Umweltforschung (DFIU)
Institut franco-allemand de recherche sur l'environnement
Hertzstraße 16
76187 Karlsruhe
www.dfiu.kit.edu

Contact coordinator: kira.schumacher@kit.edu

Project leaders: Prof. Dr. Wolf Fichtner
Prof. Dr. Frank Schultmann

Project partners

- Professur für Fernerkundung und Landschaftsinformationssysteme (FeLis), Universität Freiburg
- Association pour la Surveillance et l‘Etude de la Pollution Atmosphérique (ASPA)
- Departement Umweltwissenschaften (DUW), Universität Basel
- Deutsch-Französisches Institut für Umweltforschung (DFIU), Karlsruher Institut für Technologie (KIT)
- Génétique Moléculaire, Génomique, Microbiologie (GMGM), Université de Strasbourg
- Gestion Territoriale de l‘Eau et de l‘Environnement (GESTE), Ecole Nationale du Génie de l‘Eau et de l‘Environnement de Strasbourg (ENGEES)
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- Laboratoire de Gestion des Risques et Environnement (GRE), Université de Haute Alsace
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- Laboratoire d‘Hydrologie et de Géochimie de Strasbourg (LHyGeS), CNRS
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Chapter I

Fundamentals of Economics for Bioenergy

This section aims at briefly outlining the main concepts related to energy economics in general, with special emphasis on bioenergy. Instead of listing definitions in isolation, concepts relevant to bioenergy are formulated and discussed in context. The objective being to frame the terminology to be used in subsequent sections (generation cost, capital cost, proven technology, etc.), each particularly significant term is written in bold in order to underline its importance. Some numerical examples are also included to make clearer its application in the solution of concrete problems.

1. Introduction

The three uses of biomass for energy utilisation are basically ***heating***, ***fuels*** and ***electricity***. These are useful forms of energy; they can, consequently, be distributed, traded and commercialised. Being produced at large scales and traded at a relatively low price, they are normally categorised as ***commodities***. The generation of any of these energy carriers demands ***generation processes*** which transform the ***primary energy*** (i.e. biomass, crude oil, natural gas, etc.) into ***secondary energy*** (i.e. heat, fuels or electricity).

Biomass can be classified into ***lignocellulosic biomass*** and ***biochemical biomass***. Although these terms are not standard and differences can be found in definitions in the literature, they can be employed to denominate, for the former, biomass with a high lignin content, and for the latter, biomass that can undergo reaction by the action of enzymes, thus being converted by microorganisms. As Figure 1 shows, lignocellulosic biomass can be converted by processes such as combustion, gasification or pyrolysis. In gasification, for instance, the main product is a mixture of gases that can be utilised either as a gaseous fuel to be burnt in a gas turbine or engine for the production of heat or electricity, or both simultaneously. A second option for using this raw gas is for the synthesis of liquid fuels such as methanol, hydrogen and hydrocarbons. Similarly, biochemical biomass can be converted into biogas by enzymes in an anoxic environment (in absence of oxygen). Biogas, a mixture of methane and carbon dioxide of variable composition, can be either directly burnt in an engine for the simultaneous production of heat and electricity or utilised for the generation of a gaseous fuel via upgrading. The production of end-products (i.e. electricity, heat or fuels) can be carried out through ***conversion routes***, depending on the physicochemical process which the conversion is based on (i.e. combustion, gasification, etc.), which at the same time is conditioned by the sort of ***feedstock*** (biomass) to be converted (cf. Figure 1). For this reason the processes are normally grouped into ***thermochemical conversion*** processes, those based on the use of heat for the promotion of the reaction of the biomass, ***biochemical conversion*** processes, those based on the action of microorganisms for the conversion, and the ***physical conversion*** processes, those in which no chemical reaction takes place (at least at that stage). One distinguishing characteristic of biomass conversion is its flexibility, i.e. the possibility of converting biomass into different intermediates or end-products depending on what the most desirable option or product is. The final decision on the end-product will depend on numerous factors and, in most cases is market-driven.

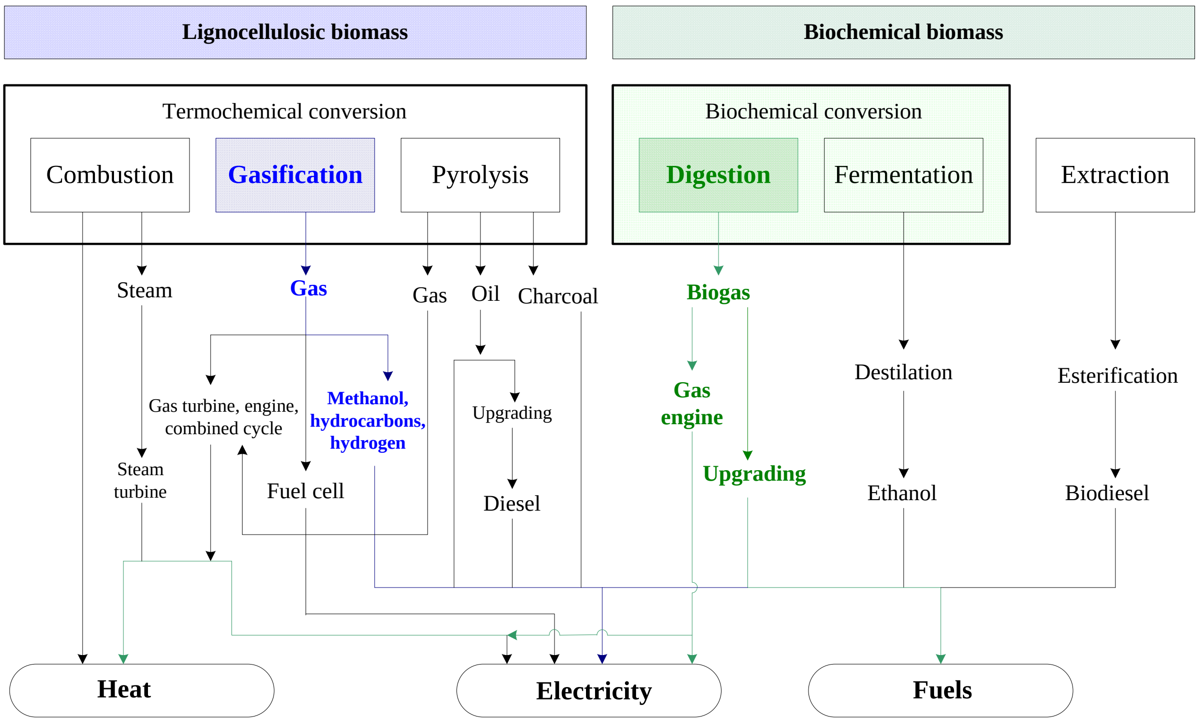
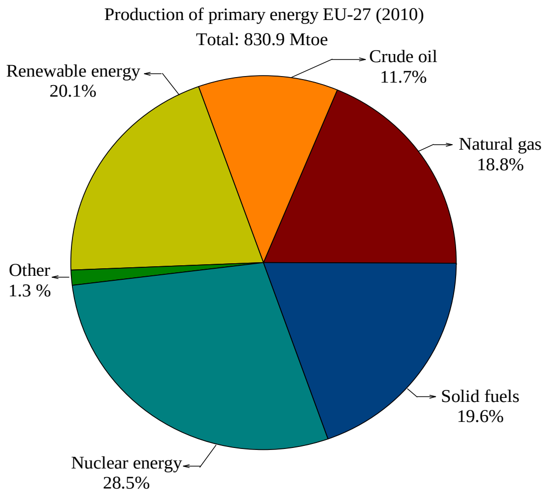


Figure 1. Major transformation routes of biomass for its conversion into secondary energy. Adapted from Faaij (2006).

Raw biomass is a ***primary source of energy*** as well as coal, crude oil or gas, and it can be part of the ***primary energy mix*** of a system. For a country or large geographical region, the primary energy mix is normally made up of indigenous sources plus net imports. ***Secondary energy***, such as electricity, can be produced locally by burning biomass, coal or gas, etc. although it can also be imported. Irrespective of its origin, it is accounted for in the ***secondary energy mix of electricity***. Figure 2 and Figure 3 show the primary energy mix and the electricity mix of EU-27 for the year 2010, respectively. In the former is observed that nuclear energy, renewable energy and solid fuels accounted for more than 60% of the supply in the form of primary energy. In the ***mix of electricity generation,*** conventional thermal and nuclear electricity are the dominating sources and constituted more than 80% of the annual generation for 2010.



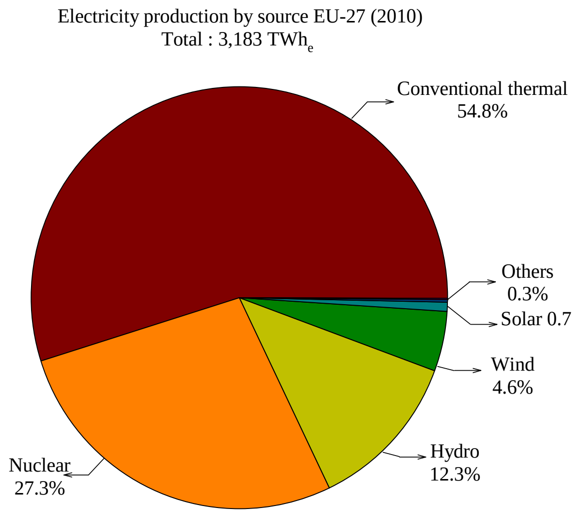


Figure 2. Total primary energy production within EU-27 in 2010. Source: Eurosat (2013a).

Figure 3. Total electricity production within EU-27 in 2010. Source: Eurosat (2013b).

2. Economics for bioenergy projects

Economic estimates are a necessary and normally challenging task for any financial or strategic study in the decision-making phase and of paramount importance for the success of any capital project. For bioenergy projects in particular, information as to economics is in general lacking and additionally may exhibit high variability attributable to the technology itself as well as the way of defining the battery limit by vendors or service suppliers, e.g. inclusion or not of biomass pre-conditioning, flue gas treatment, back-up systems, ash management cost, etc. Moreover, the definitions employed to refer to terminology such as capital cost, investment, operating cost, prices, etc. are not always used consistently in the literature. In addition to this, differences are observed in some concepts in their definitions in different disciplines, such as accounting and economic theory. For example, the term “investment” can exhibit differences in its conceptualisation in macro-economics or financing.

The accuracy of a cost estimate depends on the phase of the ***decision-making process***. This is a conceptual procedure to elucidate if a project is worth carrying out or should be stopped, if it makes sense to take the next step forward, which is normally more time-demanding and expensive. The higher the accuracy, the more costly and time-demanding the study is.

According to their accuracy, Biegler *et al.* (1999) noted that capital cost estimates can be classified into five categories: *order-of-magnitude*, with an associated error lower than 40%; *study estimate*, with associated error lower than 25%; *preliminary estimate*, with an associated error lower than 12%; *definitive estimate*, with an associated error lower than 6%; and eventually the *detailed estimate* with an associated error lower than 3%. Similarly, and as Figure 4 illustrates, the Association for the Advancement of Cost Engineering - AACE International (Crundwell 2008) proposed a classification for the level of accuracy of the estimate through four stages involving different preparation effort, these are: *concept stage*, with 50-100% associated confidence limit; *pre-feasibility*, with 30-50% associated confidence limit; *feasibility*, with 10-30% associated confidence limit; and *detailed engineering*, with 5-15% associated confidence limit.

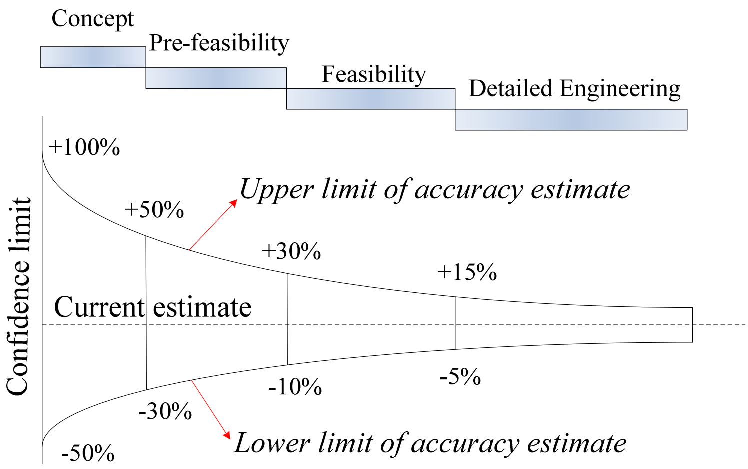


Figure 4. Level of accuracy of estimates in capital projects.
Source: Crundwell (2008).

In the following section two aspects of relevance for the formulation and evaluation of capital projects will be discussed: capital cost and operating cost. Both are crucial for the subsequent calculation of the generation cost of energy and the financial analysis of capital projects.

3. Capital cost

It is mostly accepted in cost engineering that **capital cost** is defined as the expenses incurred only one time for the subsequent production of goods or services. The capital cost can be classified into **direct capital cost** and **indirect capital cost**. The former comprises all the equipment (major equipment, bulk material, etc.) and construction (civil and infrastructure, instrumentation, site cost, etc.), while the latter is composed of the cost of engineering, procurement services, management, preliminary studies (an owner cost) and contingencies, among others (Crundwell 2008). Another way of informing capital cost is through the ***total plant cost*** or ***turn-key cost*** which includes the cost of basic equipment, erection, piping, instrumentation, civil work, management, commissioning, contingency and interest during construction (Karellas *et al.* 2010). Normally, the concepts of **total plant cost** and **investment** are used interchangeably as well as that of **Capex** (capital expenditure) (Emhjellen, *et al.* 2002; Karellas, *et al.* 2010). They will therefore be used as synonyms in the following sections.

Capital cost estimation is particularly difficult in the process and construction industries, normally leading to non-negligible overruns (Emhjellen, *et al.* 2002). The most commonly used techniques for the estimation of capital cost are the *factored estimation technique*s and the *unit cost techniques* (Crundwell 2008). Whereas the former are typically used in a preliminary stage of design, the latter are employed when a bill of quantities is available, usually when the design is in the phase of consolidation. Factored estimation techniques are based on the utilisation of historical data of plants, processes, unitary operations or items of different sizes, and being that this information available for a specific case, the cost must be updated or adjusted for the current situation. Some factors, consequently, account for time by updating from the past to the present, while others account for the amendment of plant size or capacity.

For the adjustment of time, cost index ratios are commonly used to estimate a current cost (in general on a yearly basis) with information from the past. There is a variety of cost indices for specific groups of operations and processes published regularly in specialised literature. The most commonly used are the Chemical Engineering Plant Cost Index (CEPCI), the Marshall and Swift equipment cost index (M&S) (Mignard 2013; Chauvel, *et al.* 2003), or the European Power Capital Cost Index (EPCCI) (HIS 2014). They are issued monthly and then expressed on a yearly average basis.

From Figure 5, a stable evolution of CEPI up to the year 2003 and then a sharp increase in value up to the year 2008 can be observed. Afterwards, a sudden decrease is observed with a subsequent rise up to the year 2013. A similar tendency is observed for the EPCCI (see Figure 6), for which a steady increment is observed from 2003, with a break point in 2008. This tendency can be explained by the high inflation rate observed internationally in the last decade (Index Mundi 2014), particularly for the 2004-2008 period, and the abrupt drop due to the international economic crisis in 2008.

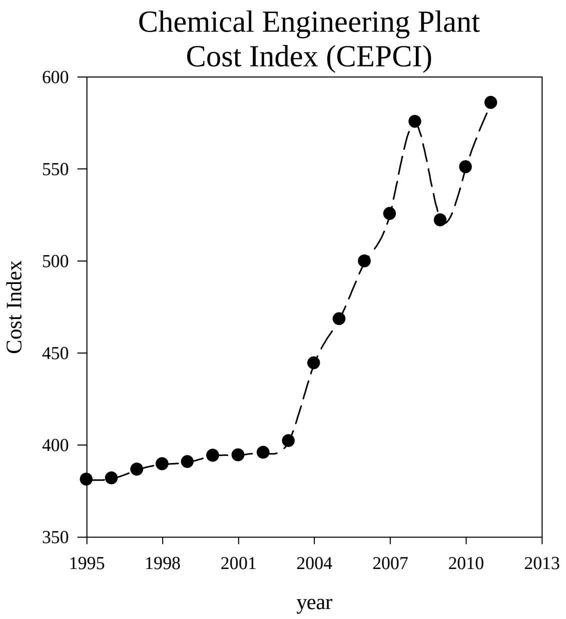


Figure 5. Chemical Engineering Plant Cost Index (CEPI). ***Source***: Chemical Engineering.

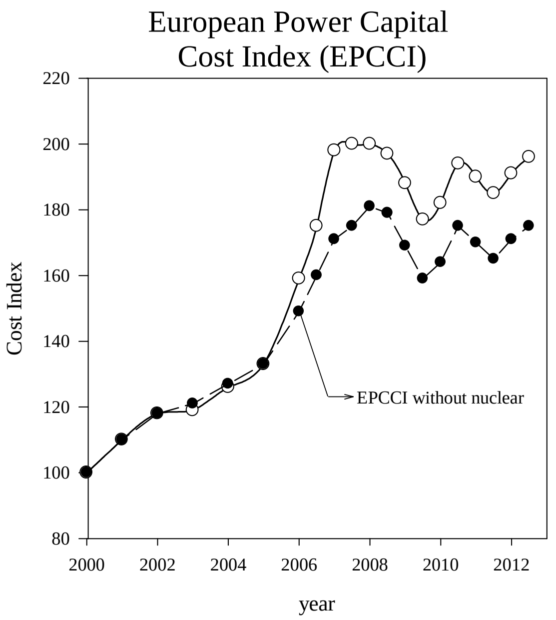


Figure 6. European Power Capital Cost Index (EPCCI). ***Source*:** IHS, Costs & Strategic Sourcing.

Normally, these dimensionless factors are applied by dividing the index for the year under evaluation (the current year, for instance) and that for which information is available, as Equation 1 indicates.

$$C_t = C_o \frac{CI_t}{CI_o} \qquad \text{Equation 1}$$

In which C_t and CI_t represent the cost and cost index for the year to be calculated, *t*, and C_o and CI_o represent the cost and index at another time, respectively.

Example 1

Karellas *et al.* (2007) report that the total capital cost for a biogas plant that processes 20,000 t y^{-1} of feedstock is approximately 3.8 million € for the year 2007. What is the total capital cost for a plant for 2013?

It can be read from figure 5 that CEPCI is 524.4 for 2007 and 569.5 for 2013. The capital cost for 2013, therefore, can be estimated as follows:

$$C_{2013} = C_{2007} \cdot \frac{CEPCI_{2013}}{CEPCI_{2007}} = 3.8 \cdot \frac{569.5}{524.4} = 4.2 \text{ million €}$$

Hence only due to the time-difference, a rise in capital cost of 400,000 € has to be considered in this project.

Another approach used to estimate capital cost is based on reference items or plants of similar characteristics. In these terms, cost of civil work, investment in major equipment and structures can be calculated by the application of an exponential correlation as defined in Equation 2.

$$C = C_o \left(\frac{Q}{Q_o} \right)^n \qquad \text{Equation 2}$$

In which C is the cost to be estimated at capacity Q, C_o is the reference cost at a known capacity, Q_o, and n is the correlation index.

Example 2

Karellas *et al.* (2007) state that the total capital cost for a biogas plant that processes 20,000 t y^{-1} of a substrate is approximately 3.8 million € for the year 2007. What would be the total capital cost for a biogas plant that processes 45,000 t y^{-1} of feedstock? Assume a correlation index of 0.67.

Applying Equation 2, the capital cost of the larger biogas plant can be estimated as follows:

$$C = C_o \left(\frac{Q}{Q_o} \right)^n = 3.8 \cdot \left(\frac{45{,}000}{20{,}000} \right)^{0.67} = 6.4 \text{ million €}$$

Equation 2 offers a remarkable corollary that it is worth pointing out, the so-called *effect of economies of scale*. This means that the larger the plant capacity, the lower the *specific capital cost*, which will lead to lower cost of energy generation as long as the new plant capacity does not imply a significantly higher specific cost of fuel supply due to transportation or storage. The natural consequence of this observation is that the generating cost is not only influenced by the technology and the price of fuel but also by the plant capacity. In others words, for plants that operate with the same fuel supplied at the same price, in the same region and constructed with the same materials, standards and technology (all things being equal), different generating cost are expected when the plants have different processing capacities.

Example 3

In the previous example, Karellas *et al.* (2007) state that the total capital cost for a biogas plant that processes 20,000 t y^{-1} of substrate is approximately 3.8 million **€** for the year 2007. By scaling this information, it was estimated that for a 45,000 t y^{-1} biomass input plant the capital cost would be approximately 6.4 million €**.** What is the **specific investment** for each plant? How does it change?

The **specific capital cost** of plant with these capacities are then:

$$C_1 = \frac{3.8\,\text{million } €}{20{,}000\, t\, y^{-1}} = 190\,\frac{€}{\text{t y}^{-1}}$$

$$C_2 = \frac{6.4\,\text{million } €}{45{,}000\, t\, y^{-1}} = 142\,\frac{€}{\text{t y}^{-1}}$$

As observed, the specific capital cost decreased in 25% just due to economies of scale.

Most equipment and investment data are expressed in by either US$ or Northwest Europe (€), as these have historically been the centres of the chemical and process industry. Additionally, the cost of constructing a productive facility depends on local infrastructure, local labour availability and its cost, cost of shipping, currency exchange rates, import duties, materials, local standards, variation in the cost of labour and other such factors. To calculate the cost of a project, the effect of the location can be included by using a location factor (LF) such as shown in Table 1 and Equation 3.

Table 1. Location factor, middle 1970 (Chauvel, *et al.* 2003).

Country	Coefficient	Country	Coefficient	Country	Coefficient
Canada	1.05	Brazil	1.10	Belgium	0.96
USA	1.00	Chile	1.08	Denmark	0.86
Mexico	1.08	Peru	0.86	Spain	0.76
Puerto Rico	1.04	Uruguay	1.06	France	0.98
Trinidad	1.08	Venezuela	0.92	N. Ireland	0.87
Argentina	1.06	Australia	1.07-1.11	Rep. of Ireland	0.79
Bolivia	0.98	Germany	0.92	Italy	0.96
				United Kingdom	0.89

$$C = Co\frac{LF}{LF_o} \qquad \text{Equation 3}$$

In which C is the capital cost to be estimated in the new place with location factor LF, and C_o is the capital cost in the known place with location factor LF_o.

Example 4

Karellas *et al*. (2007) state that the total capital cost for a biogas plant is approximately 3.8 million **€** based on price quotations, presumably obtained in Germany. What would be the total capital cost for a biogas plant of similar characteristics (capacity and feedstock to be processed) when constructed in France?

$$C = C_o \frac{LF}{LF_o} = 3.8 \cdot \frac{0.98}{0.92} = 4.0 \text{ million } €$$

Thus an increase in capital cost of approximately 6% is encountered.

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4. Operating cost

Although some authors may differ in the way they allocate and conceptualise operation and maintenance expenses (Chauvel, *et al.* 2003; Silla 2012), it is possible to distinguish between *variable cost* and *fixed cost*. Variable cost is proportional to the production level of the facility, and this expense reflects the mass and energy demand of the process. Conversely, fixed cost does not depend on the quantity produced and is directly linked to the nominal processing capacity, and is virtually known when this parameter is defined. Normally, personnel (marketing, general services, administration, etc.) are also included in fixed cost although some companies account for them as part of variable cost when employees have to work in shifts or for longer periods to ensure a continuous operation.

In common applications, variable cost is related to a processed variable or product, and as long as the plant scale does not modify the energy and mass balance significantly, the *variable cost* becomes a *constant cost*. On the other hand, when fixed cost is expressed in terms of a processed variable, it becomes variable, thus being dependent upon the actual annual production. For a biogas plant, for instance, variable cost is mainly grouped into maintenance, services, utilities (principally power to run the plant auxiliary equipments, e.g. pumps, blowers, fans, feeding systems) and heat cost. Fixed cost is simply categorised as personnel and general cost (Karellas, *et al.* 2010). Alternatively, Van Dael *et al.* (2013) includes as operational cost maintenance, insurance, repair, energy, personnel and auxiliary.

As a simplification, it can be assumed that the annual cost of operation and maintenance ($C_{o\&m}$) for a bioenergy facility includes personnel, maintenance and support services, internal consumption of electricity and heat and contingencies. Additionally, when a linear proportionality between investment (I) and this operation and maintenance cost ($C_{o\&m}$) is assumed, the annual operation and maintenance cost ($C_{o\&m}$) can be expressed as Equation 4 indicates.

$$C_{o\&m} = \beta I \qquad \text{Equation 4}$$

In which I is the total investment, and β is a fixed fraction of the investment (or capital cost). The proposed simplification has been already used by Hoogwijk (2004), Faaij (2006), Gómez *et al.* (2010; 2011) and Bidart *et al.* (2013, 2014) for renewable energy technologies estimates at pre-feasibility level.

Example 5

Gómez *et al.* (2010) propose a correlation to estimate at pre-feasibility level the investment and operation and maintenance cost for anaerobic digestion technologies for electricity generation. The proposed correlation is the following:

$$I(€) = 101.522 + 3{,}500x\,[\mathrm{x, kW_e}]$$
$$C_{o\&m}(€\ \mathrm{y}^{-1}) = 0.16 I\ [€]$$

What is the total investment and the annual operation and maintenance cost ($C_{o\&m}$) for a 500 kW_e biogas plant?

$$I(€) = 101.522 + 3{,}500 \cdot 500 = 1{,}851{,}522\ €$$
$$C_{o\&m} = 0.16 \cdot 1{,}1851{,}522 \quad = 296{,}244 \quad €\ \mathrm{y}^{-1}$$

Annual operation & maintenance cost is estimated at approximately 296,444 € y^{-1}, therefore. As observed in much literature in the field, there is no information about the yearly basis of the investment, so it is assumed that the data is given in the same period of the publication, 2010.

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5. Cost of energy generation

In general, information about cost of energy generation available in the literature varies greatly, even for OECD countries in the same region. This fact can be explained by the quick privatisation of utilities and liberalisation of power markets in the last decades (so arguing private sector confidentiality regarding cost), policy factors (the pricing of carbon dioxide emissions, for instance), the evolution of generation technologies and the introduction into the market of new developments (IEA 2010). The lack of experience in construction of existing and new technologies as well as the unprecedented level of inflation observed at the international level in last years also contributed to the uncertainty in regard to cost information for the calculation of cost of energy (IEA 2010).

The most widely used approach for calculating the cost of generating electricity is the so-called *Levelised Cost of Electricity* (LCOE) (Larsson, *et al.* 2014), which essentially means the calculation of a unitary production cost of energy (electricity in this case) under an annual basis of equivalent cash flows. This cost can be formulated as Equation 5 shows.

$$c_e = \frac{\alpha I + C_{o\&m} + C_{Fuel} + C_e}{E_e} \qquad \text{Equation 5}$$

In which c_e is the levelised cost of energy (electricity); α is the amortisation factor[1]; I the investment (including decommissioning); $C_{o\&m}$ is the operation and maintenance cost; C_{Fuel} is the cost of fuel, C_e are the environmental cost (emissions of carbon, environmental penalisation[2], etc.) and E_e is the produced electrical energy. Each value of Equation 5 ought to be expressed on an annual basis; therefore, each item has to be computed for an equal period. Furthermore, average values tend to be used.

Although the above-presented method was conceptualised for the calculation of electricity generation cost, it can be also extended for the calculation of generating cost of fuels or heat. Examples 6 and 7 present a practical application of the generation cost concept.

6. Factors affecting generation cost in bioenergy

As previously mentioned, the generating cost can diverge significantly when comparing different sources in the literature. This can be explained by the way of calculating the cost as well as the assumptions made for the economic assessment; as a matter of fact, some of these assumptions are discretional, others should be based on operating experience and others are strictly technical or dependent upon market trends. In the forthcoming sections the factors that influence the generating cost estimate most heavily will be discussed.

[1] This factor will be explained in greater detail in a subsequent section. Basically, it converts an investment equivalent into a series of annual payments over a specific time period; it makes *as if* an investment were equal to n payments at a given i interest rate.

[2] Ms Blond asked in the 5th partner meeting in Freiburg whether the environmental cost could be included in the generating cost of electricity. Actually, the answer is yes, but an estimation of the environmental cost is needed so that it can be included in the numerator of Equation 5.

6.1 Load factor

The load factor is defined as the quotient of the energy actually generated and the amount of energy obtained at full capacity operating all the time over the year[3]. In other words, it is a ratio between the energy truly generated and the theoretical maximum. Due to the very nature of almost all the renewables, the load factor plays a relevant roll in their economics. For instance, wind generation (onshore or offshore) are intermittent since wind turbines cannot operate either when wind does not blow or blows too strongly, with load factor in the range 25-30% (House of Lords 2008); conversely, biomass does not suffer the disadvantage of being intermittent, thus having load factors no lower than 80% (Fiorese, *et al.* 2014) although local-specific circumstances may explain variations from country to country.

The load factor is generally expressed in the baseload operation although some authors express it in intermediate operation, or even peak-load. Because the cost is calculated in baseload, the corresponding definition for the load factor will be used. The load factor is also alternatively expressed as the total operating time of a facility over the year (h y^{-1}).

6.2 Fuel cost

The cost of biomass as a fuel is characterised by being site-specific and natural or regional particularities influence production cost differently. For example, the cost of felling forest residue resource, the cost of supply of chips produced from the recovery of biomass left on the ground after harvesting, is approximately 40 € t^{-1} for Poland, 74 € t^{-1} for France and 76 € t^{-1} for The Netherlands (Wit & Faaij 2010)[4], thus observing large differences for countries within the EU.

In numerous evaluations, the cost of fuel supply is assumed constant in time, and this leads to underestimates of the final cost of energy generation. Additionally, it is worth pointing out that for some facilities that operate with waste-to-energy technologies (a process that utilises residual biomass for energy generation), the "fuel cost" is considered with a negative value since waste is accepted to be treated from third parties paying gate fees.

[3] The load factor should not be confused with the availability or availability factor, which refers the fraction of time, e.g. hours in a year, when the plant is available, i.e. not offline due to maintenance etc. These two terms (load factor and availability) are not used consistently in the literature.
[4] A lower heating value of 18 GJ t^{-1} is assumed for woody biomass.

6.3 Discount rate

Economists express as "time preference" the attitude of people to time. Some people would prefer to have some money right now rather than have it as a future income, perhaps under the leitmotiv *"money today worth more than money tomorrow"*; others would rather have it in the future when having a good ***interest rate*** from the bank, for instance. In some cases the emphasis is put on the present and others in the future; additionally, there is an "opportunity cost" for money when not being "employed", the ***return*** that might have been earned from investing in other promising projects. A ***risk supplement***, therefore, should be added proportionally to the risk associated with the investment; the riskier a business is, the lower the future income is valued at now. Normally, these aspects are taken into consideration to set the ***discount rate,*** a parameter needed to calculate an economic indicator such as ***net present value*** (NPV), ***annual equivalent cost*** (AEC), or ***payback period***, which measure the economic attractiveness of a capital project (Newman, *et al*. 2004).

The selection of interest rate is basically a strategic choice of an organisation and generally done by the financial planning department. As previously discussed, the discount rate represents the combination of financial cost of capital, economic cost of capital and the added effect of the perceived risk in the investment. Normally, the discount rate is considered constant during the project, and in most cases its selection is poorly justified (or not justified at all) in studies or technical reports. It is highly advisable then to take care about this issue when calculating or comparing the cost of energy generation. Values from 5% to 14 % are found in the literature to assess energy generation projects (Akbulut 2014; Murphy & Power; 2009; Gómez *et at.* 2010).

6.4 Efficiency

The concept of efficiency may have different meanings and definitions depending on the specific application, field or discipline (e.g. thermodynamics, combustion for heat generation, power generation, fuel cells, energy in buildings, etc.). In biomass fuelled systems the distinction is normally made between ***gross power*** and ***net power***, which leads to the definitions of ***gross efficiency*** and ***net efficiency***, respectively. It, therefore, can be formulated according to Equation 6,

$$\eta_e^{(g)} = \frac{E_e}{Q}, \qquad \text{Equation 6}$$

in which $\eta_e^{(g)}$ is the gross electrical efficiency, E_e is the gross electrical energy produced within the plant and Q the maximal thermal energy obtained from burning the fuel. As seen, the gross efficiency is equivalent to the gross thermal-to-conversion efficiency of the power cycle (Castellan 1983; Overend 2004).

Having to be used for the operation of the plant (feed-water pumping, internal heating, and other mechanical services), a part of the total produced energy (gross power) is not available for exploitation; consequently, the final receiver will be supplied with a lower amount of energy, the ***net power***. The energy consumed internally to run the plant is normally referred to as ***parasitic power***. As a result, the net efficiency can be expressed according to Equation 7:

$$\eta_e^{(n)} = \frac{E_e - P_p}{Q}, \qquad \text{Equation 7}$$

in which $\eta_e^{(n)}$ is the net efficiency, and P_p is the parasitic power. The demand of parasitic power as well as the impossibility of burning the totality of the fuel, heat losses, the excess air to be fed to control flue gas temperature and limitations of materials, all explains why the observed efficiency of real plants is notoriously lower than that of the thermodynamic cycle on which the process operates (Overend 2003).

6.5 Heat sales

A Combined Heat and Power system (CHP), as its name indicates, produces electricity and heat simultaneously. In principle, the cost of producing these products may be charged equally; however, both for the difficulty in doing so and because these two products are substantially different in economic and in thermodynamic terms, a common practice is to calculate the cost of generating electricity considering the incomes for selling heat as a way of reducing cost (known as the credit method). Being so, electricity is allocated as a main product and, consequently, heat as a by-product, *which enables the reduction of the cost of electricity generation*. From the calculation of levelised cost of electricity method, the sales of heat can be incorporated in Equation 5 by subtracting this income to the cost as shown in Equation 8,

$$c_e = \frac{\alpha I + C_{o\&m} + C_{Fuel} + C_e - R}{E_e}, \qquad \text{Equation 8}$$

in which R is the total income as a result of the selling of heat, which is commonly referred to ***revenue*** in order to make it distinguishable from the income obtained when electricity is sold, the main product. The price of heat can be calculated as the price paid for heating from the alternative source that can be partially or totally replaced when the heat from the CHP is recovered.

Example 6

From the energy and mass balance conducted by an OUI researcher, it was estimated that a 500 kW_e biogas plant with a CHP mode can reach a 31% net electrical efficiency and a 38% net thermal efficiency. What is the cost of electricity production for this plant when the totality of the heat can be sold at 3 ct€ kWh_{th}^{-1}? How much does this cost change when no heat is sold? Assume a 8,000 h y^{-1} load factor, 10% interest rate and, 10 years project lifespan with a negligible biomass cost.

From the previous example the investment and operation & maintenance cost were estimated by using Gómet *et al.* (2010)' s correlation, being these values:

$$I = 1{,}851{,}522\ €$$
$$C_{o\&m} = 296{,}244\ \ € \ \mathrm{y}^{-1}$$

The actual electrical energy available is:

$$E_e = 300\ kW_e \cdot 8000\ h\ y^{-1} = 2{,}400{,}000\ \mathrm{kWh}_e\,\mathrm{y}^{-1}$$

Analogously, the total heat available from the CHP to sell is:

$$E_{th} = 300\ kW_e \cdot \frac{0.38}{0.31} \cdot 8000\ h\ y^{-1} = 2{,}941{,}935\ \mathrm{kWh}_{th}\,\mathrm{y}^{-1}$$

The maximum revenue obtainable from selling the heat is:

$$R = 2{,}941{,}935\ \mathrm{kWh}_{th}\,\mathrm{y}^{-1} \cdot 0.03\ €\ \mathrm{kWh}_{th}^{-1} = 88{,}258\ €\ \mathrm{y}^{-1}$$

The cost of generating electricity is computed by applying Equation 8. When the heat can be sold, the cost is worked out as follows:

$$\mathrm{c_e} = \frac{1{,}851{,}522 \cdot 0.163\ €\ \mathrm{y}^{-1(*)} + 296{,}244\ €\ \mathrm{y}^{-1} - 88{,}258\ €\ \mathrm{y}^{-1}}{2{,}400{,}000\ \mathrm{kWh_e}\,\mathrm{y}^{-1}} = 11.3\ \mathrm{ct€\ kWh_e^{-1}}$$

When no heat is commercialised, the generating electricity cost is then calculated as:

$$c_e = \frac{1{,}851{,}522 \cdot 0.163\ € \ y^{-1} + 296{,}244\ € \ y^{-1} - 0\ € \ y^{-1}}{2{,}400{,}000\ kWh_e y^{-1}} = 14.9\ ct€\ kWh_e^{-1}$$

As observed, a substantial reduction in generating cost can be obtained (24% in this case) when the heat is commercialised, making the project much more competitive.

(*) 0.163 is the amortisation factor (α) according Equation 5.

Example 7

For a plant of 100 Nm^3h^{-1} in biogas capacity[5], investment, operation & maintenance cost ($C_{o\&m}$) and substrate supply cost were estimated by Urban *et al.* (2008) as 535,100 €, 82,700 € y^{-1} and 79,600 € y^{-1}, respectively. What is the production cost of raw biogas? Assume a 8,000 h y^{-1} load factor, 10% interest rate and 10 years project lifespan.

By applying Equation 5 adapted for fuel production, the cost of producing biogas is computed as follows:

$$c_{biogas} = \frac{0.16 \cdot 535{,}100 + 82{,}700 + 79{,}600}{100 \cdot 8{,}000} = 32.7\ ct€\ Nm^{-3}$$

[5] Nm^3 corresponds to the abbreviation for "Normal cubic meter". It is generally defined as the volume of a gas (or a mixture of them) informed in normal conditions, this is 25°C and 1 atm of absolute pressure. Being just an instrumental definition, differences can be found in literature when referring to what "normal" condition is.

7. Exemplification of some concepts

In the Upper Rhine region researchers of the OUI projects detected a promising source of biomass. This is a mixture of organic feedstock that is currently dewatered and thickened prior to disposal. Because of the steady increase in cost of operation and landfilling, OUI researchers propose the use of a biogas-based technology for the utilisation of this biomass as a source of energy.

Biogas is a ***proven technology*** and widely employed in the processing of organic feedstock such as pig manure, sludge from wastewater treatment plants, residues from energy crops, or conventional crops (maize, wheat, sugar, etc.). In contrast with ***emerging technologies*** (or *under research & development)*, which are intrinsically characterised by the risk associated with its introduction into a specific technology system (whatever this is) (Hellström 2003), proven technologies offer reliability and commercial support.

As anaerobic digestion can be used to process a residue generated in a primary sector, it is usually addressed as a *waste-to-energy* technology. Figure 7 depicts a conceptual configuration of a biogas plant. It comprises basically pre-treatment of feedstock, digestion, gas treatment and solid separation, and when biogas is burnt to produce electricity, a CHP module. More information about technical matters will be provided in subsequent sections.

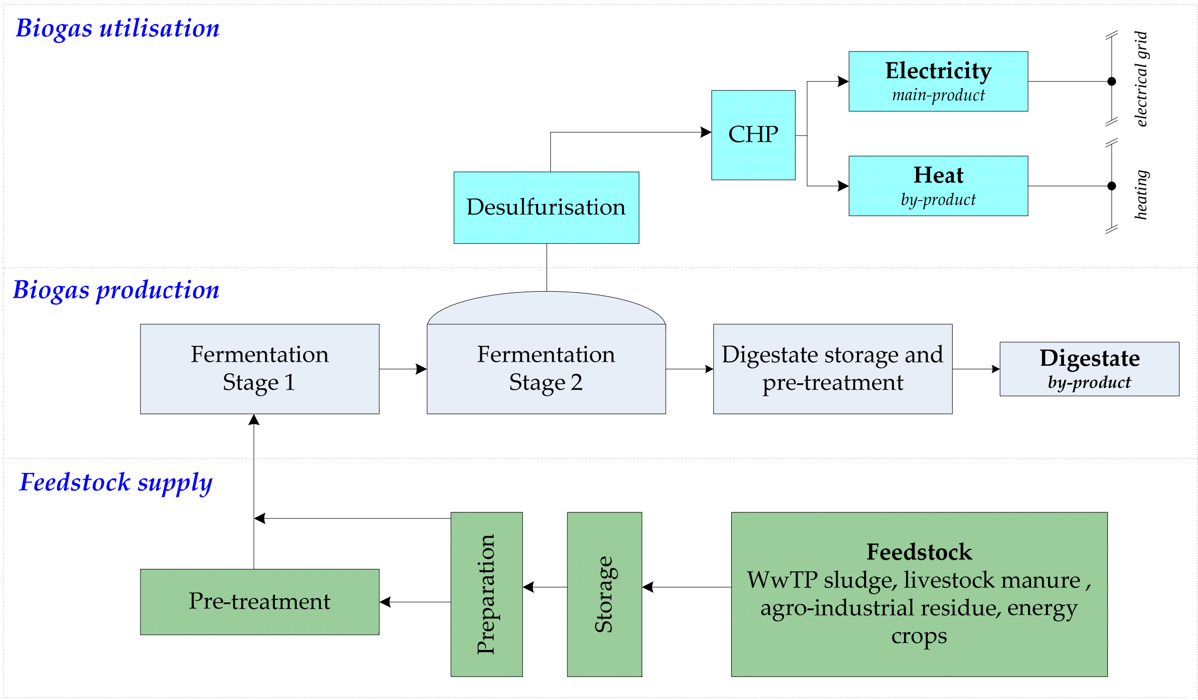

Figure 7. Anaerobic conversion of biomass for energy via a CHP scheme. Adapted from Poeschl *et al.* (2010).

The feedstock can be a single substrate or a blend of them. When only one type of substrate is used as feedstock, the process is named ***monodigestion***; when a mixture of two or more substrates is processed simultaneously, the process is addressed as ***co-digestion***. The amount of feedstock available and its stability in supply are critical points in the conception and operation of a biogas plant. The substrate can be generated and then used *in situ*, that is in a given place so without needing to be transported. This is the typical case of sludge generated from wastewater processing or manure from livestock farming. Because of their high water concentration, the transportation penalises severely the economics of this option. Nevertheless, feedstock needs to be transported when it is located away from the processing point or is spread across large areas. This is the case for crop residue or energy crops, in which operations of harvesting, conveyance and storage are present. On the one hand, larger amounts of substrates can be obtained under these conditions, thus improving the economics of the process (larger plants imply in principle lower unitary production cost). On the other hand, the supply of biomass becomes more complex and expensive, and issues of logistic and biomass storage play a relevant role in processing. The biomass available and its characterisation is an issue normally tackled in a ***biomass potential study***.

The ***pre-treatment*** aims at preparing the diverse feedstocks and homogenising them (size, pH, water content, etc.). Afterwards, the ***digestion*** of the feedstock takes place in a reactor operated either in mesophlilic (30-45°C) or thermophilic conditions (45-55°C), thus demanding an external source of heating for its operation. The main product from the digestion is biogas that basically consists of methane (60%), carbon dioxide (40%) and other mixture of trace compounds (lower than 1%). The specific concentrations of each compound in the gaseous stream depend strongly on the sort of substrate. The ***gas treatment*** constitutes the following step and is compulsory for any practical application. The main objective of this unit is basically to reduce the content of harmful substances both to the equipment and people, principally sulphur-based compounds. The ***solid separation*** operation, as its names indicates, aims to separate the liquid fraction from the solid one. The liquids collected may be directly used for irrigation, whereas the solids may be used as fertiliser to improve soils quality. At the end of the process lies the ***CHP*** unit. Normally, a CHP unit includes an internal combustion engine from which the heat released during the combustion of biogas is recovered. The electricity is generated through a generator.

As seen in Figure 7 and before described, the products of the anaerobic digestion process are electricity, thermal energy (heat), digestate and the liquid. Each product may be commercialised or traded *provided that there is a market*. Normally, in waste-to-energy technologies, electricity is allocated as the ***main product,*** and it can be virtually fed into any electricity-grid, and, consequently, sold. Additionally, it has a relatively continuous demand across the year which makes it even more attractive for production and commercialisation. Thermal energy, conversely, exhibits higher constraints for trade as a consequence of a much more limited market (normally only district heating) and with a demand being restricted to only some months of the year. As a result, heat is set generally as a ***by-product*** with a commercialisation that may improve the economics of the entire process substantially, so addressed as ***revenue***. Similarly, the digestate is another by-product that can be used as fertiliser to improve soil quality as well as the liquid for irrigation in agriculture.

The possibility of selling electricity depends strongly on the competitiveness of the project that is being assessed. In general, the ***production cost of electricity*** (and of any other energy carrier) is heavily dependant on the plant capacity, cost of feedstock, sort of technology and other such factors. The ***production cost of electricity*** is to be lower than the ***price of electricity*** so that the commercialisation can be profitable. In perfect, efficient and integrated electricity markets, the electricity price (or tariff) is determined by the interaction between the supply and demand and its computation is a complex process. Like in many others, electricity markets are also segmented, and it varies from country to country. For instance, it is possible to distinguish between the household price of electricity and industry price, as can be seen in Figures 8 and 9. For Germany, the annual average price of electricity is notoriously higher than for France, both for household or industry consumers in the last three years. Similarly, it is observed that the electricity price for household is notoriously higher than that for industry, this being valid both for Germany and France. As observed, for these two segments of the market, i.e. household and industry, electricity has different prices.

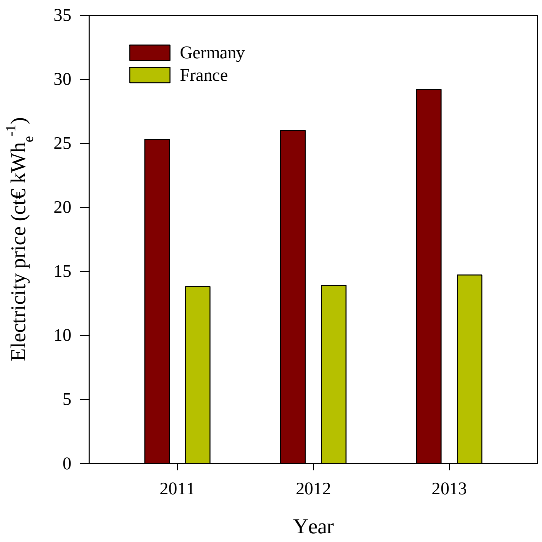

Figure 8. Household consumer electricity price in Germany and France. ***Source***: Eurosat (2013).

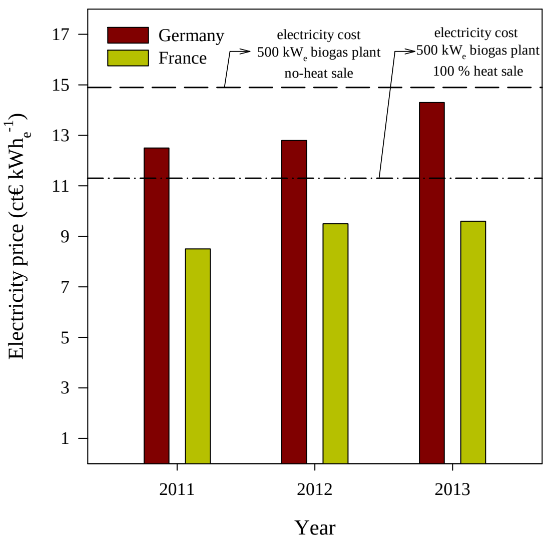

Figure 9. Industry consumer electricity price in Germany and France. ***Source***: Eurosat (2013).

When the economic feasibility of the 500 kW$_e$ biogas plant in Example 6 is assessed for the industry sector as a market, it can be observed that it would be not profitable in France since its production cost is higher than the market price; in Germany it would not be economically competitive either unless all heat were sold as a by-product. To make a biogas-based plant like this profitable in France, for instance, a subsidy would be needed, a so-called ***feed-in tariff***, and this subsidised price of electricity hast to exceed the production cost, otherwise the commercial exploitation of biomass will not be profitable. The feed-in tariffs are systems to boost renewables and have different methods of implementation varying from country to country (Mendoca 2007). Essentially, feed-in tariffs are employed as a way of addressing the barriers for the deployments of renewables, which are basically higher cost (in comparison with fossil-based generation), technical, administrative and legal drawbacks (Mendoca 2007).

8. Recapitulating remarks

In this first chapter, the main concepts related to energy economics for bioenergy were discussed. As observed, there are often discrepancies in the way economic and technical information is discussed; therefore, it is important that this is understood so that the evidence can be interpreted consistently.

Data for techno-economic analysis is in most cases lacking and, when available, often exhibits large variability, a fact attributable to numerous factors. The reluctance of companies, vendors or technology providers to make it available plays a significant role in regard to the gathering of information since the exclusivity of data might provide a competitive edge. In addition, numerous site-specific factors might make it difficult to generalise (labour cost, transportation cost, raw material, local construction standards, inflation, etc.) and could contribute uncertainties to the calculations. Moreover, the stage of the evaluation is an aspect to keep in mind because it intrinsically implies a trade-off between the quality of the estimates and the engineering resources allocated the study (i.e. budget, time, highly-skilled human resources, etc.). Consequently, significant differences in economic estimates are not only attributable to the source of information but also due to the tendency to change according to the stage of the project at which they are calculated.

The terminology and concepts already presented will be used in the subsequent chapters. This will enable a consistent framing of the techno-economic assessment of technologies, for which it is possible to make comparisons regarding performance, cost or environmental impacts.

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