Levelized Cost of Energy
in Sustainable Energy Communities

A systematic approach for multi-vector energy systems

CHAPTER 2 – The Levelized Cost of Energy indicator

The Levelized Cost of Energy indicator

2.1. Introduction

In this chapter, the concept and fundamentals related with the Levelized Cost of Energy (*LCOEn*), and its variants (Levelized Cost of Electricity: *LCOE*, Levelized Cost of Stored Energy: *LCOS*, Levelized Cost of Heat: *LCOH*, Levelized Cost of Cooling: *LCO*C and Levelized Cost of Exergy: *LCOEx*) will be presented. Firstly, this chapter pretends to provide a brief introduction to the calculation of the *LCOEn*, including the main definitions and formulations, the involved parameters and its advantages and limitations. Then, its application to electricity, thermal energy and exergy domains are presented, including the case of polygeneration and energy multi-vector systems. The theoretical part here presented will be then applied in the following chapter to some case studies.

2.2. The promoters' perspective of energy projects

Many governments and public organizations encourage the development of renewable energy sources to combat climate change, but the investors or promoters' decision depends on the estimated profitability of an energy project [1]. Before presenting the fundamentals of the *LCOEn*, the typical financial indicators used for energy projects are briefly introduced. It must be remembered that an energy generation project is not only a facility to solve a technical problem (the provision of energy to end-users), but also an economic asset which provides benefits, or at least savings, to its promoters. Unless an external obligation (in order to guarantee the provision of energy or other circumstances), an energy project will not be even considered if it does not achieve the desired "financial performance".

2.2.1. Economic feasibility of an energy project

In order to measure the financial performance of an energy project, some meters or financial indicators are calculated and compared in order to help the promoters to choose their best investment option. Typically, when evaluating the financial feasibility of an energy generation project, the following financial indicators are usually evaluated:

- **Payback Period:** this metric evaluates the period needed to return the initial investment costs or capital expenditures at year 0 ($CAPEX_0$) considering the estimated annual cash flow. It is usually measured in years and it can be "Simple" – *SPP* - (see Equation 2.1) or "Discounted" – *DPP* - (see Equation 2.2).

$$SPP = \frac{CAPEX_0}{Cash\ flow}.$$

Equation 2.1

In contrast with the *SPP*, which just considers the nominal annual cash flow of the project without determining the present value of future cash flows through discounting, the *DPP* also considers when the cash flows occur and the prevailing rate or return in the market, i.e., the discounted values of the cash flows. To discount a cash flow, a discount rate *d* that accounts for the capital and the risk costs must be considered. Thus, it depends on how the project is being financed (using internal or external resources) and on the accepted risk level of the promoters.

The *DPP* represents the number of years to return the initial expenditure by discounting future cash flows occurred in the plant lifespan. It is obtained by solving Equation 2.2:

$$-CAPEX_0 + \sum_{i=1}^{DPP} \frac{Cash\ flow_i}{(1+d)^i} = 0.$$

Equation 2.2

In Equation 2.2, as well as in the following ones, the subscript *i* indicates that the term is related to *i*-th year. Therefore, the *DPP* calculation cannot be done directly but involves an iterative procedure, as the calculation of the discounted cash flows depends on the considered *i*-th period.

Moreover, it must be considered with caution if the inflation rate has been already accounted for when evaluating the cash flows or not. If the cash flows include the inflation effect, the real discount rate (d_{real}) must be used, while if the cash flows are nominal (they do not include the inflation rate), the nominal discount rate (d_{nom}) must be used in the calculation. The relationship between the real and the nominal discount rates can be seen in Equation 2.3, where k is the inflation rate:

$$d_{real} = \frac{1 + d_{nom}}{1 + k} - 1,$$

Equation 2.3

- **Net Present Value (*NPV*):** this financial metric evaluates the sum of the cash flows of the project during its whole life span (n years) and discounts them according to an estimated discount rate. It is given by Equation 2.4:

$$NPV = -CAPEX_0 + \sum_{i=1}^{n} \frac{Cash\ flow_i}{(1 + d)^i}.$$

Equation 2.4

If the cash flows are considered constant along the life span of the project, Equation 2.4 can be simplified to the following expression:

$$NPV = -CAPEX_0 + Cash\ flow \cdot \frac{1 - (1 + d)^{-n}}{d},$$

Equation 2.5

where the term multiplying the cash flow is the inverse of the capital recovery factor (*CRF*), which represents the ratio of a constant annuity to the present value of receiving that annuity for a given time span.

- **Internal Rate of Return (*IRR*):** this metric is calculated as the discount rate that makes the *NPV* of the project equal to zero (see Equation 2.). Consistently, it can be calculated in nominal or real terms.

$$-CAPEX_0 + \sum_{i=1}^{n} \frac{Cash\ flow_i}{(1 + IRR)^i} = 0.$$

Equation 2.6

- **Cost of Energy (*COEn*):** in contrast with the above-mentioned metrics, this financial indicator is exclusive of energy projects, as it is related with the unitary costs of the product, which in this case is the energy produced by the generation plant or system. It is evaluated as the ratio of the sum of all the involved yearly costs along the life span of the project ($Costs_i$) and the sum of the energy produced in each year (En_i), without discounting, as it can be seen in Equation 2.7. It can be applied to electricity, heat, cooling, etc.

$$COEn = \frac{\sum_{i=0}^{n} Costs_i}{\sum_{i=1}^{n} En_i}.$$

Equation 2.7

The involved costs in all time periods include (see Equation 2.8) capital expenditures, operation and maintenance expenditures (*OPEX*), Fuel or input costs (herein referred to as *Fuel costs*) and possible other costs (herein referred to as *Other Costs*), such as externalities, intended as indirect societal costs and/or other indirect costs connected with the energy system.

$$Costs_i = CAPEX_i + OPEX_i + Fuel\ costs_i + Other\ costs_i$$

Equation 2.8

where *OPEX*, *Fuel costs* and *Other costs* are usually zero for i=0 (i.e., at the construction and installation year).

2.2.2. Why do we need the Levelized Cost of Energy indicator?

The above presented metrics to analyze the economic feasibility of a project present an intrinsic limitation as they are size and location dependent, i.e., they are typically used to compare different investment options but only for the same site. Therefore, they do not provide a suitable estimation method for carrying out a comparative analysis among different projects. To overcome these limitations, the Levelized Cost of Energy (and its specific applications) is a common metric, especially in the electricity sector (*LCOE*), widely used by policy makers for estimating and comparing the costs of generating technologies [2]. It considers the full life-cycle costs (fixed and variable) of a generating technology per unit of energy, thus allowing comparison among different generation technologies independently of size, costs structure and useful life [2, 3].

The *LCOEn* supplies a simple and quick procedure to measure the competitiveness of energy projects; it is widely used both for conventional and renewable power sources investments. It differs from the classical *COEn* metric in the way that it includes the present value of the total cost of building and operating a generation system over an assumed financial life time and duty cycle, converted to equal annual payments, in real terms [4]. *LCOEn* models are widely applied at national and regional levels for the energy systems design, energy generation projections and technology assessments [5].

On the other hand, the *LCOEn* is strictly related to the quantities accounted for and the assumptions made. It may therefore give rise to incomplete or misleading evaluations when used to make absolute assessments [2, 6]. It is, therefore, advisable that this metric is used appropriately, especially when comparing non-dispatchable energy technologies with conventional plants. In the case of renewable energy systems, the generated energy has not a homogeneous value as it depends on the resource availability ad it is especially affected by the intermittent nature of the source (currently, the adoption of energy storage systems still represents a costly solution). Hence, the value of the produced energy depends on the time when it is produced and, thus, the *LCOEn* is related with its variability patterns that determine its generation profile. The *LCOEn* might not adequately consider the temporal heterogeneity of the energy generation [2, 7]. Furthermore, other aspects, such as the renewable sources' location, grid-related costs and other intrinsic aspects are hardly accounted for in the classical definition of the *LCOEn*.

2.3. Definitions of the Levelized Cost of Energy (*LCOEn*)

The basic *LCOEn* formula can be derived from the following relationship that it is considered to be hold in competitive energy markets:

$$\sum_{i=1}^{n}\left[\frac{En_i \cdot p_i}{(1+d)^i}+\frac{Revenues_i}{(1+d)^i}\right] \geq \sum_{i=0}^{n}\left[\frac{CAPEX_i}{(1+d)^i}+\frac{OPEX_i}{(1+d)^i}+\frac{Fuel\ costs_i}{(1+d)^i}+\frac{Other\ costs_i}{(1+d)^i}\right],$$

Equation 2.9

where p_i denotes the annual average wholesale price, or the price at which the produced energy is sold or must be purchased from an alternative provider. *Revenues$_i$* are the possible yearly benefits that may reduce the costs. They include incentives, internalities, intended as indirect benefits, avoided externalities, as well as other indirect benefits for a third party (that are classified in the following as beneficial externalities).

The left-hand side of Equation 2.9 represents the total discounted revenues for the whole lifetime of the project, while the right-hand side shows the total discounted cost of the plant. Thus, the total annual discounted revenues must cover, at least, the total annual discounted costs, including capital expenditures, operation and maintenance, fuel costs and other costs related to the energy supply system. This approach can be also called "discounted cash flow" analysis, where the cost of a generation technology is based on discounting financial flows to a common basis.

2.3.1. Basic definition

Based on the previous stated hypotheses, the *LCOEn* can be calculated as the average energy price over the whole lifespan of the facility that covers the sum of the annual discounted net costs, as it is expressed in Equation 2.10, where the costs term includes all the costs already described by Equation 2.8:

$$LCOEn = \frac{\sum_{i=0}^{n}\left[\frac{Costs_i}{(1+d)^i}-\frac{Revenues_i}{(1+d)^i}\right]}{\sum_{i=1}^{n}\frac{En_i}{(1+d)^i}}.$$

Equation 2.10

It represents the unitary production cost of energy, including the construction and operating costs of the power generation system, for unit of produced energy averaged over an assumed financial life and duty cycle. Therefore, it provides the value of the average energy price which makes the discounted revenues compensate for the total discounted costs after considering other possible revenues [4].

Typically, the *LCOEn* is calculated over an expected lifetime of 20 to 40 years (depending on the expected useful lifespan of the project), and it is given in units of currency per kWh or per MWh.

The expression shown in Equation 2.10 can be simplified when cash flows are considered constant over the evaluation time horizon. Thus, if we consider that i) the capital expenditures different from those at time 0 (initial investment), which are commonly related with equipment replacement, can be divided uniformly along the lifespan of the project and included in the *OPEX*, ii) the yearly *OPEX* and other periodic costs and revenues are the same in nominal terms during the lifespan and are called *Periodic Costs* and *Periodic Revenues*, respectively, and iii) the yearly energy production is constant along the complete useful life span (degradation effects or unavailabilities are not considered in the first place), and is called *En*. Then the *LCOEn* formula can be simplified to that shown in the following Equation 2.11.

$$
\begin{aligned}
LCOEn &= \frac{CAPEX_0 + (Periodic\ Costs - Periodic\ Revenues) \cdot \dfrac{1-(1+d)^{-n}}{d}}{En \cdot \dfrac{1-(1+d)^{-n}}{d}} \\
&= \frac{CAPEX_0 \cdot d}{En \cdot [1-(1+d)^{-n}]} + \frac{Periodic\ Costs - Periodic\ Revenues}{En}.
\end{aligned}
$$

Equation 2.11

2.3.2. Parameters of the LCOEn

The *LCOEn* value can be taken as a reference metric to compare the competitiveness across different generation technologies. However, when comparing *LCOEn* values for alternative systems, it is important to define in a proper manner the boundaries of the system, the specific cost for the technology in use, the included internalities and externalities, such as transmission and distribution costs, R&D, tax, environmental impact studies, impacts on public health and environmental damage or government subsidies, among others and, in general, the criteria used to quantify costs and revenues. Key inputs for calculating the simplified *LCOEn* include capital expenditures, variable operation and maintenance costs, financing costs and an assumed utilization rate, capacity factor or equivalent hours for the system depending on its type [4].

In the following, all costs and revenues are grouped into direct costs, that are mainly given by capital expenditures, operation, maintenance, energy supplies; direct revenues and internalities, that include possible benefits for the stakeholder not directly related with the amount of produced energy; externalities, given by societal costs or benefits originating from the power plant. Costs and revenues adopted, as well as the inclusion or not of externalities, even if not directly translated into charges, must be clearly identified and declared when comparing the *LCOEn* of different facilities.

Direct costs

The *CAPEX* includes the total capital expenditures inside the plant boundaries, such as the generator, the civil engineering or any wiring, piping or other auxiliaries installed within the plant. The operation and maintenance costs, or *OPEX*, represent an annualized estimate of the total operating costs over the project design life, including both the cost escalation with ageing. Moreover, the *OPEX* also includes several other ongoing costs, such as insurance costs or land payments [8]. In [9], the cost of decommissioning of the plants is also taken into consideration, while in [10] the costs related to environmental taxes are considered.

The time value of money (inflation) can be included or not, depending on whether the discount rate does it or not. If the *OPEX* includes the inflation, then the real discount rate must be used in the formulation, otherwise, the nominal discount rate must be adopted (see Equation 2.3 at this concern).

Fuel costs are one of the main sources of costs in traditional generators. However, renewable energy sources (RES), such as the solar PV or wind, do not involve significant input and fuel costs and have typically low operation and maintenance costs. In this case, the capital cost represents the key quantity ruling the *LCOEn* evaluation. On the other hand, for those technologies with significant fuel costs, such as nuclear power plants or gas-fired power plants, both fuel and overnight costs affect significantly the *LCOEn* value.

Finally, precise estimations of the *LCOEn* should also consider other costs, such as the integration costs of the generation technology which are especially relevant (and difficult to calculate) in renewable energy systems. These costs can be defined as those additional costs of accommodating some generation technologies [11], or costs induced by a generation technology that are not directly related to the generation costs [2] and are included in the term of other costs in the above presented equations. They can be divided into:

- **Balancing costs:** due to the uncertainty or variability of power generation, such as the need to hold and use more operating reserves, the increase of ramping thermal power plants, cycling and others.
- **Grid-related costs:** due to the need to extend and reinforce the power network, including occasional benefits of lower grid needs and lower network losses.
- **Adequacy costs:** those deriving from the reduced deployment or utilization of old, low efficient, non-renewable or conventional power plants, which might imply a lack of conventional capacity providing backup services.

It has been observed in several studies that renewable energy sources, especially wind and solar, cause significant integration costs at penetration levels higher than 10% [12]. Moreover, apart from the cost definition and the adopted methodology, the size and composition of the integration costs of renewable energy sources are location-specific and tend to increase with growing penetration rates, while they tend to decrease over time, depending on the adaptation of the power systems.

Direct revenues and internalities

The *LCOEn* calculation through Equation 2.10 also accounts for revenues that compensate for the effect of the costs. Possible direct revenues are the availability of incentives, subsidies or the remuneration of the operation of the energy system due to side effects. For instance, in the calculation of the *LCOE* of a cogeneration plant (CHP), the remuneration of the produced thermal energy, which is a side effect of the production of electricity, must be considered (properly discounted) in the numerator of the formulation. In a similar manner, if calculating the *LCOH* of the same cogeneration plant, the remuneration for the production of electricity must be properly accounted.

On the other hand, internalities are long-terms benefits in monetary terms for the owner that are not directly related with the amount of the produced energy. Some examples of internalities are the benefits coming from the increase of the resilience due to polygeneration microgrids, from the increase in the energy quality, measured by the avoided blackouts, from the possibility of managing intermittent sources more efficiently as well as the attractiveness for investments and loans or the avoided costs related to the health issues supported by the owners (such as private insurances).

Externalities

Externalities are those indirect costs and benefits deriving from the impact of power generation on a community or on a third party to which no financial consideration is assigned. They are mainly due to negative effects on the environment, on the health and well-being of individuals. The fact that these costs are outside the logic of the market and the difficulty to translate them into economic value has often left aside their monetization. However, as long as they are not monetized, they determine the so called "market failure" [13], that is the inability of the free market to efficiently allocate goods and resources, increasing the well-being of some groups without reducing that of anyone else.

Since the 90s, growing attention has been paid in the evaluation of the externalities related to atmospheric emissions. Soon after, specific models for the estimation of concentration of pollutants have been defined, together with suitable models for the estimation of impacts. The joint use of these tools and suitable monetization functions has allowed the economic estimation of damages by a series of subsequent steps that implies the assessment of emission, dispersion or impact. The damage cost is finally supplied in terms of cost per kilogram of emitted pollutant, or per kWh of produced energy. In this context, the European Environment Agency (EEA) has supplied a simplified modelling approach assessing in monetary terms the cost of damage to health and environment from selected air pollutants emitted by industrial facilities located in European Nations [14].

The available methodologies, however, cannot be all-inclusive, as other effects on the environment as well as other non-environmental externalities are inevitably left out. Moreover, large uncertainties exist, both in emission rates and damages [15]. Especially, uncertainties exist in costs associated with climate change, being its impact a long-term, global externality [16].

Externality costs can weight directly on the owner, and thus they must be considered in the *LCOEn* calculation, both through taxes and charges or benefits. A typical cost related to a negative externality is the carbon tax to compensate for the damage to the environment due to carbon dioxide and other greenhouse gases emission. In any case, a complete comparative analysis between different production units cannot ignore the quantification of externalities.

The main studies dealing with external costs of traditional and renewable power generation, such as [17–19], generally recognize that costs per kWh are worst for coal and lignite, quantified in around € 80 /MWh and oil, around € 66 /MWh. Natural gas is cleaner, quantified in around € 30 /MWh, while lowest costs are obviously found in renewable sources. Hydro power externalities are quoted around € 1.3 /MWh, while for solar, thermal, and wind power they are less or much less than € 1.0 /MWh (data from [20]). At this purpose, some criticisms may arise from the fact that hydropower, PV and wind energy affect the landscape, and these local externalities can create much discomfort in a small group of people.

Positive externalities can be defined as societal benefits that are infeasible to charge. Information about the quantification of positive externalities is practically absent, or they are evaluated in terms of avoided negative externalities from other technologies [21]. Positive impacts could be the social and occupational repercussions that can give new impetus to rural communities or areas of industrial crisis, also avoiding housing concentration in large urban centers. For instance, the presence of green energy infrastructures inside university campuses in decentralized locations may become an attractor for students and visitors, repopulating small towns and becoming "scientific tourist" attractors. In this sense, both the Campus of Savona from the University of Genoa (Italy) and the test-bed pilot facility of the Campus of Vegazana from the University of León (Spain) are good examples where sustainable energy research infrastructures gave birth to a number of innovation projects, making the campuses "open-air" demonstrators [22, 23]. In this context, a number of courses have been established on the topic of smart energy production and management. Benefits in monetary terms might come from the appeal for students who populated the small neighborhood making it a university district, as well as in attracting EU fundings and new collaborations for the research community. Population can also benefit from the creation of a comfortable green space open to the community, where people can work, study, spend free time and play sport experiencing a healthy lifestyle, but these benefits are difficult to quantify and add in the *LCOEn* formulation.

Discount rate

The discount rate is often expressed as the Weighted Average Cost of Capital (*WACC*). This represents the required average return of the combination of equity and debt to make a project an attractive investment opportunity, where each category of capital (equity and debt) is proportionately weighted. It is usually evaluated after taxes and it is, therefore, assumed that interest on debt serves as a tax reduction. Moreover, the equity returns are indicative of the required threshold return after payment of taxes [8]. The WACC is calculated as shown in Equation 2.12:

$$WACC = Equit\ costs \cdot \%\ Equity + \ [Debt\ costs \cdot \ \ \%\ Debt \cdot (1 - Tax\ rate)],$$

Equation 2.12

where *% Debt* = *debt/capital amount* and *% Equity* = *equity costs/capital amount*.

In practice, the *WACC* may be defined in after-tax or pre-tax terms and either in real or nominal terms (i.e. including or not the inflation rate). On the other hand, taxes can be adjusted including the present value of depreciation, which for the *LCOEn* calculation is commonly stated at 0.5% per year [8].

Utilization rate or equivalent operation hours

The capacity factor, or utilization rate, of a generation system is a crucial quantity for the *LCOEn* evaluation because it directly provides the produced energy. Its careful assessment is therefore essential for having reliable estimates of the cost of energy, especially when RES systems are involved. In this case, most of the costs are related with the size of the plant, rather than with the provided energy (e.g. fuel costs) and differences among plants of the same sizes are due to their different capacity factors, for example due to the availability of the primary energy source, or to its variability. Equation 2.13 shows the relation among two systems, A and B that have the same size and costs, but different equivalent operating hours (*EOH*) or full load hours. The discount rate is taken constant during the system lifespan and the same for both systems.

$$LCOEn^B = \frac{\sum_{i=1}^{n} \frac{EOH_i^A}{(1+d)^i}}{\sum_{i=1}^{n} \frac{EOH_i^B}{(1+d)^i}} LCOEn^A.$$

Equation 2.13

2.3.3. Other calculation models and approaches

The above-presented definition of the *LCOEn* is considered as the “simplified *LCOEn*” or “*sLCOEn*”. The presented approach is relatively simplistic, given the fact that the model needs to be applied to a wide range of technologies in different countries and regions. This has the advantage, moreover, of producing a systematic, transparent and easy-tounderstand analysis. However, several different *LCOEn* models are available, as well as extended definitions.

The literature supplies variegated formulae of the *LCOEn*, with slight changes in the definition of its parameters and originated by different approaches in the model construction, to ensure that it matches research tasks and data availability [5]. The most widely spread *LCOEn* models are the U.S. DOE *LCOEn model* [24], the California Energy Commission Cost of Generation Model [25], the Department of Energy and Climate Change electricity costs model [26] and the Bureau of Resources and Energy Economics Australia Energy Technology Assessment model [27].

In [24], the levelized costs are calculated in three modes: the normalized mode, where a single discount rate and lifetime are used for all the compared technologies; the market mode, where it is used different discount rates, lifetime and other costs for each technology according to the DOE Program Estimates of 2011; or user defined. Moreover, in this model, the capital expenditures are turned into annual payments through a *CRF* which depends on the discount rate (7%) and the lifetime of the investment (30 years for generation plants). Then, the *LCOEn* is calculated in cents per kWh by the following equation:

$$LCOEn = \frac{CAPEX \cdot CRF \cdot (1 - T \cdot D_{PV})}{8760 \cdot CF \cdot (1 - T)} + \frac{Fixed\ OPEX}{8760 \cdot CF} + \frac{Variable\ OPEX}{1{,}000\,\frac{kWh}{MWh}} + \frac{Fuel\ price \cdot Heat\ Rate}{1{,}000{,}000\,\frac{BTU}{mmBTU}},$$

Equation 2.14

where *CF* is the capacity factor (the yearly average percentage of power as a fraction of capacity), *T* the tax rate paid (applied after depreciation credits) and D_{PV} the present value of depreciation, depending on the MACRS schedule (Modified Accelerated Cost Recovery System).

On the other hand, the model presented in [25] considers a variable set of fixed and variable cost components depending on whether the project is a merchant facility or owned by an investor-owned utility (IOU) or a publicly owned utility (POU). In addition, the costs can vary with location because of differencing costs of land, fuel, construction, operations and environmental licensing. Then, as fixed costs are considered the total cost of capital and financing (at the point of interconnection with the existing transmission system), insurance costs, property taxes (*Ad Valorem*), fixed *OPEX* and corporate taxes (state and federal taxes). As variable costs, the report authors consider the fuel cost, the cap-and-trade allowance costs (GHG cost) and variable *OPEX* (as a function of the operating hours).

The approach reported in [26] considers only those costs accruing to the owner or operator of the generation asset and neglects wider costs that may in part fall to others, such as the full cost of system balancing and network investment, or air quality impacts. Moreover, the authors do not consider revenue streams available to generators (e.g. from sale of electricity or revenues from other sources), with the exception of heat revenues for CHP plants which are included so that the estimates reflect the cost of electricity generation only. It must be highlighted that the authors include, apart from the already mentioned costs, pre-development costs, carbon transport and storage costs and decommissioning fund costs. They also evaluate the expected availability, efficiency and load factor to calculate the expected generation capacity by assuming always a baseload.

Finally, in [27], the *LCOEn* is defined as the equivalent to the long-run marginal cost of energy (electricity) at a given point in time because it measures the cost of producing one extra unit of energy (electricity) with a newly constructed generation plant. It includes the operation and maintenance expenditures for each year and the authors open the possibility to include other costs such as a carbon price. However, they exclude the effects of taxation, the degradation effects for output from each technology, the plant decommissioning costs and the plant residual cost.

Among possible extended definitions, the “Financial Model Approach” (FMA) calculates the *LCOEn* as the required revenue to achieve a certain internal rate or return. It is therefore suited to capture more complex financial assumptions, such as revenue requirements and the impacts of taxes and depreciation.

On the other hand, the *LCOEn* can also be defined in multiple ways, including the "Real *LCOEn*", the "inflation adjusted Real *LCOEn*" and the "Nominal *LCOEn*". The Real *LCOEn* is defined as a constant stream of values denoted in today's currency, the inflation adjusted Real *LCOEn* is defined as a nominal path that keeps a constant real value, while the Nominal *LCOEn* is defined as constant stream of values in nominal currency [28].

The Real *LCOEn* is preferred by Governments and policy makers as it uses real discount rates and removes the inflation effects associated with inputs and Operation and Maintenance (O&M) costs, or *OPEX*. On the other hand, promoters and project owners prefer to use the Nominal *LCOEn* as it includes assumptions regarding inflation. Moreover, when using a nominal discount rate, the nominal *LCOEn* can be analogous to a PPA (Power Purchase Agreement) or a FiT (Feed-in-Tariff) price which is flat across the economic life of the project [28].

2.4. Levelized Cost of Electricity (*LCOE*)

The Levelized Cost of Electricity, or *LCOE*, represents the *LCOEn* when considering power electricity generation sources. All the fundamentals stated before can be applied in this case and, actually, it represents the most common application case.

2.4.1. LCOE particularities for RES

Several foundations and organizations have carried out studies to estimate the potential for electricity production from renewables, identifying a clear disadvantage in terms of costs with respect to fossil fuels [29, 30]. It is widely known that renewable energy sources are extremely vulnerable to competing technologies. As long as it was possible to produce electricity at low costs, with little regard to pollution, the effects on the environment or other externalities, renewable energy sources were often less competitive than conventional technologies [4]. Even today, in those situations where the negative impact on the climate and the environment is disregarded, conventional technologies may seem more cost-effective.

In the next paragraphs a brief description of the *LCOE* trends and particularities for the main renewable energy sources, based mainly on [2, 31], are depicted to put them in correlation with the *LCOE* calculation in more sophisticated systems, such as polygeneration systems and multi-vector energy systems and microgrids.

LCOE of solar PV systems

The global weighted-average *LCOE* of utility-scale PV plants declined from € 381/MWh in 2010 to € 57/MWh in 2020, which means an 85% drop. Moreover, the range of LCOE costs continues to narrow in these last years. This fact can be explained due to the rapid decline in total installed costs, increasing capacity factors and lower O&M costs. In the last decade, the solar PV industry has experienced various technological developments that have contributed to decrease costs along the whole solar PV value chain. Just the decline in the solar module cost is estimated to contribute to a 46% reduction of the *LCOE* at utility-scale when comparing 2010 and 2020. Together, cost reduction in power inverters, racking and mounting and other BoS (Balance of System) hardware is estimated to contribute another 18% to the *LCOE* reduction during that period. This decreasing trend has also been observed in residential PV systems. Assuming a 5% *WACC*, the *LCOE* of residential PV systems in the markets declined from approximately € 400/MWh in 2010 to € 200/MWh in 2020 (50% drop). Other markets, such as Japan, Italy or Australia have shown even higher drops in costs. Furthermore, between 2010 and 2020, the *LCOE* of commercial PV up to 500 kW declined between 50% and 79% in these markets showing a minimum value of around € 60/MWh (China).

LCOE of concentrating solar systems

With the reduction in total installed costs and O&M costs, increasing capacity factors and falling financing costs, the *LCOE* for Concentrating Solar Power (CSP) projects fell significantly between 2010 and 2020. In the last year, the global weighted-average *LCOE* of newly commissioned CSP plants is around € 108/MWh, which means a reduction of the 68% with respect to 2010. This reduction is explained by the strong decrease of the installed costs and the increase in the capacity factors (from 30% to 42% on average). Moreover, reductions in the O&M costs and in the *WACC* are also found.

Several factors have contributed to reduce the *LCOE* of this technology since 2013. On the one hand, the broadening of the market and a larger gained experience. On the other, and with higher impact, the deployment to areas with higher DNIs (Direct Normal Irradiances), such as China, Morocco or South Africa. Furthermore, improvements in technology and cost reductions in thermal energy storage has led to an improvement in capacity factors, and has contributed to a 28% reduction in the *LCOE* over the 2010-2020 period. In the absence of a strong policy support for CSP, however, the market remains small and the pipeline for new projects meagre.

CSP and its low-cost thermal storage systems are often overlooked in favor of battery storage, given its rapid cost reductions. This is unfortunate, as CSP remains, along with pumped hydro storage, the only low-cost long-duration storage option available today. As the share of variable renewables grows, the possibility of adding low-cost long-duration storage will only grow in value.

***LCOE* of onshore wind energy**

The interest in wind power generation has increased dramatically in the last years, and the technology of large size wind turbines is now well established. Common commercial machines are rated 2-5 MW on average and the tendency is to up scaling [29, 32]. On the contrary, small size wind turbines are, at present, less competitive, as construction and operating costs are often too high with respect to the power production [33, 34]. Notwithstanding this, they represent the appropriate technology to develop the strategic aim of small-scale distributed wind power generation in standalone, or grid connected configurations, integrated with other renewable sources.

The *LCOE* of an onshore wind farm is determined by the total installed costs, the lifetime capacity factor, O&M costs, the economic lifetime of the project, and the cost of capital. The cost of the turbines and towers makes up the most significant component of total installed costs. On the other hand, with no fuel costs, the capacity factor and the cost of capital also have a significant impact on the *LCOE* calculation. Starting from this premise, the monitoring of costs and production of wind energy shows very high differences between the generation cost of small size wind turbines and that of large plants.

As far as large size applications are concerned, since 1983, the global weighted-average *LCOE* has declined approximately an 87%, achieving approximately € 41/MWh in 2019 at utility-scale. Consequently, onshore wind energy competes with hydropower as the most competitive renewable technology, without financial support.

The significant reduction of the LCOE for this technology can be explained mainly due, on the one hand, to the latest turbine technology improvements, especially in the optimization of the rotor diameter and turbine ratings, allowing a better exploitation of the sites. On the other hand, it can be found that economies of scale impact the costs of manufacturing, installation and O&M. Moreover, the O&M cost has been reduced thanks to the digitalization and improved practices. Finally, competitive auctions are leading to further cost reductions as it drives higher competitiveness.

Concerning small wind turbines, the *LCOE* is much higher and difficult to quantify, due to the huge variations the cost of installation, maintenance and of the *EOH*. As an example, an average value for Italy can be quantified in € 330/MWh in the target power ranging between 0-20 kW [35], but what is most impressive is the enormous variability of this value, with many prototypes with very low production, but also over-performing units, mainly related to turbines with generous rotor diameter with respect to the nominal rated power.

***LCOE* of offshore wind energy**

In the latest years, increasing experience and competition, advances in wind turbine technology (seeking to increase efficiency and lower costs, several 8-8.8 MW wind turbines have been installed, and 14-20 MW units are currently under development), the establishment of optimized local and regional supply chains, and strong policy and regulatory support schemes have resulted in a steady pipeline of offshore wind energy projects that have been increasingly competitive, i.e., with a lower *LCOE*.

From 2010 to 2020, the global weighted-average *LCOE* of offshore wind fell 48%, from € 162/MWh to € 84/MWh. Year-on-year, in 2020, weighted-average *LCOE* fell 9% from its 2019 value of € 93/MWh. From its peak in 2007, the global weighted-average *LCOE* of offshore wind fell by 53%. In this sense, the Netherlands had the lowest weighted-average *LCOE* for projects commissioned in 2020, at € 67/MWh, being followed by China, Denmark and Belgium.

***LCOE* of hydropower**

Hydropower has historically provided the backbone of low-cost electricity in a significant number of countries around the world. However, it must be highlighted that hydropower projects can be designed to perform very differently from each other, and thus, it makes difficult to compare them. The strategy adopted in a hydropower project depends on the characteristics of the site inflows and the needs of the local market. Moreover, recently, hydropower systems with significant reservoir storage are increasing their value as they help to facilitate the growing share of variable renewable energy.

In 2020, the global weighted-average cost of electricity from hydropower was € 44/MWh, up 16% from the € 38/MWh recorded in 2010. Despite these increases through time, however, 99% of the hydropower projects commissioned in 2020 had an *LCOE* within or lower than this range. Moreover, 56% of the hydropower projects commissioned in 2020 had an *LCOE* lower than the cheapest new fossil fuel-fired cost option.

***LCOE* of geothermal systems**

Geothermal power plants require continuous optimization throughout the lifetime of the project, which impacts directly on its *LCOE* results. The average *LCOE* for this technology varies from as low as € 40/MWh for second stage development of an existing field to as high as € 170/MWh for small greenfield developments in remote areas, showing just a slight increase in the last decade.

O&M costs in these plants are high relative to other RES technologies, because over time the reservoir pressure around the production can decline if remedial measures are not taken.

***LCOE* of bioenergy**

A wide range of *LCOE* values is observed for bioenergy-fired power plants due to the wide range of technologies, installed costs, capacity factors and feedstock costs. The global weighted-average *LCOE* of biomass-fired electricity generation for projects commissioned in 2020 was € 76/MWh, which is a similar figure than that of 2010. However, bioenergy can provide very competitive and dispatchable electricity where capital costs are relatively low and low-cost feedstocks are available, achieving an *LCOE* as low as around € 40/MWh. The most competitive projects take advantage of agricultural or forestry residues, already available at industrial processing sites. Furthermore, projects relying on municipal waste come with high capacity factors and are generally an economic source of electricity. However, their *LCOE* is usually higher than the average, especially in North America (given that these projects have been developed mostly to solve waste management issues, a slightly high *LCOE* is not necessarily an impediment to their viability).

In the case of bioenergy, the feedstock availability influences significantly the economic performance, and thus, the *LCOE*. The availability of a continuous stream of feedstock allows for higher capacity factors, but it is no necessarily more economical, as it can mean the need of more expensive feedstocks. Thus, the access to low cost feedstock offsets the impact on *LCOE* of lower capacity factors.

2.4.2. LCOE and grid parity

From the *LCOE* calculation the notion of competitiveness among generation technologies can be derived. One of the most common used indicators is the grid parity. Grid parity is the term given when the *LCOE* of a generation technology or energy system is compared with the cost of acquiring electrical energy from the electricity market (Weighted Average energy wholesale Price: *WAP*) [4], as it is expressed in Equation 2.15.

$$Grid\ parity = \frac{LCOE}{WAP_{GRID}}.$$

Equation 2.15

It is usually applied to analyze the economic feasibility and competitiveness of distributed energy generators, which must compete with the supply from the electrical grid. When the grid parity, calculated as expressed in Equation 2.15, is equal or lower than 1, it means that the proposed energy generation project can compete effectively with the external power grid. Otherwise, the economic feasibility of the project is conditioned by the existence of subsidies. As an example, in [36] a temporal analysis of the solar PV grid parity in Europe is presented. The authors observe that the solar PV technology can achieve grid parity without subsidies for 2030 in a wider area in Europe, even with low availability of solar radiation, due to the reduction of costs, the increase of the technology efficiency and the rise of the electricity costs. Nevertheless, the grid parity depends on the energy mix of the market, and whether the calculation of the *LCOE* includes or not externalities.

It must be noticed that the grid parity approach, when the energy wholesale price is not correctly weighted (e.g., the solar *LCOE* of a PV power plant is compared with the yearly mean value of the electricity price instead of comparing with the daylight hours weighted average value of the electricity), can tend to overvalue the generation from some types of technologies. A classical example, electricity from WTGs is more heavily weighted to off-peak periods when electricity prices are usually lower, while can undervalue power production from others, such as solar PV, as this technology usually generates more electricity during peak-price periods [4]. Therefore, the energy generation time profile must be considered to properly get the weighted average price of the wholesale energy to get the appropriate conclusions when comparing with the *LCOE* of the energy systems.

2.4.3. LCOE of single generator systems

Figure 2.1 represents a typical generation unit connected to the power grid. In this case, a solar PV generator is shown, but the analysis can be extended to any other generator. The generator transforms the primary energy from an energy source (En_G^{PRIM}), in this case the solar radiation, into power energy (E_G). The effective power produced by the system is, indeed, the result of its maximum generation capacity (E_G^{MAX}) minus the energy curtailed or limited (E_G^{CURT}). In the case of power plants connected to the power grid, as they are remunerated by the total amount of energy injected to the grid, the curtailed energy is minimized. On the other hand, the maximum generation capacity can be constant, such as in some fossil fuel power plants, or variable in time, such as in a solar PV power plant where the maximum power capacity depends on the available resource. In any case, the net generated energy can be expressed as the product between the rated capacity (P_G) and its equivalent operating hours (EOH_G).

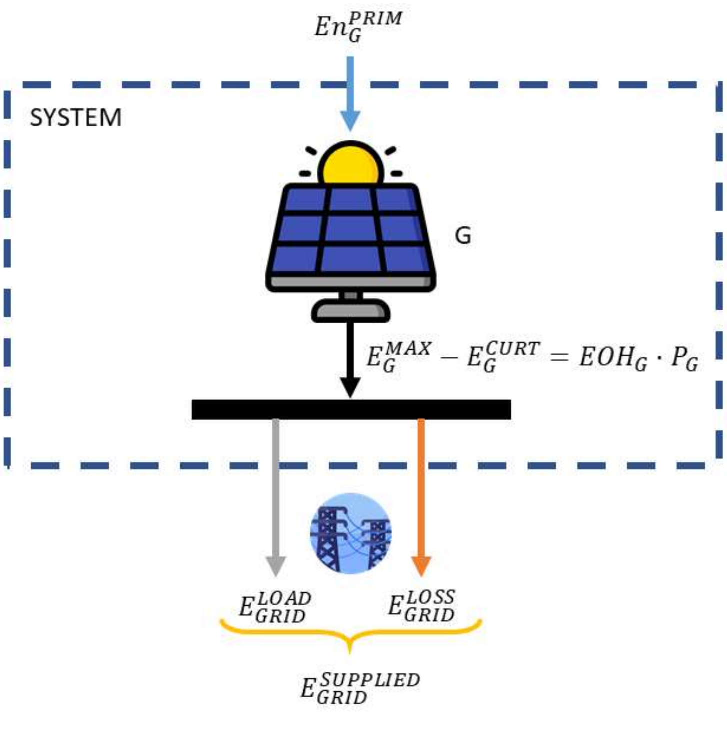

Figure 2.1. Representation of a single generation device system.

If a single-bus model is applied to represent the system, it can be concluded that the total energy produced by the power plant is supplied to the power grid to which it is connected ($E_{GRID}^{SUPPLIED}$). This energy includes both the power load (E_{GRID}^{LOAD}) and the power losses due to transport and distribution (E_{GRID}^{LOSS}). Then, the energy balance of the system, applying a single-bus model analysis, is expressed in Equation 2.16:

$$E_G = E_G^{MAX} - E_G^{CURT} = E_{GRID}^{LOAD} + E_{GRID}^{LOSS} = E_{GRID}^{SUPPLIED}.$$

Equation 2.16

The *LCOE* of the generator represented in Figure 2.2 indeed is referred to the energy served or provided to the power grid. On the other hand, the costs associated to the served energy are related to the system itself (costs associated with the generator, the infrastructure for coupling to the PCC and the operation and management) and the inputs of the system (costs associated with the consumed primary energy). Thus, the *LCOE* for a single generator system can be deduced from Equation 2.9:

$$\sum_{i=1}^{n}\left[\frac{E_i^{SUPPLIED}\cdot p_i}{(1+d)^i}+\frac{Revenues_i}{(1+d)^i}\right] \geq \sum_{i=0}^{n}\left[\frac{CAPEX_i}{(1+d)^i}+\frac{OPEX_i}{(1+d)^i}+\frac{Fuel\ costs_i}{(1+d)^i}+\frac{Other\ costs_i}{(1+d)^i}\right],$$

Equation 2.17

$$LCOE_G = \frac{\sum_{i=0}^{n}\left[\frac{CAPEX_i}{(1+d)^i}+\frac{OPEX_i}{(1+d)^i}+\frac{Fuel\ costs_i}{(1+d)^i}+\frac{Other\ costs_i}{(1+d)^i}-\frac{Revenues_i}{(1+d)^i}\right]}{\sum_{i=1}^{n}\frac{E_i^{SUPPLIED}}{(1+d)^i}}.$$

Equation 2.18

In this case, as the served energy equals the generated energy (see Equation 2.16), and recalling the definition of costs given by Equation 2.8, Equation 2.18 can be simplified, considering the net costs NC_i (costs - revenues[1]) for the *i*-th time period:

[1] In the *LCOE* evaluation, revenues are only considered when there exist side effects of the generation, such as subsidies, externalities, internalities or benefits due to cogeneration. It also must be noted that, in the *LCOE* evaluation, costs are considered positive, while revenues are negative. Taxes are not included.

$$LCOE_G = \frac{\sum_{i=0}^{n} \frac{NC_i^G}{(1+d)^i}}{P_G \cdot \sum_{i=1}^{n} \frac{EOH_i^G}{(1+d)^i}}.$$

Equation 2.19

It must be highlighted that the equivalent operating hours of the generator may vary for each period of its lifespan, but in any case, $EOH_i^G \leq 8760$ h/year, i.e., the capacity factor of the generator cannot be higher than 1.

2.4.4. LCOE of combined generation and storage systems

Energy Storage Systems or ESS devices store surplus energy, i.e., not served energy, and shifts it to another period. An ESS can be modelled as a generator working in parallel with the others, with the difference that it is not fed by an external input of primary energy source, but by the energy from the system, as represented in Figure 2.2, where E_{ESS}^{CH} and E_{ESS}^{DCH} are, respectively, the energy charged and discharged by the storage device.

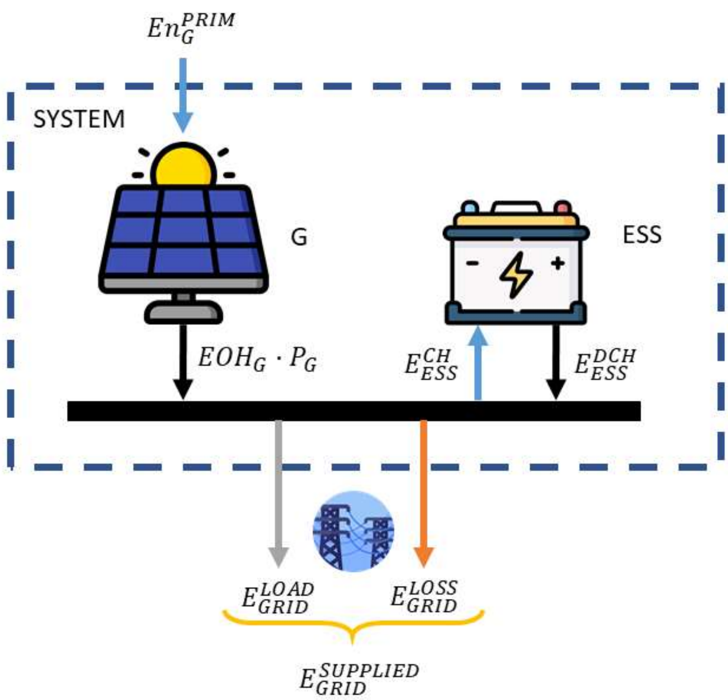

Figure 2.2. Representation of a combined generation and energy storage system.

Analogously to the analysis performed in the previous case, the energy balance of the system, applying a single-bus model analysis, is expressed in Equation 2.20:

$$E_G + E_{ESS}^{DCH} = E_{GRID}^{SUPPLIED} + E_{ESS}^{CH}.$$

Equation 2.20

Applying again Equation 2.9 to the case, the *LCOE* for this combined system is also referred to the served energy, that in this case does not coincide with the generated energy E_G. It can be deduced that the equivalent operating hours of the generator can increase (i.e., its curtailed energy can be reduced) because of the ESS presence, although there are some losses (difference between the discharged and the charged energy) due to the charging and discharging efficiency. Moreover, in this case, the total costs include not only those related with the generator (described in the previous section), but also those related with the ESS. The *LCOE* of combined generation and storage systems, $LCOE_{G+ESS}$, can be calculated by Equation 2.21:

$$LCOE_{G+ES} = \frac{\sum_{i=0}^{n} \frac{NC_i}{(1+d)^i}}{\sum_{i=1}^{n} \frac{E_i^{SUPPLIED}}{(1+d)^i}} = \frac{\sum_{i=0}^{n} \left[\frac{NC_i^G}{(1+d)^i} + \frac{NC_i^{ESS}}{(1+d)^i} + \frac{Costs_i^{SYST}}{(1+d)^i}\right]}{\sum_{i=1}^{n} \left[P_G \cdot \frac{EOH_i^G}{(1+d)^i} + \frac{(E_{ESS}^{DCH} - E_{ESS}^{CH})_i}{(1+d)^i}\right]},$$

Equation 2.21

where NC_i^G, NC_i^{ESS} are the yearly capital and operating costs related to the generator and the storage, respectively, and $Costs^{SYST}$ is an extra cost term that represents the costs of integrating and coordinating of the generator and the ESS, that cannot be associated to the individual devices. It must be also observed that, in this setting, the lifespan of the project (n) can differ from the expected useful lifespan of each device (n_G and n_{ESS}, respectively). The lifespan to be considered is represented by the useful lifespan of the generation unit ($n = n_G$), as without the generation unit, the ESS device cannot work. Then, if $n_G > n_{ESS}$, two approaches can be considered: (i) when the lifespan of the ESS ends, no storage capacity is available until the end of the lifespan of the project, with a consequent negative impact on the *EOH* of the generator; (ii) when the lifespan of the ESS ends, the old device is replaced by a new one. In this case, additional $CAPEX_i$ must be considered at the replacement time and, in a strict analysis, an economic valorization of the new device at time period *n* (if its useful lifespan has not ended) must be included as a revenue[2]. However, an intermediate third approach, although less precise, is usually adopted, according to which the replacement costs are prorated among the lifespan of the project and included in the *OPEX* of the ESS. In all the presented cases, the adopted strategy should be clearly indicated.

Equation 2.21 can be rewritten reordering the terms in the denominator and splitting the terms in the numerator:

$$LCOE_{G+ESS} = \frac{\sum_{i=0}^{n} \frac{NC_i^G}{(1+d)^i} + \sum_{i=0}^{n} \frac{NC_i^{ESS}}{(1+d)^i} + \sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left[\frac{(P_G \cdot EOH_G - E_{ESS}^{CH})_i}{(1+d)^i} + \frac{(E_{ESS}^{DCH})_i}{(1+d)^i} \right]},$$

Equation 2.22

If the first approach is adopted (the second approach will be presented in the next section applied to a polygeneration system), i.e., there is no replacement of the devices $(n \geq n_G \geq n_{ESS})$, Equation 2.22 can be expressed as a function of the *LCOE* of the generator, the *LCOS* of the stored energy and a virtual *LCOE* related to the integrating and coordinating costs:

$$LCOE_{G+ESS} = f_G \cdot LCOE_G + f_{ESS} \cdot LCOS_{ESS} + LCOE'_{SYST},$$

Equation 2.23

where f_G and f_{ESS} are the participation factors of the generator and the ESS, respectively, the $LCOE_G$ is the Levelized Cost of Electricity for the generator with energy curtailment, i.e., considering it produces $E_G^{MAX} - E_G^{CURT} = P_G \cdot EOH_G - E_{ESS}^{CH}$, and the $LCOS_{ESS}$ is the Levelized Cost of Storage of the ESS, defined in Equation 2.26, while $LCOE'_{SYST}$ indicates the virtual *LCOE* of the system costs, as defined in Equation 2.27.

[2] Several approaches can be considered to estimate the remaining value of an asset. Commonly, it is estimated considering a linear amortization of the *CAPEX* (see Equation 2.36).

$$f_G = \frac{\sum_{i=1}^{n_G} \frac{(P_G \cdot EOH_G - E_{ESS}^{CH})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left[\frac{(P_G \cdot EOH_G - E_{ESS}^{CH})_i}{(1+d)^i} + \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}\right]}.$$

Equation 2.24

$$f_{ESS} = \frac{\sum_{i=1}^{n_{ESS}} \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left[\frac{(P_G \cdot EOH_G - E_{ESS}^{CH})_i}{(1+d)^i} + \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}\right]}.$$

Equation 2.25

$$LCOS_{ESS} = \frac{\sum_{i=0}^{n_{ESS}} \frac{NC_i^{ESS}}{(1+d)^i}}{\sum_{i=1}^{n_{ESS}} \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}},$$

Equation 2.26

$$LCOE'_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left[\frac{(P_G \cdot EOH_G - E_{ESS}^{CH})_i}{(1+d)^i} + \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}\right]},$$

Equation 2.27

It must be observed in Equation 2.24 that the participation factor of the generator G is defined according to the curtailed equivalent operating hours, i.e. the energy provided by the generator in case it does not account with an ESS. Then, the *LCOE*$_G$ considering the generator working alone must be used in Equation 2.23 [3] . Moreover, in Equation 2.26, it must be recalled that the *LCOS* is defined with reference to the discharged energy of the ESS, independently of the needed charged energy on the device. Finally, the *LCOE* associated with the system integration is referred to the total supplied energy to the grid by the combination of the generator and the ESS.

[3] In Equation 2.23, the *LCOE*$_G$ refers to that calculated for a curtailed generation capacity, i.e., $P_G \cdot EOH_G - E_{ESS}^{CH}$. If other *LCOE*$_G$ value is used, then the numerator of Equation 2.24 must be in accordance.

2.4.5. LCOE of polygeneration systems

Polygeneration systems have become increasingly popular in recent years along with the increasing attention devoted to integration of traditional and renewable energy sources. Polygeneration means to use several generators and the same energy vector within a single integrated process (therefore differently with multi-vector energy systems, which will be analyzed in detail in Section 2.7). Figure 2.3 shows an example of a polygeneration system with two different generators, G1 and G2, these two-last used as subscripts for each analyzed quantity.

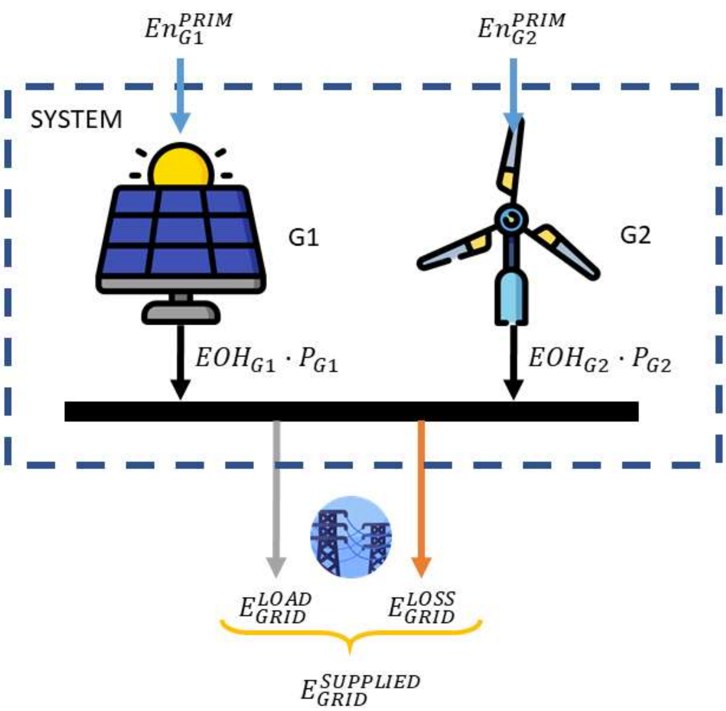

Figure 2.3. Representation of a polygeneration system.

In this case, the energy balance of the system is expressed as follows:

$$E_{G1} + E_{G2} = (EOH_{G1} \cdot P_{G1}) + (EOH_{G2} \cdot P_{G2}) = E_{GRID}^{SUPPLIED}.$$

Equation 2.28

Analogously to the combined generation and energy storage system, analyzed in the previous section, it is possible that the generation units have different lifespan values. Then, two approaches can be adopted:

a) The generation units are not replaced when their useful lifespan ends. Then the *LCOE* can be expressed as indicated in Equation 2.29:

$$LCOE_{G1+G2} = \frac{\sum_{i=0}^{n_{G1}} \frac{NC_i^{G1}}{(1+d)^i} + \sum_{i=0}^{n_{G2}} \frac{NC_i^{G2}}{(1+d)^i} + \sum_{i=0}^{\max(n_{G1},n_{G2})} \frac{Costs_i^{SYST}}{(1+d)^i}}{P_{G1} \cdot \sum_{i=1}^{n_{G1}} \frac{EOH_i^{G1}}{(1+d)^i} + P_{G2} \cdot \sum_{i=1}^{n_{G2}} \frac{EOH_i^{G2}}{(1+d)^i}}.$$

Equation 2.29

In this case, the integrating and coordinating costs of the different units ($Costs^{SYST}$) have been considered that persist until the last generator remains plugged to the system. However, running the system when a significant part of the generators decease is usually inefficient and thus, it can be set a lifespan of the system $n \leq \max(n_{G1}, n_{G2})$.

Similarly to Equation 2.22, Equation 2.29 can be expressed in terms of the individual *LCOE*s for each generation unit, as depicted in Equation 2.30:

$$LCOE_{G1+G2} = f_{G1} \cdot LCOE_{G1} + f_{G2} \cdot LCOE_{G2} + LCOE'_{SYST},$$

Equation 2.30

where f_{G1} and f_{G2} represent the participation factors of the generators G1 and G2 respectively, while the term $LCOE'_{SYST}$ represents the virtual Levelized Cost of the Electricity associated to the integration and coordination infrastructure.

$$f_{G1} = \frac{P_{G1} \cdot \sum_{i=1}^{n_{G1}} \frac{EOH_i^{G1}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{j=1}^{2} \left[P_{Gj} \cdot \frac{EOH_i^{Gj}}{(1+d)^i} \right] \right\}}.$$

Equation 2.31

$$f_{G2} = \frac{P_{G2} \cdot \sum_{i=1}^{n_{G2}} \frac{EOH_i^{G2}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{j=1}^{2} \left[P_{Gj} \cdot \frac{EOH_i^{Gj}}{(1+d)^i} \right] \right\}}.$$

Equation 2.32

$$LCOE'_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{j=1}^{2} \left[P_{Gj} \cdot \frac{EOH_i^{Gj}}{(1+d)^i} \right] \right\}}.$$

Equation 2.33

b) The generation units are replaced when their useful lifespan ends. Then, a total lifespan of the system must be considered, which would be the maximum lifespan of all the devices, not greater than an overall maximum lifespan for the system, n_{lim}:

$$n = min[max(n_{G1}, n_{G2}), n_{lim}].$$

Equation 2.34

In this case, the generation units whose lifespan are lower than the most durable, must be replaced, adding capital costs in the replacement time period ($n_{Gj}+1$). Supposing that $n=n_{G1}$ and $n_{G2} < n_{G1}$, then the *LCOE* can be expressed as indicated in Equation 2.35:

$$LCOE_{G1+G2} = \frac{\sum_{i=0}^{n} \left[\frac{NC_i^{G1}}{(1+d)^i} + \frac{NC_i^{G2}}{(1+d)^i} + \frac{Costs_i^{SYST}}{(1+d)^i} \right] - \frac{RV_{G2}}{(1+d)^n}}{\sum_{i=1}^{n} \left[P_{G1} \cdot \frac{EOH_i^{G1}}{(1+d)^i} + P_{G2} \cdot \frac{EOH_i^{G2}}{(1+d)^i} \right]}.$$

Equation 2.35

The term RV_{G2} in Equation 2.35 refers to the residual value of the second generator in the case the new G2 unit installed at time n_{G2}+1 does not end its useful lifespan at the same time than that considered for the whole system. As stated in the previous section, this residual value can be estimated through several methods. One of the most commonly used is to estimate a linear depreciation of the device, and thus, its residual value can be estimated as:

$$RV_{G2} = \left[ceil\left(\frac{n}{n_{G2}}\right) - \frac{n}{n_{G2}}\right] \cdot [CAPEX_0^{G2} \cdot \beta_{G2}],$$

Equation 2.36

β_{G2} being a reduction costs factor that accounts for the loss of the asset value (it should be defined as a function of time, as it must be evaluated at time step $z \cdot n_{G2} + 1$), regardless of its degree of wear and that is accounted at the last replacement time, $z \cdot n_{G2}$, where $z = floor\left(\frac{n}{n_{G2}}\right)$.

Equation 2.35 can be expressed as a function of the *LCOE* values of the generators, as it can be seen in Equation 2.37, keeping the assumption that $n = n_{G1} > n_{G2}$:

$$LCOE_{G1+G2} = f'_{G1} \cdot LCOE_{G1} + f'_{G2} \cdot LCOE'_{G2} + LCOE'_{SYST},$$

Equation 2.37

where $LCOE_{G1}$ is calculated according to Equation 2.19. As the lifespan of the generator G2 has been considered lower than the one of generator G1, its participation factor and *LCOE* values must be "normalized" to the considered lifespan of the system (*n*). Thus, Equation 2.38 shows the normalized participation factor for generator G2, while Equation 2.39 shows the definition of its normalized *LCOE*.

$$f'_{G2} = \frac{P_{G2} \cdot \sum_{i=1}^{n_{G2}} \frac{EOH_i^{G2}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{\sum_{j=1}^{2} \left[P_{Gj} \cdot \frac{EOH_i^{Gj}}{(1+d)^i}\right]\right\}}.$$

Equation 2.38

$$LCOE'_{G2} = \frac{\sum_{i=1}^{n_{G2}} \frac{EOH_i^{G2}}{(1+d)^i}}{\sum_{i=1}^{n} \frac{EOH_i^{G2}}{(1+d)^i}} \cdot LCOE_{G2}$$

$$+ \frac{\sum_{z=1}^{floor\left(\frac{n}{n_{G2}}\right)} \left\{ \sum_{i=z \cdot n_{G2}+1}^{min[(z+1) \cdot n_{G2}, n]} \left[\frac{NC_i^{G2}}{(1+d)^i} \right] \right\} - \frac{RV_{G2}}{(1+d)^n}}{P_{G2} \cdot \sum_{i=1}^{n} \frac{EOH_i^{G2}}{(1+d)^i}},$$

Equation 2.39

being $floor\left(\frac{n}{n_{G2}}\right)$ the number of times generator G2 is replaced during the lifespan of the system. It must be also noted that, for the replacement of the devices, the nominal $CAPEX_{0'}^{G2}$ might be reduced due to a reduction cost factor[4], as considered in the evaluation of the residual value of the asset, RV_{G2} (see Equation 2.36).

Moreover, it must be remarked that a polygeneration system can include one or several ESS devices. In this case, one should consider the economic modelling of the storage devices presented in Section 2.4.4 and the extension of Equations 2.30 or 2.37 for more than two devices. Equation 2.40 shows the *LCOE* calculation for a general polygeneration system with energy storage:

$$LCOE_{POLY} = \sum_{j=1}^{J} \left(f'_{Gj} \cdot LCOE'_{Gj} \right) + \sum_{k=1}^{K} (f'_{ESSk} \cdot LCOS'_{ESSk}) + LCOE'_{SYST},$$

Equation 2.40

where the normalized participation factors and *LCOE* values for both the generators and the ESS devices can be calculated as follows:

[4] *0'* refers to the initial time step of the replaced asset relative to its lifespan, which will be the $z \cdot n_{G2} + 1$ time step in the absolute time reference system. Then, $CAPEX_{0'}^{G2} = CAPEX_0^{G2} \cdot \beta_{G2}$.

$$f'_{Gj} = \frac{P_{Gj} \cdot \sum_{i=1}^{n_{Gj}} \frac{EOH_i^{Gj}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH}\right)_i}{(1+d)^i} \right\}},$$

Equation 2.41

where Γ is the total number of generators and Δ the total number of ESS devices.

$$LCOE'_{Gj} = \frac{\sum_{i=1}^{n_{Gj}} \frac{EOH_i^{Gj}}{(1+d)^i}}{\sum_{i=1}^{n} \frac{EOH_i^{Gj}}{(1+d)^i}} \cdot LCOE_{Gj}$$

$$+ \frac{\sum_{z=1}^{floor\left(\frac{n}{n_{Gj}}\right)} \left\{ \sum_{i=z \cdot n_{Gj}+1}^{min\left[(z+1) \cdot n_{Gj}, n\right]} \left[\frac{NC_i^{Gj}}{(1+d)^i} \right] \right\} - \frac{RV_{Gj}}{(1+d)^n}}{P_{Gj} \cdot \sum_{i=1}^{n} \frac{EOH_i^{Gj}}{(1+d)^i}},$$

Equation 2.42

$$f'_{ESSk} = \frac{\sum_{i=1}^{n_{ESSk}} \frac{\left(E_{ESSk}^{DCH}\right)_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH}\right)_i}{(1+d)^i} \right\}}.$$

Equation 2.43

$$LCOS'_{ESSk} = \frac{\sum_{i=1}^{n_{ESSk}} \frac{(E_{ESSk}^{DCH})_i}{(1+d)^i}}{\sum_{i=1}^{n} \frac{(E_{ESSk}^{DCH})_i}{(1+d)^i}} \cdot LCOS_{ESSk}$$

$$+ \frac{\sum_{z=1}^{floor\left(\frac{n}{n_{ESSk}}\right)} \left\{ \sum_{i=z \cdot n_{ESSk}+1}^{min[(z+1)\cdot n_{ESSk}, n]} \left[\frac{NC_i^{ESSk}}{(1+d)^i} \right] \right\} - \frac{RV_{ESSk}}{(1+d)^n}}{\sum_{i=1}^{n} \frac{(E_{ESSk}^{DCH})_i}{(1+d)^i}},$$

Equation 2.44

Accordingly to the previous equations, the virtual *LCOE* of the integration and coordination infrastructure must be modified, as expressed in Equation 2.45.

$$LCOE'_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{j=1}^{J} \left[P_{Gj} \cdot \frac{EOH_i^{Gj}}{(1+d)^i} \right] + \sum_{k=1}^{K} \frac{(E_{ESSk}^{DCH} - E_{ESSk}^{CH})_i}{(1+d)^i} \right\}}.$$

Equation 2.45

2.4.6. LCOE of a power grid costumer

In Figure 2.4 it is shown the case of a power costumer plugged to an external power grid. The power grid can be modelled as a generator which supplies power to the system by consuming a primary energy source, which is electrical energy, and null *CAPEX* and *OPEX* if the electrical connection infrastructure already exists and it is operated and maintained by the DSO.

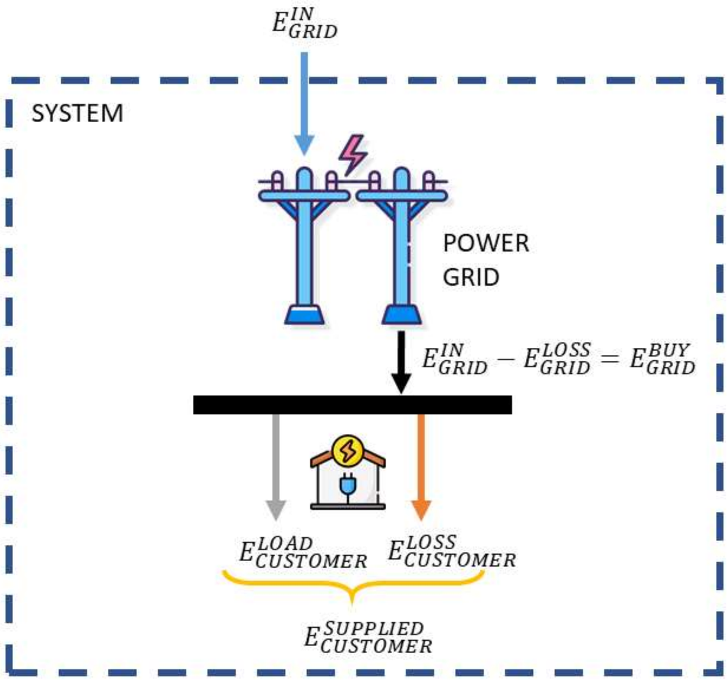

Figure 2.4. Representation of an electrical microgrid fed by the external power grid.

If a single-bus analysis is applied to the described system, the energy balance can be expressed as:

$$E_{GRID}^{IN} - E_{GRID}^{LOSS} = E_{GRID}^{BUY} = E_{CUSTOMER}^{LOAD} + E_{CUSTOMER}^{LOSS} = E_{CUSTOMER}^{SUPPLIED}.$$

Equation 2.46

Then, analogously to the previous conducted analysis, the *LCOE* of this system (*LCOE_{GRID CUSTOMER}*) can be defined as expressed in Equation 2.47. It must be noted that the *LCOE* is referred to the supplied energy to the customer. Moreover, if *CAPEX* and *OPEX* are considered null, costs are only related with the withdrawn electricity. In this case, the *LCOE* equals the weighted average price of the electricity purchased from the grid if this price remains constant for each time period.

$$LCOE_{GRID\ COSTUMER} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{GRID}}{(1+d)^i}}{\sum_{i=1}^{n} \frac{(E_{GRID}^{BUY})_i}{(1+d)^i}} = \frac{\sum_{i=0}^{n} \frac{(p \cdot E_{GRID}^{BUY})_i}{(1+d)^i}}{\sum_{i=1}^{n} \frac{(E_{GRID}^{BUY})_i}{(1+d)^i}} = \bar{p}.$$

Equation 2.47

2.4.7. LCOE of electrical microgrids

As presented and defined in the first chapter, a microgrid is a set of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. Moreover, it is conceived to operate connected and disconnected to the power grid and accounts with generators and ESS devices. Figure 2.5 represents a simple microgrid that accounts with a power generator, such as a solar PV plant, and it is connected to the external power grid with the capability not only to purchase electricity from the grid, but also to inject (and sell) electricity, following the microgrid's EMS defined strategy.

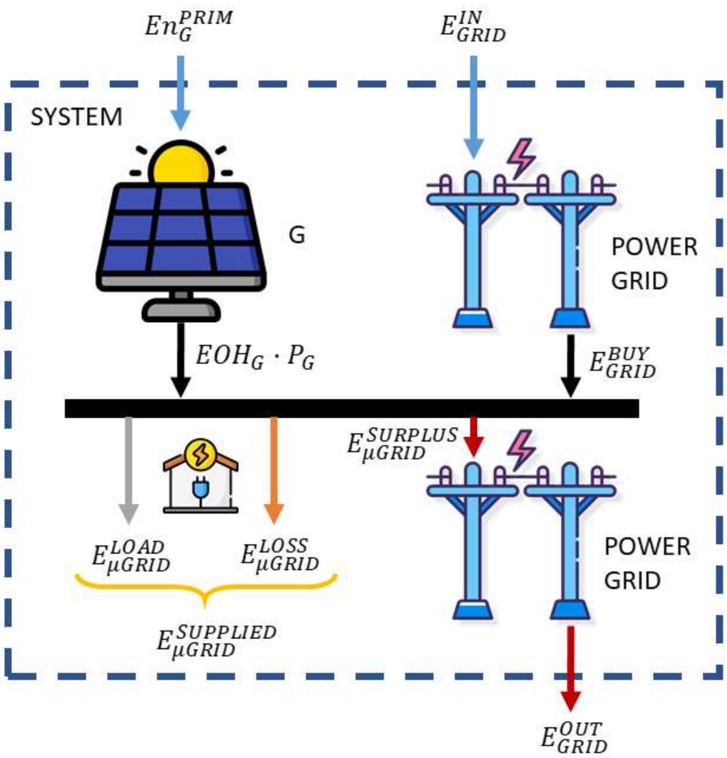

Figure 2.5. Representation of an electrical microgrid with a PV plant connected to the power grid.

Electrical microgrids manage and dispatch several generators which exploit different sources for several reasons, including the minimization of power delivery risks, the minimization of operation costs or the maximization of the exploitation of the local natural resources. The literature in this regard mainly generalizes the concept of the *LCOE* to the different existing units. By way of example, in [37], the *LCOE* evaluation includes the grid supplied energy through an additional cost term and considers the total energy consumption, rather than the produced energy. On the other hand, [38] makes a step forward deriving *LCOE* from the total aggregated cost of the distributed energy resources and the total energy generated. However, integration costs, as well as auxiliary systems or benefits from the grid are not explicitly accounted for. In [39] proposes a new formulation of the LCOE for microgrids considering the sum of discounted costs and the sum of discounted energy demands of the site.

Focusing on the case of a pure electrical microgrid, such as the one represented in Figure 2.5, the energy balance of the system can be expressed as:

$$E_G + E_{GRID}^{BUY} = E_{\mu GRID}^{SUPPLIED} + E_{\mu GRID}^{SURPLUS}.$$

Equation 2.48

Applying again Equation 2.9 to the case, it can be observed that the *LCOE* for this system is still referred to the supplied energy (as expressed in Equation 2.47). However, this quantity does not coincide with the generated energy (E_G) because part of the electricity supply is provided by the external grid. Moreover, part of the generated energy is injected back to the power grid ($E_{GRID}^{OUT} = E_{\mu GRID}^{SURPLUS} - E_{GRID}^{LOSS}$). Then, the result can be expressed as shown in Equation 2.49:

$$LCOE_{\mu GRID} = \frac{\sum_{i=0}^{n} \left[\frac{NC_i^G}{(1+d)^i} + \frac{Costs_i^{GRID}}{(1+d)^i} + \frac{Costs_i^{SYST}}{(1+d)^i} - \frac{Revenues_i^{GRID}}{(1+d)^i}\right]}{\sum_{i=1}^{n} \left[P_G \cdot \frac{EOH_i^G}{(1+d)^i} + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i}\right]}.$$

Equation 2.49

In Equation 2.49, the term of costs associated with the grid (*Costs*$_{GRID}$) are those related with the purchase of electricity, or in other terms:

$$Costs_{GRID} = CAPEX_{GRID} + OPEX_{GRID} + E_{GRID}^{BUY} \cdot \bar{p}_{GRID}^{BUY}.$$

Equation 2.50

On the other hand, in Equation 2.49, the term of revenues associated with the grid (*Revenues*$_{GRID}$) are those related with the sale of surplus energy:

$$Revenues_{GRID} = E_{GRID}^{OUT} \cdot \bar{p}_{GRID}^{SALE}.$$

Equation 2.51

Accordingly to previous analysis, Equation 2.49 can be expressed as a function of the *LCOEs* of the connected devices to the microgrid:

$$LCOE_{\mu GRID} = f''_{G} \cdot LCOE'_{G} + f''^{BUY}_{GRID} \cdot LCOE_{GRID} + LCOE''_{SYST} - f''^{SURPLUS}_{\mu GRID} \cdot LROE_{GRID}.$$

Equation 2.52

In Equation 2.52, *f''* indicates the participation factor of each energy source referred to the energy served to the microgrid, as defined in Equations 2.53, 2.54 and 2.55, while *LROE* indicates the "Levelized Revenues of Electricity", which can be defined as the discounted revenues due to the electricity sold to the power grid and other revenues, such as the provision of ancillary services or increase of the system resilience.

$$f''_{G} = \frac{P_G \cdot \sum_{i=1}^{n} \frac{EOH_i^G}{(1+d)^i}}{\sum_{i=1}^{n} \left[P_G \cdot \frac{EOH_i^G}{(1+d)^i} + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i} \right]}.$$

Equation 2.53

$$f''^{BUY}_{GRID} = \frac{\sum_{i=1}^{n} \frac{(E_{GRID}^{BUY})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left[P_G \cdot \frac{EOH_i^G}{(1+d)^i} + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i} \right]}.$$

Equation 2.54

$$f''^{SURPLUS}_{\mu GRID} = \frac{\sum_{i=1}^{n} \frac{\left(E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i}}{\sum_{i=1}^{n} \left[P_G \cdot \frac{EOH_i^G}{(1+d)^i} + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i} \right]}.$$

Equation 2.55

It must be noted in Equation 2.52 that the $LCOE'_G$ is used instead of the $LCOE_G$. This is due to the lifespan of the system (the microgrid), *n*, may not be the same than the lifespan of the generator, n_G. Thus, the *LCOE* value for the generator must be normalized to the lifespan of the microgrid, by Equation 2.42. In the case that the lifespan of the microgrid coincides with that of the generator ($n = n_G$), the *LCOE* for the generation unit can be used.

The *LCOE* for the electricity purchased from the power grid is expressed in Equation 2.56, while the *LROE* of the electricity sold is shown in Equation 2.57.

$$LCOE_{GRID} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{GRID}}{(1+d)^i}}{\sum_{i=1}^{n} \frac{(E_{GRID}^{BUY})_i}{(1+d)^i}}.$$

Equation 2.56

$$LROE_{GRID} = \frac{\sum_{i=1}^{n} \frac{Revenues_i^{GRID}}{(1+d)^i}}{\sum_{i=1}^{n} \frac{\left(E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i}}.$$

Equation 2.57

In the case the sale and purchase prices of electricity remain constant for each time period and the *CAPEX* and *OPEX* for the grid connection are not considered or neglected, then $LCOE_{GRID} = \bar{p}_{GRID}^{BUY}$ and $LROE_{GRID} = \bar{p}_{GRID}^{SALE}$.

Finally, Equation 2.58 shows the normalized *LCOE* of the integration and coordination infrastructure referenced to the supplied energy:

$$LCOE''_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left[P_G \cdot \frac{EOH_i^G}{(1+d)^i} + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i} \right]}.$$

Equation 2.58

The previously analyzed case can be extended to other configurations. For instance, Figure 2.6 represents also a microgrid, but in this case includes a multi-vector energy generator, such as a CHP unit. It is also connected to the external power grid and has the capability not only to purchase electricity from the grid, but also to inject it.

In this case, the only difference with respect to the microgrid presented in Figure 2.5 is that the CHP unit produces not only electricity but also heat to serve a heating demand. When calculating the *LCOE* of this system, the heating generation is not considered as a served or supplied product but a side effect of the electricity generation. Thus, this side effect must be accounted in the net costs of the generation unit, also with other externalities, internalities or other revenues linked to that generator, such as the avoided costs due to the fact that thermal energy is produced with the CHP unit instead of using a boiler. With this consideration, the set of Equations 2.52-2.58 also apply for this system.

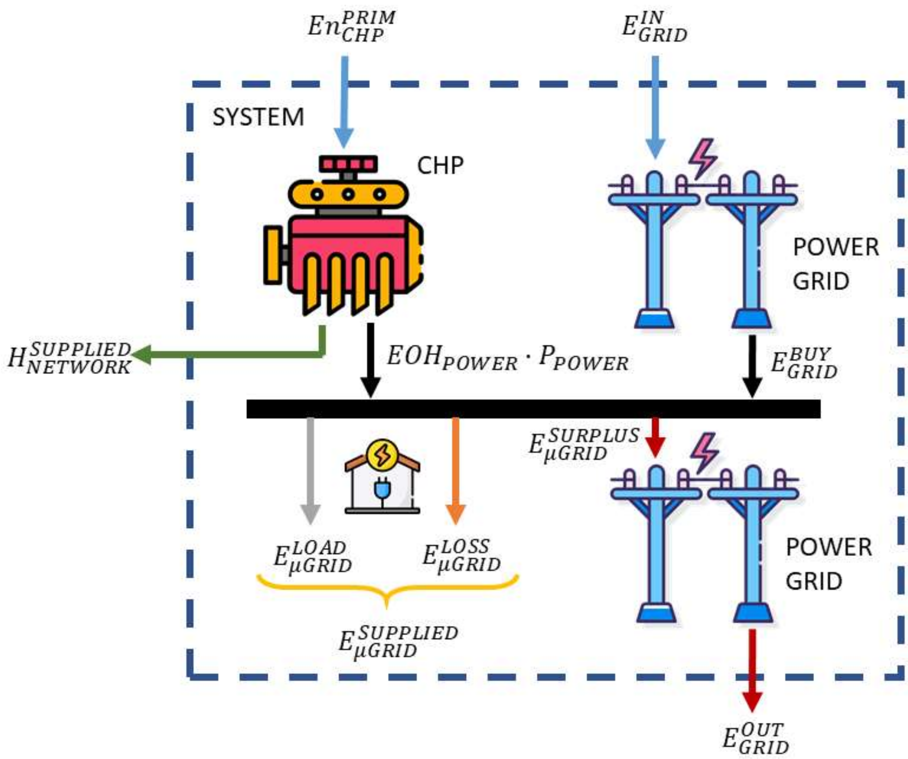

Figure 2.6. Representation of an electrical microgrid with a CHP unit and connected to the power grid.

Moreover, the presented approach for the *LCOE* evaluation of a microgrid can be generalized to a polygeneration system with several ESS devices, such that shown in Figure 2.7.

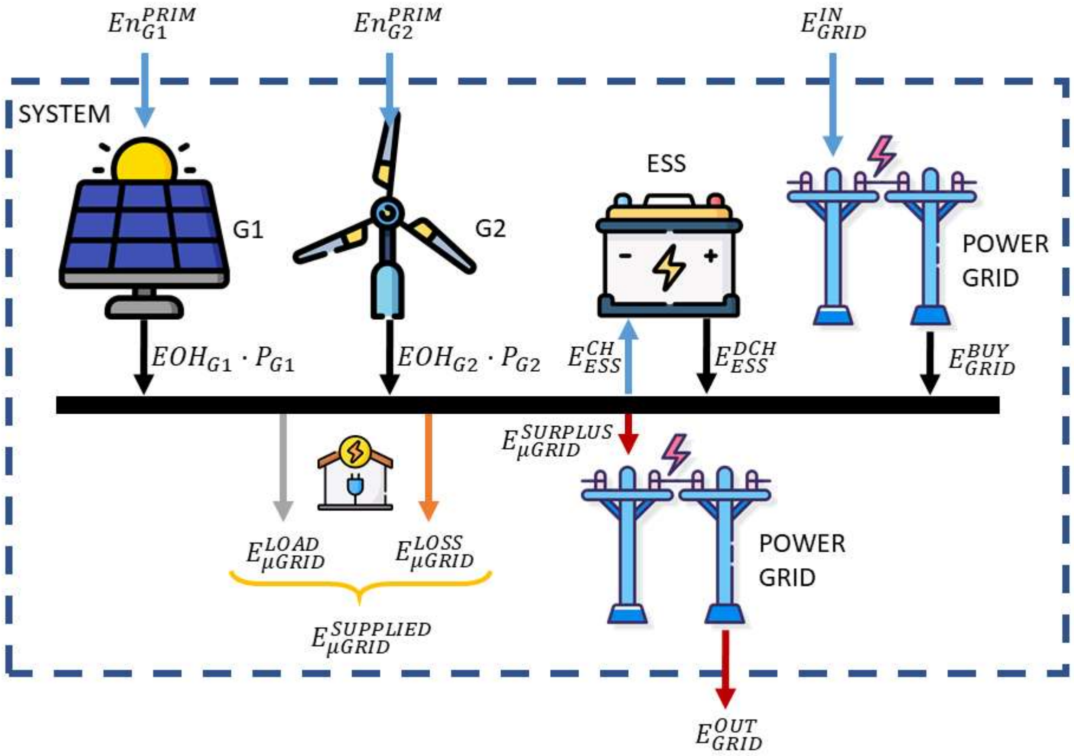

Figure 2.7. Representation of an electrical polygeneration microgrid with ESS devices connected to the power grid.

Equation 2.59 shows the generalized expression for the *LCOE* of an electrical microgrid with energy storage systems.

$$LCOE_{\mu GRID} = \sum_{j=1}^{J} \left(f''_{Gj} \cdot LCOE'_{Gj} \right) + \sum_{k=1}^{K} \left(f''_{ESSk} \cdot LCOS'_{ESSk} \right) + f''^{BUY}_{GRID} \cdot LCOE_{GRID} + LCOE''_{SYST} - f''^{SURPLUS}_{\mu GRID} \cdot LROE_{GRID}.$$

Equation 2.59

The participation factors and $LCOE''_{SYST}$ must be calculated as shown by the following expressions:

$$f''_{Gj} = \frac{P_{Gj} \cdot \sum_{i=1}^{n} \frac{EOH_i^{Gj}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH} \right)_i}{(1+d)^i} \right] + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS} \right)_i}{(1+d)^i} \right\}}.$$

Equation 2.60

$$f''_{ESSk} = \frac{\sum_{i=1}^{n} \frac{(E_{ESSk}^{DCH})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH} \right)_i}{(1+d)^i} \right] + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS} \right)_i}{(1+d)^i} \right\}}.$$

Equation 2.61

$$f''^{BUY}_{GRID} = \frac{\sum_{i=1}^{n} \frac{(E_{GRID}^{BUY})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH} \right)_i}{(1+d)^i} \right] + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS} \right)_i}{(1+d)^i} \right\}}.$$

Equation 2.62

$$f''^{SURPLUS}_{\mu GRID} = \frac{\sum_{i=1}^{n} \frac{\left(E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH} \right)_i}{(1+d)^i} \right] + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS} \right)_i}{(1+d)^i} \right\}}.$$

Equation 2.63

$$LCOE''_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma} \cdot \frac{EOH_i^{G\gamma}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(E_{ESS\delta}^{DCH} - E_{ESS\delta}^{CH}\right)_i}{(1+d)^i} \right] + \frac{\left(E_{GRID}^{BUY} - E_{\mu GRID}^{SURPLUS}\right)_i}{(1+d)^i} \right\}}.$$

Equation 2.64

2.5. Levelized Cost of Stored Energy (*LCOS*)

The *LCOEn* methodology can also be applied to domains others than the generation technologies so far, such as the energy storage or the demand response applications. As presented in the previous section by Equation 2.26 (recalled here for clearness), some academics and energy policy makers have introduced the "Levelized Cost of Storage" (*LCOS*) indicator [40]:

$$LCOS_{ESS} = \frac{\sum_{i=0}^{n_{ESS}} \frac{NC_i^{ESS}}{(1+d)^i}}{\sum_{i=1}^{n_{ESS}} \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}} = \frac{\sum_{i=0}^{n_{ESS}} \left[\frac{CAPEX_i}{(1+d)^i} + \frac{OPEX_i}{(1+d)^i} + \frac{(p \cdot E_{ESS}^{CH})_i}{(1+d)^i} + \frac{Other\ costs_i}{(1+d)^i} - \frac{Revenues_i}{(1+d)^i} \right]}{\sum_{i=1}^{n_{ESS}} \frac{(E_{ESS}^{DCH})_i}{(1+d)^i}}.$$

Equation 2.26

It must be noticed that the *LCOS* indicator is referred to the energy discharged by the ESS, while the charged energy is considered in the numerator substituting the Fuel costs. Moreover, it must be considered potential revenues that reduce the *LCOS*, such as subsidies or the provision of ancillary services to the system. This metric aims to analyze the observed costs and revenue streams associated with commercially available energy storage technologies.

If the ESS is integrated in a combined system, such as with a generator or in a microgrid, it must be remembered to normalize the *LCOS* of the ESS device according to the considered lifespan of the system, *n*, as stated in Equation 2.44, to get the *LCOS'*.

In contrast with pure generation technologies, storage devices may have a significant different behavior between in-front-of-the-meter applications and behind-the-meter applications. For instance, in [40], six different applications (use cases) are identified. The main in-front-of-the-meter cases are:

- **Wholesale:** these are large-scale energy storage systems designed to replace peaking generation technologies, such as gas-fired turbines, with the aim to meet rapidly increasing demand for power peak and be quickly taken offline as power demand decreases.
- **Transmission and distribution:** the main purpose of these energy storage systems is to defer transmission and/or distribution upgrades. Then, they are placed at substations or distribution feeders controlled by utilities to provide flexible capacity while maintaining grid stability.
- **Utility scale:** these systems are designed to be paired with large solar PV facilities to improve the market price of solar generation, reduce solar curtailment and provide grid support when not supporting solar targets.

On the contrary, the main behind-the-meter cases are:

- **Commercial and industrial stand-alone:** these are energy storage systems designed for peak shaving and demand charge reduction services for commercial and industrial end-users. They can support different management strategies and provide grid services to a utility or the wholesale market.
- **Commercial and industrial self-consumption:** analogously to the previous case, these systems are designed to shave peaks in the energy demand but being paired with self-generation technologies, such as rooftop PV systems.
- **Residential self-consumption:** these systems aim to provide backup power, power quality improvements and extension of the usefulness of self-generation,

typically, solar PV. They are designed to regulate the power supply and smooth the amount of electricity sold back to the grid from distributed PV applications.

Depending on the application, the project parameters may change significantly, as it can be seen in Table 3.1 for reference.

Table 3.1. Project parameters of different case studies of storage systems. Data from [40].

Parameter	In-Front-of-the-Meter			Behind-the-Meter		
	Wholesale	**Transmission and Distribution**	**Utility Scale**	**Commercial and Industrial Standalone**	**Commercial and Industrial self-consumption**	**Residential self-consumption**
Project life [years]	20	20	20	10	20	20
Power rating [MW]	100	10	20	1	0.50	0.01
Capacity [MWh]	400	60	80	2	2	0.04
100% DOD Cycles / day	1	1	1	1	1	1
Days / year	350	250	350	250	350	350
Annual stored energy [MWh]	140,000	15,000	28,000	500	700	14
Feasible technologies	- Lithium-Ion - Flow Battery			- Lithium-Ion - Lead-Acid - Advanced Lead		

2.6. Levelized Cost of Thermal Energy

2.6.1. Levelized Cost of Heat (LCOH)

Analogously to the *LCOE* definition for electrical systems, it is possible to define a "Levelized Cost of Heat" (*LCOH*) for thermal energy. This indicator can be used in order to compare different thermal power technologies. According to the authors of [9, 10, 41, 42], the *LCOH* can be written in a similar manner to what is written for electricity by simply replacing *E*: electricity by *H*: provided heat. Furthermore, Figure 2.8 shows a thermal energy microgrid, which represents the analogous case to that presented in Section 2.4.6 for electrical microgrids.

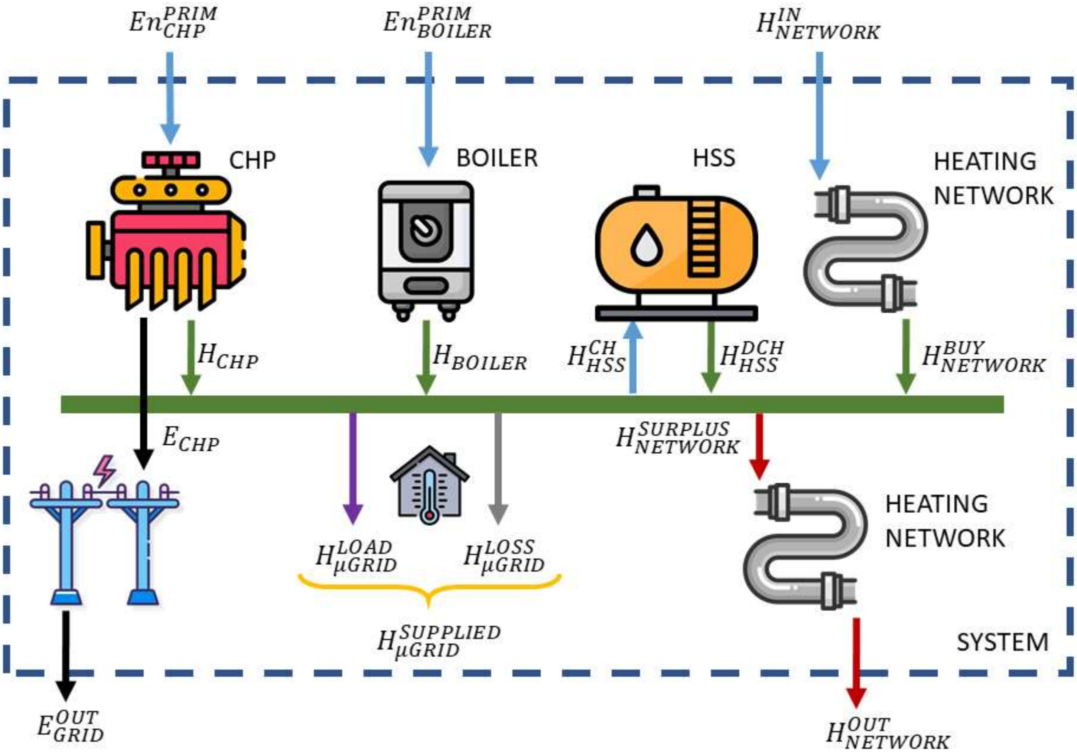

Figure 2.8. Representation of a thermal polygeneration microgrid with ESS devices connected to a heating network.

Then, the expressions to evaluate the *LCOH*, depending on the case are:

Single generator unit:

$$LCOH_G = \frac{\sum_{i=0}^{n} \frac{NC_i^G}{(1+d)^i}}{P_G^{th} \cdot \sum_{i=1}^{n} \frac{EOH_i^{G,th}}{(1+d)^i}},$$

Equation 2.65

where the super index *th* refers to the thermal capacity.

Normalized LCOH of a generator:

$$LCOH'_G = \frac{\sum_{i=1}^{n_G} \frac{EOH_i^{G,th}}{(1+d)^i}}{\sum_{i=1}^{n} \frac{EOH_i^{G,th}}{(1+d)^i}} \cdot LCOH_G$$

$$+ \frac{\sum_{z=1}^{floor\left(\frac{n}{n_G}\right)} \left\{ \sum_{i=z\cdot n_G+1}^{min[(z+1)\cdot n_G, n]} \left[\frac{NC_i^G}{(1+d)^i} \right] \right\} - \frac{RV_G}{(1+d)^n}}{P_G^{th} \cdot \sum_{i=1}^{n} \frac{EOH_i^{G,th}}{(1+d)^i}}.$$

Equation 2.66

Polygeneration system with thermal storage devices (HSS) and devices replacement:

$$LCOH_{POLY} = \sum_{j=1}^{J} \left(f'_{Gj} \cdot LCOH'_{Gj} \right) + \sum_{k=1}^{K} (f'_{HSSk} \cdot LCOS'_{HSSk}) + LCOH'_{SYST},$$

Equation 2.67

$$f'_{Gj} = \frac{P_{Gj}^{th} \cdot \sum_{i=1}^{n_{Gj}} \frac{EOH_i^{Gj,th}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma}^{th} \cdot \frac{EOH_i^{G\gamma,th}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \frac{\left(H_{HSS\delta}^{DCH} - H_{HSS\delta}^{CH} \right)_i}{(1+d)^i} \right\}}.$$

Equation 2.68

$$f'_{HSSk} = \frac{\sum_{i=1}^{n_{HSSk}} \frac{(H_{HSSk}^{DCH})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P_{G\gamma}^{th} \cdot \frac{EOH_i^{G\gamma,th}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \frac{\left(H_{HSS\delta}^{DCH} - H_{HSS\delta}^{CH} \right)_i}{(1+d)^i} \right\}}.$$

Equation 2.69

$$LCOH'_{SYST}=\frac{\sum_{i=0}^{n}\frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n}\left\{\sum_{\gamma=1}^{\Gamma}\left[P_{G\gamma}^{th}\cdot\frac{EOH_i^{G\gamma,th}}{(1+d)^i}\right]+\sum_{\delta=1}^{\Delta}\frac{\left(H_{HSS\delta}^{DCH}-H_{HSS\delta}^{CH}\right)_i}{(1+d)^i}\right\}}.$$

Equation 2.70

Thermal microgrid:

$$LCOH_{\mu GRID}=\sum_{j=1}^{J}\left(f''_{Gj}\cdot LCOH'_{Gj}\right)+\sum_{k=1}^{K}\left(f''_{HSSk}\cdot LCOS'_{HSSk}\right)+f''^{BUY}_{NETWORK}\cdot LCOH_{NETWORK}+LCOH''_{SYST}-f''^{SURPLUS}_{NETWORK}\cdot LROH_{NETWORK}.$$

Equation 2.71

$$f''_{Gj}=\frac{P_{Gj}^{th}\cdot\sum_{i=1}^{n}\frac{EOH_i^{Gj,th}}{(1+d)^i}}{\sum_{i=1}^{n}\left\{\sum_{\gamma=1}^{\Gamma}\left[P_{G\gamma}^{th}\cdot\frac{EOH_i^{G\gamma,th}}{(1+d)^i}\right]+\sum_{\delta=1}^{\Delta}\left[\frac{\left(H_{HSS\delta}^{DCH}-H_{HSS\delta}^{CH}\right)_i}{(1+d)^i}\right]+\frac{\left(H_{NETWORK}^{BUY}-H_{NETWORK}^{SURPLUS}\right)_i}{(1+d)^i}\right\}}.$$

Equation 2.72

$$f''_{HSSk}=\frac{\sum_{i=1}^{n}\frac{\left(H_{HSSk}^{DCH}\right)_i}{(1+d)^i}}{\sum_{i=1}^{n}\left\{\sum_{\gamma=1}^{\Gamma}\left[P_{G\gamma}^{th}\cdot\frac{EOH_i^{G\gamma,th}}{(1+d)^i}\right]+\sum_{\delta=1}^{\Delta}\left[\frac{\left(H_{HSS\delta}^{DCH}-H_{HSS\delta}^{CH}\right)_i}{(1+d)^i}\right]+\frac{\left(H_{NETWORK}^{BUY}-H_{NETWORK}^{SURPLUS}\right)_i}{(1+d)^i}\right\}}.$$

Equation 2.73

$$f''^{BUY}_{NETWORK} = \frac{\sum_{i=1}^{n} \frac{(H^{BUY}_{NETWORK})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P^{th}_{G\gamma} \cdot \frac{EOH^{G\gamma,th}_i}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(H^{DCH}_{HSS\delta} - H^{CH}_{HSS\delta}\right)_i}{(1+d)^i} \right] + \frac{(H^{BUY}_{NETWORK} - H^{SURPLUS}_{NETWORK})_i}{(1+d)^i} \right\}}.$$

Equation 2.74

$$f''^{SURPLUS}_{NETWORK} = \frac{\sum_{i=1}^{n} \frac{(H^{SURPLUS}_{NETWORK})_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P^{th}_{G\gamma} \cdot \frac{EOH^{G\gamma,th}_i}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(H^{DCH}_{HSS\delta} - H^{CH}_{HSS\delta}\right)_i}{(1+d)^i} \right] + \frac{(H^{BUY}_{NETWORK} - H^{SURPLUS}_{NETWORK})_i}{(1+d)^i} \right\}}.$$

Equation 2.75

$$LCOH''_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs^{SYST}_i}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left[P^{th}_{G\gamma} \cdot \frac{EOH^{G\gamma,th}_i}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(H^{DCH}_{HSS\delta} - H^{CH}_{HSS\delta}\right)_i}{(1+d)^i} \right] + \frac{(H^{BUY}_{NETWORK} - H^{SURPLUS}_{NETWORK})_i}{(1+d)^i} \right\}}.$$

Equation 2.76

$$LROH_{NETWORK} = \frac{\sum_{i=1}^{n} \frac{Revenues^{NETWORK}_i}{(1+d)^i}}{\sum_{i=1}^{n} \frac{(H^{SURPLUS}_{NETWORK})_i}{(1+d)^i}}.$$

Equation 2.77

However, it must be highlighted that, when dealing with thermal energy, the temperature at which the energy is supplied can be an important factor, as reported in [41]. Thus, when comparing *LCOH* of different technologies can be crucial to consider the same operating conditions for each technology. The evaluation of the exergy, as presented in Section 2.7 is recommended.

2.6.2. Levelized Cost of Cooling (LCOC)

Identically as defined for heat, the "Levelized Cost of Cooling" (*LCOC*) can be defined analogously to the *LCOE* by substituting *E* (electricity), or in the *LCOH* definitions *H* (heat), by *C* (cooling energy). Furthermore, the same considerations stated for heating regarding the framework boundaries and the "quality" (temperature) of the provided cooling energy must be considered.

2.7. Levelized Cost of Exergy (*LCOEx*)

Some particular energy systems, such as cogeneration plants or multi-vector energy microgrids providing power, heating, cooling and/or other services may be analyzed by specific economic and accounting approaches to separate the costs among the generated products (electricity, thermal energy, cooling energy or others). Otherwise, wrong conclusions about the efficiency of the systems can be drawn [43], for instance, if a cogeneration plant is only evaluated by its capacity to provide electricity dismissing its capacity to provide also thermal energy. However, this is not an easy task, mainly due to the different nature of the energy products, and several approaches can be adopted for this issue.

On the one hand, some researchers and policy makers prefer a physical or balance method of cost separation [43, 44]. According to this method, costs for heat production are calculated as if the heat was generated separately from the electricity [43]. The main advantages of this approach are that it provides transparent and accountable results, reduce initial assumptions and allows for seasonal fluctuations in output levels. On the other hand, the major disadvantage of this method is that any cost decreases due to cogeneration (i.e., a change in the working conditions to provide more heat instead of electricity) is accounted for electricity production only.

Another similar approach is the application of the so-called "heat credits" [44]. The heat credits can be defined as the revenue from heat generation in cogeneration systems, i.e. the value of heat produced by the cogeneration system calculated per unit of electricity generated by the system over its lifetime. This approach would be similar as defining thermal efficiency for electricity generation in cogeneration systems, targeting separation of fuel costs, or in other words, analyzing the fuel breakdown according to the final energy product (electricity or heat) and considering only the fuel costs associated with the product under analysis in the calculation.

In both cases, the electricity is assumed to be the main product. The incremental fuel is lower than the extra fuel amount that would be required if heat were produced separately [43] (it is considered a subtractive term indicating the thermal benefits, i.e., the avoided costs related to the thermal energy that is not needed to be produced in a separate plant, such as a boiler). However, one limitation that must be considered under this approach is that the heat credit rate still depends on the operation mode of the energy system (heat production vs. electricity production) and it is affected by the specific features of the generation technology [44].

In order to overcome the previous approaches' limitations, in [43] the application of the "Ginter triangle" is proposed as an alternative approach. Under this approach, a triangle is developed in the space between two axes (costs for electricity and heat). Thus, the triangle enables the estimation of the unit cost of the second product assuming the unit cost of the first one. The application of the Ginter method requires the use of coefficients to allow for separation of costs associated with combined generation. However, the determination of the separation coefficients for the cost components is complex due to the physical properties of simultaneous production. Thus, researchers, such as in [43], apply a risk analysis using a Monte Carlo simulation to determine cost ranges for energy products.

As an alternative to these approaches, we propose to evaluate the "Levelized Cost of Exergy" (*LCOEx*), which extends the *LCOEn* formulation to the total exergy produced by the system, then including electricity, thermal energy or any other energy product together.

Exergy refers to *"the maximum theoretical amount of work that can be obtained from the interaction of the system under study with the reference ambient system"* [45]. The fraction of a given form of energy which can be fully converted in other forms is called "exergy", while the fraction which cannot be transformed is called "anergy" [46]. Thus, considering any form of energy, the bigger is its exergy, the higher is its technic and economic value. The First Principle of Thermodynamics establishes the equivalence between different forms of energy, while on the other hand, the Second Principle of Thermodynamics fixes the limits for the transformation of one form of energy into another. For instance, mechanical energy and electricity can be completely transformed into other forms of energy (useful work) while thermal energy cannot. Mechanical energy and electricity are pure exergy, on the other hand the exergy content of the thermal energy is higher dependent on the temperature at which it is supplied in respect to the reference temperature of the environment [47]. For this reason, the exergy of the thermal energy can be seen as the portion which can be transformed into useful work, which can be considered as proportional to the efficiency of the equivalent Carnot cycle between the temperature at which the heat is supplied/discharged and the reference one [48]. This relation is expressed in Equation 2.78, where the temperature at the numerator, T_C, refers to the cold source, while the one in the denominator, T_H, refers to that of the hot source. The cold source or the hot source can both refer to the ambient depending on the thermal application.

$$Ex = H \cdot \left(1 - \frac{T_C}{T_H}\right).$$

Equation 2.78

For a heating power plant, the exergy associated with the thermal energy produced can then be evaluated considering the temperature at which the heat is supplied as the higher temperature, while the reference temperature of the environment is the lowest one. On the other hand, for a cooling plant, the exergy associated with the cooling energy produced can be evaluated considering as the higher temperature the reference temperature of the environment; and as the lower temperature the one of the technology used to extract heat from the environment. Considering a generic plant capable of producing both electricity and thermal energy, the exergy associated with the energy produced by the plant can be generally defined as reported in Equation 2.79, where T_a is the ambient temperature, T_s the temperature of the supplied thermal energy, and γ^{th} and γ^{co} represent the penalty factors associated to the Carnot cycle efficiency.

$$Ex = E + H \cdot \left(1 - \frac{T_a}{T_s}\right) + C \cdot \left(1 - \frac{T_s}{T_a}\right) = E + H \cdot \gamma^{th} + C \cdot \gamma^{co}.$$

Equation 2.79

From Equation 2.79 it is possible to notice that, for a generator which produces heat, the higher the temperature at which it supplies thermal energy, the lower its penalty factor; and thus, the higher the exergy associated to the produced thermal energy. Analogously, for a generator which produces cooling energy, the lower the temperature at which it provides it, the lower its penalty factor and thus, the higher the exergy associated to the produced cooling energy.

Once the concept of exergy has been properly defined, the *LCOEx* can be presented. As stated in Equation 2.80, this indicator measures the discounted cost of the exergy provided by a multi-vector system during its lifespan, i.e., the *LCOEx* is the average exergy price which makes the discounted revenues (related to the exergy content of final products) compensate the total discounted net costs.

$$LCOEx_G = \frac{\sum_{i=0}^{n_G} \frac{NC_i^G}{(1+d)^i}}{\sum_{i=1}^{n_G} \left\{ \sum_{m=1}^{M} \left[\frac{Ex_i^{G,m}}{(1+d)^i} \right] \right\}} = \frac{\sum_{i=0}^{n_G} \frac{NC_i^G}{(1+d)^i}}{\sum_{i=1}^{n_G} \left[\frac{E_i^G}{(1+d)^i} + \frac{(H^G \cdot \gamma^{th})_i}{(1+d)^i} + \frac{(C^G \cdot \gamma^{co})_i}{(1+d)^i} \right]},$$

Equation 2.80

where *m* refers to each source of exergy than the generator G can provide, up to *M*. For instance, in a pure electrical generator, such a solar PV plant, *M*=1, but in a CHP plant, *M*≥1.

If separated costs coefficients (α^E, α^{th} and α^{co}) can be defined for electricity, heat and cooling energy, respectively, Equation 2.80 can be rewritten as:

$$LCOEx_G = \frac{\sum_{i=0}^{n_G} \frac{(\alpha^E \cdot NC^G)_i}{(1+d)^i} + \sum_{i=0}^{n_G} \frac{(\alpha^{th} \cdot NC^G)_i}{(1+d)^i} + \sum_{i=0}^{n_G} \frac{(\alpha^{co} \cdot NC^G)_i}{(1+d)^i}}{\sum_{i=1}^{n_G} \left[\frac{E_i^G}{(1+d)^i} + \frac{(H^G \cdot \gamma^{th})_i}{(1+d)^i} + \frac{(C^G \cdot \gamma^{co})_i}{(1+d)^i}\right]},$$

Equation 2.81

where $\alpha^E + \alpha^{th} + \alpha^{co} = 1$. Then, the *LCOEx* of generator G can be expressed as a function of its *LCOE*, *LCOH* and *LCOC*:

$$LCOEx_G = f_G^E \cdot LCOE_G + f_G^{th} \cdot LCOH_G + f_G^{co} \cdot LCOC_G,$$

Equation 2.82

where:

$$f_G^E = \frac{\sum_{i=1}^{n_G} \frac{E_i^G}{(1+d)^i}}{\sum_{i=1}^{n_G} \left[\frac{E_i^G}{(1+d)^i} + \frac{(H^G \cdot \gamma^{th})_i}{(1+d)^i} + \frac{(C^G \cdot \gamma^{co})_i}{(1+d)^i}\right]}.$$

Equation 2.83

$$f_G^{th} = \frac{\sum_{i=1}^{n_G} \frac{H_i^G}{(1+d)^i}}{\sum_{i=1}^{n_G} \left[\frac{E_i^G}{(1+d)^i} + \frac{(H^G \cdot \gamma^{th})_i}{(1+d)^i} + \frac{(C^G \cdot \gamma^{co})_i}{(1+d)^i}\right]}.$$

Equation 2.84

$$f_G^{co} = \frac{\sum_{i=1}^{n_G} \frac{C_i^G}{(1+d)^i}}{\sum_{i=1}^{n_G} \left[\frac{E_i^G}{(1+d)^i} + \frac{(H^G \cdot \gamma^{th})_i}{(1+d)^i} + \frac{(C^G \cdot \gamma^{co})_i}{(1+d)^i}\right]}.$$

Equation 2.85

It must be noted that the exergy penalty factors for heat and cooling make that $f_G^E + f_G^{th} + f_G^{co} > 1$.

Finally, like for the *LCOE*, the *LCOH* or the *LCOC*, the *LCOEx* can be analyzed for combined systems, such a polygeneration plants or multi-vector energy microgrids. Following the same reasoning than that presented in Sections 2.4.4 to 2.4.6, the following results can be obtained:

Normalized *LCOEx* of a generator:

$$LCOEx'_G = \frac{\sum_{i=1}^{n_G} \left\{\sum_{m=1}^{M} \left[\frac{Ex_i^{G,m}}{(1+d)^i}\right]\right\}}{\sum_{i=1}^{n} \left\{\sum_{m=1}^{M} \left[\frac{Ex_i^{G,m}}{(1+d)^i}\right]\right\}} \cdot LCOEx_G$$
$$+ \frac{\sum_{z=1}^{floor\left(\frac{n}{n_G}\right)} \left\{\sum_{i=z \cdot n_G+1}^{min[(z+1) \cdot n_G, n]} \left[\frac{NC_i^G}{(1+d)^i}\right]\right\} - \frac{RV_G}{(1+d)^n}}{\sum_{i=1}^{n} \left\{\sum_{m=1}^{M} \left[\frac{Ex_i^{G,m}}{(1+d)^i}\right]\right\}}.$$

Equation 2.86

Polygeneration system with storage devices (EnSS)[5] and considering the replacement of the devices at the end of their lifespan:

$$LCOEx_{POLY} = \sum_{j=1}^{J} \left(f'_{Gj} \cdot LCOEx'_{Gj} \right) + \sum_{k=1}^{K} \left(f'_{ExSSk} \cdot LCOS'_{ExSSk} \right) + LCOEx'_{SYST},$$

Equation 2.87

$$f'_{Gj} = \frac{\sum_{i=1}^{n_{Gj}} \left\{ \sum_{m=1}^{M} \left[\frac{Ex_i^{Gj,m}}{(1+d)^i} \right] \right\}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left\{ \sum_{m=1}^{M} \left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i} \right] \right\} + \sum_{\delta=1}^{\Delta} \left\{ \sum_{m=1}^{M} \left[\frac{\left(Ex_{EnSS\delta}^{DCH} - Ex_{EnSS\delta}^{CH} \right)_i^m}{(1+d)^i} \right] \right\} \right\}}.$$

Equation 2.88

$$f'_{ExSSk} = \frac{\sum_{i=1}^{n_{ExSSk}} \left\{ \sum_{m=1}^{M} \left[\frac{\left(Ex_{ExSSk}^{DCH} \right)_i^m}{(1+d)^i} \right] \right\}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left\{ \sum_{m=1}^{M} \left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i} \right] \right\} + \sum_{\delta=1}^{\Delta} \left\{ \sum_{m=1}^{M} \left[\frac{\left(Ex_{EnSS\delta}^{DCH} - Ex_{EnSS\delta}^{CH} \right)_i^m}{(1+d)^i} \right] \right\} \right\}}.$$

Equation 2.89

$$LCOEx'_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{\gamma=1}^{\Gamma} \left\{ \sum_{m=1}^{M} \left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i} \right] \right\} + \sum_{\delta=1}^{\Delta} \left\{ \sum_{m=1}^{M} \left[\frac{\left(Ex_{EnSS\delta}^{DCH} - Ex_{EnSS\delta}^{CH} \right)_i^m}{(1+d)^i} \right] \right\} \right\}}.$$

Equation 2.90

[5] Energy Storage System (EnSS) may refer to either electrical (ESS) or thermal (HSS) devices.

Energy multi-vector microgrid:

$$LCOEx_{\mu GRID} = \sum_{j=1}^{J}\left(f''_{Gj} \cdot LCOEx'_{Gj}\right) + \sum_{k=1}^{K}\left(f''_{ExSSk} \cdot LCOS'_{ExSSk}\right) + f''^{BUY}_{GRID} \cdot LCOEx_{GRID} + LCOEx''_{SYST} - f''^{SURPLUS}_{\mu GRID} \cdot LROEx_{GRID}.$$

Equation 2.91

$$f''_{Gj} = \frac{\sum_{i=1}^{n_{Gj}}\left\{\sum_{m=1}^{M}\left[\frac{Ex_i^{Gj,m}}{(1+d)^i}\right]\right\}}{\sum_{i=1}^{n}\left\{\sum_{m=1}^{M}\left\{\sum_{\gamma=1}^{\Gamma}\left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i}\right] + \sum_{\delta=1}^{\Delta}\left[\frac{\left(Ex_{ExSS\delta}^{DCH} - Ex_{ExSS\delta}^{CH}\right)_i^m}{(1+d)^i}\right] + \frac{\left(Ex_{GRID}^{BUY} - Ex_{\mu GRID}^{SURPLUS}\right)_i^m}{(1+d)^i}\right\}\right\}}.$$

Equation 2.92

$$f''_{ExSSk} = \frac{\sum_{i=1}^{n_{ExSSk}}\left\{\sum_{m=1}^{M}\left[\frac{\left(Ex_{ExSSk}^{DCH}\right)_i^m}{(1+d)^i}\right]\right\}}{\sum_{i=1}^{n}\left\{\sum_{m=1}^{M}\left\{\sum_{\gamma=1}^{\Gamma}\left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i}\right] + \sum_{\delta=1}^{\Delta}\left[\frac{\left(Ex_{ExSS\delta}^{DCH} - Ex_{ExSS\delta}^{CH}\right)_i^m}{(1+d)^i}\right] + \frac{\left(Ex_{GRID}^{BUY} - Ex_{\mu GRID}^{SURPLUS}\right)_i^m}{(1+d)^i}\right\}\right\}}.$$

Equation 2.93

$$f''^{BUY}_{GRID} = \frac{\sum_{i=1}^{n}\left\{\sum_{m=1}^{M}\left[\frac{\left(Ex_{GRID}^{BUY}\right)_i^m}{(1+d)^i}\right]\right\}}{\sum_{i=1}^{n}\left\{\sum_{m=1}^{M}\left\{\sum_{\gamma=1}^{\Gamma}\left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i}\right] + \sum_{\delta=1}^{\Delta}\left[\frac{\left(Ex_{ExSS\delta}^{DCH} - Ex_{ExSS\delta}^{CH}\right)_i^m}{(1+d)^i}\right] + \frac{\left(Ex_{GRID}^{BUY} - Ex_{\mu GRID}^{SURPLUS}\right)_i^m}{(1+d)^i}\right\}\right\}}.$$

Equation 2.94

$$f''^{SURPLUS}_{GRID} = \frac{\sum_{i=1}^{n}\left\{\sum_{m=1}^{M}\left[\frac{\left(Ex_{\mu GRID}^{SURPLUS}\right)_i^m}{(1+d)^i}\right]\right\}}{\sum_{i=1}^{n}\left\{\sum_{m=1}^{M}\left\{\sum_{\gamma=1}^{\Gamma}\left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i}\right] + \sum_{\delta=1}^{\Delta}\left[\frac{\left(Ex_{ExSS\delta}^{DCH} - Ex_{ExSS\delta}^{CH}\right)_i^m}{(1+d)^i}\right] + \frac{\left(Ex_{GRID}^{BUY} - Ex_{\mu GRID}^{SURPLUS}\right)_i^m}{(1+d)^i}\right\}\right\}}.$$

Equation 2.95

$$LCOEx''_{SYST} = \frac{\sum_{i=0}^{n} \frac{Costs_i^{SYST}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{m=1}^{M} \left\{ \sum_{\gamma=1}^{\Gamma} \left[\frac{Ex_i^{G\gamma,m}}{(1+d)^i} \right] + \sum_{\delta=1}^{\Delta} \left[\frac{\left(Ex_{ExSS\delta}^{DCH} - Ex_{ExSS\delta}^{CH}\right)_i^m}{(1+d)^i} \right] + \frac{\left(Ex_{GRID}^{BUY} - Ex_{\mu GRID}^{SURPLU}\ \right)_i^m}{(1+d)^i} \right\} \right\}}.$$

Equation 2.96

$$LROEx_{GRID} = \frac{\sum_{i=1}^{n} \frac{Revenues_i^{GRID}}{(1+d)^i}}{\sum_{i=1}^{n} \left\{ \sum_{m=1}^{M} \left[\frac{\left(Ex_{\mu GRID}^{SURPLUS}\right)_i^m}{(1+d)^i} \right] \right\}}.$$

Equation 2.97

It must be observed that the *LCOEx* of a complex energy system is not directly the sum of the *LCOEx* of its constituent generators, but it is a weighted mean of them. Moreover, the supply temperatures of the thermal energy affect the exergy associated to each single subsystem. The higher is the installed rated power of each technology and its equivalent operating hours, the higher is its weight in the global *LCOEx*. Furthermore, considering a complex system where more than one generator is used to satisfy the same demand, control logics may affect both the individual *LCOEx* of each technology and its weighting factor, in a nonlinear manner that must be analyzed case by case. For instance, the *LCOEx* of a CHP unit can change depending on the operation strategy (e.g., electrical or thermal priority).

The *LCOEx* can be a useful indicator to compare different energy system configurations taking into account not only pure electric generators but also thermal, cooling devices and CHP units. Moreover, it is possible to define a reference scenario characterized by a certain *LCOEx* ($LCOEx^{REF}$) which can be used as a reference value for benchmarking.

2.8. Summary and chapter conclusions

In this chapter the fundamentals of the Levelized Cost of Energy (and its variants for electricity, heat, cooling energy, stored energy and exergy) have been revised and analyzed in deep. A general systematic analysis approach has been presented and, then, the definitions for a single generator, a generator with energy storage, a polygeneration system and a microgrid have been demonstrated. Depending on the characteristics of the energy community, and the focus of the analysis, the *LCOE*, *LCOH*, *LCOC*, *LCOS* or *LCOEx* must be applied. Finally, it must be highlighted that the proposed *LCOEx* results one of the most appropriate indicators for the analysis of multi-vector energy systems, as it allows the combination of the energy supply of different types and sources, keeping their physical meaning.

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