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Allocation of economic costs in trigeneration systems at variable load conditions including renewable energy sources and thermal energy storage

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Abstract

As energy systems become more and more complex, the issue of the appropriate way to allocate the cost of the resources consumed increases because the way in which allocation is made directly affects the prices of the products obtained and, thus, the consumers' behavior. Thermoeconomics has been used to explain the cost formation process in complex energy systems. The thermoeconomic analysis of a trigeneration system including renewable energy sources (RES) and thermal energy storage (TES) was developed to determine the energy, capital, and total unit costs of the internal flows and final products. This work addresses issues not yet deeply studied in thermoeconomics, namely the joint production of energy services in dynamic energy systems and the incorporation of TES, RES (photovoltaic panels) and a component with different products for each operation mode (heat pump producing heat in heating mode and cooling in cooling mode). The interconnection between charging and discharging periods through the TES units was explored, allowing the discharged flow to be traced back to its production period. The trigeneration system resulted more profitable than the reference system, with total cost savings of 9,942 €/yr, which was translated into the lower annual total unit costs of the final products.

Keywords

Cost allocation, energy systems, renewable energy, thermal storage, thermoeconomics, trigeneration.

1. Introduction

Motivated by the increasing concern about global warming caused by greenhouse gas emissions and depletion of fossil fuel resources, the transition to alternative energy systems is currently underway. In trigeneration systems, electricity (and/or mechanical energy), heating, and cooling are produced from the same primary energy source by combining cogeneration with a thermally activated technology (TAT), such as an absorption chiller. In this way, the thermal coverage can be extended to meet refrigeration demands. Nevertheless, many alternative devices may be incorporated in various existing configuration modes [1–4]. Trigeneration systems benefit from the energy integration of the processes in their equipment, achieving higher energy efficiency, lower primary energy consumption, lower unit cost of the final products, and lower environmental burdens relative to conventional energy systems [5–8].

The optimal design of trigeneration systems must address two fundamental issues [9,10]: the synthesis of the plant configuration (installed technologies and capacities, etc.) and the operational planning (strategy concerning the operational state of the equipment, energy flow rates, purchase/selling of electricity to the grid, etc.). A common approach to this problem is the single-objective model aimed at fulfilling an objective function (e.g. economic cost, environmental burden, thermodynamic efficiency) that is to be maximized or minimized [11]. The reviews by [12,13] gather the characteristics of the optimization methods for polygeneration systems presented in recent publications, indicating the time scale, the objective function, and solution method.

The design procedure for buildings applications must provide energy systems that are flexible, efficient and reliable. Finding the optimal configuration of trigeneration systems in the commercial-residential sector is a complex problem because of the wide variety of technology options available for energy services production and great diurnal and annual variability in energy demands and energy supply prices. Complexity is increased by the incorporation of renewable energy sources, such as photovoltaic panels and solar thermal collectors, which are characterized by non-manageable production and non-simultaneity between production and consumption. The inclusion of TES units allows to overcome the mismatch problem between production and consumption, reducing heat wasting to the environment and enhancing overall system performance [14,15]. Moreover, according to [16,17], TES is particularly beneficial in energy systems characterized by: (i) time-varying energy prices, (ii) low-grade waste heat production, and (iii) intermittent renewable energy sources.

Thermoeconomics combines thermodynamic principles with economic analysis, aiming at revealing opportunities of energy and cost savings in the analysis, diagnosis, and optimization of energy conversion systems that are not available through conventional methods [18,19]. Thermoeconomics allows the cost formation process to be transparent throughout the system, from resources consumed to final products. The fundamental problem of cost allocation can be formulated as follows [19]: Given a system whose limits have been defined and a level of aggregation that specifies the constituting subsystems, how to obtain the cost of all flows becoming interrelated in such structure.

The question of the proper way to allocate the cost of the resources consumed to the internal flows and final products of the system is more complicated as energy systems become increasingly complex (multiple resources, multiple technologies, multiple products, joint production, TES, RES). This is an important issue because the way in which allocation is made directly affects the prices of the products obtained and, thus, the consumers' behavior. In trigeneration systems common resources are consumed to produce three different products and there is no way, based on pertinent facts, to identify the share of resources consumed associated with each one of them. Therefore, the allocation of resources in joint production processes is always arbitrary [20–23]. Nevertheless, an appropriate allocation criterion should: (i) allow all products to remain competitive and profitable relative to their alternatives available in the market [20,21], (ii) consider the context in which joint production takes place, as well as value judgements [24], and (iii) be evaluated on a case-by-case basis, which means that there is no approach suitable for every situation [25]. Ultimately, the decision on the allocation method must be made in accordance with the objectives of the analysis.

Proposals for cost allocation in cogeneration systems have mainly focused on large industrial systems at steady or quasi-steady operation. Energy systems in buildings differ fundamentally from the ones in the industry in that the variability of energy demands requires that components operate at partial load; also, these systems are inserted in an economic environment that dictates energy prices for resources. Therefore, further development and refinement of existing methodologies is required [26,27].

The fundamentals of thermoeconomics for energy systems with variable energy demands or operated at partial load have been discussed in detail by Piacentino and Cardona [26] and Lozano et al. [27]; these works also addressed the issue of the appropriate way to allocate capital costs of components considering variable annual operation. In the context of tertiary sector buildings, the proposed cost assessment methodologies have been applied to trigeneration systems that cover the energy demands of a large-scale hotel [26] and a medium-size hospital [27]. In a later study, Lozano et al. [28] demonstrated the application of thermoeconomic analysis to evaluate costs of different nature (e.g. energy, economic, environmental), focusing on the appropriate way to allocate energy resources and environmental loads in a trigeneration system with different operation modes. Wang and Mao [29] discussed cost allocation in a trigeneration system based on biomass gasification with different operating modes. Examples of thermoeconomic analyses considering off-design operation conditions include a combined cycle power plant based on gas turbine [30], a district heating system based on cogeneration for a university campus [31], and a cogeneration steam cycle in a desalination plant [32].

The present paper intends to contribute by proposing cost allocation approaches to some issues in thermoeconomics that have not been deeply studied in the context of buildings applications, such as the incorporation of (i) joint production of energy services (electricity, heat, and cooling) in dynamic energy systems, (ii) TES units (for heat and cold), (iii) RES (solar energy), and (iv) a component with different products for each operation mode (heat pump in heating mode producing heat and in cooling mode producing cooling).

The allocation proposals are applied to a trigeneration system that must attend the electricity, heating, and cooling demands of a multifamily building located in Zaragoza, Spain. The hourly unit costs of the internal flows and final products of the system are obtained for the period of one year.

This paper is structured as follows: Section 2 describes the trigeneration system including TES and RES, as well as the mathematical model used to determine its optimal configuration and multiperiod operational planning; furthermore, this Section also defines the reference system considered throughout the paper. Section 3 presents the cost allocation proposals, including the stages of the definition of the productive structure, the interconnection between hourly periods through the TES units, and the capital cost allocation proposals. Section 4 presents and discusses the obtained unit costs of the internal flows and final products of the system on an hourly, monthly, and annual basis. Finally, Section 5 draws the conclusions of this work.

2. Description of the trigeneration system

In a previous paper, Pina et al. [33] have proposed a mixed integer linear programming (MILP) model for the synthesis and multiperiod operational planning of trigeneration systems including TES and RES. The MILP model considers a superstructure containing the candidate technologies for the energy supply system. After the optimization procedure, the superstructure is reduced to the optimal configuration. The objective function of the optimization model is to minimize the total annual cost, which includes capital (equipment purchase, installation and maintenance costs) and operation (resource consumption and profit from sale of electricity) costs. The system must attend the electricity, heating, and cooling demands of a multifamily building located in Zaragoza, Spain. The reader is referred to Ref. [33] for an in-depth explanation of the data and the model employed.

The superstructure considered in [33] is depicted in Fig. 1. Natural gas F_p, electricity purchased from the grid E_p, and solar radiation F_{pv} and F_{st} are the energy resources that can be used by the system to attend the electricity E_d, heating Q_d, and cooling R_d demands of the consumer center. Heat can be produced at two temperature levels: low-temperature heat is only used to cover the heating demand, while high-temperature heat can also be used for cooling production. The cogeneration module GE (natural gas reciprocating engine coupled to a heat recovery system) consumes natural gas F_c and produces electricity W_c, low-temperature heat Q_{cd}, and high-temperature heat Q_{cr}; also, a portion of the total heat produced can be dissipated to the environment Q_{cl}. The gas boiler GB consumes natural gas F_a and produces low-temperature heat Q_{ad} and high-temperature heat Q_{ar}. The photovoltaic panels PV produce electricity W_{pv} from the incident solar radiation F_{pv}. The single-effect absorption chiller ABS uses high-temperature heat Q_r to produce cooling R_q; this technology also consumes a small quantity of electricity W_{abs}. The reversible heat pump HP and the solar thermal collectors ST are assumed to operate in two operation modes according to the month of the year:

- From January to May and from October to December: The HP operates in heating mode (HPQ), consuming electricity W_{hp} to produce low-temperature heat Q_{hp}. The ST produces low-temperature heat Q_{std} from the incident solar radiation F_{st};
- From June to September: The HP operates in cooling mode (HPR), consuming electricity W_{hp} to produce cooling R_{hp}. The ST can produce low and/or high-temperature heat Q_{std} and Q_{str}, respectively.

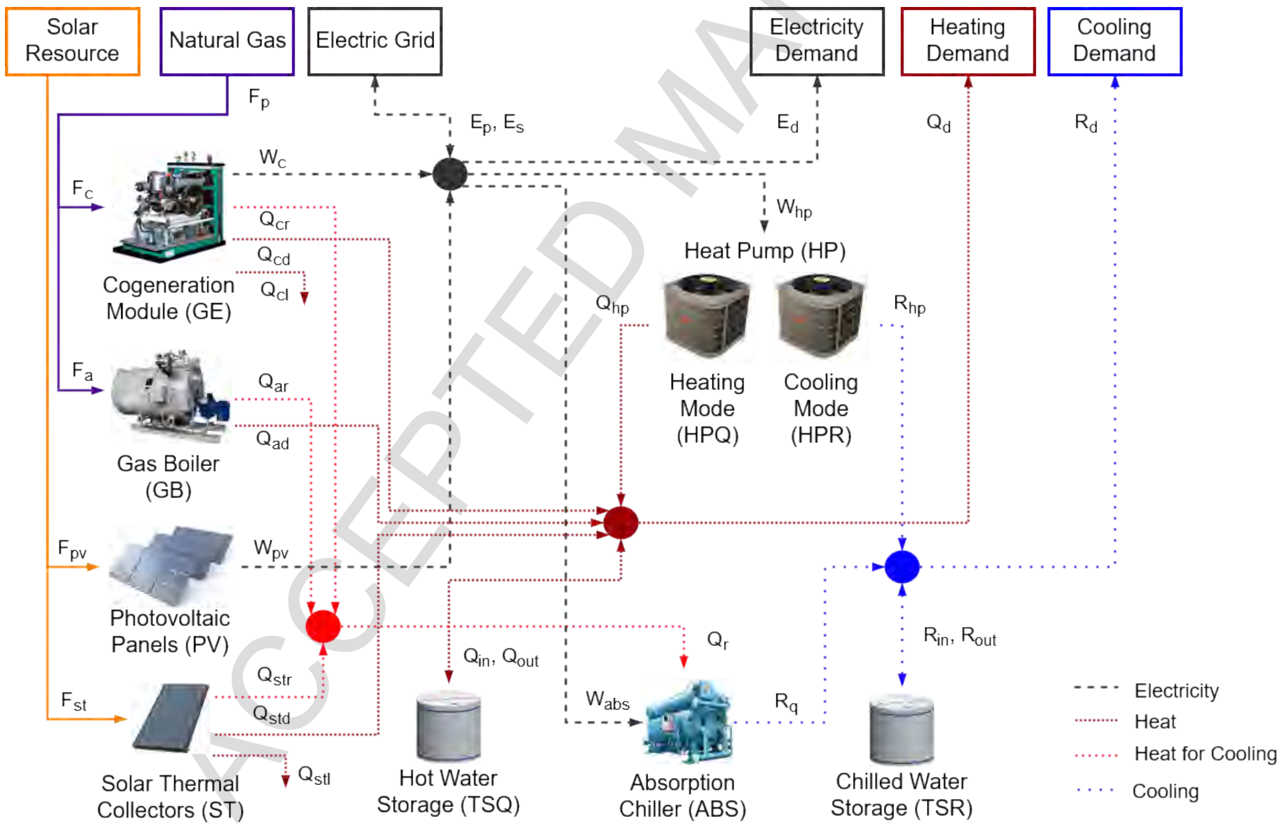

Fig. 1. Superstructure of the trigeneration system.

Both operation modes consider the possibility of dissipating heat from the ST Q_{stl}. Finally, two thermal energy storage tanks are considered, one for low-temperature heat (TSQ) and another for cooling (TSR). Energy can be charged to/discharged from the TSQ Q_{in}/Q_{out} and TSR R_{in}/R_{out}. Energy losses Q_s and R_s are proportional to the stored energy S_q and S_r, respectively, and to an hourly energy loss factor.

The analysis covers the period of one year, which is described by 12 representative days *d* (one for each month of the year), divided into 24 consecutive periods *h* of 1-hour duration.

The annual electricity, heating, and cooling demands of the multifamily building are 255 MWh/yr, 574 MWh/yr, and 114 MWh/yr, respectively. Electricity is required all through the year. The heating demand is composed of domestic hot water, required all year round, and space heating, required from November to April. The cooling demand is required from June to September. Hourly energy demands are known for all representative days. An example is given in Fig. 2, which presents the hourly electricity E_d and heating Q_d demands for January and the hourly cooling demand R_d for July.

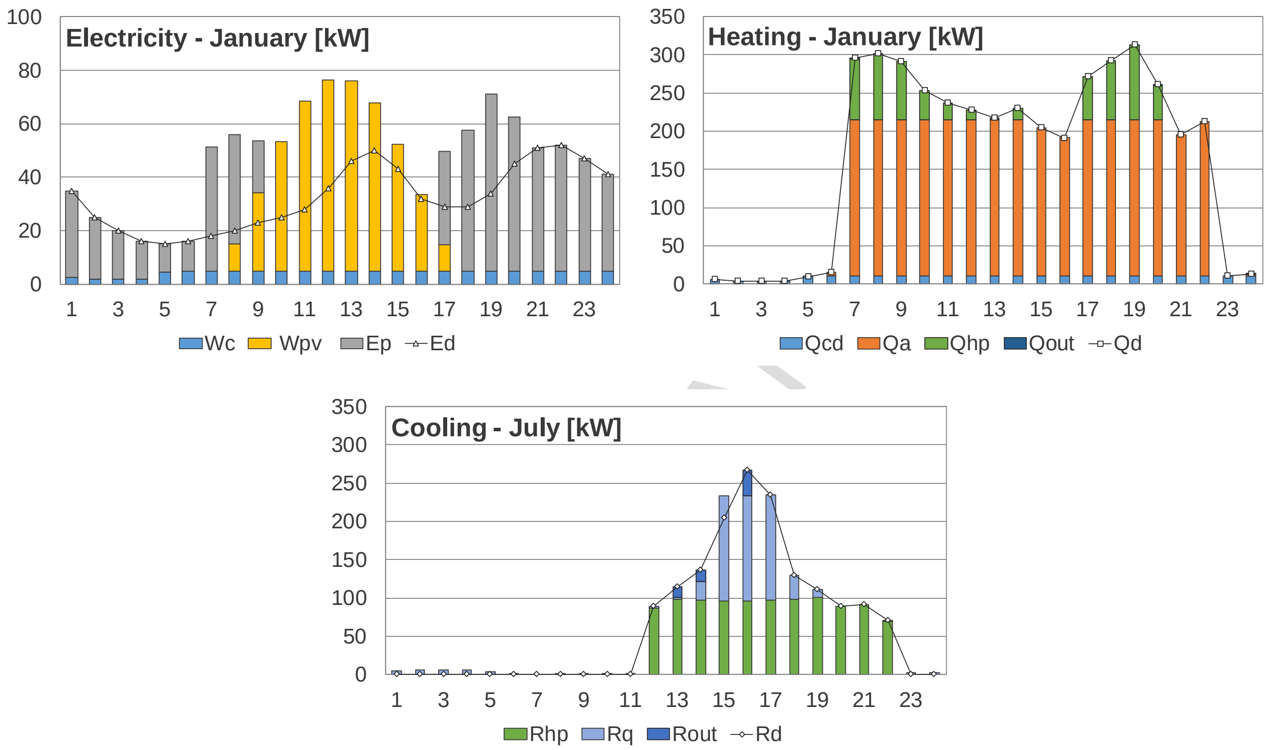

Fig. 2. Hourly production and energy demands for different representative days of (a) electricity in January, (b) heating in January, and (c) cooling in July.

The MILP model was developed and solved using the software LINGO [34]. The objective function minimizes the total annual cost C_{tot}, which is the sum of the annual fixed cost C_{fix} and annual energy cost C_{ene}.

$$Min\ C_{tot} = C_{fix} + C_{ene} \tag{1}$$

The annual fixed cost is expressed by

$$C_{fix} = \sum_i Z(i) = fam \cdot (1 + fic) \sum_i INV(i) = fam \cdot (1 + fic) \sum_i ZU(i) \cdot CAP(i) \tag{2}$$

where *fam* is the amortization and maintenance factor (0.15 yr^{-1}) over the system operational lifetime *nry* (20 yr) and *fic* is the indirect costs factor (0.20). For each component *i*, *Z(i)* is the annual fixed cost, *INV(i)* is the investment cost, *ZU(i)* is the unit bare module cost, and *CAP(i)* is the installed capacity.

For each hourly period h of each representative day d, the annual energy cost considers the purchase costs of natural gas and electricity and the revenue generated by selling electricity to the grid.

$$C_{ene} = \sum_d \sum_h NRY(d) \cdot \left(c_g \cdot F_p(d,h) + cE_p \cdot E_p(d,h) - cE_s \cdot E_s(d,h)\right) \quad (3)$$

where c_g and cE_p are the purchase costs of natural gas (45 €/MWh) and electricity (140 €/MWh), respectively, and cE_s is the selling price of electricity (140 €/MWh) [35]. *NRY(d)* is the number of representative days type *d* per year (*NRY(1, 2, …, 12)* = 31, 28, …, 31).

The objective function is subject to capacity limits, production restrictions, and energy balance equations. Binary variables are used to determine technology selection from the superstructure (installed/not installed), while all other variables are continuous (e.g. energy flow rates, economic flows). More details on the optimization model are provided in Pina et al. [33].

The optimal economic cost configuration was obtained by solving the optimization model leaving all binary variables free. All candidate technologies were included except for the solar thermal collectors ST.

The reference system considered in this work was obtained by imposing the installation of only a gas boiler GB and a heat pump HPR (operating in cooling mode only); in this way, the electricity consumed by the HPR and sent to the consumer center is attended by purchase from the electric grid.

The system configuration and installed capacities, as well as other capital cost data, are provided in Table 1 and Table 2 for the optimal economic system and the reference system, respectively. Table 3 presents the total annual cost for both configurations.

Table 1. Capital costs for the optimal economic system.

Component *i*	Installed capacity *CAP*	Unit bare module cost *ZU*	Investment cost, € *INV*	Annual fixed cost, €/yr *Z*
GE	4.8 kW_{el}	2700 €/kW_{el}	15,497.9	2,324.7
GB	203.4 kW_{th}	77 €/kW_{th}	18,790.0	2,818.5
PV	640.0 m^2	264 €/m^2	202,368.0	30,355.2
ABS	101.0 kW_{th}	518 €/kW_{th}	62,773.2	9,416.0
TSQ	1.1 kWh	150 €/kWh	201.3	30.2
TSR	33.1 kWh	300 €/kWh	11,867.3	1,780.1
HP	102.4 kW_{th}	481 €/kW_{th}	59,079.2	8,861.9
Total	-	-	370,576.9	55,586.5

Table 2. Capital costs for the reference system.

Component *i*	Installed capacity *CAP*	Unit bare module cost *ZU*	Investment cost, € *INV*	Annual fixed cost, €/yr *Z*
GB	313.0 kW_{th}	77 €/kW_{th}	28,921.2	4,338.2
HP	283.7 kW_{th}	481 €/kW_{th}	163,777.0	24,566.6
Total	-	-	192,698.2	28,904.7

Table 3. Total annual cost for the optimal economic and reference systems.

	Reference System	Optimal Economic System
Natural gas consumption, MWh/yr	603.7	648.4
Purchased electricity, MWh/yr	285.5	139.5
Sold electricity, MWh/yr	-	130.0
Cost of natural gas, €/yr	27,166.0	29,176.5
Cost of purchased electricity, €/yr	39,967.0	19,531.2
Profit from the selling of electricity, €/yr	-	18,200.6
Annual energy cost €/yr	67,132.9	30,507.0
Annual fixed cost, €/yr	28,904.7	55,586.5
Total annual cost, €/yr	96,037.7	86,093.5

As previously mentioned, the hourly operation of the system is obtained for all representative days of the year. In the case of the optimal economic system, an example is provided in Fig. 2, which presents the hourly productions of electricity and heating in January and of cooling in July.

The configuration of a trigeneration system is generally more complex than that of conventional production systems and requires higher investment costs. Nevertheless, the higher investment is compensated by savings in the consumption of energy resources over the plant's operational lifetime. As a matter of fact, the optimal economic system presents savings of 36,626 €/yr in annual energy cost relative to the reference system. Conversely, the additional investment cost corresponds to 177,879 €. Dividing the latter by the former results in a Simple Payback Period of 4.9 years.

3. Thermoeconomic cost allocation

Cost accounting tackles the problem of allocating the costs of the resources consumed to the internal flows and final products of the system. In the present analysis, the energy resources are natural gas, electricity from the electric grid, and solar radiation. Provided that all energy flows in each hourly period are known, as well as the unit costs of the resources consumed, the aim is to objectively determine the unit costs of the products obtained. In this regard, it is essential to connect the flow that is being valued to the different resources consumed, so that each flow receives its corresponding share of costs. Furthermore, it must be noted that apart from energy resources, the capital costs of the technologies installed must also be allocated to the internal flows and final products of the system.

The productive structure is the tool generally used in thermoeconomics to unveil the distribution of resources to the internal flows and final products of an energy system. Identifying the appropriate productive structure is a crucial step when performing a thermoeconomic analysis [19,27,36,37]. This task requires the definition of the main product, or the purpose, of each of the system's components with the aim of allocating the resources consumed throughout the plant. Therefore, the productive structure is not necessarily equal to the physical structure of the system, depicted in Fig. 1, and many alternatives can be proposed according to the objective of the analysis. Clearly, different costs of the final products are obtained for different productive structures. This underlines the importance of appropriately defining the productive structure of the energy conversion system, so that the results are obtained in accordance with the objectives of the analysis. Once the productive structure has been defined, cost conservation balance can be applied to its elements obtaining the unit costs of the flows and unveiling the cost formation process.

The following subsections describe: (i) the definition of the productive structure, including the treatment for the combined production of electricity, heat and cooling, and the disaggregation of energy flows and devices, (ii) the interconnection between the charging and discharging periods through the TES units, (iii) the capital cost allocation proposals, (iv) the cost allocation in the reference system, and (v) the cost allocation proposals for the optimal economic system.

3.1. Definition of the productive structure

The energy system's physical structure depicts the devices that constitute the system and the energy flows that connect them with each other and the system with its boundaries (economic market and consumer center). When it comes to precisely allocating resources to internal flows and final products, defining the productive structure requires the deepest possible conceptual disaggregation level of the physical structure, which results in the definition of new virtual flows and devices. The properties of these virtual flows should be obtained based on the knowledge of all flows in the physical structure.

For the present analysis, the graphic representation of the productive structure proposed is presented in Fig. 3. Some flows identifiable in the productive structure have the same value and units as the ones in the physical structure of Fig. 1. The determination of the additional virtual flows is explained throughout this Section.

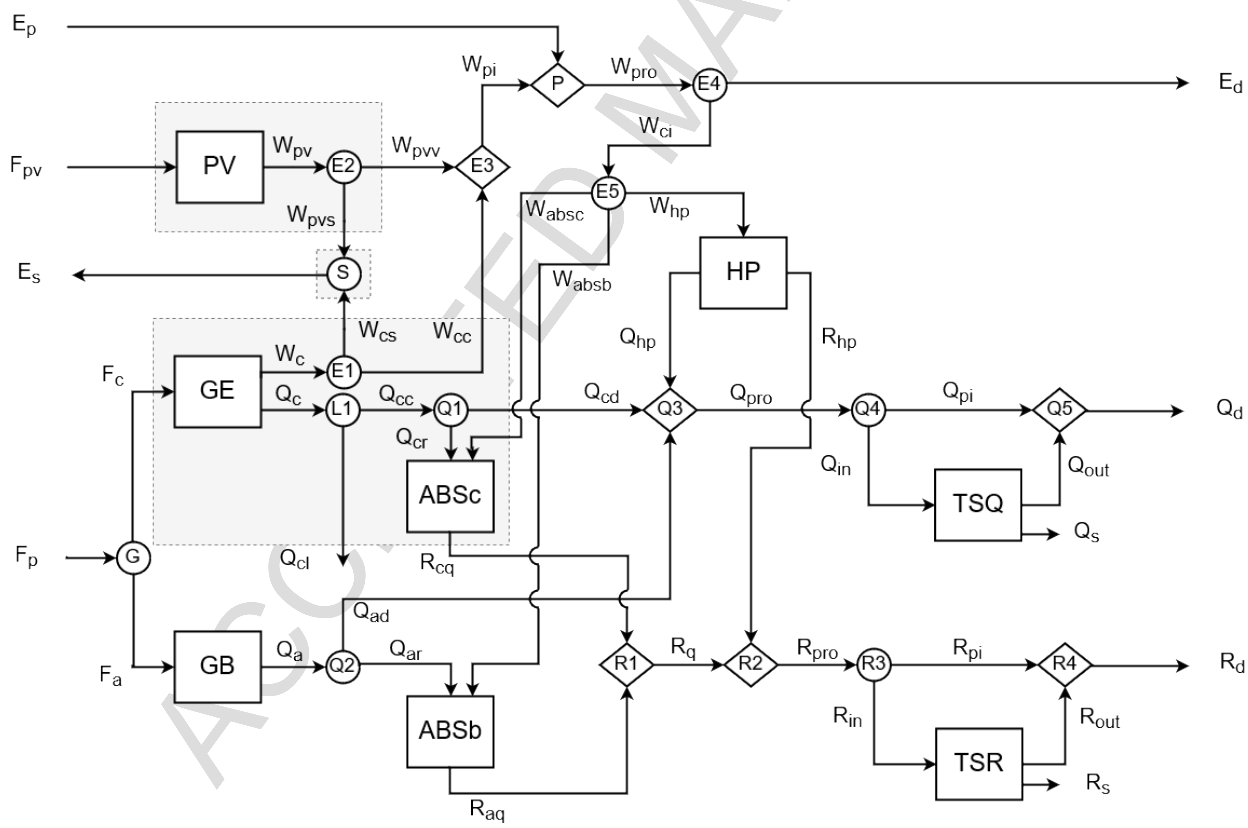

Fig. 3. Productive structure of the trigeneration system.

The productive structure is composed of: (i) productive units (white rectangles), associated with an energy transformation process, in which the input flows are consumed to produce a particular product;

(ii) junctions (rhombs), where two or more flows merge into one output flow; (iii) distributors (circles), where a homogeneous flow is divided into two or more output flows; and (iv) subsystems (gray rectangles), which may include one or more of the aforementioned elements and will be defined in the following paragraphs.

Sold electricity subsystem

In the trigeneration system analyzed herein, the possibility of selling electricity to the grid provides an income that reduces the annual operation cost. Given that electricity can be produced by the gas engine GE and the photovoltaic panels PV, when both are in operation it was proposed to proportionally distribute the sold electricity between them according to their power productions; by doing so, the income of selling electricity to the grid can be allocated to the internal flows and final products of the system [38].

For each hourly period h of each representative day d, the parameter δ_1 was defined for the sold electricity distribution, expressing the share of cogenerated electricity in proportion to the total electricity produced by the system:

$$\delta_1(d,h) = {W_c(h)}/\left(W_c(h) + W_{pv}(h)\right) \tag{4}$$

The sold electricity E_s is distributed between the GE and the PV as follows:

$$W_{cs}(d,h) = \delta_1(d,h) \cdot E_s(d,h) \tag{5}$$

$$W_{pvs}(d,h) = \left(1 - \delta_1(d,h)\right) \cdot E_s(d,h) \tag{6}$$

The sold electricity subsystem is shown in Fig. 4. It is important to explain the choice for representing element S as a distributor (circle) instead of as a junction (rhomb): Even though the junction representation could be justified by the energy flows' directions ($W_{cs} + W_{pvs} = E_s$), the purpose of the sold electricity subsystem is to incorporate the income of selling electricity to the grid to the internal flows and final products of the system; therefore, despite the energy flows' directions, S functions as a distributor in which both energy flows W_{cs} and W_{pvs} receive the same electricity selling price cE_s, whose value was defined in Section 2.

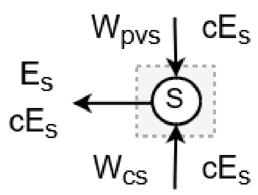

Fig. 4. Sold electricity subsystem.

Photovoltaic subsystem

The photovoltaic subsystem depicted in Fig. 5 follows from the sold electricity subsystem. In this way, the part of the photovoltaic electricity that is not sold W_{pvv} receives the benefit associated with the selling of W_{pvs}.

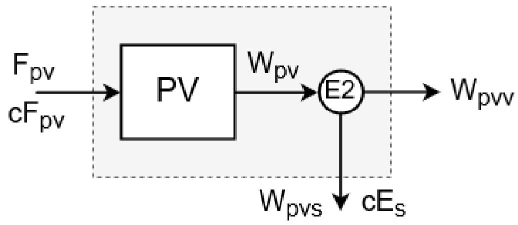

Fig. 5. Photovoltaic subsystem.

The photovoltaic electricity that is not sold W_{pvv} is

$$W_{pvv}(d,h) = W_{pv}(d,h) - W_{pvs}(d,h) \quad (7)$$

Trigeneration subsystem

The combined production of energy services that takes place in trigeneration systems is achieved through thermal integration of the production processes [5,6]. Such a high level of integration hinders the determination of a logical distribution of the resources consumed towards the cogenerated products. As described by Lozano et al. [27,28] and Pina et al. [39], the fundamental device of a cogeneration system is the cogeneration module GE, in which the joint production of electricity (and/or mechanical energy) and heat takes place. By incorporating a TAT, such as an absorption chiller ABSc, the cogenerated heat can be extended to cooling production. The combination GE+ABSc thus make the trigeneration subsystem shown in Fig. 6.

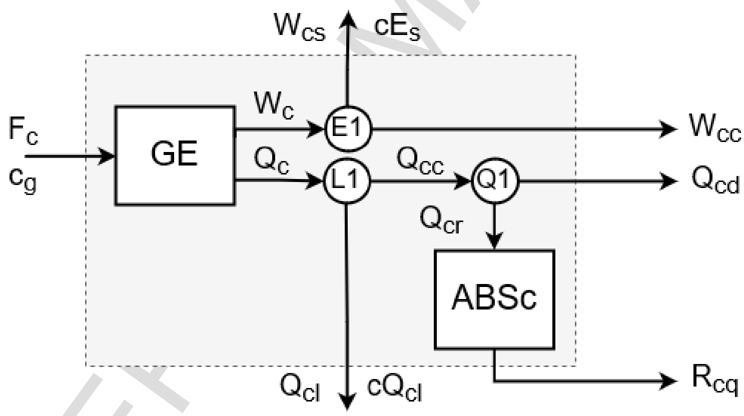

Fig. 6. Trigeneration subsystem.

In the trigeneration subsystem the cogenerated electricity W_c is partly sold to the grid W_{cs} at price cE_s and partly internally consumed by the system W_{cc} (Eq. (8)). The cogenerated heat Q_c can be (i) used to attend the heat demand Q_{cd}, (ii) consumed in the ABSc for cooling production R_{cq}, and/or (iii) wasted into the environment Q_{cl}. As previously mentioned, the purchase price of natural gas c_g and the electricity selling price cE_s are defined by the market (Section 2); moreover, heat dissipation takes place with no associated cost (cQ_{cl} = 0 €/kWh). Therefore, the three cogenerated products to which costs should be allocated are W_{cc}, Q_{cd} and R_{cq}.

$$W_{cc}(d,h) = W_c(d,h) - W_{cs}(d,h) \quad (8)$$

ABS conceptual disaggregation

Supporting the production of the trigeneration subsystem is the gas boiler GB. When both GE and GB are in operation, there are two heat sources available to drive the absorption chiller ABS. In this regard, in accordance with [27,28,39], the ABS can be divided into two virtual devices ABSc and ABSb; in this way, each virtual device will consume energy from its specific source.

The ABS is divided into ABSc and ABSb. The ABSc consumes cogenerated heat Q_{cr} and a small quantity of electricity W_{absc} and produces cogenerated absorption cooling R_{cq}. The ABSb consumes conventional heat Q_{ar} and a small quantity of electricity W_{absb} and produces conventional absorption cooling R_{aq}. These virtual flows can be associated with the ones in Fig. 1 as follows:

$$W_{abs}(d,h) = W_{absc}(d,h) + W_{absb}(d,h) \tag{9}$$

$$R_q(d,h) = R_{cq}(d,h) + R_{aq}(d,h) \tag{10}$$

For the distribution of the electricity and cooling associated with the ABS, the parameter δ_2 is defined, which expresses the share of available cogenerated heat in the total heat produced:

$$\delta_2(d,h) = {Q_{cc}(h)}/\left(Q_{cc}(h) + Q_a(h)\right) \tag{11}$$

where,

$$Q_{cc}(d,h) = Q_{cd}(d,h) + Q_{cr}(d,h) \tag{12}$$

$$Q_a(d,h) = Q_{ad}(d,h) + Q_{ar}(d,h) \tag{13}$$

The cooling produced from cogenerated heat R_{cq} and the cooling produced from conventional heat R_{aq} are

$$R_{cq}(d,h) = \delta_2(d,h) \cdot R_q(d,h) \tag{14}$$

$$R_{aq}(d,h) = \left(1 - \delta_2(d,h)\right) \cdot R_q(d,h) \tag{15}$$

Analogously, the electricity consumed by the ABSc W_{absc} and ABSb W_{absb} are

$$W_{absc}(d,h) = \delta_2(d,h) \cdot W_{abs}(d,h) \tag{16}$$

$$W_{absb}(d,h) = \left(1 - \delta_2(d,h)\right) \cdot W_{abs}(d,h) \tag{17}$$

Other virtual flows

The electricity produced by the trigeneration subsystem W_{cc} and by the photovoltaic panels W_{pvv} compose the electricity produced in the hourly period W_{pi} (Eq. (18)). The electricity consumed in the hourly W_{pro} period (Eq. (19)) is composed of the electricity produced W_{pi} and the electricity purchased from the grid E_p. The electricity internally consumed by the system W_{ci} (Eq. (20)) corresponds to the electricity consumed by the heat pump W_{hp} and by the absorption chillers W_{absc} and W_{absb}.

$$W_{pi}(d,h) = W_{cc}(d,h) + W_{pvv}(d,h) \tag{18}$$

$$W_{pro}(d,h) = E_p(d,h) + W_{pi}(d,h) \tag{19}$$

$$W_{ci}(d,h) = W_{pro}(d,h) - E_d(d,h) \tag{20}$$

The heat produced by the heat pump Q_{hp}, by the trigeneration subsystem Q_{cd}, and by the gas boiler Q_{ad} compose the total heat produced in the hourly period Q_{pro} (Eq. (21)). Part of Q_{pro} can be charged Q_{in} to the TES unit TSQ; the part that is not charged is the heat produced and consumed in the hourly period Q_{pi} (Eq. (22)).

$$Q_{pro}(d,h) = Q_{cd}(d,h) + Q_{ad}(d,h) + Q_{hp}(d,h) \tag{21}$$

$$Q_{pi}(d,h) = Q_{pro}(d,h) - Q_{in}(d,h) \tag{22}$$

The same reasoning applies to the determination of the cooling flows R_{pro} (Eq. (23)) and R_{pi} (Eq. (24)).

$$R_{pro}(d,h) = R_q(d,h) + R_{hp}(d,h) \tag{23}$$

$$R_{pi}(d,h) = R_{pro}(d,h) - R_{in}(d,h) \tag{24}$$

For the TES units TSQ and TSR, there is an implicit aspect to the definition of the productive structure which is explored below.

3.2. Interconnection between hourly periods through the TES units

In the trigeneration system analyzed herein, the heating demand can be met by heat production in the GE, GB, and HPQ, and the cooling demand can be covered by the ABS and HPR. Each component consumes different external resources and/or internal products valued at different costs, thus the heat and cooling supplied will have different production costs according to the system operation mode. Because the TES units allow to decouple production from consumption, it becomes necessary to know not only the quantity of energy that must be charged and discharged, but also the origin of the discharged energy. By doing so, the resources consumed to produce the charged flow can be forwarded to the discharging periods and to the final products.

The optimization model provides the amount of charged or discharged energy in each hourly period [33]. Following the methodology described in Pina et al. [38,39], a new set of equations was proposed, which unveils the distribution of the charged energy between the discharge periods. These equations can be either included in the optimization model or solved separately. It must be noted that they do not change the optimal operation of the system from the optimization model.

The same methodology was applied for both TSQ and TSR. An example is presented for the interconnection between hourly periods through the TSR in July. As can be seen from Fig. 7, the TSR is charged at hours 1-6, 8-12, 15, 23 and 24, and discharged at hours 13, 14 and 16. The energy charged at hour 2 $R_{in}(2)$ = 6.02 kWh is directed to hours 13 (*IN(2,13)* = 5.77 kWh) and 14 (*IN(2,14)* = 0.25 kWh), so that $R_{in}(h)$ is equal to the sum of all *IN(h,z)* leaving period *h*. The discharged energy at hour 14 $R_{out}(14)$ = 14.50 kWh proceeds from hours 2 (*OUT(2,14)* = 0.22 kWh), 3 (*OUT(3,14)* = 5.39 kWh), 4 (*OUT(4,14)* = 5.41 kWh), 5 (*OUT(5,14)* = 3.42 kWh) and 6 (*OUT(6,14)* = 0.07 kWh), in a way that $R_{out}(h)$ is equal to the sum of all *OUT(y,h)* arriving at period *h*. Energy losses r_s are evaluated along the pairs *(y,z)* and are proportional to the input *IN(y,z)*, an energy loss factor of 0.01 h^{-1} and the storage duration in hours. $LOSS(2,14)$ = 0.03 kWh corresponds to the energy losses along the pair *(2,14)*, which is determined by the sum of all r_s along the same pair. The energy losses associated with a discharge $LOSS_{out}(h)$ are obtained by the sum of all $LOSS$ arriving at the discharge period h; for example, the energy losses due to the discharge at hour 14 are:

$$LOSS_{out}(14) = LOSS(2{,}14) + LOSS(3{,}14) + LOSS(4{,}14) + LOSS(5{,}14) + LOSS(6{,}14) = \ 1.56\ kWh$$

The $LOSS_{out}(h)$ values will be used in the capital cost allocation of the TSQ and TSR proposed in Section 3.5.

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17..22	23	24	1...	LOSS
(1,13)	IN, OUT	5.26												4.66								
	rs		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05								0.60
(2,13)	IN, OUT		5.77											5.17								
	rs			0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05								0.60
(2,14)	IN, OUT		0.25												0.22							
	rs			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00							0.03
(3,14)	IN, OUT			6.02											5.39							
	rs				0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05							0.63
(4,14)	IN, OUT				5.98										5.41							
	rs					0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05							0.57
(5,14)	IN, OUT					3.74									3.42							
	rs						0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03							0.32
(6,14)	IN, OUT						0.08								0.07							
	rs							0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00							0.01
(6,16)	IN, OUT						1.23										1.12					
	rs							0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01					0.12
(8,16)	IN, OUT								1.99								1.84					
	rs									0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02					0.15
(9,16)	IN, OUT									0.33							0.31					
	rs										0.00	0.00	0.00	0.00	0.00	0.00	0.00					0.02
(10,16)	IN, OUT										0.33						0.31					
	rs											0.00	0.00	0.00	0.00	0.00	0.00					0.02
(11,16)	IN, OUT											0.33					0.31					
	rs												0.00	0.00	0.00	0.00	0.00					0.02
(12,16)	IN, OUT												0.33				0.32					
	rs													0.00	0.00	0.00	0.00					0.01
(15,16)	IN, OUT															28.83	28.54					
	rs																0.29					0.29
(23,13)	IN, OUT													2.10					2.42			
	rs	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02						0.02		0.32
(24,13)	IN, OUT													1.83						2.09		
	rs	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02								0.26
Rin(h)		5.26	6.02	6.02	5.98	3.74	1.31	-	1.99	0.33	0.33	0.33	0.33	-	-	28.83	-	-	2.42	2.09		-
Rout(h)		-	-	-	-	-	-	-	-	-	-	-	-	13.76	14.50	-	32.74	-	-	-		-
Rs(h)		0.04	0.10	0.16	0.21	0.27	0.31	0.32	0.31	0.33	0.33	0.33	0.33	0.33	0.19	0.04	0.33	-	-	0.02		3.96

Fig. 7. Interconnection between hourly periods through the TSR in July.

3.3. Allocation of capital costs

This section discusses the adequate way to distribute the capital cost of each component to its useful products considering variable annual operation. For components with constant production, a "consumption of capital resources per hour" can be determined and used to assign the capital cost to product flows:

$$hZ(i) = {}^{Z(i)}/_{HY(i)} \tag{25}$$

where *HY(i)* is the annual operating hours of component *i*.

It becomes evident that this consideration is not valid for variable load operation because it implies that all operating hours of the *i*th component are assigned with the same capital cost. In this way, if the component operates at partial load, its cost per unit product would increase dramatically, which does not make economic sense [26,27]. By assuming distribution of the capital cost of a component based on its productivity, it is possible to assign the same capital cost value to each unit produced and avoid dependence on the load factor. Therefore, the following expression follows:

$$kZ(i) = {Z(i)}/{PY(i)} \quad (26)$$

where *PY(i)* is the annual production of component *i*. This is the approach considered for the GB, PV, and ABS. For components that produce more than one product in combined or joint production, the attribution is made based on the main product, e.g. the electricity in the GE.

The TES units require a different approach because these devices deal with two dimensions: quantity (stored energy) and time (storage duration). Allocating capital costs based on their productivity (annual discharged energy) would neglect the associated storage time. The storage time is important because the greater the storage time, the greater the energy losses. For example, discharging 1 kWh after a 1-hour storage time incurs less energy losses than discharging the same 1 kWh after a 12-hour storage time. Energy losses, on the other hand, relate both storage time and stored energy. Therefore, based on the methodology presented in Section 3.2, it is proposed herein to allocate more capital costs to discharges associated with larger storage times.

In this regard, a unit capital cost per energy loss unit *LZ(i)* is defined, relating the annual capital cost *Z(i)* and the annual energy losses *LY(i)*, for each TES unit *i*.

$$LZ(i) = {\mathrm{Z}(i)}/{LY(i)} \quad (27)$$

It is evident that this assumption can only be applied when energy losses are considered. Otherwise, the approach based on productivity (*kZ* based on the annual discharged energy) would suffice.

The HP is a special case because it has two operation modes producing two different products at different times. Two different capital cost allocation proposals are explored in this paper:

(i) HP capital cost allocation A: main product

From the analysis of the operation of the system throughout the year it can be seen that the HP's main product is the cooling R_{hp}. In fact, 75% of the annual cooling demand is covered by the HP, while only 8.6% of the annual heating demand is covered by this device. Moreover, the load factor of the HP in cooling mode is 27% against 8% in heating mode, as shown in Table 4.

Therefore, a sensible capital cost allocation proposal is to allocate the entire HP annual capital cost *Z(HP)* to the cooling R_{hp}. The approach based on the productivity (Eq. (26)), with *PY(HPR)* as the annual R_{hp} production, would apply.

(ii) HP capital cost allocation B: shared allocation

An alternative to the previous allocation proposal is to consider that there is not a main product and that the HP annual capital cost should be distributed between both heat Q_{hp} and cooling R_{hp} productions. Assuming that the HP's annual capital cost *Z(HP)* can be expressed as the sum of the heat and cooling contributions:

$$Z(HP) = kZ(HPQ) \cdot PY(HPQ) + kZ(HPR) \cdot PY(HPR) \quad (28)$$

where *kZ(HPQ)* and *kZ(HPR)* are the capital unit costs of the Q_{hp} and R_{hp}, respectively. By assuming that the cost ratio between *kZ(HPQ)* and *kZ(HPR)* is equal to the HP's cooling/heating capacity ratio *rCAPhp = CAP(HPR)/CAP(HPQ) = 0.90*, the following expression is obtained:

$$kZ(HPQ) = 0.90 \cdot kZ(HPR) \tag{29}$$

Solving Eqs. (28) and (29) provides the capital unit costs of both HP products.

The values of the capital unit costs discussed in this Section are presented in Table 4 for the optimal economic system and in Table 5 for the reference system.

Table 4. Capital unit costs for the optimal economic system.

Component	Annual fixed cost, €/yr	Annual production, MWh/yr	Annual losses, MWh/yr	Capital unit cost per production, €/MWh	Capital unit cost per losses, €/MWh	Load factor, %
i	Z	PY	LY	kZ	LZ	
GE	2,324.68	38.48	-	60.41	-	91.84
GB	2,818.50	475.34	-	5.93	-	26.68
PV	30,355.20	249.23	-	121.80	-	17.10*
ABS	9,415.97	28.77	-	327.30	-	3.25
TSQ	30.20	-	0.03	-	1,198.28	25.64
TSR	1,780.10	-	0.50	-	3,579.18	17.17
(A) HP	8,861.88	85.72	-	103.38	-	35.44
(B) HPQ	3,034.63	49.60	-	61.18	-	8.01
(B) HPR	5,827.35	85.72	-	67.98	-	27.42

*Considering nominal panel power.

Table 5. Capital unit costs for the reference system.

Component	Annual fixed cost, €/yr	Annual production, MWh/yr	Annual losses, MWh/yr	Capital unit cost per production, €/MWh	Capital unit cost per losses, €/MWh	Load factor, %
i	Z	PY	LY	kZ	LZ	
GB	4,338.18	573.50	-	7.56	-	20.92
HPR	24,566.55	113.99	-	215.52	-	3.85

3.4. Cost allocation in the reference system

The conservation of costs applied to the productive structure of the system enables the cost formation process to be transparent throughout the system, from the resources consumed (energy and capital costs) to the final products. The unit costs of the internal flows and final products represent the amount of resources that must be consumed to produce one unit of the flow. Total unit costs account for both energy and capital components. By neglecting the capital term in the cost balances of the components, the unit energy costs are obtained.

The first and foremost requirement to performing cost allocation is the knowledge of the operational state of the system, which means that all energy flows in each hourly period *h* of each representative day *d* must be known. For the sake of clarity, the notation *(d,h)* will be omitted from the forthcoming equations.

The productive structure of the reference system is shown in Fig. 8, which includes the associated annual energy flows and the prices of the energy resources consumed. The application of cost balances to the reference system is quite straightforward, as explained in the following paragraphs.

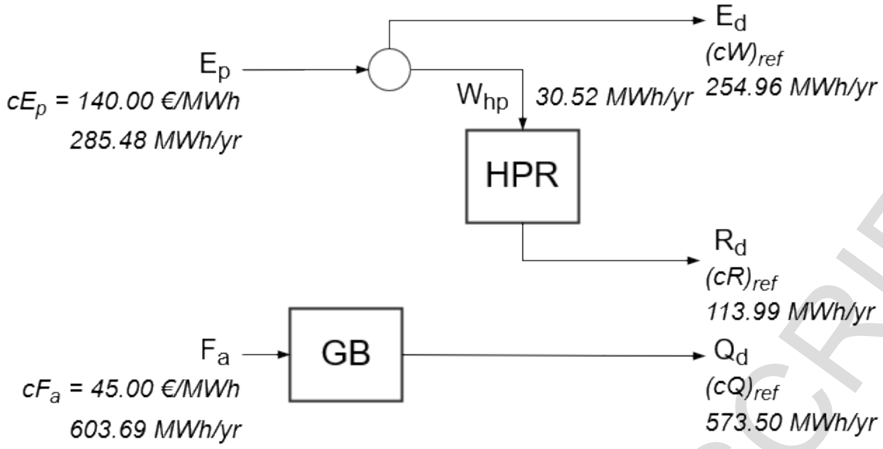

Fig. 8. Productive structure of the reference system.

The purchased electricity E_p at price cE_p has two destinations: (i) attend the electricity demand E_d, and (ii) drive the HPR for cooling production R_d. For the distributor (circle), a generally accepted accounting principle, which states that the unit costs of the products from the same line are equal, is applied. Therefore, the cost balance equation in the distributor is

$$cE_p \cdot E_p - cW_{hp} \cdot W_{hp} - (cW)_{ref} \cdot E_d = 0 \tag{30}$$

and the corresponding auxiliary equation is

$$cW_{hp} = (cW)_{ref} \tag{31}$$

Solving Equations (30) and (31) allows for the determination of the reference cost of electricity $(cW)_{ref}$ = cW_{hp} = cE_p = 140 €/MWh.

As heat is exclusively produced in the GB with natural gas F_a at price cF_a, all capital and energy costs are allocated to the produced heat; the cost balance in the GB is

$$cF_a \cdot F_a - (cQ)_{ref} \cdot Q_d + kZ(GB) \cdot Q_d = 0 \tag{32}$$

which allows for the determination of the reference cost of heat $(cQ)_{ref}$ = 55 €/MWh.

The cooling demand is attended by the HPR consuming purchased electricity. The cost balance applied to the HPR, considering capital and energy costs is

$$cW_{hp} \cdot W_{hp} - (cR)_{ref} \cdot R_d + kZ(HPR) \cdot R_d = 0 \tag{33}$$

which yields the reference cost of cooling $(cR)_{ref}$ = 253 €/MWh.

Table 6 and Table 7 present the energy, capital and total unit costs obtained for the reference system.

3.5. Cost allocation proposals for the optimal economic system

For the trigeneration system analyzed herein, all energy flows and market costs are known for each hourly period *h* of each representative day *d*. Electricity and natural gas prices were given in Section 2. As in the previous Section, the notation *(d,h)* will be omitted from here on.

The cost conservation principle is applied to all productive units, junctions, distributors, and subsystems in the productive structure of the trigeneration system (Fig. 3). For distributors, the accounting principle introduced in the previous Section was considered, in which the unit costs of the products from the same line are considered equal. In the case of the junctions, provided that the unit costs of the entering flows are known, the unit cost of the junction's product is directly obtained from the cost balance equation. In the productive units with only one product, an energy transformation process takes place, so the unit cost of the product is directly obtained from the cost balance equation provided that the unit costs of the consumed flows are known.

However, as previously discussed, the trigeneration system analyzed herein impose some difficulties to the cost allocation problem that have not been deeply studied in thermoeconomics so far. These difficulties are addressed accordingly:

(i) Joint production in the trigeneration subsystem

The following expression is obtained by applying cost balance to the trigeneration subsystem:

$$cF_c \cdot F_c + cW_{absc} \cdot W_{absc} - cW_{cs} \cdot W_{cs} - cW_{cc} \cdot W_{cc} - cQ_{cl} \cdot Q_{cl} - cQ_{cd} \cdot Q_{cd} - cR_{cq} \cdot R_{cq} + k \cdot W_c + kZ(ABS) \cdot R_{cq} = 0 \quad (34)$$

As previously mentioned, no cost was allocated to the dissipation of cogenerated heat to the ambient (cQ_{cl} = 0). Considering that the resources consumed by the trigeneration subsystem must be allocated to its three useful cogenerated products (W_{cc}, Q_{cd}, R_{cq}) two auxiliary equations are needed to determine their unit costs (cW_{cc}, cQ_{cd}, cR_{cq}). In accordance with Lozano et al. [27,28], considering an equal share of benefits among the consumers, it was proposed to apply the same discount *d* to all cogenerated products with respect to a reference cost:

$$d = 1 - cW_{cc}/(cW)_{ref} = 1 - cQ_{cd}/(cQ)_{ref} = 1 - cR_{cq}/(cR)_{ref} \quad (35)$$

The reference costs considered herein are those of the reference system (Table 7). From the criterion of equal discount, the two auxiliary equations emerge:

$$cW_{cc}/(cW)_{ref} = cQ_{cd}/(cQ)_{ref} \quad (36)$$

$$cW_{cc}/(cW)_{ref} = cR_{cq}/(cR)_{ref} \quad (37)$$

(ii) Heat pump with a different product for each operation mode (heating or cooling mode)

In the case of the HP, the component consumes electricity to produce either heat or cooling, depending on the operation mode. Cost balance in the HP provides the following expression:

$$cW_{hp} \cdot W_{hp} - cQ_{hp} \cdot Q_{hp} - cR_{hp} \cdot R_{hp} + kZ(HPQ) \cdot Q_{hp} + kZ(HPR) \cdot R_{hp} = 0 \quad (38)$$

which is valid for both capital cost allocation criteria proposed in Section 3.3.

(iii) Free solar resource

By considering the solar resource as free of charge (cF_{pv} = 0) in the photovoltaic subsystem, only capital cost and the income of selling electricity ($cW_{pvs} = cE_s$), when applicable, are allocated to its internal product.

$$cF_{pv} \cdot F_{pv} - cW_{pvv} \cdot W_{pvv} - cW_{pvs} \cdot W_{pvs} + kZ(PV) \cdot W_{pv} = 0 \quad (39)$$

(iv) TES units (TSQ and TSR)

The cost allocation in the TES units follows from the methodology developed in Section 3.2, which considers the interconnection between hourly periods through the TES units as a charging and discharging network.

From the cost balance in distributor R3 it follows that the unit cost of the charged cooling cR_{in} is equal to the unit cost of the cooling produced in the hourly period cR_{pi}. This reflects the fact that the energy stored in the TSR may have different unit costs according to the hourly period in which it was produced. Considering that the penalty for energy wasting must be allocated to its useful products, no cost was allocated to the energy losses R_s (cR_s = 0 €/kWh). The unit cost of the discharged cooling cR_{out} was obtained by tracing the discharged flow back to its origin periods according to the following equation:

$$cR_{out}(h) \cdot R_{out}(h) = LZ(TSR) \cdot LOSS_{out}(h) + \sum_{z \neq h} cR_{in}(z) \cdot IN(z,h) \quad (40)$$

in which the first term of the right side corresponds to the capital cost of the TSR and the second to the energy costs.

The same reasoning applies to the TSQ.

4. Results

The unit costs of the internal flows and final products of the trigeneration system were assessed for the 24 hourly periods of each representative day by solving the linear equation system proposed in Section 3 using the software EES (Engineering Equation Solver) [40]. Based on the hourly unit costs, the consolidated monthly and annual values were obtained.

Section 3.3 presented two capital cost allocation proposals for the heat pump HP. Table 6 presents, for each proposal, the annual total unit costs obtained of the system's final products (electricity E_d, heat Q_d, and cooling R_d) and the HP's products (heat Q_{hp} and cooling R_{hp}).

Table 6: Annual total unit cost comparison for different HP allocation proposals.

Annual energy flow	HP proposal A – Main product Total unit cost, €/MWh	HP proposal B – Shared allocation Total unit cost, €/MWh	Reference costs Total unit cost, €/MWh
E_d	123	123	140
Q_d	52	58	55
R_d	216	190	253
Q_{hp}	49	111	-
R_{hp}	135	100	-

From the analysis of the unit costs obtained, it can be seen that proposal A (R_{hp} as the HP's main product so that it receives all capital cost $Z(HP)$) leads to very different unit costs of the HP's products: Q_{hp} is 63% cheaper than R_{hp}; most importantly, the final products of the system Q_d and R_d are both cheaper than their respective reference costs $(cQ)_{ref}$ and $(cR)_{ref}$: 5% and 15%, respectively. On the other hand, proposal B (HP capital cost $Z(HP)$ is shared between both products Q_{hp} and R_{hp}) leads to similar unit costs of the HP's products: Q_{hp} is 11% more expensive than R_{hp}; but now the obtained Q_d is 5% more expensive than $(cQ)_{ref}$, while R_d is 25% cheaper than $(cR)_{ref}$.

A general conclusion from this is that proposal B leads to an overcharged heat due to a higher capital cost share, while proposal A produces more balanced unit costs in line with the reference costs. This analysis demonstrates the potential effect that different cost allocation approaches can have on the unit costs of the internal flows and final products obtained.

Additionally, the knowledge of the operational behavior of the system allows for a better understanding of which technology dominates the production of each energy service. From the data provided in Table 4, the HP produces 85.72 MWh/yr of cooling, while the absorption chiller ABS accounts for 28.77 MWh/yr; regarding the heat production, the HP produces 49.60 MWh/yr against the 475.34 MWh/yr produced by the gas boiler GB. It becomes clear that while the HP dominates the cooling production, it is only used in heating mode to cover heat peak demands. Thus, this information may be used to support the decision to allocate all HP capital cost to the cooling alone.

In the light of the above discussion, HP capital cost allocation proposal A was selected as the most appropriate for this analysis and, thus, the results presented from here on are those obtained with this approach. Table 7 presents the main results on a yearly basis. As can be seen, the total annual cost has been distributed between the final products (electricity E_d, heat Q_d, and cooling R_d). It is interesting to notice how energy and capital costs contribute to the final cost of flows. For example, while cooling R_d is the cheapest product in terms of energy consumption, it becomes the most expensive one when capital costs are included. In fact, capital accounts for 94% of the total cost of cooling. Conversely, the most expensive final product regarding energy consumption, heat Q_d, ends up with the lowest total unit cost (only 17% is due to capital cost).

Regarding the HP's products, the heat Q_{hp} turns out as competitive as the cogenerated heat Q_{cd}, while the cooling R_{hp} results as the best option for cooling production in the system. The absorption chiller ABS is only used to cover peak demands (low load factor), which, along with its high capital cost, leads to significantly high unit costs of the cooling produced: R_{cq} and R_{aq} are 28% and 61% more expensive than the reference cooling $(cR)_{ref}$. The unit costs of the discharged heat Q_{out} and cooling R_{out} from the TES units TSQ and TSR are also more expensive than their corresponding reference costs. The capital cost of the TSR accounts for almost the entirety of R_{out} total unit cost. Despite the high unit costs, it stands as a more profitable alternative to increasing installed capacity of other equipment.

The monthly unit energy and total unit costs, as well as the monthly energy consumptions, of the internal flows and final products of the system are presented in Table 8, Table 9 and Table 10, respectively.

Table 7. Annual energy flows, unit costs and total costs of internal flows and final products.

	Energy flow, MWh/yr	Unit capital cost, €/MWh	Unit energy cost, €/MWh	Total unit cost, €/MWh	Total cost, €/yr
Reference system					
$(cW)_{ref}$	255	-	140	140	35,695
$(cQ)_{ref}$	574	8	47	55	31,504
$(cR)_{ref}$	114	216	37	253	28,839
Final products					
E_d	255	107	16	123	31,468
Q_d	574	9	43	52	29,973
R_d	114	203	14	216	24,654
Cogenerated products					
W_{cc}	31	34	95	130	3,995
Q_{cd}	82	18	30	48	3,959
R_{cq}	5	293	30	323	1,754
Other products					
W_{pvv}	127	239	-135	104	13,234
W_{pro}	297	106	18	124	36,760
Q_a	475	6	47	53	25,335
Q_{hp}	50	21	29	49	2,452
Q_{out}	1	53	33	87	76
Q_{pro}	574	9	43	52	29,943
R_{hp}	86	138	-3	135	11,594
R_{aq}	23	340	68	408	9,525
R_{out}	5	668	22	691	3,356
R_{pro}	114	186	13	200	22,873

Looking into the cogenerated electricity W_{cc} and heat Q_{cd}, it can be seen that their total unit costs increase during the summer, when cooling production R_{cq} occurs. For example, from May (lowest value) to July (highest value), the unit energy cost of the W_{cc} increases 14%; when including capital costs, the increase in the same period is of 31%. This change is due to the higher capital cost that must be allocated to the cogenerated products in the summer months: From June to September, the trigeneration subsystem produces three products W_{cc}, Q_{cd} and R_{cd}, which receive the capital costs of the GE and ABSc; however, for the rest of the year only W_{cc} and Q_{cd} are produced and so only the capital cost of the GE must be allocated. As a consequence, the cogenerated cooling R_{cq} is never cheaper than the reference cooling and the W_{cc} results more expensive than the reference electricity in the months of July and August.

The consideration of free solar resource and the incorporation of the benefit of selling electricity to the grid lead to negative unit energy costs of the photovoltaic electricity W_{pvv} (Table 8). This electricity contributes to reducing the unit energy costs of other flows originated from it, such as the cooling in the HP R_{hp} and the discharged cooling R_{out}.

Table 8. Monthly unit energy costs, €/MWh.

Month	E_d	Q_d	R_d	W_{cc}	Q_{cd}	R_{cq}	W_{pvv}	W_{pro}	Q_a	Q_{hp}	Q_{out}	Q_{pro}	R_{hp}	R_{aq}	R_{out}	R_{pro}
Jan	70	45	-	95	32	-	-54	75	47	35	39	45	-	-	-	-
Feb	35	45	-	93	31	-	-118	39	47	32	38	45	-	-	-	-
Mar	21	42	-	93	30	-	-126	21	47	7	29	42	-	-	-	-
Apr	-8	39	-	91	29	-	-179	-5	47	17	33	39	-	-	-	-
May	-30	38	-	90	29	-	-209	-30	47	-	29	38	-	-	-	-
Jun	-18	38	-5	98	30	30	-155	-23	47	-	31	38	-12	69	6	-5
Jul	-7	39	24	103	30	31	-132	-1	47	-	30	38	3	68	29	23
Aug	-7	37	16	101	30	30	-142	-6	47	-	30	37	-1	69	31	16
Sep	-2	38	-5	99	30	29	-156	-6	47	-	31	38	-8	-	17	-5
Oct	7	38	-	92	30	-	-178	8	47	46	37	38	-	-	-	-
Nov	33	46	-	93	31	-	-127	33	47	-	33	46	-	-	-	-
Dec	75	44	-	95	32	-	-40	75	47	30	39	44	-	-	-	-

Table 9. Monthly total unit costs, €/MWh.

Month	E_d	Q_d	R_d	W_{cc}	Q_{cd}	R_{cq}	W_{pvv}	W_{pro}	Q_a	Q_{hp}	Q_{out}	Q_{pro}	R_{hp}	R_{aq}	R_{out}	R_{pro}
Jan	130	53	-	121	47	-	115	130	53	52	83	53	-	-	-	-
Feb	125	53	-	120	47	-	106	126	53	51	75	53	-	-	-	-
Mar	123	51	-	120	47	-	105	123	53	41	59	51	-	-	-	-
Apr	119	50	-	120	46	-	99	120	53	43	60	50	-	-	-	-
May	116	50	-	119	46	-	95	116	53	-	61	50	-	-	-	-
Jun	120	52	186	139	49	317	102	119	53	-	115	51	133	408	740	160
Jul	123	53	235	156	52	331	105	124	53	-	123	53	137	408	553	225
Aug	123	53	220	152	53	322	103	123	53	-	128	53	136	408	803	207
Sep	123	52	180	142	51	315	102	122	53	-	121	52	133	-	793	146
Oct	121	50	-	120	46	-	99	121	53	47	81	49	-	-	-	-
Nov	125	53	-	120	47	-	105	125	53	-	60	53	-	-	-	-
Dec	130	53	-	121	47	-	117	130	53	51	80	53	-	-	-	-

Table 10. Monthly energy consumption, MWh/month.

Month	E_d	Q_d	R_d	W_{cc}	Q_{cd}	R_{cq}	W_{pvv}	W_{pro}	Q_a	Q_{hp}	Q_{out}	Q_{pro}	R_{hp}	R_{aq}	R_{out}	R_{pro}
Jan	24	126	0	3	7	0	10	31	99	19	0	126	0	0	0	0
Feb	22	94	0	2	7	0	9	24	82	5	0	94	0	0	0	0
Mar	24	59	0	2	7	0	11	26	47	5	0	59	0	0	0	0
Apr	21	32	0	2	7	0	10	22	21	4	0	32	0	0	0	0
May	22	14	0	2	7	0	10	22	7	0	0	14	0	0	0	0
Jun	19	13	17	3	7	1	12	23	7	0	0	13	15	1	1	17
Jul	19	11	48	3	6	2	14	28	26	0	0	11	32	14	2	48
Aug	19	10	35	3	6	2	13	27	16	0	0	10	26	8	1	36
Sep	19	11	14	3	7	1	11	22	5	0	0	11	13	0	1	14
Oct	22	13	0	2	7	0	9	22	6	0	0	13	0	0	0	0
Nov	21	70	0	2	7	0	8	21	63	0	0	70	0	0	0	0
Dec	24	120	0	3	7	0	10	30	97	15	0	120	0	0	0	0

In Section 3.3 it was proposed to allocate the capital cost of the TSQ and TSR to the discharged energy in proportion to the energy losses associated with the discharge. This effect becomes clear when analyzing the monthly operation of the TSQ. As can be seen from

Table 9, the total unit cost of the discharged heat Q_{out} increases considerably during the summer months. This happens because of a change in the operation of the system. From June to September, the HP operates in cooling mode, which requires that the system maintain the TSQ charged for more hours than in the non-summer months. In fact, storage time triples in summer months. This increase in energy losses, due to longer storage periods, results in the allocation of more capital costs to the discharged heat.

For comparison's sake, the unit capital costs of the TSQ and TSR were also assessed with the productivity approach *kZ* (annual discharged energy), resulting in *kZ(TSQ)* = 34.66 €/MWh and *kZ(TSR)* = 366.35 €/MWh. A comparison of the monthly total unit costs of the discharged energy cQ_{out} and cR_{out} obtained with both approaches (A: productivity approach; B: annual energy losses approach) is presented in Fig. 9. As can be seen, the productivity approach led to more stable total unit costs over the months; however, it does not account for the changes in the operation of the TSQ and TSR, as explained in the previous paragraph.

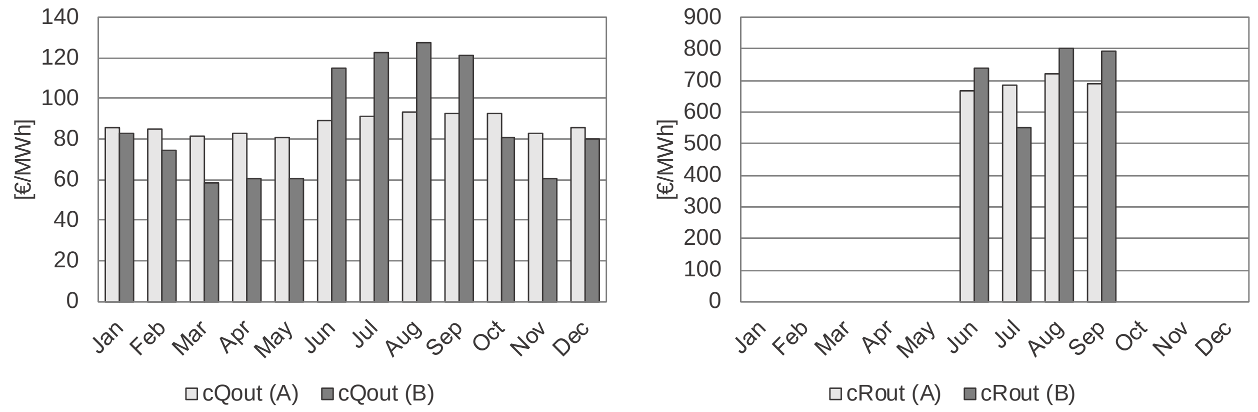

Fig. 9. Monthly total unit costs of the discharged energy considering productivity approach (A) and annual energy losses approach (B) for the TSQ (left) and TSR (right).

Considering the interconnection between hourly periods, it was possible to evaluate the unit energy cost of the discharged energy from the TSQ and TSR. By knowing the origin periods of the discharged energy and the unit costs of the charged energy in those periods, the cR_{out} and cQ_{out} could be assessed. Similar to Fig. 7, Fig. 10 presents a sample of the unit energy costs of the discharged cooling from the TSR on a representative day of July.

	2	3	4	5	6	7	8	9	10	11	12	13	14
(2,14) cIN, cOUT	0.0315												0.0356
(3,14) cIN, cOUT		0.0315											0.0352
(4,14) cIN, cOUT			0.0315										0.0348
(5,14) cIN, cOUT				0.0291									0.0319
(6,14) cIN, cOUT					0.0269								0.0291
cRin(h)	0.0315	0.0315	0.0315	0.0291	0.0269	-	-	-	-	-	-	-	-
cRout(h)	-	-	-	-	-	-	-	-	-	-	-	-	0.0343

Fig. 10. Unit energy costs of charged and discharged energy to/from the TSR in July.

Finally, it is interesting to analyze the annual cost savings distribution between the electricity, heating and cooling relative to the reference system. The energy, capital and total annual cost savings are presented in Table 11.

Table 11. Economic savings relative to reference system.

	E_d	Q_d	R_d	Total
Energy cost savings, €/yr	31,558	2,335	2,733	36,626
Capital cost savings, €/yr	-27,331	-804	1,451	-26,684
Total cost savings, €/yr	4,227	1,531	4,184	9,942
Unit energy cost savings, €/MWh	124	4	24	-
Unit capital cost savings, €/MWh	-107	-1	13	-
Total unit cost savings, €/MWh	17	3	37	-

As can be seen, the cooling and the electricity received the highest total annual savings, 37 €/MWh and 17 €/MWh, respectively, while the heat received only 3 €/MWh. In energy terms, electricity was the product with the highest energy cost savings, 124 €/MWh, followed by the cooling and the heating with 24 €/MWh and 4 €/MWh, respectively. Capital cost savings are negative because the trigeneration system requires higher investment and maintenance costs than the reference system; however, it was interesting to note that the cooling received a positive capital cost saving, which means that the optimal economic system attributes less capital cost to cooling than the reference system. This is due to the energy integration in the optimal economic system which allows for a lower HP installed capacity and higher load factor than the reference system.

5. Conclusions

In the present paper, the thermoeconomic analysis of a trigeneration system including renewable energy source (photovoltaic panels) and thermal energy storage was developed. The MILP model proposed in a previous paper [33] was used to determine the optimal economic configuration and operational planning of the trigeneration system. The thermoeconomic analysis was carried out for the period of one year, obtaining the energy, capital and total unit costs of the internal flows and final products of the system on an hourly, monthly and annual basis.

This work addressed issues not yet deeply studied in thermoeconomics, such as the inclusion in trigeneration systems of (i) thermal energy storage units (for heat and cooling), (ii) a component with different products for each operation mode (heat pump HP in heating mode producing heat and in cooling mode producing cooling), (iii) free renewable energy source (solar energy), and (iv) joint production of energy services in dynamic energy systems (electricity, heat, and cooling). Concerning the joint production of energy services, it was proposed to apply the same discount to all cogenerated products with respect to their reference costs, which corresponded to the separate production costs.

Capital cost allocation proposals were made, particularly regarding the HP and the TES units. In the case of the HP, the knowledge of the operational behavior of the system was essential to identify the dominating device of each energy service production, leading to the consideration of cooling as the HP's main product, thus receiving all HP's capital cost. Regarding the TES units, it was argued that capital cost allocation based on productivity (annual discharged energy) should be discouraged when energy losses are considered, and an allocation based on annual energy losses would be more appropriate. The reason is that energy losses account for both the quantity of energy stored and the duration of energy storage (time difference between charge and discharge). In this way, more capital cost is allocated to the energy discharged after a longer period of storage time.

The definition of the productive structure involves connecting the energy resources consumed to the internal flows and final products of the system. In multiperiod analyses such as the one carried out in this paper, the incorporation of TES units imposes an increased challenge to the cost allocation problem because it requires connecting the hourly periods of charge to the hourly periods of discharge; only then the discharged energy can be traced back to its charging period and to the energy resources consumed. Thus, this paper addressed the issue of the interconnection between hourly periods through the TES units, as proposed in a previous paper [39], unveiling the distribution of the charged energy between the discharge periods and obtaining the hourly unit costs of the discharged energy.

Based on the results obtained it was demonstrated that different allocation approaches can result in different unit costs of the internal flows and final products. The thermoeconomic analysis allowed the total annual cost of the system to be distributed between the electricity, heating and cooling produced. The energy, capital and total annual cost savings relative to the reference system were also distributed between the system's final products. The three products presented positive total annual savings, which indicates that the cost allocation proposals developed herein promoted a fair cost distribution.

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Highlights

- The thermoeconomic analysis of a trigeneration system is performed
- Novel capital cost allocation approach for the thermal energy storage is proposed
- The energy, capital and total unit costs are determined for all energy flows
- The unit costs are assessed on an hourly, monthly and annual basis
- The total unit costs obtained are lower than the reference costs adopted herein