Opportunities and economic assessment for a third-party delivering electricity, heat and cold to residential buildings

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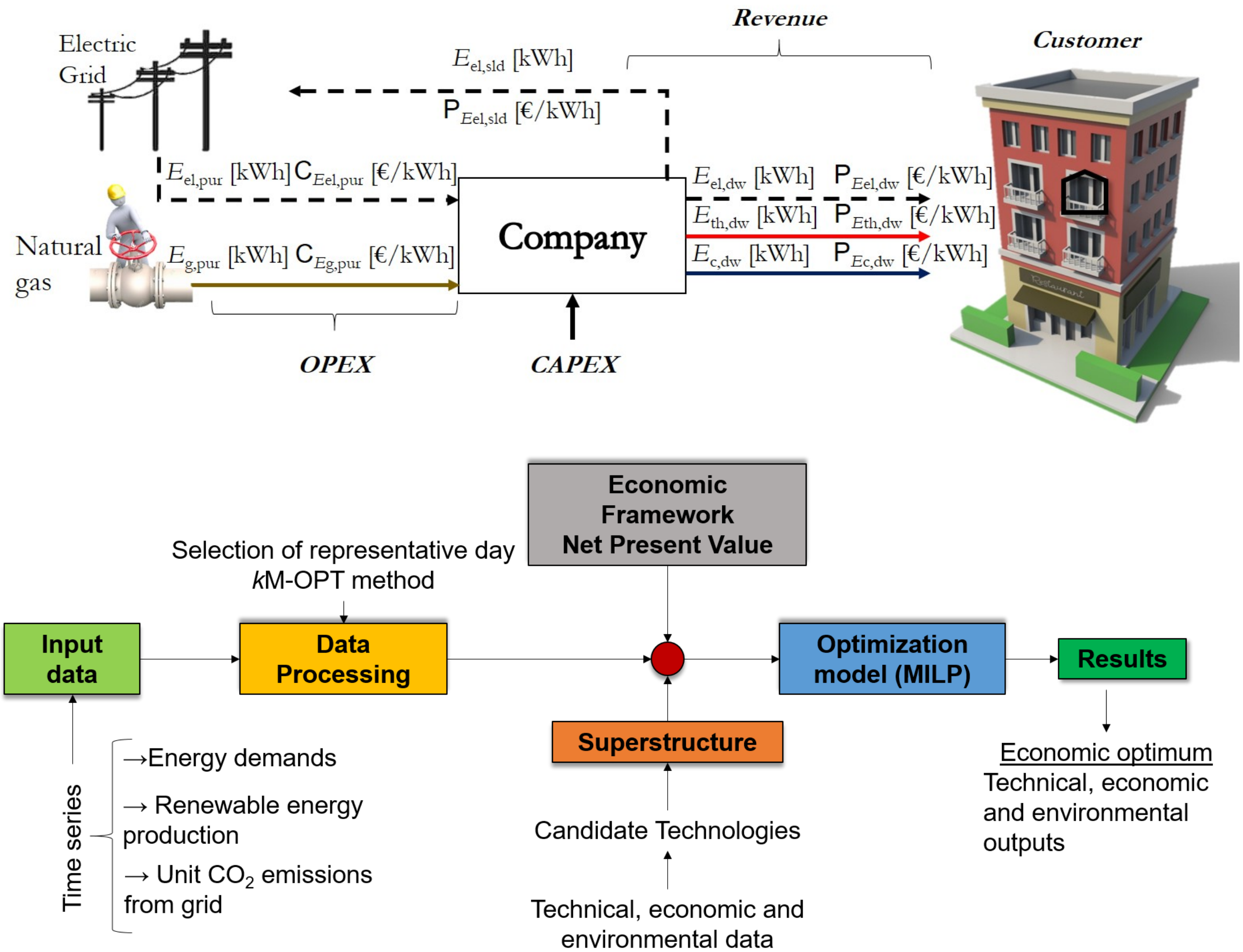
Abstract

In the present context of energy transition towards a carbon neutral society, residential sector plays an important role to combat climate change since it represents about 40% of the global final energy consumption and 30% of direct CO_2 emissions in the European Union. Polygeneration systems, facilitating the integration of renewable energies, are a feasible alternative enabling efficient use of natural resources with low environmental impact. This work analyzes the economic viability, in terms of net present value (NPV), and environmental benefit ($CO_{2\,eq}$ emissions) of an energy supplier company playing the role on an aggregator for both demand and supply. As an owner of a polygeneration system, optimally designed through a MILP approach, it delivers various energy services (electricity, space heating, domestic hot water and cold) to several customers (50 dwellings). The analysis is performed, considering three different business models, in two different locations, Zaragoza (Spain) and Marseille (France), with different energy demands, energy mixes and energy regulations. The optimal configuration obtained, consisting of cogeneration module, PV, reversible heat pump, boiler and thermal energy storage has shown to be very resilient and cost-effective in the scenarios analyzed. Results indicate that the proposed scheme represents an added value for both the supplier company (aggregator), with a positive NPV, and the final customers (owing savings greater than 30%), with significant reduction of $CO_{2\,eq}$ emissions.

Keywords: Polygeneration Systems; Aggregator; Net Present Value; Optimization; Renewable Energy; Residential Sector

Graphical abstract



Contents

Nomenclature

Latin symbols

A	surface area, m^2
a_0	optical efficiency, –
a_1	first heat loss coefficient, $\mathrm{W\,m^{-2}\,K^{-1}}$
a_2	second heat loss coefficient, $\mathrm{W\,m^{-2}\,K^{-2}}$
C	cost, €
$\mathscr{C}$	thermal Capacitance, $\mathrm{J\,kg^{-1}}$
CAP	installed capacity, kWh or MWh
$C_{\mathcal{P}}$	power coefficient, –
c	specific heat capacity, $\mathrm{J\,K^{-1}\,kg^{-1}}$
CAPEX	capital expenditures, €
CF	cash flow, €
COP	coefficient of performance, –
$\mathcal{D}$	demand, kWh
DD	degree day –
DCF	discounted cash flow, €
Dep	depreciation, €
DOD	allowable depth of discharge, %
E	total energy, J or kWh
G	irradiation, $\mathrm{W\,m^{-2}}$
Fm	installation costs, €
$\mathcal{G}$	building heat loss coefficient, $\mathrm{W\,K^{-1}\,m^{-3}}$
$\mathcal{I}$	solar irradiance, $\mathrm{W\,m^{-2}}$
IT	income tax, €
ItR	interests rate, %
LCC	life cycle cost, €
LF	loss factor, %
LHV	lower heating value, $\mathrm{J\,m^{-3}}$ or $\mathrm{J\,kg^{-1}}$
LT	life time, year
MCR	major components replacement, €
N	integer number, -
NOCT	nominal operating cell temperature, °C
NPV	net present value, €
O&M	operation and maintenance costs, €
OPEX	operational expenditures, €
$\mathcal{P}$	power, W
P	price, €
PP	payback period, year
Q	heat, J or kWh
q	flow-rate, $\mathrm{m^3\,s^{-1}}$ or $\mathrm{L\,s^{-1}}$
R	revenue, €
$\mathscr{R}$	thermal resistance, $\mathrm{W^{-1}\,K\,m^2}$
RV	residual value, €
r	discount rate, %
SD	self-discharge, %/month
SOC	state of charge, %
T	temperature, K or °C
TI	taxable income, €
Tr	tax rates, %
t	time, s or min
$\overrightarrow{U}$	velocity, $\mathrm{m\,s^{-1}}$
V	volume, m^3
VAT	value added tax, %
z	position, m

Greek symbols

η	efficiency, – or %
κ	open-circuit voltage thermal coefficient, $\mathrm{K^{-1}}$
ρ	density, $\mathrm{kg\,m^{-3}}$
ω	weight of a representative day, –
Ψ	Very large number (e.g., 10^6), –

Subscripts and superscripts

a	air
amb	ambient
c	cooling
$\not{c}$	cycle
cd	cold
cell	cell
ch	charge
cut	cutoff
d	day
dw	dwellings
dis	discharge
el	electrical
fu	fuel
g	gas
gd	grid
htg	heating
h	hour
in	indoor
inv	inverter
K	contract
m	month
nom	nominal
out	outdoor
pan	panel
pip	pipe

pur	purchased
ref	reference
sld	sold
sp	set point
stor	storage
th	thermal
wat	water

Acronyms

AbCh	absorption chiller
ACU	air conditioning unit
BEES	battery electrical energy storage
CCHP	combined cooling, heating and power
CHP	combined heating and power
CM	cogeneration module
DH	district heating
DHW	domestic hot water
EES	electrical energy storage
EU	European Union
FC	fuel cell
FiT	feed-in tariffs
GA	genetic algorithm
GB	gas boiler
GIS	geographic information system
GS	gas storage
HP	heat-pump
ICE	internal combustion engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRR	internal rate of return
LCA	life cycle assessment
Mch	mechanical chiller
MILP	mixed integer linear programming
MT	micro-turbine
PV	photo-voltaic
RES	renewable energy system
ST	solar thermal
TES	thermal energy storage
TSC	thermal storage for cooling
TSH	thermal storage for heating
WT	wind turbine

1 Introduction

1.1 Foreword

In the ongoing race for a decarbonized world, challenges are numerous. Indeed, current statistics and future projections based on Stated Policies Scenario presented in World Energy Outlook 2022 [1] show an increase of the demand. Unfortunately, this latter is still mainly based on fossil fuels, which endangers obviously the climate but also abiotic resources availability. When analyzing more finely this demand, building sector represents 40% of the total final consumption in the EU, 75% of which being supplied by fossil fuels [2]. The estimated energy demand increase by 2050 would be about of 79% and 84% for the heating and cooling demand respectively [3]. Therefore, the residential buildings are identified by the IPCC as a paramount objective in the pathway to limit global warming [4].
To tackle such a problem, the usual approach mainly relies on renewable energy sources (RES) and energy efficiency [5–7]. In the former case, the preferred solutions involve increased deployment of photovoltaic (PV) and wind (WT) energy as well as solar thermal (ST) energy [8–11]. In the latter case, several options are envisaged. It is first planned to further develop district heating and cooling networks [5,12,13], and to integrate more smartness [14,15] and more cross-sectoral interactions [16,17]. There is consequently a strong impetus for multi-energy systems [18, 19] which flexibilize the energy management, or more appropriately, to energies management since multi-energy flows are involved. Among the available technologies, heat-pumps (HP) and combined-heat-and-power (CHP) are serious candidates [6, 20, 21], especially in a context of renewable electricity or to pave the way for biogas or power-to-gas [2,19,22]. Secondly, the smart-grid concept could be further extended, especially to other energy networks, as well as the flexibility of the whole network. To achieve such a goal, it has been pointed out that the advent of aggregators should be promoted [23] to either access all types of market or to increase energy sharing (see for instance Chapter III, Article 16.3 of the previous reference). In the same idea, it appears that innovation in the development of new business models should be encouraged [24, 25]. Finally, it is worth highlighting that all these solutions should benefit or will probably require a more important use of energy storage [2, 11, 24, 26], especially when increasing the usage of non-manageable RES, such as solar energy or wind energy [27].

1.2 Literature review

With regard to the above discussion, it is clear first that polygeneration systems in multi-energy carriers networks are to be considered when planning the features of the future energy network. Secondly, business models have to be investigated for third-party companies that would play this role, proposing generation assets between the customers and the historical grids (and more centralized production). Unsurprisingly, many papers have been devoted to such a topic: the interested reader is referred to [15], and [28] for a recent review of future infrastructures involving polygeneration systems, but also to [29] for an overview of models and assessment techniques, and to [30] concerning investment models assessment. To name but a few examples of the advantages of polygeneration systems, they help to gain in flexibility [31] and can increase self-sufficiency [32, 33]. Besides, they reduce the economic risks [34] and can permit to reduce CO_2 emissions and costs [30,35]. Concerning the aggregators, a tremendous literature is also available, specifically in the field of smart-grids. Thus, the associated organization and possible business models are particularly well presented in [36, 37]. For "simple" energy communities, with an energy provider that interacts with the customers (consumers or prosumers), tens of best practices have been intensively analyzed in [38], and a cross-analysis of the corresponding socio-technical issues and challenges can be found in [39].

The design of polygeneration system is usually based on an optimization process, whose application to energy systems is well described in [40, 41]. Thus, cost minimization is performed in [31] to optimally design a system involving PV and a CHP, as well as batteries (BEES) and thermal storage (TES), so as to supply an isolated tourist resort in Northern Italy. The optimized solution corresponds to more than 85% of the electricity provided by the cogeneration module for the whole year, and the supply of heat between 20% and 100% for winter and summer period respectively. Similarly, an autonomous isolated microgrid based on PV and WT and BEES is designed for Agios Efstratios (a Greek island), by means of a techno-economic analysis performed with `HOMER` in [42]. The obtained results lead to a penetration of RES greater than 68% for all scenarios. In [43], `HOMER` is still used to optimize a hybrid RES system involving PV or WT or both of them, BEES being available for lowering intermittency issues. It permits to establish cost maps for Barcelona, Spain and Jeju Island, Korea. One can see that, though these studies consider several types of RES, they only consider electricity demand, and the idea is always to minimize the costs. Concretely, this means that investments are supposed to be supported by the users. Correspondingly, no business model nor aggregation philosophy are developed.
Afterwards, and closer to this study are works devoted to poly-generation technologies in multi-carrier energy systems. Let us mention here that the used taxonomy defines polygeneration technologies as appliances able to provide more than one type of energy and multi-carrier energy systems as networks involving several types of energy flows (produced either by single- or poly-generation systems). One of the earlier work on energy community is due to Weber & Shah, who used a MILP optimization to decrease CO_2 emissions and increase self-sufficiency of a 6 500 inhabitants eco-town in England, United Kingdom [44]. They combined here CHP plants with HP, together with PV, WT and ST. Among the results, the interested points to consider are twofold: firstly, external (historical) grids appear essential if storage is not involved, and secondly (and more interestingly), ST is essential at the building level even if the role of solar collectors is minimal compared to the HP. Das & Al-Abdeli shed light on the influence of the electrical and thermal loads in [45]. Studying a stand-alone grid involving PV and BEES, and either an internal combustion engine (ICE) or a microturbine (MT) used as a CHP plant, they demonstrated that the levelized cost of electricity is not really impacted by the power management strategy, namely following the electric load or the thermal load or both. Moreover, an hybrid power management strategy is always more efficient. Nevertheless, they point out that the analysis should be extended to take into account cooling demand. Next, Jiménez Navarro et al. proposed to optimize a combined cooling, heating and power (CCHP) grid for a park located in Málaga, Spain [46]. When minimizing the total annual cost of a CHP, with boiler as backup, combined with mechanical and absorption chillers and cold TES, they showed the importance of a base load demand to guarantee the performance in case of large daily variations. In addition, the demand uncertainties were clearly able to jeopardize the investment. This leads the authors to conclude that guaranteeing the benefits is important for a real extension of CCHP, which implicitly creates the impetus for investigating adequate business models. Then, in [47], Li et al.proposed an optimized design so as to minimize the load shedding in multi-energy networks, carrying electricity and heating and gas vectors. Combining PV and fuel cells (FC) with CHP, together with electric and gas boilers, as well as hydrogen storage. They showed that the location of the PV panels, *ceteris paribus*, influenced greatly the sizing of the other components. Moreover, a decrease of the investment costs of the FC and the electrolyzer increased the PV capacity. However, cooling demand is once again absent from such a study. More recently, Bartolini et al. [22] were interested in power-to-gas potential in a small multi-energy district involving a large set of technologies: PV and FC, two types of CHP and a air-source HP, sensible TES and Lithium-ion BEES, electrolyzer and hydrogen storage, electric air-conditioning-unit… For real user demands and renewable electricity production data in Austin, Texas, US, they conducted a MILP optimization to

minimize the total cost. They clearly show the boons of multi-energy architectures and storages and their interests to develop RES communities. Though considering a large set of technologies, prices were set constant, and the objective function is still to minimize the total costs. Using also a MILP approach, Zhu et al. maximized the NPV or IRR of five different buildings in Shanghai, China [48]. The involved technologies were PV and WT, together with CHP and electric boiler and TES, as well as an absorption chiller and an electric chiller. Better results were obtained when the optimization criterion was NPV maximisation. Moreover, there was still a need for imported electricity and the impacts of both FiT and electrical and thermal mismatch were important. Here again, even if a time-of-use pricing is employed, it is based on customers prices and all values are kept constant. Next, in [49], a system relying on PV and WT, coupled with lithium-ion BEES, is optimized with HOMER using either a diesel ICE or a gas MT or a FC to meet the electrical and thermal loads. An hybrid solution, coupling PV and WT and MT, is shown to have the lowest cost, and CO_2 emissions are (logically) lower with FC-based solutions. As mentioned by the authors, further investigations should consider the role and influence of TES on this design; and one can add also that cooling demand should be taken into account. As a last example, one can have a look on the interesting work of Li et al., who use a bi-level optimal configuration strategy for electrical, heating and cooling demand of an energy community (Xiong'an New Area, China). Here again, a large set of technologies are present: PV and WT, MT and electric ACU and AbCh, EES and GS and TES. Several scenarios are scrutinized, to minimize the costs, however selling extra-energy is not considered, prices are fixed and once again, there is no real business developed.

When turning to the aggregators studies, recent works have further demonstrated their interests. The important underlying question is still to asses their economic value [50]. It is indeed particularly tricky due to the current change of both the markets and the role of each actors, accompanied by some uncertainties or too strict legal rules [46] or, in the contrary, by a lack in regulation [51]. Thus, in [52], a stochastic optimisation approach is used to model technical and economic aggregation possibilities. Here, value mapping is obtained, and permit to identify the best transactions prices between the various agents. Nevertheless, the approach relies on the assumption the profit margin of the aggregator will not decline, which cannot permit to question its economic viability. In addition, this only considers electricity demand, which is pointed out as a needed extension by the authors as well as considering "upstream/downstream" consisting in proposing energy production and exchanging with the surrounding networks. Considering a set of 61 libraries in Barcelona, Spain, Barbero et al. first describes the levers and brakes on four European electricity markets so as to investigate the role of a third-party company acting as a demand aggregator [53]. This latter directly signs contracts with the customers (consumers and/or prosumers). Their results show a relatively low revenues, yet as recognized by the author, aggregation is only done on ACU. More important, different energy vectors should be addressed. Similarly, the review of Lu et al. [54] indisputably ascertain the various possibilities of aggregation, mainly demand and load aggregation and production aggregation. They argue the necessity to develop relative market, and to focus on small customers, relying on the following pillars: prices, variable generation and flexibility. Furthermore, their statement could be extended to all energy vectors, and not restricted to electricity. Such an argument is also shared by papers alike, where the importance of further research is mentioned concerning the interactions between energy communities and the external agents [39], and concerning the definition of complete business models addressing the customers concerns, the fair remuneration of all actors and the long-term stability of such schemes [55].

Finally, the current state of the art suggests that optimal design of polygeneration involving all set of technologies to build multi-energy carriers networks and development of possible business models of aggregators, as energies providers, are key questions which need to be investigated altogether.

1.3 Contribution and novelty of the study

In respect with the previous discussion and conclusion, the goal of this study is to investigate the economic viability [46] and environmental benefit of an energy supplier company, acting as an aggregator. It delivers various energy services, such as electricity, space heating, domestic hot water, and cooling to cover all types of demands [45, 47]. These services are obtained by polygeneration system, owned by the aggregator, which has also access to the regional/national electrical and gas grids [53]. By investing directly in these equipments, it relieves such a burden from the customers who will not have to assume the initial investment costs and future operating costs, guaranteeing them no specific fees [55]. The proposed scheme based on aggregators is not very common in most countries [38, 53]. In this work it is applied in two different countries, France and Spain, where even with different energy mixes and energy regulations, a very common paradigm is that each customer (dwelling) has its own boiler and/or heat pump and establishes an individual contract with the gas and/or electricity supply company in order to cover the dwelling energy demands. Therefore, the underlying idea is to look if there is an added-value for both i) the supplier company playing the role of an aggregator, and ii) the final customers (dwellings), considering: a) several technologies tested in the analyzed polygeneration framework; b) various business models; c) two different locations of two different countries (Spain and France) in order to scrutinize the effects of demand and regulations on the final configuration and sizing of the optimal polygeneration system. Concretely, the polygeneration system is obtained by optimizing a superstructure involving flexible appliances, RES and storage (both electrical and thermal). The objective function is to maximize the NPV [52]. It is achieved through a MILP formulation, while considering also the environmental benefits, i.e., paying attention to the $CO_{2\,eq}$ emissions. In terms of contribution, the novelty of this study are manyfold:

1. Energy service is offered for all types of energy vectors required by residential customers (i.e., electricity, heating and cooling) through a complete set of the main current available technologies, namely PV and WT, and ST, and AbCh for production, CHP and HP and GB for conversion, TES and BEES for energy storage. In this latter case, energy discharge is considered.

2. Optimized design of the whole system is considered together with testing several business models for the aggregator proposing this energy-as-a-service contract.
More precisely, to the best of the authors knowledge, the specific novelties here are:

    - in the three business models tested:
        (a) case A: constant price of energy for the customer and no resale authorized for the aggregator.
        (b) case B: variable price of energy for the customer and no resale authorized for the aggregator.
        (c) case C: variable price of energy for the customer and resale authorized for the aggregator.
    - to consider non-constant prices of energy over time
    - to not only focus on the costs but to consider the revenues, and then the NPV, integrating also the tax rates in its calculation
    - in the size of the sample, consisting in a small district, of 50 dwellings.

The paper is organized as follows. The methodology is presented in section 2 and the test cases in section 3. Sections 4 and 5 are devoted respectively to the presentation of the obtained results and their analysis and discussion, and section 6 concerns the conclusions and perspectives.

2 Methodology

The proposed strategy to address the research questions raised above is schematically depicted in Fig. 1. Based on annual energy demands and possible production of RES, 12 representative days are selected and used to determine the optimum design. This latter corresponds to the maximum NPV, yet payback period (PP) and $CO_{2\,eq}$ emissions are also scrutinized. Details concerning these various parts are developed thereinafter, as well as the three business models tested.

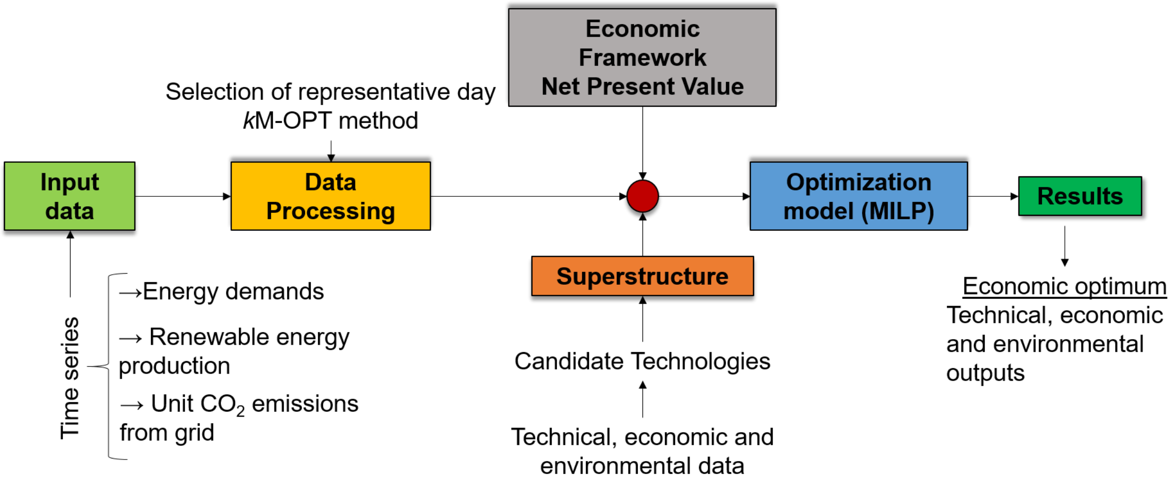


Figure 1: Flowchart of the design process

From a physical and practical viewpoint, the present situation of a third-party, between the customers and the historical grids, and offering energy-as-a-service is illustrated in Fig. 2. The aggregator has to attend the demand (electricity $E_{\mathrm{dw,el}}$, heating $E_{\mathrm{dw,th}}$ and cooling $E_{\mathrm{dw,c}}$) of a residential building compound of 50 dwellings. By aggregating these demands, and by means of its own appliances, production or conversion or storage units, the aggregator tries to answer customers needs and to achieve economic viability. The aggregator can also sell energy surplus or rely on the outter grids in case of shortage. The analysis is performed for Zaragoza, Spain and Marseille, France, considering thus different, yet relatively close physical conditions, and more important different regulations and historical energy mix.

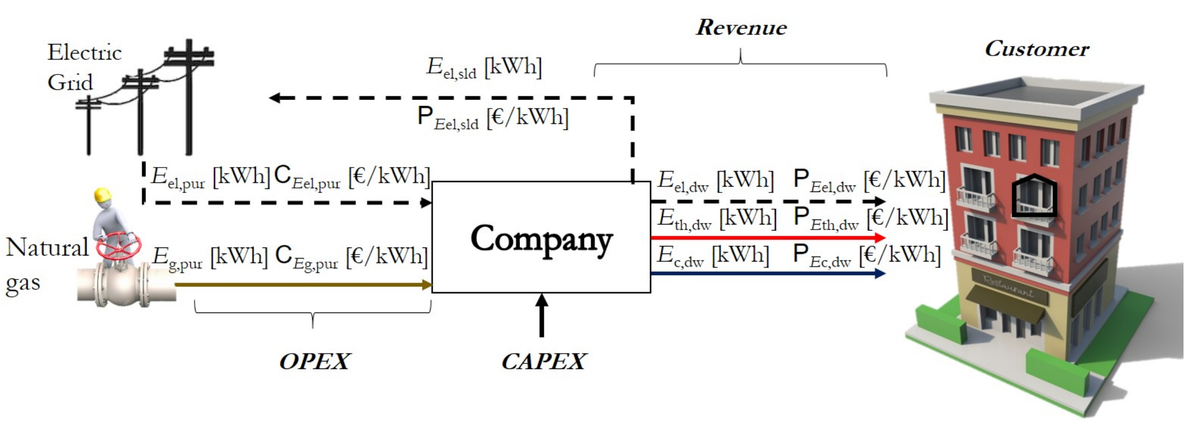


Figure 2: Illustration of the role of a third-party acting as an aggregator and an energy provider

2.1 Superstructure

Fig. 3 illustrates the archetypal architecture of the multi-energy system, together with the technologies candidate for the design step. These possible appliances can be divided according to the kind of energy that they provide. PV panels and wind turbines (WT) produce electricity; gas boiler (GB) and solar thermal collectors (ST), heat; and single-effect absorption chiller (AbCh), cooling. Some technologies supply two services, such as the conversion units, namely the cogeneration modules (CM/CHP), producing both electricity and heat, or the reversible heat pump (HP) providing heating or cooling. Lastly, thermal energy storage is available for heating (TSH) and cooling (TSC), while batteries (BEES) are considered for electricity. The aggregator is also connected to the local electrical and gas grids, where it can buy in case of shortage or inject (for some scenarios). Obviously, the required appliances, such as inverters and inverter chargers, are involved to take into account the need to convert direct current into alternating current and conversely. Lastly, for the sake of simplicity, the efficiency of every technology is assumed constant.
CO_2 emissions being computed, the legal coefficients for gas and electricity are considered for each country. The former is of 0.203 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\,\mathrm{kWh}$ and 0.227 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\,\mathrm{kWh}$ in Spain [56] and France [57] respectively; for electricity, the mix is very different (see Fig. 4), due to French nuclear energy.

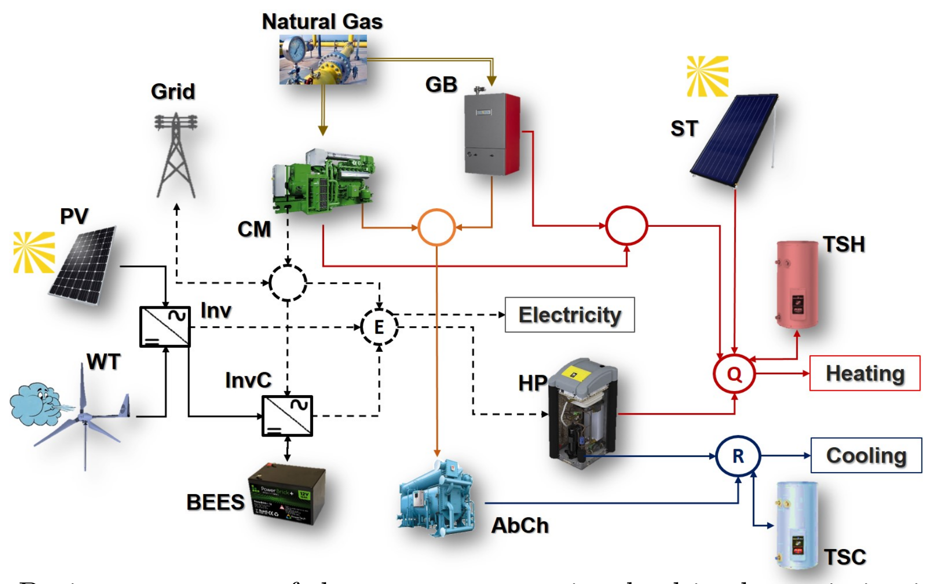


Figure 3: Basic components of the superstructure involved in the optimization design

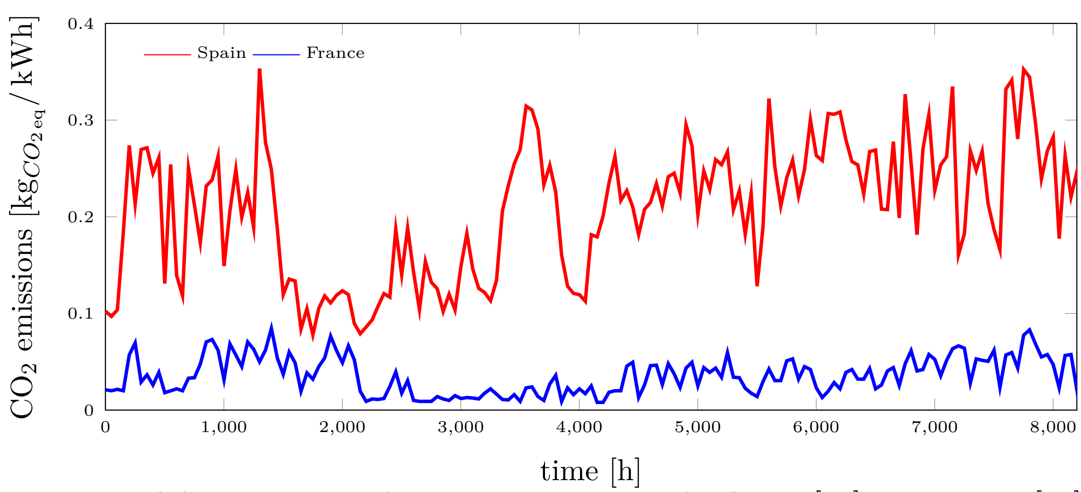


Figure 4: Hourly $CO_{2\,\mathrm{eq}}$ emissions from the electric grid for Spain [58] and France [59] in 2018

2.2 Supply and demand

2.2.1 Poly-generation production

As mentioned above, there are many types of technologies considered in this study (see Fig. 3) which are further detailed here. Let us start with the production units. The first ones concern the RES producing electricity, namely PV and WT.
The hourly power for PV is [60–62]:

$$\mathcal{P}_{\text{el,PV}} = \mathcal{I}\, A \cdot \eta_{\text{PV}} \cdot \eta_{\text{inv}} \tag{2.1a}$$

$$\eta_{\text{PV}}(T) = \eta_{\text{pan}} \left(1 - \kappa\left(T_{\text{cell}} - T_{\text{cell}}^{\text{ref}}\right)\right) \tag{2.1b}$$

$$T_{\text{cell}} = T_{\text{amb}} + \left(\text{NOCT} - T_{\text{cell}}^{\text{ref}}\right)\frac{\mathcal{I}}{\mathcal{I}^{\text{ref}}} \tag{2.1c}$$

For WT production, the power profile follows a classical cubic form [63–65]:

$$\mathcal{P}_{\text{WT}} = \begin{cases} 0 & \text{if} \quad U \leq U_{cut,\text{bot}} \text{ or } U \geq U_{cut,\text{top}} \\ \dfrac{1}{2}\rho_{\text{a}}\, C_{\mathcal{P}} U^3 \dfrac{U^3 - {U_{cut,\text{bot}}}^3}{{U_{\text{nom}}}^3 - {U_{cut,\text{bot}}}^3} \times A \times \eta_{\text{WT}} & \text{if} \quad U_{cut,\text{bot}} < U \leq U_{\text{nom}} \\ \dfrac{1}{2}\rho_{\text{a}}\, C_{\mathcal{P}} U^3 \times A \times \eta_{\text{WT}} & \text{if} \quad U_{\text{nom}} < U \leq U_{cut,\text{top}} \end{cases} \tag{2.2}$$

In the case of heat production by ST, it is proportional to the mean temperature difference between the collector temperature and the ambient temperature [66–68]:

$$\mathcal{P}_{\text{th,ST}} = \mathcal{I}\, A \cdot \eta_{\text{ST}} \tag{2.3a}$$

$$\eta_{\text{ST}}(T) = \mathsf{a}_0 - \frac{\mathsf{a}_1}{\mathcal{I}}\left(T - T_{\text{amb}}\right) - \frac{\mathsf{a}_2}{\mathcal{I}}\left(T - T_{\text{amb}}\right)^2 \tag{2.3b}$$

All the other production or conversion energy devices are completely controllable. Among devices delivering a single type of energy, only the GB and the AbCh are missing. The corresponding description is, for the boiler [69, 70]:

$$\mathcal{P}_{\text{th,GB}} = \eta_{\text{GB}} \cdot \mathsf{q}_{\text{fu}} \cdot \text{LHV} \tag{2.4}$$

and for the chiller [71]:

$$\mathcal{P}_{\text{c,AbCh}} = \text{COP} \cdot \mathcal{P}_{\text{th}} \tag{2.5}$$

Finally, for cogeneration devices, one gets [70, 72]:

$$\mathcal{P}_{\text{th,CHP}} = \eta_{\text{th,GB}} \cdot \mathsf{q}_{\text{fu}} \cdot \text{LHV} \tag{2.6a}$$

$$\mathcal{P}_{\text{el,CHP}} = \eta_{\text{el,GB}} \cdot \mathsf{q}_{\text{fu}} \cdot \text{LHV} \tag{2.6b}$$

and for the reversible HP, it is [20]:

$$\mathcal{P}_{\text{th,HP}} = \text{COP}_{\text{htg}} \cdot \mathcal{P}_{\text{el}} \tag{2.7a}$$

$$\mathcal{P}_{\text{c,HP}} = \text{COP}_{\text{c}} \cdot \mathcal{P}_{\text{el}} \tag{2.7b}$$

2.2.2 Energy storage

For storage, the energy balance is done on an hourly basis, taking into account an energy loss factor. Whatever the type of energy stored (heat or electricity), the evolution of the available energy is [73]:

$$E_{\mathrm{stor},i}^{\mathrm{h}+1} = LF_i \cdot E_{\mathrm{stor},i}^{\mathrm{h}} + \left(\mathcal{P}_i^{\mathrm{ch}} - \mathcal{P}_i^{\mathrm{dis}}\right)\Delta t \qquad \text{for } i = \mathrm{el}, \mathrm{th} \tag{2.8}$$

In the case of BEES, the loss coefficient corresponds to the self-discharge value [74]. Besides the hourly energy losses, the round trip efficiency η_{rt} is also considered. Lastly, the number of cycles must be lower or equal to the cycle life of the battery:

$$N_{¢} \leq N_{¢,\mathrm{failure}} \tag{2.9}$$

On the other hand, for both TSH and TSC, sensible water tanks are considered since their heat losses are often lower [75, 76] and, more important, because their technology readiness level is higher.

2.2.3 Energies demand

As explained before, consumption profiles are divided between heat (space heating and DHW – $E_{\mathrm{th,dw}} = E_{\mathrm{htg}} + E_{\mathrm{DHW}}$ –), cooling and electricity. In the first case, heating and cooling needs are calculated with a classic $\mathscr{R} - \mathscr{C}$ model, or an average volumetric or total heat loss coefficient model [77–81]:

$$\mathcal{P}_{\mathrm{htg,c}} = \mathcal{G} \cdot V \cdot (T_{\mathrm{sp}} - T_{\mathrm{out}}) \tag{2.10a}$$

$$\mathcal{P}_{\mathrm{htg,c}} = \frac{\mathscr{C}}{\Delta t} \cdot \left(T_{\mathrm{sp}} - T_{\mathrm{out}} - (T_{\mathrm{in}} - T_{\mathrm{out}})\, e^{-\frac{\Delta t}{\tau}}\right) \tag{2.10b}$$

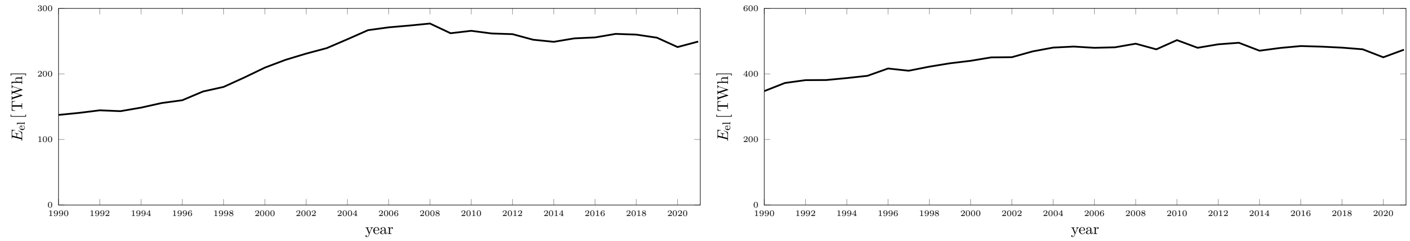
Outdoor temperatures are taken from [82] and are thus different for Marseille and Zaragoza. $\mathscr{C}$ is set to 0.3 kWhK^{-1}. For space heating, temperatures set points are taken equal to 20 and 21°C for Marseille and Zaragoza respectively. For cooling, they are equal to 26 and 25°C.
For the DHW demand, it is based on a wanted volume of hot water at 40°C, varying monthly over the year. Initial temperature of the water supplied to the tank is variable and taken from [83]. For an average temperature in the tank of 60°C, the DHW demand reads:

$$E_{\mathrm{DHW}} = \rho_{\mathrm{wat}} V_{\mathrm{h}} \cdot c_{\mathrm{wat}} \cdot (60 - T_{\mathrm{pip}}) \tag{2.11a}$$

$$V_{\mathrm{h}} = V_{\mathrm{DHW}}^{\mathrm{m}} \frac{40 - T_{\mathrm{pip}}}{60 - T_{\mathrm{pip}}} \tag{2.11b}$$

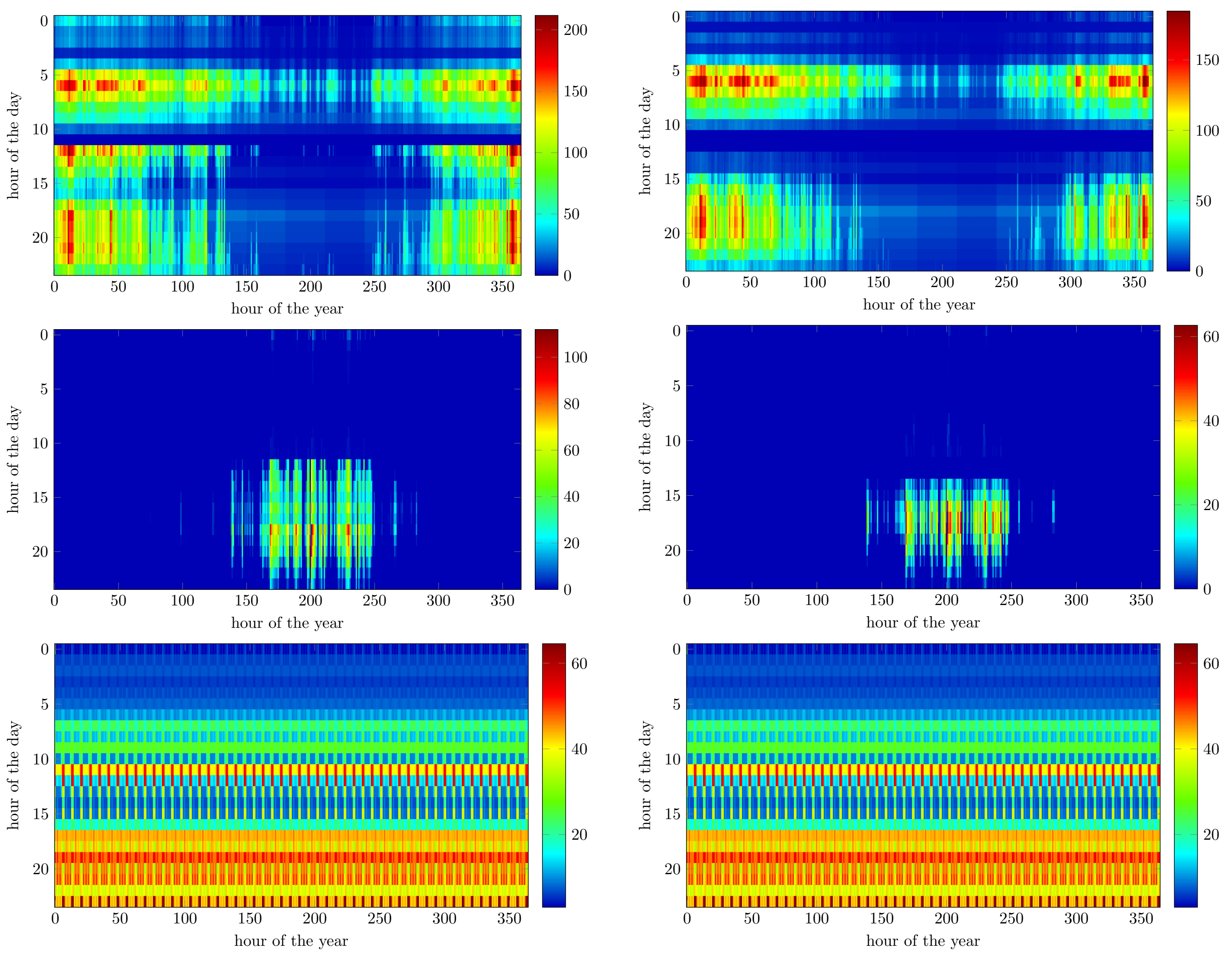
Finally, the electrical consumption is composed of a typical consumption week, with important variations between weekdays and week-ends, and also with differences between Marseille and Zaragoza. It is based on a profile corresponding to a single household electrical consumption, obtained with the CREST model [84, 85]. A gaussian noise is then applied to each of the 50 households, to represent variations in user behaviors. Each profile is used as a single representative year used as a reference for the whole optimization process. This choice is motivated by two reasons: i) future day-to-day variations are nearly impossible to foresee, ii) the aggregated electricity consumption is relatively stable, as observable in Fig. 5 for the last 15 years.

Eventually, the complete annual energy profiles are provided in Fig. 6. In addition, Fig. 7 presents the consumption of the day where the peak consumption occurs for heating, cooling and electricity. These peaks are reached in December for heating and July for cooling. As electricity consumption consists in a typical consumption week, the consumption peak occurs the week-end. Lastly, the annual corresponding aggregated consumptions are gathered in Table 1.



(a) Spain (b) France

Figure 5: Electricity consumption over the years according to IEA database [86]



(a) Spain (b) France

Figure 6: Annual hourly energy profiles (in kW) for heating (above), cooling (middle) and electricity (below) demand

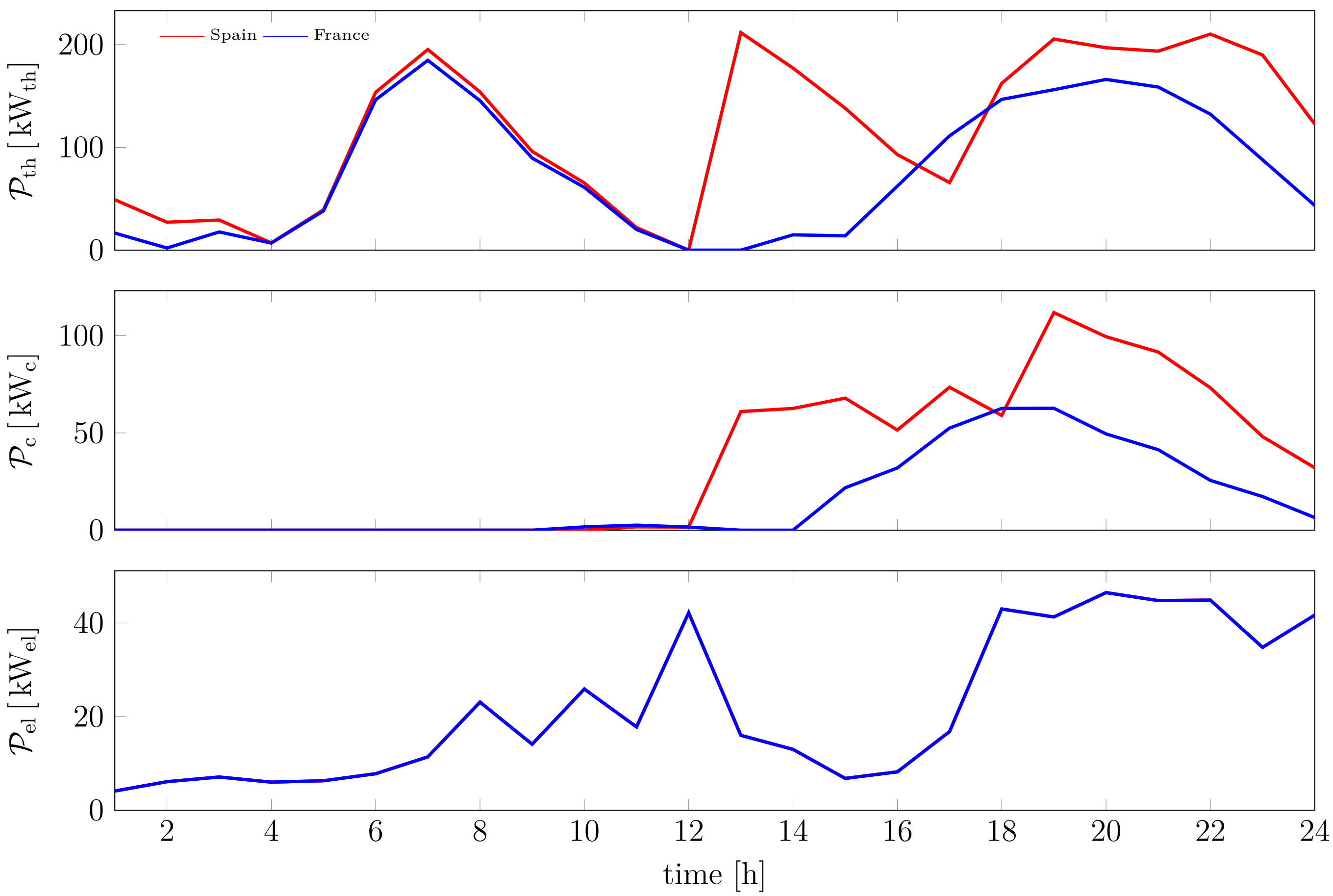


Figure 7: Daily energy demand profiles at peak, for each energy type

Table 1: Annual energy demands in kWh/year

Location	Dwellings	Heating	Cooling	Electricity
Zaragoza	50	335 412	26 132	206 804
Marseille		234 300	11 014	206 755

2.2.4 Representative days

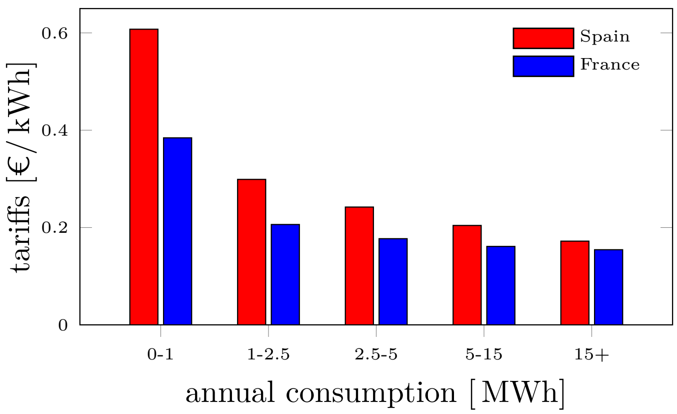
Usually, when several time series and binary variables are involved, optimization is computationally expensive. Therefore, representative days have been widely used to tackle this issue [87, 88]. Since this work considers up to seven time series, some having high variability such as WT production and hourly $CO_{2\,eq}$ emissions from the grid (especially in Spain), the kM-OPT method [89] was applied. This method merged two methods, the k-Medoids method developed by Domínguez-Muñoz et al. [90] which aims to group the days of the year into clusters; and the OPT method developed by Poncelet et al. [91] which fits the data duration curve obtained from representative periods to the duration curve of the original time series.

Thus, a set of 12 representative days D_{rep} can be built, where each representative day consists of a set H of 24 time periods h of 1 hour, with a daily respective weight ω for each location. The corresponding values are available in Table 5 and are discusses in section 3.2.

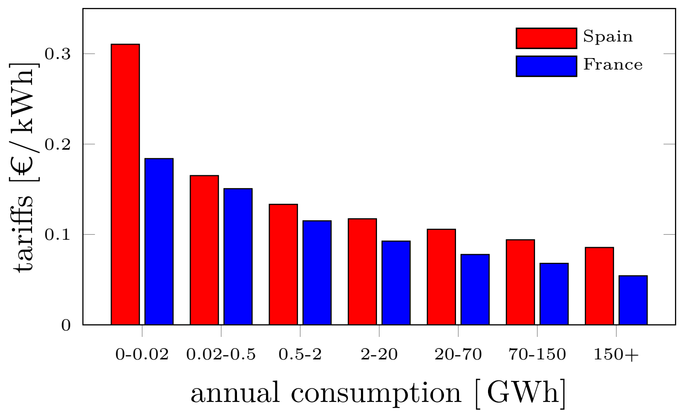
2.3 Economic model

2.3.1 Gross and retail energy prices

The electricity and fuel prices depend on the total annual consumption: the higher the consumption, the lower the price. Consequently, it is logical to set different available prices for the customers and for the aggregator. Figs. 8a and 8b present the average price for the last 2 years for electricity tariffs for households and non-households respectively. Figs. 9a and 9b present the same average prices for the last 2 years for natural gas. In this sense, for the customers, the reference system is based on household tariffs, whereas the aggregator can buy at non-household prices. For electricity, in the 20-500 MWh/year range, the tariff is 0.1477 €/ kWh for France and 0.1582 €/ kWh for Spain. For natural gas, consumption below 288 MWh/year is expected in France, corresponding so to a tariff of 0.0622 €/ kWh, whereas, for Spain, the expected consumption is about 0.28-2.8 GWh/year, for a tariff of 0.045 €/ kWh. These are the average values for 2018 [92].

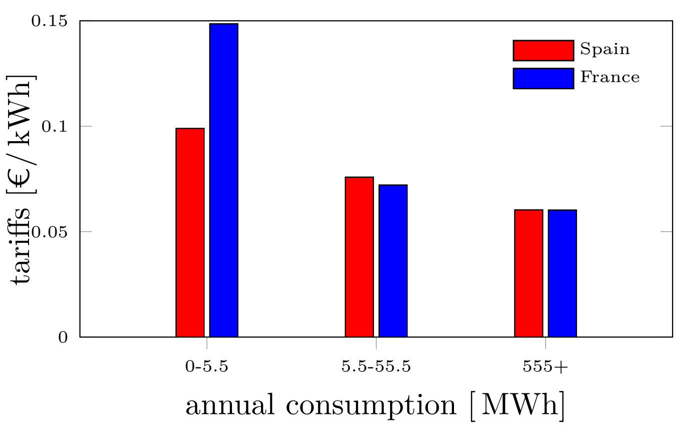


(a) Households

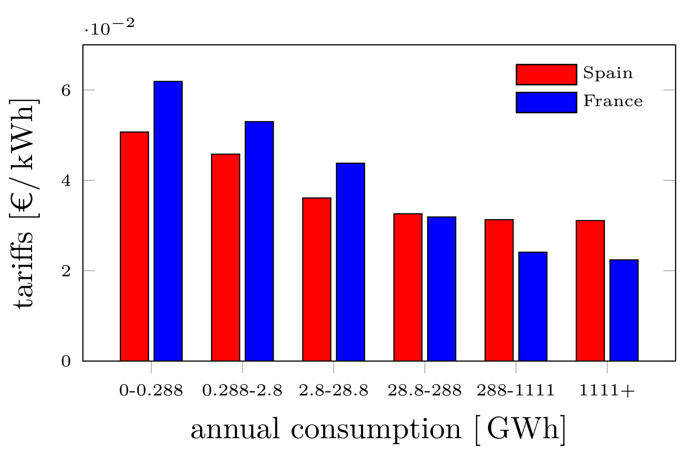


(b) Non-households

Figure 8: Electricity prices [92]



(a) Households

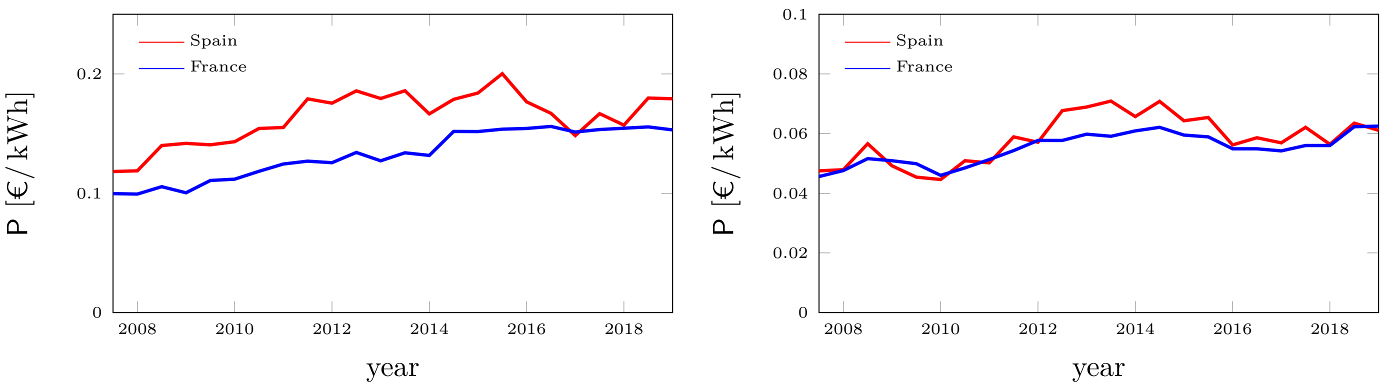


(b) Non-households

Figure 9: Natural gas prices [92]

2.3.2 Energy prices evolution

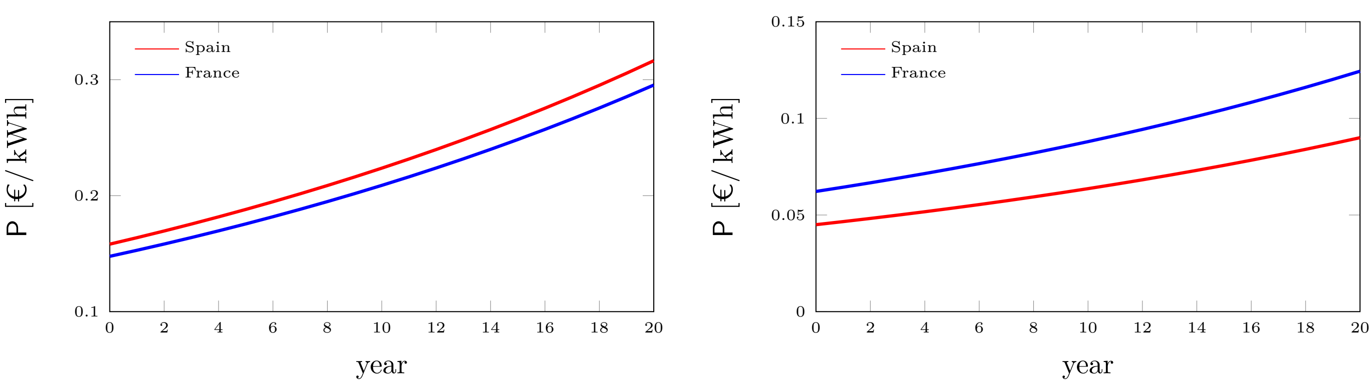
Electricity and natural gas prices have a high variability and tend to increase. From 2007 to 2019 (12 years), electricity and natural gas prices in France and Spain have increased about 50% and 40% respectively (see Figs. 10a and 10b) according to the Eurostat survey tool from the European Commission [92]. Therefore, in a horizon of 20 years (2038), it is expected that electricity and natural gas prices can double or even triple, and hence, also the price of final energy (electricity, heating and cooling).



(a) Electricity (b) Natural gas

Figure 10: Energy prices from 2007 to 2019 for households [92]

As a consequence, in an horizon of 20 years, the hypothesis is that electricity and natural gas prices double following an exponential function $\mathsf{P}^i = \mathsf{P}_0(2^{1/20})^i$ (roughly +3.5% per year), where P^i is the unit price of each energy vector at year i. The final prices applied during the present simulations are represented on Fig. 11.



(a) Electricity (b) Natural gas

Figure 11: Retained projections for the energy prices evolution

2.3.3 Net present value

Among the investment assessment metrics, it is very common for operators in financial analysis to rely on the net present value (NPV) criterion [52] as well as the payback period (PP). The first one is indeed a good indicator of the measurement of the balance between discounted benefits and costs, for the whole lifetime of the project. Such method allows to estimate if a quantity of money earned immediately has more value than 10 years later. The second one permits, *ceteris paribus*, to favor projects allowing a faster return of the invested money.

Concretelly, a discount rate r is applied to all cash flows. It is proportional to the year corresponding to the net cash flows, after balancing the input and output flows.
In practice, one gets:

$$\mathsf{NPV} = -\mathsf{CAPEX} + \sum_{i=1}^{\mathsf{LT}} \frac{\mathsf{CF}_i}{(1+\mathsf{r})^i} \tag{2.12a}$$

$$\mathsf{CAPEX} = \sum_{\text{set of technologies } j \in J} \Big(\mathsf{C}_j \ (1 + Fm_j)\Big) \cdot \mathrm{CAP}_j \cdot (1 + \mathsf{VAT}) \tag{2.12b}$$

$$\mathsf{CF}_i = \mathsf{R}_i - \mathsf{OPEX}_i - \mathsf{IT}_i \tag{2.12c}$$

Revenue comes from the sales of the various types of energy (heating, electricity, cooling) to the customer and, for case B and C, to the electricity fed to the grid:

$$\mathsf{R}_i = \sum_{\text{consumers}} \mathsf{P}_{E_{\text{el,dw},i}} E_{\text{el,dw},i} + \mathsf{P}_{E_{\text{th,dw},i}} E_{\text{th,dw},i} + \mathsf{P}_{E_{\text{c,dw},i}} E_{\text{c,dw},i} \underbrace{+ \Big(\mathsf{P}_{E_{\text{el,sld},i}} E_{\text{el,sld},i}\Big)}_{\text{case C only}} \tag{2.13}$$

Usually, the operational expenditures express as:

$$\mathsf{OPEX}_i = \mathsf{MCR}_i + \sum_{\text{set of technologies } j \in J} \mathsf{O\&M}_{j,i} \tag{2.14}$$

but in the present case, the second term only contains the operational costs consisting in the purchase of electricity ($E_{\text{el,pur}}$, at unit price $\mathsf{C}_{E_{\text{el,pur}}}$) and of natural gas ($E_{\text{g,pur}}$, at unit price $\mathsf{C}_{E_{\text{g,pur}}}$), since the maintenance costs are considered within the installation factor Fm in Eq. 2.12b.
Accordingly, Eq. 2.14 can be re-written:

$$\mathsf{MCR}_i = \begin{cases} \sum_{j \in J} \frac{\mathsf{CAPEX}_j}{(1+\mathsf{r})^i} & \text{if } i < \mathsf{LT}_j \\ 0 & \text{otherwise} \end{cases} \tag{2.15a}$$

$$\sum_{j \in J} \mathsf{O\&M}_{j,i} = \mathsf{C}_{E_{\text{el,pur},i}} E_{\text{el,pur},i} + \mathsf{C}_{E_{\text{g,pur},i}} E_{\text{g,pur},i} \tag{2.15b}$$

Finally, the income tax is:

$$\mathsf{IT}_i = \mathsf{TI}_i \times \mathsf{Tr} \tag{2.16a}$$

$$\mathsf{TI}_i = \mathsf{R}_i - \mathsf{OPEX}_i - \mathsf{Dep}_i \tag{2.16b}$$

$$\mathsf{Dep}_i = \frac{\mathsf{CAPEX} - \mathsf{RV}}{\mathsf{LT}} \tag{2.16c}$$

For the sake of clarity, the sum of the discounted cash flow appearing in Eq. 2.12a can be divided into three parts: revenues, operational expenditures an income taxes. Thus, the first term will express for the three cases considered here:

$$\text{case A:} \quad \sum_{i=1}^{\mathsf{LT}} \frac{\mathsf{R}_i}{(1+\mathsf{r})^i} = \aleph \sum_{i=1}^{\mathsf{LT}} \frac{1}{(1+\mathsf{r})^i} \tag{2.17a}$$

$$\text{case B:} \quad \sum_{i=1}^{\mathsf{LT}} \frac{\mathsf{R}_i}{(1+\mathsf{r})^i} = \aleph \sum_{i=1}^{\mathsf{LT}} \frac{(2^{1/20})^i}{(1+\mathsf{r})^i} \tag{2.17b}$$

$$\text{case C:} \quad \sum_{i=1}^{\mathsf{LT}} \frac{\mathsf{R}_i}{(1+\mathsf{r})^i} = \Big(\mathsf{P}_{E_{\text{el,sld},0}} E_{\text{el,sld},0} + \aleph\Big) \sum_{i=1}^{\mathsf{LT}} \frac{(2^{1/20})^i}{(1+\mathsf{r})^i} \tag{2.17c}$$

$$\text{with} \quad \aleph = \sum_{\text{consumers}} \mathsf{P}_{E_{\text{el,dw},0}} E_{\text{el,dw},0} + \mathsf{P}_{E_{\text{th,dw},0}} E_{\text{th,dw},0} + \mathsf{P}_{E_{\text{c,dw},0}} E_{\text{c,dw},0} \tag{2.17d}$$

Similarly, the second term reads (for all cases):

$$\sum_{i=1}^{\mathsf{LT}} \frac{\mathsf{OPEX}_i}{(1+\mathsf{r})^i} = \sum_{i=1}^{\mathsf{LT}} \frac{\mathsf{MCR}_i}{(1+\mathsf{r})^i} + \left(\mathsf{C}_{E_{\text{el,pur},0}} E_{\text{el,pur},0} + \mathsf{C}_{E_{\text{g,pur},0}} E_{\text{g,pur},0}\right) \sum_{i=1}^{\mathsf{LT}} \frac{\left(2^{1/20}\right)^i}{(1+\mathsf{r})^i} \tag{2.18}$$

And, eventually, the term associated with the income tax is straightforward, giving Eq. 2.16 and Eqs. 2.17 and 2.18.

Concretely, a 20 years lifetime is considered. A 5% value for the nominal discount rate is common [26,93] and so adopted here; this leads to real discount rate of 3.4%. Finally, the tax rates Tr for the incomes of the aggregator is set to 25%, while the VAT is 21% for Spain and 20% for France. Lastly, the residual value is assumed null at the end of the project.

2.4 Optimization model

In the present work, the objective function is to maximize the NPV [48,94], and the PP is also investigated to ensure a (preferably) faster solution:

$$\max\ \mathsf{NPV} = \max\left(-\mathsf{CAPEX} + \sum_{i=1}^{\mathsf{LT}} \mathsf{DCF}_i\right) \tag{2.19}$$

the capital expenditures being given by Eq. 2.12b and the discounted cash flows by Eqs. 2.17 and 2.18. The associated choice variables and constraint conditions are:

- Installation of technologies: The installation of the components is determined by the binary variable Y_{ins} considering the maximum capacity of each component:

$$\text{CAP}(j) \leq Y_{ins}(j) \cdot \max\ \text{CAP}(j) \qquad \forall j \in J \tag{2.20}$$

- Energy balance: It is carried out in each node of the superstructure for every day d and hour h. For the generic variable E, representing any type of energy (electricity E_{el}, heating E_{th} or cooling E_{c}), one gets for each time step between the inputs and outputs:

$$\sum E^{in}(\text{d},\text{h}) = \sum E^{out}(\text{d},\text{h}) \qquad \forall\ E_{\in}\{E_{\text{el}}, E_{\text{th}}, E_{\text{c}}\},\ \text{d} \in D_{rep},\ \text{h} \in H \tag{2.21}$$

- Energy storage: The stored energy at the beginning of the day (h = 1) must be equal at the end of the day (h = 24) due to the use of representative days:

$$E_{\text{stor}}(\text{d},1) = E_{\text{stor}}(\text{d},24) \tag{2.22}$$

- Installed capacity limitations: The total energy production is mandatory equal or lower than the installed nominal capacity:

$$E(\text{d},\text{h}) \leq \text{CAP}(j) \qquad \forall\ E_{\in}\{E_{\text{el}}, E_{\text{th}}, E_{\text{c}}\},\ j \in J, \text{d} \in D_{rep},\ \text{h} \in H \tag{2.23}$$

  In the case of the electric grid, the contracted power $\mathcal{P}_{\text{K}}$ is set according to the purchased or sold electricity:

$$\mathcal{P}_{\text{K}} \geq E_{\text{el,pur}}(\text{d},\text{h}) + E_{\text{el,sld}}(\text{d},\text{h}) \qquad \forall\ \text{d} \in D_{rep}\ \text{h} \in H \tag{2.24}$$

- Operational restrictions: Partial load PL of the cogeneration module is considered by applying a binary variable Y_{ON} along with the Ψ number. This last one is used to model, for instance, specific piecewise-defined functions; its value being dependent on the type of problem [95].
  Thus, the engine can be operated such that it works with linear performance only above the minimum PL, and below the engine is off. In this way, the engine can modulate according to:

$$\mathcal{P}_{\text{CHP}} - PL \cdot \text{CAP}_{\text{CHP}} \geq -\Psi \cdot (1 - Y_{ON}) \tag{2.25a}$$

$$\mathcal{P}_{\text{CHP}} \leq \Psi \cdot Y_{ON} \tag{2.25b}$$

  Here, a value of 10^6 has been set for Ψ.

- RES: For the renewable production, the aim is to find the surface areas of the PV modules A_{PV} and ST collectors A_{ST}, and the number N_{WT} of WT.

Finally, the optimization of the polygeneration system is carried out by solving a MILP model developed in the optimizer software `Lingo` [96]. During the calculations, the CO_2 emissions are also computed. They correspond to emissions of burnt fuel and to the electricity mix of the grid:

$$\text{CO}_{2\,\text{eq}} = \sum_{d=1}^{12} \omega(d) \left(\sum_{\text{h}=1}^{24} \text{CO}_{2,\,\text{fu}}(\text{d},\text{h}) + \text{CO}_{2,\,\text{gd}}(\text{d},\text{h}) \right) \tag{2.26a}$$

$$\text{CO}_{2,\,\text{fu}}(\text{d},\text{h}) = \sum_{j \in J} \text{CO}_2(j) \cdot \mathsf{q}_{\text{fu}}(j,\text{d},\text{h}) \qquad \forall\ \text{d} \in D_{rep},\ \text{h} \in H \tag{2.26b}$$

$$\text{CO}_{2,\,\text{gd}}(\text{d},h) = \text{CO}_{2\,\text{gd}}(\text{d},\text{h}) \cdot (E_{\text{pur}}(\text{d},\text{h}) - E_{\text{sld}}(\text{d},\text{h})) \qquad \forall\ \text{d} \in D_{rep},\ \text{h} \in H \tag{2.26c}$$

Therefore, the outputs of the optimization are the presence (or absence) of each component together with its sizing (or installed capacity), the primary energy consumption, the CO_2 emissions and obviously the value of the maximized NPV.

3 Case studied

3.1 Reference case

In order to establish unambiguously the boons of the present configuration, where customers contract with an aggregator, which owns poly-generation systems and storage, a reference system has been defined (see Fig. 12). Considering the current situations in Spain and France, in this reference system, each dwelling has a GB with an efficiency of 96% to cover the heating demand and a mechanical chiller (Mch) with a COP_c of 4.0 for the cooling demand. In turn, each dwelling has an individual contract with the electricity and natural gas companies (at household tariffs). The annual electricity and natural gas consumption per dwelling for Zaragoza and Marseille are presented in Table 2.

Table 2: Annual electricity and natural gas consumption in kWh/year per dwelling-Reference system.

Location	**Electricity**	**Natural gas**
Zaragoza	4 268	6 988
Marseille	4 192	4 881

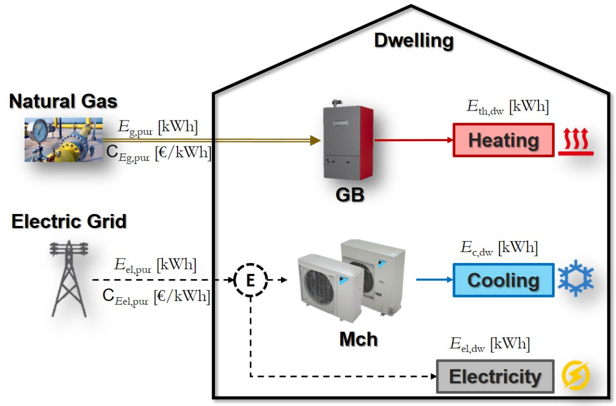


Figure 12: Conventional reference energy system for a dwelling.

The operational unit price of each energy service can be calculated with the efficiency of the GB and the $\mathrm{COP_c}$ of the Mch, based on the 2018 tariffs. For Zaragoza, electricity consumption is below 5 000 kWh/year and natural gas consumption is below 50 000 kWh/year. For Marseille, electricity and natural gas consumption are both below 5 000 kWh/year.
For each case was considered a fixed cost proportional to $\mathcal{P}_{\mathrm{K}}$, around 10 and 30 €/ kW for France and Spain respectively. In the reference case, based on the energy demand profiles depicted in Fig. 7, the expected contracted power $\mathcal{P}_{\mathrm{K}}$ from the electric grid, for a residential building composed of 50 dwellings, is of 93 kW in Zaragoza and 80 kW in Marseille. For a dwelling in Zaragoza, it is around 1.85 kW and for Marseille around 1.6 kW; as a reminder, large consumption, such as heating, do not rely on electrical appliances, which explains these rather low values.
For both countries, additional fees for electricity and natural gas costs must also be applied as subscription fees. For natural gas, it is about 110 €/year, added to the heating bill. For electricity, it is about 120 €/year, added to the electricity and cooling bills, proportional to their annual consumption. The individual bills per dwelling are so multiplied by 50 in order to have a reference value. To this end, only operational costs have been considered.

3.2 Simulation plan

First, in Table 6 are presented all the technical, economic and environmental data of the different technologies. The investment costs are calculated based on the unit cost, and considering the installation costs, by applying a factor Fm for each technology (see above). The maintenance costs are within the offset of the average installation costs considered since, for most of the equipments (PV, WT, etc.), they are only about 1% of the installation costs [97]. Replacements costs are also integrated.
Secondly, the characteristics of the three cases evaluated, summarized in Table 3, are:

- Case A: Selling the energy services to the customer at 95% of the reference price, remaining constant for 20 years. Electricity sale to the grid is not allowed.
- Case B: Selling the energy services to the customer at 70% of the reference price at the starting point (2018), and increasing these prices in the same way of the electricity and natural gas (exponentially at $a_0(2^{1/20})^i$). Electricity sale to the grid is not allowed.
- Case C: Selling the energy service to the customer at 70% of the reference price at the starting point (2018), and increasing these prices in the same way of the electricity and natural gas (exponentially at $a_0(2^{1/20})^i$). Electricity sale to the grid is allowed at 0.05 €/ kWh.

Table 4 shows the unit cost of electricity and natural gas for households, as well as the unit price for electricity, heating and cooling.
Finally, the set of 12 representative days D_{rep} is shown in Table 5. Two additional days corresponding to cooling and heating peak demands are considered with weight zero, having influence in the sizing equipment but not on the operational cost.

Table 3: Summary of the three different test cases

Case	**Pricing**	**Selling electricity**
A	95% of initial reference price, without increase	No
B	70% of reference price, increase throughout the years	No
C	70% of reference price, increase throughout the years	Yes

Table 4: Tariffs and unit price services for 1 dwelling reference system 2018.

Location	**Customers** $\mathsf{P}_{E_{\mathrm{el,dw,0}}}$ [€/ kWh]	$\mathsf{P}_{E_{\mathrm{th,dw,0}}}$ [€/ kWh$_{\mathrm{th}}$]	$\mathsf{P}_{E_{\mathrm{c,dw,0}}}$ [€/ kWh$_{\mathrm{c}}$]
Zaragoza	0.2430	0.0802	0.0608
Marseille	0.1774	0.1558	0.0443

Table 5: Set of representative days

Location	**Month**	**day (d)**	**weight (ω)**	**Month**	**day (d)**	**weight (ω)**	**Month**	**day (d)**	**weight (ω)**
Zaragoza	February	37	34	May	132	37	August	228	39
	February	50	23	May	136	23	September	245	28
	April	112	19	May	146	27	September	256	38
	April	115	35	July	208	18	December	339	44
Marseille	January	24	22	June	165	44	September	256	33
	January	29	28	June	168	29	November	310	44
	February	44	13	July	193	37	November	319	50
	May	143	24	August	220	22	December	352	19

Table 6: Technical, economic and environmental data

Component	Technical data (Tech)	Economic data (Econ) C	Fm	N_{comp}	Environmental data (Env) CO_2 emissions $[\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\star]$	References Tech	Econ	Env
CM	$\eta_{\mathrm{el}} = 28\%$; $\eta_{\mathrm{th}} = 56\%$; $PL = 15\%$	1 150 €/ $\mathrm{kW_{el}}$	0.7	10	65 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kW_{el}}$	[98]	[99]	[100]
PV (polycrystalline)	255 $\mathrm{W_{pk}}$; $\eta_{\mathrm{pan}} = 15.66\%$; $\kappa = 0.0032\,\mathrm{K^{-1}}$	113.4 €/$\mathrm{m^2}$	0.9	20	161 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{m^2}$	[101]	[102]	[103,104]
WT	30 kW	2 330 €/ kW	0.9	20	720 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kW}$	[105]	[106]	[107,108]
ST	$\mathtt{a}_0 = 81\%$; $\mathtt{a}_1 = 3.188\,\mathrm{W\,m^{-2}\,K^{-1}}$; $\mathtt{a}_2 = 0.011\,\mathrm{W\,m^{-2}\,K^{-2}}$	257 €/$\mathrm{m^2}$	1.5	20	95 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{m^2}$	[109,110]		[111]
GB	$\eta_{\mathrm{GB}} = 96\%$	80 €/ $\mathrm{kW_{th}}$	0.5	20	10 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kW_{th}}$	[112]		
HP	$\mathrm{COP_{htg}} = 3.0$; $\mathrm{COP_c} = 4.0$	400 €/ $\mathrm{kW_{th}}$	0.5	20	160 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kW_{th}}$	[113,114]		[100]
AbCh	$\mathrm{COP_c} = 0.7$	485 €/ $\mathrm{kW_{th}}$	1.5	20	165 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kW_{th}}$	[115]		
TSC	$LF = 0.5\%\mathrm{h^{-1}}$	257 €/ $\mathrm{kWh_{th}}$	0.1	15	62 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kWh_{th}}$	[112,113]		[116–118]
TSH	$LF = 0.2\%\mathrm{h^{-1}}$	212 €/ $\mathrm{kWh_{th}}$			31 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kWh_{th}}$			
BEES(lithium-ion)	$\eta = 95\%$; DOD = 90%; $N_{\not{c},\mathrm{failure}} = 2000$; $LF = 0.0042\%\mathrm{h^{-1}}$	370 €/ kWh	0.25	12	160 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kWh_{el}}$	[119,120]		[121]
Inv	$\eta = 98\%$	400 €/ kW	0	15	191 $\mathrm{kg}_{CO_{2\,\mathrm{eq}}}/\mathrm{kW}$	[122,123]		[103,104]
InvC	$\eta = 94\%$	774 €/ kW	0.25					

4 Results

The optimization model has 56 456 constraints and 45 394 variables of which 2 689 are integers. As mentioned previously, the corresponding MILP formulation is solved with `Lingo` [96]. The runtime varies from 1 minute up to 3 hours, case C being the longest. All runs were performed on an Intel Core i5-6200 CPU @ 2.3 GHz, with a memory of 8 GB and 64-bit system.

Table 7 and Fig. 13 show the results of the optimization for the installed capacity for each appliances and cases; Tables 8 and 9 gather the corresponding investment costs and electricity and natural gas consumption. Moreover, the final bills for the customers, for the reference case as well as the three test cases, are provided in Table 10. The summarized values of the economic indicators are presented in Table 11. Eventually, Table 12 presents the annual $CO_{2\,eq}$ emissions per dwelling.

Table 7: Results in terms of capacity (kW for generation units, kWh for storage units) of the optimization of the polygeneration system

Technology	**Case A**		**Case B**		**Case C**	
	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille
$\mathcal{P}_K$	48.8	67.2	48.8	67.2	49.7	67.7
CM	22	4.5	22	4.5	20.2	4.1
PV	29	20.8	29	20.8	49.4	43.1
Inv	35	25	35	25	59.2	51.7
HP	111	69.7	111	69.7	110.6	69.7
GB	82	96.6	82	96.6	87.4	98.8
TSC	13	0	13	0	12.5	0
TSH	24	9.5	24	9.5	23.7	8.1

Table 8: Results in terms of investment (€) of the optimization of the polygeneration system

Technology	**Case A**		**Case B**		**Case C**	
	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille
$\mathcal{P}_K$	1 463	672	1 463	672	1 491	677
CM	51 502	10 527	51 502	10 527	47 806	9 514
PV	48 497	34 550	48 497	34 550	82 476	71 467
Inv	16 854	12 007	16 584	12 007	28 663	24 837
HP	80 271	50 151	80 271	50 151	80 271	50 151
GB	11 907	13 906	11 907	13 906	12 689	14 231
TSC	4 265	0	4 265	0	4 265	0
TSH	6 846	2 661	6 846	2 661	6 695	2 270

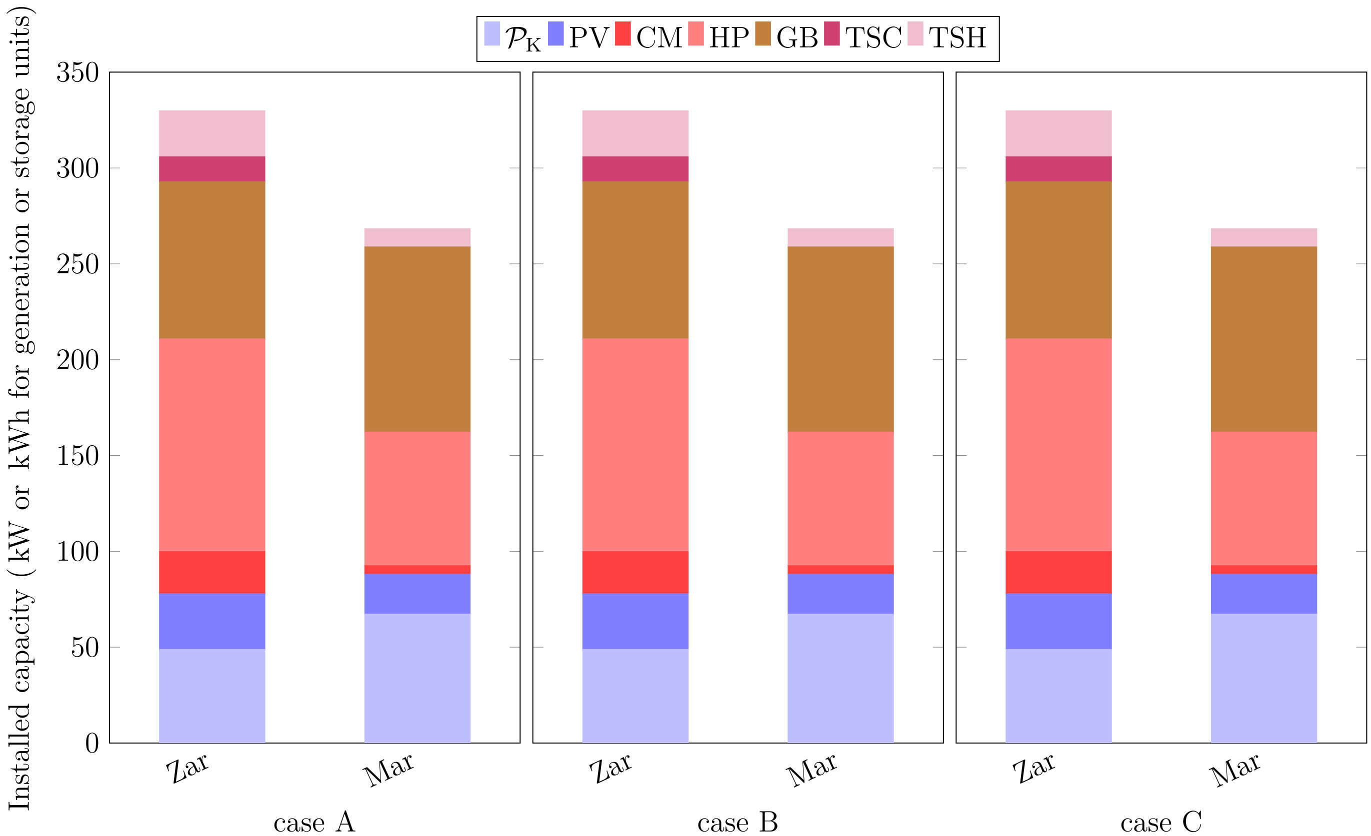


Figure 13: Installed capacity of each technologies for the optimized solution of each test case

Table 9: Annual energy flows in MWh/year

Commodity	**Reference**		**Case A**		**Case B**		**Case C**	
	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille
Electricity Purchased	213	210	94	193	94	193	83	178
Electricity Sold	N/A	N/A	N/A	N/A	N/A	N/A	16	21
Natural gas	349	244	418	143	418	143	396	132

Table 10: Total individual customer bills in $k€$

Service	**Reference**		**Case A**		**Case B**		**Case C**	
	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille
Electricity	56.1	42.6	47.8	34.9	35.2	25.7	35.2	25.7
Heating	32.4	42.0	25.6	34.7	18.8	25.6	18.8	25.6
Cooling	1.8	0.6	1.5	0.5	1.1	0.3	1.1	0.3
Total bills	90.3	85.2	74.8	70.0	55.1	51.6	55.1	51.6
NPV Total bills	1 819	1 717	1 068.3	999.5	1 111.4	1 039.8	1 111.4	1 039.8

Table 11: Economic results

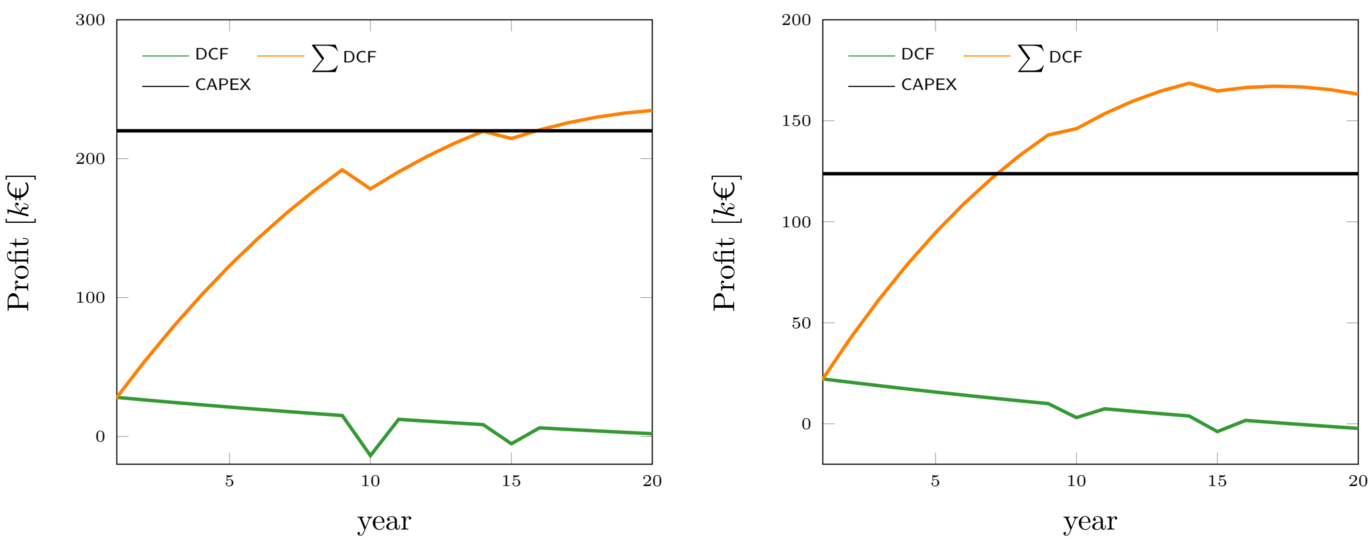
Indicator (k€)	**Case A**		**Case B**		**Case C**	
	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille
NPV	14.7	39.4	46.6	69.5	55.0	75.9
CAPEX	220.1	123.8	220.1	123.8	262.9	172.5
$\sum$ DCF	234.7	163.2	266.7	193.3	317.9	248.3
R	1 068.3	999.2	1 110.9	1039.5	1 127.2	1 060.3
OPEX	760.0	784.0	760.0	784.4	708.7	732.3
IT	73.6	52.1	84.2	62.1	100.6	79.6

Table 12: Annual $CO_{2\,\mathrm{eq}}$ emissions in $k_{CO_2}/year$

Source	**Reference**		**Case A**		Case B		**Case C**	
	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille	Zaragoza	Marseille
Electric grid	44 350	7 550	19 683	7 446	19 689	7 446	14 140	6 267
Natural gas	70 950	55 400	84 919	32 566	84 916	32 566	80 419	29 903
Equipment	0	0	3 382	2 218	3 382	2 218	4 888	3 872
Total	115 300	62 950	107 983	42 229	107 987	42 229	99 446	40 042

4.1 Case A

The optimal configuration is composed mainly of a heat pump and gas boiler, with some PV, and a cogeneration module coupled with hot thermal storage. For the specific case of Zaragoza, a small cold thermal storage is also selected. In both locations, the contracted power decreases by 48% and 16% in Zaragoza and Marseille respectively, with respect to the reference energy system. This is due to the support of technologies such as PV and CHP. Nonetheless, for Marseille, there is more dependency on the electric grid, the contracted power ($\mathcal{P}_{\mathrm{K}}$) being higher (+37%). As a result, the capacity of technologies such as CHP and PV are lower in Marseille (-80% and -28%): this is because electricity is cheaper in France. The reversible HP capacity in Zaragoza is almost the double of Marseille (111 and 69.7 kW). This explains also the absence of TSC in Marseille.
Concerning energy bought to the electric grid, it decreases by 56% by comparison with the reference system in Zaragoza. In contrast, gas consumption increases there by 20%. For Marseille, electricity and natural gas consumption decrease by 8% and 41% respectively. These results are in accordance with the higher heating demand, along with the lower natural gas price in Zaragoza with respect to Marseille, and also to the difference in installed capacity of CM.
According to the economic results in Table 11, the aggregator business model is clearly more profitable in Marseille than in Zaragoza, yet for average similar savings for the customer around 41% and 42% along the project. This entails first that a real win-win relation is achievable, i.e., that both parts can benefit from this configuration. Secondly, in terms of investment effectiveness, the economic projection of the profitability depicted in Fig. 14 underlines that payback period is drastically different: it is of 16 and 7 years for Zaragoza and Marseille respectively. This logically coincides with the important differences in the NPV visible in Table 11.
As a last remark, it is worth mentioning that a positive NPV is obtained, in spite of a progressive decrease of the yearly discounted cash flow. In other words, case A can be beneficial however the aggregator will have to accept that its revenue will be less attractive in the future (due to the constant prices guaranteed to the customers, while its energy costs are increasing when relying on the external grids).



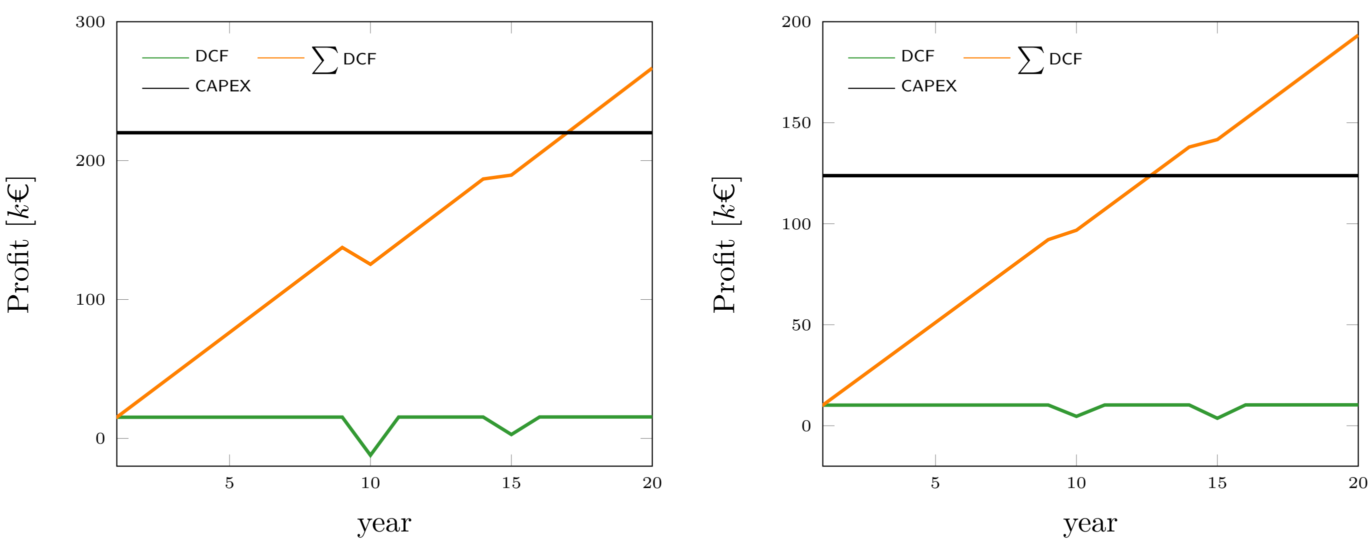
(a) Zaragoza (b) Marseille

Figure 14: Economic projection of the profitability in case A

Regarding the environmental impact, Table 12 shows the $CO_{2\,eq}$ emissions per year due to the investment and operation of the energy system. According to the results, 77% is due to combustion, 18% to the electric grid and only 5% is coming from the $CO_{2\,eq}$ emissions embodied in the equipment in France. In turn, for Spain, 79% is due to the combustion, 18% to the electric grid and only 3% arises from the $CO_{2\,eq}$ emissions of the equipment. Although both locations have similar values in terms of percentage, there is a remarkable difference in absolute terms (+157% for Zaragoza). On the other hand, when the total $CO_{2\,eq}$ emissions are compared to the reference system, they decrease about 6% and 33% for Zaragoza and Marseille. Therefore, the polygeneration system in this case has a higher impact in Marseille, in spite of the availability of nuclear energy which is already largely decarbonized.

4.2 Case B

The results of the optimal configuration and design are the same as the previous one (Tables 7 and 8) and the consumptions also, as shown in Table 9.
Nonetheless, as presented in Table 11, NPV is about three times the one obtained for Zaragoza and about twice the one obtained for Marseille with respect to the case A. Even with the same investment as in case A, the NPV are significantly higher: +76% in Marseille and 3 times more in Zaragoza. Furthermore, Marseille's aggregator is still the most profitable. In this case, the savings for the customer are about 39% with respect to the reference system for both locations along the project. This clearly demonstrated an interest for both parts: the customers and the aggregator.
However, in return of a lower initial energy price (70% instead of 95%), and though its revenue will be larger in the end, the aggregator has to accept a longer payback period: 17 and 13 years for Zaragoza and Marseille respectively (Fig. 15). Obviously, this could be reduced, without hampering the boons for the customer, either by using another initial price (for instance 80%) or by modifying the annual energy increase defined in section 2.3.2 or in Eq. 2.17b.



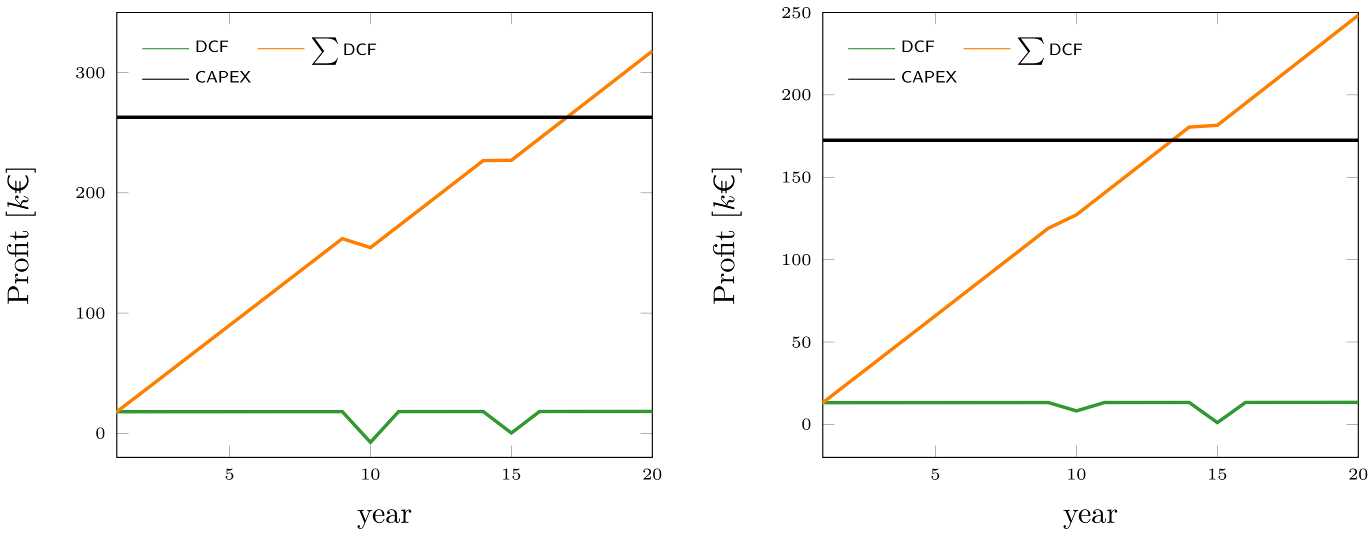
(a) Zaragoza (b) Marseille

Figure 15: Economic projection of the profitability in case B

4.3 Case C

Table 7 and Table 8 show respectively capacity and investment costs associated to this configuration. In this case the same components are selected but the optimal sizing is different. The most important

difference lies in the PV system which increases by 70% and 107% in Zaragoza and Marseille respectively. CM and GB capacity are stable: -7% in Zaragoza and -10% in Marseille for the former, and +7% in Zaragoza and +2% in Marseille for the latter.
Concerning energy consumption, purchased electricity and gas consumption decrease by 61% and 13% respectively compared to the reference system in Zaragoza, whereas, in Marseille, they decrease by 15% and 46% respectively (see Table 9). More electricity is sold to the grid in Marseille than in Zaragoza, though the irradiation is higher, due to a better self-consumption.
Regarding the economic results in Table 11, there are no differences with the previous case from the customers point of view. However, for the aggregator, its NPV now increases compared to case B (+18% and +9% in Zaragoza and Marseille respectively), which was already better than case A. Investment costs increase by 19% and 39% in Zaragoza and Marseille respectively, mainly because of the increase in PV capacity installed.
Regarding the economic projection of the investment, the payback period is now 17 and 14 years for Zaragoza and Marseille respectively (Fig. 16). These values come once again from the lower initial energy prices which delay the return on investment, but they are also due to a higher initial investment (+19.5% and + 39.3% for Zaragoza and Marseille). In other words, the PP is not singularly affected, compared to case B, even with these higher CAPEX. Therefore, this configuration is particularly interesting for the aggregator, as shown by the associated NPV. Finally, there is no noticeable effect for the customer, and it is still more beneficial than the reference situation.



(a) Zaragoza (b) Marseille

Figure 16: Economic projection of the profitability in case C

Looking now at the environmental impact, Table 12 shows the $CO_{2\,eq}$ emissions per year: in Spain, 81% is due to combustion, 14% to electric grid and 5% to equipment. In France, 74% is due to combustion, 16% to electric grid and 10% to the equipment. Thus, appliances have a higher impact on the total $CO_{2\,eq}$ emissions in Marseille (9.7%). Concerning the total CO_2 emissions, they decrease by 14% in Zaragoza whereas in Marseille they decrease by 36% compared to reference. In this case, electricity sale to the grid allows higher emissions reductions with more impact in Zaragoza than in Marseille.

5 Discussion

5.1 Classic approach

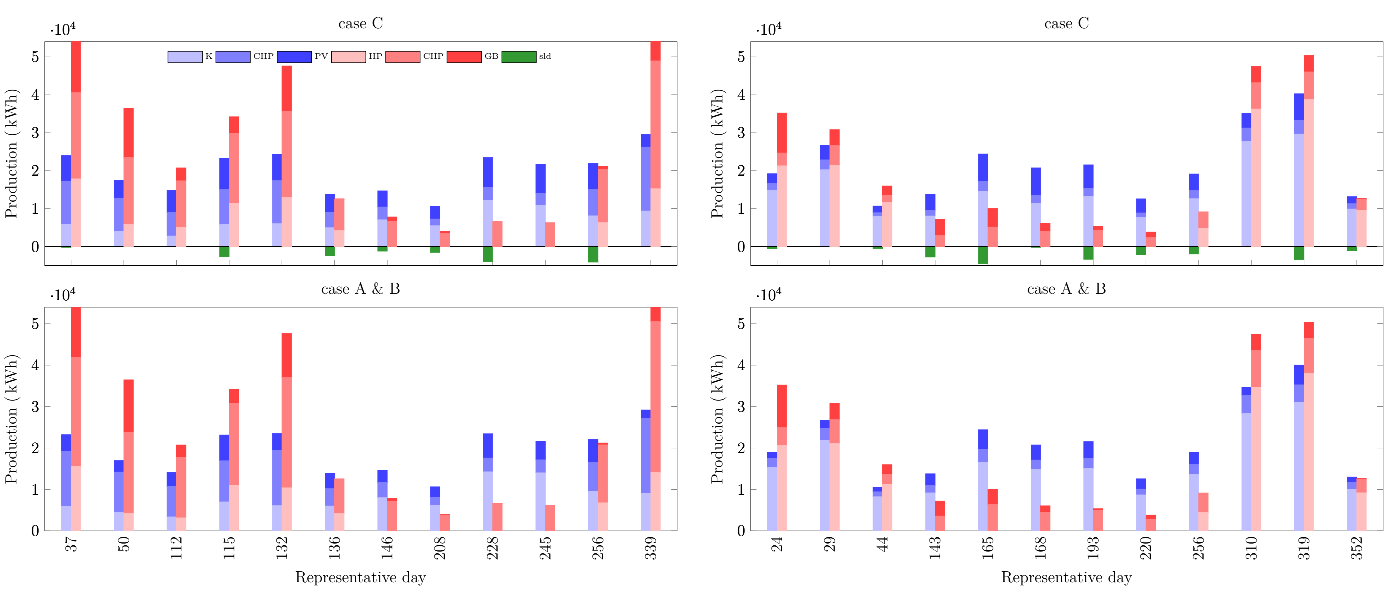
The energy balances for the optimal configurations of the three cases (A, B and C) of the two main vectors (electricity and heat) are provided in Fig. 17 for all the representative days of a typical year, for both locations. One can see that renewable energy is an important part of the total energy mix, and that call to gas boiler is limited in terms of capacity for heat demand. In contrast, there is still a need to rely on the external grid for the electricity demand, which thus imposes to rely on the national portfolio and its associated CO_2 emissions. For case C, where selling electricity is allowed (appearing in green, and as exports -i.e., negatively- in the pictures), it is interesting to note several points: i) the electricity sold is not constant over the year and is limited to specific periods, ii) the sales of electricity are not necessarily obtained concomitantly to te lower demands, iii) last but not least, the opportunity to inject on the network is here very similar in both countries which, should these results be generalized to other regions and cities, could question the European regional cross-border compensation through multiplicity.

Then, for the cost of the contracted power from the membership fees apart, the cost for the reference system is of about 1 717 k€ (34.3 k€/dwelling) for France and about 1 819 k€ (36.4 k€/dwelling) for Spain. The difference between the total cost of the energy bills for the reference system and the revenue of the aggregator corresponds to potential savings for the customer.

For the three business models tested, the results show savings for the customers of approximately 40% compared to reference, as shown in Table 10 and observable on Fig. 18. These results are in accordance with similar works [70,73,124] that enlightened the better economic efficiency of a polygeneration system, in comparison with conventional and single-energy solutions. It also confirms previous conclusions obtained by Lund et al. [125], showing a better optimum solution when considering all the energy vectors (heat and electricity here). In other words, it is possible to achieve significant savings for the consumers. Besides, it is worth recalling that these latter are released from the burden of the financial management of such systems since all the investment and operational costs are supported by the aggregator. In fact, these boons could also be singularly higher since the retained projection was finally very conservative. Indeed, from 2020 to 2021, energy prices were tripled in Spain and it is not sure that such variations could not occur again, or even that the expected decrease will lead to lower values than the present projections. Furthermore, due to the European legislation, the gross price is correlated to the last marginal cost of production, which usually correspond to the use of combined cycle gas turbines. More explicitly, the electricity price is influenced by the fluctuations of the gas price, even for countries like France where the main part of the electricity comes from nuclear and hydropower plants. In this sense, a novel analysis has been proposed below, considering the current energy crisis.

Concerning economic aspects, NPV are always positive. This clearly demonstrates the supportability of polygeneration systems managed by a third party between national grids and residential consumers, whose consumptions are aggregated. Though presumably anecdotal, this last point is paramount. Even with schemes that do not particularly favor the aggregator, and without any specific incentives, it is possible to develop a profitable business model in spite of the risks and investments consented by the aggregator. Similar insights were obtained, e.g., for the case of Barcelona, Spain in [43] however it was only a partial result since only costs were considered. With a complete business model, including VAT and tax rates, these preliminary results are here corroborated. From the aggregator viewpoint, higher NPV are achieved when a variable price is applied to the customer, but at the cost of a longer payback period. The possibility to resell extra-production of electricity brings another source of revenues, increasing the NPV of 18% and 9.2% in Zaragoza and Spain respectively. The practical conclusions are twofold. First, incentives are not necessarily required, though they could favor or accelerate the deployment of such third-parties but, second, it clearly simplifies both the management of the system and allows for complementary earnings for the aggregator.

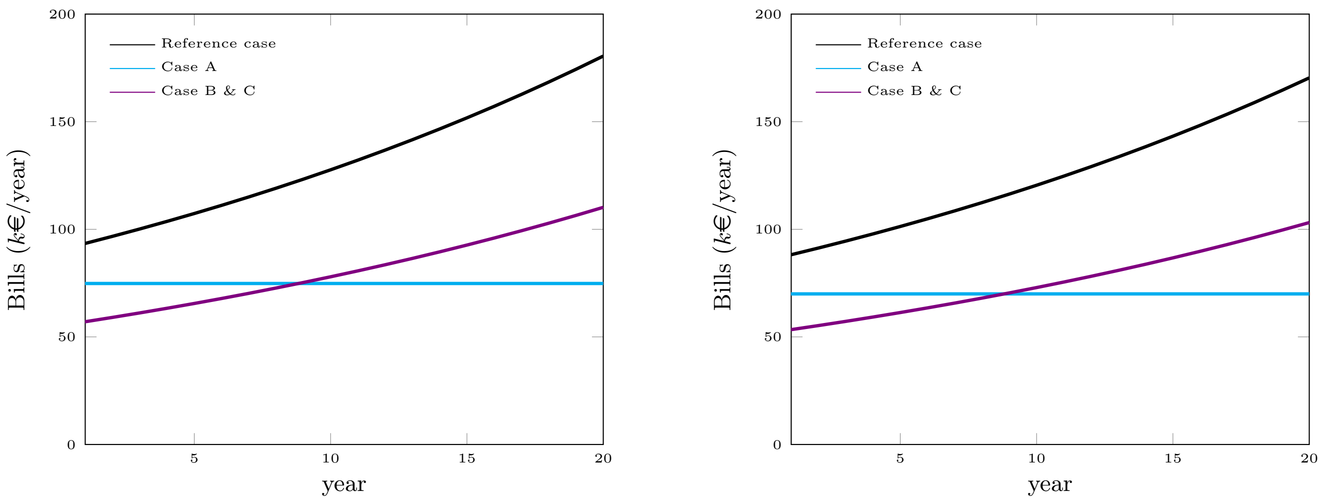
Regarding the chosen production units, the optimal configuration always contains for both locations a combination of PV, CM, reversible HP, GB and TSH; TSC being also selected in Zaragoza. Here again, it is important to remark first that such physical solutions agree well with other studies pertaining to energy communities [70,72,126]. The dependency of the pricing strategy on this sizing is finally not very strong (case A and B being relatively close), yet the resale of electricity plays a more important role. Meanwhile, technologies such as WT, ST and single-effect AbCh are not chosen anywhere. Similarly, and more interesting in the current siren song, no special tropism is observed toward batteries; this is still in accordance with prior works, as for instance on the role and more interesting benefits of thermal storage in comparison with battery [127]. This underlines the necessity to think carefully of the associated business models, or to specific tariffs or incentives if such technologies are to have a significant place in the energy paradigm.
In practice, PV and CM enable the reduction of the contracted power from the electric grid and, hence, the corresponding costs. Nevertheless, the results show that there is a higher dependency on the electric grid in Marseille, due to lower electricity prices. On the thermal side, the reversible HP capacity is higher in Zaragoza because of its higher cooling demand. Consequently, due to the support of the reversible HP, cogeneration module and TSH and GB capacities tend to be lower in Zaragoza, although the heating demand is higher in Zaragoza. Moreover, yet unsurprisingly, reversible HP are better exploited where cooling and heating demands are more balanced.



(a) Zaragoza (b) Marseille

Figure 17: Annual energy balances of the representative days for all optimal cases

Lastly, all scenarios decrease the CO_2 emissions. When selling electricity is forbidden, $CO_{2\,\mathrm{eq}}$ emissions reduction is of 6% and 33% in Zaragoza and in Marseille respectively. In absolute terms, this means reductions about 7.1 $t_{CO_{2\,\mathrm{eq}}}$ in Zaragoza and 21 $t_{CO_{2\,\mathrm{eq}}}$ in Marseille compared to the reference system. However, when selling electricity is allowed, $CO_{2\,\mathrm{eq}}$ emissions reduction, compared to the previous cases,



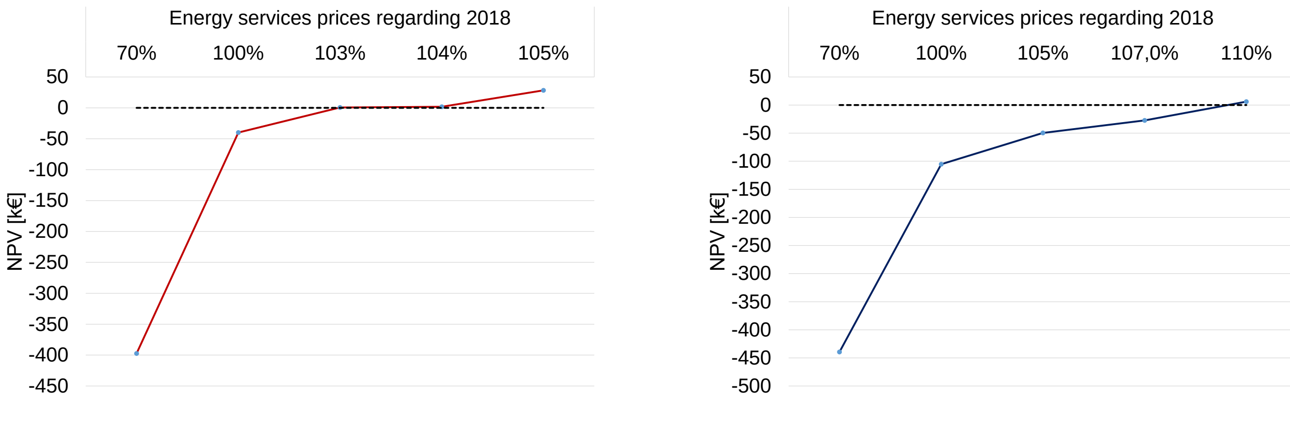
(a) Zaragoza (b) Marseille

Figure 18: Annual bill for the 50 dwellings along the years

is of 8.5 $t_{CO_{2\,\mathrm{eq}}}$ in Zaragoza and only of 2.2 $t_{CO_{2\,\mathrm{eq}}}$ in Marseille. Therefore, selling electricity in Zaragoza has a higher impact. It is also important to notice that the lower $CO_{2\,\mathrm{eq}}$ emissions from the electric grid in France are more significant to explain the lowest pollution than the lower demand in heating and cooling. Eventually, we would like to discuss a possible important evolution of the energy regulation. Indeed, it is highly probable that tax carbon increases in Europe, or at least we can hope so. If it were the case, it is important to notice that the present business models all tend to decrease CO_2 emissions compared to the business-as-usual model. Nevertheless, this taxation could also decrease the raw financial performance of the aggregator; except if the tax is accompanied with subventions for renewable energies, incentives that could help the aggregator to strengthen its position. A last advantage is the higher predictability of the CO_2 emissions of the polygeneration system, when compared for instance with the energy mix, and the associated possibilities for customers to not undergo national choices to which they are not in accordance with. Meanwhile, knowing that the polygeneration system produces electricity through several renewable ways, it would be still better or equal to the business-as-usual system.

5.2 Current crisis

At the time of the Ukrainian conflict, the world is dealing with the increase of energy prices. Although it is a temporal situation, it is a perfect moment to question the assumptions concerning these latter, and to infer the possible consequences on the optimal solution and economic viability of aggregators. To shed light on these interrogations, a novel optimization has been carried out, taking as starting points for the electricity and natural gas prices the double of those presented in 2018. Likewise, a sensitivity analysis of the prices for the energy services of the customers is performed to find the value allowing the aggregator to remain feasible economically. In this case, the sale of electricity is not allowed. According to the results, the business of the aggregator in Zaragoza and Marseille reach the equilibrium point when the energy services prices are above 4% (Figure 19a) and 9.5% (Figure 19b) of those presented as reference in 2018 respectively.
Therefore, even in such extraordinary conditions, these results present the aggregators as a good alternative to smooth the impact of energy prices increases on the consumers. Usually, the consumers should sign up the electricity and natural gas services directly at household prices. Nowadays, this means they



(a) Zaragoza (b) Marseille

Figure 19: NPV vs Energy services prices regarding 2008. Equilibrium point NPV=0

would have to pay the double or more of the reference household energy prices of 2018. Nevertheless, according to the results, an aggregator could sell the energy service at, for instance, above 30% of the price of 2018 obtaining good benefits. At the same time, the customers do not feel the high increase of the energy prices (double or triple) promptly, but gradually.

Table 13: Optimal sizing capacity at double energy prices regarding 2008 prices

Technology	Zaragoza	Marseille
$\mathcal{P}_{\mathrm{K}}[\mathrm{kW_{el}}]$	36.8	63.3
CM $[\mathrm{kW_{el}}]$	31	8
PV [kW]	67	57
Inv [kW]	81	68
ST $[\mathrm{m}^2]$	-	21
HP $[\mathrm{kW_{th}}]$	104	70
GB $[\mathrm{kW_{th}}]$	65	58
AbCh $[\mathrm{kW_{th}}]$	3	-
TSH $[\mathrm{kWh_{th}}]$	48	58
TSC $[\mathrm{kWh_{th}}]$	18	-

The increase of energy prices leads to reduce electricity and gas consumptions, which directly lead to a reduction of the operational CO_2 emissions (see Table 14, compared to previous Table 12). By comparing these results with the three previous test cases, such a situation turns to be environmentally helpful for Zaragoza since reductions between 1.76% and 9.53% are obtained. However, there are no benefits for Marseille and even a slight worsening (though anecdotal). This is due to the increase of the embodied CO_2 emissions in the equipment, which do not compensate the reductions of the consumptions decrease.

Table 14: Annual CO$_2$ emissions in $\mathrm{kg_{CO_{2,eq}}}$ year^{-1}

Source	Zaragoza	Marseille
Electric grid	13 289	5 943
Natural gas	78 031	31 805
Equipment	6 373	5 135
Total	97 693	42 883

6 Conclusion

This paper studied the economic viability and social interest of an aggregator, third party between the classic distribution grids and several tens of customers. The basic research question was to investigate if a business model can ensure some revenues to the aggregator, proposing energy-as-a-service to a set of tens of customers. All the basic energy vectors needed for residential users are considered, i.e., heating, cooling and electricity. Their production can be proposed by a large set of technologies: PV, wind turbines and solar collectors for the generation units; heat-pump, combined heat-and-power, gas boiler and absorption chiller for the conversion units; thermal (hot and cold) and electrical storages. In case of shortage, the aggregator can partly rely on the external grids. An optimization is conducted to find the most profitable situation. To highlight the possibilities of such an organization, three various business models are tested: one with a constant energy price and two others considering different variable energy prices. Meanwhile, the resale of the extra-electricity produced can be authorized or not. Finally, two locations have been tested, Zaragoza in Spain and Marseille in France, so as to study the influence of the local regulations on the optimal configuration for relatively similar demand (with slight variations, principally for the cooling demand).

The results show that all these configurations lead to a similar polygeneration system. This latter combines mainly PV with cogeneration and reversible HP, as well as a gas boiler and a hot TES. In the Spanish case, cooling storage is also present. It is worth highlighting that WT, ST and batteries are not enough cost-effective to be selected, meaning that incentives or specific pricing could (or should) be considered to promote their use. The most important and interesting result demonstrated is that a win-win situation is achievable, where both the consumers and the aggregator can develop a doubly beneficial situation. In comparison with the reference case, the savings for the customers are always greater than 30%, which is enough to be really accountable. Besides, it is always possible to get a positive NPV, which shows the economic viability of the concept. All in all, an added-value is found and there are some interests for both parts: the customers do not have to support the expenditure and operational costs and could still change their energy providers, the aggregator can generate sufficient revenues. The most favorable situation for its incomes is with a variable pricing, and with the possibility to resale the extra-production of electricity. Eventually, reductions of the CO_2 emissions are achieved but with a great variation between France, where significant decrease around 30% are obtained, and Spain, where they are diminished between 6 and 13%.

In the following of this work, it is planned to extend the study to smart mixed grids, that is to say to electrical grids and heat networks operated in a smart grid context. Indeed, the demand side management techniques could be used for all types of energy and thus give an interesting leeway to better manage the polygeneration system, and/or increase the self-sustainability and self-consumption, and/or decrease the total installed capacity of several technologies (production units as well as storage). Moreover, another important mechanism is to be considered: the price-elasticity of the demand which can lead to severe modifications of the demand, similarly to demand response strategies, and is worth investigating. Finally, the integration of negative externalities in the business model and the two main solutions are envisioned: either a coasian solution with a cap-and-trade market, or a pigouvian solution with a carbon tax, or even a mix of both solutions. Last, the demand part could be refined, using for example the multi-level thermal request prediction developed by Guelpa et al. [128] to benefit from a compact model for the buildings demand. Added to this, it would be instructive to either use or to perform a comparative analysis using demand profiles that integrate one or several scenarios of the climate evolution in the next 30 years. For instance, a downscaling approach could be used [129] for such a purpose. Finally, the present results also give an impetus for a more refined and extended economic study of the role and added-value of the aggregator between the customers and the classic energy providers, but also on its positioning between the transport and distribution operators.

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