2013 IREP Symposium-Bulk Power System Dynamics and Control –IX (IREP), August 25-30, 2013, Rethymnon, Greece

Integrated Energy and Ancillary Services Provision in Multi-Energy Systems

Pierluigi Mancarella
University of Manchester, UK
p.mancarella@manchester.ac.uk

Gianfranco Chicco
Politecnico di Torino, Italy
gianfranco.chicco@polito.it

Abstract

Multi-energy systems (MES) in which operation and planning of electricity networks is optimally framed within a context of interaction with other energy vectors such as heat, cooling and gas, are receiving increasing interest from the point of view of providing flexibility to the power system. In this outlook, MES have the potential to provide real time demand response services by deploying the possibility to internally shift energy vectors between different plant components, thus decreasing the equivalent electricity input from the grid. This could be particularly relevant to provide ancillary services to future systems. On these premises, the aim of this paper is to set out a framework for the techno-economic assessment of integrated provision of energy and ancillary services from MES while supplying local multi-energy demand. The concepts of fuel-to-power arbitrage or equivalently of multi-energy arbitrage, electricity shifting potential, and ancillary services profitability maps are introduced and discussed to synthesize the developed framework. Specific numerical applications are presented to illustrate through case studies the implications of the proposed concepts.

1. Introduction

There is increasing interest arising for the study of multi-energy systems (MES) [1] whereby operation and planning of electricity systems is optimally framed within a context of interaction with other energy vectors such as heat, cooling and gas, most noticeably. This is mainly driven by a number of aspects, among which:

(i) the need for decarbonising end-use energy types such as heat and cooling, which are often both more carbon intensive and harder to decarbonise than electricity;

(ii) the fact that the coupling among the energy vectors is becoming more substantial at all levels of the electricity chain, from large-scale generation (for instance though Combined Heat and Power – CHP – plants coupled to heat networks) to utilisation (for instance, with the widespread use of Electric Heat Pumps – EHP) and thus there is great potential for economic and environmental optimisation at both operational and planning stages;

(iii) the fact that interactions with energy vectors other than electricity can provide flexibility to the electrical system potentially to a larger and more economical extent than other electricity-only options.

Within a MES context, in particular, distributed multi-generation (DMG) [2][3] plants that are capable to locally supply multi-energy loads could play a key role in the development of more flexible energy systems, at the same time leading to better environmental and economic performance. The simplest and most typical example of DMG system is a CHP plant for cogeneration of electricity and heat [4], whose application is already widespread in many areas and activities. More advanced cogeneration options can also be provided by coupling EHP to the CHP prime mover, with the potential to enhance in a significant way the plant flexibility and environmental performance [5], as well as economic profitability of the overall MES. Further extension of cogeneration to multiple energy production is the trigeneration (or CCHP – Combined Cooling Heat and Power) case [2][6] where electricity, heat and cooling are produced from fuel inputs. In the "classical" trigeneration case, a CHP plant supplies electricity and heat, and part of this heat is in turn used to supply absorption chillers for cooling production. A more general case of DMG plant is where multiple pieces of equipment are available for multi-energy production, for instance with absorption and electric chillers for cooling production and CHP, boilers and EHP for heating production [7], and interactions with various external energy networks.

The possibility of having multiple pieces of equipment to supply different energy loads also paves the way to the potential of exploiting the *flexibility* provided from the interaction of multiple energy vectors. Studies in this direction have been for instance performed in [8]. A systematic formalization of the potential to deploy the

978-1-4799-0199-9/13/$31.00 ©2013 IEEE

flexibility intrinsic in *shifting* from one form of energy to another in order to provide real-time demand response services has been formulated by the authors in [9]. In fact, MES plants are typically characterized by excellent dynamic performance (particularly relatively small schemes, in the order of less than 1 MW_{el}) and it is thus possible to switch quickly *within* the plant from one form of energy supply (most noticeably electricity) to another while still supplying the entire multi-energy load. For instance, heat can be provided by a CHP engine, a boiler, or an EHP, which means that if there is a need to decrease the electrical input to the plant from the grid the EHP can be switched off and the CHP can be ramped up (if there is headroom for it), while the backup boiler makes up in case for the rest of heat load to supply. Similarly, *electrical* cooling (in electric chillers) could be switched onto *thermal* cooling (through heat-fired absorption chillers), again providing decrease of the electrical input to the plant. Clearly, these flexible options do not only bring possibility to optimise the plant operation for instance following dynamic prices [7][10], but also open up to the provision of different real-time demand response services.

The aim of this paper is to extend the systematic framework developed in [9] for real-time demand response in MES by explicitly modelling and analyzing the possibility to provide ancillary services in an integrated way with energy services. The fundamental modelling aspects refer to the possibility of optimising the internal operation of the plant based on external (price) signals (including potential ancillary services contracts), basically by considering price arbitrage between electricity and fuel (for instance from an EHP to a boiler, but also from a CHP to a boiler). It is in fact the combination of these energy shifting and price arbitrage opportunities that provides flexibility to the DMG plant for ancillary services. In this sense, while in [9] the focus was on energy arbitrage, in this work it is possible to introduce the concept of *fuel-to-power* arbitrage, where indeed the "power" component is more relevant to the provision of (usually fast and short-duration) ancillary services as opposed to energy services. This is carried out starting from the concept of *electricity shifting potential*, that is, the possible reduction in the electricity input from the electrical grid obtainable by exploiting internal energy shifting in the DMG plant without changing the user's load. The electricity shifting potential can be considered as a measure of the plant *flexibility*. Simplified expressions of the electricity shifting potential are developed in this paper under specific assumptions.

Another novel contribution of this paper is the introduction of specific *ancillary services profitability maps*, elaborated in the lines of the demand response profitability maps introduced in [9]. These maps are developed as an effective way to visualize the results and understand and quantify how internal energy source switching can be used for ancillary services provision. This is relevant to different types of ancillary services with different time scales, with activation within seconds (for example, for frequency response purposes) to minutes (for example, for tertiary reserve services), for which various types of flexibility from different MES equipment can be deployed. In addition, different types of market contexts and payment schemes can apply, and hence the maps are discussed with respect to considering both *availability fees* (payments received by the plant only to be ready to provide services, usually proportional to the nominal ancillary service capacity) and *exercise fees* (payments received when the service is called upon, for instance proportional to the energy that has been delivered). It is important to highlight that in all cases ancillary services are provided in the form of equivalent electricity input reduction to the DMG plant or increased electricity output *without* affecting the multi-energy demand of the user. This is a key difference with respect to other systems where ancillary services are provided by affecting the user's comfort level (e.g., when air conditioning units are switched off the internal ambient temperature may change).

A further relevant aspect for the provision of ancillary services is the size of the plants that are entitled to offer capacity and energy in the relevant business. A minimum amount of capacity is generally required to participate in the provision of ancillary services by specific regulations of some jurisdictions. The analysis carried out in the paper and the numerical examples are mainly focused on the characteristics of small-scale MES. However, the results indicated in this paper may be combined by considering an operator managing the availability of a group of MES of suitable aggregated size for instance in a virtual power plant configuration.

This paper is organized as follows. Section 2 recalls the basic information and nomenclature of the components used in MES. Section 3 illustrates the concepts referring to the flexibility that can be originated by the MES operation, and provides the formulation of the specific quantity called *electricity shifting potential*, used to characterise the limits within which flexibility can be introduced in providing ancillary services such as demand response and reserves. Section 4 deals with the conceptual aspects of the integrated provision of energy and ancillary services from MES, and presents the framework for characterising the possible benefits of the participation of MES to the provision of different services through the adoption of suitably defined ancillary service profitability maps. Section 5 shows the results of a number of detailed case study applications. The last section contains the concluding remarks.

2. Components and modelling of multi-energy systems

2.1. Typical MES components

Typical components available in MES and particularly in DMG plants for combined generation of electricity, heat and cooling are the following:
- Combined heat and power (CHP) units;
- Auxiliary Boilers (AB);
- Electrical heat pumps (EHP);
- Electric chillers (CERG – Compression Electric Refrigeration Group);
- Absorption/adsorption chiller (WARG – Water Absorption/Adsorption Refrigeration Group).

The core of a MES is usually a CHP generator for combined production of heat and power. Typical CHP technologies are microturbines (for building applications), internal combustion engines (for building or district energy systems applications), and gas turbines for applications of few to a few dozens of megawatts. Heat could also be extracted from large scale generators and transported through heat networks for final use. Natural gas is the widespread as a fuel, while it is likely that in the future biomasses and biogas will play a more important role.

The CHP plant is typically sided by an auxiliary boiler (AB) fed on natural gas or other fuel, for both thermal backup and peak shaving purposes. As it will be illustrated later, the AB does actually play a key role in providing flexibility to the MES and particularly in the context of ancillary services provision.
Heat can also be produced through an EHP (see for instance the high-efficiency CHP-EHP combined scheme of [5]) of different technologies such as ground-source, water–source, air-source, and so on, where electricity is used to drive a compressor to extract "free" heat available in the environment and provide end use heat at a higher temperature [11].

Cooling production for air conditioning or industrial purposes (e.g., food refrigeration) is, on the other hand, conventionally provided through a CERG whose compressor is electrically driven to extract heat (that is, provide cooling through chilled eater or cooled air) from the ambient to condition and inject it outside at higher temperature. In many cases, the EHP is actually a bi-modal machine that can serve also as a chiller by simply reverting the thermodynamic cycle.
Cooling can (also or alternatively) be provided through a WARG [11] that produces cooling from a heat supply (basically, the electrical compressor is replaced here by a "thermo-chemical" compressor so that heat in different forms such as hot water, steam or exhaust gases can be used to drive the thermodynamic cooling cycle). As mentioned above, a WARG supplied by heat from CHP represents the classical trigeneration scheme where cooling is produced mostly in summer and heating in winter, hence guaranteeing an effective deployment of the cogenerated heat and therefore high utilisation of the CHP plant [2].

Further components that could be coupled within MES but which are less widespread are gas based chillers/heat pumps that could be directly powered by mechanical compressors ("engine-driven") and absorption heat pumps [11].

2.2. Input-output efficiency models of multi-energy components

For system studies, the easiest way to represent MES components is through input-output representations that use relevant energy efficiency black-box models [2][7]. For instance, for a CHP system one can consider the fuel input energy vector F and the outputs energy vectors electricity W and heat Q (all energy vectors are here represented as energy, in kWh, or average power in a given time interval, in kW). Therefore, the CHP plant can be characterised by the electrical efficiency and the thermal efficiency (output-to-input energy ratios), defined as

$$\eta_{WF}^{\mathrm{CHP}} = \eta_W = \frac{W_y}{F_y} \text{ (CHP electrical efficiency)} \quad (1)$$

$$\eta_{QF}^{\mathrm{CHP}} = \eta_Q = \frac{Q_y}{F_y} \text{ (CHP thermal efficiency)} \quad (2)$$

where the first term contains the general representation using the output and input energy vectors as subscripts and the second term introduces a synthetic notation. Also, in this specific context the subscript y indicates cogenerated entries.

This representation is indicated as "black-box" in that there is no need for going into the thermodynamic details of the plant description. At the same time, such models are adequate to represent the plant in a synthetic but powerful way for system studies and particularly to formulate optimisation and real-time response models [9]. This approach is also consistent with the classical representation of electricity-only power plants, where the fuel input is typically expressed as a polynomial function of the electricity output.

Similarly to cogeneration plants, the cooling/heating components that have been introduced above can also be represented as input-output black-boxes. For instance, the cooling generation equipment can be characterized by the relevant *COP* (Coefficient of Performance), generally defined as output (cooling energy R) to the input depending on the specific equipment, e.g., electrical energy W for an EHP or thermal energy Q for a WARG

$$\eta_{RQ}^{\mathrm{WARG}} = COP_{\mathrm{t}}^{\mathrm{WARG}} = \frac{R^{\mathrm{WARG}}}{Q^{\mathrm{WARG}}} \text{ (WARG } COP\text{)} \tag{3}$$

$$\eta_{RW}^{\mathrm{EHP}} = COP_{c}^{\mathrm{EHP}} = \frac{R^{\mathrm{EHP}}}{W^{\mathrm{EHP}}} \text{ (EHP cooling mode } COP\text{)} \tag{4}$$

and an EHP operating in heating mode is characterized by the heat-to-electricity *COP*

$$\eta_{QW}^{\mathrm{EHP}} = COP_{t}^{\mathrm{EHP}} = \frac{Q^{\mathrm{EHP}}}{W^{\mathrm{EHP}}} \tag{5}$$

Heat generators are modelled in the same way, with a boiler defined by its thermal efficiency

$$\eta_{QF}^{\mathrm{AB}} = \eta_{t} = \frac{Q^{\mathrm{AB}}}{F^{\mathrm{AB}}} \tag{6}$$

In general, the performance indicators indicated above are not constant, i.e., their values can change with respect to the loading level and other conditions such as the external temperature.

While such representations are powerful enough at a component level, for the optimisation framework that is used here a further step is needed, that is, to represent the components through a matrix formalism that can be easily embedded within the formulation of the overall MES plant. More specifically, by denoting as $\boldsymbol{X}$ the set containing the components belonging to the MES, each component black-box $X \in \boldsymbol{X}$ can be described through an efficiency matrix where the relevant performance indicators are in such positions to opportunely represent the input-output energy flow relations. Hence, if the general form of an efficiency matrix for an individual component X is denoted as $\mathbf{H}^{X}$, the relevant output-to-input connection is written as [7]:

$$\mathbf{v}_{o}^{X} = \mathbf{H}^{X} \cdot \mathbf{v}_{i}^{X} \tag{7}$$

where $\mathbf{v}_{o}^{X} = \left[\, F_{o}^{X},\ W_{o}^{X},\ Q_{o}^{X},\ R_{o}^{X} \,\right]^{\mathrm{T}}$ is a vector with the relevant output vectors and $\mathbf{v}_{i}^{X} = \left[\, F_{i}^{X},\ W_{i}^{X},\ Q_{i}^{X},\ R_{i}^{X} \,\right]^{\mathrm{T}}$ a vector with the relevant inputs for the component X. For instance, if we consider the four energy vectors that are typically encountered in a trigeneration plant, that is, F, W, Q, and R, and we identify the entries of $\mathbf{H}^{X}$ through a two-letter subscript where the first letter refers to the output energy vector and the second one to the input energy vector (consistent with the notation used above in the definition of the efficiencies and *COP* values), we can write

$$\mathbf{H}^{X} = \begin{pmatrix} \eta_{FF}^{X} & \eta_{FW}^{X} & \eta_{FQ}^{X} & \eta_{FR}^{X} \\ \eta_{WF}^{X} & \eta_{WW}^{X} & \eta_{WQ}^{X} & \eta_{WR}^{X} \\ \eta_{QF}^{X} & \eta_{QW}^{X} & \eta_{QQ}^{X} & \eta_{QR}^{X} \\ \eta_{RF}^{X} & \eta_{RW}^{X} & \eta_{RQ}^{X} & \eta_{RR}^{X} \end{pmatrix} \tag{8}$$

It has to be highlighted that in order to allow a more straightforward representation of the energy flows, as well as an automatic construction of the overall plant matrix representation starting from the individual components (see [7]), it is convenient that the same types of ordered entries for both inputs and outputs are used for all components and for the MES plant as a whole. In particular, in the specific trigeneration case considered here, if we use the order F, W, Q, and R, for both inputs and outputs, the matrix representation of different types of equipment can be found in [7] for the CHP, WARG and AB, and in [9] for the EHP operating in cooling mode or in heating mode.

2.3. Multi-energy plant input-output model

Starting from the black-box matrix representation of the plant components, it is possible to derive an input-output black-box matrix formulation (basically a *plant efficiency matrix*) of the whole plant as well [7], in line with the energy hub model [12] which is again very convenient to model interactions with external networks and markets. An algorithm to derive the plant efficiency matrix from the individual component efficiency matrices and considering the plant topology and control variables is provided in [7], while visual inspection in a backward procedure (from energy outputs to energy inputs) can be applied as well, particularly for relatively simple cases.

The connections between components and with the external energy networks can effectively be represented through a connectivity matrix [7] that indeed models the plant topology. Furthermore, for the purpose of elaborating control strategies, the energy flows can be modelled through properly defined *dispatch factors* [12] or *splitting ratios* [13] that are usually part of the decision variables set, defined as the (relative) amount of an energy vector at flow splitting points (bifurcations) in order to supply different components. In particular, with reference to the notation of Fig. 1, the dispatch factor array is denoted as

$$\boldsymbol{\alpha} = [\, \alpha_{W}^{\mathrm{EDS}},\ \alpha_{F}^{\mathrm{FDS}}, \alpha_{W}^{\mathrm{CHP}},\ \alpha_{Q}^{\mathrm{CHP}},\ \alpha_{Q}^{y},\ \alpha_{Q}^{\mathrm{AB}} \,]^{\mathrm{T}} \tag{9}$$

The overall DMG plant (with a trigeneration case as a representative example) hence defined can be represented as

$$\mathbf{v}_{o} = \mathbf{H} \cdot \mathbf{v}_{i} \tag{10}$$

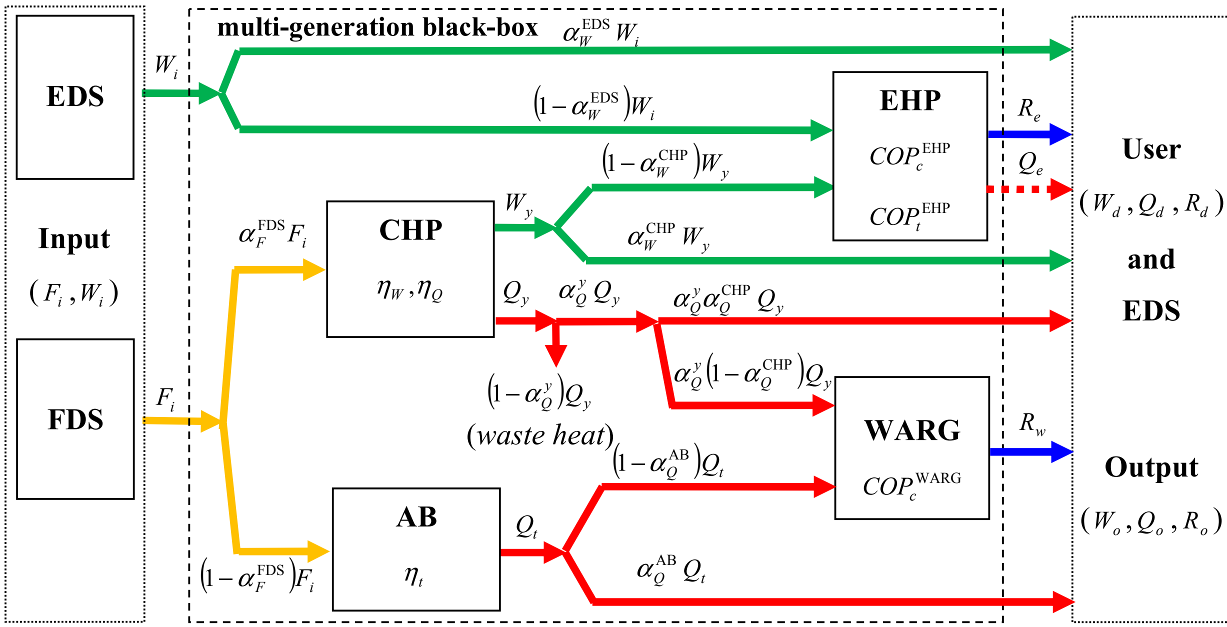


Fig. 1. Black-box model of the multi-energy system interacting with the electricity distribution system EDS and the fuel distribution system FDS. The EHP may be run in cooling mode (with output R_e) or in heating mode (with output Q_e); these outputs are mutually exclusive.

where $\mathbf{H}$ is the overall input-output efficiency matrix connecting the plant inputs to the plant outputs, $\mathbf{v}_o$ is the array of the ordered output energy vectors (F_o, W_o, Q_o and R_o) and $\mathbf{v}_i$ is the array of the ordered input energy vectors (F_i, W_i, Q_i and R_i). The arrays are ordered in the same way as for the individual component matrices, as discussed above.

Considering a typical trigeneration case for production of electricity, heat and cooling, a MES can be composed of a CHP system, an AB, a bimodal EHP (for both heating and cooling production) and a WARG. An example of such a system layout is shown in Fig. 1. This illustrative scheme receives electricity supply from the Electrical Distribution System (EDS) and fuel from the Fuel Distribution System (FDS). Electricity can be both bought from and sold to markets through the EDS. Heat demand can be met by exploiting three components (that can also operate simultaneously), that is, the CHP, the AB, and the EHP (operating in "heating mode"). The cooling demand can be met by using (again in case simultaneously) the WARG and/or the EHP (operating in "cooling mode"). Electricity can be drawn from the EDS and/or produced by the CHP output (and can be sold back as well). The EHP operation in heating mode or in cooling mode is mutually exclusive, although integrated schemes with simultaneous heating and cooling are also possible.

Let us introduce the binary variable m^{EHP} in order to provide a unified representation of the MES with the EHP operating either in the heating mode ($m^{\mathrm{EHP}} = 1$) or in the cooling mode ($m^{\mathrm{EHP}} = 0$), with respect to the distinct representations shown in [9].

The overall plant matrix representation becomes:

$$\mathbf{H}_c = \begin{pmatrix} 0 & 0 & 0 & 0 \\ \alpha_W^{\mathrm{CHP}} \alpha_F^{\mathrm{FDS}} \eta_W & \alpha_W^{\mathrm{EDS}} & 0 & 0 \\ \eta_{QF} & m^{\mathrm{EHP}} COP_t^{\mathrm{EHP}} (1-\alpha_W^{\mathrm{EDS}}) & 0 & 0 \\ \eta_{RF} & (1-m^{\mathrm{EHP}}) COP_c^{\mathrm{EHP}} (1-\alpha_W^{\mathrm{EDS}}) & 0 & 0 \end{pmatrix} \tag{11}$$

with

$$\begin{aligned} \eta_{QF} &= \alpha_Q^{\mathrm{AB}} (1-\alpha_F^{\mathrm{FDS}}) \eta_t + \alpha_Q^y \alpha_F^{\mathrm{FDS}} \eta_Q + \\ &\quad + m^{\mathrm{EHP}} COP_t^{\mathrm{EHP}} (1-\alpha_W^{\mathrm{CHP}}) \eta_W \alpha_F^{\mathrm{FDS}} \end{aligned} \tag{12}$$

$$\begin{aligned} \eta_{RF} &= COP_c^{\mathrm{EHP}} (1-\alpha_W^y) \alpha_F^{\mathrm{FDS}} \eta_W + \\ &\quad + (1-m^{\mathrm{EHP}}) COP_c^{\mathrm{WARG}} \left[(1-\alpha_Q^{\mathrm{AB}})(1-\alpha_F^{\mathrm{FDS}}) \eta_t + \alpha_Q^y \alpha_F^{\mathrm{FDS}} \eta_Q \right] \end{aligned} \tag{13}$$

More schemes with different types of equipment in "parallel" or "bottoming" configuration with respect to the CHP can also be considered. The relating details are illustrated in [2][14].

3. Flexibility in multi-energy systems

3.1. Baseline operation of multi-energy systems

A MES such as the one in Fig. 1 can be operated according to manifold control strategies, including typical ones such as local electrical load following (basically operating as a microgrid from an economic perspective, minimising the exchanges with the EDS), local thermal load following, full capacity, and so on [6][14][15]. Alternatively, control strategies can be optimally formulated according to a given objective function, for instance for cost minimisation purposes considering all the multi-generation options and hourly or half-hourly (or any other reference interval) electricity and gas prices. Such *baseline* operation strategies are considered here the reference against the potential to provide further services (and in particular ancillary services), with response times in the order of seconds to minutes, as it will be better explored later. In the sequel, operational optimisation with respect to *half-hourly pricing* (as in the UK managed spot market) and over a daily time window will be considered here as the baseline "energy-only" reference.

A comprehensive problem formulation for operational optimisation from the point of view of the MES operator has been defined by the authors in [7][15] and can be synthetically described by considering the array $\mathbf{x}$ containing the decision variables:

$$\mathbf{x} = \left[F_i, W_i, \boldsymbol{\alpha}^{\mathrm{T}}, W_y, Q_y, Q_t, R_e, R_w\right]^{\mathrm{T}} \tag{14}$$

where the superscript T denotes array transposition. The variable R_e refers to the EHP operating in cooling mode and is replaced by Q_e if the EHP operates in heating mode (the mode of operation has to be defined at the beginning of each time interval to which the optimisation refers).
The minimum cost optimisation is formulated as

$$\min\left\{\rho_f^{\mathrm{FDS}} F_i + \rho_i^{\mathrm{EDS}} \max\{W_i, 0\} + \rho_o^{\mathrm{EDS}} \min\{W_i, 0\}\right\} \tag{15}$$

s.t. $\mathbf{f}(\mathbf{x}) = \mathbf{0}$ (equality constraints)
$\mathbf{g}(\mathbf{x}) \leq \mathbf{0}$ (inequality constraints)
in which:
ρ_f^{FDS} fuel price;
ρ_i^{EDS} price of the electricity bought;
ρ_o^{EDS} price of the electricity sold.

Prices are expressed in [mu/MWh], where 'mu' stands for 'monetary units'. The calculations are made by allowing the electricity input from the EDS to be unconstrained (i.e., it can assume positive and negative values). An additional variable $W_o = -\min\{W_i, 0\}$ is introduced to specify a posteriori with respect to the optimisation the electrical energy output to the EDS (with a positive value).

The equality constraints $\mathbf{f}(\mathbf{x})$ are given by the multi-energy balances for all the plant components, as well as for the overall plant. The inequality constraints $\mathbf{g}(\mathbf{x})$ are formulated by considering the maximum capacity limits and the minimum operational limits of the various components, as well as the dispatch factor limits (from 0 to 1), the non-negativity limit on the fuel input, and the limits on the fuel or energy inputs to the individual plant components (details can be found in [15]).
In particular, for the CHP let us consider the maximum limits (set to the rated values) $\overline{W}^{\mathrm{CHP}}$ for the electricity output and $\overline{Q}^{\mathrm{CHP}}$ for the heat output, as well as a technical lower limit set to 50% of the corresponding output (below which the CHP is switched off).
Let us assume that the other MES components (AB, EHP, WARG) have maximum limits consistent with the possibility of supplying the related demand without restrictions (as we assume that setting up the limits has been preliminarily made during MES planning), and that their minimum technical limit is set to zero.

3.2. Flexibility in multi-energy components

As mentioned above, with increasing requirements for flexibility in power systems there is a great potential to exploit flexible resources that might be available from other energy vectors in MES and from DMG in particular. For instance, while classical CHP plants have typically been designed for and operated in thermal load following applications with electricity basically coming as a by-product (in this sense, there would be little room to provide flexibility to the electrical network), installing thermal storage (which is much cheaper than electricity storage, although with different characteristics) allows decoupling of electricity-and-heat supply-and-demand and makes it possible to provide flexible electricity services (for instance, in response to market prices). This concept is already being exploited in various places as demand response resource [16] for instance to provide flexible balancing services in wind-rich systems. This approach can be extended to DMG where however energy storage might even not be needed. In fact, besides improving the system reliability (which is critical in many applications) redundancy of multi-generation components also opens the way to deploying the intrinsically available flexibility by optimising system operation over different time scales and eventually at the planning stage as well. In particular, within the context outlined above and starting from the predefined baseline control strategy, in a MES it is possible to resort to *energy-shifting* potential internal to the plant from one form of energy to another (*multi-energy arbitrage*, which could be seen as a generalisation of the *fuel substitution* concept) to provide flexible services overlaying the baseline "energy" services.

As a consequence of internal rescheduling of the multi-energy sources, *electricity shifting potential* can be defined [9] as the time-dependent maximum reduction in the electricity input from the EDS starting from a given initial operational state and referring to a given time interval (e.g., one half-hour in the specific case analysed here, but conceptually also for shorter periods). The major sources of such flexibility in a DMG plant are the CHP plant on the generation side and the EHP on the consumption side, as widely explored in [9], for which details are given below. The operational point changes that allow reduction of the plant electricity input in response to external signals (for instance to provide ancillary services, as in this work) are of course subject to the plant constraints and physical constraints. More specifically, from the electrical point of view some actions that do not entail variations in the CHP output (e.g., switching off the EHP) can be carried out almost instantaneously (i.e., in the time frame of seconds). Other operations requiring the change of the electrical (and therefore thermal too) CHP output level may require longer time (in the order of few minutes, considering the relatively high ramping rate capability of small-scale CHP systems). Such operational constraints do therefore also have implications on the service that can be provided.
As mentioned above, a key aspect that needs to be pointed out is that, notwithstanding the nature of internal energy shifting, changes in the way the multi-energy load is dispatched do not affect the user's comfort level, as *their energy load remains the same* and so does therefore the service provided.

3.3. Flexibility in MES with CHP and EHP

Let us consider flexibility within the context of reducing the equivalent electrical input from the EDS by a certain quantity in response to an external signal and starting from the baseline control strategy (in other words, the "electricity shifting potential" defined above). A first way to determine new operational conditions in a MES as the one in Fig. 1 is through *internal* load shifting of the different energy vectors, for instance by switching heat/cooling loads from the EHP onto the AB/WARG. Also (or alternatively), the equivalent MES input can be decreased by increasing the CHP generation set point (if there is headroom for that), owing to the twofold effect of increasing the local electricity production *and* the thermal production for heating/cooling purposes (which in case displaces heat/cooling previously produced through electricity in the EHP operating in heating/cooling mode, respectively).

In the following subsections the electricity shifting potential is assessed by determining the maximum electrical energy that can be provided while operating the CHP without wasting heat (further analyses could be in principle also carried out with the option of wasting heat too, if allowed by regulation). Explicit formulations are indicated by considering the EHP operating in cooling mode or in heating mode, respectively.

In the illustration below, let us introduce the number n_T of time intervals of analysis within one hour, used for representing the relations (for example referring to electricity) between average power P (in kW) and energy $W = P/n_T$ (in kWh) supplied in each time interval. For instance, assuming a half-hourly time interval ($n_T = 2$), the energy values are equal to one half of the average power values.

3.4. EHP operating in cooling mode

For the EHP operating in cooling mode, let us consider the following notation, referring to the initial solution point at minimum energy costs:

- electricity taken from the EDS to supply the EHP:
$$W_{\mathrm{EDS}\rightarrow\mathrm{EHP}} = \left(1-\alpha_W^{\mathrm{EDS}}\right)W_i \tag{16}$$
- electricity taken from the CHP to supply the electrical load:
$$W_{\mathrm{CHP}\rightarrow d} = \alpha_W^{\mathrm{CHP}} W_y \tag{17}$$
- heat taken from the CHP to supply the heating load:
$$Q_{\mathrm{CHP}\rightarrow d} = \alpha_Q^{y}\alpha_Q^{\mathrm{CHP}} Q_y \tag{18}$$

In order to determine the electricity shifting potential, the amounts of electricity that can be reduced by shifting the corresponding energy away from the EDS supply have to be identified. Looking at Fig. 1, a first component that can be shifted in any case is $W_{\mathrm{EDS}\rightarrow\mathrm{EHP}}$, as it is possible to replace the corresponding portion of cooling output with an equal amount of cooling output supplied by the WARG (with heat input).

Another component can be identified by taking into account the electricity loading margin of the CHP, with the aim of increasing the CHP electrical output if the CHP is still not working at maximum loading. For this purpose, however, thermal demand (both "sheer" heat and the equivalent thermal demand from WARG supply) needs to be large enough, otherwise the CHP cannot be loaded entirely if heat is not to be wasted. Furthermore, a CHP unit operating at maximum electrical output to serve the EHP and the "sheer" electrical demand can still provide a contribution to the electricity shifting potential, as the EHP cooling load can be totally switched to the WARG output, thus redirecting the corresponding electrical energy (flowing from the CHP to the EHP) to supply the load, sending the possible excess electricity to the EDS. The second component of the electricity shifting potential for the multi-energy system with EHP operating in cooling mode has then a more elaborated formulation. Using a rewritten version of the expressions introduced in [9], the complete expression of the *electricity shifting potential* is:

$$\xi_c = \min\left\{\min\left\{\frac{\overline{W}^{\mathrm{CHP}}}{n_T}, \left(Q_d - Q_{\mathrm{CHP}\to d} + \frac{R_e}{COP_c^{\mathrm{WARG}}}\right)\frac{\eta_W}{\eta_Q}\right\}, \frac{\overline{W}^{\mathrm{CHP}}}{n_T} - W_{\mathrm{CHP}\to d}\right\} + W_{\mathrm{EDS}\to\mathrm{EHP}} \quad (19)$$

where efficiencies and *COP*s are evaluated at the partial loading conditions of the corresponding equipment.

In addition to the general formulation, a sufficient and intuitive condition for the electricity shifting potential is introduced in this paper. If the cooling load to shift from the EHP output to the WARG output is sufficiently high so that the total thermal demand seen from the CHP is higher than the maximum CHP heat output (that can therefore be used to supply the WARG input even without using the AB), that is,

$$\text{if } \frac{R_e}{COP_c^{\mathrm{WARG}}} > \frac{\overline{Q}^{\mathrm{CHP}}}{n_T} - Q_y \quad (20)$$

then the electricity shifting potential may be written in a simplified way as follows:

$$\xi_c' = \frac{R_e}{COP_c^{\mathrm{EHP}}} + \frac{\overline{W}^{\mathrm{CHP}}}{n_T} - W_y \quad (21)$$

In the above equations (20) and (21), the *COP* values are again considered at the partial loading conditions of the corresponding equipment. The condition is sufficient but not necessary, as the formulation (19) can be used whenever the heat to supply (including the heating load) is greater than the maximum CHP heat output, in order to make it possible to exploit the full CHP electrical output for the purpose of increasing the electricity shifting potential. The rationale of equation (19) is in fact to sum up the electricity initially required to supply the EHP (because the cooling energy given by the EHP can be totally shifted to the WARG output) to the electricity that remains available starting from the initial CHP electrical output to reach the maximum CHP electrical output (that replaces the electricity from the EDS to the electrical load and, if additional electrical energy is available, injects the excess electricity into the EDS).

3.5. EHP operating in heating mode

With respect to the concepts illustrated in the previous subsection, the first component that can be shifted away from the EDS is again $W_{\mathrm{EDS}\to\mathrm{EHP}}$, as the heat output of the EHP can be shifted to the AB output. Then, the electricity margin existing at the CHP electrical output can be used to supply the load (and in case to provide excess electricity to the EDS), provided that there is sufficient thermal loading at the CHP heat output. Using a rewritten version of the expressions introduced in [9], the complete expression of the *electricity shifting potential* is:

$$\xi_c = \min\left\{\left(\min\left\{\frac{\overline{Q}^{\mathrm{CHP}}}{n_T}, Q_d + \frac{R_d}{COP_c^{\mathrm{WARG}}}\right\} - Q_{\mathrm{CHP}\to d}\right)\frac{\eta_W}{\eta_Q}, \frac{\overline{W}^{\mathrm{CHP}}}{n_T} - W_{\mathrm{CHP}\to d}\right\} + W_{\mathrm{EDS}\to\mathrm{EHP}} \quad (22)$$

where the efficiencies and *COP* are evaluated at the partial loading conditions of the corresponding equipment. More details can be found in [9].

4. Integrated provision of energy and ancillary services from multi-energy systems

4.1. Introductory concepts

While there is substantial literature dealing with day ahead or intraday markets for combined analysis of energy and reserve (see for instance [17]-[18]), there is little or no work at all on the potential to provide such integrated services in a MES context and the role of DMG options to provide different ancillary services. In fact, while in a conventional generation plant spare capacity is needed to be able to provide spinning reserves (including frequency response) and similar services and playing in ancillary services market might not be profitable as opposed to energy markets, in a MES context "equivalent" capacity could be provided by internally shifting between energy vectors and without affecting the final multi-energy demand, as already mentioned above with respect to defining MES flexibility. For instance, if at a given time electricity were optimally generated through an electric chiller and a reserve service were called upon (in real time), the absorption chiller fed by thermal power could kick-in to produce cooling and the electricity previously used for the electric chiller could be used to provide reserve. Similar reasoning could be carried out to optimally bid in integrated energy/reserve markets by taking into account the available operational flexibility and the costs and benefits from moving from one operational point to another.

Based on this idea, the contribution proposed in this paper addresses the formulation of an operational framework and relevant optimisation problem to provide integrated services in MES by deploying what could be called *multi-energy/power arbitrage*. Essentially, energy provision might be replaced by power or capacity services provision depending on what is most economical. In particular, potential to optimally provide various types of reserve services (from primary and secondary frequency response to standing reserve) together with optimal scheduling of energy market participation (e.g., day-ahead and hour-ahead balancing market) can be considered. However, before doing this it is critical to consider "timing" issues and in particular the different timescales (from day ahead to real time) to commit and provide such services.

4.2. Potential ancillary services to be provided by MES

There are a number of different ancillary services that could be provided within a context of MES and by DMG plants in particular. While the specific services depend on the country market arrangements and it is out of the scope of this work to even attempt to list them in a comprehensive way, it is worth highlighting at a high level what general categories of services are needed according to the way power systems and most markets around the world work. In this respect, moving from "faster" to "slower" services (in terms of required response speed), "frequency response" (both primary and secondary) services fall within the first category. Response speed would typically be between intra-seconds (primary frequency response) and tens of seconds (secondary frequency response). It also needs to be highlighted that in this context frequency response is meant as a type of "spinning" reserve, in the sense that the services are called only when there is need for instance due to a generation outage, while "continuous" services such as "regulation" are not considered here. A second category refers indeed to more traditional "spinning reserve", intended as a service with response to be provided in a time scale in the order of few to tens of minutes (and it could be merged with the concept of secondary frequency response in some cases). "Non-spinning reserve" or "standing reserve" may be intended as relatively slower services, for instance to be provided from tens of minutes to one hour or so, although in many case spinning and non-spinning reserves may be required to react within the same time scale with the only different being the operational and dynamic characteristics of the different services and providers. Further ancillary services may refer to "balancing mechanisms", that is, spot markets managed by the system operator to guarantee close to real time supply-demand balance, with timeframes within one hour from real time delivery, and which may eventually merge with various reserve services that the system operator may contract separately.

4.3. Timing issues for ancillary services provision

A distinction among three specific issues referring to the timing at which the various types of ancillary services can be provided is presented here.

1. Service commitment. A first "timing" issue for provision of ancillary services taking into account energy market interactions refers to the time of the commitment of the service. For instance, a reserve service can be contracted with different lead times, from months to day or hours ahead. In alternative, reserve bids could be formulated by the DMG plant, again with different lead times. In most cases, when ancillary services are contracted in advance an *availability fee* is generally paid (normally in mu/MW/h), while if the service is called upon an additional *exercise fee* (normally in mu/MWh) may or may not be paid, depending on the market structure. On the other hand, if reserve services are committed through bidding close to real time (hours ahead), it may be that there is certainty to be called to provide the service, in which case an equivalent availability/exercise fee may be paid. Mixed schemes where a service is contracted in the long term and an availability fee is paid and then a bid takes place to actually competitively provide the service close to real time are possible as well.

2. Service notice. A second key criterion to consider in the analysis of ancillary services provision is the service notice. In fact, particularly when services are contracted with relatively long lead time, the notice to provide system support is critically important as this affects the possibility to internally reschedule the MES internal resources so as to deploy arbitrage opportunities between energy and ancillary services markets. For instance, if enough notice is given, internal reschedule of the MES resources could be in principle possible (including starting up a CHP system or changing its "baseline" operating set points) so as to maximise the economic benefits in the integrated energy and ancillary markets. Clearly the notice is also related to the type and volume of service that can be provided as different machines have different dynamic constraints, as discussed below.

3. Service speed. Another critical point related to the notice is represented by the speed at which the service needs to be provided, which influences again the volume and type of machine. In fact, for instance frequency response services may be needed within seconds and therefore need to be activated in an automatic way. At the same time, load shedding is the most appropriate form to provide it in a MES context, with for example an EHP being replaced by the boiler. On the other hand, "slower" reserve services or balancing services may be needed within minutes, so that also CHP could in principle change their operational set points besides EHP changes.

4.4. Ancillary services profitability maps

The relevant terms to assess the possible benefits that a MES can obtain from provision of ancillary services depend on the characteristics of the different ancillary services. For instance, an energy-only term appears for "pure" demand response and balancing services. Conversely, for reserve services remuneration generally includes a term referring to capacity (at the availability fee) and a term referring to energy (at the exercise fee).
The assessment of the benefits in the energy-only case can be conducted by resorting to the *profitability maps* introduced in [9] for real-time demand response. For what concerns the reserves, additional concepts are illustrated here to extend the concept of profitability maps to the case with capacity and energy, leading to the definition and application of novel *ancillary service profitability maps*.

If the reserve service is not called, the benefit for the multi-energy system can be evaluated by considering only the availability fee (in mu/kW for the relevant time period). In this case, the MES operator would find the highest convenience in offering a capacity corresponding in energy terms to the energy shifting potential, that is, the capacity $n_T \xi_c$.

More generally, the MES is called to provide the reserve service by actually supplying energy. In this case, the benefit is calculated as the difference between the total revenues (from availability and energy) and the total extra costs for providing the reserve requirement through electricity shifting (taking into account all the cost terms referring to the time interval under analysis, including possible startup costs or additional costs of the MES equipment to change its operating point). In this case, it is possible to draw the ancillary service profitability map as a three-dimensional representation containing the variation of the benefit with respect to the electrical energy shift for different values of the exercise fee, taking the availability fee as a parameter.
The borderline conditions for the convenience of participating in the reserve service by providing capacity *and* energy is the locus of the points separating positive and negative benefits. By drawing the ancillary service profitability maps for different values of the availability fee it is possible to quantify the impact of the availability fee on the location of the borderline conditions.

The details of application of the ancillary service profitability maps are shown in the next section on a sample of illustrative cases.

5. Case study applications

5.1. General framework for the case study

A number of case studies have been carried out to illustrate the concepts that are proposed for MES with different types of equipment, with specific applications to trigeneration applications for tertiary buildings such as hospitals, hotels, supermarkets, and so on, as well as aggregated loads in district energy systems facilitated by heat/cooling networks.

Some detailed results are presented in this paper by considering the MES structure of Fig. 1 in the case of a Summer day in which the EHP operates in cooling mode, and no waste heat is allowed at the CHP output. The multi-energy demand pattern along the day (for electricity, heat and cooling energy) is represented in Fig. 2, for time intervals of one half hour (n_T = 2). The electricity price evolution for buying electricity at energy market conditions is taken from a real case (Fig. 3). The price for selling electricity to the EDS is assumed to be one half of the buying price. The gas price is 40 mu/MWh and is assumed constant during the day, having been defined in advance from dedicated contractual provisions.

In these conditions, the baseline optimisation of the multi-energy operator taking into account the evolution of the multi-energy internal demand and the energy costs is such that the CHP is called to operate only in the time intervals with higher electricity prices (the half-hours number 19 to 23, that is, starting from hour 9.30 am up to hour 12.00 am). Our attention is then concentrated on the time period from hour 8.30 to hour 13. In that time period, the energy flowing in the MES system components is represented in Fig. 4 (electricity), Fig. 5 (heat) and Fig. 6 (cooling).

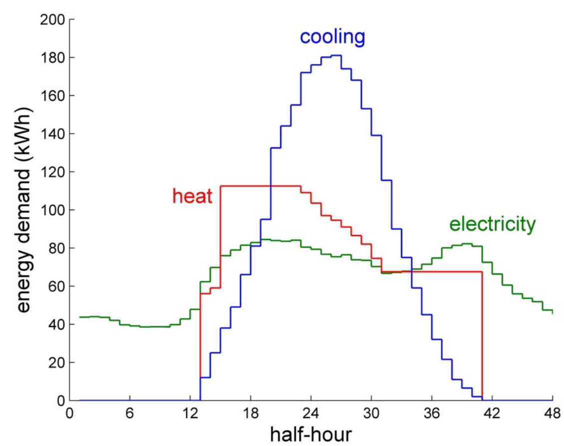


Fig. 2. Electricity, heat and cooling energy demand during the day considered in the analysis.

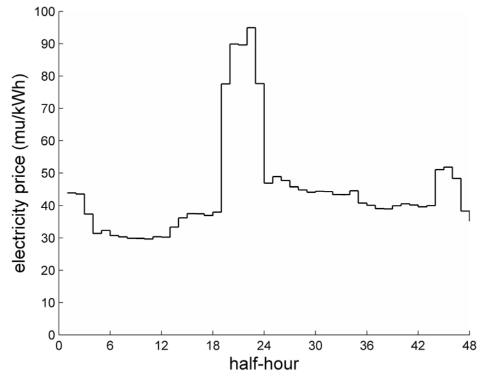


Fig. 3. Evolution of the price for buying electricity from the EDS.

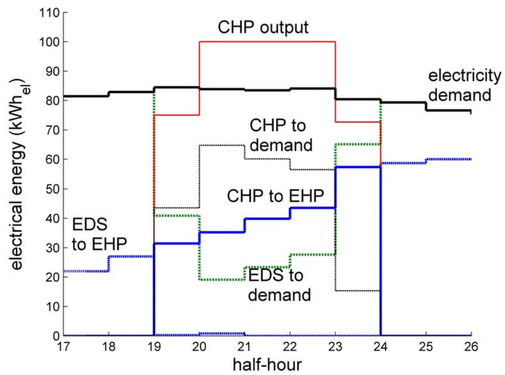


Fig. 4. Electrical energy in the period from hour 9 am to hour 1 pm.

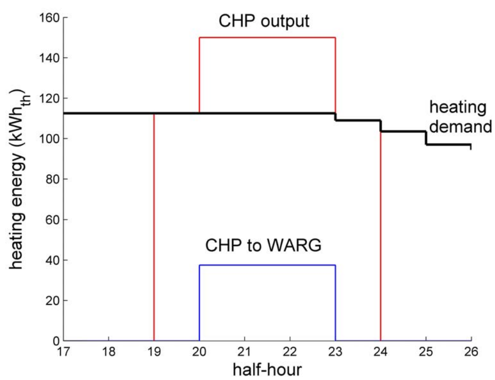


Fig. 5. Heating energy in the period from hour 9 am to hour 1 pm.

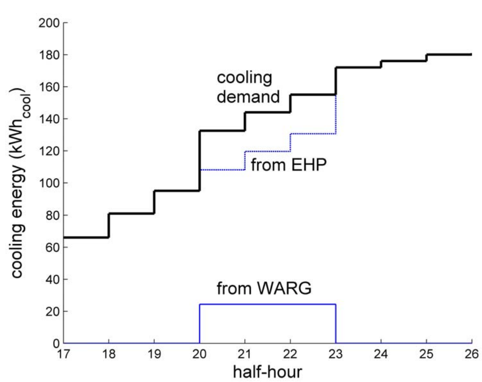


Fig. 6. Cooling energy in the period from hour 9 am to hour 1 pm.

The following subsections present the details on two specific cases, namely:

- *Case 1*, in which the CHP operates at full load in the optimal energy cost solution;
- *Case 2*, in which the CHP is off in the optimal energy cost solution.

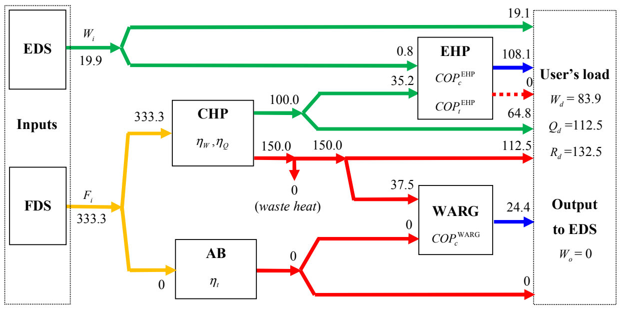
5.2. Example for a half-hour with CHP in operation in the optimal energy cost solution – Case 1

Let us consider a half-hourly time interval from starting at hour 10.00 am in the Summer period. The electricity prices are 89.88 mu/MWh (buy from the EDS) and 44.94 mu/MWh (sell to the EDS). The gas price 40 mu/MWh. The energy loads are 83.9 kWh$_{el}$ (electricity), 112.5 kWh$_{th}$ (heat) and 132.5 kWh$_{cool}$ (cooling). In the solution of the cost optimisation (Fig. 7a) the CHP is in operation, the EHP operates in cooling mode to serve part of the cooling load, being the remaining part of the cooling load supplied through the WARG.

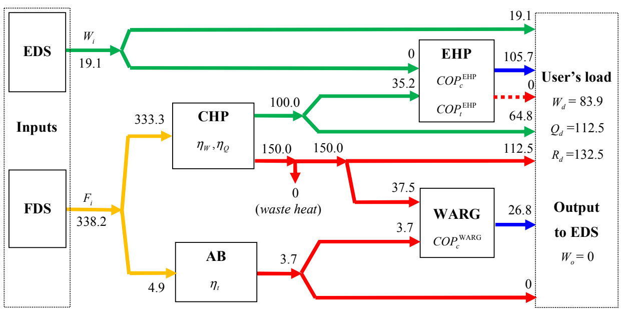
The objective of reducing the electricity input from the EDS is reached by shifting the cooling load from the EHP output to the WARG output. In this way, the electrical energy initially supplied by the CHP to the EHP can be used, by maintaining the CHP at its full output, to serve the electrical load and to sell the excess electricity to the EDS. The process of shifting the electrical quantities can be conceptually described by considering the following phases:

1) remove the electrical energy flowing from the EDS to the EHP and shift the corresponding portion of cooling load to increase the WARG output. The outcome of this phase in shown in Fig. 7b.
2) switch the remaining portion of the EHP cooling output to the WARG output, using the corresponding electrical energy provided by the CHP from the EHP supply to the electrical load. In this process, the CHP continues its operation at maximum energy output, and the electrical energy provided by the EDS is progressively reduced, reaching zero (Fig. 7c) and successively starting to inject electricity into the EDS, up to the final condition of Fig. 7d).

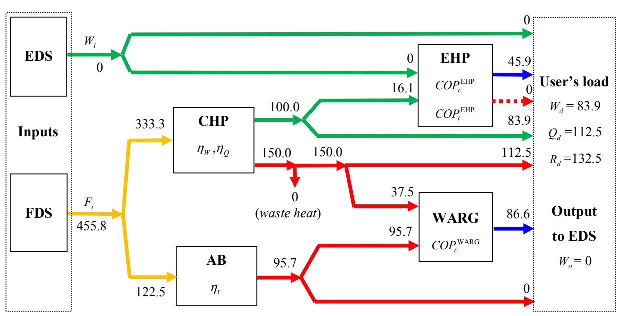
The electricity shifting potential is the sum of the electricity withdrawn by the EHP. The total extra costs incurred by the multi-energy system operator is represented in Fig. 8 in function of the electrical energy shift. The cost characteristic is monotonically increasing, changing its slope in the condition at which the electrical energy input from the EDS becomes zero, because of the different price coefficients for the electricity bought from and sold to the EDS. The curves represented are not exactly linear because of non-constant efficiencies of the components at partial loads.



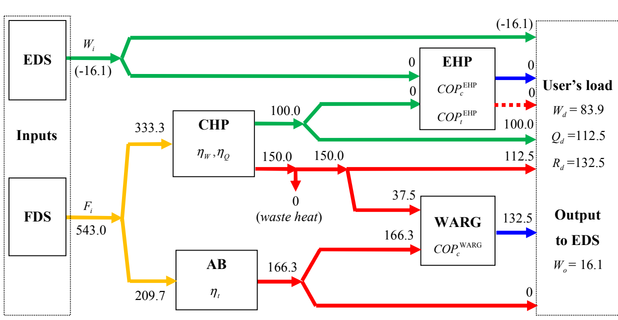
a) initial solution with optimal energy costs



b) electricity shift 0.81 kWh$_{el}$: electricity input from grid to EHP withdrawn, with corresponding cooling output switched to the WARG (extra energy costs 0.12 mu)



c) electricity shift 19.92 kWh$_{el}$: null electrical input from EDS (extra energy costs 2.92 mu)



d) electricity shift 36.05 kWh$_{el}$: null EHP cooling output (extra energy costs 5.87 mu)

Fig. 7. Case 1 with trigeneration and EHP in cooling mode, half-hour starting at hour 10.00 am (numerical values in kWh).

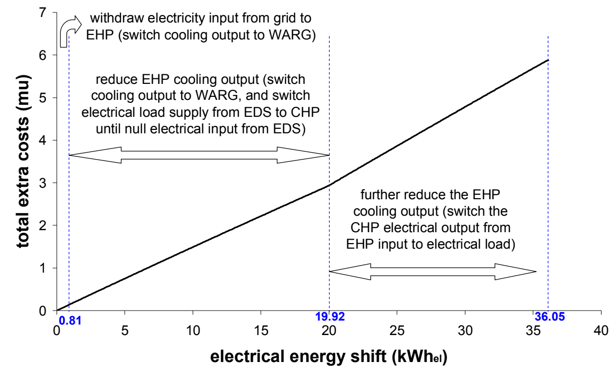


Fig. 8. Total extra costs for shifting energy outside the optimal point.

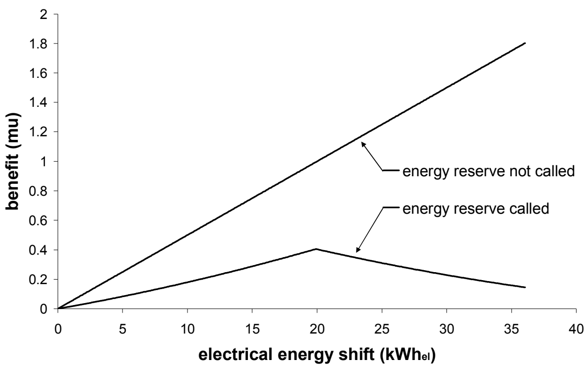
In order to assess the possible convenience of using this multi-energy system to provide reserve services, being the CHP already in operation the electricity shift may occur in a fast way, without leading to additional startup costs. This electricity shifting process is then adapt to provide both spinning (meant here in the sense of relatively "faster") and non-spinning (meant here in the sense of relatively "slower") reserve services.

Let us consider two situations, assuming exemplificative values for the capacity availability fee (0.05 mu/kW/halfhour) and for the exercise fee (0.117 mu/kWh), assuming these values are estimated by the multi-energy system operator to construct the offers in a reserve procurement scheme in which the winning offers are paid according to a pay-as-bid model:

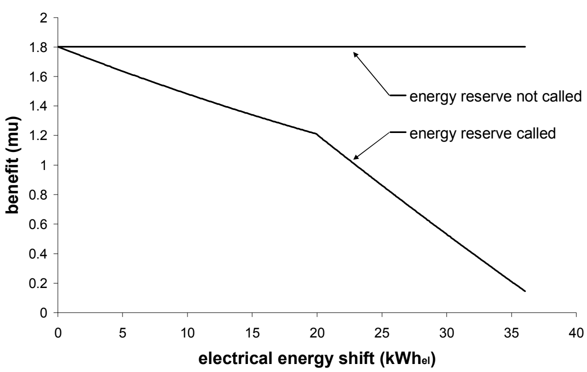
a) The operator of the multi-energy system may choose the capacity to offer for the reserve service, in the range from zero to the capacity corresponding with the electricity shifting potential; the plant, if called, has to provide the energy corresponding to the offer capacity (non-marginal plant, Fig. 9a).
b) The multi-energy system offers the capacity of 72.1 kW (corresponding to the entire electricity shifting potential of 36.05 kWh$_{el}$) as reserve capacity, but it may be called to provide the energy corresponding to the capacity offered, or less (Fig. 9b). In other terms, it has resulted as the marginal plant in the competitive reserve procurement.

More specifically, the contents of Fig. 9b describe the benefit variation corresponding to the segment of Fig. 9a with electrical energy shift equal to the electricity shifting potential (36.05 kWh$_{el}$) from the point with energy reserve not called to the point with energy reserve called.
In both cases, the benefit for the operator successfully participating in the competitive provision of the reserve service is calculated as the difference between the revenues and the extra costs incurred, in two different conditions:

i) considering only the revenues from capacity availability (in the hypothesis that the available plant is not called to provide energy);
ii) considering the revenues from capacity availability and energy provided (if the plant is called to provide energy).



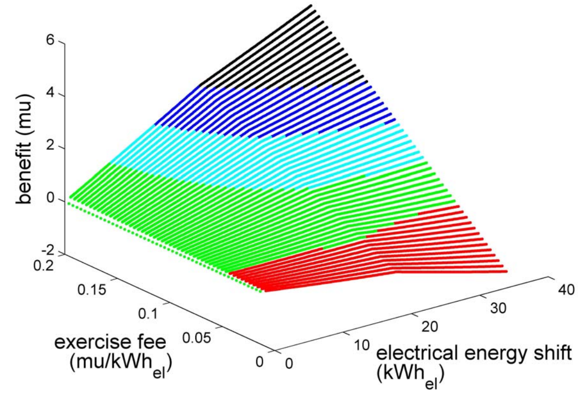
a) case with capacity offer at various levels up to the electrical energy shifting capacity and energy reserve that may be called from the total capacity offered or not called (non-marginal plant)



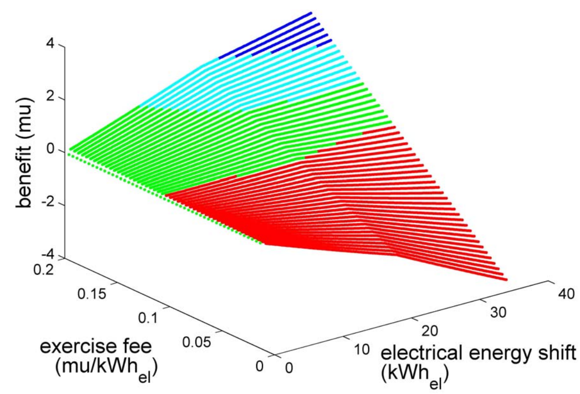
b) case with capacity offer at the electricity shifting potential and energy reserve that may be called totally or partially (marginal plant)

Fig. 9. Benefits occurring when the energy reserve is called or not.

A parametric analysis has been carried out for providing some hints on the capacity/energy arbitrage. The outcomes of this analysis are represented by drawing the ancillary service profitability map. Fig. 10a and Fig. 10b show the results for availability fee of 0.05 and 0.02 mu/kW/halfhour, respectively. In these figures, the points on the vertical axis are introduced with colours changing at steps of 1 mu. The borderline condition for the benefit indicates that there is no benefit when the exercise fee is relatively low. For values of the exercise fee around 0.1 mu/kWh_{el} and availability fee of 0.05 mu/kW/halfhour the most convenient solution appears at the intermediate electrical energy shift of 19.92 kWh_{el} (as in Fig. 9a) while for higher values of the exercise fee the most convenient condition is located at the electricity shifting capacity.



a) availability fee 0.05 mu/kW/halfhour



b) availability fee 0.02 mu/kW/halfhour

Fig. 10. Ancillary service profitability map for *Case 1*.

5.3. Example for a half-hour with CHP not in operation in the optimal energy cost solution

Let us consider the half-hourly time interval starting at hour 12.00 am in the Summer period. The electricity prices are 46.86 mu/MWh (buy from the EDS) and 23.43 mu/MWh (sell to the EDS). The gas price 40 mu/MWh. In the solution of the cost optimisation (Fig. 11) the CHP is not in operation. The EHP operates in cooling mode.

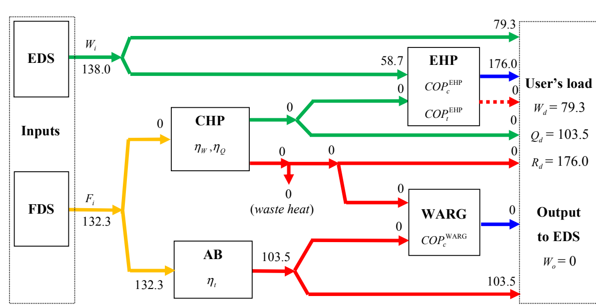


Fig. 11. Initial solution for half-hour starting at hour 12.00 am (values in kWh).

The objective of reducing the electricity input from the EDS can be reached through different strategies. For example, two strategies are considered here:

a) *Case 2a*: first reduce the electricity flowing from the EDS to the EHP;
b) *Case 2b*: first reduce the electricity flowing from the EDS to the local load.

5.3.1. Analysis of Case 2a

In this case, the first action is to shift the 58.7 kWh_{el} provided from the EDS to the EHP. Since the final goal of the electricity to be shifted is to supply the cooling load, the cooling load has to be shifted from the EHP output to the WARG output. There are two ways for obtaining the required shifting:

- supply the WARG from the AB;
- supply the WARG from the CHP output.

In the first way, the AB is already in operation, and the shifting is viable without implying further startup costs. Conversely, the second way requires the start up of the CHP, with the corresponding startup costs and time needed to get the CHP in operation at the minimum level (in our case, set to 50% of the full capacity). Let us then consider the illustrative example in which the initial electricity shifting is obtained by supplying the WARG from the AB. The result is shown in Fig. 12a.

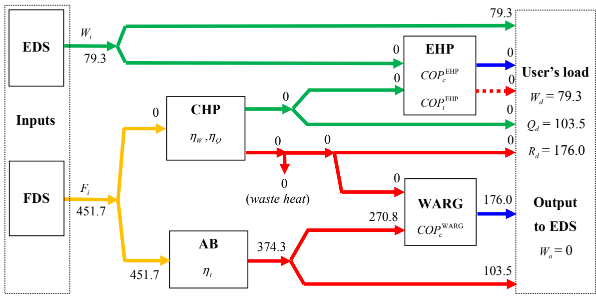
At the end of this action, the EHP is offline and the EDS is still serving the local electrical load. There is then further potential of further reducing the electricity input from the EDS. However, the only way to produce electricity to the local load is to start the CHP, incurring in the corresponding startup costs and with the limitation of providing at least the minimum level of CHP output. For the small-scale CHP unit, let us consider a constant term representing the startup costs and set it to 2 mu for this illustrative example.

When the CHP enters in operation at its minimum level, it provides 50 kWh_{el} of electricity and an amount of heat corresponding to its characteristic heat-to-electricity ratio. The CHP is then simultaneously replacing the electricity supplied by the EDS and the heat supplied by the AB to the local load. In this respect, we can consider an intermediate solution (Fig. 12b) in which the CHP heat output reaches the value of the local heat load (103.5 kWh_{th}). In this condition, the CHP has not reached its rated output, so that there is still room for increasing the CHP production, provided that a solution is found for using both electricity and heat production. Concerning electricity, the local load has not been totally supplied, so there is the possibility to complete the supply of the local load, and also to produce further electricity up to the CHP limit, as excess electricity can be injected into the EDS. About heat, there is the possibility of replacing the heat input to the WARG by switching the source from the AB to the CHP. If all the heat flowing from the AB to the WARG is switched to the CHP output before reaching the CHP limit, the excess heat could be wasted off. However, this is not the case in the example considered here. The full switching of the 138 kWh_{el} of the initial electricity input from the EDS (i.e., the electrical energy shifting of 138 kWh_{el}) is reached in the solution shown in Fig. 12c, before reaching the full CHP output. Furthermore, using the additional operational margin of the CHP to provide energy at its rated output, the final solution (Fig. 12d) corresponds to selling 20.7 kWh_{el} of electricity to the EDS, exploiting the electricity shifting potential of 158.7 $kWh_{el.}$

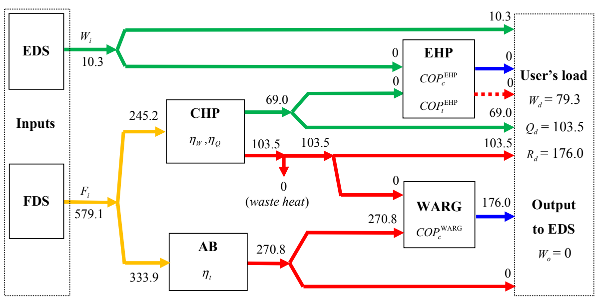
The overall synthesis of Case 2a is represented as follows. Fig. 13 indicates the changes in the flows of electricity when the electrical energy shift increases. Fig. 14 shows the total extra costs referring to the different values of the electrical energy shift for the strategy under consideration. In the first part the costs increase because of shifting of the cooling load production from the EDS-EHP to the more costly solution supplied by the FDS and using the AB and the WARG. The second part requires the CHP startup and its usage above its technical minimum. Notwithstanding the practical benefits of the combined production of heat and power in energy efficiency terms, with the prices taken into account in this example the CHP was off in the optimal costs solution and with the CHP introduction the total extra costs exhibit a further increase. It can be seen that a discontinuity appears when the electricity input from EDS becomes null. This is due to the difference between the selling and buying electricity prices. The details are shown in Fig. 15. The total extra costs are the sum of the monotonically increasing fuel & CHP startup costs and of the monotonically decreasing electricity costs. At the zero crosspoint the electricity costs change their sign and slope, so that the total extra costs become lower than the fuel & CHP startup costs, but with the overall effect of increasing the slope of the total extra costs.

The effects of offering capacity to provide reserve services is addressed by looking at the representations shown in Fig. 16 and Fig. 17. The exemplificative values of the capacity availability fee (0.05 mu/kW/halfhour) and of the exercise fee (0.117 mu/kWh) are the same at those used for Case 1.

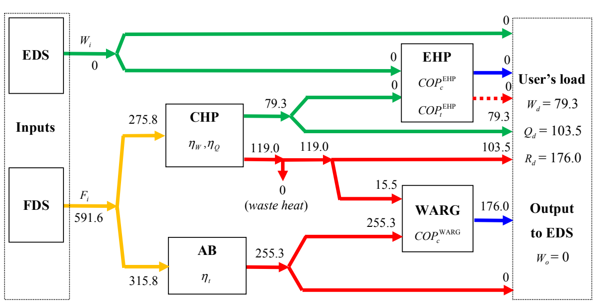
For this multi-energy unit, the capacity offer for spinning reserve (faster) services is limited to 117.4 kW (providing an electrical energy shift of 58.7 kWh_{el}). The additional 200 kW CHP capacity (with the corresponding energy of 100 kWh_{el} leading to the electrical energy shifting potential of 158.7 kWh_{el}) can be offered for non-spinning (slower) reserve services.



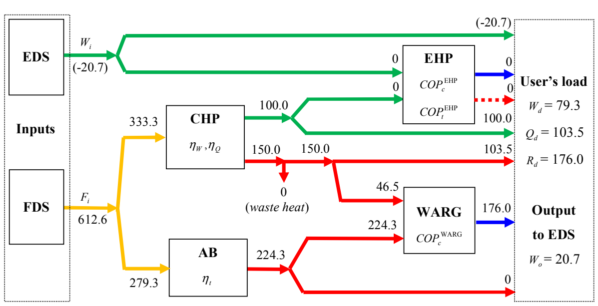
a) Solution after 58.7 kWh$_{el}$ electrical energy shift (values in kWh).



b) Solution after 127.7 kWh$_{el}$ electrical energy shift (values in kWh).



c) Solution after 138 kWh$_{el}$ electrical energy shift (values in kWh).



d) Solution after 158.7 kWh$_{el}$ electrical energy shift (values in kWh).

Fig. 12. Summer case 2a with trigeneration and EHP in cooling mode, half hour starting at hour 12.00 am (numerical values in kWh).

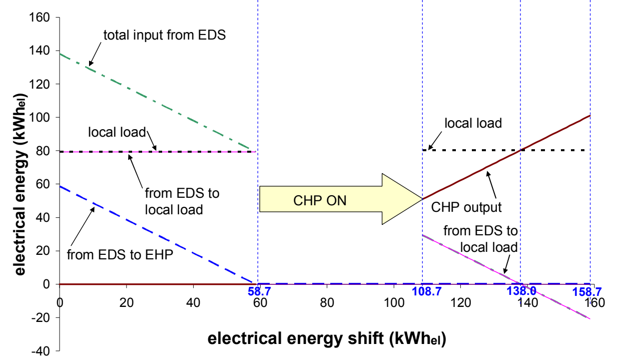


Fig. 13. Electrical energy flows at different levels of electrical energy shift.

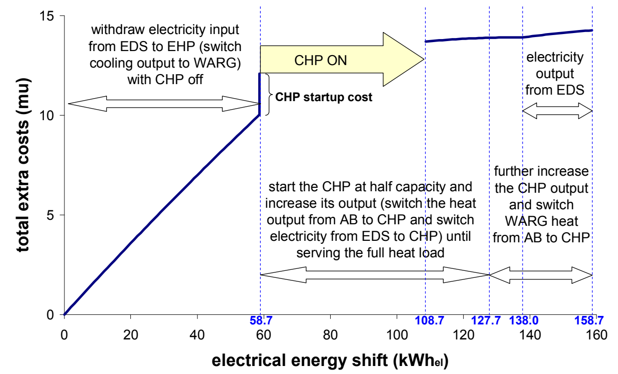


Fig. 14. Total extra costs at different levels of electrical energy shift.

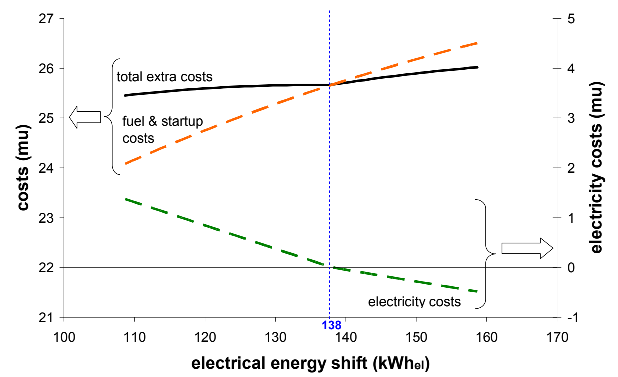


Fig. 15. Details of the total extra costs components.

Fig. 16 shows the possible situations in which the owner of the multi-energy system can decide the amount of capacity to offer to the non-spinning reserve service, taking into account that the total energy corresponding to that capacity offered may be called or not. The capacity is the one corresponding to the half-hourly electrical energy shift. The results show that, considering the prices assumed in this example, the benefits in case of producing electricity by changing the operation point remain negative when the CHP is off, whereas positive benefits are obtained by exploiting the CHP capacity (even in the presence of the startup costs).

Fig. 17 refers to the last point of Fig. 16, in which the capacity of 117.4 + 200 = 317.4 kW (corresponding with the electricity shifting potential of 158.7 kWh_{el}) is offered as non-spinning reserve, considering for this service an availability term of 0.05 mu/kW and an exercise fee (to be added in the case in which the multi-energy system is called to provide the reserve service) of 0.117 mu/kWh_{el}. The case in which different values of energy can be called at the same available capacity (equal to the electricity shifting potential) in a marginal plant are indicated for generality. The results show that, taking into account the startup costs when the CHP switches on, the benefit is always positive, for any amount of reserve energy that may be called. The plot of Fig. 17 also highlights a possible critical aspect for the marginal plant: energy reductions from to 58.7 kWh_{el} 108.7 kWh_{el} are not viable, as the CHP cannot operate in a region below its minimum technical limit. Further energy balancing from other sources would be needed to compensate for part of the energy to be provided in this case.

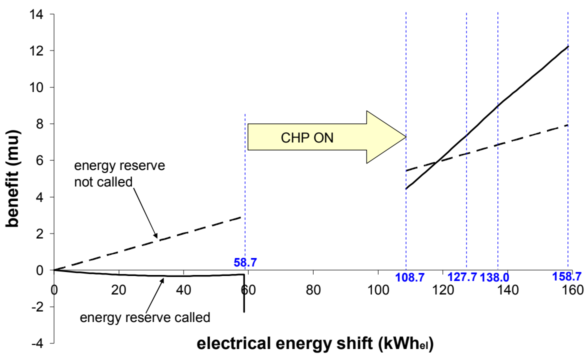


Fig. 16. Benefits for different values of electrical energy shift corresponding to offered capacity and reserves called to operate or not.

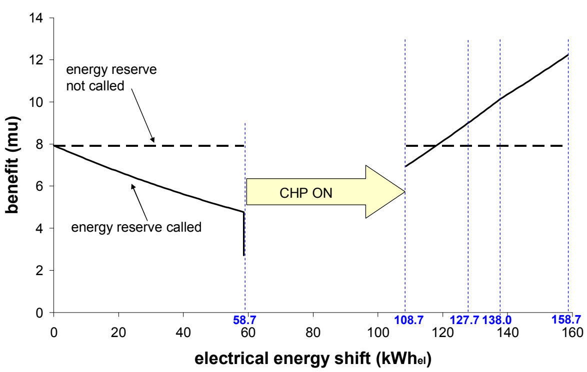
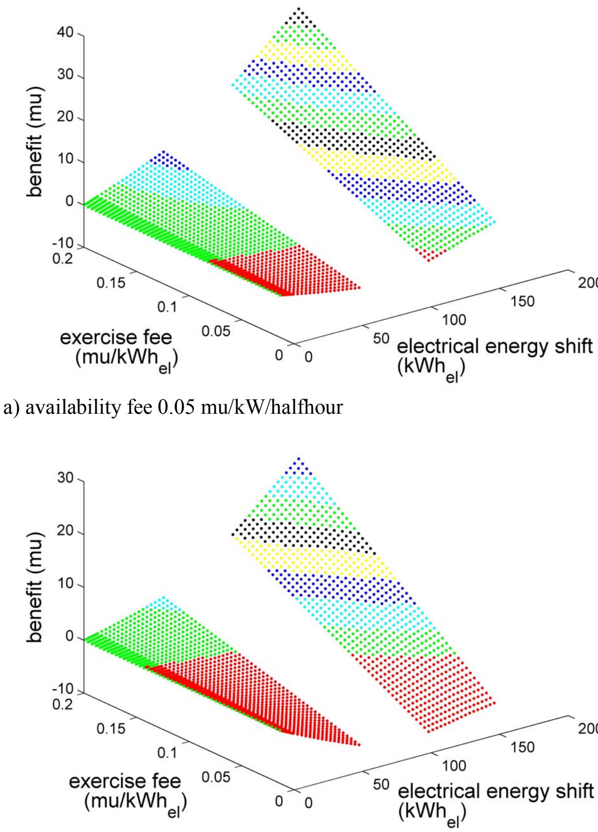


Fig. 17. Benefits for different values of electrical energy shift with capacity offered corresponding to the electricity shifting potential.

The ancillary service profitability maps are shown in Fig. 18a and Fig. 18b for an availability fee of 0.05 mu/kW/halfhour and 0.02 mu/kW/halfhour, respectively. In these figures, the points on the vertical axis are introduced with colours changing at steps of 3 mu. The borderline condition for the benefit indicates the region in which there is no convenience. In Case 2a, the most convenient electrical energy shift is the electricity shifting capacity, provided that the availability and exercise fees are sufficiently high to lead to a corresponding positive benefit.



a) availability fee 0.05 mu/kW/halfhour

b) availability fee 0.02 mu/kW/halfhour

Fig. 18. Ancillary service profitability map for *Case 2a*.

5.3.2. Analysis of Case 2b

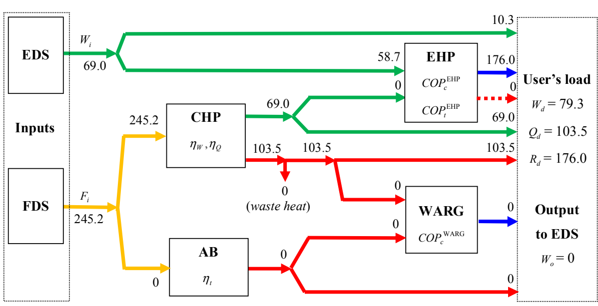
In this case the electrical demand has to be directly covered by the CHP. Being the CHP initially off, this implies that non-spinning reserve services can be provided taking into account the CHP startup costs. The first action is then to shift 79.3 kWh_{el} to serve the local load from the EDS to the CHP, correspondingly shifting an amount of heat load indicated by the CHP heat-to-electricity ratio from the AB to the CHP. For illustrative purposes, this action is shown here in two steps. In the first step electricity and heat are shifted until all the heat load is supplied by the CHP (Fig. 19a). In these conditions, the CHP is still not at its maximum output. In the second step the CHP loading is continued until the electricity flowing from the EDS to the electrical load becomes null, as it has been shifted to the CHP electrical output (Fig. 19b).

From this point, it would be interesting to further increase the CHP output above the value of the local electrical load, selling the excess electricity to the EDS. However, this is not possible yet, as the EDS is still providing supply to the EHP. The further action is then to shift the cooling load to be served from the EHP to the WARG, using the heat supply from the AB at the WARG input (the CHP heat output cannot be increased, even though it is not at its maximum, because it is not possible to provide excess electricity until the electrical input from the EDS becomes null). The solution, leading to an electrical energy shift of 138.0 kWh_{el}, is reported in Fig. 19c.

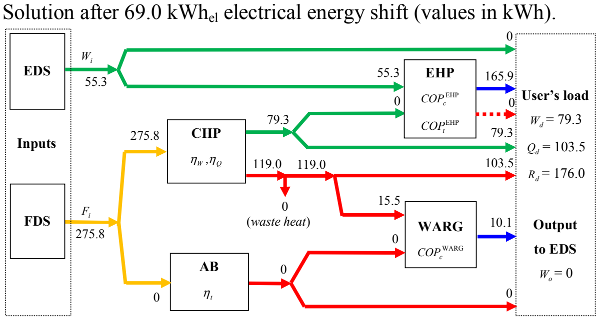
Now the CHP can be further loaded until its limit conditions are reached. For this purpose, part of the heat supplying the WARG is shifted from the AB to the CHP, until reaching 150 kWh_{th} at the CHP heat output. The corresponding electricity output increases to 100 kWh_{el}, selling 20.7 kWh_{el} to the EDS. The new condition reached is shown in Fig. 19d. The final point is the same as the one obtained in Fig. 12d, in particular with the same electricity shifting potential.

The overall synthesis of Case 2b is represented in Fig. 20, indicating the changes in the flows of electricity when the electrical energy shift increases. The CHP is initially loaded up to a given output, then it remains at that output and in the final phase of the process the CHP output increases again to reach the full loading condition.

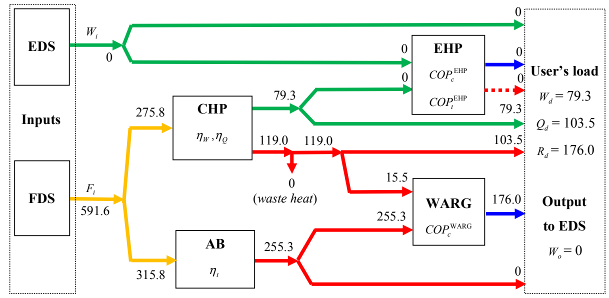
Fig. 21 shows the total extra costs referring to the different values of the electrical energy shift for the strategy under consideration. The startup costs of the CHP are considered for any value of the electrical energy shift.



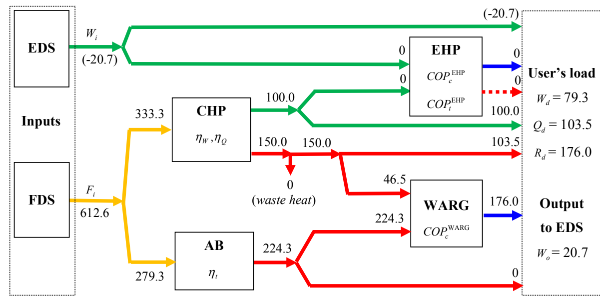
a) Solution after 69.0 kWh_{el} electrical energy shift (values in kWh).



b) Solution after 82.7 kWh_{el} electrical energy shift (values in kWh).



c) Solution after 138.0 kWh_{el} electrical energy shift (values in kWh).



d) Solution after 158.7 kWh_{el} electrical energy shift (values in kWh).

Fig. 19. Case 2b with trigeneration and EHP in cooling mode, half hour starting at hour 12.00 am (numerical values in kWh).

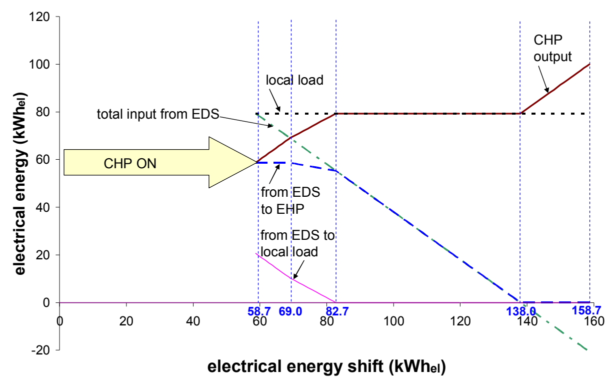


Fig. 20. Electrical energy flows at different levels of electrical energy shift.

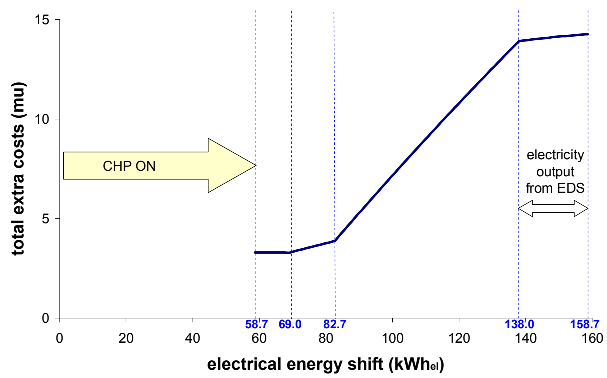


Fig. 21. Total extra costs at different levels of electrical energy shift.

The benefit of using the multi-energy system to provide the reserve service is determined as in the previous cases. The exemplificative values of the capacity availability fee (0.05 mu/kW/halfhour) and of the exercise fee (0.117 mu/kWh) are the same at those used for Case 1 and Case 2a. Fig. 22 shows that a non-monotonic evolution of the benefit appears when the electrical energy shift increases when the energy reserve is not called. This may give room to the decision maker for establishing the capacity to offer. In particular, Fig. 23 refers to the marginal plant offering the capacity corresponding with the electricity shifting potential, whose benefit could even increase in some intermediate conditions of energy provision with respect to the energy provided at the offered capacity.

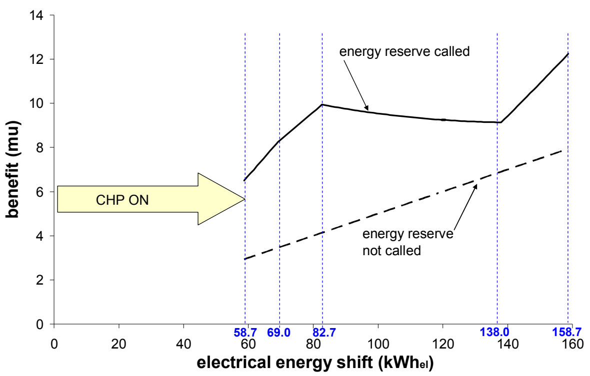


Fig. 22. Benefits for different values of electrical energy shift corresponding to offered capacity and reserves called to operate or not.

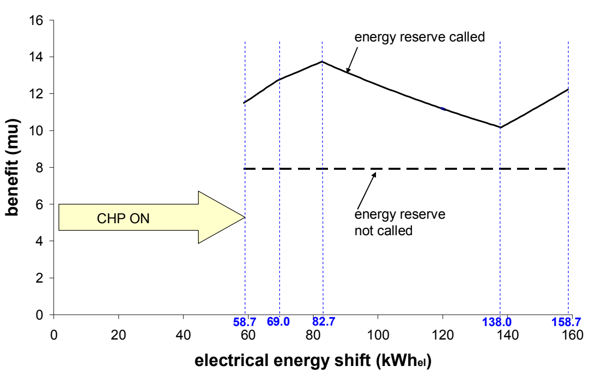
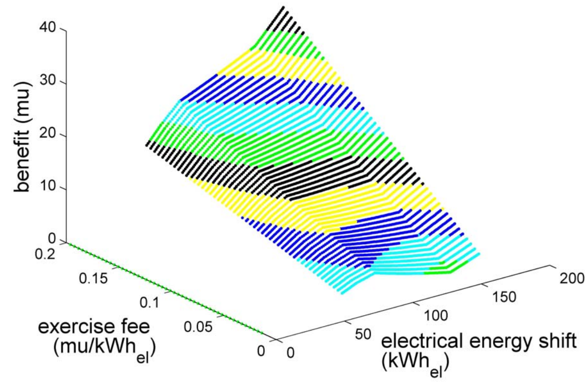
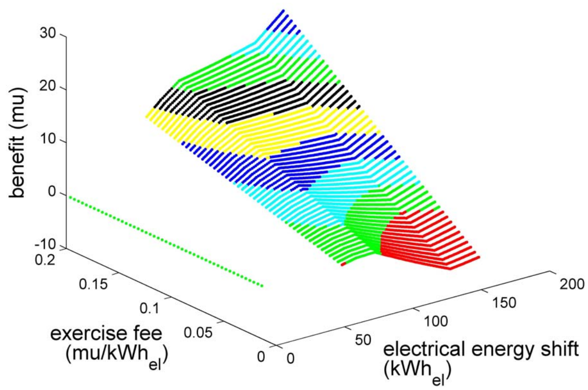


Fig. 23. Benefits for different values of electrical energy shift with capacity offered corresponding to the electricity shifting potential.

The ancillary service profitability maps are shown in Fig. 24a and Fig. 24b for availability fee of 0.05 mu/kW/halfhour and 0.02 mu/kW/halfhour, respectively. In these figures, the points on the vertical axis are introduced with colours changing at steps of 3 mu. For the availability fee of 0.05 mu/kW/halfhour all the conditions indicated in the Fig. 24a are convenient. The maximum benefit is at the electrical energy shift of 82.7 kWh_{el} for the lowest values of the exercise fee and moves to the electricity shifting potential when the exercise fee increases. If the availability fee becomes lower, there are conditions at which considering the electricity shifting potential would lead to negative benefits, while positive benefits are obtained for lower values.



a) availability fee 0.05 mu/kW/halfhour



b) availability fee 0.02 mu/kW/halfhour

Fig. 24. Ancillary service profitability map for *Case 2b*.

6. Conclusions

This paper has presented a novel view on the possibility of exploiting multi-energy systems to provide ancillary services, in particular of reserve type. The study has been specifically focused on energy shifting occurring in the multi-energy system without changing the local energy loads. In this case, the provision of reserve services is a particularly valuable option for the multi-energy system, as it enables the operator obtaining benefits without affecting the energy usage and thus the comfort of the customers.

As specific contents, this paper has introduced an extension of some concepts such as electricity shifting potential and profitability maps, defined by the authors with reference to real time demand response. The extension basically refers to the introduction of the framework needed to address both the capacity side and the possible provision of energy in the reserves context.

The ancillary service profitability maps that have been developed enable the energy system operator to manage the energy resources available within the limits of the electricity shifting potential. The convenience of offering the multi-energy system resources depends on the costs of the different types of energy (e.g., electricity and gas) and on the values of the economic entries such as the availability fee and the exercise fee.
A number of results have been shown for some illustrative test cases. The nature of these results depends on the specific data and the convenience of the solutions cannot be directly generalized. However, the explicit construction of the ancillary service profitability maps has been shown to explain the entries needed to perform the analyses and to highlight the variability of the results on the basis of various technical and economic parameters.

The framework developed in this work may be useful to address specific problems such as resource scheduling and offer definition for a decision maker willing to participate in energy and reserve markets. For example, a decision maker could operate in the direction of offering the entire electricity shifting potential as a reserve, or to participate in the reserve and in the balancing markets with different offer quantities of the available resources. Details on this issue will be addressed in future work. In addition, work in progress deals with elaborating on the *spread* between the benefit occurring when the multi-energy system is not called to provide reserve energy and the benefit occurring when it is called, as well as with taking into account the probability of being called or not to provide the available service.

References

[1] P. Mancarella, “Multi-energy systems: An overview of concepts and evaluation models”, Invited Paper, *Energy*, under review.

[2] P. Mancarella and G. Chicco, *Distributed multi-generation systems. Energy models and analyses*, Nova Science Publishers, Hauppauge, NY, 2009.

[3] G. Chicco and P. Mancarella, “Distributed multi-generation: A comprehensive view”, *Renewable and Sustainable Energy Reviews*, Vol. 13, No. 3, pp. 535-551, 2009.

[4] J. H. Horlock, *Cogeneration – Combined Heat and Power*, Pergamon Press, 1987.

[5] P. Mancarella, “Cogeneration systems with electric heat pumps: energy-shifting properties and equivalent plant modeling”, *Energy Conversion and Management*, Vol. 50, No. 8, pp. 1991-1999, 2009.

[6] G.Chicco and P.Mancarella, “From cogeneration to trigeneration: profitable alternatives in a competitive market”, *IEEE Trans. on Energy Conversion*, Vol. 21. No. 1, pp. 265-272, 2006.

[7] G. Chicco and P. Mancarella, “Matrix modelling of small-scale trigeneration systems and application to operational optimization”, *Energy*, Vol. 34. No. 3, pp. 261-273, 2009.

[8] D. Papadaskalopoulos, et al., "Decentralized Participation of Flexible Demand in Electricity Markets. Part II: Application with Electric Vehicles and Heat Pump Systems", IEEE Trans. on Power Systems, 2013, in press.

[9] P. Mancarella and G. Chicco, “Real-time demand response from energy shifting in Distributed Multi-Generation”, IEEE Transactions on Smart Grid, 2013, in press.

[10] M. C. Bozchalui, S. A. Hashmi, H. Hassen, C. A. Cañizares and K. Bhattacharya, Optimal Operation of Residential Energy Hubs in Smart Grids, IEEE Trans. on Smart Grid, Vol. 3, No. 4, December 2012, pp. 1755–1766.

[11] L.D. Danny Harvey, A handbook on low-energy buildings and district energy systems, Earthscan, London, 2006.

[12] M. Geidl and G. Andersson, “Optimal Power Flow of Multiple Energy Carriers”, IEEE Trans. on Power Systems, Vol. 22, No 1, February 2007, pp. 145–155.

[13] A. Valero, M. Lozano, “An introduction to thermoeconomics”, Chapter 8 in Boehm RF, ed., Developments in the design of thermal systems. Cambridge University Press, Cambridge, UK, 1997.

[14] P. Mancarella, From cogeneration to trigeneration: energy planning and evaluation in a competitive market framework, PhD Dissertation, Politecnico di Torino, Torino, Italy, 2006.

[15] Mancarella and G.Chicco, Operational optimization of multigeneration systems, Book Chapter in the book “Electric power systems: Advanced forecasting techniques and optimal generation scheduling” (ISBN 9781439893944), J.P.Catalão (ed.), CRC Press, Taylor & Francis Group, 2012.

[16] M. Houwing, et al., “Demand response with micro-CHP systems”, *Proceedings of the IEEE*, Vol. 99, No. 1, pp. 200-213, 2011.

[17] D. Kirschen and G. Strbac, *Fundamentals of Power System Economics*, John Wiley & Sons, 2004.

[18] C.K. Simoglou, P.N. Biskas and A.G. Bakirtzis, “Optimal Self-Scheduling of a Thermal Producer in Short-Term Electricity Markets by MILP”, *IEEE Trans. on Power Systems*, Vol. 25, No. 4, pp. 1965-1977, 2010.

[19] L.M. Arroyo and A.J. Conejo, Optimal Response of a Power Generator to Energy, AGC, and Reserve Pool-Based Markets, *IEEE Trans. on Power Systems*, Vol. 17, No. 2, pp. 404-410, 2002.