The potential of the natural gas grid to accommodate hydrogen as an energy vector in transition towards a fully renewable energy system

Piero Danieli*[a], Andrea Lazzaretto[b], Jafar Al-Zaili[c], Abdulnaser Sayma[c], Massimo Masi[a], Gianluca Carraro[b]

[a] University of Padova, Department of Management and Engineering, Vicenza, Italy
[b] University of Padova, Department of Industrial Engineering – DII - Padova, Italy
[c] City, University of London, Department of Mechanical Engineering and Aeronautics – London, UK,
**Corresponding author*

Abstract:

The temporal and geographical availability of renewable energy sources is highly variable, which imposes the importance of correct choices for energy storage and energy transport systems. This paper presents a smart strategy to utilize the natural gas distribution grid to transport and store the hydrogen. The goal is twofold: evaluating the capacity limits of the grid to accommodate "green hydrogen" for preset increasing shares of renewable energy sources (RESs) and determining at the same time the optimal mix of wind, photovoltaic (PV), biomethane and power-to-gas systems that minimizes the investment and operation costs. To this end, the energy supply system of an entire country is modelled and optimized considering the real characteristics and pressure levels of the gas grid, which is assumed to be the only storage mechanism of green hydrogen. The operational concept is to fill up the gas grid with hydrogen during the day and with natural gas during the night while always consuming the natural gas-hydrogen blend. Green hydrogen is generated by electrolysers powered by PVs, wind turbines and biomethane power systems. Results of the optimizations showed that: i) as long as the share of RES does not exceed 20%, there is no need to use the gas grid as RES storage system, ii) from 20 to 50% of RES share the gas grid receives the surplus of electricity in the peaks that would be necessary to "complete" the dispatchability of RES electricity, iii) above 50%, the excess of electricity in the peaks has to be used to generate the thermal energy required by the consumers. The gas grid can be used as unique renewable energy carrier and storage system up to 65% of RES share.

Keywords:

Power to gas, natural gas distribution grid, hydrogen, renewable energy share, methane and hydrogen blend

Introduction

The European energy policies are currently pushing for a fast transition to energy scenarios characterized by high share of renewable energy sources (RES). In the short to medium term, the main targets are the decarbonization of the energy sector (e.g., 30-50% reduction of CO2 emission in 2030-2050 compared to 2019) and the share of renewable energy into the electricity mix (e.g., 55% of share in 2030 and 90% in 2050) [1]. In this context, the future evolution of the energy mix should be driven by the minimization of the economic, environmental, and social cost associated with the conversion of renewable energy sources. Most of these costs derive from the necessity of energy storage systems to handle the intermittency of RES, which in turn requires minimizing the installation and operation costs of these systems. To this end, smart strategies must be developed starting from the present technological, economic, and social structure of each country and developing reliable optimization models including i) the present mix of energy sources, ii) the available grids and energy inputs, iii) the design and operative constraints of each energy conversion and storage unit and iv) the evolution of the energy scenarios (in terms of availability and costs) in the considered time span. Italy shows a share of RES of about 32% in the electric energy mix and the inclusion of renewables is currently allowed by water reservoirs for hydropower, while for photovoltaic and wind systems by the electric grid (as a virtual energy storage) and by small and local electric energy storage capacities. In the future evolution of the energy scenarios, large-scale renewable energy storage systems represent a key issue that must be addressed. Several studies have faced the theme of large-scale energy storage systems for intermittent energy sources indicating the following as the most feasible technologies: pumped hydro storage (PHS) [2], compressed air energy storage (CAES) [3, 4], underground thermal energy storage (UTES) [5, 6], underground hydrogen or methane storage (UHS, UMS) using power-to-gas systems [7, 8] and thermal energy storage (TES) using aboveground tanks [9]. Although these systems seem to be the best options for large-scale applications, they share major issues such as high costs, location dependencies and technical implementation problems. Thus, it is evident the necessity to find strategies to minimize the energy storage systems by optimizing the coupling between power generation and energy demands or by using alternative and less expensive storage systems. An opportunity is given by power-to-gas technologies which can be supported by an existing and widespread infrastructure, such as the natural gas grid, acting as storage and transport device. In this respect, the utilization of existing apparatus may be of great help in minimizing the economic, environmental, and social costs of both individuals and the entire community [10]. The injection of hydrogen or syngas (from RES using power-to-gas units) into the actual gas grid is a topic of very high interest as proven by the vast number of works available in the recent scientific literature. From the exergy point of view, power-to-hydrogen (PTH) and power-to-methane (PTM) are commonly considered the most efficient systems to make renewable electricity dispatchable [11]. To achieve highly efficient and green solutions, particular attention must be given to the production pathway of hydrogen [12]. Thus, the power-to-gas technologies have to be selected considering both economic [13, 14] and operational aspects that can compromise the grid capability of energy delivery [15]. The actual gas grids are not conceived to transport hydrogen. Therefore, several studies focus on the evaluation of the potential issues of this novel practice. In the medium-to-long period, embrittlement may affect the structural performance of pipelines [16], but many concerns also exist about possible leakages in the pipe sealings, which undermine the people safety in urban areas [17]. Moreover, the low density and low volumetric energy content of hydrogen may limit the energy delivery capability of the grid [18, 19] especially during peak load conditions. In fact, the additional pressure drops deriving from the transport of hydrogen could not be entirely covered by the compressors installed into the grid [20]. From the end-consumers' point of view, many works in the literature evaluate the influence of methane/hydrogen mixtures on the performance of stationary power generation systems directly connected to the gas grid, such as internal combustion engines (ICE) or gas turbines (GT) [27-29]. Most studies indicate that the use of methane/hydrogen mixture in ICEs [21-26] can improve the efficiency and reduce the emission of pollutant however, in case of GTs [27-29] this practice involves large and expensive modifications of the burners and of the operation parameters to maintain high efficiency levels. In the last few years, the behaviour of domestic appliances fueled by hydrogen enriched natural gas (HENG) has also been investigated by an increasing number of authors [30-32] indicating the necessity to rethink the regulations about risk assessment [33]. The use of these mixtures does not seem to have a negative impact on the industrial sectors which exploit the combustion of natural gas natural gas, such as glass or iron furnaces [34]. The quality of the products does not vary if the process parameters are adjusted in accordance with the percentage of hydrogen in the gas grid. In general, the scientific literature agrees that the natural gas grids and all the device connected to it can work without any modification until a 10% of hydrogen in volume. In between 10% and 20%, the principal limits are represented by compressors capabilities [18]. Within the 20-50%, the grid could still be operated by substituting some components or varying the operating conditions of the grid. As a result, the operation of the grid within 10% HENG mixtures involves just modest costs, whereas exceeding that threshold implies the need of precise economic evaluations to state the effective convenience of the system [35] compared to other solutions conceived to reach high share of RES. The cost of many power-to-gas technologies is constantly evolving, and many cost projections appeared in the literature indicate these systems as attractive in the near future [36, 37]. In this context, the attention is also on adequate incentive policies that should be applied to achieve specified energy scenarios using power-to-gas technologies with the support of the actual gas grid [38-41]. Another major research topic is about the modelling of the gas grid to simulate its operation with different percentages in volume of hydrogen, and to optimize its interaction with other systems such as the electric grid. Many models are utilized to simulate the grid as an isolated system, to explore the capabilities of the grid to work with various blends of methane/hydrogen [42-45] and identify the feasibility limits to the injection of hydrogen into the grid [46-50]. It should be noted that the power-to-gas systems act as a bridge between gas and electric grids [51, 52], which have a mutual dependency. Thus, the inclusion of a simplified model (without real constraints) of the electric grid allows to assess the capability of the gas grid to avoid curtailment of RES [53-55] and to give insights for the grid re-design or modification aimed to achieve a more efficient coupling with the electric grid [56-58]. Most of the models presented in the literature include limiting assumptions that may strongly affect the results. This is more evident when vast frameworks (i.e., entire countries, large regions, long time frames) are considered. Just a few authors considered the seasonal variability of the natural gas and electricity consumptions [59] as well as of the geographical distribution of the renewable energy sources [60-62]. Other losses of accuracy come from neglecting the line-packing [63] (variation of the pipelines pressure to improve the flexibility of the gas grid) which has a noticeable impact on the gas grid capability to store RES [64].

Most of the mentioned papers in the literature considers the existing technical constraints of the gas grid, focusing their analysis to small temporal and geographical frameworks and neglecting some key features of the gas grid. The principal novelty of this paper is to provide an optimization approach that can suggest minimum-cost solutions towards a 100% RES scenario, widening the perspectives of past studies by focusing on the entire energy system of a country and taking into account the flexibility features of the real gas grid and the constant development of new technologies that inevitably follows the increasing shares of RES. The general scale of the proposed investigation involves the need of some critical assumptions to simplify the optimization process and achieve reasonable computation times. These assumptions are listed and discussed into a dedicated Section of the paper. The proposed optimization strategy has been applied to a real case study considering the real physical volume, pressure and possible pressure variations of each pipeline of the gas grid. The main goal of the work is to develop an optimization framework of a national energy conversion system to evaluate the capability of the gas grid to store and transport the hydrogen generated by RES in future energy scenarios. These scenarios are characterized by pre-determined increasing share of RES. The objective function of the optimization process is the minimization of the investment and operation costs of the renewable energy systems, as a whole, that are progressively included into the total energy conversion system. The optimization procedure evaluates the mix of renewable systems and their temporal variation in the entire system to fulfill the fixed shares of the RES. The storage of hydrogen into the gas grid gives flexibility to the management of the thermal and electric demands and can be considered as a “hybrid” alternative to traditional thermal and electric energy storage systems. The paper provides a solution to the problems related to the energy transition towards a 100% RES scenario by minimizing the costs associated with the storage of these sources. Although the Italian energy system was studied as case study in this paper, the proposed strategy is general and can be applied to other countries with similar architecture of the energy system.

Other important novelty of the current study is related to the modelling of the gas grid. The developed model allows evaluating the capability of the grid to store renewable energy and calculating the actual amount of renewable energy that can be made dispatchable by the grid. This is achieved in the model by introducing the option to vary the operating pressure of the grid (usually called “line packing”), and constantly monitoring the content of the grid (i.e., the amount of H_2 and CH_4). In comparison with other works in the literature, the following features are introduced: i) the gas grid can transport any percentage of H_2 mixed in blend with CH_4, ii) H_2 is consumed in mixture with natural gas in already available power plants and boilers connected to the gas grid. Assumptions i) and ii) are justified by considering the strong push given to the natural gas industry to adapt the current infrastructure to the use of H_2/CH_4 blends. In fact, there is a consent within the industry that the gas grid infrastructures will evolve in response to the anticipated RES share scenarios. In any case, the possible excess of H_2, compared to the storage capacity of the grid dictated by its technical limits at a certain time, could be stored in other storage capacities, which are out of the scope of this paper.

2. Critical assumptions of the model

The critical assumptions of the model are listed in the following bullet points. The reasons behind these choices are provided in this section to highlight their ineffectiveness on the results of the analysis, in view of the considered objectives.

- Uniform distribution of H_2 in the grid. This critical assumption takes into account that the H_2 generation points are distributed into the country to maintain the same ratio between H_2 and CH_4 in the entire grid. This hypothesis is the more acceptable the higher the electrolysers installed capacity since a large number of H_2 generation units could be reasonably distributed capillary in the country. The assumption is coherent with the structure of the energy systems, which is considered to be composed of a single unit per energy conversion system without considering the specific spatial location.
- Neglect of transport sector consumptions. In accordance with the objectives of the paper, aimed to investigate the potential utilization of the gas grid by the sectors (industrial and residential) that at present rely on it and the electric grid, it is assumed that the transport sector will be de-carbonized independently from the gas grid in future scenarios. Accordingly, the energy consumptions of the transport sector are not considered here. Although this hypothesis is assumed here to noticeably simplify the model, it finds support from some recent projections which indicate the full-electric vehicles as the most viable "green" solution in the future [65].
- Neglect of renewable thermal energy systems. Heat pumps converting renewable electricity into heat and thermal solar power systems are here neglected because they could guide the optimizations towards the exclusion of the grid as H_2 storage and carrier system. By including this assumption, the gas grid represents the only "bridge" from renewable electricity to renewable heat. Thus, the utilization of the grid with blends of methane/H_2 is indirectly imposed.
- Constant electric and thermal energy demands. The energy demands are considered as constant over the years. This assumption is due to two reasons: i) the uncertainties about the demographic trend do not allow to make solid predictions; ii) the demographic trend in many EU countries (for example Italy, which is the case study considered in the paper) is rather stable by some decades and noticeable modifications are not expected in the future [66] – the possible increase of energy demand due to immigration are assumed to be compensated by the increased efficiency of devices for energy final use expected in the future; iii) The evolution of the demands magnitude alone (i.e. increasing or decreasing) does not impair the results of the analysis because does not vary the temporal position of the mismatches between demands and availability of RESs and so, the overall outcomes (focused on the use of the grid to store and carry renewable H_2) are not influenced except for the temporal achievement of the various scenarios. In contrast, possible modifications of the demand trend, not accounted for in the model, could have a more critical impact on the results. However, to account for

this, it would be necessary to consider demand management strategies which are out from the scopes of the present paper.

- Constant efficiency of the energy conversion technologies. The efficiency of the technologies included in the model are considered as constant over the years. This assumption helps simplifying the calculations. On the other hand, as described in the following sections, only solar panels, wind turbines, biogas reactors and PEM electrolysers are allowed as technologies for new installations. Except for the last one, these are very well-established technologies whose efficiency is not predicted to vary strongly. Although PEM efficiency is going to increase in the future, its constant efficiency assumption would not remarkably affect the overall result of the analysis, being the electrolysers the only chance to convert renewable electricity into heat (there are no competing technologies that could be selected because of higher efficiency or lower cost).

3. Italian case study: system description

To evaluate the applicability of the proposed strategy, the Italian case of study is selected because of the large availability of real data related to the gas grid. The energy system layout is chosen in accordance with the real energy generation mix that is currently present in Italy. Figure 1 shows the block diagram of the national energy system including twelve macro-units, each one representing the total fleet of plants of a specified category identified by the type of energy source. The elements (13 in total) of the system are:

- Five renewable energy units: photovoltaics (PV), wind turbines (WT), geothermal plants (GTH), hydropower plants (HP), biomethane plants (BG).
- One unit producing renewable hydrogen: Polymer Electrolyte Membrane electrolyser (PEM).
- One energy storage unit for natural gas and renewable hydrogen: the gas grid.
- Three energy units connected to the gas grid: electric power plants (P_G), cogeneration plants (CHP_G), and boilers (B_G).
- Three energy units fed by other fossil fuels other than gas grid: electric power plant (P_C), cogeneration power plant (CHP_C), and boilers (B_C).
- The electricity grid.

The temporal availability of RES and consumer demands (electricity and thermal energy) are evaluated using historical data. The detailed description of all the system units is given in the following.

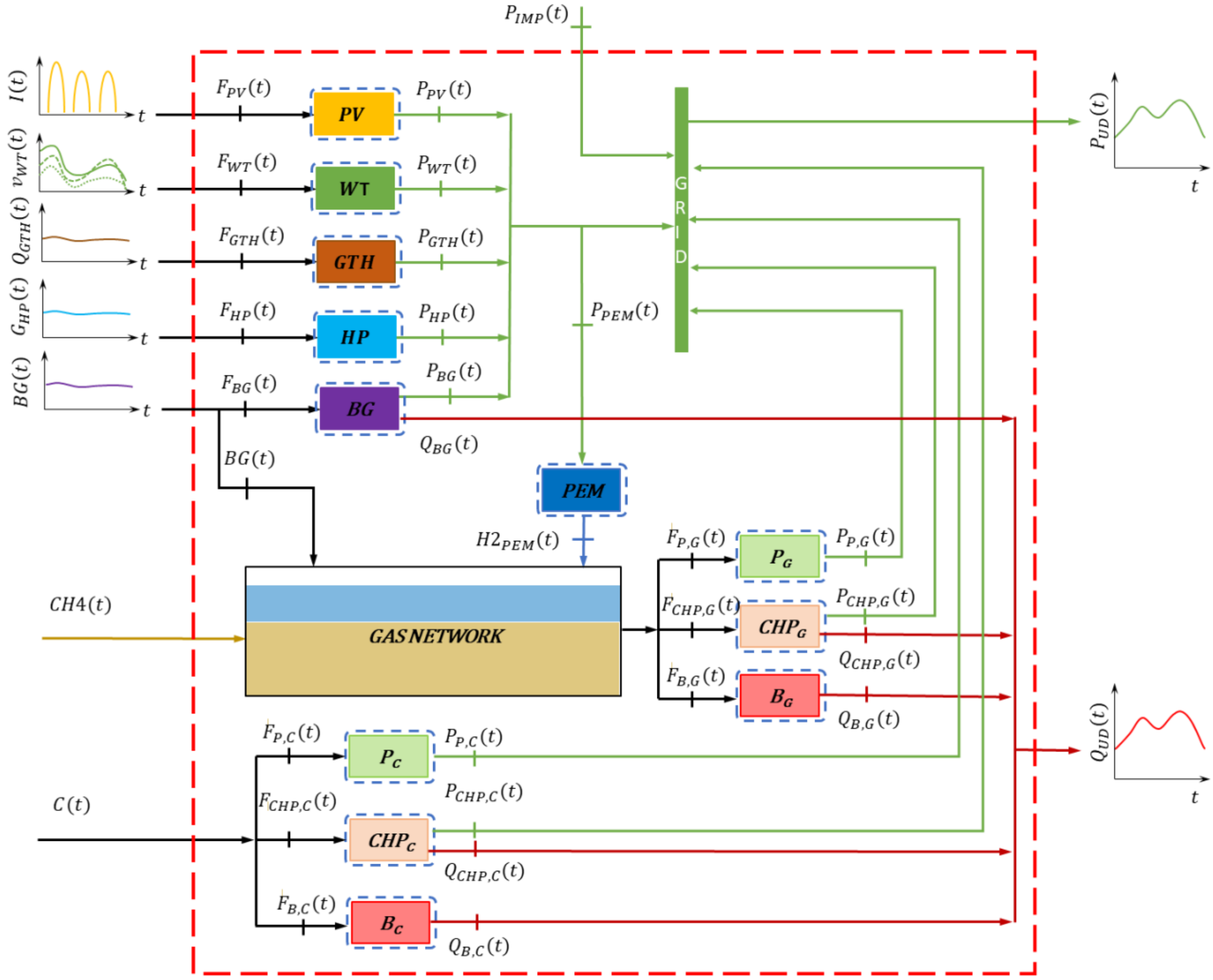

Fig. 1 – The block diagram of the country-level energy system visualizing the interaction between the macro-units of the system with the gas grid and electricity grid

Electric and thermal energy demands

The energy demands considered in this work does not take into account the transport sector, which accounts for about 19% [67] of the total energy consumption in Italy. In the current analysis the evolution of the transport sector is considered to follow an independent path and to have no interactions with the energy system shown in Fig.1. The trends of the electric and thermal energy demands are simplified considering three representative days corresponding to winter season, mid-season (counted twice) and summer season. These trends are obtained from historical data reported by the principal operator of the national electricity grid [68] and by the manager of the natural gas distribution grid. Figure 2 shows the hourly electricity and thermal energy demands of the three representative days. These demands are generated as described in the following:

- Electric energy demand. The trends of hourly electricity production are available in the annual reports of the electric grid operator for one day per month and indicate the amount of energy produced by hydroelectric plants, geothermal plants, wind turbines, solar systems, fossil fueled plants and the electricity imported from other countries. As a result, the hourly electricity consumption is known. The daily trends of March, July, and December (available for 2016-19) reports have been averaged here to obtain plausible demands (the available data is always related to the same day of the month).
- Thermal energy demand. Measurements of the natural gas flow rate (collected every 15 minutes) are available from a pressure reduction station serving a large municipality in the Veneto region (North-Eastern Italy). This station feeds a vast community, including large

urban and industrial areas. Therefore, the natural gas consumption trend (normalized) obtained from these measurements have utilized to obtain a suitable approximation of the average national consumption. To this end, the daily trends (for March, July and December) of the gas demand are first obtained by averaging the measured data of each month (i.e., every time step is averaged considering all days of the month). These trends are then normalized with respect to the cumulative averaged daily consumption. To evaluate the national gas demand, the monthly consumptions available in the annual reports of the grid operator have been averaged using data of 2016-19. The total daily consumptions for March, July and December are calculated dividing the monthly averaged values by the number of days of the month. Finally, the normalized curves derived from the measurements in the pressure reduction station are used to generate the daily national demand of natural gas. The estimate of the thermal energy consumption is based on the assumption that the entire thermal energy consumption follows the trend of the natural gas demand. It is important to observe that the gas demand trends also include the consumption of the units generating electricity. Thus, the amount of natural gas consumed for electricity generation is calculated and subtracted from the natural gas demands. The calculation takes into account the performance data of the electricity generation units working with methane and the corresponding daily production trends. These data are available from reports of the electric grid manager.

The calculated electricity and thermal energy demands are considered to be the same for all scenarios, thus the future evolution of the energy demands has been neglected. The inclusion of the variability of the energy demands is out of the scope of this analysis but will be certainly included in further developments of the work. The focus of this work is to identify the capability limits of the gas grid as energy storage and carrier system, and to propose an approach to guide the energy policies in the next future.

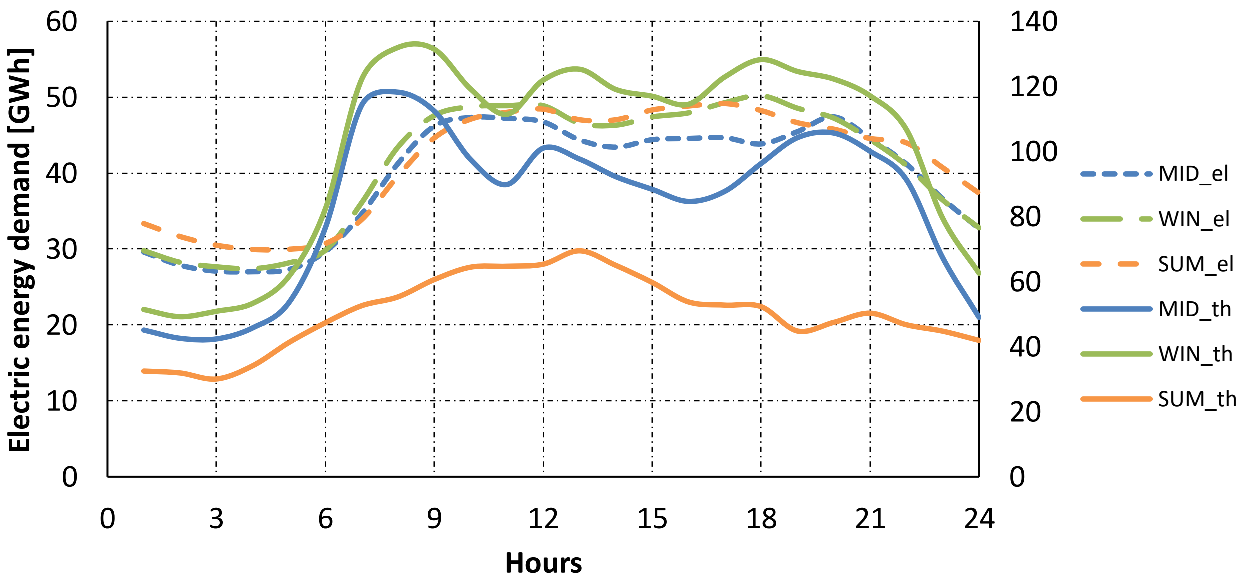

Fig. 2 –Typical daily electricity and thermal energy consumptions of winter, summer and middle seasons.

Renewable energy generation

Renewable electricity is generated from solar panels, wind turbines, biomethane plants, hydropower plants, geothermal plants. The availability of solar and wind energy is consistent with the seasonal trend of solar irradiation and wind velocity. However, wind turbines are commonly run at constant load by electricity operators because of economic reasons. Accordingly, the producible energy from wind is considered as a daily constant depending on the season. Similarly, the availability of the other RESs is considered to be constant during the day but dependent on the season (hydro and geothermal) or on the installed capacity (biomethane). A quote of renewable electricity can be also generated by power plants fed by green hydrogen (see Fig.1). Similarly, renewable thermal energy can be generated by CHP biomethane systems and by the CHP units and boilers that are directly connected to the gas grid (when it operates with blends of CH_4/H_2, as shown in Fig. 1). In this analysis, heat pumps are not considered for two reasons: i) the large-scale installation of this technology would require a strong extension of the electric grid which is unfeasible in highly populated areas [69], ii) the presence of heat pumps would deviate from the principal focus of the investigation, which regards the capacity limits of the gas grid. For the same reason, thermal solar systems are neglected as well. The utilization of fuel cells used to reconvert hydrogen into electricity must involve the separation of the hydrogen from methane by means of membranes [70]. This solution is neglected here because it is very complex and hard to manage in large scale applications since the separated methane should be recompressed and re-injected into the local grid. From here on, the acronym RESs refers to the sources just described.

Energy generation from fossil fuels

Three types of energy conversion unit are connected to the gas grid: power plants that generate only electricity (P_G), cogeneration power plants (CHP_G) and boilers (B_G). There is no distinction between industrial and domestic boilers since they can only be supplied by the gas grid. Nor the domestic heat or the industrial heat can be provided by heat pumps. The same types of units (P_C, CHP_C, B_C) are fed by an alternative fossil fuel (C_t) the characteristics of which are obtained from a weighted combination of the fuels (other than natural gas such as coal and liquid fuels) utilized in the national energy system. The knowledge of the consumption of each fossil fuels other than natural gas is not a useful information because they are not transported by the gas grid. Thus, these fuels are all merged in a single one to simplify the calculations.

Green hydrogen production

Hydrogen is produced entirely by renewable electricity using PEM electrolysers generating high pressure hydrogen (they use water pumps to pressurize water instead of hydrogen compressors installed downstream as the alkaline electrolysers). Although alkaline electrolysers are less expensive than PEM ones, the cost of hydrogen compressors is high and strongly dependent on the size of the system. Considering a national scale optimization problem, it is calculated only the total installed capacity of a certain energy conversion system neglecting the size of each installed unit. As a result, the selection of PEM electrolysers allows considering more proper and suitable costs. In this work it is assumed that hydrogen can only be injected into the gas grid. Since the grid works at different pressure levels, the capability of electrolysers to produce pressurized hydrogen has crucial importance.

Gas grid

The gas grid is considered as an energy storage system that can be charged using separate flow rates of methane and hydrogen (see Fig.1). On the other hand, the grid can be discharged consuming its content as it is at the given time step. Thus, if the gas grid contains a blend of methane/hydrogen, the single components cannot be utilized (i.e., only the blend can be consumed). The energy capacity of the gas grid is calculated from available data about the pipelines extension (number, length, size) and their nominal pressure rate. It is important to note that the energy capacity of the grid depends on the gas contained in it, because different CH_4/H_2 blends show different energy densities at a given pressure level.

4. Methods

The first of the following sub-sections presents the concept of the gas grid used as energy storage and transport system, the second introduces the optimization problem and the third provides an insight on the mathematical model of each energy storage and conversion unit.

4.1. Utilization of the gas grid as energy storage and transport system for renewable hydrogen

This Section describes how the gas grid can be utilized as renewable hydrogen storage and transport system. As mentioned in Section 3, membranes used to separate hydrogen from a gas blend are not included in this analysis. Thus, hydrogen can be extracted from the grid in its pure form only when the grid is filled with 100% hydrogen. In case of CH_4/H_2 blends, the discharge of H_2 and of CH_4 is simultaneous, in the proportion they have in the blend. Figure 3 illustrates how the gas grid can be utilized as hydrogen storage system by properly managing the injection of different flow rates of methane and hydrogen. The "daylight operation" represents the part of the day characterized by high availability of RES (e.g., presence of solar radiation) while the "overnight operation" refers to scarce availability of RES (e.g., lack of solar radiation). Accordingly, the grid is charged with green hydrogen during the day and methane during the night, whereas during the entire day the energy conversion units consume the hydrogen-methane blend. Thus, the share of hydrogen in the blend will increase (the storage system is charged) during the day and decrease (the storage system is discharged) during the night. Figure 3-a shows a graphical representation of the grid energy balance: the grid is kept always full because a reduction of its filling results in a contextual reduction of pressure, which is generally allowed within minimum ranges to preserve its functionality. Figure 3-b shows the temporal variation of the energy content of the gas grid (i.e., of methane and hydrogen) corresponding to the energy balance shown in Fig. 3-a. Note that the "daylight" and "overnight" operations are here considered because the example is related to the solar energy source. The charging/discharging concept can be extended to any RESs (e.g. wind) whenever a mismatch between the energy demand and the RES availability occurs.

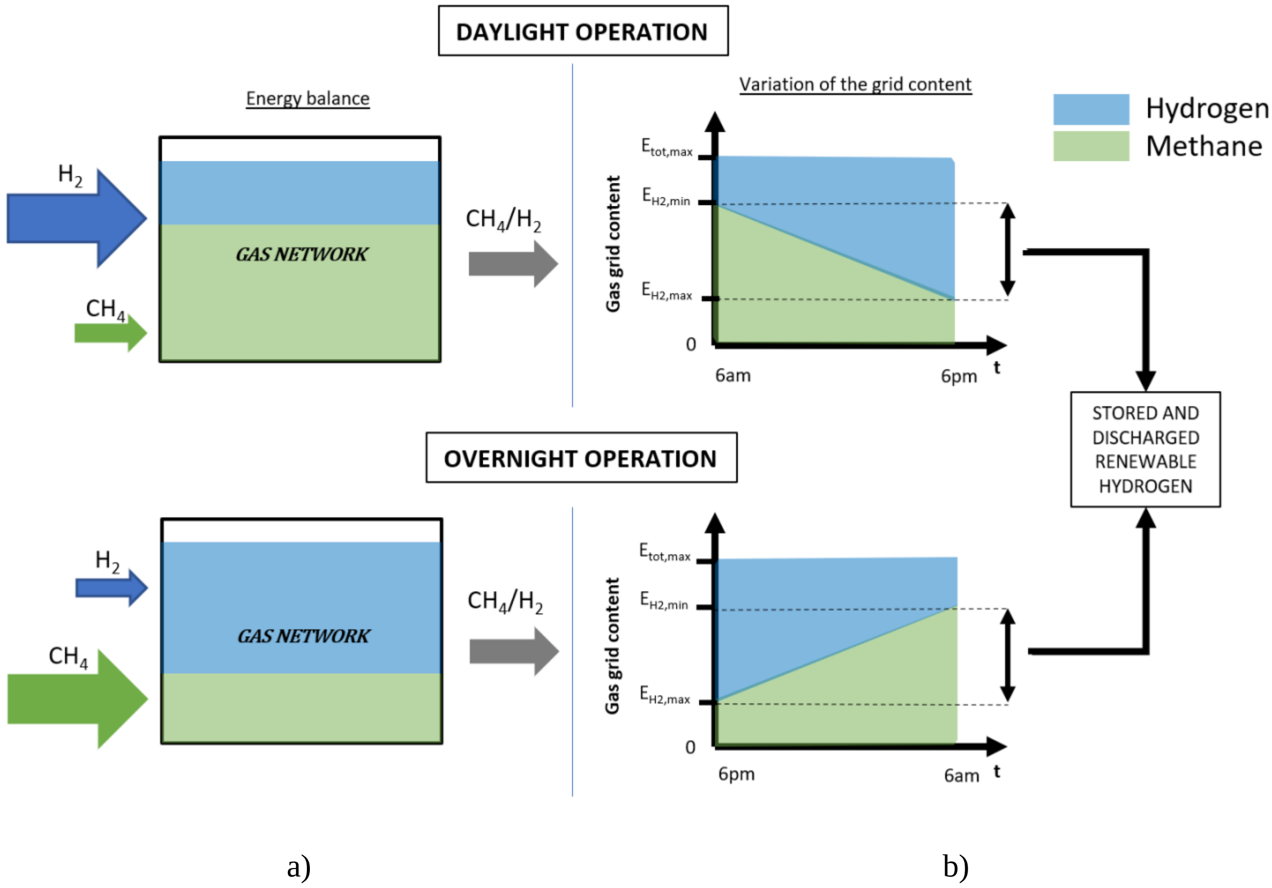

Fig. 3 – the operational strategy for storage of renewable hydrogen into the gas grid in daylight (upper) and overnight operation (lower). a) the energy balance in the gas grid, b) the temporal variation of the gas grid content

The amount of energy stored in the gas grid using hydrogen is defined as:

$$E_{H2,stor} = E_{H2,max} - E_{H2,min} \quad (1)$$

In addition to the storage function, the gas grid also plays the role of transport system of green hydrogen. The daily averaged content of hydrogen indicates the amount of hydrogen transported within the grid, which is a key parameter for the retrofitting of the gas grid when operated with CH_4/H_2 blends. Figure 4 shows an example of the daily trend of the energy content. Figure 4 also reports the energy-based and volume-based average hydrogen content of the grid, defined by the following equations:

$$E_{H2,avg\%} = 0.5 * \left(\frac{E_{H2,max} - E_{H2,min}}{E_{tot,max}}\right) * 100 \quad (2)$$

$$V_{H2,avg\%} = 0.5 * \left(\frac{V_{H2,max} - V_{H2,min}}{V_{tot,max}}\right) * 100 \quad (3)$$

$$V = f(E_{H2}, p_{grid}) \quad (4)$$

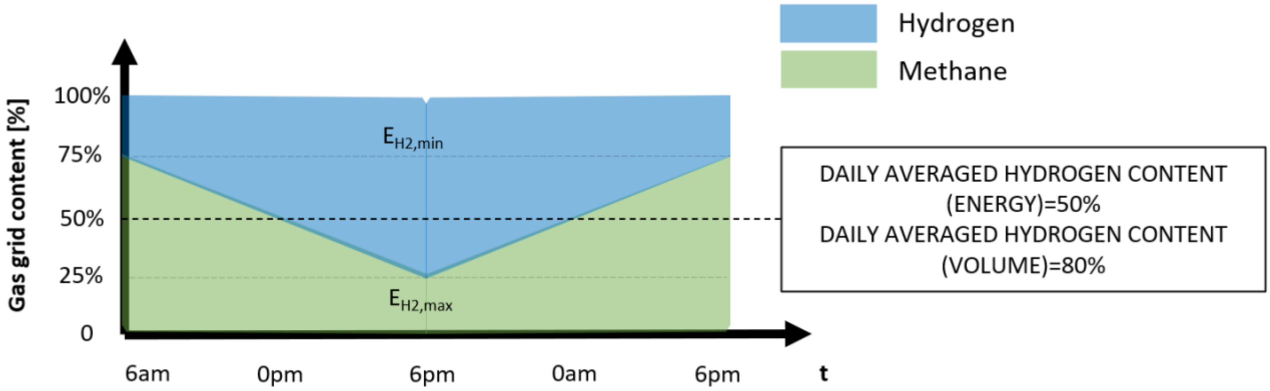

Fig. 4 – Daily averaged hydrogen content of the grid in terms of energy and volume

It is worth observing that the volume content of the grid is larger than the corresponding energy content (80% vs 50%) because of the large difference between the energy density of methane and hydrogen at the same pressure.

4.2 The Optimization problem

The design optimization problem was implemented in Python and solved with the QP solver of Gurobi commercial optimizer. It can be written in a general form as:

$$\begin{aligned} &find\ \boldsymbol{x}(t)\ that\ minimize\ \boldsymbol{Z} = f(\boldsymbol{x}(t)) \\ &subject\ to \begin{cases} \boldsymbol{g}(\boldsymbol{x}(t)) = 0 \\ \boldsymbol{h}(\boldsymbol{x}(t)) \leq 0 \end{cases} \end{aligned} \quad (5)$$

where $\boldsymbol{x}(t)$ is the array of the decision variables, $\boldsymbol{Z}$ is the objective function, $\boldsymbol{g}(\boldsymbol{x}(t))$ and $\boldsymbol{h}(\boldsymbol{x}(t))$ are the equality and inequality constraints deriving from the model of the system.

Decision variables

The decision variables are associated with the design and operation of the energy mix required to achieve the pre-set share of energy generation from RES (see Section 4.3). The design decision variables, listed in the following are, related to the current case of study and they can be properly redefined in accordance to the RES availability of each application: surface of installed solar panels ($A_{sol,new}$ [m^2]), nominal power of installed wind turbines ($CP_{WT,new}$ [GW]), nominal power of the installed plants producing biomethane (BG_{new} [GW]), nominal power of the installed electrolysers for hydrogen generation ($P_{PEM,max}$ [GW]) and new installation of boilers connected to the gas grid (B_{new} [GW]).

Other decision variables refer to the operation of the energy system during the hourly time steps of the considered sample days:

- Electric power output of the units working with fossil fuels and biomethane: $P_{P,G}(t)^{WIN,MID,SUM}$; $P_{CHP,G}(t)^{WIN,MID,SUM}$; $P_{P,C}(t)^{WIN,MID,SUM}$; $P_{CHP,C}(t)^{WIN,MID,SUM}$;$P_{BG}(t)^{WIN,MID,SUM}$.
- Electricity imported from other countries: $P_{IMP}(t)^{WIN,MID,SUM}$.
- Thermal power output of the units working with fossil fuels and biomethane: $Q_{CHP,G}(t)^{WIN,MID,SUM}$; $Q_{B,G}(t)^{WIN,MID,SUM}$; $Q_{B,C}(t)^{WIN,MID,SUM}$; $Q_{CHP,C}(t)^{WIN,MID,SUM}$; $Q_{BG}(t)^{WIN,MID,SUM}$.
- Hydrogen produced by electrolysis: $H_{2,PEM}(t)^{WIN,MID,SUM}$.
- Hydrogen energy content of the gas grid: ratio_$H_2(t)^{WIN,MID,SUM}$ (defined in Section 3.3).
- Gas grid filling factor: $cap(t)^{WIN,MID,SUM}$ (defined in Section 3.3).
- Biomethane injected into the gas grid: $CH_{4,BIOMETHANE}(t)^{WIN,MID,SUM}$.

Fixed parameters

Fixed parameters are quantities that are considered to be known as a priori in the current study:

- Renewable energy share scenario.
- Electric and thermal energy demands.
- Solar irradiation availability.
- Seasonal utilization factors of wind turbines, geothermal plants, and hydropower plants.
- Installed power capacity of hydropower and geothermal plants.
- Energy conversion efficiencies of the power generation plants, electrolysers and biomethane compressors.
- The LCOE of the renewable energy generation units.
- The costs of methane and of the alternative fuel feeding the fossil-fueled units.
- Maximum installation capacity of wind turbines and biomethane where limits imposed by the environmental footprint [71, 72]

Objective function

The objective function to be minimized is the annual cost of energy:

$$Z = \sum_{s} \sum_{t} \left(C_{LCOE} + C_{imp} + C_{gas} + C_{fuel} \right) \begin{cases} \forall s \in \{seasons\} \\ \forall t \in \{hours\} \end{cases} \tag{6}$$

where C_{LCOE} is the levelized cost of energy associated with wind turbines, PVs, biomethane and hydrogen produced with PEM electrolysers. C_{imp} is the cost of the imported electric energy, calculated considering the unitary cost per kWh, C_{gas} is the cost of natural gas injected into the grid and C_{fuel} is the cost of the alternative fossil fuel employed by the power plants that are not connected to the gas grid.

All the given LCOEs are specific costs per kilowatt-hour (thermal in case of H_2 and biomethane) and their temporal trend is reported in Fig. 5. The future projections of these costs are consistent with actual economic analyses published in the literature [73]. It should be noted that assumed LCOE takes into account the evolution of the performance parameters of each technology such as the capacity factor and the conversion efficiency. The LCOE values associated with hydrogen correspond to the maximum estimation suggested in the literature. This to take into account that H_2 is produced only from intermittent RESs, involving high costs due to the low capacity.

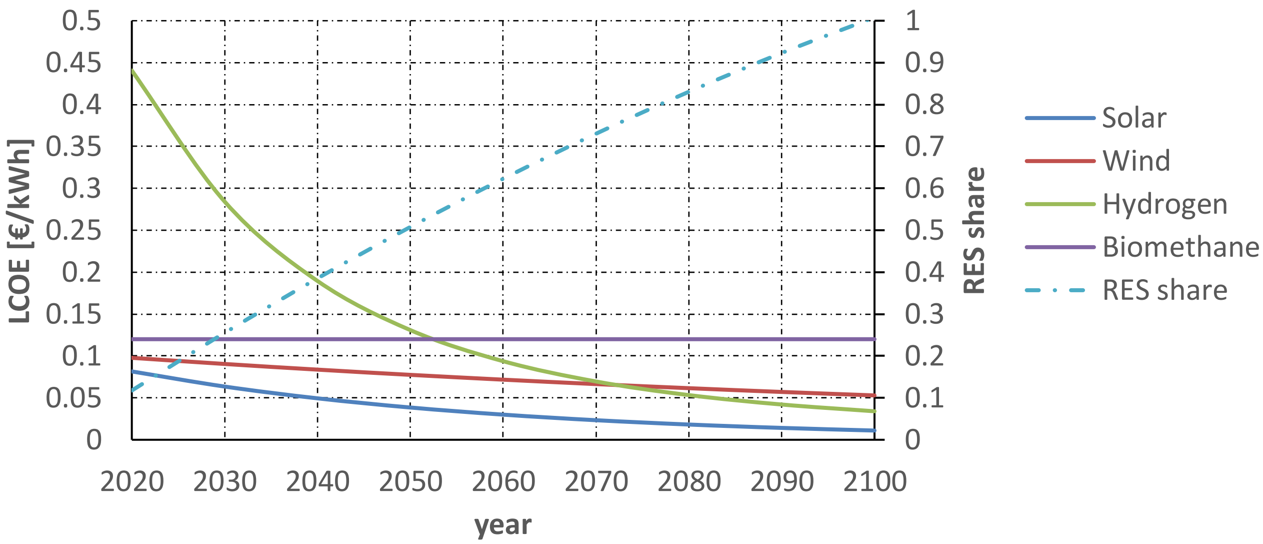

Fig. 5 – Projections of the LCOE of the energy systems based on RES and of the RES share.

Figure 5 also shows the evolution (dotted line) of the renewable energy share scenarios against the year associated with its achievement. This trend is derived from the predictions reported by the principal policy makers in Europe [74] to achieve pre-set targets of decarbonization. Table 1 summarizes the economic assumptions of the model.

Table 1 – Economic assumptions of the model

	RENEWABLE ENERGY UNITS					
	PVs	Wind Turbines	Biomethane	PEM	Biomethane power generators	Compressed biomethane
LCOE [€/MWh]	See Fig.5	See Fig.5	See Fig.5	See Fig.5	12	0.45
	FOSSIL-FUELED UNITS AND IMPORTED ELECTRICITY					
	P_G	CHP_G	B	P_C	CHP_C	P_{imp}
C_{gas} [€/MWh]	14	14	14	-	-	
C_{fuel} [€/MWh]	-	-	-	3.5	3.5	
C_{imp} [€/MWh]	-	-	-	-	-	150

The cost associated with biomethane accounts for the amount that is injected into the grid (which requires the installation of an additional compressor) and the amount that is used directly in biomethane power conversion units.

4.3 Model of the system

This Section presents the equations describing the operation of the system, which appear as constraints in the optimization problem (i.e., $\boldsymbol{g}\big(\boldsymbol{x}(t)\big) = 0$ and $\mathrm{h}\big(\boldsymbol{x}(t)\big) = 0$ in Eq. (1)).

The total renewable energy share scenario is the main constraint driving the optimization of the energy system:

$$REP_{tot} = \sum_{s}\sum_{t}\left(\frac{P_{RE}(t) + Q_{RE}(t)}{Q_{UD}(t) + P_{UD}(t)}\right)\begin{cases}\forall s \in \{seasons\}\\ \forall t \in \{hours\}\end{cases} \tag{7}$$

The renewable electric energy share is defined as:

$$REP_{el} = \sum_{s}\sum_{t}\left(\frac{P_{RE}(t)}{Q_{UD}(t) + P_{UD}(t)}\right)\begin{cases}\forall s \in \{seasons\}\\ \forall t \in \{hours\}\end{cases} \tag{8}$$

where $P_{RE}(t)$ is the electric power generated from renewables, $Q_{RE}(t)$ is the thermal power generated from renewables.

Other constraints of the model are the thermal and electric energy balances and the equations describing the operation of the energy conversion units and energy storage systems (gas grid).

The electricity and thermal energy balances are:

$$\begin{gathered}P_{BG}(t) + P_{imp}(t) + P_{P,G}(t) + P_{P,C}(t) + P_{CHP,G}(t) + P_{CHP,C}(t) + P_{PV}(t) + P_{WT}(t)\\ + P_{GTH}(t) + P_{HP}(t) = P_{UD}(t) + P_{PEM}(t) + P_{Comp,BG}(t)\end{gathered} \tag{9}$$

$$Q_{BG}(t) + Q_{B,G}(t) + Q_{B,C}(t) + Q_{CHP,G}(t) + Q_{CHP,C}(t) = Q_{UD}(t) \tag{10}$$

To simplify the calculations, the off-design behavior of each energy conversion unit is described by linear equations. In other words, each unit always work close to the nominal conditions. The loss in accuracy deriving from this assumption is considered acceptable thinking that the number of energy conversion units is not defined because of the national scale of the analysis. At part load operation, the proper number of units can be considered to work at nominal conditions while the rest is turned off. The equations presented in the following refer to the units included in the considered energy system (see Fig. 1). However, their general form can be extended to any other unit that is included in each application. Likewise, the efficiency of the energy conversion units and the equations describing the energy capacity of the gas grid must be properly chosen in accordance with the analyzed system.

a. Biomethane power generation plants are cogeneration internal combustion engines. The electric efficiency $\eta_{el,BG}$ and thermal efficiencies are set equal to 0.39 and 0.42, respectively. The thermal power output is defined as a function of the electric power output to impose the simultaneous production of heat and electricity, and so avoiding the utilization of binary variables. $F_{BG}(t)$ is the amount of produced biomethane that feeds the system.

$$P_{BG}(t) = F_{BG}(t) * \eta_{el,BG} \tag{11}$$

$$Q_{BG}(t) = P_{BG}(t) * \frac{\eta_{th,BG}}{\eta_{el,BG}} \tag{12}$$

The production trend of biomethane is assumed to be constant. The current biomethane production (BG) is entirely consumed in CHP systems whereas the production resulting from the installation of new plants (BG_{new}, which is limited to 84.65 GW as stated in technical report [75]) can be consumed into power plants or injected into the gas grid ($CH_{4,bio}(t)$).

$$BG + BG_{new} = F_{BG}(t) + CH_{4,bio}(t) \tag{13}$$

b. The electric efficiencies of electric power generation plants and CHP plants that are connected to the gas grid are set equal to 0.52 and 0.38, respectively. The thermal efficiency of these CHP units is set equal to 0.412. These are weighted values derived by performance data of the real mix of power plants that are currently installed in the country. These units represent a very large group of systems. Therefore, the equations describing their operation are linear without the constant term and with an upper boundary defined by the currently installed capacity. Since the size of the smallest unit is negligible in comparison with the total demand, the minimum part load operation is considered null.

$$P_{P,G}(t) = F_{P,G}(t) * \eta_{el,P,G} \quad (14)$$

$$P_{CHP,G}(t) = F_{CHP,G}(t) * \eta_{el,CHP,G} \quad (15)$$

$$Q_{CHP,G}(t) = P_{CHP,G}(t) * \frac{\eta_{th,CHP,G}}{\eta_{el,CHP,G}} \quad (16)$$

c. Similarly, to the previous case, the electric efficiencies of energy conversion units working with alternative fossil fuels are set equal to 0.32 and 0.20, respectively. The thermal efficiency of the CHP units is set equal to 0.376.

$$P_{P,C}(t) = F_{P,C}(t) * \eta_{el,P,C} \quad (17)$$

$$P_{CHP,C}(t) = F_{CHP,C}(t) * \eta_{el,CHP,C} \quad (18)$$

$$Q_{CHP,C}(t) = P_{CHP,C}(t) * \frac{\eta_{th,CHP,C}}{\eta_{el,CHP,C}} \quad (19)$$

d. The conversion efficiency of the boilers is set equal to 0.9.

$$Q_{B,G}(t) = F_{B,G}(t) * \eta_{th,B} \quad (20)$$

$$Q_{B,C}(t) = F_{B,C}(t) * \eta_{th,B} \quad (21)$$

e. The electric power output of the PV systems is a function of the solar irradiation ($I_{sol}(t)$) and of the surface of the installed panels ($A_{sol} + A_{sol,new}$). A_{sol} is a qualitative value of the currently installed surface of PVs which takes into account both the efficiency and the averaged locations [76] of the panels in the country. $A_{sol,new}$ allows distinguishing the amount of energy that is generated in additional installed panels to correctly evaluate the LCOE costs in the objective function.

$$A_{sol} = \frac{P_{PV,installed}}{I_{sol,ref}} \quad (22)$$

$$P_{PV}(t) = (A_{sol} + A_{sol,new}) * I_{sol}(t) \quad (23)$$

where $P_{PV,installed}$ is the nominal power of the PVs installed at present (20.865 GW) considering a reference solar irradiance $I_{sol,ref} = 1000\ W/m^2$.

f. The electric power output of the wind turbines is a function of the seasonal utilization factor ($U_{f,WT,s}$) and of the installed capacity ($CP_{WT} + CP_{WT,new}$). C_{WT} is the nominal power of the currently installed wind turbines (10 GW) while $C_{WT,new}$is the new installed capacity that can be indicated by the optimizations (limited to 150 GW as suggested by [72]). $U_{f,s}$ depends on the seasonal availability of wind and it is set equal to 0.328 (winter), 0.347 (mid) and 0.169 (summer).

$$P_{WT,s}(t) = U_{f,WT,s} * (CP_{WT} + CP_{WT,new}) \quad (24)$$

g. Geothermal and hydro power plants electric power outputs ($P_{GTH}(t)$ and $P_{HP}(t)$) have fixed trends depending on their seasonal utilization factors $U_{f,GHT,s}$, $U_{f,HP,s}$ (seasonal) and installed power capacities CP_{GTH} (813 MW) and CP_{HP} (19000 MW).

$$P_{GTH,s}(t) = U_{f,GTH,s} * CP_{GTH} \quad (25)$$

$$P_{HP,s}(t) = U_{f,HP,s} * CP_{HP} \quad (26)$$

where $U_{f,GTH,s}$ is set equal to 0.812 (winter), 0.964 (mid), 0.985 (summer) and $U_{f,HP,s}$ to 0.323 (winter), 0.179 (mid), 0.266 (summer).

h. The power consumption of PEM electrolysers is calculated considering a fixed efficiency (0.6) in accordance with [77]. This value takes into account the energy employed to pressurize the water and so to produce pressurized hydrogen to be injected directly into the gas grid.

$$P_{PEM}(t) = \frac{H_2(t)}{\eta_{el,PEM}} \quad (27)$$

i. The amount of biomethane that is injected into the grid must be compressed. The specific energy consumption of compressors is calculated assuming that the biomethane is compressed to 70 bara (highest pressure of the grid) and considering a mechanical/electric efficiency of 0.8. As a result, the specific energy consumption ($\eta_{comp,BG}$) is set equal to 0.0247 $kWh_{el}/kWh_{biomethane}$.

$$P_{Comp,BG}(t) = \eta_{comp,BG} * CH_{4,bio}(t) \quad (28)$$

j. $P_{UD}(t)$ and $Q_{UD}(t)$ are the electric and thermal power demands that are considered having a fixed trend (see Section 2).

The natural gas grid is modeled as a methane/hydrogen storage system using the following equations:

$$E_{CH_4}(t) = E_{CH_4}(t-1) + CH_{4,bio}(t-1) - F_{CH4,P,G}(t-1) - F_{CH4,CHP,G}(t) - F_{CH4,B}(t) + CH_4(t-1) \quad (29)$$

$$E_{H_2}(t) = E_{H_2}(t-1) + H_{2,PEM}(t-1) - F_{H_2,P,G}(t-1) - F_{H_2,CHP,G}(t-1) - F_{H_2,B}(t-1) \quad (30)$$

$$E_{H_2}(t) + E_{CH_4}(t) = E_{grid}(t) \quad (31)$$

$$E_{grid}(t) \geq cap_{min} * \left(-5379.21 * ratio_{H_2}(t) + 5609.13\right), \qquad cap_{min} = 0.9 \quad (32)$$

$$E_{grid}(t) \leq cap_{max} * \left(-5379.21 * ratio_{H_2}(t) + 5609.13\right), \qquad cap_{max} = 1.1 \quad (33)$$

where $E_{CH_4}(t)$, $E_{CH_4}(t)$, $E_{grid}(t)$ are the methane, hydrogen and total energy contents of the gas grid; $CH_{4,bio}(t)$, $H_{2,PEM}(t)$ and $CH_4(t)$ are the amounts of biomethane, hydrogen and methane injected into the grid; $F_{CH_4,P,G}(t)$, $F_{H_2,P,G}(t)$, $F_{CH_4,CHP,G}(t)$, $F_{H_2,CHP,G}(t)$, $F_{CH_4,B}(t)$, $F_{H_2,B}(t)$ are the amounts of methane and hydrogen (composing the blend) consumed by electric power generation systems, CHP systems and boilers. The energy balances of methane and hydrogen are considered separately to determine the energy allocation of methane and hydrogen into the grid:

$$ratio_{H_2}(t) = \frac{E_{H_2}(t)}{E_{H_2}(t) + E_{CH_4}(t)} \quad (34)$$

This equation introduces a nonlinear constraint. It is also necessary to define:

i. The constraints on the capacity of the gas grid (Eq. 32 and Eq. 33). The real volumes and pressure levels of the national gas grid are used to calculate the amount of energy that could be stored in the grid for different blends of methane/hydrogen ($ratio_{H_2}$) and the resulting values are interpolated. cap_{min} and cap_{max} represent the minimum and maximum variation of the grid pressure out to the nominal value. The pressure of the gas grid is commonly allowed to vary within ±10% (note that pressure is directly proportional to the energy content of the grid at variable blends of methane/hydrogen).

ii. The constraints imposing the consumption of the current methane/hydrogen blend into the grid (Eqs. (35-40)).

$$F_{CH_4,P,G}(t) + F_{H_2,P,G}(t) = F_{P,G}(t) \quad (35)$$

$$F_{CH_4,CHP,G}(t) + F_{H_2,CHP,G}(t) = F_{CHP,G}(t) \quad (36)$$

$$F_{CH_4,B}(t) + F_{H_2,B}(t) = F_B(t) \quad (37)$$

$$(F_{CH_4,P,G}(t) + F_{H_2,P,G}(t)) * ratio_{H_2}(t) = F_{H_2,P,G}(t) \quad (38)$$

$$(F_{CH_4,CHP,G}(t) + F_{H_2,CHP,G}(t)) * ratio_{H_2}(t) = F_{H_2,CHP,G}(t) \quad (39)$$

$$(F_{CH_4,B}(t) + F_{H_2,B}(t)) * ratio_{H_2}(t) = F_{H_2,B}(t) \quad (40)$$

Equations (35-37) link the variables appearing in the methane and hydrogen balances to the consumptions of the energy conversion units while Eq. 38 to Eq. 40 impose that those units consume the blend present in the grid at the time step (t).

Additional constraints and assumptions:

- The electricity consumption of the electrolysers is imposed to be completely renewable using the following equation.

$$P_{PV}(t) + P_{WT}(t) + P_{GTH}(t) + P_{HP}(t) + P_{BG}(t) \geq P_{PEM}(t) \quad (41)$$

- The increasing RES shares can be achieved only by installing new power capacity of PVs, wind turbines, biomethane plants, electrolysers, and boilers to convert the renewable hydrogen present in the grid to heat. At present, the other renewable systems have already reached the maximum power capacity allowed by the environmental conditions.
- The currently installed power generation systems are considered to be able to work with any blend of methane/hydrogen. This assumption is consistent with the time frame necessary to achieve the REP scenarios. The current technologies may improve and adapt to work with the methane/hydrogen blends indicated by the results of the optimizations.

5. Results and Discussions

In this section the results of the optimizations are presented and discussed. As showed in Section 3, the objective of the optimization is to minimize the sum of total cost. The baseline case is the current status of the energy mix in Italy which shows a total RES share equal to 11.58% in accordance with the 2019 reports of the Ministry of Economic Development [78]. Figure 6 provides a graphical representation of the baseline case showing the electric and thermal energy consumptions, and the corresponding energy mix. The horizontal axis represents 24-time steps that include 3 representative days (winter, summer and mid-season) each composed of 8 time-steps (of three hours each). To consider four representative days (entire year), the mid-season day is taken into account twice in the optimization problem. The number of time steps included in one representative day is limited to eight to reduce the computation time. As shown in Fig. 6, most of the electricity demand is covered by fossil-fueled power plants and imported electricity. The higher amount of renewable electricity is generated by solar PVs followed by wind generators and then by hydropower, geothermal power and biomethane. In the baseline case there is no hydrogen production. Conversely, the thermal demand is covered only by fossil-fueled boilers and CHP plants.

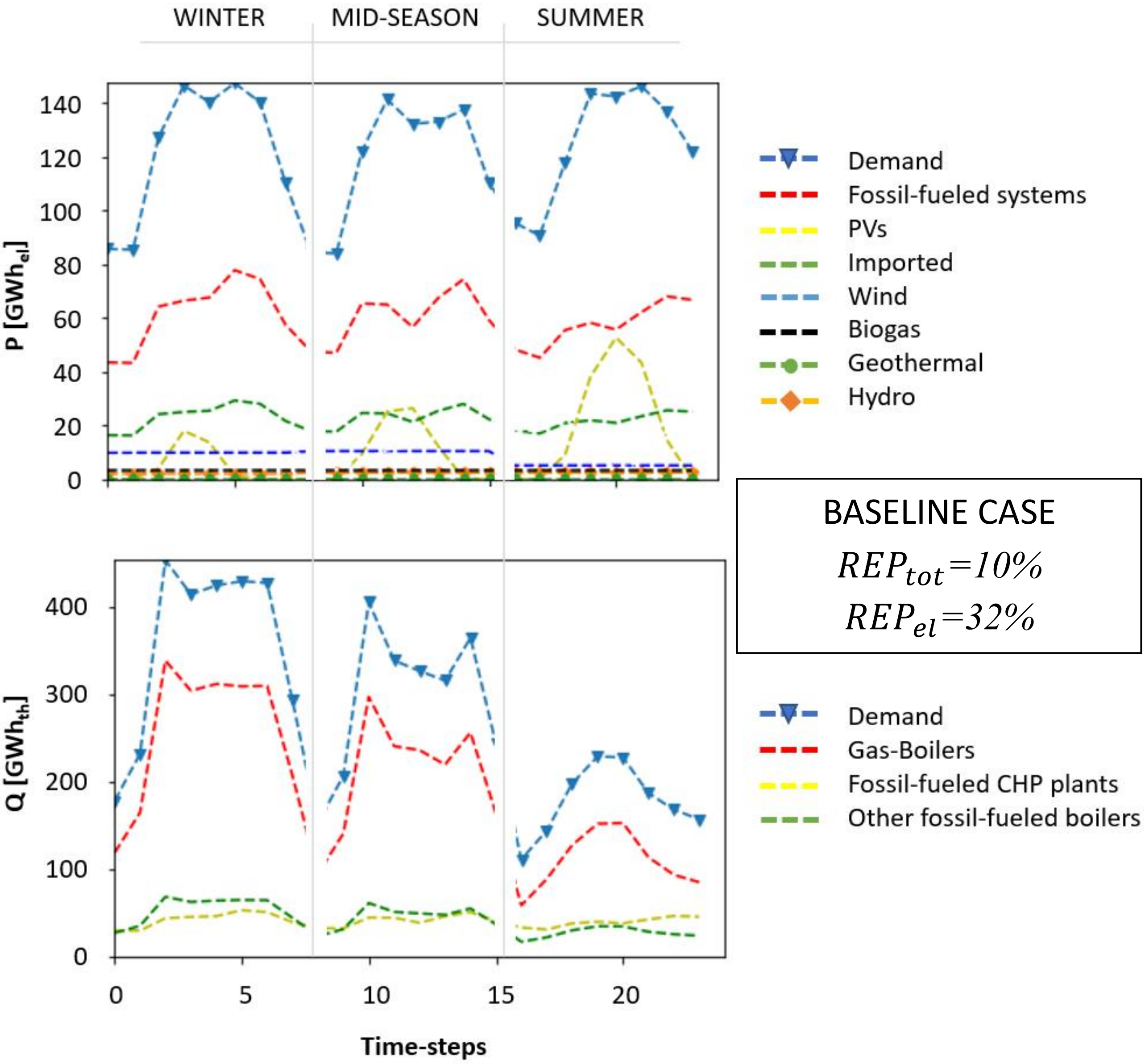

Fig. 6 – Electricity (upper) and thermal (lower) energy consumptions and mix of power systems that satisfy the demands in the baseline case.

Figures 7-9 compare the optimum electric/thermal energy mix and the best operation of the gas grid to achieve increasing renewable energy shares. Table 2 compares the most representing parameters resulting from the optimizations.

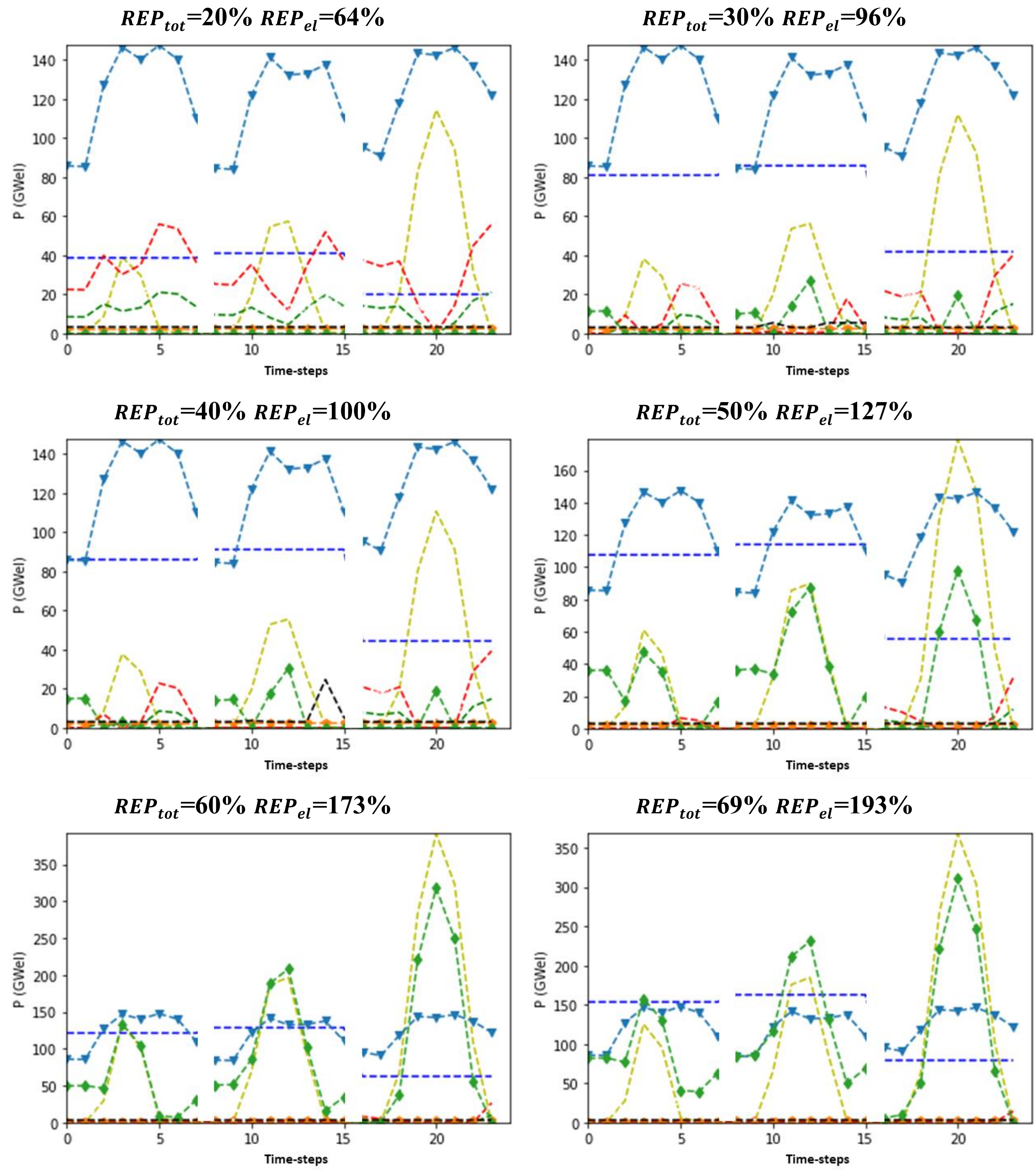

Fig. 7 – Electricity consumptions and mix of power systems that satisfy the demand for increasing shares of RESs resulting from the optimizations.

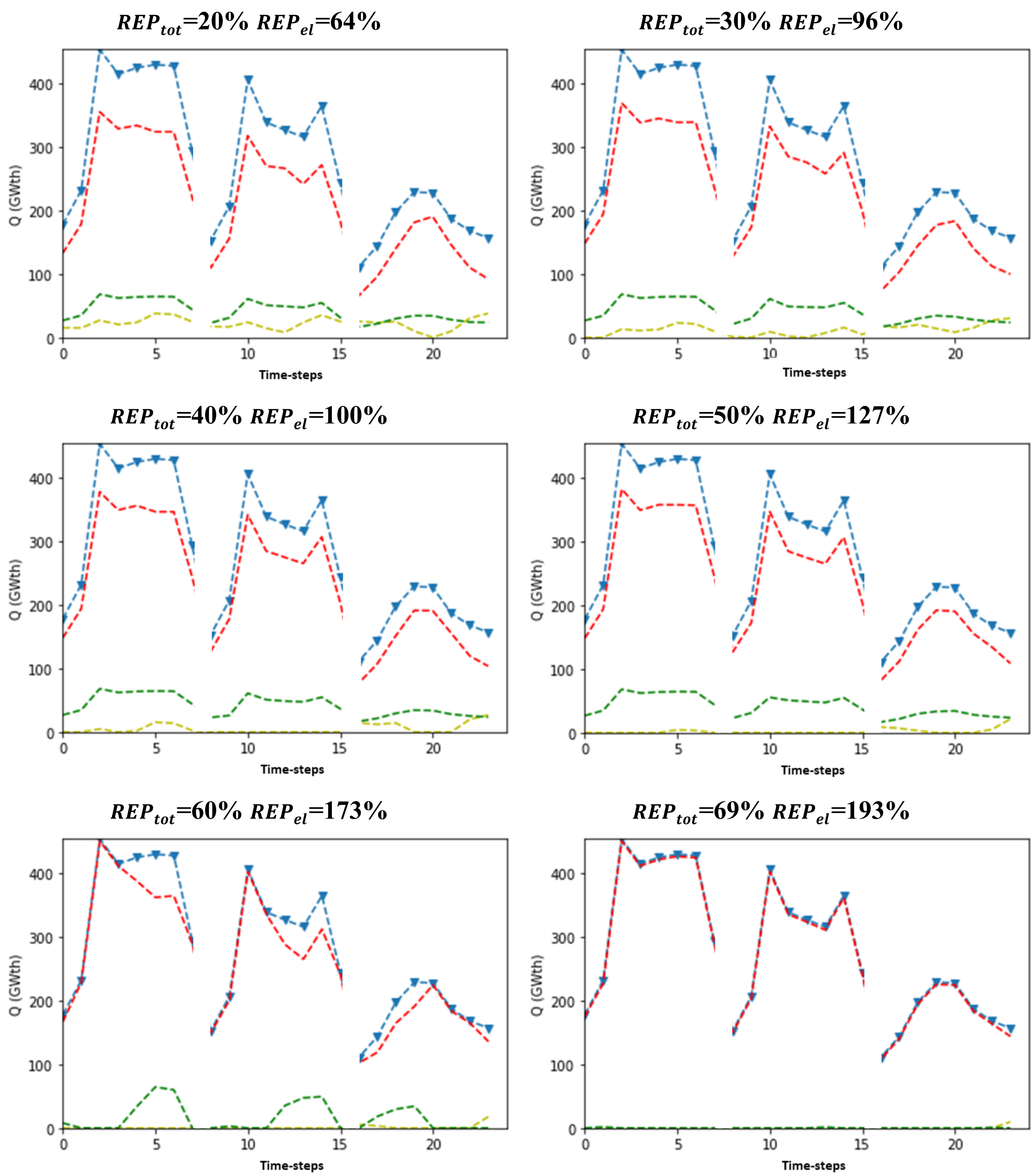

Fig. 8 – Thermal energy consumptions and mix of power systems that satisfy the demand for increasing shares of RESs resulting from the optimizations.

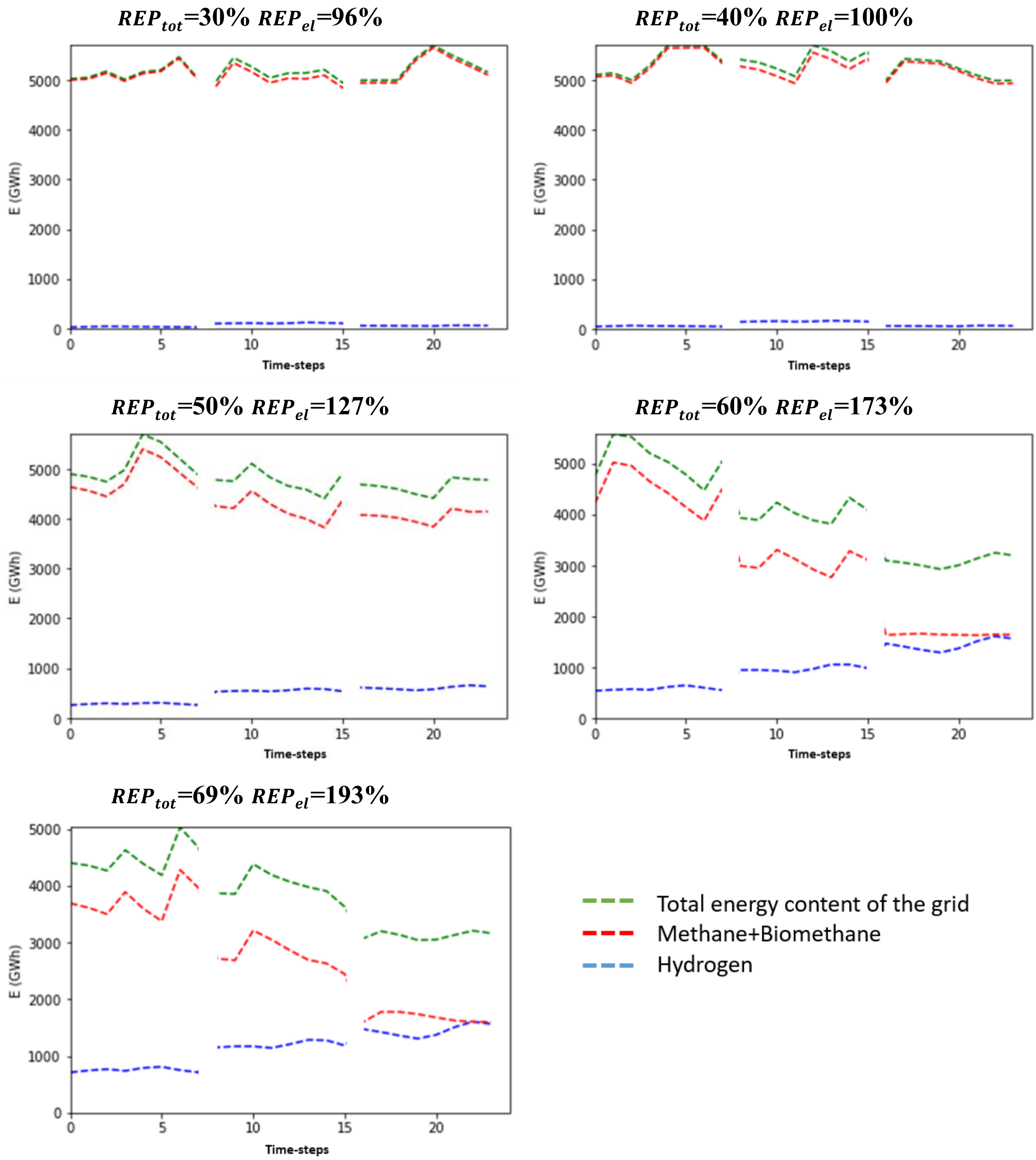

Fig. 9 – Distribution of the energy content of the gas grid between methane, biomethane and hydrogen for increasing shares of RESs resulting from the optimizations.

Table 2- The results of optimization for case of Italy over 45 years from 2019 to 2064 and comparison with the baseline case of 2018.

Year	2018			2023			2031			2039			2047			2055			2064		
REP_{tot}[%]	10.3			20			30			40			50			60			64.5		
REP_{el}[%]	31.7			63.75			95.7			100			126.5			172.6			193.0		
CO2 reduction energy mix [%]				14.35			30.3			48.32			62			64.3			70		
Season	W	MID	S	W	MID	S	W	MID	S	W	MID	S	W	MID	S	W	MID	S	W	MID	S
REP_{tot}[%]	0.09	0.09	0.16	0.16	0.19	0.29	0.25	0.30	0.37	0.37	0.43	0.54	0.45	0.54	0.69	0.50	0.64	0.91	0.55	0.69	0.93
REP_{el}[%]	0.31	0.30	0.36	0.59	0.65	0.67	0.93	1.03	0.84	0.97	1.09	0.85	1.20	1.36	1.15	1.45	1.80	1.87	1.70	2.05	1.92
$CP_{WT,new}$ [GW]				29.24			72.3			77.45			99.2			113			150.00		
$A_{sol,new}$ [m^2]				2.44*10^7			2.35*10^7			2.3*10^7			5.05*10^7			13.5*10^7			12.5*10^7		
BG_{new} [GW]				0.00			5.8			62.5			84.25			84.25			84.25		
PEM_{new} [GW]				0.00			27.2			30.4			98			317			310		
$E_{H2,stor,PV}$ [%]				0	0	0	0	13	4	0	14	4	24	22.4	19.2	34	30	27.6	31	28	27
$E_{H2,stor,WT}$ [%]				0	0	0	2.5	1.2	0	3	1.5	0	3.5	1.6	0	2.1	2.2	0	4	2	0
$E_{PTH,WT}$[%]				0	0	0	3.4	2.7	0	4.4	3.7	0	10	13.7	0	29	28	0	31	30	0
$E_{PTH,PV}$[%]				0	0	0	0	26.2	5.8	0	30.7	6	66	80	42	100	100	75	100	100	82
$E_{H2,avg}$ [%]				0	0	0	0.6	2	1	0.9	2.6	1	5.5	11	12	12	26	44	16.5	30	45
$V_{H2,avg}$ [%]				0	0	0	1.5	8	5	5	10	2	14	30	32	32	55	75	45	63	75

In the following Sub-Sections, the results are discussed considering the evolution of the optimal mix of the energy systems, and of the operation of the gas grid towards increasing RES shares.

5.1 Evolution of the renewable units mix

This Sub-Section summarizes the main observations about the evolution of the optimal mix of PVs, wind turbines and biomethane to invest on, in order to achieve the preset shares of RESs.

- The sole installation of solar PV systems and of a small amount of wind turbines is the best option to reach a share of RES of about 20%.
- In between 20 and 40% of RES share the installation of solar units is almost constant and lower than in the 20% scenario. This is because of the higher variability with time of the electricity generated by PV than that generated by wind, which introduces the need for “peak shaving” (storage of the excess of electricity generated in the form of hydrogen) starting from 20% share of RES. Conversely, up to 20%, the peaks of PV generation can be totally absorbed by the demand without the need of peak shaving. This need in turn implies the utilization of electrolysers for hydrogen production and storage, with a remarkable increase of costs, which suggests limiting the inclusion of PV in favor of Wind. Thus, the transition between the two scenarios (20%<RES share<40%) occurs by installing wind turbines, biomethane injected into the grid and a small amount of electrolysers to convert the peaks of generation into hydrogen.
- Starting from 40% of RES share, the electricity demand can be entirely fulfilled by RES (REP_{el}=100%). Thus, it becomes essential to generate thermal energy from RES to reach the subsequent scenarios. As a result, 50% of RES share is achieved by installing:
    i. the maximum capacity of biomethane that is allowed depending on land availability, and amount of wastes and residues. The biomethane is assumed to be completely injected into the gas grid.
    ii. electrolysers, fed by new installations of both PV and wind, to convert renewable electricity into hydrogen, and then to heat, in boilers and CHP units connected to the gas grid.
- The RES share of 65% corresponds to the maximum storage capability of the gas grid and can be achieved with large investments on electrolysers, wind, and PV units.

5.2 Evolution of the fossil-fueled units mix

Remarks about the evolution of the most convenient operation and investments on the fossil fueled units are listed in the following:

- At increasing RES share, the imported electricity and the fraction provided by fossil-fueled units progressively decrease to zero. These units are gradually shut down due to the increasing amount of electricity generated by renewable energy systems.
- Similarly, at increasing RES share, also the thermal energy generated by CHP plants decreases to zero as the electricity they would generate is substituted by RES electricity. On the other hand, the thermal energy generated by boilers rises. A higher percentage of the electricity demand is covered by RES electricity, and as a result the CHP power plants are curtailed until they are completely excluded from the energy mix.
- The boilers which are not connected to the gas grid start to be curtailed at 60% share of RES and they are completely excluded from the mix at 65% share of RES. Because of the lower cost than the gas-fired boilers, the non-gas boilers are excluded from the energy mix except when it is necessary to produce large amounts of renewable heat (i.e., when RES_{el} passes 100%).
- It is also interesting to highlight that non-gas boilers are curtailed during the time-steps corresponding to the “discharge” of hydrogen from the grid. During this phase, the

consumption of hydrogen should be maximized therefore, the boilers connected to the gas grid have priority in the energy mix.

- The boilers connected to the grid consume blends of methane/hydrogen having an increasing percentage of hydrogen and so they convert increasing quantities of renewable electricity to heat.

5.3 Optimal operation of the gas grid with the integration of hydrogen

This sub-Section lists the key findings about the operation of the gas grid and highlights the optimal blends of methane/hydrogen to be used in the grid. A close look to the amount of renewable energy stored in the grid is also provided.

- The gas grid allows achieving a RES share of 65% without any other energy storage system.
- The grid makes up to 34% of solar and 4% of wind electricity dispatchable.
- The grid transports hydrogen (from RES) to heating systems, which are therefore fed by renewable energy. The grid transports, in the form of hydrogen, up to 100% and 30% of the electricity generated from solar and wind, respectively.
- Green hydrogen production should be considered when it becomes mandatory to generate large amounts of thermal energy from renewables, i.e. when RES systems fully cover the electricity demand (RES share > 40%) and the maximum biomethane installation capacity is achieved. This is because of the high cost of electrolysers and the low energy conversion efficiency of the green hydrogen generation chain (renewable electricity → hydrogen → renewable energy).
- The generation of hydrogen starts being convenient from 20% of RES share (see also Section 4.1). From 20% to 40% of RES share, hydrogen is generated only to exploit the excess of electricity in the peaks of wind and solar electricity production requiring an increase of the power installed in the electrolysers from 0 to 30 GW. Beyond 40%, corresponding to the saturation of the electricity demand by RES (i.e., REP_{el}=100%) and to the maximum installation capacity of biomethane, the installation of electrolysers increases sharply (from 30 to 310 GW) to fulfil the need to transform large amounts of renewable electricity into heat.
- The percentage of hydrogen transported by the gas grid is variable throughout the seasons and increases in the scenarios of increasing RES share in accordance with the rising number of renewable units in the energy mix. For intermediate RES share (30-40%), there is maximum availability of renewable energy during the intermediate seasons, and the gas grid works with 1-15%vol of hydrogen. For high-RES shares (50-70%) the maximum availability of renewable energy is during summer and corresponds to 65-75%vol of hydrogen into the gas grid.

Figure 10 provides a graphical representation of the evolution of the RES share corresponding to each source against the total RES share. It is interesting to note that even though the installed capacity of solar panels is always remarkably higher that wind turbines and biogas plants, the same cannot be observed in terms of generated energy. In fact, in almost all scenarios the renewable energy generated from wind and biogas is higher than the amount deriving from solar plants because of the different availability of these RESs. The specific RES share displayed in Fig. 10 is calculated as the ratio between the total renewable energy generated by each source and the total electric and thermal energy consumptions. It is important to mention that increasing the total RES share, an increasing amount of renewable electricity is converted into heat (using H2 injected into the grid) so, the sum of the specific RES shares (i.e. the single-source contributes) does not correspond to the one in the horizontal axis (because of the conversion losses).

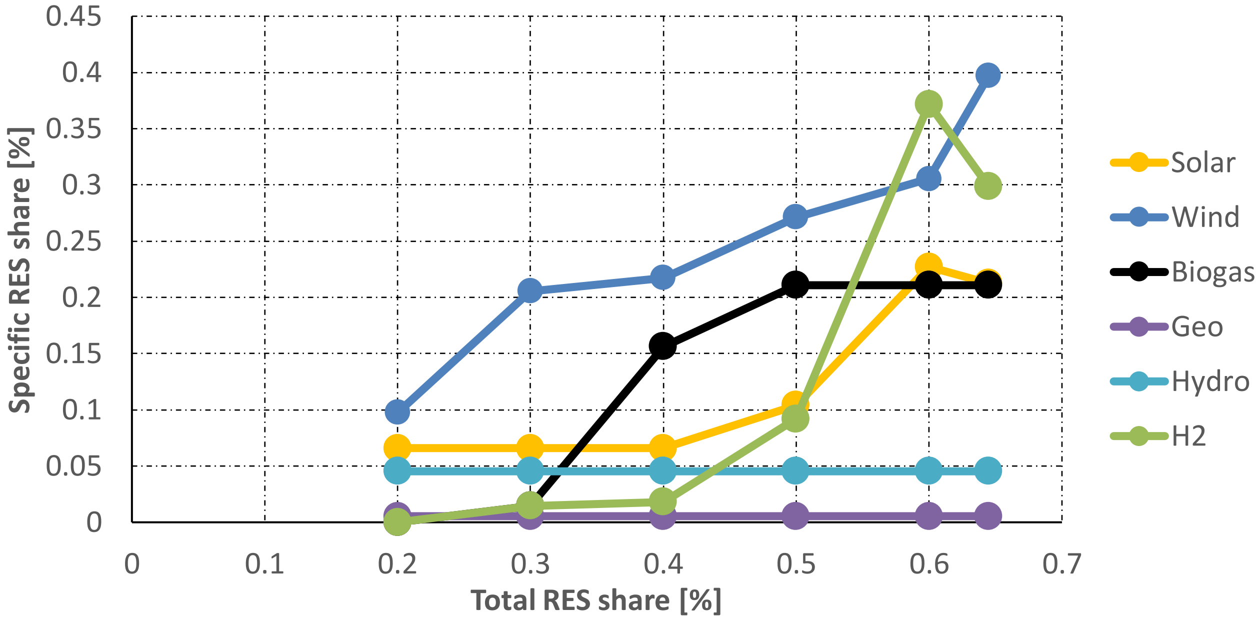

Fig. 10 – Distribution of the energy content of the gas grid between methane, biomethane and hydrogen for increasing shares of RESs resulting from the optimizations.

Figure 10 emphasizes that in absence of energy storage systems out of the gas grid, the RES share should be based on energy sources characterized by constant availability (i.e. wind and biogas). Although these RESs have high installation costs, they are more convenient than more inexpensive solutions such as solar panels, which must be coupled to PEM elctrolysers to manage the peaks of generation. The use of PEM is extensively introduced for high-RES shares since it represents the only way to convert renewable electricity into heat within the constraints of the model. It can be noted that the solar RES share follows the trend of installed PEM because it is the most inexpensive solution to couple with the electrolysers.

6. Conclusions

The paper investigates the potential role of the existing infrastructures of the gas grid in future energy scenarios with increasing share of RES, where large-scale energy storage systems will become of crucial importance. The large investments and operation costs associated with storage capacities could be totally, or at least partially, avoided by utilizing the existing infrastructures, which might be asked to change their primary function in the next future. To this end, an original approach is proposed, based on the search for the optimal mix of energy conversion units in the national energy system, considering the gas grid as the only renewable energy storage system for injection of green hydrogen. Pre-selected scenarios with increasing RES shares are set as constraints of the optimization procedure, which follows the criterion of cost minimization. The optimization results indicate that it is convenient to minimize the use of electrolysers until it becomes necessary to achieve high renewable energy share scenarios. Until a 40% share of renewables, the gas grid has to be utilized to transport biomethane and a small amount of hydrogen, which is produced to shave the generation peaks of wind and solar systems. In this way, hydrogen and methane mainly contribute to the generation of renewable heat because most of the energy conversion units connected to the gas grid become the boilers. Until the 40% of RES share, the gas grid is utilized to transport up to 15%vol of H_2 while up to 14% of solar energy is stored in the grid. When the renewable electricity generation is high enough to cover the entire demand (i.e., the RES share is approximately equal to 40%) the utilization of hydrogen is necessary to achieve higher RES share. In fact, it represents the only way to generate renewable heat within the boundaries imposed in the model. In between 50 and 65% of RES share the results indicate that it is convenient to invest first in solar and then in wind power generation units paired with hydrogen systems until the maximum storage capacity of the grid is achieved. The maximum achievable RES share is found to be 65%, which is the upper limit imposed by the maximum storage capacity of the grid.

This analysis clearly shows that the investments in power-to-gas systems become an option only when they represent the only way to achieve high share of RES. In these circumstances the gas grid can give a fundamental support in the transition towards a 100% renewable scenario because it allows absorbing and converting the surplus of renewable electricity into renewable heat. From the retrofitting point of view, it is worth noticing that until 40% of RES share the grid does not require any retrofitting even playing an important role in the energy system. Only above these RES share large investments are required to transport up to 70%vol of H_2. In any case, the timeframe related to the achievement of this last scenario (45 years from now) could be consistent with the corresponding need of retrofitting. Eventually, it is interesting to notice that especially in the first period of the energy transition, a better coupling between energy generation and demand could allow reducing the utilization of hydrogen and therefore pushing even further the maximum achievable RES share using the gas grid as the sole renewable energy storage system. In this case, specific energy policies should be imposed with the support of proper incentives.

Note that the results of the present work stimulated further analyses, which are already under development and that will overcome the critical assumptions listed in Section 2.

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Nomenclature

Acronyms		*C*	*cost, €*
PRS	*Pressure Reduction Station*	*V*	*volume, m^3*
PV	*Photovoltaic system*	CH_4	*methane*
WT	*Wind Turbine system*	H_2	*hydrogen*
GTH	*Geothermal system*	***Greek symbols***	
HP	*Hydro Power system*	η	*efficiency*
BG	*Biomethane system*	***Subscripts and superscripts***	
PEM	*Polymeric Electrolyte Membrane electrolyser*	*th*	*thermal*
CHP	*Cogenerative system*	*ref*	*reference efficiency*
B	*Boiler system*	*el*	*electric*
P	*Electric power system*	*new*	*new*
RES	*Renewable Energy System*	*sol*	*solar*
REP	*Renewable Energy Penetration*	*grid*	*grid*
LCOE	*Levelized Cost Of Electricity*	*avg*	*average*
WIN	*Winter*	*stor*	*stored*
MID	*Middle-season*	*G*	*gas*
SUM	*Summer*	*C*	*non-gas fuel*
Symbols		*imp*	*imported*
P	*Electric energy, GWh*	*t*	*time-step*
I	*Solar Irradiance, GW/m^2*	*UD*	*user demand*
F	*Fuel, GWh*	*min*	*minimum*
Q	*Thermal energy, GWh*	*max*	*maximum*
CP	*Power capacity, GW*	*RE*	*renewable*
A	*Surface, m^2*	*tot*	*total*
E	*Energy content, GWh*	*bio*	*biomethane*
cap	*Relative energy capacity of the grid, -*	*fuel*	*fuel*
ratio, -	*ratio, -*		

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