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On the optimal mix of renewable energy sources, electrical energy storage and thermoelectric generation for the de-carbonization of the Italian electrical system

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Abstract The integration of intermittent renewable energy sources (RES) requires a substantial amount of electrical energy storage and significant increase of the grid capabilities. To keep these upgrades within reasonable limits, strategies maintaining a moderate but flexible thermoelectric power have been investigated. Based on the experimental loads for Italy in 2013, the implications of increasing the contribution of scalable RES, particularly wind and photovoltaic, are investigated in detail. The optimal value of the storage depends on its round-trip efficiency (1.3 TWh for hydroelectric storage and 6 TWh for power to gas). For RES producing 100% of the annual demand, the use of the optimal storage and of about 10 GW of thermoelectric power allows a substantial de-carbonization (more than 90%) of the electricity production still maintaining a capacity factor of the thermoelectric generators above 40%. Avoiding thermoelectric generation is possible but it requires overproduction by RES, between 120 and 200% of the annual electricity demand, depending on the storage technology and the mix between wind and photovoltaic generation. The calculations have been performed for realistic values of the storage round-trip efficiency and for various combinations of photovoltaic and wind powers. The capital costs required are also estimated at current costs of present day technologies.

1 Introduction

Europe is successfully pursuing the goal of increased production of electrical energy from Renewable Energy Sources (RES) [1]. Italy has already achieved the target of 35% RES share of the electricity production and has defined a plan to further increase the RES share up to 60% by 2050 [2]. Furthermore, the COP 21 agreement calls for even more ambitious goals as negative CO_2 emissions are required by 2075 to limit global warming to 2 °C [3].

Even though the capital investment costs per unit output power of new RES plants have decreased considerably, the integration of RES electricity production in the grid poses a number of challenges that are becoming more apparent as the share of RES energy increases such as the impact on the transmission grid and on the operation of the conventional thermoelectric generation (TEG) plants. On a longer time scale, the need for adequate electrical

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energy storage (EES) will become essential. This motivates a detailed analysis to determine the best strategy for de-carbonization of the electricity production [4–9].

In order to illustrate the scale of the challenge, we take as the reference case a situation in which RES produce 100% of the annual electricity demand (~ 300 TWh for Italy in 2013) [5]. In the absence of EES, thermoelectric generators (TEG) are still needed as a back-up system for the periods in which the RES production is insufficient to cover the instantaneous electric load. The load in 2013 reached a maximum of 54 GW. Subtracting the contribution of dispatchable RES (hydroelectric, geothermal and biomasses generation) the maximum load is reduced to about 47 GW: in the absence of intermittent RES this is the value to be covered by the installed TEG power. However, even if RES would produce 100% of the annual electricity demand, in the absence of EES the installed power of the TEG system would be only marginally reduced (~ 40 GW), whereas the TEG annual electricity production (taken here as an indicator of the CO_2 emissions) would be roughly a quarter of the total demand, leading to very low capacity factor of the TEG system [4, 5].

EES can in principle be used in order to compensate for the low-production phase of RES and to eliminate the need for backup systems. Taking again the reference case and assuming 100% round-trip conversion efficiency, the amount of electrical energy stored during the phases of RES overproduction would exactly cover the demand during the phase in which RES are insufficient. However, the amount of seasonal EES, which would have to be available in order to eliminate the need of a TEG system, is in the order of a few tens of TWh (20–50 TWh for Italy, depending on the combination of wind and photovoltaic) [5]. This level of storage is about two orders of magnitude above the amount of pumped hydroelectric storage available in Italy and it seems difficult to achieve with any storage technology. Furthermore, as shown in Ref. [6], if realistic values for the round-trip efficiency are considered, the seasonal storage loses its character because it can contribute to the electric system only shortly after periods with excessive surplus production.

If seasonal storage is unfeasible we may investigate the possibility of electricity production by RES in excess of the annual demand. However, as we will show in this paper, RES overproduction alone cannot solve the problem as there are always phases in which the intermittent RES production is negligible. Therefore, a sizable amount of EES is needed also in this case. Thus, it is legitimate to ask if an optimal combination of storage, RES production and TEG production can be found that achieves a substantial de-carbonization without compromising the economic use of the TEG system and with a minimal investment in infrastructures.

In this paper, we generalize the approach of Ref. [5] in two ways. First, we analyse various solutions for the EES by considering realistic values of the EES round-trip efficiency. Specifically, we analyse the case of hydroelectric storage, power-to-gas (P2G) with hydrogen and P2G with methane. Second, we assume that the TEG power provides the backup needed to satisfy the power balance but only up to a pre-defined limit P_M. The backup power in excess of P_M must then be provided by the storage system. This approach minimizes the above-mentioned problem of having a large fleet of TEG always available as it limits a priori the maximum available TEG power and allows operation at higher TEG capacity factor. The requirements on the storage system as a function of the maximum TEG power are quantified for increasing values of the RES share of the total electricity production. This approach is used to analyse also the possibility of RES shares above 100% with the goal of finding the optimum trade-off among installed RES power, EES and TEG system.

The questions we want to address are the following:

1. what is the minimal level of EES that must be provided?
2. how much electricity must be produced by intermittent RES to minimize the storage requirements?
3. what are the main cost drivers in the de-carbonization of electricity?

The paper is structured as follows. The next section describes the analysis methodology and the corresponding assumptions. Section 3 reports in detail the equations of the model. These are independent of the specific technology for the storage system. The technical constraints on the storage system are introduced in Sect. 4. The results of the models are discussed in Sect. 5 and the technical implications are reported in Sect. 6. A simplified analysis of the investment costs is presented in Sect. 7. Conclusions are the subject of the final Sect. 8 of the paper.

2 Methodology and assumptions

In agreement with the approach of Ref. [4], we do not rely on arbitrary scenarios for the future electricity demand. We simply assume the same electric load as in year 2013 for Italy and scale-up the amount of photovoltaic (PV) and wind powers (with different assumptions on the mix of these two RES) to achieve the target of a certain global RES share S_{RES} of the total electricity demand (with the reference case corresponding $S_{\mathrm{RES}} = 100\%$). In this exercise, we keep constant the amount of electricity produced by the other RES (hydropower, biomass and geothermic) because it seems unlikely that they can be scaled up substantially. In order to find the optimal combination of RES production, storage and TEG generation the following approach is adopted.

- First, a global share S_{RES} of electrical energy produced by RES is assumed; we also fix a value for the fraction f_{PV} of the RES energy provided by PV;
- It is assumed that the TEG power provides the backup needed to satisfy the power balance but only up to a pre-defined limit P_{M};
- We then evaluate the maximum EES needed (for various assumptions on the efficiency of the storage system) to match the load at each point of the time sequence.

In this way for each scenario characterized by a certain value of S_{RES}, P_{M}, storage efficiency and PV share we determine the amount of storage required (in energy and power), the amount of power that needs to be instantaneously managed by the grid and the required capital investments.

In Italy for the year 2013, the thermal installed power was 75.779 GW (of which 0.729 GW from geothermic) and a net production of around 183 TWh (5.3 TWh from geothermic). For the Hydroelectric the net installed power was about 22 GW (and a net production of 54 TWh), while for the photovoltaic and wind we had 18 GW (21 TWh net production) and 8.5 GW (15 TWh) respectively. The net import, in this year, was equal to 42.138 TWh.

The thermal data include the electricity produced by biomass (a gross production of 17 TWh with 4 GW of installed power). The energy used for pumping was 2.5 TWh. Thus, Italy is among the countries with the largest share of RES within the European Union with 112 TWh from RES, more than 35% of the total electricity demand, with about 11% from intermittent RES.

The data about the load on the grid, on RES generation and net import have been taken from the Italian transmission system operator TERNA [10]. They are provided in the form of a set of hourly data.

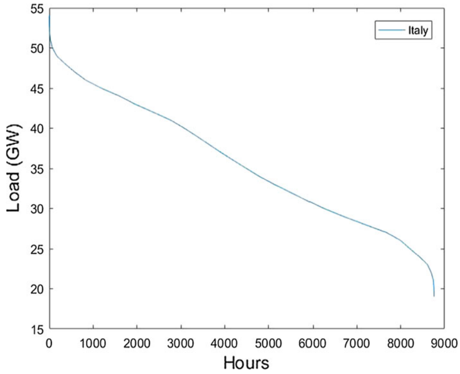

Fig. 1 Duration curve of Italy, year 2013. During that year the maximum load was 53.7 GW [10]

It is convenient to present the load data in terms of the histogram showing how many hours the grid has to provide power up to a certain level. The duration curve of the load is shown in Fig. 1.

We define the power needed on the grid to satisfy the demand as the energy absorbed during each time interval (1 h) divided by the duration. This quantity, therefore, represents the average power used during each time interval. Figure 1 shows that the power needed to satisfy the demand in 2013 had a maximum at about 54 GW and a minimum at 18 GW.

3 Model equations

The reference case is defined by the condition that the annual electricity production by RES is equal to the annual amount of electricity demand. As already noted, this does not necessarily mean that electricity is produced by RES alone because, if wind and photovoltaic at a given time are insufficient, a backup electricity source has to generate the rest.

In order to determine the amount of backup power required, and taking into account the already noted saturated level reached by geothermal and hydroelectric power, we first define the reduced load energy E_{red} as the total load energy E_{load} (i.e. the annual electrical energy demand) minus the energy annually produced by the geothermal (E_{geo}) and hydroelectric (E_{hydro}) systems

$$E_{\mathrm{red}} = E_{\mathrm{load}} - E_{\mathrm{hydro}} - E_{\mathrm{geo}} \tag{1a}$$

$$P_{\mathrm{red.load}} = P_{\mathrm{load}} - P_{\mathrm{hydro}} - P_{\mathrm{geo}} \tag{1b}$$

where $P_{\mathrm{red.load}}$ is the reduced load power.

Then, the 2013 values of photovoltaic (P_{PV2013}) and wind (P_{wind2013}) power are scaled up by a factor α_{PV} and α_{W} respectively

$$P_{\mathrm{wind}} = a_{\mathrm{W}} P_{\mathrm{wind2013}}; P_{\mathrm{PV}} = a_{\mathrm{PV}} P_{\mathrm{PV2013}}. \tag{2}$$

The condition that the energy generated in one year by wind and PV systems matches a given fraction S_{RES} of the reduced load energy yields a condition on their linear combination

$$a_{\mathrm{W}} E_{\mathrm{wind2013}} + a_{\mathrm{PV}} E_{\mathrm{PV2013}} = S_{\mathrm{RES}} E_{\mathrm{red}}. \tag{3}$$

In order to determine α_W and α_{PV} we need a second condition. This is obtained by fixing the share of PV power over the total

$$f_{PV} = a_{PV} E_{PV2013}/(S_{RES} E_{red}). \tag{4}$$

In each time interval, the difference between the reduced load power and the sum of wind and PV power defines (if positive) the value of the backup power P_{backup} to be produced

$$\begin{aligned} P_{backup} &= P_{red.load} - P_{wind} - P_{PV} \quad \text{if } P_{backup} > 0 \\ &= 0 \qquad\qquad\qquad\qquad \text{otherwise} \end{aligned} \tag{5a}$$

If the difference is negative (i.e. the intermittent RES production is larger than the load), the difference is the surplus power

$$\begin{aligned} P_{surplus} &= P_{wind} + P_{PV} - P_{red.load} \text{ if } P_{surplus} > 0 \\ &= 0 \qquad\qquad\qquad\qquad \text{otherwise} \end{aligned}. \tag{5b}$$

The surplus power can be used to pump a storage (if available) that, in turn, can replace part of the backup power. Thus, the backup power is given by the following expression

$$P_{backup} = P_{TEG} - h_c \mathrm{d}W_{stg}/\mathrm{d}t \text{ with } \mathrm{d}W_{stg}/\mathrm{d}t < 0 \tag{6}$$

with W_{stg} the energy accumulated in the storage system, η_c the conversion efficiency and P_{TEG} the power produced by the TEG system.

The stored energy W_{stg} evolves according to

$$\mathrm{d}W_{stg}/\mathrm{d}t = h_p P_{surplus} - (1/h_c)\left(P_{backup} - P_{TEG}\right) W_{stgmin} \leq W_{stg} \leq W_{stgmax} \tag{7}$$

with η_p the pumping efficiency (see Sect. 4). The power of the storage system in the conversion phase is therefore $P_{stg} = \eta_c\ \mathrm{d}W_{stg}/\mathrm{dt}$.

The storage is allowed to vary between a minimum value W_{stgmin} (for simplicity assumed to be zero in the following) and a maximum value W_{stgmax}. When these two limiting values are reached, the storage system is no longer able to produce or absorb power, respectively, and $\mathrm{d}W_{stg}/\mathrm{d}t = 0$. The initial value of the storage is determined by imposing the condition that the final value of the storage (i.e. 12:00 pm of December 31) must be equal to the initial value (i.e. 00:00 am of January 1).

In Ref. [5] P_{TEG} was defined as a base-load power (a constant value between two dates and zero otherwise) and Eq. (7) was solved (for $\eta_p = \eta_c = 100\%$ at fixed f_{PV} with different values of W_{stgmax} until the instantaneous electricity demand was satisfied. In the present paper, we assume that P_{TEG} exactly matches the backup power, but, differently from Refs.[4, 5], we set a maximum value P_M for P_{TEG}. If the backup power is smaller than P_M, the backup power is delivered by the TEG system

$$P_{backup} = P_{TEG} \quad \text{if } P_{backup} < P_M \tag{8a}$$

whereas, if $P_{backup} > P_M$, the power delivered by the storage covers the rest

$$P_{backup} = P_M - h_c \mathrm{d}W_{stg}/\mathrm{d}t \quad \text{if } P_{backup} > P_M \tag{8b}$$

The equations are solved with different values of W_{stgmax} until a consistent solution is found that matches the instantaneous electricity load for all the hourly data.

4 Technical constraints and implications

An increase of the electricity produced by wind and photovoltaic by a significant factor has large implications both technical and economic. Adequate investments and robust technologies have to be considered for both the generation and storage of the electricity, taking into account the fluctuations on the supply side. An important repercussion is also expected due the rate of power changes to be managed by the grid since the allocation of demand must take into account also the variability of the sources. In this section, we limit the analysis to a review of the present and projected data for different EES technologies.

4.1 Effects on the electric grid

The total power that must be managed by the grid is the sum of the RES, TEG and backup/storage power. The maximum power over the year is taken here as the relevant figure. As shown in Refs. [4, 5], the amount of grid power is insensitive to the RES generation up to a share of 40%. Above this value, the grid power increases substantially up to a value two times larger for 100% of RES production. Note that this analysis does not include the impact on the stability of the grid (in frequency and voltage), which is significantly affected by distributed generation from intermittent RES, and the possibility of distributed storage, which can reduce the amount of power actually transmitted along the grid. The model considered in this paper assumes an ideal grid that manages all the generated electric power.

4.2 Analysis of the efficiency of the storage

In this section, we review the available data on the efficiency of different EES technologies.

4.2.1 Hydroelectric storage

Pumped hydroelectric storage is a well-tested technology. It has a deployment time (the time needed to reach full power from the time of the request) of ~ 3 min. It has a very large efficiency both in conversion and in pumping (a round-trip efficiency for new systems in the range 75–82%) [11]. For our analysis, we assume a pumping efficiency $\eta_p = 75\%$ and a conversion efficiency $\eta_c = 95\%$.

The theoretical maximum pumped hydroelectric storage in Italy is in the range 1.0–7 TWh [11–13], depending on whether it is possible to link pairs of already existing reservoirs or a new upper/lower reservoir needs to be constructed. However, the energy that can be accumulated in a single stroke in the existing pumped storage plants can be estimated at about 200 GWh [5]. The present pumped hydroelectric storage capability is limited to a power of 7.5 GW.

4.2.2 Power-to-gas storage

For the chemical storage, the power-to-gas (P2G) system has been considered, with two possible options: pure hydrogen and methane [14, 15]. In the first case, hydrogen is produced by electrolysis and then used in fuel cells. In the second case, hydrogen is produced via electrolysis and then combined with carbon dioxide via the so-called “methanation”, an exothermic reaction also known as Fischer–Tropsch process. The end product, methane, is basically synthetic natural gas and so it can be transported to the required destinations using the natural gas grid without any particular restriction. The major advantage of methanation, over direct use of hydrogen, is indeed the full compatibility with the existing infrastructures for the transport of natural gas [16]. In Italy, the amount of gas that can be stored is about 17 bcm that correspond to stored energy of about 170 TWh [17].

The power-to-gas storage has not been tested yet in large-scale installations. It has a round-trip efficiency less than 30% at present, mostly due to the efficiency of the electrolysis (~ 60%), of the methanation (~ 65%) and of the conversion (~ 62% for Combined Cycle Gas Turbine and 50% for fuel cells) but improvements are expected in the next decades (with target values of 80% for electrolysis and methanation).

For our analysis, we assume a pumping efficiency $\eta_\mathrm{p} = 80\%$ and a conversion efficiency $\eta_\mathrm{c} = 40\%$ [16] for both H2 and methanation. Simulations have been carried out to check the sensitivity of the results to the choice of η_p and η_c. They show that the results are mostly sensitive on the round-trip efficiency $\eta_p \eta_c$.

It is important to note that in the case of methanation the conversion into electricity is made by the same TEG system used to burn fossil fuels. This has a substantial impact on the evaluation of the capacity factor of the TEG system.

5 The transition from the present situation to 100% RES share: requirements on the storage system

The different sets of values for the pumping and conversion efficiency, which have been considered, are summarized in Table 1.

For each set of values, a consistent solution has been found in the (P_M, W_stgmax) space at fixed f_PV. In Ref. [4] f_PV was determined by minimizing the total amount of back up energy in the absence of storage. The minimum value was obtained for f_PV ~ 25% and was referred to as the "optimal mix". However, the presence of storage and base-load power can alter the value of f_PV that minimizes the TEG energy. In Ref. [5] it was shown that the amount of base-load energy could be minimized for f_PV ~ 30 to 70%. Thus, we consider here two representative cases with $f_\mathrm{PV} = 25\%$ and $f_\mathrm{PV} = 60\%$, respectively.

5.1 The 2013 Italian situation (15% RES share)

We start by analyzing conditions close to the present Italian situation characterized by an amount of PV and wind roughly equal to 15% of the reduced load, of which 9% is covered by PV and 6% by wind ($f_\mathrm{PV} = 60\%$). Under these conditions 44.5 GW of installed TEG meet the demand in the absence of EES with a total production of 218 TWh (see Sect. 6).

If the RES mix would be shifted towards the "optimal mix" ($f_\mathrm{PV} = 25\%$), the results would be similar except for a slight decrease of the value of P_M needed in the absence of storage (43.5 GW). In Fig. 2 the amount of maximum storage vs. P_M is plotted.

As P_M approaches a critical value P_Mcrit, W_stgmax shows an abrupt increase for both $f_\mathrm{PV} = 25\%$ and $f_\mathrm{PV} = 60\%$. No solution exist for $P_\mathrm{M} < P_\mathrm{Mcrit}$. The value of P_Mcrit is 43GW for $f_\mathrm{PV} = 25\%$ and 44GW for $f_\mathrm{PV} = 60\%$. Therefore the difference between P_Mcrit and the P_M

Table 1 Considered scenarios for the pumping and conversion efficiency

	Ideal case	Hydroelectric storage	P2G storage
Pumping efficiency η_p(%)	100	75	80
Conversion efficiency η_c(%)	100	95	40

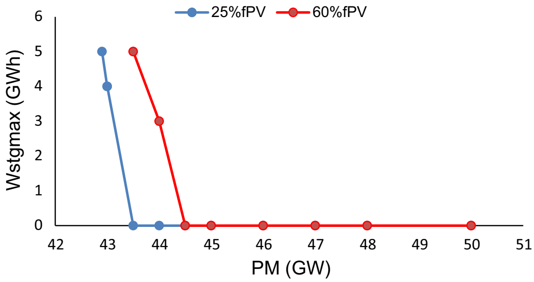

Fig. 2 Maximum energy accumulated in the storage system W_{stgmax} versus the threshold power of the TEG system for a intermittent RES share of 15% corresponding to the 2013 Italian situation, for two values of the share of photovoltaic power

value corresponding to no storage is very small. This result basically means that the amount of storage is irrelevant in this case of low RES share and that a minimum TEG power of about 44 GW is necessary.

5.2 The near term objective of 40% RES share

This objective is presently foreseen to be achieved around 2030. The two scenarios considered ($f_{\text{PV}} = 25\%$ and $f_{\text{PV}} = 60\%$) have a TEG energy of about 155 TWh (see Sect. 6), i.e. 50% lower than the annual demand (in agreement with the target of reducing at least 40% the greenhouse gas emissions in 2030 [18]). The results of the simulations are shown in Fig. 3 for two values of f_{PV} and two values of the storage efficiency. In the case of hydroelectric storage efficiency, for $f_{\text{PV}} = 25\%$, we have $P_{\text{Mcrit}} = 34$ GW and $P_{\text{M}} = 42$ GW in the case of no storage, whereas for $f_{\text{PV}} = 60\%$ $P_{\text{Mcrit}} = 42$ GW and $P_{\text{M}} = 45$ GW in the case of no storage. Again the two values are very close signalling the fact that the presence of storage does not substantially affect the results.

5.3 The medium-term objective of 70% RES share

If the RES share increases above the critical value of 40% of the reduced load, the request on the storage system becomes substantial and we need to distinguish between the hydroelectric storage and the P2G storage. The results of the analysis for this case are summarised in Fig. 4.

At this level of RES share, the amount of TEG energy produced is reduced to about 100 TWh (see Sect. 6). In the case of hydroelectric storage efficiency, we have $P_{\text{Mcrit}} = 20$ GW and $P_{\text{M}} = 40$ GW in the case of no storage, for both $f_{\text{PV}} = 25\%$ and $f_{\text{PV}} = 60\%$.

Taking an average value $P_{\text{M}} = 30$ GW the values of hydroelectric storage required (206 GWh for $f_{\text{PV}} = 25\%$ and 368 GWh for $f_{\text{PV}} = 60\%$) is comparable with the maximum presently available (~200 GWh) but an increase by a factor two to three is needed in the pumped power (18 GW for $f_{\text{PV}} = 25\%$ and 24 GW for $f_{\text{PV}} = 60\%$, to be compared with the presently installed 7.5 GW).

A reduction of 5 GW of the maximum backup power down to $P_{\text{M}} = 25$ GW has a significant impact on the storage system requirements as it implies an increase in storage to 608 GWh for $f_{\text{PV}} = 25\%$ and to 2170 GWh for $f_{\text{PV}} = 60\%$. The maximum power to be delivered from the storage system increases to 22 GW for $f_{\text{PV}} = 25\%$ and to 32 GW for $f_{\text{PV}} = 60\%$.

The general trend is the same for hydroelectric and P2G storage. However, the reduced round-trip efficiency of P2G storage makes the amount of required maximum storage much larger.

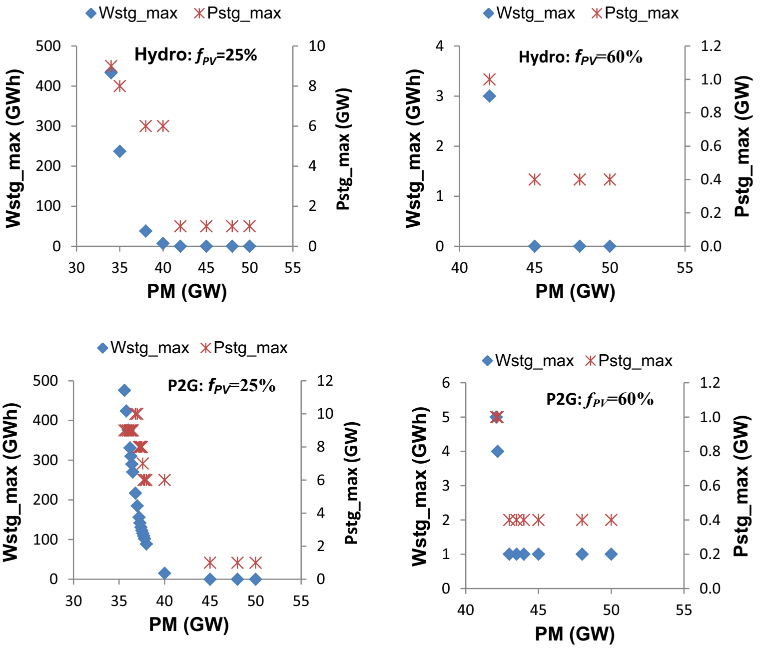

Fig. 3 Comparison of the Maximum energy storage and the maximum power storage at different thermoelectric generation powers for 40% RES share. Top: Hydroelectric storage considering two sets of the photovoltaic efficiencies. Bottom: Power-to-gas storage again considering two photovoltaic efficiencies

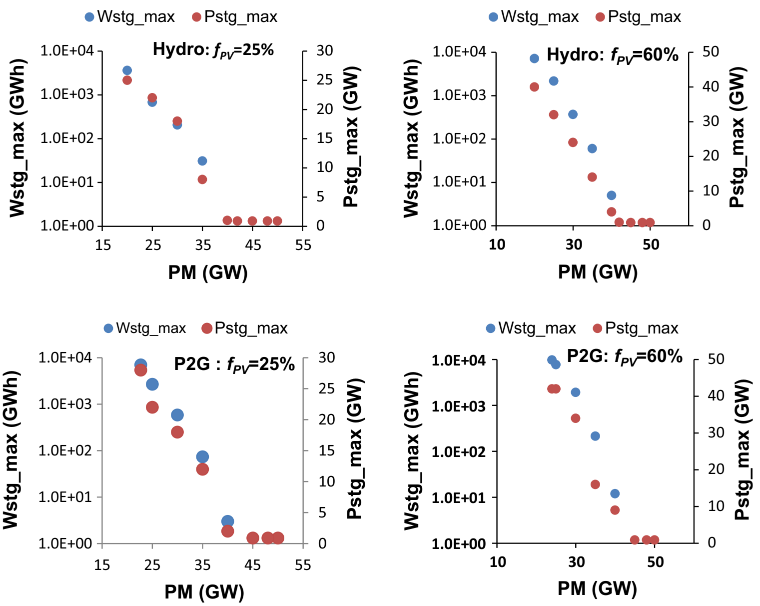

Fig. 4 Comparison of the Maximum energy storage and the maximum power storage at different thermoelectric generation powers for 70% RES share. Top: Hydroelectric storage considering two sets of the photovoltaic efficiencies. Bottom: Power-to-gas storage again considering two photovoltaic efficiencies

5.4 The reference case. 100% RES share

For completeness and for comparison with previous studies, in this subsection the case of 100% RES share (RES production = annual electricity demand) is considered. The results are shown in Table 2 and in Fig. 5.

It should be noted that the values of storage in Table 2 are substantially lower than those necessary for a seasonal storage that are in the range of 20–50 TWh [4, 5]. These results confirm the possibility that a significant reduction in the TEG power can be achieved with a moderate amount of EES.

Table 2 Comparison of the different scenarios for 100% RES share and $f_{PV} = 25\%$

P_M	E_{TEG} (TWh)	Capacity factor	W_{stgmax} (GWh) Ideal case	W_{stgmax} (GWh) eta = 75–95%	W_{stgmax} (GWh) eta = 80–40%
35 GW	63.3	0.2066	15	16	40
30 GW	63	0.24	80	72	200
25 GW	61.3	0.3276	200	180	600
20 GW	57	0.3276	600	589	1980
15 GW	50	0.3809	1250	1480	8250
12 GW	43	0.4136	2200	2940	19,000
10 GW	38	0.435	3360	5200	No solution

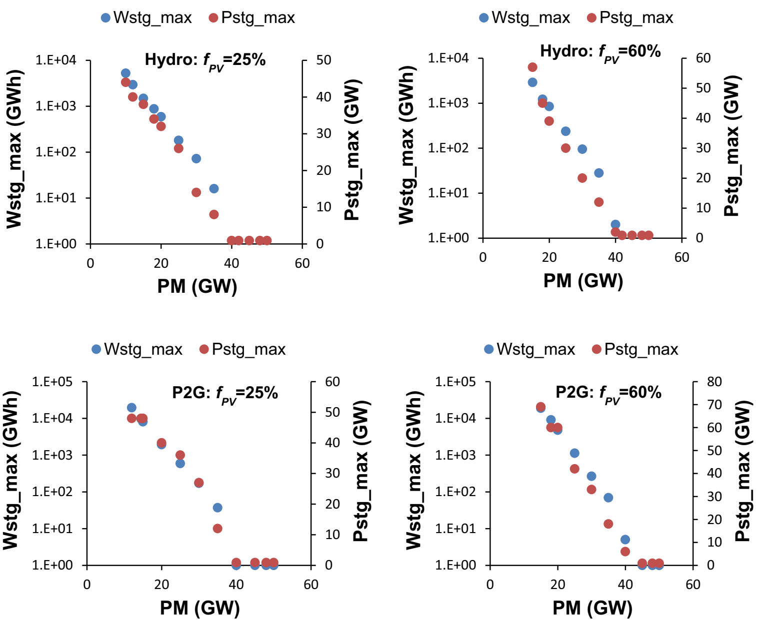

Fig. 5 Comparison of the maximum energy storage and the maximum power storage at different thermoelectric generation powers. Top: Hydroelectric storage considering two sets of the photovoltaic efficiencies. Bottom: Power-to-gas storage again considering two photovoltaic efficiencies

For 100% RES share, the amount of TEG energy produced is reduced to about 50 TWh (~50 TWh for $f_{PV} = 25\%$ and ~63 TWh for $f_{PV} = 60\%$) for P_M ~15 GW. The values of hydroelectric storage required (1478 GWh for $f_{PV} = 25\%$ and 2897 GWh for $f_{PV} = 60\%$) is about five times the presently available storage and an increase by a factor 7 is needed in the pumped power (26 GW for $f_{PV} = 25\%$ and 28 GW for $f_{PV} = 60\%$, to be compared with the presently installed 7.5 GW).

6 Comparison of different de-carbonization strategies

In this section, we comment on the general trends obtained from the results presented in Sect. 5. Our aim is to determine the requirements on the maximum TEG power, the EES and the grid as the amount of RES electricity increases as foreseen by all the de-carbonization policies. In addition, we consider the possibility of avoiding a TEG system through overproduction by RES.

Four strategies are considered through the combination of the following conditions:

- use of hydroelectric storage for a case with dominant wind energy ($f_{PV} = 25\%$) and a case with dominant PV energy ($f_{PV} = 60\%$)
- use of P2G storage (either with H2 or methane) again for a case with dominant wind energy ($f_{PV} = 25\%$) and a case with dominant PV energy ($f_{PV} = 60\%$).

We consider first the energy production of the TEG system that is directly related to the CO_2 production if the TEG energy is made from fossil fuels. Figure 6 shows the reduction of the TEG energy with the RES share for the two limiting cases of no EES and infinite EES. In each case, the two curves almost coincide up to a RES share of 70%. Beyond this value they start diverging since the presence of storage allows reducing the use of the TEG system. The

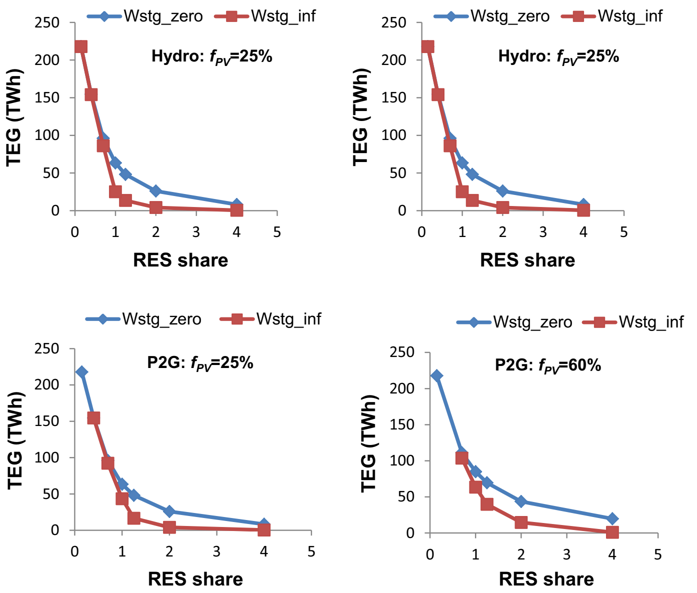

Fig. 6 Thermoelectric generation energy as a function of the RES share for two limiting cases: maximum energy storage equals to zero ($W_{stgmax} = 0$) and to infinite

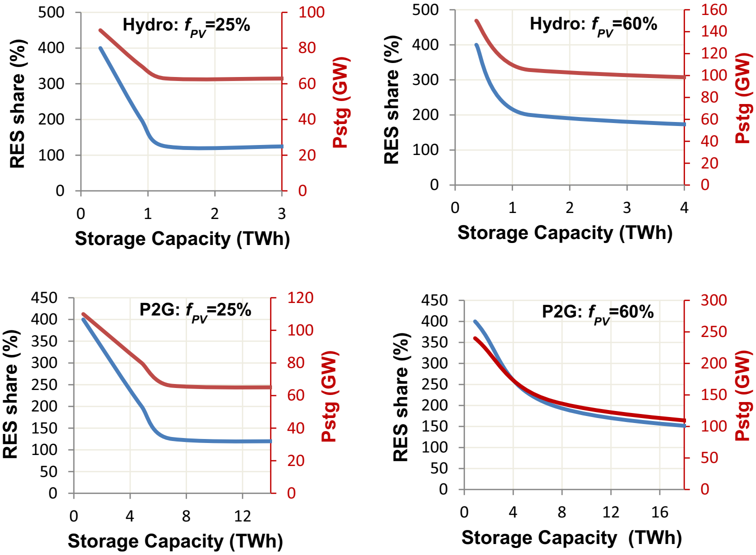

Fig. 7 RES share and maximum storage power versus storage capacity to avoid the use of thermoelectric generation ($P_M = 0$)

reduction of the TEG energy is similar for both storage systems at fixed f_{PV} and has a weak dependence on f_{PV}, with the $f_{PV} = 25\%$ case showing a more marked reduction of the TEG energy that for a RES share of 100% is about 10% of the value without RES. Thus, for a RES share below unity the impact on de-carbonization is relatively insensitive to the choice of the storage capacity and RES mix. Most of the reduction in the TEG energy takes place up to 100% RES share. Above this value of RES share the slope of the curve decreases and the reduction of TEG energy, via the increase of installed RES power, becomes less effective.

Can we avoid entirely a TEG system by producing more electrical energy than the annual consumption? Figure 7 shows the amount of RES overproduction needed to achieve the condition $P_M = 0$ as a function of the maximum storage for the hydroelectric and P2G storage efficiencies and two values of f_{PV}. No solutions exist at zero storage: the RES share tends to diverge as a critical value for storage is approached. This is due to the fact that the duration curve of the intermittent RES does not match the shape of the reduced load and there are periods with negligible production of both wind and PV power. For the case in which most of the RES energy is provided by wind ($f_{PV} = 25\%$) the amount of RES share decreases sharply at first and becomes almost insensitive to the maximum storage above 1.3 TWh for hydroelectric storage and 6 TWh for P2G storage. The well distinguishable knee in the curve shows that there is no (or limited) convenience in increasing the storage above these values that therefore represent an "optimal" value and a well-defined target in the de-carbonization of electricity. At the value of storage corresponding to the knee, a moderate overproduction (120%) from intermittent RES is needed. For the case of dominant PV power ($f_{PV} = 60\%$) the decrease of RES share with maximum storage is gradual but an "optimal" storage similar to that obtained for $f_{PV} = 25\%$ can still be defined. However, the values of RES share are larger than for $f_{PV} = 25\%$: a hydroelectric storage of 1 TWh requires 200% overproduction whereas 120% overproduction can satisfy the demand but requires about 15 TWh of storage. Also for P2G the storage required is of the order of 20 TWh in order to meet the demand

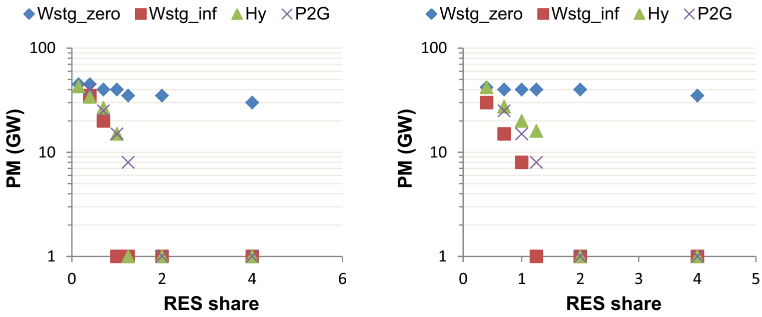

Fig. 8 Power produced by thermoelectric system versus RES share for two cases: no storage (blue) and unlimited storage (red) using 100% round-trip efficiency. The case of Power-to-gas storage (max storage considered 10 TWh) and Hydroelectric storage (max storage 1.3 TWh) are also shown. Left: photovoltaic efficiency = 25%; right: photovoltaic efficiency = 60%

with a moderate overproduction. These results generalizes the result of Ref. [5] obtained for 100% round-trip efficiency (see Fig. 12 of Ref. [5]). Due to the very low value of the P2G case with respect to what can be reasonable made achievable (see also Sect. 7 on costs) in the following we will use the value of 10 TWh for the simulations with P2G storage.

Figure 7 also shows the amount of storage power needed in the case $P_M = 0$ as a function of the maximum storage. The shape of the two curves in Fig. 7 is similar and an optimal value of the storage power can be seen for the value of the optimal storage. It should be noted that the storage power is a factor of two lower for $f_{PV} = 25\%$ with respect to $f_{PV} = 60\%$. As shown in Sect. 7, the storage power is a larger cost driver than the storage energy and its minimization is necessary to reduce the investment costs.

Having defined an "optimal" value of the EES we now analyse the amount of TEG power at fixed storage capacity as a function of the RES share. Four values of storage are considered: infinite storage, zero storage, 1.3 TWh with hydroelectric storage and 10 TWh with P2G storage. The maximum TEG power P_M is sensitive to the available storage already for a RES share smaller than 70%. Figure 8 shows P_M vs. the RES share for different values of the available storage and different storage technologies. The curve for infinite storage corresponds to P_{Mcrit}. For a RES share of 70% the maximum TEG power with no storage is a factor two larger than the power needed with either 1.3 TWh of hydro storage or 10 TWh of H2 storage. Note that the case of methanation is, as far as P_M is concerned, equivalent to the case of no storage. In this case, the sum of the power of the TEG system using fossil fuels and that of the storage system using synthetic methane is, by definition, equal to the difference between the reduced load and the RES production (i.e. the backup power in the absence of storage). Thus, although the increase in RES share has a substantial impact on de-carbonization also in the case of methanation, the price to be paid is to maintain a large fleet of TEG generators running at low capacity factor (see below). Clearly, as the RES share increases, the part of the fuel produced via methanation increases and this has an impact on the variable operation costs. The quantification of this aspect is however beyond the scope of this paper. Apart from methanation, 65% of the reduction in P_M occurs up to a RES share 100%. With sufficiently high RES overproduction it is possible to avoid a TEG system ($P_M = 0$), however, the needed amount of RES overproduction strongly depends on the available storage. In the ideal case (100% round-trip efficiency) considered in Refs. [4, 5] the value of storage needed to avoid TEG plants for 100% RES share was 20 to 50 TWh. Figure 8 shows that such a case is almost equivalent to a situation with infinite storage. With either 1.3 TWh

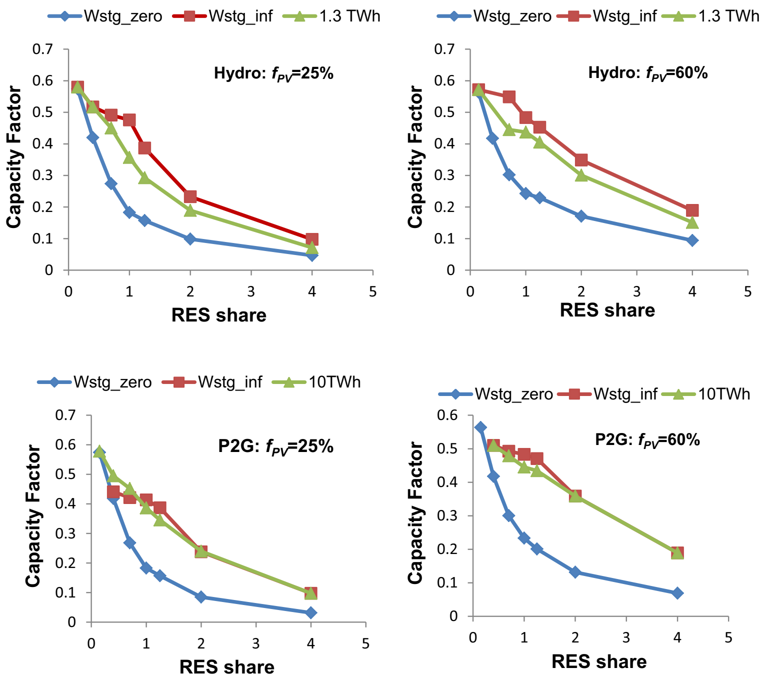

Fig. 9 Capacity Factor as a function of the RES share for maximum energy storage equal to zero ($W_{stgmax} = 0$), equal to infinite, equal to 1.3 TWh of hydroelectric storage (top) and equal to 10 TWh of Power-to-gas storage (bottom)

hydroelectric storage or 10 TWh H2 storage P_M decreases almost linearly down to 1 GW for 200% of RES share. Conversely, in the absence of storage (or in the case of methanation) P_M depends weakly on the RES share up to a RES share of 400%. Thus, except for methanation, during the phase of building up the RES power it is possible to progressively reduce the installed TEG power, with a positive effect on the TEG capacity factor. However, a minimum amount of storage (of the order of the optimal value) must be made available.

We can now quantify the capacity factor of the TEG system for the four different cases. Figure 9 shows that indeed the capacity factor for RES share of order 100% can be roughly doubled with this approach provided the "optimal" amount of storage is available: the capacity factor ranges between 50% in the case of infinite storage to 20% in the case of no storage. These numbers have to be compared with 70% capacity factor in the case of no RES. The curves corresponding to 1.3 TWh hydroelectric storage or 10 TWh P2G storage are close to the infinite storage case. As expected, the use of a cap on the maximum TEG power allows increasing the capacity factor of the TEG system above the values that would be obtained in the absence of storage. Note that above a RES share of 100% the capacity factor drops rapidly to values in the range 20–30%. However, this corresponds to a situation with a minimal amount of installed TEG power.

In summary, as the RES installed power increases a minimum storage of about 1.3 TWh for pumped hydroelectric storage or 10 TWh for P2G must be made available. At this level of storage, the process of de-carbonization can progress by increasing the intermittent RES installed power up to a RES share around 100%. At this level of RES share and storage, the amount of installed TEG power is about 12 GW and the amount of TEG energy produced is

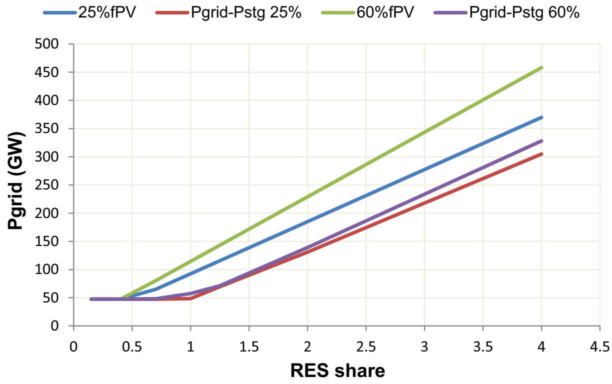

Fig. 10 Grid power (P_{grid}) as function of intermittent RES production for four cases: photovoltaic efficiency = 25% (blue line) and 60% (green line), grid power minus the power due to the storage system for a photovoltaic fraction of 25% and P_{grid} minus the storage power for a photovoltaic fraction of 60% (purple line)

only a few tens of TWh with a capacity factor around 40–50%. In parallel to the increase of the energy storage, also the power of the storage system has to increase. For the 100% RES case the power of the storage system is around 68 GW (with a presently installed pumped storage power equal to 7.5 GW).

Finally, in Fig. 10, the P_{grid} versus the RES share is reported for two values of the PV fraction. Here we have evaluated the power that the grid has to manage by taking the annual maximum of the sum of the RES, TEG and storage powers. The grid power does not depend on the maximum storage because it is fixed by the RES production and by the backup power that is the sum of the TEG and storage power. The grid power does not depend on the RES share up to 40% and then increases linearly with increasing RES share. The case with dominant PV power is systematically larger than the case with dominant wind power.

In order to evaluate the impact of local storage technologies to reduce the impact on the grid, we have subtracted the power due to the storage system (red and purple line in Fig. 10). In this case, the effect on the grid is minimal up to a RES share of 100%, increasing linearly for larger values of RES share.

We stress that the impact on the grid would require a more detailed model that is beyond the scope of the present paper.

7 Analysis of the investments costs

In the following, an estimate is provided of the investment costs required to increase the percentage of RES in the energy portfolio of Italy for the various scenarios described above. The aim of this analysis is not to provide an exact quantification of the costs of different strategies, but rather to identify the main cost drivers that each strategy entails.

The elements included are the costs of:

- the RES installed power (for PV and wind),
- the storage systems (hydroelectric and power-to-gas), and
- the grid upgrade.

The amounts of wind and PV power to be considered are given in Eq. (2). The costs for the additional installed power can be calculated from the following relations:

$$C_{\text{wind}} = (P_{\text{wind}} - P_{\text{wind2013}})c_{\text{wind}}\,;\; C_{\text{PV}} = (P_{\text{PV}} - P_{\text{PV2013}})c_{\text{PV}}$$

where $c_{\text{wind}} = 0.85$€/W [19] and $c_{\text{PV}} = 1.2$€/W [20].

For the storage, two different systems have been considered: pumped hydroelectric energy storage and power-to-gas storage. The cost has to be considered separately for the power it has to deliver and for the energy it has to store. For hydroelectric storage the costs have been estimated as:

$$C_{\text{hydro}} = (P_{\text{stgmax}} - P_{\text{hydro2013}})c_{\text{hydro-power}} + (W_{\text{stgmax}} - W_{\text{stgmax2013}})c_{\text{hydro-energy}}$$

where P_{stgmax} is the maximum value of the storage power, $c_{\text{hydro-power}} = 0.75$€/W [17] and $c_{\text{hydro-energy}} = 10$€/kWh [17]. It should be noted that the costs may vary significantly depending upon the possibility of using already available reservoirs or the need of constructing e.g. an additional reservoir to an already existing dam.

For the power-to-gas storage, we have separated the costs for the two options that have been considered: pure hydrogen (electrolysis only) and methane (electrolysis + methanation). In the first case, the storage costs have been estimated in the following way:

$$C_{\text{Hydrogen}} = P_{\text{stgmax}} c_{\text{hydrogen}-\text{power}} + W_{\text{stgmax}} c_{\text{hydrogen}-\text{energy}}$$

where $c_{\text{hydrogen-power}} = 0.7$ €/W [16, 21, 22] and $c_{\text{hydrogen-energy}} = 0.4$ €/kWh [16].

In the case of methanation, only the power installation costs have to be considered:

$$C_{\text{P2G}} = P_{\text{stgmax}} c_{\text{P2G-power}}$$

where $c_{\text{P2G-power}} = 1.5$€/W [16, 23]. Here we assume that the cost cover the plant for the electrolysis and methanation only since the production can be made through the existing gas-based TEG plants.

It should be stressed that the value W_{stgmax} and P_{stgmax} are not the same for hydroelectric storage and power-to-gas storage as they depend on the pumping and conversion efficiencies that are different in the two cases.

With regard to the grid upgrades, it is assumed that the average distance to be covered by the electric lines from the RES generating stations, typically in the south of Italy, to the storage units in the north of the country is 600 km. Moreover, it should be noted that the actual Italian grid is dimensioned to withstand a peak load of 55 GW [10]. Two main options are the alternating and direct current (AC and DC) solutions. In terms of transmission capability, the power rating of the required equipment is limited by the voltage and current that are allowed on each specific component. Coming to the cost of the two transmission systems, the breakeven length between HVAC and HVDC transmission depends on the length and on the rating of the transmission system. The breakeven distances for an onshore transmission system with a rating of 2 GW (GVA) for overhead lines (OHL) and underground cabling (UGL) are, respectively, equal to 310 km and 250 km [24]. Since overhead lines are not compatible with offshore generation and the distance to cover is of the order of 600 km, the costs have been evaluated for an HVDC underground grid according to the following formula:

$$C_{\text{grid}} = (P_{\text{grid}} - P_{\text{grid2013}}) \times \text{ distance } \times c_{\text{grid-HVDC}}$$

where $c_{\text{grid-HVDC}} = 1.5$ M€/km/GW [24] and an average distance = 600 km has been assumed.

We want to stress that the assumptions listed above are aimed at determining the main cost drivers of the de-carbonization process by assigning different weights to the various capital cost items, rather than at determining the exact amount of capital investments. Also, the curves showing the cumulative capital investments as a function of RES share (assumed to be an increasing function of time with specific targets set by the energy policy) cannot be easily translated into a profile of investments without a model for the time to deploy a specific technology for storage or grid upgrade.

The increase in the installed RES power is in the range of 60–120 GW, depending on the scenario considered for a 100% RES share. The associated investments correspond to 50–150 B€ for the installed power upgrade. An increase of 10 GW of the power delivered to the grid is estimated in our model to cost about 10 B€. Since a 100% RES share scenario requires a three-fold increase of the power on the grid (with a present maximum value of ~ 55 GW), the grid upgrade would translate in about 100 B€ costs. The increase in the power delivered by the storage system is in the range of 60 GW which translate into an investment cost between 40 and 90 B€. Finally, an increase by 10 TWh of stored energy by hydro system would cost, according to our model, about 100 B€ (but would cost nothing for methanation!). Thus, in principle all the three elements (installed RES power, storage and grid upgrade) may have a similar weight in the investment costs for a RES share of 100% although their weight is different for lower RES share, therefore indicating the priorities for the infrastructure upgrade.

To be specific, for the 40% RES share capital investments are dominated by the increase in the installed power and therefore are insensitive to the choice of the storage system (under our idealized assumptions the grid does not require a substantial upgrade up to this RES share). The case with larger installed PV power has a capital investment about twice the case with wind due to the larger cost per unit power assumed in the present paper and the larger amount of installed power required for PV. For 70% RES share, the costs are dominated by the installation costs of the RES power and, on a lower extent, by the grid upgrade and are independent of the storage technology. For larger RES share the cost of the storage increases but most of the capital cost remains associated with the installed RES power.

An overview of the results for the main cases studied in the paper is provided by the plots of Figs. 11 and 12. The number given here for the costs can be compared with the value of the electricity market in Italy that is in the order of 60 B€/year.

The total investment cost, the amount of TEG energy produces (as an indicator of the CO_2 emission) and the maximum TEG power P_M are shown in Figs. 11, 12 and 13, for the case of hydroelectric storage (with a maximum value of 1.3 TWh assumed) and for the case of P2G storage (with a maximum storage of 10 TWh) methanation and hydrogen respectively. The following observations can be made.

- The investment costs for energy storage are small compared with the investment costs for the power of the storage system. This is true also for the case of hydroelectric storage because the amount of energy storage is an order of magnitude lower than in the case of H2 and this compensates for the larger unit cost of storage.
- The cost of the increase in the storage power are comparable for H2 and hydroelectric storage and a factor two smaller than for methanation.

Note that the grid costs do not depend on the specific storage technology in our model.

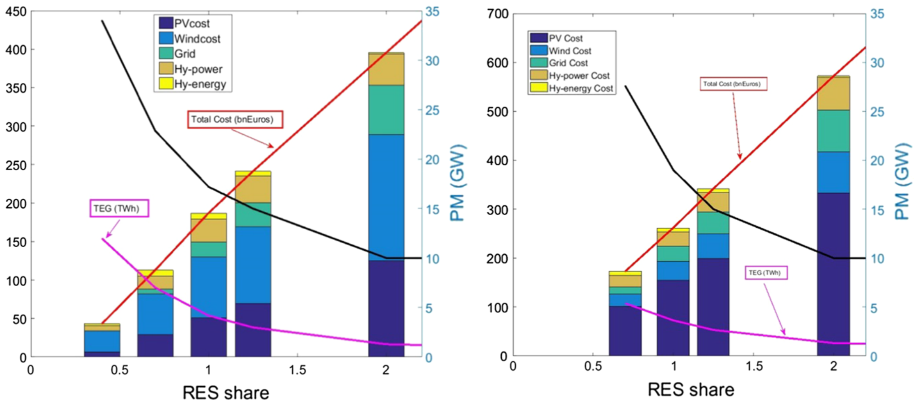

Fig. 11 Total costs and P_M versus the RES share for hydroelectric storage. Left plot: 75–95 and 25% f_{PV}. Right plot: 75–95% and 60% f_{PV}. The maximum storage is 1.3 TWh

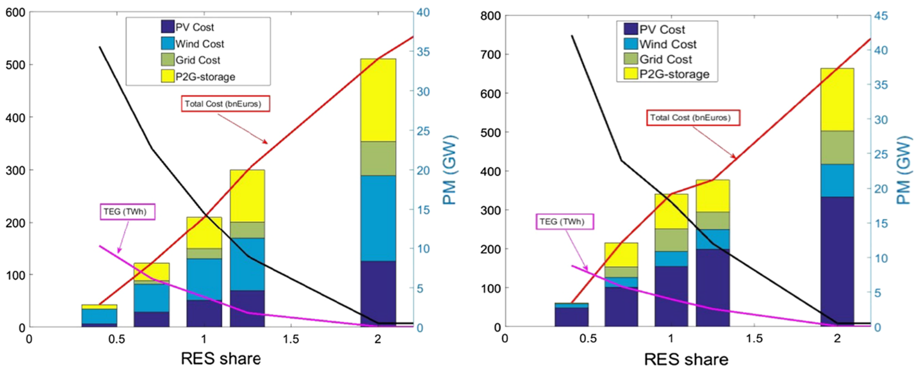

Fig. 12 Total costs and P_M versus the RES share for power to gas (methanation) storage. Left plot: 80–40% and 25% f_{PV}. Right plot: 80–40% and 60% f_{PV}. The maximum storage is 10 TWh

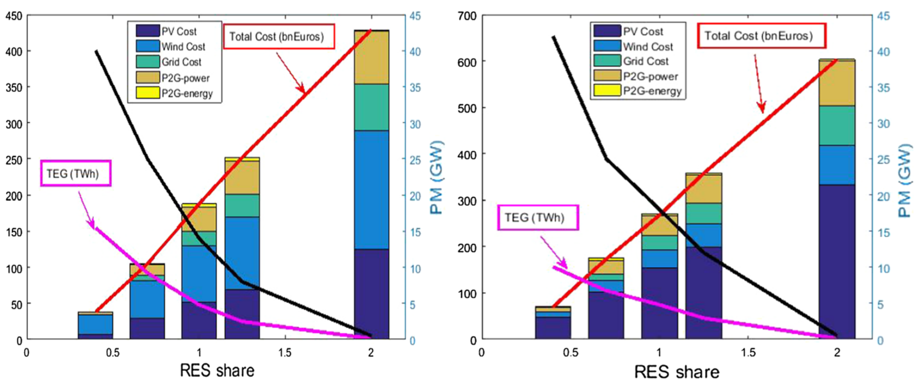

Fig. 13 Total costs and P_M versus the RES share for power to gas (H2) storage. Left plot: 80–40% and 25% f_{PV}. Right plot: 80–40% and 60% f_{PV}. The maximum storage is 10 TWh

8 Conclusion and policy implications

In this paper, we have shown that the integration of RES into the electrical system can be pursued through a combination of storage and TEG systems. Tables 3 and 4 summarize the main parameters of the various scenarios.

We have quantified the "optimal" amount of storage as a function of the efficiency of the storage system. This amount of storage should come progressively into operation and becomes essential beyond an intermittent RES share of 70%. The “optimal” amount of storage depends upon the storage technology considered: for hydroelectric storage it is about 1.3 TWh whereas for P2G storage is about 6 TWh (see Fig. 9). In the case of hydroelectric storage this corresponds to a sixfold increase of the present hydroelectric pumped storage capacity, and in line with detailed estimates of the hydroelectric potential for Italy [13], with a parallel increase of the pumped storage power to 69 GW from the present 7.5 GW capacity. If methanation is used for P2G, only the methanation plants have to be constructed as the needed storage is well below the present capability of the methane network. If H2 is used for P2G, dedicated repositories have to be constructed in addition to the H2 production plants. The values of “optimal” storage are therefore the targets for any de-carbonization process of the electrical sector. It is important to note that the amount of “optimal” storage is well below what would be expected for a seasonal storage.

To avoid entirely TEG generation is possible but it requires, in addition to the optimal storage, an overproduction by intermittent RES between 120 and 200%, with the best condition achieved using hydroelectric storage and dominant wind production ($f_{PV} = 25\%$). The increase of RES share is effective in reducing the TEG energy (taken as an indicator of CO_2 emission) up to 100% RES share. Thus, the most effective approach for de-carbonization appears to be a RES share around 100% and the use a moderate amount (~ 10 GW) of TEG

Table 3 Summary of the different scenarios for hydroelectric storage

	2013 (RES 15%)	RES 70%		RES 100%		RES 125%		RES 200%	
f_{pv} (%)	60	25	60	25	60	25	60	25	60
PV power (GW)	18.4	41	99	59	142	74	177	118	283
Wind power (GW)	8.5	78	42	111	59	139	74	222	118
TEG power (GW)		23	27	16	18	0.5	13	0.5	0.5
TEG energy (TWh)	218	90	107	53	70	1.8	48	1	1.5
TEG capacity factor		0.45	0.45	0.38	0.44	0.35	0.4	0.24	0.35
Storage power (GW)	7.5	22	32	38	45	63	57	84	105
Maximum storage used (TWh)		1.3	1.3	1.3	1.3	1.3	1.3	1	1.3
PV cost (bnEuros)		29	101	50	150	70	200	125	323
Wind cost (bnEuros)		54	39	80	39	100	50	164	85
Power storage cost (bnEuros)		17	24	28.5	33.8	40	40	63	78
Energy storage cost (bnEuros)		10	10	10	10	10	10	9.5	10
Grid improvement cost (bnEuros)		12	24	20	30	30	44	64	85

Table 4 Summary of the different scenarios for P2G Storage

	2013 (RES 15%)	RES 70%		RES 100%		RES 125%		RES 200%	
f_{pv} (%)	60	25	60	25	60	25	60	25	60
PV power (GW)	18.4	41	99	59	142	74	177	118	283
Wind power (GW)	8.5	78	42	111	59	139	74	222	118
TEG power (GW)		22.7	24	14	20	8	12	0.5	0.5
TEG (TWh)	218	90	104	48	74.5	25	45	1	1.6
TEG capacity factor		0.45	0.48	0.4	0.43	0.35	0.43	0.24	0.36
Storage power (GW)		28	42	48	60	66	85	105	140
Maximum storage used (TWh)		2.7	10	10	10	10	10	4.8	7.2
PV cost (bnEuros)		29	101	51	155	70	200	125	330
Wind cost (bnEuros)		53	25	78	39	100	50	160	84
CH4 power storage cost (bnEuros)		33	63	60	90	99	127	157	210
H2—power storage cost (bnEuros)		15.4	29	33	42	46	59.5	73	98
Energy Storage cost (bnEuros)		1	4	4.5	4	4.5	4	1.9	2.9
Grid improvement cost (bnEuros)		6.6	14	20	30	31	44	64	85

power. This strategy allows maintaining a capacity factor of the TEG system above 40%. This value for the capacity factor is non optimal but could still be economically acceptable for a progressive integration of RES.

For Italy, this approach predicts that a reduction between 80 and 90% of the electrical energy produced by thermoelectric generators can be achieved through a sevenfold increase of the 2013 electricity production via wind and PV. The installed thermoelectric power can be progressively reduced down to 12 GW.

No significant advantage is found in increasing the production of electricity much above a RES share of 100%. However, this possibility will have to be analysed in the context of a policy of integration between the various energy sectors (electricity, transport and space heating).

The results with dominant PV share have systematically more stringent requirements that those with dominant wind share. This is not optimal for Italy and may have an impact on the cost of the de-carbonization process.

The estimated cumulative cost to achieve a RES share of 100% is in the range of 200–350 B€, to be compared with a value of the electricity market in Italy of the order of 60 B€/year. Most of this amount (63%) is related to the increase of intermittent RES power, about 10% is estimated for the grid upgrade and the rest for the storage system. The investments in the storage system are mostly associated with the increase in power and are similar for the case of H2 and hydroelectric storage and a factor two higher for the case of methanation, reflecting the difference in the presently estimated unit costs of these technologies.

Finally, we note that the analysis presented here does not address the issue of the frequency and voltage stability of the grid, which is significantly affected by the increase in the RES share, which requires adequate margins to be implemented.

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Data Availability Statement This manuscript has associated data in a data repository. [Authors' comment: The data used in the present study are available at www.terna.it.]

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