# Assessing the renewable energy policy paradox: a scenario analysis for the Italian electricity market

Cieplinski, A.[1] * D'Alessandro, S.[1] Marghella F.[2]

**Abstract**

The renewable energy policy paradox states that the combination of liberalized markets with low marginal cost and intermittent technologies tends to reduce electricity prices and, hence, the profitability of new investments in wind and solar energy, thus rendering price-incentive policies less effective or more costly. The majority of simulation models are not suited to assess the feasibility of middle and long term goals under the price policies already in place. To fill this gap, this study applies a novel integrated top-down-bottom-up dynamic macrosimulation model to the Italian economy (2015-2040). To incorporate uncertainty about the future costs of generation and storage technologies, fossil fuel prices, demand elasticities, macroeconomic performance and price incentives, we rely on exploratory model analysis to build scenarios from three clusters out of the 1,000 different simulations. Our results suggest a decreasing trend in electricity prices in contrast to the latest official projections. Accordingly, the expansion of renewable energy slows down and none of the 1,000 simulations reach the 2030 target of 55% renewable energy in electricity supply. Despite the ineffectiveness of the price subsidy policy in the first ten years (2021-2030), it still seems to be crucial to reach very high penetration of variable renewable energy sources by 2040.

## Highlights

- We build a macrosimulation model for the Italian power system called NET
- A high penetration of VREs drives spot prices down in our simulations
- Price incentives increase VREs but are not enough to reach Italys RES targets
- The Renewable Energy Policy Paradox holds
- Reduced electricity demand growth and carbon prices are key for decarbonization goals

**Keywords:** Renewable energy policy paradox, electricity markets, energy modelling, National Energy and Climate Plans

[1]Department of Economics and Management, University of Pisa, Italy.

[2]Althesys Strategic Consultants, Italy.

* Corresponding author: andre.cieplinski@ec.unipi.it

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# 1 Introduction

The decarbonization of developed economies is the first and perhaps most important step to maintain global warming within 1.5° C until 2050. Among the many challenges ahead such as the overhaul of transportation systems, industrial processes and agriculture, electricity generation calls the most immediate action. Responsible for 41% of worldwide carbon dioxide emissions in 2017 and 35% of European Union emissions in the same year and with an expected increase in demand from the electrification of transportation and heating in the near future, a quick substitution of fossil fuel fired power plants is a necessary step towards a low-carbon society [1].

Fortunately, we have a blueprint for the large scale implementation of proven renewable energy sources (RES) [2; 3]. Countries that invested heavily on RES technologies such as Denmark, Germany and the UK have observed record shares – 62.4%, 38.0% and 30.9%, respectively, in 2018 – of their electricity generation being fulfilled by RES. Italy is no exception and has increased the share of RES in generation from 16.3% in 2005 to 33.9% in 2018 [4], boosted by public incentives introduced in 2007 [1]. Nonetheless, even larger investments in RES will be necessary to meet the ambitious emission targets set by the EU and the Paris agreement. The Italian NECP [5], for instance, projects 55% of generation from RES in 2030, while the Spanish government expects a whopping 85% for the same year [6].

Recent contributions have shed new light on the limits of renewable energy expansion in liberalized markets due to their combination of low marginal costs and intermittent supply. The gradual expansion of solar and wind power tends to reduce prices during their production hours, thus limiting the profitability and willingness to invest in these proven renewable technologies [7]. The renewable energy policy paradox (REPP) [8] argues that it is the expansion of variable renewable energies (VREs) themselves to limit their profitability and halt additional investments. Moreover, the decreasing trend and increasing volatility of electricity prices due to the penetration of VREs will also render typical financial incentives such as feed-in tariffs, feed-in premiums and direct investment subsidies either less effective or more costly.

Empirical studies have confirmed this expected negative correlation between VRE installed capacity or supply and electricity prices in Germany [9; 10] and Spain [11; 12]. However, it is still unclear how soon and how much the REPP may become a serious obstacle for the energy transition. Its impacts on the effectiveness and cost of price policies for VRE expansion also deserves further scrutiny. Anticipating the future barriers related to the expansion of VREs,

Abbreviations: CCGT: Combined Cycle Gas Turbine; EU: European Union; GDP: Gross Domestic Product; MGP: Day-Ahead Market (*Mercato del Giorno Prima*); MOS: Merit Order Stack; NECP: National Energy and Climate Plan (*Piano Nazionale Integrato Energia e Clima*); NET: New Electricity Trends (Model); PUN: National Single Price (*Prezzo Unico Nazionale*); REPP: Renewable Energy Policy Paradox; RES: Renewable Energy Source; TSO: Transmission System Operator; UK: United Kingdom; VREs: Variable Renewable Energies.

[1] Decree of February 19, 2007 for solar and following decrees for solar and other renewable sources.

recent proposals have called for changes in market design with more spatial-time granularity and later gate closures [13; 14].

The Clean Energy Package, recently launched by EU, introduces a reformed layout for wholesale as well as retail power markets, partly filling the gaps within legislation to integrate renewables, but does not fix some existing misalignments [15] and seems not ready to accommodate the large mass of RES generation needed for the energy transition [16]. Most of all, relying on an energy-only spot market, in which VREs and fossil fuels plants should both place bids reflecting their marginal costs, it does not solve the problems identified in the REPP. However, given the need for large and fast penetration of VREs, anticipating future barriers to wind and solar capacity expansion and the conditions under which RES targets may be reached under the current liberalized market design is a momentous step towards clean power generation. At the same time, it is essential to assess the extent to which traditional price policies already in place are able to contribute to overcoming REPP.

Nevertheless, contemporary bottom-up optimization models are not suited to asses the *viability* of the ambitious goals for RES expansion in Europe. Linear optimization models identify the cost-minimizing choices that *do* reach decarbonization targets, but are unable to assess the *feasibility* of such configurations [1]. Thus, a proper evaluation of the feedbacks hypothesized for a hybrid and truly dynamic model is required, with the aim to replicate the decreasing trend in prices that follows the expansion of VREs and its consequences for electricity demand and new investments in RES.

This study is the first to consider the implications of the REPP to the achievement of middle and long-term decarbonization goals of electricity systems. We apply an integrated top-down-bottom-up dynamic macrosimulation model to the Italian economy, between 2015 and 2040[2]. To incorporate the uncertainty about the future costs of generation and storage technologies, fossil fuel prices, demand elasticities, macroeconomic performance and prices, we perform an exploratory model analysis to group $1,000$ simulations in three clusters that constitute our scenarios.

The Italian day-ahead electricity market (MGP)[3] provides a fitting case to evaluate the REPP. Empirical studies for the Italian market found evidence that increases in supply from renewables have reduced wholesale electricity prices [19] and increased their volatility [2]. The share of renewables is expected to further increase from the current 34% to 55% in 2030, with 35% of the demand expected to be fulfilled by solar and wind [5]. Moreover, the Italian government established a new set of price incentives[4] for investments in VREs, whose effectiveness is questionable given the lack of bids for solar capacity in the first auction [20].

Our results suggest a decreasing trend in electricity prices, in contrast with the latest projections from the gas and power Italian TSOs [21]. Accordingly, the expansion of VREs is slowed down and none of the $1,000$ simulations reach the 2030 target of 55% RES in electricity sup-

[2]The longest horizon to which we have some comparison for target RES penetration and prices.

[3]The MGP accounted for 91.5%, on average, of total electricity demand in the period 2015-2018. Calculation based on data from GSE [17] and Terna [18].

[4]The main mechanism can be included in the category of floating feed-in premiums with strike price, according to the classification presented in [13]. As a matter of fact, it is a two ways contract for difference between a seller (RES plant owner) and a buyer (public institution). See the Decree of July 4, 2019.

ply. Despite the ineffectiveness of the price subsidy policy, implemented in roughly half of the simulations, in the first ten years after its introduction (2020-2030), as predicted by Blaquez et al. [8], it still seems to be rather crucial for the achievement of high RES shares in the system by 2040. Finally, the most relevant factor for this attainment is a low or moderate expansion of electricity demand.

The following section describes the modelling methodology and the exploratory models analysis. Section 3 presents the simulation results and is followed by their discussion in section 4.

# 2 Material and methods

This section provides an overview of the modelling procedures and cluster analysis that underpin our results. It does not present a detailed account of the model equations or the statistical tests performed in the cluster analysis, which can be found in the supplementary information together with additional results.

## 2.1 Model

We develop a dynamic macrosimulation model – New Electricity Trends (NET) – tailored to assess the feasibility of current targets with a high penetration of RES. NET is a system dynamics model and, thus, incorporates complex nonlinear feedbacks that emerge from the causal relations between its variables [22; 23].[5]

The model is hybrid with a bottom-up electricity module that interacts with a top-down macroeconomic model. The latter is a simplified version of the Eurogreen model [24]. It considers three heterogeneous groups of workers and six industries in a demand-led ecological macroeconomics model. The electricity module considers 13 different generation and 3 storage technologies in the 6 zones[6] of the Italian electricity market. Figure 1 illustrates the heterogeneous agents, industries and technologies modelled in NET and some of the main relations between them.

[5]The model was developed using the software Vensim DSS.

[6]The six zones are: i. North (Val D'Aosta, Piedmont, Liguria, Lombardy, Trentino, Veneto, Friuli Venezia Giulia and Emilia Romagna), ii. Center-North (Tuscany, Umbria and Marche), iii. Center-South (Lazio, Abruzzo and Campania), iv. South (Molise, Puglia, Basilicata and Calabria), v. Sardinia and vi. Sicily.

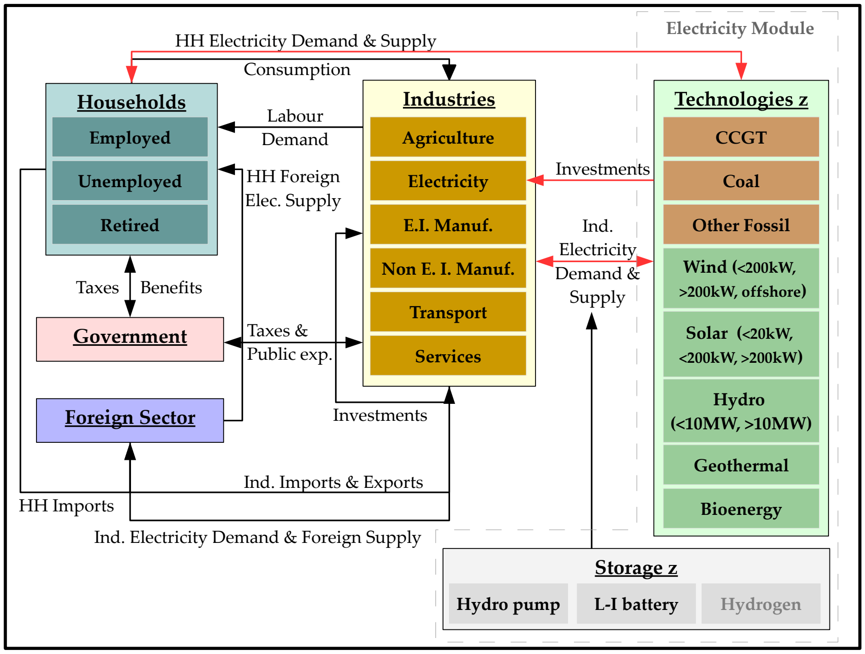


**Figure 1: Macroview.** List of and main connections among the heterogeneous households, industries and technologies included in NET model. The abbreviations in the industries column refer to Energy Intensive Manufacturing (E.I. Manuf.) and Non-Energy Intensive Manufacturing (Non E. I. Manuf.), respectively. The red arrows show the main connections between the two modules.

There are two main channels of integration between the macro and electricity modules. The first is through electricity demand and prices. The level output in each industry and households' consumption determines the total electricity demand that is met by suppliers. Thus, variations in employment and labour income, wages and exports, for instance, have a direct impact on the electricity market. However, the prices determined by the composition of electricity supply have a feedback effect on its demand through households' demand elasticity and industries' choice of technology. A consistent fall in electricity prices leads to an increase in households' consumption and also favours the adoption of more energy-intensive (and labour-saving) technologies. Therefore, we have a balancing feedback loop. An electricity price reduction increases demand which, in turn, favours the entry of technologies with higher production costs in the mix, thus increasing prices.

The second channel is through the expansion of installed capacity. The sum of the investments by all generation technologies is aggregated and constitutes the actual investment of the Electricity industry in the macroeconomic module. In this case we have a reinforcing loop. Investments from the electricity module increase final demand and GDP, resulting in higher electricity demand which increases prices, profits and enables further investments in generation technologies. It should be noted, however, that the Electricity industry constitutes a small proportion of total investments. Hence, it is very unlikely that this reinforcing loop will lead to instability in the whole model since it will be more than compensated by variations in investments from the other five industries.

The model works on two different levels of time resolution and geographical granularity. The macroeconomic module is defined at the national level with yearly variables whereas the electricity module considers the six zones of the Italian market and has a hourly time definition for supply, demand and prices, but maintains a yearly time-step for investments in new capacity. To limit the time requirement for the simulations but maintain the hourly frequency and the detailed seasonality necessary to evaluate systems with a high share of VREs [25] we adopted one, 24 hours, representative day per month, resulting in 288 hours per year. These features allow our model have a high geographical coverage and medium time resolution according to the classification proposed by Prina et al. [26].

The smallest unit of analysis in the electricity module are generation technologies per market zone that undertake investments in new installed capacity. The total amount invested, in MWs, depends on the expected increase in demand, in each zone, and is split between technologies in proportion to their accumulated profits[7] Moreover, this accumulated profits must cover at least 25% of the total investments to be carried by a technology in a zone while the rest is financed. Therefore, even if the desired amount of investments is determined by zone, the actual expansion of capacity will lead similar technologies to expand the most in the zones where they are more profitable due to regional price differences or productivity, in the case of VREs. There are also limits to the expansion of certain technologies. It is assumed that large ($>$ 10 MW) hydroelectric only invests to maintain current capacity, no further expansion of coal and other fossil[8], and a maximum 17,450 MW for onshore and 950 MW for offshore wind [28].

The matching of electricity demand and supply is hourly. We apply the historical seasonality of energy demand to the annual values determined in the macroeconomic module. We assume that all RES, except for bioenergy, have priority of dispatchment. Given their installed capacity and historical hourly production profile, wind, solar, and geothermal sell their production in full.[9] Hydroelectric supply also depends on capacity and historical seasonality, but is further affected by random shocks on reservoir capacity[10].

Excess demand after RES is then covered by imports. These are again a function of the observed imports in our representative hours, but change in time as a decreasing function of the growth rate of domestic hourly supply capacity. Finally, the residual demand after RES and imports is covered by fossil fuel sources and bioenergy in proportion to the supply capacity of each technology.

Thus, the composition of supply and prices are not determined according to a merit order stack (MOS) model. Even though RES, which have lower marginal costs, and imports, whose

[7] Flexible resources do not receive any revenues from ancillary services market or capacity market. This is a simplification, since mark-up shares from balancing operations are lately increasing for thermal plants. The introduction of a capacity market based on reliability options will generate an additional source of revenues for flexibility suppliers in the Italian market from 2022 to 2023, while for the following years the mechanism is under discussion [27].

[8] The latter includes oil products such as fuel oil, gasoil and other non renewable sources such as wastes.

[9] The output profile of wind and solar is specific to each market zone.

[10] We calculate approximate reservoir capacity as the ratio between actual and full capacity supply. The shocks are normally distributed with mean and standard deviation given by the calculated values for reservoir capacity between 2015 and 2017.

prices have historically been lower in neighbouring countries, cover demand before costlier fossil fuel technologies, the market prices in our model do not reflect the marginal cost of the marginal technology. Traditional MOS models tend to underestimate the elasticity of prices to the composition of supply, particularly reducing intraday volatility [29]. In our model hourly prices are a function of operational costs – fixed and variables operational and maintenance costs plus fuel and emissions costs – per MWh of all the technologies that supply on that hour weighted by their respective quantities. We then calibrate the elasticity of hourly prices to variations in this weighted operational cost using data for the first five simulated years (2015-2019). Although this approach is different from adding spreads that are increasing in capacity utilization over marginal cost, as in Ward et al. [29], it reaches similar results since supply from costlier technologies will only gradually increase market prices instead of instantly shifting prices to match their marginal cost.

These rather wholistic modelling choices for the dynamics of investments, electricity supply and prices are not without limitations. Several technical aspects of real systems such as plant ramp rates, start-up costs, ancillary services and network constraints are ignored.[11]. Moreover, the model considers exclusively the day-ahead market. Nonetheless, they allow us to have a simple enough model that is capable to assess long-term trends in profitability and investments while reproducing the expected increase in price volatility under various policy and technological scenarios.

We also adopt a simple procedure to introduce three storage technologies (hydro pumps, lithium-ion batteries, hydrogen with electrolyzer and fuel cell) and consider their effect on prices. Storage technologies operate if and only if the percentage of RES in supply is above a threshold ($\tau^{ST} \geq 80\%$) and if that technology is profitable. New installed storage capacity, in MW, is given by the average hourly excess supply of RES, net of existing storage demand. This amount is then distributed between the three technologies according to their expected profitability from energy arbitrage given the current hourly prices, operational and investment costs. Data on technical specifications were obtained from Schmidt et al. [30][12]. It is further assumed that storage technologies perform exclusively intraday arbitrage and discharge in fixed hours[13].

Finally, we consider a price subsidy policy for intermittent RES. Since NET considers aggregates by technology and zone, it is impossible to replicate actual auctions for each technology. Hence, we assume that the price paid to each technology is equal to the minimum necessary to cover its costs, including the cost of debt that finances investments, from 2020 on whenever this policy is active in the simulations. This full cost price is bounded by the rules of the cur-

[11] Even though we model the impact of network constraints on zonal prices indirectly, see section 3.5. for the supplementary information.

[12] Including round trip efficiency, time and cycle degradation, shelf life and construction time, operational costs and investment and replacement costs.

[13] Since our model imposes a cap on maximum wind capacity the vast majority of intermittent renewable supply depends on solar energy, hence storage technologies tend to charge during peak solar production hours and discharge between 7 and 10 p.m.

rently active Italian Law[14] that establishes a maximum price[15] per auction and a minimum that corresponds to 30% of the maximum for large solar ($\geq$ 200 kW), onshore and offshore wind; and to 70% of the maximum for small scale wind ($<$ 200 kW) and solar ($<$ 200 kW).

### 2.2 Exploratory model analysis and scenarios

To cope with the uncertainty we perform $1,000$ simulations allowing for variations in key parameters of the model such as investment costs, fuel prices and GDP growth. We then perform a cluster analysis on the resulting simulations, which cover a broad parameter space, to identify three clusters of simulations which constitute the base for our scenarios. Therefore, the scenario results presented in the following section are actually means and standard deviations built from all the simulations included in each cluster.

The variables selected for the sensitivity analysis are summarized in Table 1. It presents the variables included in the sensitivity analysis, their minimum and maximum values, the minimum variation ($\Delta$), and their mean values in our three scenarios. The cluster analysis is based on the three main outcome variables at the final simulation year (2040): electricity demand, the share of RES on supply and national prices. The investment cost, fuel cost and $CO_2$ price variables listed in Table 1 are set to vary to a maximum of plus/minus 33% of their baseline projection for 2040[16]. That is, when the sensitivity is active they start diverging in 2020 and gradually increase or decrease with respect to baseline projections until the final year of the simulation. Variables marked with units "Y/N" are randomly chosen to be active or inactive. In storage, the variable % exported refers to the amount that is exported whenever there is an excess supply of renewable energy and the variable storage threshold to the parameter $\tau$ explained in the previous section. Price elasticity is that of households electricity demand. Since the GDP is determined endogenously in NET, we add an exogenous variation in export growth to evaluate the impact of macroeconomic fluctuations on the electricity market. Finally, the seed of the random extraction of new technologies for the six industries in the macroeconomic module is set to vary randomly.

[14] Decree of July 4, 2019.

[15] The maximum prices per MWh are of €70 for onshore wind ($\geq$ 200 kW), €150 for offshore and small wind plants ($<$ 200 kW), €70 for large solar ($\geq$ 200 kW) and €90 for smaller solar plants ($<$ 200 kW).

[16] The baseline projections already predict a reduction of investment costs in solar, wind and storage technologies. Our sensitivity analysis then projects greater or smaller declines.

**Table 1: Sensitivity analysis and cluster characteristics**

| Variable | Units | Min. | Max. | $\Delta$ | LRES-HD | Baseline | HRES-LD |
|---|---|---|---|---|---|---|---|
| Investment costs (2040) | | | | | | | |
| Solar ($\geq$ 20kW)† | 1,000 €/MW | 273 | 547 | 14 | 390 | 403 | 426 |
| Solar (< 20kW) | 1,000 €/MW | 407 | 813 | 20 | 580 | 600 | 634 |
| Wind ($\geq$ 200kW) | 1,000 €/MW | 627 | 1,253 | 31 | 912 | 921 | 970 |
| Wind (< 200kW) | 1,000 €/MW | 3,223 | 6,447 | 83 | 4,693 | 4,738 | 4,990 |
| Wind (offshore) | 1,000 €/MW | 1,654 | 3,308 | 161 | 2,408 | 2,431 | 2,560 |
| Lithium-Ion Battery | 1,000 €/MW | 65 | 130 | 3 | 97 | 97 | 99 |
| Pumped Hydroelectric | 1,000 €/MW | 257 | 457 | 11 | 341 | 346 | 341 |
| Hydrogen | 1,000 €/MW | 1,269 | 2,538 | 63 | 1,865 | 1,926 | 1,894 |
| Production costs (2040) | | | | | | | |
| $CO_2$ price | €/t$CO_2$ | 22.5 | 67.5 | 2.2 | 32.7 | 43.1 | 52.2 |
| Gas price | €/MWh | 20.1 | 40.3 | 1.0 | 28.2 | 30.0 | 31.3 |
| Coal price | €/MWh | 6 | 12 | 0.3 | 8.7 | 8.9 | 9.2 |
| Storage | | | | | | | |
| New Storage | Y/N | 0 | 1 | - | 0.50 | 0.49 | 0.50 |
| % exported | % | 0 | 100 | 10 | 49.3 | 48.3 | 52.1 |
| Storage threshold ($\tau^{ST}$) | % | 80 | 100 | 5 | 90.1 | 90.4 | 89.7 |
| Phase-out coal | Y/N | 0 | 1 | - | 0.55 | 0.51 | 0.47 |
| Price subsidy policy | Y/N | 0 | 1 | - | 0.45 | 0.47 | 0.55 |
| Elect. price elasticity | % | -31.4 | 0 | 5.7 | -29.4 | -24.2 | -19.2 |
| Export growth | % | -2 | 2 | 0.5 | 0.7 | 0.4 | -0.8 |
| Seed | | | | | | | |

† applies to solar technologies greater than 200kW and between 200 and 20kW.

The simulations are clustered using k-means. Even though five clusters would have provided more statistically differentiated groups of simulations, according to the statistics reported in section 4 of the supplementary information, it did not provide qualitative differences with respect to only three clusters. Hence, we opted to build our scenarios based on three clusters to maintain the presentation and interpretation of the results as simple as possible.

A graphical representation of the clusters that compose our three scenarios is presented in Figure 2. It plots the simulations with respect to the three (scaled) clustering variables in simplexes for selected years. Differences between clusters increase from 2020 to 2040. This indicates that the clusters change due to the variables employed in the sensitivity analysis and were not already different from the beginning of the simulations. Most of the differences are seen in demand (bottom) and the share of RES (left), whereas prices remain somewhat similar in the three clusters.

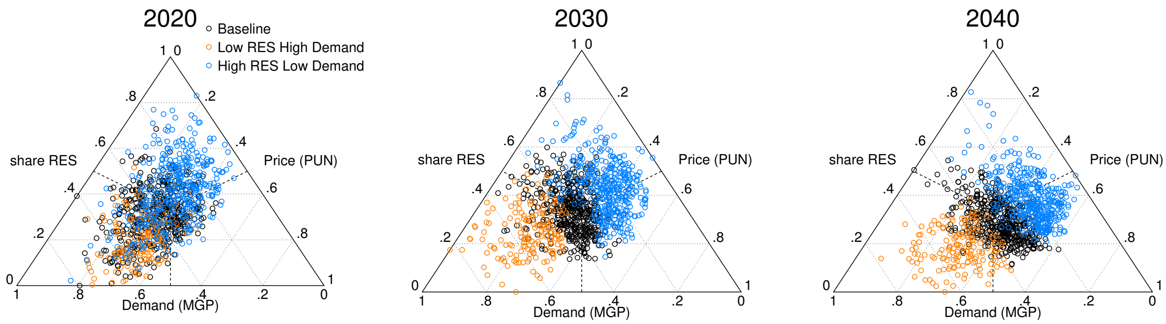


**Figure 2: Clusters analysis results.** The simplexes plot the 1,000 simulations as a function of the three outcome variables used to define the clusters: National Single Price (PUN), electricity demand in the Day-Ahead Market (MGP) and the % of RES in electricity supply. Simulations are colored according to the specific scenarios they are included in for the simulated years of 2020, 2030 and 2040.

The orange circles represent the first scenario termed Low RES-high demand (LRES-HD). The blue ones represent the scenario High RES-low demand (HRES-LD). The black circles were assigned to the Baseline scenario that rests in between the other two. On average, the scenarios do not present large differences in investment costs of solar, wind and storage, even though HRES-LD has slightly higher investment costs for solar and wind. $CO_2$, gas and coal prices increase gradually from LRES-HD to HRES-LD. Moreover, the HRES-LD scenario is also characterized by a greater percentage of simulations with an active price subsidy policy, lower household demand elasticity and lower export and, consequently, GDP growth. The share of simulations in which there is a phase-out of coal is, perhaps surprisingly, higher in LRES-HD. However, we note that coal represents a small share of current supply in Italy – 7.1% in the day-ahead market in 2018 [17] – and is substituted by CCGT in the event of a phase-out which, therefore, does not affect the % of RES in our model. The next section also explores the differences within these scenarios with respect to the variables employed in the sensitivity analysis (Table 1).

# 3 Results

This section presents the simulation results based on the three scenarios identified in the cluster analysis. It focuses on the dynamics of the three main outcome variables – electricity demand, the share of RES and prices – and compares them to the values projected by MATTM-MiSE-MIT [5] and Snam–Terna [21], for 2030 and 2040 respectively. The second subsection dwells deeper into the effectiveness of the price subsidy policy simulated, checking for differences between and within the three scenarios.

### 3.1 Main results

The main simulation results are plotted in Figure 3. The three top panels plot the % of RES in supply (top-left), annual average national prices (top-center) and total electricity demand in the day ahead market (top-right). The bottom panels show the average yearly prices received by gas fired CCGT (bottom-left), wind (bottom-center) and solar (bottom-right). These are calculated, in each year, as the average national prices in the hours these technologies supply weighted by the quantities supplied.

Each graph plots the means (solid lines), a one standard deviation confidence interval (shaded areas), the minimum and maximum values (dashed lines) for our three scenarios. The solid horizontal red line represents the 2030 NECP projections and the three dashed horizontal lines the 2040 values projected in the three scenarios of Snam–Terna [21][17]. Finally, the red dots plot actual values observed between 2015 and 2018[18].

We observe an inverse relation between the share of RES and electricity demand, and a decreasing long-term trend in prices. The expansion of VREs capacity, due to reduced investment costs, is unable to substitute gas fired plants with strong demand growth, as in the LRES-HD scenario. Although the scenarios do not differ as much in terms of prices, the better performing simulations in terms of RES share tend to have higher annual prices. Higher fossil fuel and $CO_2$ prices, as in the HRES-LD scenario, contribute to the expansion of VREs in two ways. First, by increasing national prices. Second, they also increase costs and limit the profitability and, hence, new investments in fossil fuel based technologies[19].

The three bottom graphs in Figure 3 reveal that almost all of the decreasing trend in national prices are explained by a pronounced reduction of hourly prices during the day, when solar energy is active. The average price received by CCGT plants (bottom-right) remains stable in the three scenarios until 2030 and increases slightly thereafter. Such an increase is due to a shift in the supply profile of CCGT towards peak evening hours following the expansion of solar capacity[20]. It also benefits wind (bottom-center), whose prices remain nearly constant on average after 2030. The average price received by solar energy (bottom-right), however, falls throughout the whole simulation from around 50 in 2015 to almost 20 €/MWh in 2040. Unlike CCGT and wind, average solar prices are virtually equal in the three scenarios. This confirms that the installed solar capacity is similar, on average, in the three scenarios and that the higher shares of RES in HRES-LD are a direct result of lower electricity demand.

[17]The National Single Price projected for the NECP in 2030 is calculated from the zonal prices in Snam–Terna [21, p. 114]. The black dashed line is the business as usual scenario. The blue and pink dashed lines represent the decentralized and centralized development scenarios, respectively. Both of the development scenarios project expansions of RES and increased energy efficiency. However, the centralized scenario relies more heavily on the development of flexible energy from gas, including bio and synthetic methane, while the decentralized scenario projects greater electrification of consumption, electric vehicles and expansion of VREs and storage technologies.

[18]Note that the values for the electricity demand graph correspond to the total demand which is higher than the day-ahead market that our model simulates.

[19]These conclusions are further supported by the additional results presented in section 5 of the supplementary information.

[20]However, it is important to note that this does not translate directly to higher total profits and investments in CCGT, since their total number of production hours is also reduced.

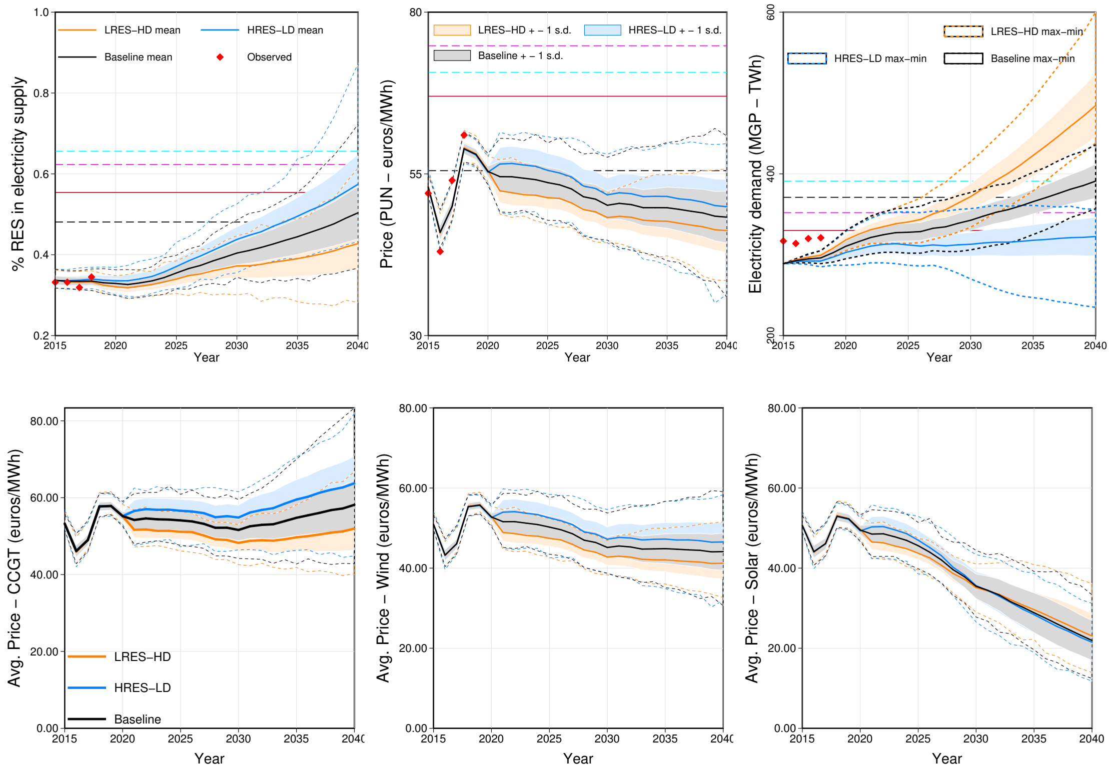


**Figure 3: Main indicators** % of RES in supply (top-left), national prices (top-center), day-ahead market electricity demand (top-right), average prices received by CCGT (bottom-left), wind (bottom-center) and solar (bottom-right). Solid lines present the means for all simulations within each scenario, shaded areas correspond to a one standard deviation confidence intervals, and dashed lines represent the minimum and maximum values for each cluster. The red horizontal lines are the reference values for [5]. The black, blue and pink dashed lines represent values for the baseline, decentralized and centralized scenarios, respectively, from [21].

The panels in Figure 3 also allow us to draw some initial comparisons to the 2030 and 2040 projections from MATTM-MiSE-MIT [5] and Snam–Terna [21], respectively. None of the 1,000 simulations reach the 2030 target of 55% of RES. By the end of the simulation the mean of the HRES-LD scenario reaches a 57.4% of RES and stays within about one standard deviation of the two Snam–Terna [21] policy scenarios. Our baseline scenario ends up at 50.4%, between the 55% NECP target and the 48% of Snam–Terna [21] business as usual scenario. The LRES-HD scenario achieves only a 42.8% share of RES. The best performing simulations, most within HRES-LD and some in the Baseline, represented by the maximum dashed lines, reach shares of RES above 70%. In contrast with the means of the scenarios, these accelerate after 2030 due to the price subsidy policy as we will argue in greater detail in the following subsection.

In terms of total electricity demand our Baseline projects about 390 TWh in 2040, slightly above the 370 TWh of Snam–Terna [21] business as usual. HRES-LD stagnates around the value projected by the NECP for 2030 of 330 TWh due to lower GDP growth rates. The LRES-HD scenario, however, predicts a remarkable increase in electricity demand fueled by a higher elasticity of demand to the decreasing prices.

Nonetheless, the most striking difference between our simulations and the reference lines in the graphs lies in the deviation in annual average national prices. While, in line with Brouwer et al. [31], our three scenarios project decreasing annual prices with an expansion of the RES share, Snam–Terna [21] scenarios predict a significant increase in prices in a high VREs system[21]. This positive correlation between the penetration of RES and prices is at odds with the empirical evidence from several European markets [19; 9; 10; 11; 12; 32] and is explained by the methodological differences between NET and optimization models.

Since optimization models calculate the cost minimizing mix of generation technologies to reach certain goals, including the target share of RES, their prices reflect the MOS of such mix. Moreover, linear optimization models do not consider whether their optimal allocation of generation technologies are a likely outcome of the evolution of the system. Therefore, the positive correlation between the share of RES and prices in Snam–Terna [21] should be attributed to the rigidity of the MOS model explained by Ward et al. [29]. Even with a high penetration of low marginal cost VREs, as long as gas fired plants remain the marginal technology, market prices will reflect their costs, which are boosted by increasing fuel and $CO_2$ prices[22]. In contrast, prices in our model reflect the weighted average of the marginal costs of the supplying technologies. Hence, an increase of low marginal cost VREs in supply does result in falling prices.

The results so far do not consider variability in hourly prices which are expected to increase with further penetration of intermittent VREs [33; 29]. Figure 4 plots the evolution of hourly prices in the three scenarios of our model during three selected months. We opt to present the results for April (historically the month of lower total demand in Italy), July (the peak load month) and December (a cold month). The panels in Figure 4 depict the means (solid lines), one standard deviation confidence intervals (shaded areas) and the maximum and minimum prices (dashed lines). Each graph presents the evolution of hourly prices within the 24 hours of the month, in five year intervals from 2015 to 2040.

[21]The NECP does not indicate price projections for electricity spot market. The values are reported in the TSOs joint scenarios.

[22]We don't have access to hourly prices in these scenarios.

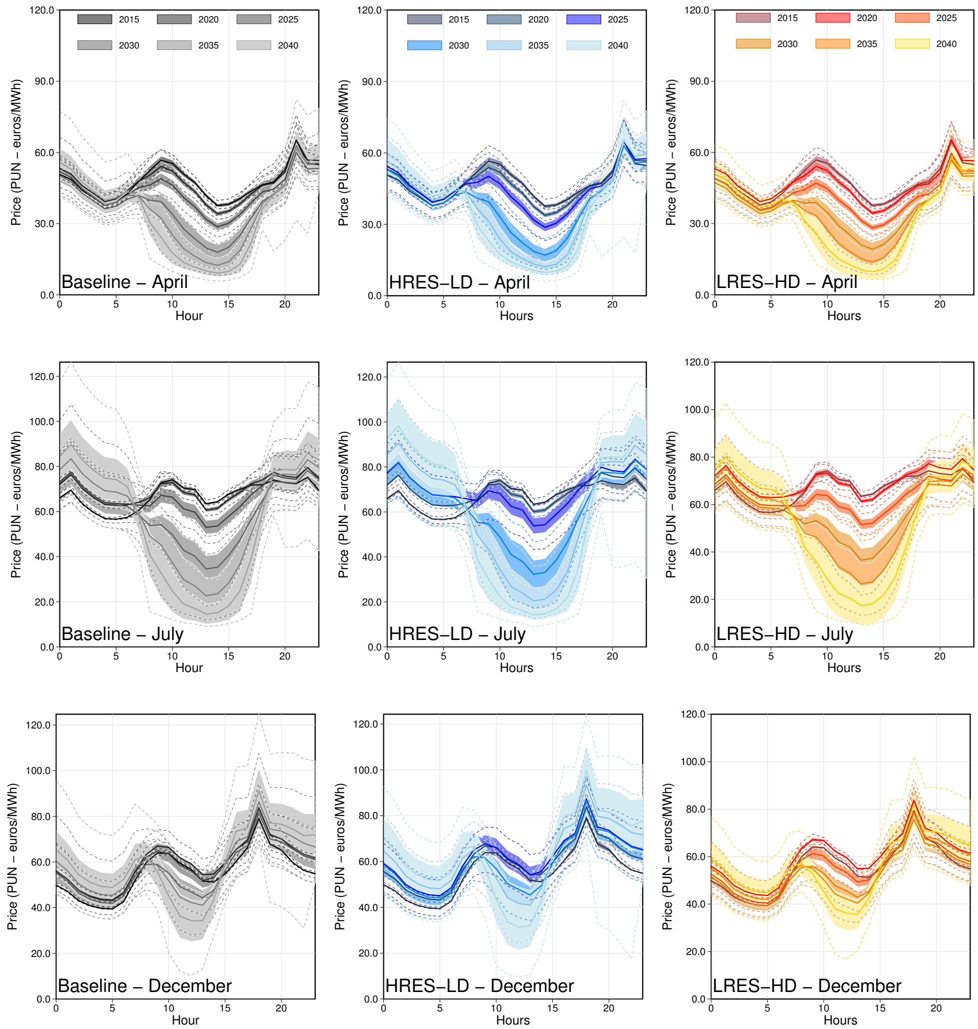


**Figure 4: Hourly prices** in April (top), July (middle) and December (bottom) for the Baseline (left), HRES-LD (center) and LREs-HD scenario (right). Solid lines present the means for all simulations within each scenario, shaded areas correspond to a one standard deviation confidence intervals, and dashed lines represent the minimum and maximum values for each cluster. All the graphs plot these values in five year intervals from darker (2015) to lighter colors (2040).

As for the annual average prices, we do not see striking differences between our three scenarios. In all three of them there is an increase in intraday price volatility with a notable decrease during the productive hours of solar energy. These fall of daytime prices accelerate from 2030 onward in July and after 2035 in April and December. Our scenarios also project a moderate increase in hourly prices during night hours, mostly due to the increasing fuel and $CO_2$ prices of CCGT, which is more noticeable during July and December than in the typically low demand month of April.

Still there are distinctions between the three scenarios that are worth noticing. The two scenarios with lower energy demand, Baseline and HRES-LD, reach low prices during more hours than LRES-HD, particularly in July, and also higher prices during night hours in July and

December. Moreover, on the lower right-hand-side of all the Baseline and HRES-LD graphs we see the effect of storage on night prices through the minimum dashed lines. These represent the lowest price simulation within these two scenarios which are those with a large increase of storage capacity, mostly Lithium-ion batteries and some pumped hydro systems. However, we do not observe similar decreases in night prices until 2035.

### 3.2 Policy effectiveness

We now focus on the variables listed in Table 1 that lead to the results and differences among our three scenarios, with a particular interest in the role of the price subsidy policy and its effectiveness to promote the expansion of VREs. Overall, the price subsidy does not seems to effectively contribute to the growth of intermittent renewables between the scenarios[23], but are very effective within each scenario. Our results also suggest that this policy takes a long time to become effective. Significant differences in the share of RES among simulations with and without the price subsidy policy are observed between 2030 and 2040.

The next results focus primarily in differences between scenarios. Figure 5 presents box plots for our three main outcome variables, % of RES in electricity supply, national prices and total electricity demand in 2030 and 2040. Each graph presents two box plots for each scenarios, differentiation among simulations in which the price subsidy police is inactive (left) and active (right). The reference lines are the same plotted in Figure 3.

Even though we observe some differences between our three scenarios in 2030, simulations with and without the price subsidy policy are virtually indistinguishable within the same scenarios. Between the three scenarios, as in Figure 3, HRES-LD simulations have higher % of RES, slightly higher prices and lower total electricity demands. Simulations in the LRES-HD, on the other hand, present larger demand and a lower % of RES in supply. In the final year of the simulations (2040) there is an increase in variance between simulations, within all scenarios. Still, median % RES in simulations with an active price subsidy are only marginally above those without the policy. These results would suggest the price subsidy policy is ineffective, as predicted by Blaquez et al. [8].

[23] Note that, from Table 1, simulations with an active price subsidy policy are more frequent in HRES-LD, which reaches higher shares of RES, than in the other two scenarios.

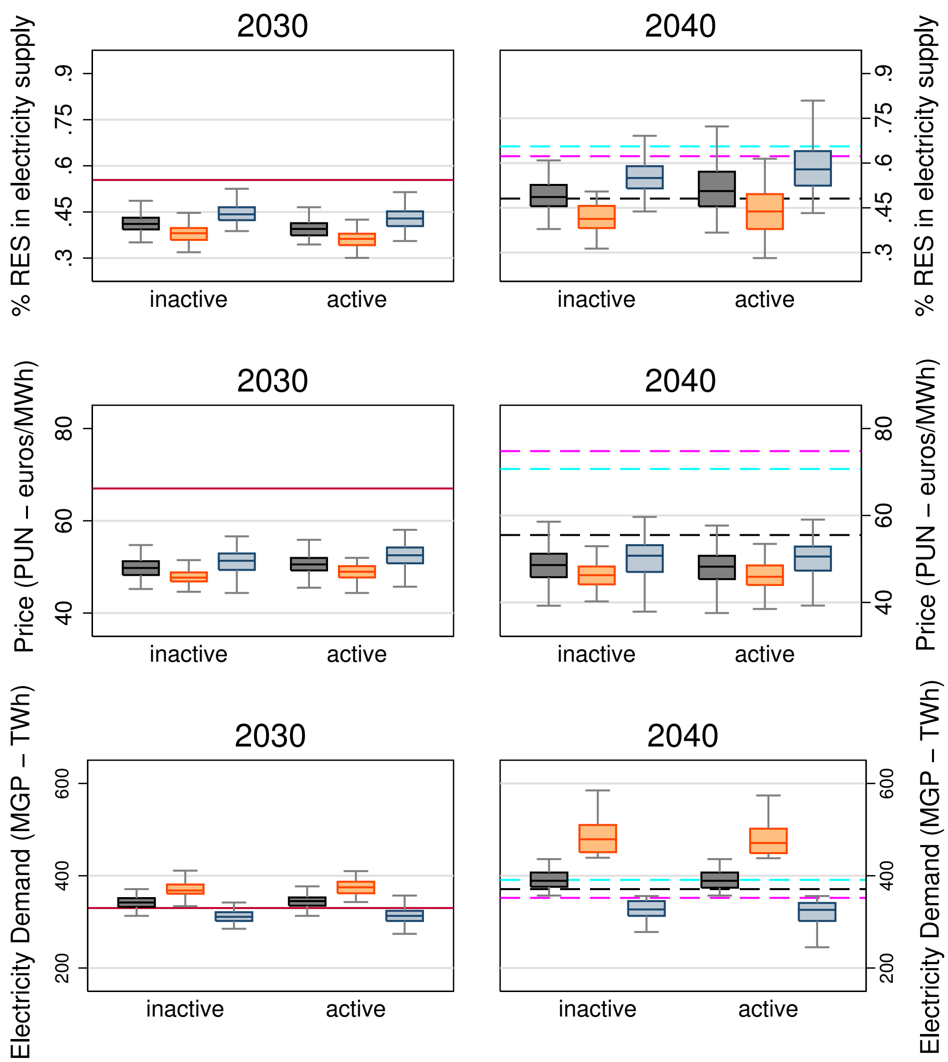


**Figure 5: Differences between scenarios and price policy effectiveness.** Each graph presents the boxplots for the simulations with the price subsidy police inactive (left) and active (right) in 2030 (left column) and 2040 (right column) with respect to the three main outcome variables: % RES (top row), national prices (center row) and day-ahead market electricity demand (bottom row). The darker lines in the middle of the boxes represent the median and its top and bottom the $75^{th}$ and $25^{th}$ percentiles, respectively. the maximum and minimum values on the whiskers correspond to 1.5 times the interquartile range (Q(75)-Q(25)). The red horizontal lines are the reference values for [5] for 2030. The black, blue and pink dashed lines represent values for the baseline, decentralized and centralized scenarios, respectively, from [21] in 2040.

Still, the box plots do not fully illustrate the importance of the price subsidy policy to reach higher shares of RES, neither does it represent how other variables in the sensitivity analysis, listed in Table 1, explain within-scenario variability. To do so, we resort to Figure 6. The six graphs plot the mean values of sensitivity variables (y-axis) for simulations in each decile of the % of RES in electricity supply (x-axis), by scenario in the last simulated year (2040). The relative size of the symbols represent the number of simulations in each decile. Hence, values on the y-axis close to the mean for all deciles indicate that a variable is not relevant for the achievement of a high % of RES, since simulations are equally likely to achieve a high % of RES with high a low values of that sensitivity variable. By contrast, values in the y-axis close to the maximum and minimum values allowed in the sensitivity, for the highest(lowest) deciles of RES, imply that such variable is crucial to achieve (impede) a large penetration of RES.

The top-left graph shows a positive correlation between the % of RES and the percentage of simulations with an active price policy. In all three scenarios, virtually all simulations that achieve a very high share of RES in supply, above 60% in 2040, rely on a price subsidy for VREs.

There is also a positive correlation with $CO_2$ prices (top-center), slightly positive one with gas prices (bottom-left) and practically no correlation with coal prices (top-right). These three variables have a dual impact on VREs expansion. They increase the price received by renewable energy sources when fossil fuel plants are also in the supply mix, while also increasing production costs of the latter. Consequently, higher fuel and $CO_2$ prices tend to increase the profits per MWh of RES with respect to gas and coal fired plants, which later favour new investments in solar and wind energy. The absent correlation between the share of RES and coal prices is due to its initially low supply capacity and gradual phase-out in about half of the simulations. $CO_2$ prices are more closely connected to a larger penetration of RES than gas prices, probably because they affect all fossil fuel based technologies.

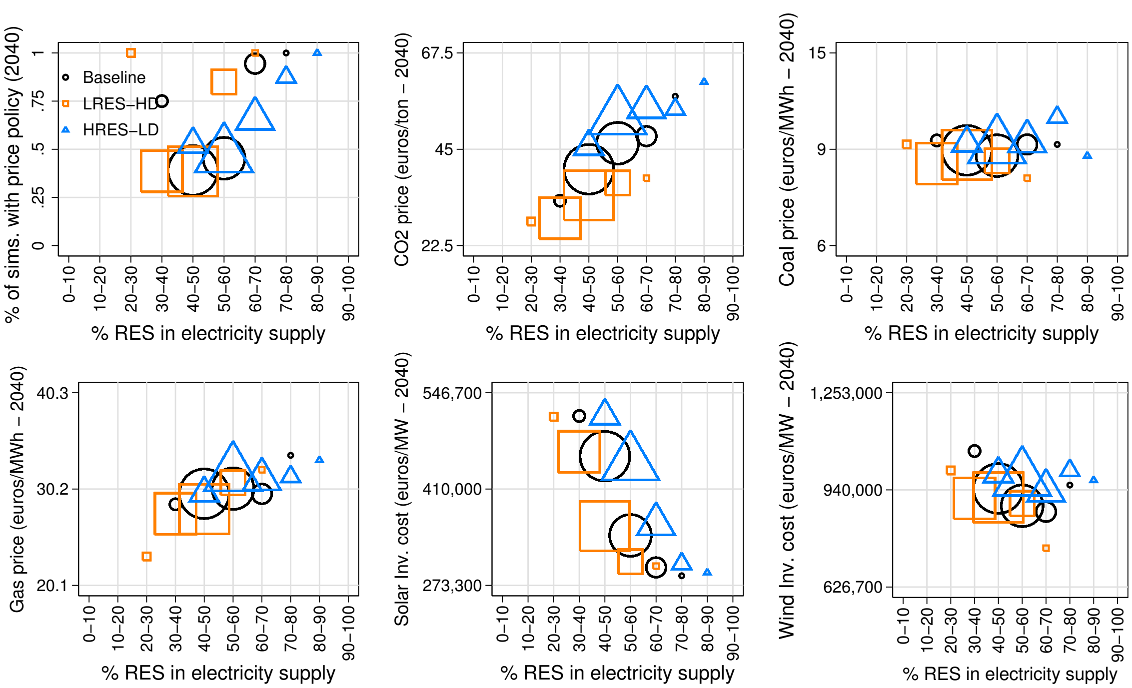


**Figure 6: Sensitivity variables and differences within scenarios.** Each graph presents the mean values of sensitivity variables (see Table 1) for the simulations in each decile of % RES in 2040. The presented variables are the price subsidy policy (top-left), $CO_2$ price (top-center), coal price (top-right), gas price (bottom-left), solar investment cost per MW (bottom-center) and onshore wind investment cost per MW (bottom-right). The relative size of the symbols indicate the number of simulations in each decile.

The last two graphs in Figure 6 relate variations in the investment costs of one MW of solar (bottom-center) and wind (bottom-right) energy. Reductions in solar energy investment costs are strongly tied to a larger % of RES in all three scenarios. However, there seems to be no correlation with wind investment costs[24]. Although somewhat surprising, this is due to the cap imposed on onshore and offshore wind capacity in our model.

Even though we simulate a specific form of price subsidy policy, based on the characteristics of the current Italian program[25], the results above allow us to comment on the impact of different settings. Our simulations indicate some effectiveness of the subsidy only after 2030, which seems in line with the REPP [8]. The results are further sustained by Figure 25 of the Supplementary Information. The simulations have kept the maximum and minimum values for the bids in the price policy fixed throughout all the simulation. Hence, the late effectiveness of the policy is verified when total costs, mainly investment costs for VREs, fall below the minimum bids in the simulated policy, on average. This, in turn, leads to an increase in profits per MWh and investment capacity of wind and solar energy.

Therefore, we may hypothesize that a costlier price subsidy, with higher minimum bids, would be effective earlier and contribute to reach the official 55% goal of RES in electricity supply by 2030 [5]. Alternatively, gradual reductions of maximum and minimum bids tailored to follow the trends in technological progress and investment costs would very likely be futile and met with little demand from investors.

# 4 Conclusion

This study has applied our new dynamic simulation model – NET – to assess the renewable energy policy paradox and to identify further obstacles that may hinder the achievement of the goals established in Italy's current energy strategy.

The simulation results support the renewable energy policy paradox hypothesis. The simulated price policy is shown to be ineffective, at least until very late in our scenarios. However, the results also suggest that a subsidy paying prices above the full cost faced by VREs, although costlier, could increase the % of RES under current market design.

Electricity demand and GDP growth play a crucial role in our results. Even with similar price subsidies, reductions in investment costs of VREs and increases in fossil fuel and $CO_2$ prices, simulations with a strong growth in total demand do not reach high shares of RES in supply. These results suggest caution when advocating for the electrification of end-uses to boost RES, as suggested by Bellocchi et al. [34]. Despite the importance of providing clean energy sources for transportation and residential heating to reduce carbon emissions, our results point out to the necessity of combining electrification with a contained expansion of total energy demand.

Our price projections are in striking contrast with the increasing ones provided by Snam–Terna [21]. This divergence highlights the importance of employing different techniques to

[24]The specific values presented in the two graphs refer to solar technology greater than or equal to 200 kW and between 200 and 20 kW, and to onshore wind greater or equal to 200 kW.

[25]Decree of July 4, 2019.

assess the reliability of scenarios for the evolution of electricity markets. Additionally, if indeed national prices follow a decreasing trend with larger penetration of VREs, price subsidy policies that pay the difference between auction bids and market prices might be much more attractive for VREs.

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## CRediT author statement

**André Cieplinski**: Conceptualization, Data curation, Formal analysis, Methodology, Resources, Software, Visualization, Writing- Original draft preparation- Reviewing and Editing. **Simone D'Alessandro**: Conceptualization, Supervision, Writing- Reviewing and Editing. **Francesco Marghella**: Conceptualization, Data curation, Investigation, Resources, Validation, Writing- Reviewing and Editing.

## Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Data Availability

Data and codes used to produce all the figures are available at: http://doi.org/10.5281/zenodo.4058432. Althesys Strategic Consultants owns all the commercial rights on the NET model, but it is available for research purposes from the corresponding author (**A.C.**), upon reasonable request.

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