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Original Research Article

Analysing the Influence of Carbon Prices on Users' Energy Cost and the Positive Impact of Renewable Energy Sources

Groppi D.[*1], Pastore L.M.[2], Astiaso Garcia D.[2], de Santoli L.[2]*

[1]Department of Planning, Design, Technology of Architecture
Sapienza University of Rome, Via Flaminia 72, Rome, Italy
[*]e–mail: daniele.groppi@uniroma1.it
[2]Department of Astronautical, Electrical and Energy Engineering
Sapienza University of Rome, Via Eudossiana 18, Rome, Italy

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ABSTRACT

Decarbonisation is a difficult process and a core scepticism lies in the potentially higher cost of energy due, for instance, to the Emission Trading System. It is possible to analyse the energy transition process and provide guidance for policy actions thanks to integrated planning tools. This research explores the impact of carbon prices on the optimal design of the Italian energy system in order to understand their influence on the uptake of renewable energy sources as well as on consumers' energy cost. The research employs the H2RES software under different carbon pricing scenarios and understand its impact on the optimal energy mix, cost of electricity and hydrogen. The outcomes show how different carbon price trends lead to different energy costs until 90% renewable penetration, point at which the energy mix is mostly detached from carbon pricing mechanisms and energy costs become stable and independent from external price signals.

KEYWORDS

Smart energy system, Energy modelling, 100% renewable energy system, Energy economy, Carbon price.

INTRODUCTION

The full decarbonization of economies is a world-wide topic with most countries, and full continents, fully involved towards achieving these results [1]. Such commitment has prompt the development of energy modelling tools to research and analyse 100% renewable energy systems [2]. Thanks to such studies, it has been proven that such goal is indeed achievable [3]; however it is not a trivial task and indeed both technical [4] and economic [5] challenges exist. From a technical perspective, the non-dispatchability of the most used renewable energy sources (RES) such as photovoltaic (PV) and wind turbines (WTs) poses on of the most critical that is the need for flexibility [6]. Even though electric batteries (EBs) represent part of the solution they, alone, cannot entirely solve the problem in the most economical way [7] especially when considering life-cycle analysis [8]. This has led to the development of the concept of smart energy systems that favours the development of multi-source and multi-vector energy systems that fully exploit the potential offered by sector coupling solutions [9]. Indeed research in the field of sector coupling has grown enormously [10]. Chovancova *et al.* [11] analyse the impact of the

[*] Corresponding author

transportation sector in the European Union; while Karameros *et al.* [12] specifically analysed the impact of electric vehicles at micro-grid level. Nevertheless, transport is not the only sector that is analysed, indeed Hosseinnejad *et al.* [13] analysed the important water-energy nexus. The heating sector is also an important sector for this topic as demonstrated by the high amount of research in literature. As examples the research of Catrini *et al.* [14] is mentioned in which the optimal design and operation of thermal grids is discussed. Also, Baglivo *et al.* [15] analysed an important enabling technology that is the air source heat pump under varying climate change assumptions.

In terms of policies, currently, one of the most important policy-tools towards the energy transition is the carbon tax (or carbon pricing) that can increase the marketability of sustainable and carbon-free technologies [16]. Nevertheless, such tool must be used with caution in order to avoid a negative impact on the economy. This is particularly worrisome for some key energy consuming sectors such as transportation and industry [17]. If for heating and light transport, electrification is considered the main decarbonisation strategy [18]; the same cannot be said for heavy and long-range transport as well as for industry since this is not yet feasible or cost-effective. Indeed, it has been analysed that a fast decarbonisation of hard-to-abate sectors might lead to investment in technologies that might not be market ready and thus will lead to a price increase for consumers [19]. Nevertheless, there are studies that prove that the increase of prices for consumers would be limited and the most significant overprice would be found in aviation-related activities, mostly tourism, because of a 10-20% increase in ticket prices [20]. Additionally, the indirect impact on related economic sectors as well as unemployment in specific areas are reason for concerns. Therefore, innovative solutions are needed to reduce CO_2 emissions in hard-to-decarbonise sectors [21].

Also for electricity prices, it has been studied that the energy transition could increase the energy cost and as such could increase energy poverty [22]. Indeed, a substantial body of literature examines the effects of the European Union's Emission Trading Scheme (EU ETS) on electricity prices. Pereira et al. analysed its impact on energy poverty [23]. Other studies focus on understanding the pass-through rates ranging from 30% to 100% in the electricity sector [24]. This is also confirmed by Hintermann for the specific case of Germany [25].

Research on the market impact of Australia's carbon pricing mechanism employing modelling approaches projected pass-through rates ranging from 17% to 400% [26]. An exception is reference [27], who estimates a pass-through rate closer to 100% for the Western Australian market.

Reference [28] find that, on average, the wholesale electricity price rose by 90% of the increase in carbon costs for coal generators. Their methodology involved meticulous estimation of the change in profits (disregarding fixed costs) as a result of the carbon tax package.

Among the limited number of empirical studies conducted after implementation of the carbon pricing mechanism, reference [29] examined the impact of a carbon tax from July 2010 to October 2013, using monthly data while controlling for coal and natural gas prices as well as electricity demand. The estimated pass-through rates ranged from 101% to 132%.

Increased electricity cost could create several issues, Priesmann *et al.* [30] investigated how the cost of the energy transition creates inequalities if not accompanied by income-based redistribution. It has also been analysed how increasing electricity prices if perceived unfair by the community could put at serious risk the whole energy transition [31].

Furthermore, another broad range of literature analyse the possible solutions. Santamouris [32] concluded that the economic assistance, in the form of subsidies, has been the main policy of European countries to minimise the burden of energy costs for households with low incomes; even though, this solution does not provide energy-poor households with a long-term solution. On the contrary, it merely minimises the risk of poverty in the short term [33]. The literature argues that rehabilitation programmes, to improve the energy performance of buildings, should provide a long-term solution for households threatened by energy poverty [32].

On the other hand, Hasheminasab *et al.* [34] concluded that renewable energy sources can satisfy the energy demand and tackle Energy Poverty.

In this context, it is also important to consider the decarbonisation of hard-to-abate sectors such as transport and industry. Hydrogen is considered an essential technology to unlock the full decarbonisation of such sectors as mentioned in various studies analysed in the review paper [35].

In this framework, it is of utmost importance to understand how the energy transition would impact the cost of energy production and as such the cost of living. Indeed, the present research aims at understanding how different carbon pricing trends can impact the optimal energy mix and the cost of energy production.

In order to assess the impact on the real cost of electricity and hydrogen, the future role of different technologies and to identify the best allocation of different decarbonisation options, computational energy models are key tools to support energy planning processes [36]. Bottom-up energy models allow to analyse different options for the energy system decarbonisation by investigating the role of different renewable and Power-to-X technologies [37].

One of the main differences between energy models is due to their approach that can be either simulation or optimisation [38]. Models based on simulation tend to run different scenarios with a varying setting of the variables under study and analyse the obtained results. The identification of the "preferred" solution is based on the analysis of such results and the experience of the modeler. Optimisation models instead identify the mathematical optimum once the objective function is properly defined [39]. Depending on the mathematical approach models can be linear, mixed integer and non-linear [40].

Models can be either based on a horizon year [41] or can be long-term thus analysing several years and being able to the so-called energy transition pathways [42]. The H2RES model, which is used in this research, has been developed with the intent of providing a long-term model with a hourly-resolution and the ability to analyse sector coupling solutions that is also open-source; thus filling a pre-existing gap in the universe of energy models [43].

Another gap in research is the evaluation of the cost of energy production as a result of long-term optimisation that most times stops at mentioning the total cost of the system without separating such costs for the different sectors. Such lack leads to unclear results in terms of cost of energy for consumers of different type, from residential to industrial.

The purpose and novelty of this paper is to analyse the impact of different carbon pricing scenarios on the optimal energy mix, the investment on flexible technologies and sector coupling solutions (e.g. storage, hydrogen technologies, heat pumps, electric boilers) and thus on the energy price, intended as electricity and hydrogen price, that will directly impact the cost of energy for users. Indeed, carbon pricing is among the main tools that have been identified by the EU to "incentivise" the uptake of clean technologies, or more precisely to disincentivise the use of polluting ones, but there are concerns about the energy price during such transition that could lead to economic and social issues. This research does not take into account delocalisation of industries or other businesses thus assumes that the Carbon Border Adjustment Mechanism will work perfectly.

In the next sections at first the case study will be duly presented, then the H2RES model will be explained and then the scenarios that will be analysed. In the next section the obtained results will be presented and discussed and in the end the conclusions of this research will be shown.

MATERIAL AND METHODS

The main objective of this research is to identify the economic optimal energy mix of the Italian energy system while gradually decarbonizing it under different carbon price assumptions. To do so, the H2RES software has been utilized as briefly described in the following section. For more information on the model here the official website to download the open-source software is referenced [44], as well as additional references where the model has been already tested and validated [43][45][46].

H2RES energy model

H2RES is an open-source software for long-term optimisation of energy systems that adopt power-to-X solutions. The model is based on an hourly time resolution and has a high technical resolution. The sectors that are considered in the model are power, heating, industry and transport. A schematic flowchart of the model is shown in **Figure 1**.

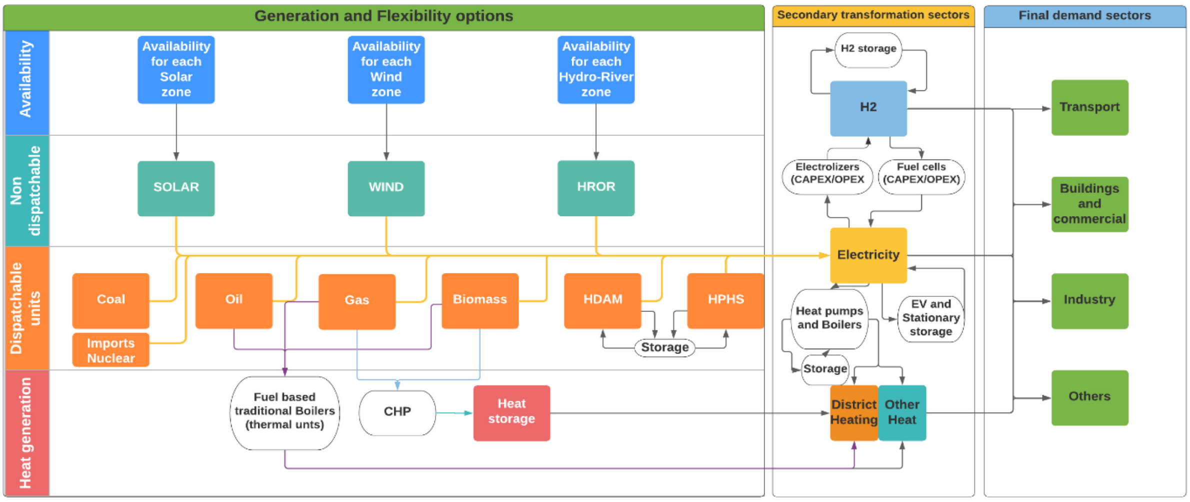


Figure 1. Flowchart of the H2RES model **[43]**

The objective function of the H2RES is represented by the cost of the energy system and the optimisation is thus aiming at the optimal, minimum, cost for each year of simulation. The mathematical description of the objective function is shown in eq. **(1)**:

$$\sum_{y}\sum_{p}\sum_{t} df_y\big[vC_{t,p,y}D_{t,p,y} + C_{t,y}K_tInv_{t,y} + R_{t,p,y}Ramp_{t,p,y} + I_{p,y}Imp_{p,y} + CO_2Price_yCO_2Levels_{t,p,y}\big] \quad (1)$$

All the cost endured by an energy system are included in eq. (1) such as dispatching cost, capital cost, ramping cost, import as well as cost of carbon dioxide (CO_2) emissions. Indeed, $D_{t,p,y}$ represents the energy that is dispatched by technology *t*, in hour *p* of year *y* (expressed in MWh) while $C_{t,p,y}$ is the variable cost (expressed in EUR/MWh) related to such dispatched energy dependent on the specific technology t and mainly based on its efficiency that determines the used fuel, and its cost, as well as operation and maintenance cost that are referred as "$NonFuelCost$" (expressed in EUR/MWh) as described in eq. **(2)**:

$$vC_{t,p,y} = \left[\frac{FuelCost_{t,p,y}}{eff_{t,p,y}} + NonFuelCost_{t,p,y}\right] \quad (2)$$

The term K_t represents the annualized capital cost of each technology multiplied to $Inv_{t,y}$ (expressed in EUR/MW), the capacity that is invested every year, and $C_{t,y}$ (expressed in MW), the investment cost of said technology in said year. This gives the liberty to perceive the effect of a learning curve and thus the decrease in cost through time of certain technologies.

$R_{t,p,y}$, the third term of the equation, represents the operation of ramping up or down of technology t in every hour of each simulated year (expressed in MW) that is multiplied to $Ramp_{t,p,y}$ that is the unit cost of such operation (expressed in EUR/MW).

$I_{p,y}$ instead is the amount of imported energy (expressed in MWh) and is multiplied to $Imp_{p,y}$, the cost of imported energy (expressed in EUR/MWh), that can be decided for each hour of each simulated year by the user.

The last term of the equation represents the cost of CO_2 emissions, obtained multiplying the emission of each technology ($CO_2Levels_{t,p,y}$) and the cost of said emissions (CO_2Price_y) representing the carbon pricing mechanism in place.

Regarding the analysis of other sectors, the heating one is the sector that is modelled with the highest detail. Indeed, for the heating sector district heating networks are clustered together by technology and fuel (e.g. all district heating supplied by a gas-fired CHP are clustered together) while the remaining heating demand is inputted separately. All technologies that supply the heating demand are an input to the model that optimise the operation of such technologies thus leading to the final demands of different energy vectors. The model also optimises the investment in different technologies such as heat pumps, electric boilers and other boilers using several fuels, depending on the installed. Industrial and transportation demands are inputted as different energy vector demands for each year. The model then optimises the use of technologies to supply such demands (e.g. electricity, hydrogen). For each energy vector and demand, the model is constrained to ensure that the production and import of such vector must match the demand (i.e. electricity, heating, hydrogen, various fuels used for power production but also for industry and transportation).

In terms of policy options, the H2RES model enables to set maximum values of CO_2 emissions, minimum values of RES share and the maximum value of critical excess electricity production (CEEP).

As previously mentioned, more details on the model are left to other sources, since the algorithms have not been expanded by this research [44][46].

Technical and economic assumptions

From a policy constraints point of view, the research did not impose any RES share in electricity nor other sub-sectors. The main policy imposition was on the overall emissions in years 2030 and 2050 based on official objectives for Italian, and most European Countries, to track Country's decarbonisation process based on official Italian data [47]. It has also been considered both a CEEP limit at 5%, identified as maximum acceptable value for energy planning purposes [48], and a CEEP price of 45 EUR/MWh that is considered as "cost of curtailment" (this value is assumed based on average cost of production in Italy for RES generators).

The analysis has been carried out considering the average biomass availability as a constraint for the energy optimisation process.

The economic assumptions for the analysed technologies are shown in Table 1. Fuel prices are considered increasing by 1% each year starting from the fist simulated year, i.e. 2020. While for the capacity factors of solar, wind and hydro units they have been assumed to remain constant throughout the years.

Table 1. Input data for H2RES model

Technology	**Units**	**INV (MEUR/unit) 2020**	**2030**	**2040**	**2050**	**Efficiency/FLHs**	**Source**
PEMFC	MW	1.3	1.1	0.9	0.8	50%	[49]
SOFC	MW	3.3	2	1.3	0.8	60%	[49]
Alkaline Electrolyser	MW	0.65	0.45	0.3	0.25	66.5-78	[49]
SOEC Electrolyser	MW	4.5	1.9	1.3	0.78	77-83.5%	[49]
PEM Electrolyser	MW	0.92	0.65	0.45	0.4	58-70.5%	[49]
H2 storage (tanks)	MWh	0.057	0.045	0.027	0.021	-	[49]
PV	MW	0.92	0.58	0.42	0.33	1179 h/yr	[50][51]
On-shore Wind	MW	1.79	1.07	0.92	0.86	1853 h/yr	[50][52]
Off-shore Wind	MW	3.22	1.93	1.66	1.59	2131 h/yr	[50][52]
biomass boiler	MW_{th}	0.47	0.447	0.425	0.404	79-85%	[49]
gas boiler	MW_{th}	0.278	0.265	0.252	0.24	90%	[49]
air-to-water HPs	MW_{th}	1.2	1.076	1.016	0.956	3.282 (SCOP evaluated)	[49]
geothermal HP	MW_{th}	1.932	1.836	1.74	1.566	4.621 (SCOP evaluated)	[49]
Electric boilers	MW_{th}	0.89	0.85	0.81	0.77	100%	[49]

The maximum capacity allowed to be installed is shown in **Table 2**.

Table 2. VRES capacity installation potential in Italy [53][50] [54]

RES	Capacity potential (GW)
PV	357.4
On-shore Wind	115.4
Off-shore Wind	55.7

In the following sub-section the 3 scenarios that have been analysed are described.

Carbon price variability scenarios

The analysed scenarios entail a varying carbon price as shown in **Table 3**.

Table 3. Carbon price trends and scenarios for H2RES model

Scenario	Carbon Price EUR/t CO_2 2023	2025	2030	2035	2040	2045	2050	Source
Stable-Medium-Increase (SMI)	85.3	100	120	160	200	280	350	[55]
Low-to-High- (LtH)	85.3	80	70	130	300	500	500	[56]
Stable-Low-Increase (SLI)	85.3	90	100	100	110	120	130	assumption

All scenarios starts from the average price, that has been recorded in 2023, one of the highest yearly average ever since the ETS system has been set up [57].

Starting from such common point the 3 scenarios see different trends. The Low-to-High (LtH) scenario sees a decrease in the carbon price to pre-war and pre-pandemic values until 2030. Year after which the carbon price sees a steep increase in order to reach the ambitious target of full decarbonisation by 2050. This trend reflects the outcomes of the POLES model developed by Enerdata in collaboration with the European Commission's JRC IPTS and University of Grenoble-CNRS (EDDEN laboratory) [56].

The Stable-Medium-Increase (SMI) scenario represents a stable increase in cost up until a maximum value of 350 EUR/t CO_2 in 2050 and it is the result of the LIME-EU model [55].

The Stable-Low-Increase (SLI) scenario represents a stably increasing price with very low maximum price of 130 EUR/t CO_2 in 2050. This scenario is based on assumptions made by the authors and represents the unlikely scenario in which the market is able to decarbonise even faster than the EU can hope and as such the ETS cap on emission has a lower impact on the carbon price increase.

Cost of Energy

In order to understand the impact that a varying carbon price would have on the cost of energy the Levelised Cost of Electricity (LCOE) and the Levelised Cost of Hydrogen ($LCOH_2$) have been evaluated in the different scenarios.

The simplified LCOE and $LCOH_2$ have been evaluated singularly for each technology as per the following eqs. (3) and (4) based on [58]:

$$\mathrm{LCOE} = \frac{CAPEX \times (crf + O\&M_{\mathrm{fixed}}) \; + \; O\&M_{\mathrm{var}}}{E_{\mathrm{gen}}} \tag{3}$$

$$\mathrm{LCOH_2} = \frac{CAPEX \times (crf + O\&M_{\mathrm{fixed}}) \; + \; O\&M_{\mathrm{var}}}{H_{2,\mathrm{gen}}} \tag{4}$$

where:

- $CAPEX$ represents the initial investment (expressed in EUR);
- crf is capital recovery factor;
- $O\&M_{\mathrm{fixed}}$ represents the yearly fixed cost for O&M and is expressed as percentage of the CAPEX cost;
- $O\&M_{\mathrm{var}}$ are the yearly variable cost based on the yearly production of either electricity of hydrogen assumed to be constant along the years (expressed in €);
- E_{gen} and $H_{2,\mathrm{gen}}$ are the yearly energy production assumed constant in the technology lifetime (evaluated as an average of the overall production during the whole technology lifetime), expressed in MWh.

Respectively the E_{gen} and $H_{2,\mathrm{gen}}$ have been evaluated based on the actual output of the simulated scenarios in order to respect the perfect foresight of the model and reflect that in the post-processed results.

The LCOE and $\mathrm{LCOH_2}$ were calculated for each technology for each year of installation, then the yearly LCOE and $\mathrm{LCOH_2}$ were evaluated yearly as a weighted average of the installed capacity of each technology based on the installed capacity each previous year considering of course the technology lifetime.

In theory, in order to evaluate the LCOE it was necessary to first assume a cost of hydrogen in order to evaluate the LCOE of Fuel cell technologies. Once the LCOE of all technologies had been evaluated it was possible to calculate the Energy Generation cost of the Italian Energy

System as a whole. Only after having evaluate this value it was possible to evaluate the $LCOH_2$, the obtained value was then compared to the previously assumed one to evaluate the FC LCOE and an iterative process was performed when necessary (i.e. for errors over 5%). Nevertheless, it would be necessary to develop the iterative analysis with different initial hydrogen prices since they might influence the obtained $LCOH_2$ if their impact on the overall energy generation cost was too high. Thus, the dependence of these two should be analysed. This was not an issue since FC were not installed by the optimisation.

As per the energy generation cost this has been evaluated based on technologies LCOEs for two different market structures that are the Pay-as-Bid and the System Marginal Price [59]. The Pay-as-Bid better represents the actual generation cost and the model's approach that should thus represent the real cost of generation. Nevertheless, the System Marginal Price better represents the actual cost of energy from a market perspective.

CASE STUDY – THE ITALIAN ENERGY SYSTEM

This research adopts as case study the Italian energy system as described here below.

The inputs for the H2RES model have been considered to be the same as Ref. [17]. The model is based mostly on Eurostat data [60] plus information provided in official Italian documentation, namely from Terna, Italian TSO [61], the Italian Ministry for the Ecologic Transition (Ministero della Transizione Ecologica) [62] and ISPRA (Istituto superiore per la protezione e la ricerca ambientale) [63]. Particularly, the considered GHG emissions in 2019 are limited to 313.8 Mt CO_{2eq} [63] (evaluated as total GHG emissions minus energy fugitives, industrial processes and waste that are not modelled and cannot be optimised by the model) while the other constraints for emissions are set for 2030, namely 43.7% less than those of 2005 [64] evaluated with the same assumption as for 2020, thus equal to 246.7 Mt CO_{2eq}, and for 2050 with full decarbonisation. The simulated period starts in 2020 even though the data from energy consumption are from 2019 that have been considered more reliable since based on pre-COVID times.

From Table 4 to Table 10 the data adopted for the Italian energy system model are shown.

Table 4. Electricity demand by sector

Sector	Electricity consumption (TWh)
Households and Services	154.8
Industry	119.5
Transport	11.5
Consumption of the energy branch	19.8
Distribution and transmission losses	17.8
Import	43.9
Export	5.8

Table 5. Heating demand by technology

Technology	Fuel consumption (TWh)
Natural Gas boilers	247.5
Oil boilers	29.03
Biomass boilers	73.3
Heat pump	29.0 (Ambient heat)
Thermal solar	2.5

Table 6. District Heating demand

DH	Heat demand (TWh)
Households and Services supplied by boilers	4.0
Households and Services supplied by CHPs	10.1
Industry supplied by CHP	50.1

Table 7. Transport demand

Fuel	Annual consumption (TWh)
Diesel	224.0
Petrol	115.1
LPG	27.3
NG	13.3
Jet Fuel	10.5
Biofuels	14.8
Electricity	11.5

Table 8. Industry fuels demand

Industry	Annual consumption (TWh)
Coal	6.9
Oil	115.1
NG	99.3
Biomass	4.9

Table 9. Renewable electricity capacity and annual generation

Technology	Capacity (GW)	Electricity generation potential (TWh)
Hydroelectric	22.8	46.3
PV	20.1	23.7
Wind	10.9	20.2
Bioenergy	4.2	19.5
Geothermal	0.8	6.0

Table 10. Central power plants capacity and national average efficiencies

Technology	Capacity (GW)	Electrical efficiency (-)	Thermal efficiency (-)
NG - Electricity only	24.1	0.532	-
Oil - Electricity only	0.5	0.401	-
Coal - Electricity only	8.3	0.376	-
Biomass - Electricity only	1.9	0.413	-
NG - Combined Heat and Power	17.1	0.436	0.238
Oil - Combined Heat and Power	2.5	0.325	0.219
Biomass - Combined Heat and Power	2.2	0.287	0.316

The decarbonisation pathways of the transport sector has been considered as an input, since the model does not fully optimise such sector yet. Indeed, light-duty vehicles have been assumed to shift towards electrification with a linear trend reaching a maximum value of 90% share of the overall fleet in 2050. Heavy-duty vehicles instead are assumed to be decarbonized through the use of Synthetic Liquid Fuels (SLFs) obtained by biomass hydrogenation [65]. The solution has already been proven by Korberg *et al.* [66]. The trend of decarbonization of heavy-duty transport is also linear starting only in 2035 and reaching full decarbonization in 2050.

The decarbonisation pathway of the industrial sector instead is assumed considering that only part of it can be electrified, i.e. 13 TWh/yr, and a linear trend has been considered for it. The remaining demand is considered to shift to a mix of synthetic liquid fuels and synthetic natural gas starting from 2035 with a linear growth until reaching the full decarbonisation of the industrial sector in 2050.

Based on these assumptions **Figure 2** is obtained, it depicts the trend of electricity and hydrogen demand throughout the analysed years.

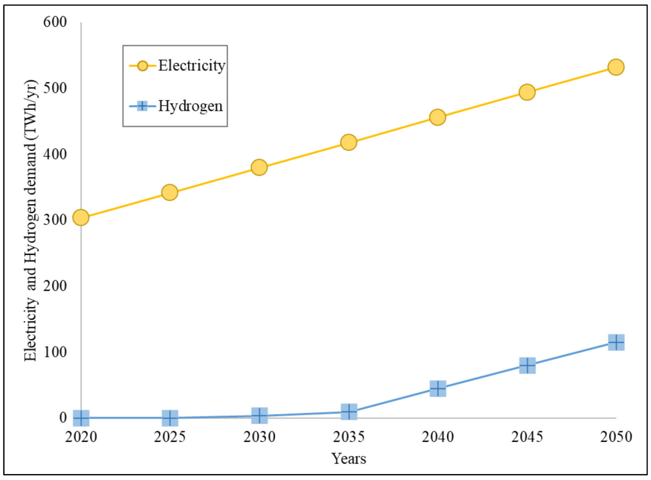


Figure 2. Electricity and Hydrogen demand trends

The import/export capacity is limited to 5 GW; more information about the case study assumptions are shown in [67] and [68].

RESULTS AND DISCUSSION

In this section the three analysed scenarios are compared and discussed upon. The discussion of results aims at understanding general terms that might be valid for different contexts than the Italian case study. In **Figure 3**, the different investment trends can be seen.

No major differences are found in the optimal energy mix for the 3 scenarios showing that the biggest driver is represented by the overall emissions constraint and not by the carbon price. Slight differences are found in the timing of installation, showing a bigger investment in PV in 2035 in the SMI scenario compared to the other scenarios, while the LtH scenario prefers to recover such under-investment in 2040. The SLI scenario instead recovers the missed investment regularly throughout the years. These differences can be linked to the carbon price; indeed 2035 represents the year with the biggest change for the SMI scenario while 2040 represents the biggest change for the LtH scenario. The SLI scenario instead has a more stable growth that reflects the carbon price trend. It must be noted that the biggest investment to reach 2030 objectives are made in the heating sector and particularly to flexible technologies that enable a better exploitation of the installed RES technologies. This can easily be a result that is common to other Countries with similar situation in terms of climate.

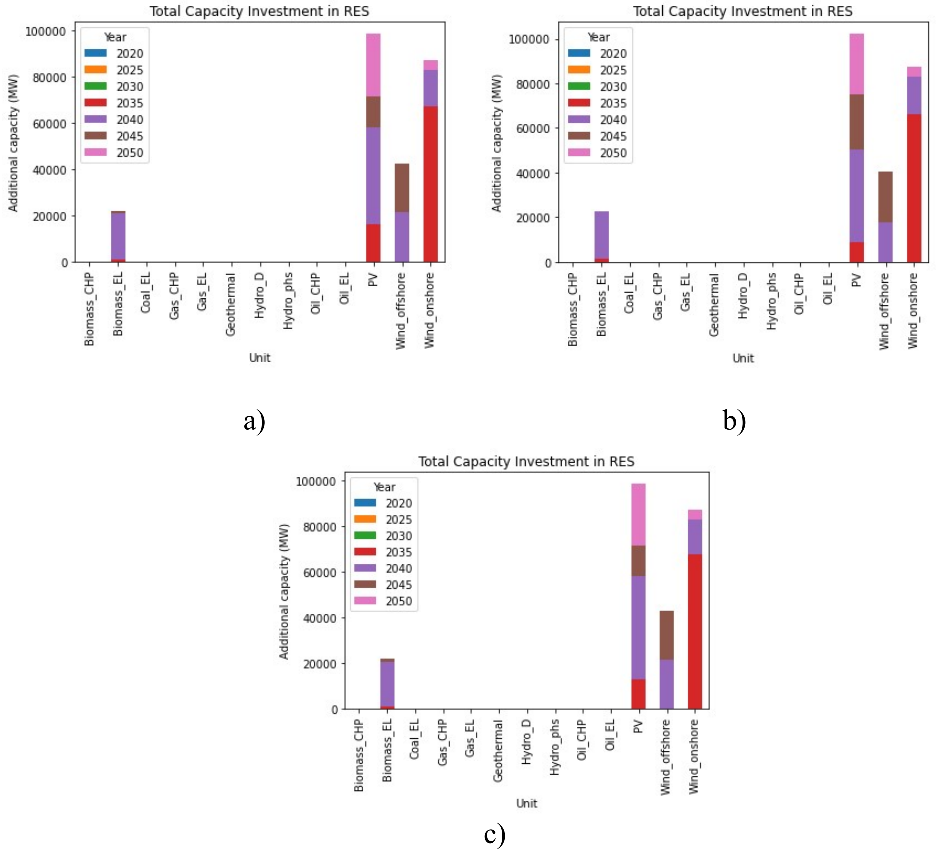


Figure 3. Yearly installed capacity per scenarios a) SMI, b) SLI and c) LtH

Figure 4 shows the yearly generation for the three scenarios.

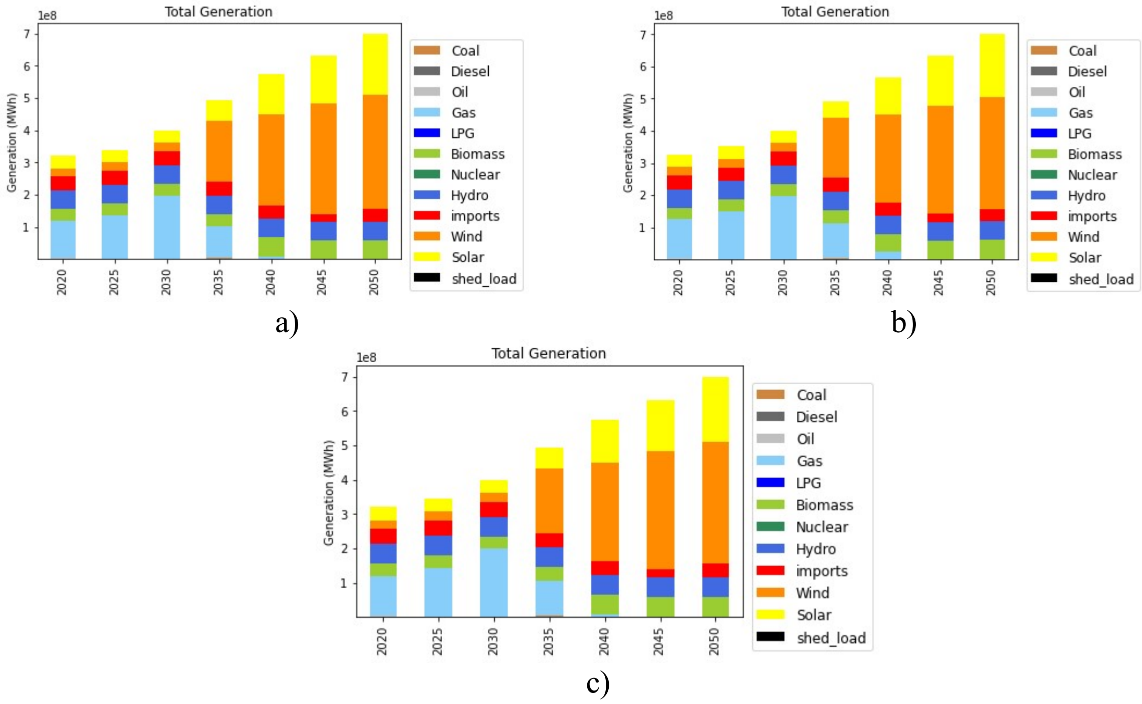


Figure 4. Yearly production per technology per scenarios a) SMI, b) SLI and c) LtH

As expected, the generation patterns reflect the capacity investment. In **Table 11**, the investment in electrolysers (ELY) are shown for the 3 scenarios.

Table 11. Investment in electrolysers and hydrogen storage technologies expressed in MW and MWh, respectively

Scenario	Tech	2025	2030	2035	2040	2045	2050
SMI	Alkaline (MW)	0	480	1512	18802	7571	6205
	H_2 storage (MWh)	0	3364	14988	203847	0	0
SLI	Alkaline (MW)	0	480	1270	15544	11688	7064
	H_2 storage (MWh)	0	3364	17166	191302	0	0
LtH	Alkaline (MW)	0	480	1458	19041	7343	6238
	H_2 storage (MWh)	0	3364	16720	202184	0	0

As suggested by the previous figures, the only effect that different carbon price trends have are a slight difference in the timing of investment with the biggest difference being in the SLI scenario compared to both the SMI and LtH scenarios. Indeed, the stable growth of the SLI scenario enables to delay the investment of ELY thus obtaining lower CAPEX. Nevertheless, in all scenarios Alkaline ELY are the selected technologies (over PEM and SOC) and they are always installed starting from 2030 when the industrial demand is increased and the need for flexibility due to variable RES is also higher. The hydrogen production is strictly connected to the industrial demand that is shown in **Figure 2**. In **Figure 5** the comparison of LCOE for RES technologies is shown.

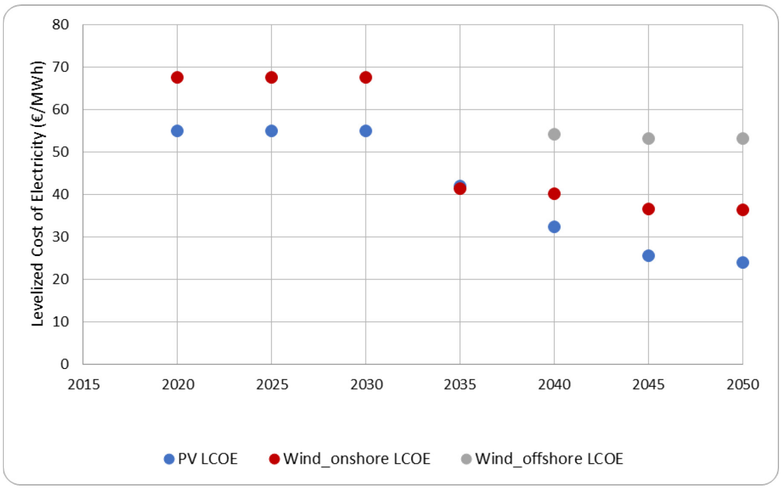
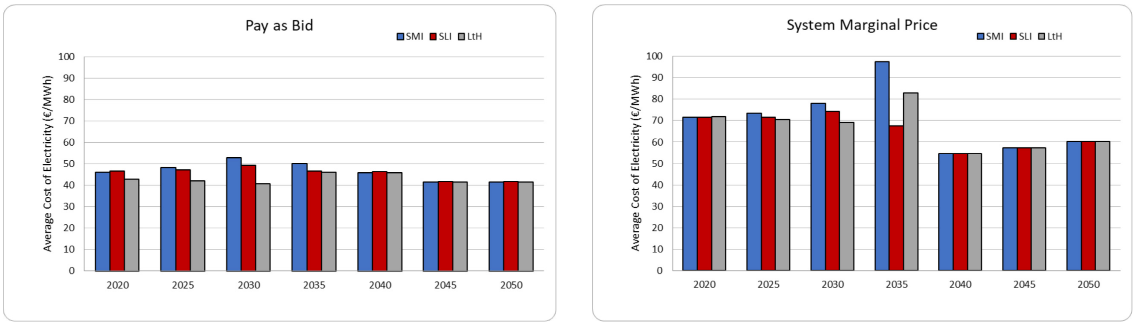


Figure 5. Renewable Generators Levelised Cost of Electricity per year of installation

It must be explained that LCOE for offshore wind is not represented until 2040 because that is the first year when the technology is installed. Given that the LCOE is evaluated based on the perfect foreseeable production, this cannot be evaluated for previous years. Furthermore, the PV and onshore wind's LCOEs are constant until 2035 because no new investment are made in those years as previously explained (see discussion of **Figure 3**).

Figure 6 shows the electricity energy price of the whole system. **Figure 6** shows the difference in the cost of electricity price that would then be reflected in the cost of electricity for consumers. The first important outcome to notice is that from 2040 onwards all scenarios present very similar cost of electricity and this is due to the very high RES share (higher than 90%) that is needed to fulfil the overall emissions constraint that detach the electricity cost to the carbon price as well as the fluctuations of global market price and thus protecting Countries and their consumers to geopolitical instability as well. It is noteworthy to notice that the System marginal price is always higher than the respective Pay-as-Bid price except for years 2040 and onwards for the same reason explained above, thus the high RES share with similar LCOE thus avoiding an excessive extra-profit due to much more expensive traditional, fossil fuel supplied, generators.



a) b)

Figure 6. Yearly electricity generation cost for a) Pay-as-Bid and b) Marginal Price markets structure

It is also interesting to notice that the SMI shows to have the highest cost of electricity each year before 2040 and this is true for both PaB and SMP markets. This is due to the fact that the carbon price is higher than other scenarios in the first years when traditional technologies are still in place and running thus affecting the overall price. Here it is well visible how the electricity price evolves during the energy transition with the highest prices in 2030 and 2035 for PaB and SMP, respectively. The same can be seen for the SLI scenario with the only difference in having the peak price in 2030 for both market systems. In comparison with the SMI scenario, SLI always has lower electricity cost due to the lower carbon price.

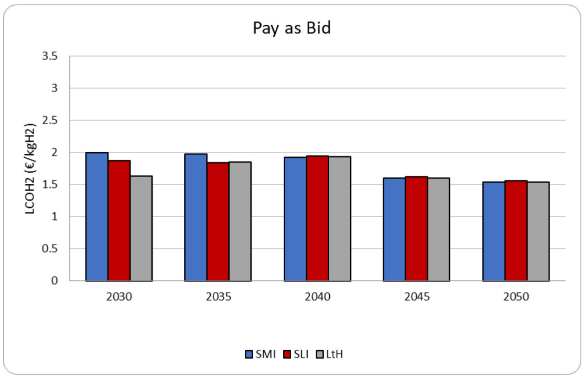
A different trend can be seen for the LtH scenario. LtH manages to have lower electricity price in the years before 2035 since the carbon price is the lowest than all scenarios. Then, in 2035 an increase is seen in both market structures, but while it matches the other scenarios' results in the PaB market, it surpass the SLI in the SMP market due to the steep increase in carbon price that is not matched by the newly installed RES generators. It must be said that we are comparing scenarios with the same overall emissions with different carbon prices and by doing this we are assuming that the decarbonisation is indeed somehow separated from the carbon pricing systems. This assumption causes some possible alteration due to the fact that, for instance, the LtH scenario has the time to reach a higher RES share before establishing higher carbon prices thus avoiding to pay the carbon cost in the years when it matters the most.

The highest difference in average cost of electricity is found in 2030 for PaB (i.e. 13 EUR/MWh) between SMI, the highest, and LtH, the lowest; while for SMP the highest difference is found in 2035 and it equates to 29 EUR/MWh between SMI, the highest, and SLI, the lowest.

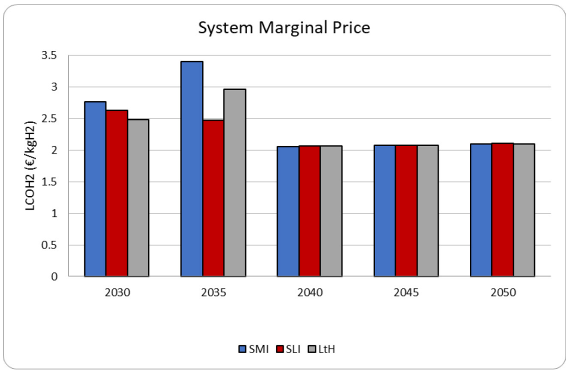
It is noteworthy to underline, that even if scenarios have the same carbon tax in year 2020, due to the method adopted to evaluate LCOEs based on the actual production along the whole technology lifetime, the LCOE of technologies may change since the production in sequent years is affected by the carbon tax thus leading to different denominators, thus different LCOE and yearly electricity generation both with PaB and SMP.

Regarding the $LCOH_2$, this has been evaluated for the two market structures as well as for completely green hydrogen under the assumption that all hydrogen production would rely on Power Purchase Agreements (PPAs) with newly installed RES generators (a weighted average of the RES installed in the same year as the hydrogen technologies). The results are shown in **Figure 7**.

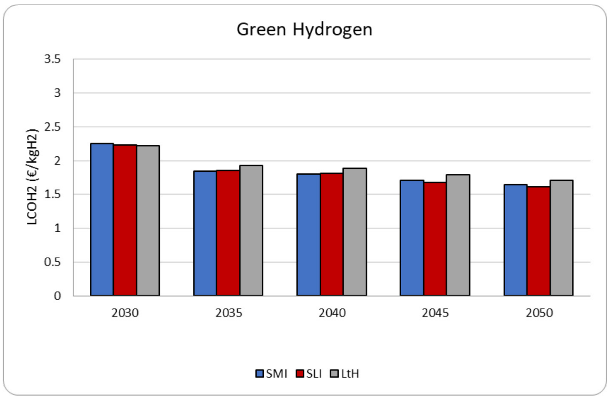
Regarding the free markets (e.g. PaB and SMP), the same trends that had been encountered and described for cost of electricity can be seen once again and this is of course due to the cost of electricity that is needed for hydrogen production. What is interesting to notice is that even though the Green Hydrogen assumption avoids an increase in cost during the transition, that is instead happening in both PaB and SMP with peaks encountered in 2040 and 2035 respectively, it always ends up in higher costs than the PaB solution. This is due to the fact that PPA are medium to long-term contracts, thus hydrogen production does not benefit from new and cheaper RES installations like it does when connected to the market. So, PPA ensure more stable prices but do not ensure cheaper prices than the market. Thus, green hydrogen should be incentivised otherwise the market solution might be totally or partially preferred thus leading to not-100%-green hydrogen.



a)



b)



c)

Figure 7. Levelised cost of hydrogen for a) Pay-as-Bid martket, b) Marginal Price market and c) Green hydrogen through Power Purchase Agreement

The developed analysis has proved once again that carbon pricing mechanisms is a powerful and impactful tool and as such must be applied with caution. Indeed, it has an impact on the electricity production cost that can be as high as 13 EUR/MWh with a peak in 2030 (see **Figure 6**), year after which the RES share is high enough, and RES generators are so competitive that the LCOE is practically disconnected from carbon pricing. This latter statement also proves the importance of RES and self-sufficiency in terms of stability. In terms of hydrogen production, the $LCOH_2$ shows a similar trend than the one identified for the LCOE and similar outcomes can be drawn. Additionally, an interesting insight can be done for green hydrogen and the use of PPA. Indeed, they seem to be the optimal solution during the transition period when due to the carbon pricing mechanism and the presence of fossil-fuelled power plant the power grid has a higher cost than RES generators. Nevertheless, this is not true once higher RES share are reached in the power grid that lead to the PPA being more expensive than the power grid and the free market since they are relying on older, and more expensive, technologies. On the other hand, it is also interesting to notice that the selection of technologies for the optimal power mix is not very much impacted by the carbon tax. These results are linked to the particular case study that has been analysed but can also be generalised to other similar contexts. In particular, the results obtained about green hydrogen pricing and the impact of PPAs are true for every case study.

CONCLUSION

The aim of this paper was to understand the impact of carbon pricing on the cost of electricity generation that directly affects the cost at consumer level. Of course the obtained results have to be considered strongly connected to the assumptions made in terms of method and input data. In order to reach the foreseen goal, three different carbon pricing trends from 2025 to 2050 have been analysed. Results of this analysis show that the overall emission limit must be either removed or at least adapted to the carbon pricing trend in order to appreciate the effect of the carbon pricing on optimal investment and operation of generators. Nevertheless, it has been possible to notice how both electricity and hydrogen generation prices change depending on the applied carbon price. The results show that the best option is to keep as low as possible the carbon price in the first years with the security that it will rise drastically after 2030. If by 2030 the CO_2 emissions are reduced, we can assume that this could happen thanks to other external drivers and thanks to the menace of a much higher carbon price later, then the lowest electricity prices are met for the 2025-2050 time frame. The exact same trend can be seen for the levelized cost of hydrogen. It has also been concluded that the PPA solution on one hand can be attractive since it ensures stable and competitive electricity prices but on the other hand it can lead to higher prices than a market-based solution.

This research represents an initial analysis but many options for further investigations are possible. Indeed, different trends of carbon pricing should be analysed as well as the possibility to either eliminate the carbon emission constraint or connect it to the carbon pricing thus neglecting other external factors and drivers for the energy transition. Furthermore, another research that the authors aim at investigating is the levelized cost of storage and how this is connected to the increase in RES share for balancing purposes and also the levelized cost of heat that could, for research purposes, be differentiated between residential and industrial heat. Also, it would be interesting to investigate the link between fossil fuel prices and trends with the energy price (i.e. electricity, hydrogen and heat). Additionally, it should also be considered a varying import price and the possibility of grid expansion towards foreign Countries in order to include these variables within the optimisation problem.

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NOMENCLATURE

Abbreviations	
CAPEX	Capital Expenditure
CO_2	Carbon Dioxide
CHP	Combined Heat & Power
CEEP	Critical Excess Electricity Production
EBs	Electric Batteries
ELY	Electrolyser
EU ETS	European Union's Emission Trading Scheme
HP	Heat Pump
ISPRA	Istituto Superiore per la Protezione e la Ricerca Ambientale
LCOE	Levelised Cost of Electricity

$LCOH_2$	Levelised Cost of Hydrogen
LPG	Liquified Petroleum Gas
LtH	Low-to-High
NG	Natural Gas
O&M	Operation & Maintenance
PaB	Pay-as-Bid
PV	Photovoltaic
PPAs	Power Purchase Agreements
PEM	Proton-Exchange Membrane
PEMFC	Proton-Exchange Membrane Fuel Cell
RES	Renewable Energy Sources
SOFC	Solid Oxide Fuel Cell
SOEC	Solid Oxide Electrolyser Cell
SLI	Stable-Low-Increase
SMI	Stable-Medium-Increase
SLFs	Synthetic Liquid Fuels
SMP	System Marginal Price
TSO	Transmission System Operator
WTs	Wind Turbines

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