Clean mobility infrastructure and sector integration in long-term energy scenarios: The case of Italy

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Abstract

As main contributors to greenhouse gas emissions, the power and transportation sectors have a crucial role in energy system decarbonization. Moreover, their interaction is expected to increase significantly. On the one hand, plug-in electric vehicles add a new electric load, increasing the grid demand and potentially requiring substantial grid upgrade. On the other hand, hydrogen production for fuel cell electric vehicles or for clean fuels synthesis could exploit the projected massive power overgeneration by intermittent and seasonally dependent renewable sources via Power-to-Hydrogen.

This work investigates the infrastructural needs involved with a broad diffusion of clean mobility, adopting a sector integration perspective at the national scale. The analysis combines a multi-node energy system balance simulation and a techno-economic assessment of the infrastructure to deliver energy vectors for mobility. The article explores the case of Italy in the long term, considering a massive increase of renewable power generation capacity and investigating different mobility scenarios, where the combined presence of battery vehicles and fuel cell vehicles accounts for 50% of the total stock. First, the model solves the energy balances, integrating the consumption related to mobility energy vectors and taking into account power grid constraints. Then, an optimal infrastructure is identified, composed of both a hydrogen delivery network and a widespread installation of charging points.

Results show that the infrastructural requirements bring about investment costs in the range of 43-63 G€. Lower specific costs are associated with the exclusive presence of FCEVs, whereas the full reliance on BEVs leads to the most significant costs. Scenarios that combine FCEVs and BEVs lie in between and suggest that the overall power+mobility system benefits from the presence of both drivetrain options.

Highlights

- Clean mobility infrastructure is studied to deliver energy vectors for mobility.
- A sector-integrated analysis evaluates long-term interweaving advantages and excess energy recovery.
- Hydrogen and electricity are compared as clean energy vectors in a future Italian energy system.
- Different scenarios are simulated and compared from a techno-economic perspective.
- Results suggest that the overall system benefits from the presence of both drivetrain options.

Keywords

Decarbonization; Infrastructure; Sector integration; Mobility; Electrification; Hydrogen.

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List of abbreviations

BEV	Battery Electric Vehicle
CNG	Compressed Natural Gas
DSO	Distribution System Operator
EFLH	Equivalent Full-Load Hours
ENTSO-E	European Network of Transmission System Operators for Electricity
EVSE	Electric Vehicle Supply Equipment
FCEV	Fuel Cell Electric Vehicle
GDP	Gross Domestic Product
GH2	Gaseous Hydrogen
GHG	GreenHouse Gas
HRS	Hydrogen Refueling Station
ICE	Internal Combustion Engine
ICEV	Internal Combustion Engine Vehicle
IEA	International Energy Agency
IEC	International Electrotechnical Commission
LCOE	Levelized Cost of Electricity
LH2	Liquid Hydrogen
LHV	Lower Heating Value
NUTS	Nomenclature of Territorial Units for Statistics
O&M	Operation and Maintenance
P2G	Power-to-Gas
PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
PV	PhotoVoltaic
RES	Renewable Energy Source
TSO	Transmission System Operator
ZEV	Zero-Emission Vehicle (at tailpipe)

1. Introduction

The decarbonization of national energy systems will require a strong integration of the various sectors involved with energy conversion or use in different forms [1–3]. Moving towards clean mobility solutions will make the transport sector interweave significantly with power generation, as the main alternatives for low-emission vehicles are based on electric drivetrains. These involve electricity consumption either directly or indirectly: on the one hand, plug-in electric vehicles need to be charged via grid connection; on the other hand, fuel cell electric vehicles rely on clean hydrogen, which can be produced via electrolysis fed by renewable electricity. Moreover, hydrogen could be further synthesized into low-carbon fuels for use in conventional vehicles.

Plug-in electric vehicles (PEVs) bring about a new electricity demand that adds up to the existing one, entailing high peak power requests in case of a contemporary connection to the grid of a large number of customers. On the one hand, such demand could be partially controllable for customers accepting ‘interruptible-type’ purchase contracts and some potential exists for the provision of grid services through vehicle-to-grid solutions (mainly short-term storage, with limited support to intraday balances [4]). On the other hand, an assessment of the potential power surge brought about by massive battery electric vehicle (BEV) deployment quickly leads to a multiple of today’s peak demand (see Section 4), thus requiring an extreme and unlikely grid renovation perspective. Moreover, even such a robust grid might not cope with the seasonality of clean electricity generation, considering that the most considerable RES potential in Italy is related to solar energy through photovoltaics, which features nearly three times more electricity generation in summer months than in winter ones. In the absence of a high capacity and long-term energy storage solution, a massive overgeneration in summer would occur due to the seasonality of PV[1] and a rather flat profile of electricity demand along the year, ending up with many TWh of electricity not delivered to any customer. On the opposite, the production of hydrogen with electrolyzers could exploit such large quantities of non-predictable and seasonally-dependent excess electricity. Hence, Power-to-Hydrogen would allow to feed both mobility and other energy-intensive sectors; thus, it constitutes, in parallel and with a synergistic effect to the increasing electrification, a strategical building block of future energy systems.

1.1. Literature review

The topic of sector integration has been a key research focus lately, addressing the complex challenges brought about by a shift towards clean energy resources involving many different end uses. On the one hand, the intermittency and the low predictability of most renewable energy ources call for management methods and solutions that will likely rely on energy storage systems [5]. On the other hand, accounting for a multiplicity of end uses enables integration techniques that can positively help the overall system dynamics (e.g., diverse patterns and trends in different sectors) [6].

In the framework of the development of energy networks, sector coupling is mostly supported by the Power-to-Gas (P2G) technology, which recovers otherwise-lost electricity and electrochemically converts it into a useful fuel. First, hydrogen is produced; then, additional processing may be added to obtain synthetic natural gas, methanol, or others [7]. Guandalini et al. [8] looked at the expected surplus of electric generation in Italy's and Germany's future power systems and estimated the potential for hydrogen production. One possible destination of the produced hydrogen is the injection into the natural gas grid, used as a storage sink. Clegg and Mancarella [9] modeled the seasonal flexibility of such an option. Moreover, Vandewalle et al. [10] investigated inter-sectoral technical and economic effects on the natural gas grid triggered by P2G introduction. Furthermore, Guandalini et al. [11] studied the changes in the natural gas grid dynamics in presence of hydrogen, whereas Pellegrino et al. [12] compared the effects of hydrogen and synthetic natural gas in the grid. Another option is the direct use of the produced hydrogen, e.g., as a feed in the chemical industry or as a fuel for mobility. Rego de Vasconcelos and Lavoie provided a review of power-to-x applications in the production of fuel and chemicals. Robinius et al. [13] modeled the sector coupling between power and mobility. Colbertaldo et al. [14] compared a set of medium- and long-term scenarios for power generation and road transport in Italy, assessing the technical feasibility and environmental effects. A third hydrogen destination is re-electrification, e.g., in fuel cells or conventional power plants, which was analysed by Colbertaldo et al. [15] for large-scale application in the California power system. Welder et al. [16] analyzed the different uses of hydrogen in a long-term evolution of the German system focusing on re-electrification pathways.

The decarbonization of transportation will primarily involve the diffusion of vehicles equipped with electric drivetrains [17]. Both plug-in electric vehicles (PEVs) and fuel cell electric vehicles (FCEVs) are available on the market; today's stock shares in most countries are small, but the deployment rate is growing fast. A more significant number of PEVs is present, thanks to earlier commercialization and possibility of direct use with

[1] Although wind generation shows a two-period annual variability (high in winter; low in spring, summer, and autumn), the differences are moderate and the day-long profile does not follow a precise pattern like solar energy does.

existing infrastructure (early adopters could recharge from domestic sockets); however, a growing interest is emerging on FCEVs, with Japan leading the way [18], thanks to higher mileage and shorter refueling time, as well as implementation for freight transport and buses without payload reduction [19]. Both vehicle types require the development of an adequate infrastructure to bring the energy vector from the production points to the refueling stations, whose diffusion is required by users to embrace the new technology.

For PEVs, the transmission and distribution infrastructure is the power grid. The main challenge is about final charging equipment installation at private or public locations and grid reinforcement, as well as about the effects on power grid management and the possible need for electric energy storage. Patt et al. [20] related the willingness to buy a PEV to the availability of charging points. Hardman et al. [21] reviewed a broad set of studies on infrastructure requirements for stronger PEV market introduction and identified home and work as primary charging points. Also, they found out that the grid impact may be negligible in the short term, when relatively few plug-in vehicles are circulating, especially in terms of pure battery-type vehicles (for instance, the expected fleet of BEVs in Italy and Germany in 2022 will account for only 2-3% of the total stock), but the effect will become relevant with large stock shares of PEVs. Masoum et al. [22] studied such impact, which appears most relevant at the distribution grid scale. Mao et al. [23] developed a model that combines stochastic charging loads and grid constraints to evaluate the impact of PEVs on grid assets.

The hydrogen infrastructure is minimal today (e.g., nearly 400 refueling stations worldwide [24]) and the development relies on logistics and network theory, incorporating all steps from production to storage, transmission, and distribution. Samsatli et al. [25] studied the case of a Great Britain hydrogen network, developing a nodal model and assuming the dedicated installation of wind turbines for hydrogen production. Viesi et al. [26] proposed a scheme for the introduction of FCEVs among passenger cars and buses in Italy, also assessing hydrogen refueling station positioning. Reuß et al. [27] developed a detailed hydrogen supply chain model, digging into the storage needs, while also assessing various combinations of technologies, including gaseous and liquid hydrogen, pressurized vessels and caverns.

Finally, Robinius et al. [28] developed a combined infrastructure assessment, comparing needs and costs related to the deployment of battery or hydrogen cars in Germany, at various stock shares.

1.2. Article content and structure

This work analyzes the integration of the power and transport sectors and evaluates the infrastructure requirements associated with clean mobility, reconciling previous separate modeling efforts [14,28]. First, the national energy system balances are solved, to evaluate the RES share on electric consumption and the availability of surplus generation, taking into account the PEV demand and estimating the P2G capacity that can be installed for hydrogen production to feed FCEVs. Then, infrastructural needs are evaluated for the supply of the new energy vectors to the users, considering the amounts to be delivered and the spatial location of production and demand. Finally, the economics of the different solutions is analyzed.

The case of Italy is investigated, assessing the infrastructure needs for the transformation of Italy's road transport into a cleaner sector where BEVs and FCEVs reach a cumulative share of 50% of the passenger car fleet. For the time horizon of 2050, a high-renewable power generation sector is assumed, comprising a significant increase of solar and wind installed capacity. The uneven geographical distribution of such resources within the north-south stretched shape of the country, combined with a non-homogeneous energy demand by both electrical loads and mobility, leads to a significant transfer of energy vectors from the high-generation southern areas to the high-consumption northern areas.

Section 2 and 3 describe the modeling approach and provide the values of the simulated scenarios. The representation and the characteristics of the mobility infrastructure are detailed in Section 4, together with data and parameters. Section 5 outlines the simulation results, whereas Section 6 develops a discussion and comparison on such results. Finally, Section 7 summarizes the main understandings.

2. Energy system balances in integrated power and transport sectors

From a long-term perspective, the power sector will comprise an enormous renewable generation capacity and the transport sector will include a high share of low-emission vehicles based on battery and hydrogen technologies. Hence, a strong interaction is expected between the two sectors: the power demand by plug-in electric vehicles will affect the overall electric balance, whereas the surplus electricity generation from intermittent RES will be a crucial resource driving the production of clean hydrogen for fuel cell vehicles.

The developed model for energy system balance is built on the electricity network structure, which requires a continuous supply-consumption equilibrium. The mobility sector is involved in the power balance directly with the electric demand by PEV charging or by new refueling stations and indirectly with the hydrogen production via P2G, which is fed by excess RES power generation. The simulations exploit a nodal model that represents the spatial resolution of the selected geographical region (e.g., country or group of countries), based on previous modeling developments, as described in [14]. Figure 1 provides a schematic of the energy flows in the integrated systems; intra-nodal and inter-nodal exchanges can be identified.

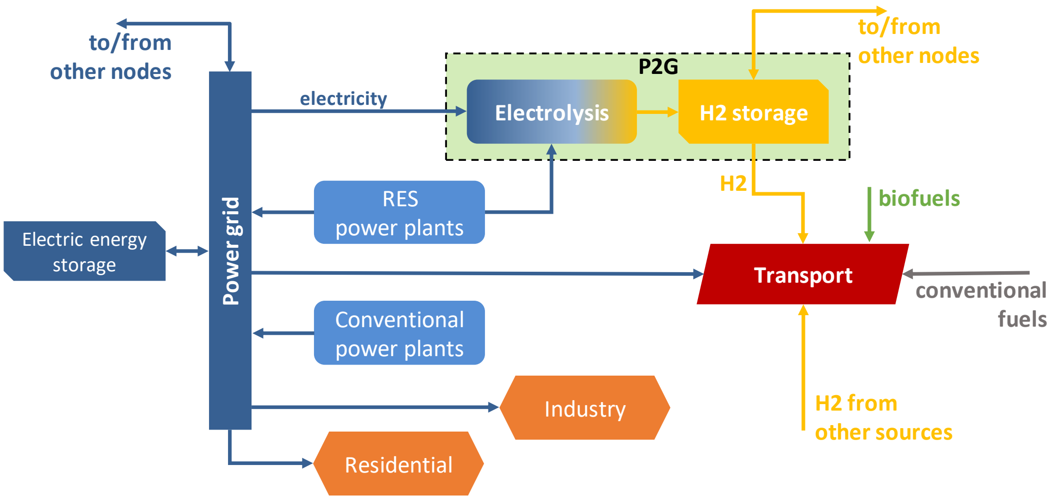

Figure 1 – Schematic of the energy flows within one nodal zone.

2.1. Power sector

The operation of the electricity grid imposes a continuous and instantaneous balance of power generation and consumption. The simulation model adopts a lumped nodal scheme: the exchange of electricity between nodes is limited by the power transfer capacity as identified by the TSO (combining current status and expected changes), whereas energy distribution is unconstrained within each node, i.e., a 'copper plate' grid assumption is applied. This assumption is required to limit the model complexity, allowing to neglect intra-nodal distribution issues, which are highly dependent on the specific node infrastructural status as well as on generation and load conditions. Despite local portions of the grid are typically highly interconnected and feature high power capacity reserves, the methods inevitably introduces a simplification [29]. However, the impact on results is an underestimation of the available excess electricity, thus making the simulations conservative, since the additional distribution limitations would further reduce the inability to accommodate larger amounts of intermittent generation [13]. The investigated framework involves future scenarios of significant generation overcapacity, which are likely to bring about the necessity of substantial reinforcements at both inter-nodal and intra-nodal level. In such context, the presence of Power-to-Hydrogen is crucial at all level, and the distribution system operators (DSOs) could act just like the TSO, using electrolyzers as infrastructural element to limit grid expansion needs [30].

The model solves a balance equation of active power flows for each node z at each time step t (e.g., 15 min or 1 h) along the simulated time horizon (typically 1 year), considering the availability of storage systems and the possibility of curtailment:

$$P_{RES}^{z,t} + \sum_j P_{exch,j}^{z,t} + \sum_s P_{out,s}^{z,t} + P_{conv}^{z,t} = P_{load}^{z,t} + \sum_s P_{in,s}^{z,t} + P_{in,P2G}^{z,t} + P_{curt}^{z,t} \quad (1)$$

where $P_{RES}^{z,t}$ is the generation from RES power plants, $P_{conv}^{z,t}$ is the generation from conventional power plants, $P_{exch,j}^{z,t}$ is the power exchange with a connected neighboring node j (positive if entering node z, including a loss factor from the supplying node to the receiving node), and $P_{curt}^{z,t}$ is the curtailed electricity (i.e., the generation that exceeds the load, the storage capacity, and the P2G capacity). $P_{load}^{z,t}$ is the total electrical demand, which comprises conventional grid loads ($P_{grid}^{z,t}$) and transport-related consumption by PEV charging ($P_{PEV}^{z,t}$) and hydrogen compression in refueling stations ($P_{HRS}^{z,t}$), whose details are provided in Section 4.1:

$$P_{load}^{z,t} = P_{grid}^{z,t} + P_{PEV}^{z,t} + P_{HRS}^{z,t} \quad (2)$$

Many electric-to-electric storage technologies can be included, each of which has a power output $P_{out,s}^{z,t}$ and a power input $P_{in,s}^{z,t}$. For any storage technology s, the time evolution of the storage energy content E_s^t is expressed by eq (3):

$$E_s^t = E_s^{t-1}(1 - \varepsilon_{sd}^s) + P_{in,s}^t \cdot \Delta t \cdot \eta_{in,s} - \frac{P_{out,s}^t \cdot \Delta t}{\eta_{out,s}} \quad (3)$$

where η_{in}^s and η_{out}^s are efficiency values that represent the energy losses involved with the charging and discharging processes, respectively, and ε_{sd}^s is the self-discharge coefficient for the given time step.

The quantity $P_{in,P2G}^{z,t}$ in Eq. (1) corresponds to the amount of electricity that is absorbed by P2G facilities, which depends upon the availability of RES overgeneration and the electrolysis system capacity $P_{inst,P2G}^{z}$, aiming to minimize $P_{curt}^{z,t}$.

The model equations are solved by applying a myopic approach, i.e., at each time step, the system is only aware of the past conditions and the solver optimizes the energy flows (in particular, power exchanges among the zones and operation of storage devices) to minimize the need for conventional generation in that single time step. The optimization is performed by means of linear programming algorithms in Matlab®.

The system simulation also outputs the P2G size $P_{inst,P2G}^{z}$ in each zone z and the hydrogen storage requirements. The values are calculated to maximize the use of surplus RES generation while constraining the system utilization above a minimum capacity factor. Such constraint is expressed by Eq. (4) in terms of equivalent full load hours (EFLH, defined as the number of hours that the system should have operated at nominal power to treat the same total amount of electricity that it actually treated over the year):

$$\frac{\sum_t P_{in,P2G}^{z,t} \cdot \Delta t}{P_{inst,P2G}^{z}} \geq EFLH_{min} \quad (4)$$

2.2. Transport sector

The innovative and zero-emission passenger car technologies considered are plug-in electric vehicles (PEVs) and fuel cell electric vehicles (FCEVs).

The PEV category includes plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs). They both feature an onboard battery that can be charged via an external electrical connection, so that these vehicles run – at least partially – on electricity provided by an external source [31]. During electric-propelled motion, local pollutant emissions are absent, whereas GHG emissions depend upon the electricity generation mix. At large PEV shares, the electricity demand for the charging process significantly affects the energy system balance, depending on both the total consumption and the temporal distribution of the load are relevant. This is expressed in the balance equations by the term $P_{PEVs}^{z,t}$ of Eq. (3). First, the annual demand is calculated combining the vehicle stock, the average specific consumption, and the yearly traveled distance. Second, it is distributed over the simulation time steps by means of a hourly time profile. During the development of the study, multiple time series were compared among the available theoretical models and measured data, e.g., flat constant consumption, variable demand with two peaks along the day, mid-day peak following PV power generation, cost-driven consumption based on time-of-use pricing [32,33]. The implementation of different options showed little to no macro-effects in the simulation results. For the simulations in Section 5 a day-long hourly profile is consideredand repeated identically, featuring two peaks (morning and evening) that relate to workday start and workday end, resembling a user-driven behavior (see also Section 4.2 about the charging infrastructure) [32].

In a FCEV, hydrogen feeds a fuel cell system that generates the power that drives the electric motor. A battery decouples fuel cell generation and motor consumption, allowing faster transients and at-need peaks. Although relying on a today-uncommon energy vector, FCEVs offer many of the advantages of conventional vehicles such as long traveling range and short refueling time, plus high fuel efficiency and zero local emissions. They share with PEVs the dependence of GHG emissions upon the production method (zero in case of electrolysis fed with electricity from RES, medium to high in case of electrolysis with non-RES electricity, natural gas reforming, or coal gasification). Here, hydrogen production is assumed to occur via electrolysis operated on surplus generation from intermittent RES up to what is allowed by the energy system balance, under the consideration that direct use of electricity is energetically preferred to the conversion into a different energy vector. The term $P_{in,P2G}^{z,t}$ in Eq. (1) accounts for the electricity use in P2G systems for this purpose. In case of insufficient P2G production, residual hydrogen demand is assumed to be supplied by local production via conventional technologies or imported from elsewhere – the latter being environmentally preferred when involving clean production methods. Whatever the production mode, the hydrogen needs to eventually be supplied to the cars (or other transport vehicles, which may include trucks, buses, and others). The filling of onboard tanks happens at hydrogen refueling stations, which have a non-negligible energy consumption, mostly related to the compression processes up to above 700 bar, as required by the onboard hydrogen tanks of passenger cars. The compressors run on electricity and the typical station layout involves multiple storage vessels at various pressure levels [34], so that the consumption is not concentrated at the refueling moment but spread throughout the day. Given the total annual hydrogen demand from FCEVs in node z, the related electricity demand is evaluated and homogeneously distributed on the simulated time steps, obtaining the term $P_{HRS}^{z,t}$ of Eq. (2). The whole hydrogen supply infrastructure is detailed in section 4.1.

3. The case of Italy

3.1. Power sector scenario

In the next decades, a considerable increase in the installed power generation capacity from renewable sources is expected, supported by European Union directives [35] and national policies [36]. The scenario considered in this work for the year 2050 is depicted in Table 1, together with today's status. A large part of the RES increase is already foreseen by existing national plans for 2030 [36,37], also reported in Table 1. The assumed onshore wind capacity in 2050 is equal to the potential estimated in [38], which considers land area availability and expected turbine improvements. Offshore wind is a still-to-establish technology in the deep waters that characterize the Mediterranean Sea. However, it has been included in the 2030 national energy plans [36,37] and several studies have been developed over the years. The value of installed capacity that is considered here is an average from a set of Italian studies [39], which appears consistent with more recent assessments by IEA [40]. The solar PV capacity corresponds to the potential for building-integrated installations, taking into account available areas [41], average solar irradiation [42], and expected panel improvements (i.e., 25% nominal efficiency and 90% performance ratio). The installed capacity of geothermal and hydropower plants is not increased from today's values. Although new installations are likely to occur, the total new capacity is difficult to predict and the suggested values vary significantly in forecast studies, while never representing very high shares [43–45]. Moreover, the strong dependence of hydropower generation on weather conditions is not easily modeled on historical data. The same evolution uncertainty applies to biomass power plants, whose resource is also in competition with food uses and biofuel production, which will be essential to decarbonize some difficult-to-electrify sectors (e.g., mobile uses like aeronautics). Hence, bioenergy is deliberately left out of the assessment, assuming that the available capacity will exploit its dispatching capabilities and these power plants will act as balancing units rather than as surplus-providing (thus being a favored low-CO_2 part of the term $P_{conv}^{z,t}$ of Eq. (1)). Among bioenergy, the particular case of waste-to-energy is separated and combined with RES generation, as it deals with the non-optional need of waste disposal. Data of installed capacity and annual feed are taken from the official Italian medium-term requirements [46], assuming a flat operation along the year and resulting in an annual electricity generation corresponding to less than 2% of the country demand.

The considered nodal resolution corresponds to the six electrical market areas, upon which the power transfer limits are defined (see Figure 2). The distribution of the new capacity among the areas is kept nearly proportional to the present one (as available from national reports [47]); a correction factor is implemented following a review of allocation strategies that looked at alternative distribution methods based on relevant parameters (e.g., resource availability, land area, built area).

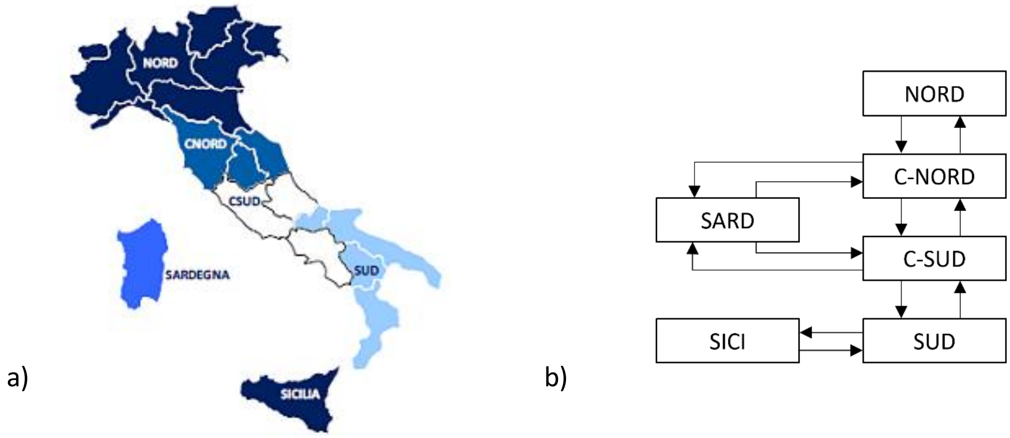

Figure 2 – Italy's nodal resolution: a) geographical clustering [48]*; b) schematics of inter-nodal connections.*

Besides the additional consumption by mobility (PEV charging and HRS operation), which is treated separately, the electricity demand is assumed stable at the value of the reference year, based on the recent trend showing little variations and the fact that energy efficiency measures are expected to offset increases due to electrification of other loads. We do not include, for simplicity, other technology shifts that could develop on the long period (e.g., the transition from natural gas-based heating to heat pumps, which would enlarge the winter power demand and contribute to the misalignment concerning the summer-prevailing RES availability).

Time series of electricity generation and consumption by market area are taken from the Italian Transmission System Operator database [49] and rescaled according to the installed generation capacity and to the annual load, respectively. The reference year is 2015.

Pumped hydroelectric plants take part in the simulation as grid-connected energy storage systems. Today's installed capacity is considered (nodal distribution follows Figure 2), since the erection of new large dam-based installations is poorly feasible and the forecasted growth by 2050 [37] is not detailed. The values are provided in Table 1. Besides the exploitation of pumped-hydro storage plants, P2G is considered in this work as the main solution for the absorption of overgeneration. The installed capacity of electrolysis systems is a result of the energy system simulation, dependent upon the imposed constraint on equivalent full-load hours ($EFLH_{min}$ = 2000 h/y). Electric-to-electric storage technologies other than pumped-hydro are not considered. Grid-scale batteries are a viable option mostly over short time scales or behind-the-meter applications, which are out of this hourly energy flow-based analysis. The study neglects for simplicity the role of vehicle-to-grid interactions on a few-hour timescale, which is however less and less applicable as soon as the required storage timescale grows. Also, the additional role of P2G systems as flexibility providers in the electric grid is not assessed, and will be the focus of future studies.

Transmission limits along inter-zonal power lines are assigned using values from TYNDP2018 for the year 2040, which assume an increase of the allowed power flows in the order of 30-50% from current status, based on ongoing or under planning projects for a substantial grid reinforcement [43]. The values vary seasonally, similarly to current data [50], featuring a lower maximum capacity in summer months due to higher ambient temperature that limits the maximum current in order to avoid overheating.

Table 1 – Installed capacity of RES power plants by source, electricity demand, and pumped hydroelectric storage capacity, in the reference year [49]*, in the 2030 national plan* [37]*, and in the considered long-term scenario.*

	Reference (2017)	National plan (2030)	Long-term scenario (2050)	
			Capacity	Allocation to zones
Solar PV	19.7 GW	50.0 GW	137.2 GW	By resource potential and land area
Onshore wind	9.8 GW	17.5 GW	49.1 GW	Same as reference year
Offshore wind	0.0 GW	0.9 GW	9.5 GW	As from estimates in [39]
Renewable hydro	18.9 GW	19.2 GW	18.5 GW	Same as reference year
Geothermal	0.8 GW	0.9 GW	0.8 GW	Same as reference year
Gross electricity demand (excl. PEVs and HRSs)	320 TWh/y	337 TWh/y	320 TWh	Same as reference year
Pumped hydroelectric storage	7 GW - 700 GWh	10 GW	7 GW - 700 GWh	Same as reference year

3.2. Evolution of the mobility sector

This study focuses on the infrastructural needs brought about by the mobility sector evolution, aiming at comparing different scenarios that feature a large introduction of zero-tailpipe-emission technologies. This is in line with the ongoing push for CO_2 and local pollutants reduction, as supported by both policymakers and bottom-up movements. A different field of study may be found in the literature that focus on optmizing the demand [XX].

This work analyzes three different evolution cases of passenger car market, which are presented in Table 2. All cases assume that non-ICE-based vehicles (i.e., FCEVs or BEVs) will make up 50% of the total fleet, featuring either the exclusive presence of one technology or a combination of the two. The value is a round figure and does not claim to be an exact forecast, but rather to represent an intermediate reference, taking into account that existing studies and forecasts for 2050 range from very pessimistic (e.g., the EU Reference Scenario 2016 foresaw 5% BEVs, 2% FCEVs, 6% PHEVs [51]) to very optimistic (e.g., the IEA-2DS-highH2 scenario proposed a combination of nearly 30% FCEVs, 15% BEVs, and 19% PHEVs [52]) and works were developed that investigate an extreme transition to 100% FCEV [53] or to 100% BEV [54] for passenger cars.

Among ICE-based vehicles, the gasoline share is assumed larger than the diesel one due to recent trends of legislation about diesel limitation. Alternatives fueled by compressed natural gas (CNG) or liquified petroleum gas (LPG) are included at a 10% share, because their presence is historically significant in Italy (about 8% of today's stock [55]) and they are expected to play a relevant role in clean mobility, also associated with the rise of biomethane.The total stock of passenger cars in Italy was about 38 million cars in 2017. Data for the past 10 years (2008-2017) shows little variations, depicting an overall increase in the order of 1% in 10 years [55]. Starting from the current high car ownership ratio[2], different long-term analyses forecast either a slight

[2] The car ownership ratio is defined as the ratio between the number of registered passenger cars and the population.

decrease [52] or a moderate increase [44]. Here, we consider a total fleet in 2050 identical to the 2017 situation.

The average annual traveled distance is kept equal to the present value of about 11,000 km/y (available forecasts focus on diesel and gasoline vehicles and propose slight increments and decrements, respectively [56]).

Average fuel efficiencies in the scenario are obtained from market evolution curves, considering a progressive improvement from current values to high-efficient solutions in 2050 and a car substitution rate equal to 11 years (corresponding to the recent trend, [57]). For FCEVs, the assumed average hydrogen consumption in 2050 is 0.65 kg_{H2}/100km [58], whereas the average electricity consumption by BEVs is 12.6 kWh_{el}/100km, assuming a battery size equal to 75 kWh on average, which guarantees a nominal driving range of over 500 km [28].

Table 2 – Vehicle stock shares in the reference year and in the future scenario, in the three analyzed cases.

	Reference (2017)	Scenario (2050)		
		Case A	Case B	Case C
ICEV gasoline	49.7%	25%	25%	25%
HEV gasoline	0.2%			
ICEV diesel	42.0%	15%	15%	15%
HEV diesel	<0.1%			
ICEV LPG/CNG	8.1%	10%	10%	10%
BEV	<0.1%	0%	50%	25%
FCEV	0.0%	50%	0%	25%

Given the national stock of zero- emission vehicles (ZEVs) within passenger cars (comprising BEVs and FCEVs), the total annual demand for electricity and hydrogen is evaluated from fuel efficiencies and average annual mileage. Subsequently, the national demand is disaggregated to geographical regions[3] according to four parameters: population, population density, passenger car stock, and average income per capita. Figure 3 shows the resulting distribution of the ZEV fleet (and subsequently of the demand for the energy vectors) among the different provinces. It is assumed that the adoption of both drivetrain technologies is governed by similar market and regulation policy factors, therefore the relative distribution is presumed to be the same for both PEVs and FCEVs. It can be noticed that the provinces in the north present larger values on average (darker colors), mainly dependent upon higher population density and higher income per capita. Furthermore, the provinces of the three main cities (Rome, Milan, Naples – see **Fehler! Verweisquelle konnte nicht gefunden werden.**) show the highest share of up to 4.0%, followed at a distance by Turin (2.5% of the country demand), whereas most provinces fall below the 1.5% share.

[3] Geographical regions corresponding to NUTS-3 classification [95].

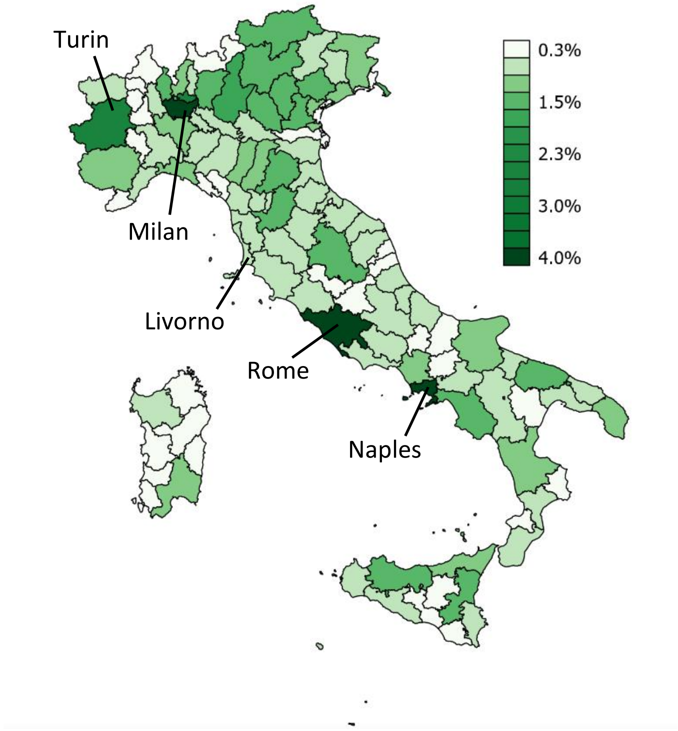

Figure 3 – Relative distribution of ZEVs and subsequent energy vector demand expected in 2050, by province.

The absolute values of demand vary in each case, depending upon the actual number of vehicles of each category. Table 3 presents the aggregated electricity and hydrogen demand of the six areas considered in the power sector modeling (see Figure 2) for the three analyzed vehicle penetration scenarios (see Table 2). Note that, inevitably, the hydrogen demand is larger in energy terms (TWh_{H2}/y) with respect to the electric demand (TWh_{el}/y), due to the lower 'tank-to-wheel' conversion efficiency of the hydrogen-to-mobility chain (see Section 3.2). The corresponding electricity demand for hydrogen production would also be higher, including the additional effect of power-to-hydrogen conversion, but such increase is partially compensated by a higher flexibility with respect to PEV demand. These effects will be evident in the results in Section 5. In line with the observed regional vehicle distribution differences, northern and central Italian regions show the most significant energy demands. Moreover, the NORD zone provides almost 50% of the overall ZEV energy demand, highlighting the energy relevance of this area.

Table 3 – Demand of energy vectors for clean mobility in the three analyzed cases.

	Case A		Case B		Case C	
	FCEVs	PEVs	FCEVs	PEVs	FCEVs	PEVs
	TWh_{LHV}/y	TWh_{el}/y	TWh_{LHV}/y	TWh_{el}/y	TWh_{LHV}/y	TWh_{el}/y
NORD	24.1	0.0	0.0	12.2	12.1	6.1
C-NORD	6.4	0.0	0.0	3.2	3.2	1.6
C-SUD	8.7	0.0	0.0	4.4	4.4	2.2
SUD	5.6	0.0	0.0	2.8	2.8	1.4
SICI	3.7	0.0	0.0	1.9	1.8	0.9
SARD	2.1	0.0	0.0	1.1	1.0	0.5
Italy	50.6	0.0	0.0	25.6	25.3	12.8

4. Infrastructure for clean energy vectors in transport

This section describes the main aspects of hydrogen and electricity delivery for ZEV-based mobility, and discusses the infrastructure modeling methodology as well as the main technical and economic parameters.

The diffusion of FCEVs is mainly constrained by the need for combined development of the fleet itself and the dedicated infrastructure to provide widespread accessibility, the latter presenting challenges related to the energy-intensive hydrogen production and processing. On the opposite, PEVs can be more easily integrated into the current energy system thanks to the possibility of utilizing existing power infrastructure and relatively low energy demand. However, large PEV shares will require additional facilities, from charging points where vehicles can physically connect to the grid to power line reinforcements that guarantee the electricity transfer. Indeed, the main challenge appears to be the increased peak power demand related to concurrent electricity withdrawn from the grid, rather than the total annual consumption. The latter is estimated in the order of 10% of today's electricity demand when considering a replacement of 50% of the passenger cars by BEVs in Italy[4], while the power load request could be as high as 100 GW when considering 25% of those vehicles connected to 22-kW charging points[5] at the same time, to be added to the regular grid load that averages at about 36 GW and peaks at 55 GW today [49]. The situation would grow four to eight times worse for an unrealistic (if not irrational) 100% BEV scenario.

4.1. Hydrogen supply infrastructure

For FCEVs, the fuel supply challenge is twofold: (i) best environmental advantages are achieved when hydrogen is produced in clean ways and (ii) geographically unmatched locations of production and demand require a reliable and robust distribution network. Moreover, clean production pathways involve intermittent RES, hence hydrogen storage systems immediately enter the picture.

The hydrogen supply chain model applied in this analysis is based on the modular design approach by Reuß et al. [27] and Cerniauskas et al. [59], which enables the techno-economic assessment of various hydrogen delivery pathways. For the assessment, the methodology considers the technical constraints such as the required hydrogen pressure and capacity as well as the economic parameters of facilities' scale and

[4] Authors' calculations, considering today's situation of about 38 million passenger cars and 300 TWh/y electricity demand.

[5] Note that such 22-kW chargers imply a few hours for full charge, while advanced fast chargers such as Tesla Supercharger are rated at 150 kW or more, providing a 20-80% battery recharge in about 20 min.

utilization. Moreover, geospatial attributes and constraints are accounted for, such as source and sink positions as well as their connections, like train or street routes. Due to their cost competitiveness in different geographical regions shown in the literature [27,60], the analyzed hydrogen delivery options encompass LH2 trailer delivery as well as GH2 hydrogen supply with pipeline transmission and subsequent trailer distribution. The overview of the relevant pathways of hydrogen supply chains and associated components is given in Figure 4. The following sections will gradually describe each supply chain component.

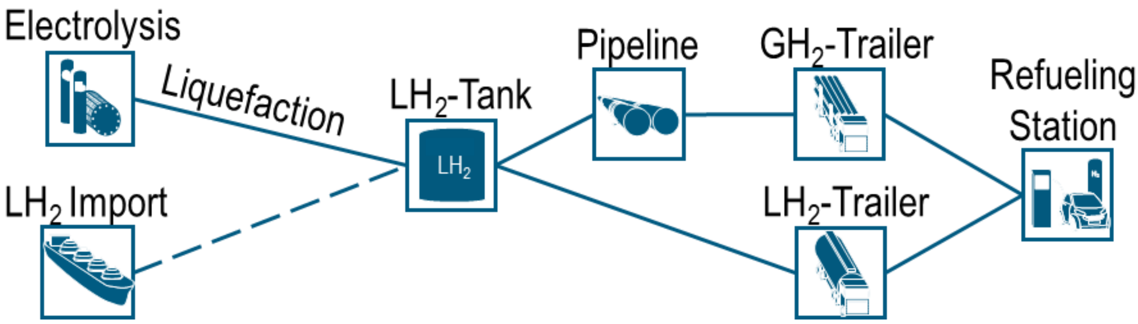

Figure 4 – Schematic of the considered hydrogen supply chains.

<u>*Hydrogen production*</u>

Intermittency of renewable energy sources such as wind and solar PV requires flexible energy conversion systems, like electrolyzers, which can act as a flexible load for power grid balancing while fostering the production of a clean energy vector. Based on the high load flexibility and the expected significant cost reductions, proton exchange membrane (PEM) electrolysis is selected as the most appropriate long-term technology for hydrogen production [61] from the electricity surplus resulting from the nodal system balance. However, results would not change very significantly when considering alkaline-based electrolysis (having only slight differences in terms of efficiency and a lower turndown ratio), which is instead expected to be more economical in the short to medium term [62]. The P2G plants are considered to be located at the centroid of each Italian region (NUTS-2 level, according to the European Nomenclature Territorial Units for Statistics)

. First, the P2G installed capacity and input electricity (i.e., recovered surplus RES generation) are calculated at each market zone (see Figure 2) from the nodal system balances. Then, the quantities are allocated on regional centroids on the basis of the weighted relative RES generation (proportionally) and electric demand (in an inversely proportional manner), calculated upon historical data.

In the event of insufficient in-country hydrogen production to meet the demand, it is considered to import hydrogen, which involves overseas production via RES-based electrolysis and hydrogen-driven ship transportation with ocean-going LH2 tankers, featuring a capacity of 160,000 m^3 [63]. Based on the approach after Heuser et al. [64], the estimated hydrogen import cost at the port is set to 3.9 €/kg_{H2}. By excluding southern regions that will already feature large hydrogen production and applying a minimum distance approach, the port of Livorno (see **Fehler! Verweisquelle konnte nicht gefunden werden.**) is selected for hydrogen import as it also shows a vicinity to energy-intensive industrial plants like refineries and chemical processing plants. After delivery in liquid form at the port, hydrogen is locally stored, then distributed with cryogenic trucks and re-gasified at the hydrogen refueling stations. Table 4 provides an overview of the most important assumptions regarding hydrogen production and processing applied in this study.

Table 4 – Main parameters of hydrogen production.

Parameter	**Value**	**Ref.**
Electrolyzer system cost	500 €/kW_{el}	[65]
Electrolyzer system LHV efficiency	70%	[13]
Minimum equivalent full-load hours	2000 h/y	Own assumption
Hydrogen import cost at the port (LH2 form)	3.9 €/kg_{H2}	Based on [64]

Hydrogen storage and processing

The production of hydrogen via P2G from surplus RES electricity will show significant fluctuations on both short (daily to weekly) and long (seasonal) time scales. On the contrary, hydrogen demand at refueling stations will be rather stable, e.g., in terms of daily amounts. Hence, a need for hydrogen storage facilities arises, which is challenged by the low energy density of hydrogen at ambient conditions (about 3 kWh/m^3). The main options are high-pressure storage in gaseous form in tanks or underground cavities and liquid storage in cryogenic vessels [66]. Italy does not present many adequate salt cavern sites [67], which are instead the preferred underground option. The country is rich in depleted oil and gas reservoirs, currently used for natural gas storage [68] and potentially adaptable for hydrogen injection; however, the use with pure hydrogen is still under evaluation due to microbial activity that appears to favor undesirable hydrogen sulfide formation [69], needing purification after hydrogen extraction. An alternative is given by the construction of artificial Lined Rock Caverns (LRC), which may constitute a highly promising option, but further investigation is needed and reliable cost estimates are not available [70,71]. Therefore, this option is left to further assessment and evolutions of the analysis presented here. Aboveground installation of large gaseous tanks (e.g., over 10 t_{H2}) is assumed unlikely due to the associated significant land footprint and difficult social acceptance, in addition to very high costs (see Section 5 for a preliminary assessment). Therefore, liquid hydrogen can be a candidate technology for the needed seasonal management of production and demand. Large quantities favor this technology since the liquefaction plants have strong economies of scale, but it suffers from boil-off rates due to the inevitable evaporation of the fluid over time. Furthermore, hydrogen liquefaction is an energy-intensive process, thus reducing the overall energy efficiency of the hydrogen delivery infrastructure

For the Italian scenario simulations presented in Section 5, liquid hydrogen storage is the considered option for the needed management of the energy vector. The hydrogen storage facilities are assumed located at production points and the needed capacity is evaluated in terms of storage time to be guaranteed, considering a set number of days at the average daily production. Table 5 provides the main considered parameters of the hydrogen storage and processing equipment. For more detailed information regarding compressor, liquefaction, and liquid hydrogen pump modeling, the reader could refer to the relevant literature [72,73].

Table 5 – Main parameters of hydrogen storage and processing.

Parameter	**Value**	**Ref.**
Liquefaction system efficiency	6.78 kWh_{el}/kg_{H2}	[72]
Boil-off rate at LH_2 storage	0.03%/day	[72]
Storage time	60 days	[27]
LH2 pump energy demand	0.1 kWh_{el}/kg	[28]
Evaporation energy demand	0.6 kWh_{el}/kg	[28]
Compression energy demand	Depending on Δp	[27]

Hydrogen delivery

Decentralized power generation in the future energy system poses a significant challenge to the infrastructure as geographical unmatching of energy production and demand requires a reliable and robust delivery network. Furthermore, in the case of hydrogen, the supply chain implementation would require new infrastructure construction to deliver the energy vector to the final consumer. The delivery of hydrogen is modeled in two physical states: gaseous and liquid. In the gaseous pathway, the delivery can occur either through a pipeline or via trailer, whereas in the case of liquid hydrogen, only liquid trailer supply is considered. Studies have shown that, due to low capacity, trailers are generally more cost-effective at low throughputs, whereas pipelines provide the most cost-effective means of hydrogen transport for high supply volumes [60]. Moreover, liquid hydrogen trailers have superior payload capacity over the gaseous ones, thus making liquid hydrogen more attractive for delivery over higher distances.

More specifically, in this study, we focus on the comparison of the pipeline transmission with subsequent gaseous trailer distribution and liquid hydrogen delivery. In the case of the gaseous hydrogen supply pathway, the distinction between transmission and distribution is made at the centroid of the relevant NUTS-3 region.

The main techno-economic inputs used in the study originate from the former analyses on countrywide hydrogen infrastructure available in the literature [13,27]. Thereafter, the supply network approach is developed at the backdrop of the works from Reuß et al. [27] and Baufumé et al. [74], by employing the rail and road networks for pipeline and trailer provision, respectively. Furthermore, the linear flow problem to minimize infrastructure cost is expanded with available connections to sources and sinks, whereas the connection between the fuel stations and the relevant centroid is approximated with the mean distance in the specific NUTS-3 region, as measured from current data [75,76]. The occurring complexity of the transport network flow optimization is further reduced by applying the algorithm of the minimum spanning tree that bounds the number of possible network branches in the candidate grid before the optimization [77]. Table 6 summarizes the relevant input parameters employed in the hydrogen delivery cost analysis.

Table 6 – Main technical and economic parameters of the hydrogen delivery infrastructure [13,27,28].

	Pipeline	GH2-Trailer	LH2-Trailer	Truck
Pressure	100 bar	500 bar	-	-
Payload	-	720 kg	4500 kg	-
Investment cost	$2.2\times10^{-3}\cdot d^2+0.86\cdot d+247.5$ €/m (d = pipeline diameter)	660,000 €	860,000 €	160,000 €
O&M cost	4 %/y	2 %/y	4 %/y	12 %/y
Lifetime	40 y	12 y	12 a	8 y
Operating hours	8760 h/y	2000 h/y	2000 h/y	2000 h/y
Driver cost	-	-	-	35 €/h

Hydrogen refueling stations

As mentioned in Section 2.2, hydrogen refueling stations (HRSs) introduce an electricity consumption term that mainly depends upon hydrogen compression (in case of GH2 transport) or pumping (in case of LH2 transport) from the on-site storage to the delivery pressure. A value of 1.9 kWh/kg$_{H2}$ or 0.6 kWh/kg$_{H2}$ characterizes the two options, respectively [27]. In the system simulations, the smallest investigated spatial resolution is the province level (NUTS-3), neglecting further detail of each HRS position and considering today's average distance from the corresponding provincial centroid. The electric demand is calculated at province level and aggregated at the electric market zone to obtain the value of $P_{HRS}^{z,t}$ consistently with Eq. (2). The consumption is assumed to be homogeneously distributed along the day, considering that an appropriate station operation exploits intermediate storage tanks to spread the pressure increase along the day [34]. All simulations presented in Section 5 consider an average HRS specific consumption equal to that of GH2 fuel stations (1.9 kWh$_{el}$/kg$_{H2}$). Note that the corresponding annual electric demand represents less than 1% of the overall country consumption, and preliminary simulations showed that effects on the profiles are negligible.

The considered hydrogen refueling stations are presumed to be assembled on existing gasoline/diesel refueling station sites and their capacity is distributed by employing a mixed-integer linear optimization approach (MILP) to minimize the investment cost of hydrogen refueling stations within a region with discrete fuel station size options. This methodology resembles other studies investigating the minimal fuel station network size that is necessary to deliver sufficient coverage in the introductory phase of a new fuel [78–80]. Moreover, the fuel station locations are selected by assigning the highest priority to the highway stations, then followed by the ones located on main roads and lastly those on secondary roads [81]. The assumed learning effects imply that the investment cost of the hydrogen refueling stations is reduced by 6% every time total hydrogen refueling station capacity is doubling. Table 7 summarizes the base investment costs for 700 bar refueling stations of different sizes (assumed identical for both GH2 and LH2 stations).

Table 7 – Hydrogen refueling station investment cost [27,28].

	S	M	L	XL	XXL
Capacity [kg/d]	212	420	1000	1500	3000
Investment cost [€]	800,000	1,100,000	1,940,000	2,700,000	4,850,000
O&M cost	0.1 %/y	0.1 %/y	0.1 %/y	0.1 %/y	0.1 %/y
Learning rate	6 %	6 %	6 %	6 %	6 %
Lifetime [years]	10	10	10	10	10

4.2. Plug-in electric vehicle charging

The infrastructure that supports PEV diffusion comprises the Electric Vehicles Supply Equipment (EVSE) to transfer power from the grid to the vehicles and the corresponding power line upgrade. The EVSE can be installed as a single charging point or within a larger charging station. The International Electrotechnical Commission (IEC) defines four charging modes, based on the type of power, the voltage level, and the presence of control and protection functions [82]:

- Mode 1 involves slow charging from a regular socket-outlet, via single-phase or three-phase AC, without dedicated control or protection;
- Mode 2 differs from Mode 1 for the presence of an in-cable protection device;
- Mode 3 comprises slow or fast charging via AC power, involving specific socket-outlet with in-cable control and protection functions;
- Mode 4 is fast DC charging and requires dedicated equipment where the control and protection functions are installed.

The PEV charging process can take place at households (single-family-owned, building-shared, or on-street Mode 1 or Mode 2 EVSEs) or at public locations (Mode 3 or Mode 4 chargers). In the first case, the simple equipment architecture reduces the investment cost, whereas the low power rating imposes longer charging times. In the second case, the high power capacities allow shorter charging times that guarantee both the access by more customers and the increase of travel distances without the need for long stops.

The assessment approach of this work is elaborated from [28]. Charging points at private dwellings are typically operated for overnight charging; hence, time ranges of 5-6 hours are reasonable. In the considered time horizon (the year 2050), the typical power capacity of chargers in households is assumed to increase from today 3.6 kW to 11 kW. Public charging points are distinguished by their location: in cities vs. at service stations along freeways. The first option includes a combination of Mode 3 and Mode 4 chargers, whereas charging points along freeways are assumed to feature Mode 4 fast DC charging to allow for short stops. At present, the typical power rating of Mode 3 chargers is 22 kW and Mode 4 chargers up to 150 kW are offered. In the long term, the ratings will increase, and the analysis assumes an average nominal power of 40 kW and 350 kW, respectively. Table 8 summarizes the main parameters considered in the analysis (the numbers are estimated from today's data considering power rating increase and learning curve effects).

Table 8 – Technical and economic parameters about plug-in vehicles charging infrastructure [28].

	Nominal power	Cost
Home charger M1/M2 (indoor)	11 kW	1,252 €/unit
Outdoor charger M1/M2	11 kW	2,566 €/unit
Public charger M3	40 kW	4,512 €/unit
Public charger M4	350 kW	53,580 €/unit
Freeway charger M4	350 kW	53,580 €/unit

The number of PEV charging points is estimated considering the PEV fleet and the charging point features, with a few additional assumptions.

Overnight charging takes place at households, in private garage, indoor parking spots, or reserved outdoor spots, via Mode 1 and Mode 2 chargers. In the present analysis, the number of home chargers is set equal to 60% of the number of PEVs, considering some cases of shared use as well as the possibility of owning a PEV without having access to a private charging connection (expected as reasonable to push a massive presence). Such value is slightly smaller than the average share of dwellings that features a private parking option in Italy [83]. Moreover, the proportion of indoor ('home') and outdoor ('street') chargers varies by zone across the country, due to the uneven share of indoor and outdoor parking spot availability (dwellings with an 'outdoor only' car spot range from 15% in zone 'NORD' to 31% in zone 'SARDEGNA'). For the assessment of Mode 3 chargers distributed in cities and towns, a homogeneous PEV-to-charging-point ratio of 20 is assumed. The number of Mode 4 chargers is estimated by analogy with today's liquid fuel distribution infrastructure, taking into account the different fueling time (5-10 mins for ICEVs vs. 15-20 mins for BEVs in the long term) and the different frequency of refueling or charging due to different mileage (the ratio BEV-to-ICEV is about 2). Italy features about 20,900 refueling stations (excluding 411 stations located at freeway service areas [75]) and 6 dispensers per station on average are assumed. Based on that, the BEV-per-charging-point parameter is calculated, which ranges from 44 to 54 in the six zones and averages at 50 in the country. Then, for each case, given the number of PEVs in the stock, the required number of charging points can be estimated.

As mentioned, charging on freeways is treated separately, under the consideration that an appropriate number of charging equipment must be installed to guarantee coverage (note that most Italian freeways are toll roads and no driver would like to exit and re-enter, wasting time at the barriers and raising the total toll). The average distance between charging stations is set equal to 30 km, similar to the relative position of today's service areas (28 km along the 7000 km of the network [84]). Data regarding the average daily transit along the main sections of freeways are used, together with the corresponding lengths [85], to evaluate the number of BEVs traveling on freeways, assuming that the occurrence is equal to the stock share in the studied large-penetration cases. The subsequent charging needs also depend upon the car mileage, for which a reduction from the average is considered to account for sustained fast driving typical of freeways, estimating a specific fuel consumption of 18 kWh_{el}/100 km.

Finally, the specific cost of electricity at charging points depends upon the generation cost, the transmission and distribution fee, and the additional infrastructure cost. Moreover, premium pricings are typically added for the fast-charging options; however, this cost component is highly commercially-dependent and is neglected here for simplicity. The first two elements vary depending on the charging connection and the user type, whereas the third relates to the dispensed electric energy by each charger type. To establish the generation cost, the average levelized cost of electricity (LCOE) is computed on the basis of the generation shares obtained from the energy balance simulations. A unique country-wide value valid in all zones is defined, in line with the Italian policy of uniform national price ('Prezzo Unico Nazionale', PUN). Data for the LCOE of the different sources are taken from [44] as reported in Table 9 (although the forecasts to 2050 are inherently uncertain, the values are in line with other projections, such as [86]).

Table 9 – Levelized cost of electricity in 2050, by source.

Energy source	**LCOE**
Solar PV	55 €/MWh_{el}
Wind onshore	72 €/MWh_{el}
Wind offshore	90 €/MWh_{el}
Geothermal	81 €/MWh_{el}
Renewable hydro	118 €/MWh_{el}
Natural gas (combined cycles, with carbon capture)	113 €/MWh_{el}

To account for the transmission and distribution fee, the analysis looks at the ratio between final user price (excluding taxes and levies) and generation cost, as obtained from the historical time series [87,88]. The procedure implies a situation similar to today's structure, assuming the market price as an indicator of generation cost and following the existing structure that assigns a category to each consumer based on the annual consumption. For the Mode 1-Mode 2 charging at or close to home, the connection is assumed to belong to a high-consumption category of the household sector. Mode 3 and Mode 4 chargers fall within the non-household sector: charging points in cities are considered to belong to a low-consumption category (like a small factory), whereas freeway stations are treated as mid-category connections. This results in a transmission fee equal to 98%, 64%, or 23% of the generation cost, respectively.

When assessing the shares of each charging mode, passenger cars with a home charging option (60% of the total, see above) rely on that for 55% of the charging needs, whereas the remaining occurrences exploit fast charging in the city (27%) or along freeways (15%). Public Mode 3 charging covers only occasional charging events, comprising up to 3% of the total charging demand. The long-term perspective foresees PEV deployment even in the absence of a home charger; these cars (40% of all PEVs in the simulated scenarios) are assumed to rely mostly on fast charging in city (82%), then along freeways and using Mode 3 charging points in cities with the same shares considered for home charging-equipped cars.

5. Simulation results

The study investigates three cases, which differ by the stock shares of low-emission vehicles. In each case, first, the year-long power system balance is simulated, taking into account the electricity demand from the transport sector (PEV charging and HRS operation) and including the estimation of P2G installed capacity under the given constraints. Then, infrastructural needs are evaluated with the proposed method on the basis of the FCEV and PEV fleets. Finally, the economics of the resulting system is assessed.

5.1. Case A: 50% FCEVs and 50% ICEVs

Looking at the case of an exclusive deployment of FCEVs as a clean alternative for passenger cars, the additional electric load affecting the electricity balances is made of the distributed HRS consumption for hydrogen compression and dispensing, equal to 2.9 TWh_{el}/y in the country (considering the highest value of

HRS specific demand, corresponding to GH2 fuel stations). If all hydrogen had been produced domestically via electrolysis, the corresponding electricity consumption would have been about 77.8 TWh_{el}/y (based on the hydrogen demand and the electrolyzer efficiency, see Table 3 and Table 4). However, electrolyzer operation is constrained by the availability of excess renewable generation, which is the only allowed domestic production pathway (any residual hydrogen demand is satisfied via import); hence, the actual electricity consumption is lower (see 'Recovered surplus electricity' in Table 10). The year-long energy balances provide available surplus electricity in the order of 96.3 TWh_{el}/y in the country, corresponding to about 30% of the annual consumption (grid + mobility, excl. electrolysis) and to 36% of the total wind and solar generation. In the absence of constraints, this would lead to a theoretical hydrogen production of about 2000 kt_{H2}/y. However, given the inter-nodal power transfer limits and the EFLH constraints, the potential production reduces to nearly 1500 kt_{H2}/y, exploiting about 73% of the available overgeneration (note that the energy demand for the liquefaction process downstream the electrolysis is included in the evaluation, leading to an overall electricity-to-LH2 process with 60% efficiency, which influences the EFLH constraint effect).

Concerning the power sector, the RES share is equal to 68.5%, showing how overgeneration becomes significant well before approaching the target of a 100% renewable-based electricity generation. Under the current installation trend and forecast, biomass plants could provide a share of 4-6% of the electric demand. The rest comes from natural gas-fired combined plants, which are assumed as the average fossil fuel solution in Italy, given the absence of nuclear and the ongoing decommissioning of coal (a different energy system evolution may involve installation of CCS-equipped plants, import under zero-carbon contracts, more extensive grid expansion, additional energy storage technologies, or a combination of all these).

At the zone level, the RES share on electricity consumption varies significantly, with a detrimental effect by the impossibility to provide large amounts of clean power to the northern regions where the demand is the highest. Table 10 summarizes the main zonal results. The little overgeneration in the zone 'NORD' leads to no installations of P2G due to the impossibility of satisfying the EFLH requirements.

Table 10 – Power sector simulation results, by zone, in case A.

	RES share	Total surplus electricity	Installed P2G capacity	Recovered surplus electricity	Curtailment
NORD	52.5 %	3.8 TWh_{el}/y	0.0 GW	0.0 TWh_{el}/y	3.8 TWh_{el}/y
C-NOR	80.3 %	5.5 TWh_{el}/y	0.0 GW	0.0 TWh_{el}/y	5.5 TWh_{el}/y
C-SUD	86.9 %	6.4 TWh_{el}/y	0.0 GW	0.0 TWh_{el}/y	6.4 TWh_{el}/y
SUD	94.4 %	40.9 TWh_{el}/y	17.5 GW	35.1 TWh_{el}/y	5.8 TWh_{el}/y
SICI	92.3 %	20.1 TWh_{el}/y	8.7 GW	17.5 TWh_{el}/y	2.6 TWh_{el}/y
SARD	98.7 %	19.7 TWh_{el}/y	8.5 GW	17.2 TWh_{el}/y	2.5 TWh_{el}/y
Total Italy	68.5%	96.3 TWh_{el}/y	34.7 GW	69.7 TWh_{el}/y	26.6 TWh_{el}/y

From the economic optimization, the hydrogen production via P2G (electrolysis) is equal to 1282 kt_{H2}/y, covering 72.8% of the total, taking into account intermediate losses. The residual amount is satisfied via ship import. The required hydrogen infrastructure is detailed in terms of size and investment cost in Table 11 for the two considered options of hydrogen delivery described in Section 4.1. The terms 'transmission' and 'distribution' refer to long-haul high-volume transport and short-distance transport, respectively, reflecting the nomenclature of the power and the natural gas grids. Both alternatives involve transmission up to a hub at the province scale plus local ‘last mile’ distribution via truck. Where a number of trucks is indicated, it corresponds to the total number of trailers required to supply the yearly demand.

Table 11 – Technical features and investment cost of the hydrogen infrastructure in case A, in the two options of GH2 and LH2 delivery.

			GH2 pipe + GH2 truck	**LH2 truck**
Size	*Electrolyzer capacity*		34.7 GW	
	LH2 storage tanks		241 kt_{H2}	
	Transmission		4666 km pipelines	3812 trucks
	Distribution		3254 trucks	
	Number of HRS		6888	
Investment cost	*Production*	*Electrolyzers*	15.26 G€	15.26 G€
		Ports	0.19 G€	0.17 G€
	Conditioning		10.16 G€	8.30 G€
	Storage		8.68 G€	8.68 G€
	Transmission		2.94 G€	3.89 G€
	Distribution		2.67 G€	
	HRS		6.30 G€	6.30 G€
	Total		46.19 G€	42.60 G€

The pipeline network structure obtained from the infrastructure optimization for the GH2 delivery options is represented in blue in Figure 5, where line width corresponds to pipeline capacities (the scale is exponential) and province color reflects the hydrogen demand (the darker, the greater, see Figure 3). It can be noted that the backbone pipelines are the north-south connection, with especially large capacities in the central-northern area (Tuscany region, which includes Livorno where the hydrogen import port was assumed to be located). It can be noted that the high RES capacity in the Sardinia island leads to a large overgeneration and, therefore, to a significant hydrogen production that must be transferred to the mainland.

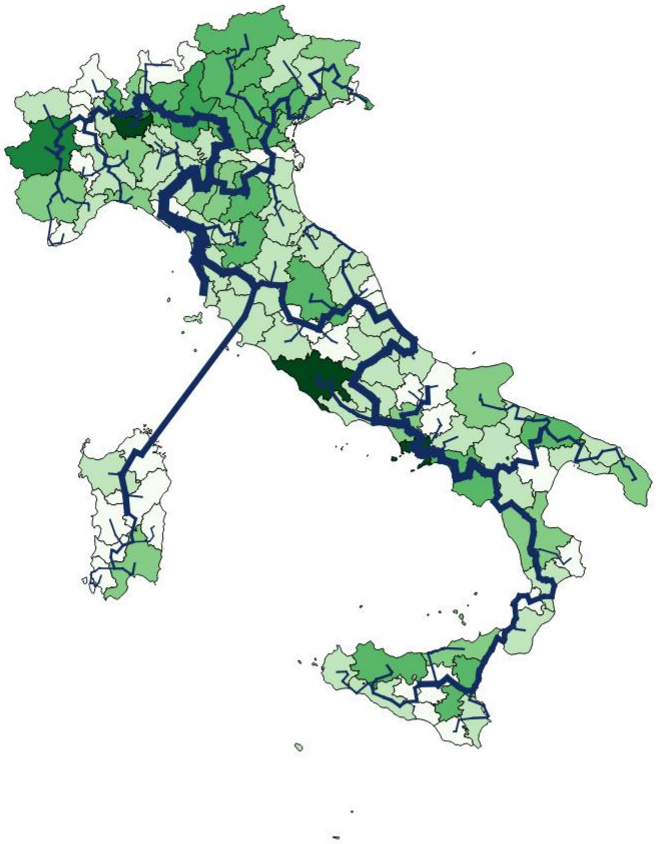

Figure 5 – Geographical layout of the hydrogen pipeline network in the 'GH2 pipe + GH2 truck' option, case A.

Figure 6 shows the hydrogen cost in the two options, by component. The 'transmission' term refers to the pipelines, while the 'distribution' term accounts for the truck-based transport. The LH2 delivery option offers a smaller total cost of hydrogen, featuring a reduction of about 6% with respect to the GH2 delivery. The advantage is mainly due to the intermediate step of liquefaction, which is always included for storage purposes. Indeed, the use of gaseous storage implies additional investment and operational costs for intermediate evaporation and compression that are not present when adopting LH2 delivery. For comparison, the alternative option of combining GH2 delivery and aboveground gaseous storage tanks was simulated, leading to a storage cost component of nearly 5 €/kg_{H2}, which is significantly larger than the values for liquid storage, even considering the liquefaction (the sum of storage and conditioning amounts to 1.89-2.38 €/kg_{H2}). On the opposite, if proper locations existed for salt caverns, the storage cost component would drop to 0.10 €/kg_{H2} (estimation based on specific CAPEX values from [27]). As already mentioned, an intermediate situation is expected for solutions based on artificial caverns (LRC), which are not considered in this work.

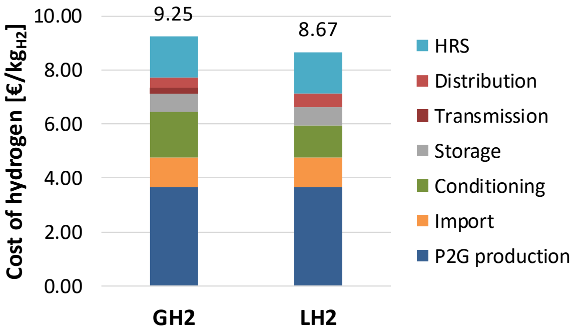

Figure 6 – Hydrogen cost, by component, for the two hydrogen delivery options, in case A. The 'Conditioning' component includes only liquefaction in the LH2 case (for storage and delivery), while it comprises liquefaction (for storage) and compression (for delivery) in the GH2 case.

The P2G production term is the most significant cost component in the hydrogen cost. Therefore, it is interesting to assess its potential improvement. The considered investment cost of electrolyzers already takes into account the long-term projections of cost reduction, so these components should not have further decrease margins. Hence, it is straightforward to address the operational costs and vary the cost of the electricity fed to the electrolyzers. In a long-term vision of the energy markets, the added value of electrolyzers as flexibility-enhancing components will enable additional revenues and/or access to lower electricity prices through the provision of grid services. Moreover, the assumed value of 0.06 €/kWh_{el} is equal to today's average market price, but the LCOE of solar and wind power plants is quickly decreasing and recent studies predict long-term values for solar PV in the range of 0.02-0.04 €/kWh_{el} [89–91]. Therefore, new simulations are performed that assess the effects of a lower cost of the electricity fed to electrolyzers and adjacent liquefaction plants. The infrastructure layout does not vary because there are no changes in the underlying assumption of priority to the local production from available surplus electricity; hence, the energy balances do not change and production and demand points remain the same. Figure 7 shows the country-averaged hydrogen cost, by component, when the cost of the electricity fed to electrolyzers and liquefaction plants is set to 0.03 €/kWh_{el}. The change significantly impacts the results, reducing the final cost of hydrogen at values close to 8 €/kgH2, closer to the targets for a sustainable market diffusion.

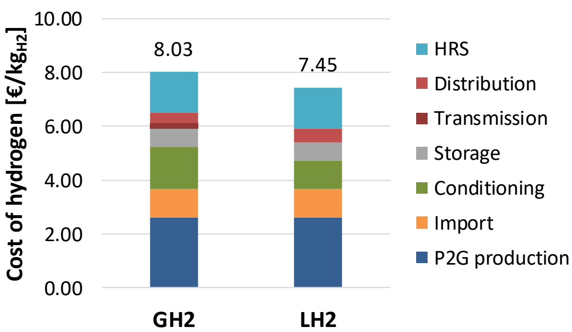

Figure 7 – Hydrogen cost, by component, for the two hydrogen delivery options, when the cost of electricity is 0.03 €/kWh_{el}, in case A.

Further advantages could be achieved by constraining the electrolysis sizing to guarantee a larger EFLH value (e.g., 3000 h/y) based on the available surplus electricity. However, this would lead to a smaller installed capacity, limiting the recovery of clean excess generation and requiring a larger hydrogen import.

5.2. Case B: 50% BEVs and 50% ICEVs

If the passenger car evolution is pushed onto BEVs only, the additional electric load corresponds to the charging needs. With the given assumptions, at 50% passenger car stock share, such demand is 25.6 TWh_{el}/y, equal to about 8% of the non-mobility consumption.

With the assumed power generation scenario, the energy balance simulation yields a RES share of 66.3% as the country average. This is the lowest value among the three analyzed cases and it is coherent with the largest increase of the electrical demand. On the opposite, the total surplus electricity is the smallest (88.4 TWh_{el}/y); however, it is still a significant amount (about 26% of the total grid+mobility consumption or 33% of the total solar and wind generation) and it is completely lost. Also, no P2G capacity is installed, although the overgeneration could feed up to 32.4 GW of electrolyzers within the EFLH constraints. Results by zone are provided in Table 12, where the column detailing the surplus electricity represents lost energy (obviously, such a scenario is unfavorable in terms of curtailment, unless other storage technologies are introduced to recover such a large amount of clean electricity).

Table 12 – Power sector simulation results, by zone, in case B.

	RES share	**Total surplus electricity**
NORD	49.8 %	2.7 TWh_{el}/y
C-NOR	77.0 %	4.6 TWh_{el}/y
C-SUD	84.7 %	5.3 TWh_{el}/y
SUD	93.7 %	38.1 TWh_{el}/y
SICI	91.3 %	18.9 TWh_{el}/y
SARD	98.2 %	18.8 TWh_{el}/y
Total Italy	66.3 %	88.4 TWh_{el}/y

The required infrastructure that satisfies the charging needs is composed of about 11.2 million EVSE to be installed at household plus over 900,000 Mode 3 and 380,000 Mode 4 charging points in the urban and semi-urban environment, whereas charging along freeways is supplied by means of about 9400 chargers to be hosted in 526 stations. Figure 8 illustrates the number of charging points and the corresponding investment cost. At the country scale, the investment cost sums up to 41.9 G€. This estimated investment cost refers only to PEV chargers, neglecting the additional cost components related to grid reinforcement, which were estimated in the range 50-60% of the cost of the chargers in the study about Germany [28]. Considering that the grid extension is comparable between the two countries (e.g., total length of low-voltage lines close to 1 million km) and the structure is similar (e.g., the ratio between low-voltage and medium-voltage lines is 2.34 in Germany vs. 2.23 in Italy), taking into account the conservative value of 50%, the total investment cost becomes 62.8 G€, which is 36-47% larger than the values obtained for the hydrogen infrastructure in case A. Note also that the hydrogen infrastructure assessment considers the entire supply chain, including the production facilities (electrolyzers), while the PEV total cost neglects the additional power plants that may be needed to comply with the electricity generation demand.

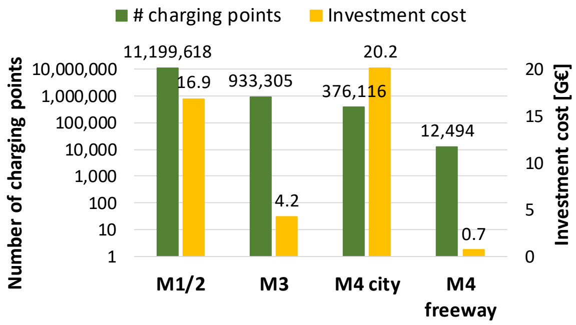

Figure 8 – Number of PEV charging points and related investment cost, in case B.

Looking at the final cost of the energy vector at charging points, the average LCOE is 87.90 €/MWh$_{el}$, based on the generation shares (see Section 4.2 for the calculation method). Household chargers are assumed to cover 60% of the fleet and an additional 70% utilization factor is introduced to account for the occasional need for charging elsewhere, making them responsible to feed about 42% of the annual PEV electricity consumption in the country. Taking into account the oversizing factor and the estimated traveled distances on freeway sections, freeway charging stations dispense about 20% of the passenger car electrical demand. The remaining is supplied via Mode 3 and Mode 4 chargers in cities, which cover 6% and 32% of the load, respectively. The resulting specific cost of electricity at the charging point is displayed in Figure 9 (values consider the infrastructure but do not include taxes and levies). Private chargers have the advantage of a low investment cost, which overcomes the larger transmission and distribution fee. Charging along freeways shows a low total cost thanks to a relatively low number of chargers that guarantee network coverage. However, given the monopolistic operation of service areas, the calculated cost value at freeway locations may not be a proper indicator of the hydrogen price for the final user.

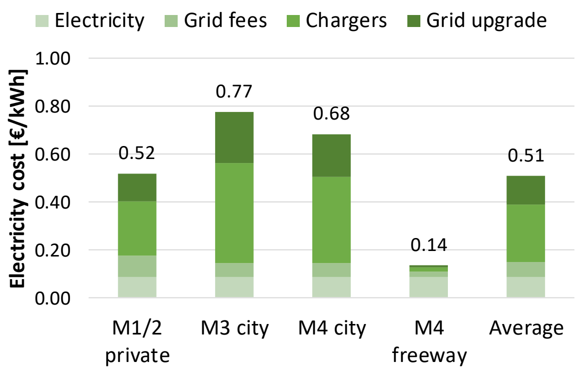

Figure 9 – Specific cost of electricity at charging points, by charger type, in case B.

5.3. Case C: 25% FCEVs, 25% BEVs, and 50% ICEVs

The third simulated case investigates a combined development of hydrogen and electricity as energy vectors for clean mobility.

The effect on the power sector is an intermediate increase of demand with respect to case A and case B, with overall additional consumption of 14.3 TWh$_{el}$/y (12.8 TWh$_{el}$/y for PEV charging and 1.4 TWh$_{el}$/y for HRSs). At the country level, the RES share on electricity consumption is 67.4%, with the same zonal differences seen in the previous simulations (see Table 13). The overall surplus generation is 92.2 TWh$_{el}$/y, corresponding to about 28% of the total electricity demand and to about 34% of the total wind and solar generation. With respect to case A, the RES overgeneration decreases by 4%, whereas it increases by 4% if compared to case B.

Here, P2G operation is capable to recover up to 67.4 TWh_{el}, i.e., it absorbs 73% of the overgeneration, satisfying the entire mobility hydrogen demand in the country without the need of import.

Table 13 – Power sector simulation results, by zone, in case C.

	RES share	Total surplus electricity	Installed P2G capacity	Recovered surplus electricity	Curtailment
NORD	51.1 %	3.2 TWh_{el}/y	0.0 GW	0.0 TWh_{el}/y	3.2 TWh_{el}/y
C-NOR	78.7 %	5.0 TWh_{el}/y	0.0 GW	0.0 TWh_{el}/y	5.0 TWh_{el}/y
C-SUD	85.9 %	5.8 TWh_{el}/y	0.0 GW	0.0 TWh_{el}/y	5.8 TWh_{el}/y
SUD	94.1 %	39.4 TWh_{el}/y	15.7 GW	33.7 TWh_{el}/y	5.7 TWh_{el}/y
SICI	91.8 %	19.5 TWh_{el}/y	7.9 GW	16.9 TWh_{el}/y	2.6 TWh_{el}/y
SARD	98.5 %	19.2 TWh_{el}/y	8.0 GW	16.7 TWh_{el}/y	2.5 TWh_{el}/y
Total Italy	67.4 %	92.2 TWh_{el}/y	31.6 GW	67.4 TWh_{el}/y	24.8 TWh_{el}/y

The results in terms of hydrogen infrastructure size and investment cost are summarized in Table 14. Production via electrolysis systems is sufficient to cover the demand, without the need for any ship import. It is evident how the hydrogen delivery system is affected by the economies of scale: in the presence of a halved FCEV fleet (change from case A to case C), the investment cost decreases only by 35-37%. For the GH2 case, this is consistent with the fact that the overall pipeline network structure (length and size) does not vary significantly.

Table 14 – Investment cost and specific hydrogen cost, by component, in the 'GH2 pipe + truck' delivery option.

			GH2 pipe + GH2 truck	LH2 truck
Size	*Electrolyzer capacity*		31.6 GW	
	Storage tanks		233 kt_{H2}	
	Transmission		4404 km pipelines	1924 trucks
	Distribution		1620 trucks	
	Number of HRS		3431	
Investment cost	*Production*	*Electrolyzers*	10.43 G€	10.43 G€
		Ports	-	-
	Conditioning		7.45 G€	6.24 G€
	Storage		4.32 G€	4.32 G€
	Transmission		2.23 G€	1.96 G€
	Distribution		1.33 G€	
	HRS		3.34 G€	3.34 G€
	Total		29.11 G€	26.29 G€

Figure 10 illustrates the hydrogen pipeline network resulting from the infrastructure optimization for the GH2 delivery option, with the same graphical conventions and scales used in Figure 5. With respect to case A, here the absence of any import need is shown by the different infrastructure layout in the central-northern part (no coastal path from the Livorno port to the main pipeline). Moreover, the reduced overall number of vehicles in the country and the limited relative quantities in the southern provinces is reflected in the identification of isolated sections featuring pipelines with small capacities.

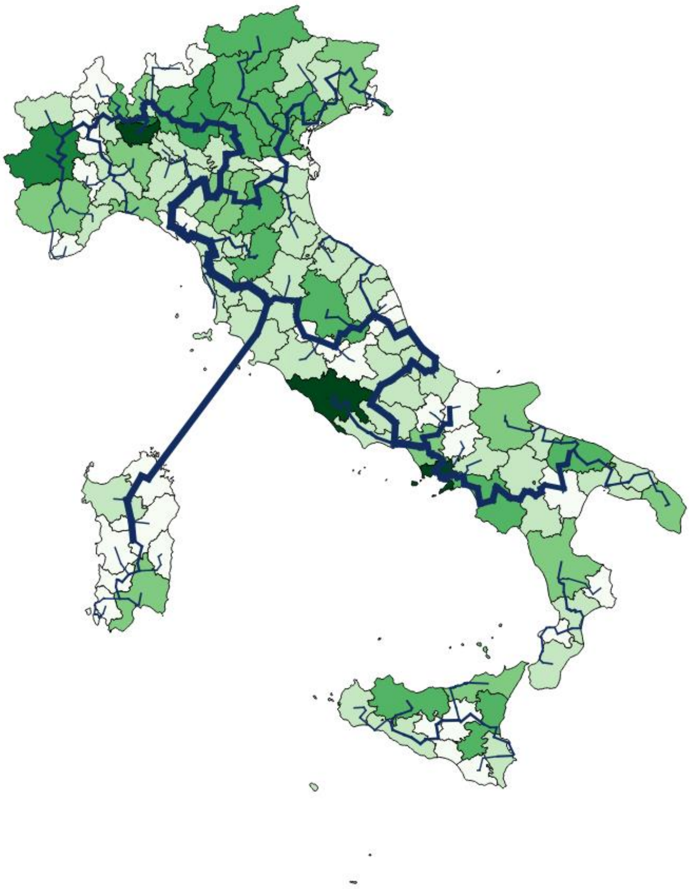

Figure 10 – Geographical layout of the hydrogen pipeline network in the 'GH2 pipe + GH2 truck' option, case C.

Figure 11 shows the hydrogen cost in the two options, by cost component. Overall, hydrogen is 12-13% more costly than in case A, due to the reduced advantages by economies of scale. The role of P2G on the hydrogen specific cost is higher than in case A (about 50% instead of about 40%), because here this technology is responsible for all hydrogen production but it has a cost per kg higher than the assumed hydrogen import cost. Again, a relevant cost component is the conditioning, which involves liquefaction for most of the produced hydrogen since the storage is assumed in the liquid phase.

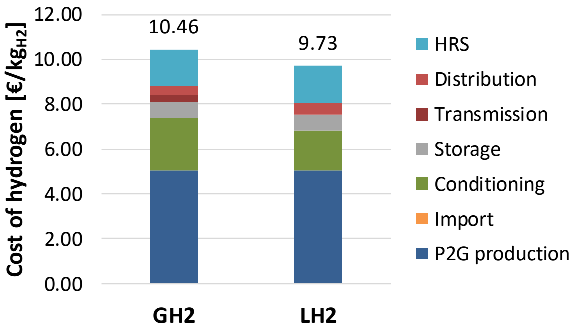

Figure 11 – Hydrogen cost, by component, for the two hydrogen delivery options, in case C. The 'Conditioning' component includes only liquefaction in the LH2 case (for storage and delivery), while it comprises liquefaction (for storage) and compression (for delivery) in the GH2 case.

Analogously to case A, hydrogen cost is further evaluated considering a cost reduction for clean otherwise-curtailed electricity that feeds electrolyzers and liquefaction plants. The resulting effects are in line with those discussed in Section 5.1, as shown in Figure 12.

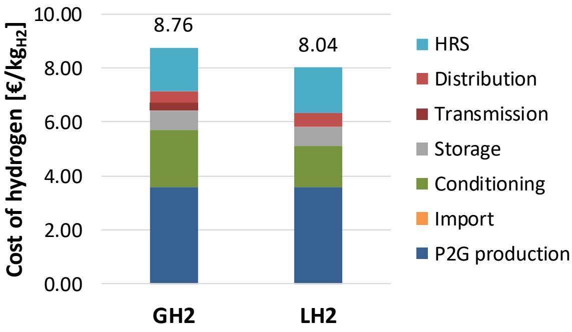

Figure 12 – Hydrogen cost, by component, for the two hydrogen delivery options, when the cost of electricity is 0.03 €/kWh$_{el}$, in case C.

In this case, both a hydrogen delivery infrastructure and a PEV charging network are required. The charging infrastructure is detailed in Figure 13: comparing to case B, the number of chargers decreases approximately linearly with the fleet reduction, as expected. However, the request to uniformly cover the charging capability along freeways imposes a constant number of stations (placed on the same basis of an assumed average distance equal to 30 km) and the line upgrade depends upon the location rather than upon the exact number of charging connections installed. The estimated investment cost is 21.0 G€ for the chargers. Taking into account the 50% additional cost related to grid improvement (electric lines, management devices, transformers), the total investment cost for the PEV charging infrastructure is 31.4 G€.

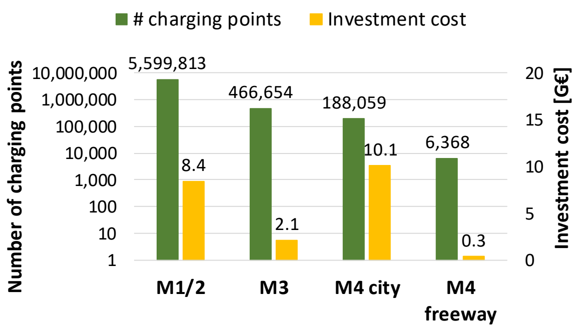

Figure 13 –Number of PEV charging points and related investment cost, in case C.

The specific cost of electricity at charging points is depicted in Figure 14. The average LCOE is 87.64 €/MWh$_{el}$, based on the generation shares of the different technologies obtained from the simulation (see Section 4.2 for details of the calculation method). The distribution of charging modes is similar to that of case B, due to the consistency of assumptions: about 42% of the annual PEV electricity consumption is dispensed by Mode 1 or 2 chargers at households, 5% in cities by Mode 3 chargers, and 53% by Mode 4 fast-charging points. The values of electricity cost are in line with the results of case B, reflecting the modularity that characterizes the PEV charging infrastructure.

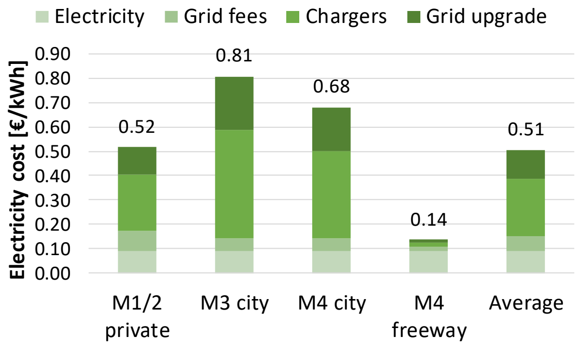

Figure 14 –Specific cost of electricity at charging points, by charger type, in case C.

In conclusion, in the case of a passenger car stock comprising 25% PEVs and 25% FCEVs, the total cost of infrastructure is the sum of the hydrogen supply network and the PEV charging points. This adds up to 60.5 G€ or 57.7 G€, depending on the hydrogen delivery option. Hence, in terms of investment cost, the combined presence of FCEVs and BEVs is 35% more costly than a hydrogen-only market evolution (case A) and 8% less expensive than a BEV-only passenger car fleet (case B). Looking at the specific cost of the energy vectors at the final delivery point, hydrogen cost increases by 12-13% from case A, due to limited economies of scale when the fleet reduces, whereas electricity cost is nearly the same as in case B. Converting the energy vector specific cost into a cost per traveled km, hydrogen and electricity are closely comparable in case C (see Section 6).

6. Comparison and discussion

In this section, the three cases are compared. Table 15 summarizes the main results from the simulations, in terms of infrastructure size and characteristics, investment costs, and specific costs of the delivered energy vectors. For the hydrogen infrastructure, the data consider only the lowest-cost hydrogen delivery option to simplify the table and improve readability. The cost of electricity to PEVs is calculated as an average among the different charging modes, according to the assumed fractions of at-home, in-city, and on-freeway charging events, as discussed in Section 4.2. The cost per traveled km weighs the specific cost of each energy vector on the consumption of the associated car type.

The hydrogen delivery infrastructure suffers from low modularity, due to seasonal storage and large transfer capacity that do not scale linearly with the vehicle fleet, as shown by the increase of hydrogen cost in case C. This low modularity is more challenging at very small demands, but the relevant economies of scale also leads to much lower specific costs at high throughputs, as highlighted by the lower values in case A. On the contrary, above some minimum requirements for vehicles spreading at low penetration shares, such as the distance among stations on freeways, PEV charging points offer scalability; however, this happens at a higher total cost, as evident in case B. The combination of the two infrastructures (case C) appears more costly than a full-hydrogen development (case A) but less expensive than a BEV-only option (case B). An FCEV/BEV ratio equal to one reduces the investment cost from the case of exclusive presence of BEVs, while keeping the same average energy vector cost per traveled km. Indeed, the average value benefits from the lower costs of the hydrogen section.

This means that, in a likely market-driven fleet development that will involve both vehicle options, the infrastructure is a challenging aspect whose economical optimum relies on the identification of synergies, also considering the possibility of a lower price of the electricity fed to electrolyzers if it is valued as a recovery of otherwise-lost generation (see Figure 7 and Figure 12). Given the lower cost per km of hydrogen in presence of a sufficiently large number of FCEVs, a combination with a FCEV/BEV ratio higher than 1 could reduce the overall costs.

Table 15 – Comparison of results in the three analyzed cases.

		Case A	Case B	Case C
H_2 demand	*kt_{H2}/y*	1519	-	760
PEV electricity demand	*TWh_{el}/y*	-	25.6	12.8
P2G capacity	*GW_{el}*	34.7	-	31.6
RES share in electricity consumption	*%*	68.5%	66.3%	67.4%
Domestic RES share in H_2 demand	*%*	72.3%	-	100.0%
H_2 delivery infrastructure investment cost	*G€*	42.6	-	26.3
Hydrogen cost at HRS	*€/kg*	8.67	-	9.73
	€/km	0.056	-	0.063
PEV charging infrastructure investment cost	*G€*	-	62.8	31.4
Electricity cost at EVSE	*$€/kWh_{el}$*	-	0.507	0.507
	€/km	-	0.064	0.064
Total investment cost for low-emission mobility infrastructure	*G€*	42.6	62.8	57.7
Average cost of energy vectors for low-emission mobility	*€/vehicle/y*	615.15	696.17	692.95
	€/km	0.056	0.064	0.063

To assess the magnitude of the discussed investments, the values could be compared to other country-scale infrastructural interventions, such as replacements and upgrades in the power grid or in the natural gas pipeline network. The multi-year programs of the network system operators are typically in the range of € billion. The latest industrial plan of the Italian electricity TSO (*Terna SpA*) foresaw investments for about 6.2 G€ between 2019 and 2023 [92]. Similarly, the Italian natural gas grid TSO (*Snam SpA*) has an ongoing plan for 6.5 G€ investment to upgrade the infrastructure between 2019 and 2023 [93]. Furthermore, the RES installed capacities that characterize the power sector in the studied scenarios involve an investment cost of nearly 120 G€ (assuming a long-term specific cost of 600 €/kW$_p$ for solar PV and 1200 €/kW for wind plants and considering only the newly-built capacity). By this point of view, the cost for the mobility infrastructure would be in the range of 35% to 52% of the new electric RES capacity investment cost, respectively in the case of hydrogen delivery to FCEVs or electricity provision to PEVs. As a final comparison term, the investment cost could be assessed against the country's gross domestic product (GDP), which was approximately 1700-1800 G€ in recent years [94]. Therefore, the investment cost for the analyzed cases is in the range of 2.5-3.5% of the GDP. If the investment could be spread over 20 years and the GDP is assumed to remain constant, the annual impact is below 0.17% of the GDP. Furthermore, the infrastructure build-up would consitute an economic stimulus and lead to a GDP growth as well.

7. Conclusions

The study presented in this work investigated the infrastructure development involved with the distribution of energy vectors for clean mobility, focusing on hydrogen and electricity as main solutions for the decarbonization of the passenger car stock. The analysis considered a long-term situation of integrated energy sectors and interwoven energy vectors, where hydrogen is produced primarily from surplus power generation by intermittent RES. The study developed modeling scheme based on the integration of (i) energy system simulation at the nation scale, (ii) optimal hydrogen delivery infrastructure assessment, and (iii) plug-in vehicle charging needs evaluation.

The case of Italy was investigated, looking at a long-term scenario that features a strong increase in the installed capacity of RES power plants as well as a massive introduction of low-emission vehicles, in accordance with national plans that aim at 30% renewable energy by 2030 and in line with EU targets that require to widen the decarbonization beyond the power sector.

The analysis showed that the impact of mobility technologies on power balances is significant, affecting both the exploitation of renewable generation and the grid. Results indicated that, when a considerable fraction of low-emission passenger cars is deployed, the infrastructural requirements are relevant and bring about significant costs (investment in the range 43-63 G€). At a 50% share of clean mobility, the exclusive presence of FCEVs implies lower investment and energy vector costs, whereas the full reliance on BEVs involves the most significant cost. Scenarios that combine FCEVs and BEVs allow to reduce the investment cost in-between the two extreme cases, although keeping the mean energy vector cost per traveled km close to the BEV-only case. Such a combined solution shows that the overall power+mobility system benefits from the presence of both drivetrain options. Hence, openness to technologies is strategically preferable, in order to avoid technology bias, especially at an early stage of development of the diverse options. Indeed, a varied vehicle stock country-wide could take advantage of both economies of scale related to a large-scale cost-efficient hydrogen delivery network and modularity linked to strategically located PEV charging.

When compared to other infrastructural interventions like power grid or natural gas network upgrading in the same country, the costs for the delivery infrastructure of clean energy vectors to mobility do not appear unbearable, also given the long period available to distribute them. A proper long-term planning and a synergistic approach are essential to provide a best-case solution where the combination of technologies and energy vectors offers the highest benefits, also taking into account further sectors that easily integrate and reduce the cost impact (steel industry, production of chemicals, possibly also residential uses).

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