Design and Optimization of a Multi-Mode Hydrogen Delivery Infrastructure for Clean Mobility

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ABSTRACT

This work addresses the infrastructural needs arising from the widespread deployment of hydrogen for clean mobility, by developing a model to optimize the design and operation of a hydrogen distribution infrastructure. The developed tool combines the use of detailed spatial data through a Geographic Information System to define the candidate networks' topologies and the resolution of a multi-modal transport optimization model to determine the cost-optimal infrastructure, considering a year-long time horizon with daily resolution.

The analysis looks at a 2050 scenario with a 25% share of fuel cell electric vehicles among passenger cars, considering the Italian region of Lombardy as case study. Results show the advantages of infrastructural integration in terms of modalities and delivery areas. The resulting optimal infrastructure relies on the parallel use, with a specific mix, of all transport modalities (pipelines, compressed hydrogen trucks, and liquid hydrogen trucks), achieving an average cost of hydrogen production and delivery between 5 €/kg and 8 €/kg.

KEYWORDS

Hydrogen, Infrastructure, Geographic Information System, Optimization, Supply chain, Clean mobility.

INTRODUCTION

In order to meet the ambitious target of neutral carbon balance set by the European Green Deal [1], the Member States of the European Union (EU) are required to undergo a paradigm-shifting energy transition that will reshape the way energy is generated, stored, and consumed in all sectors. The decarbonization of transportation will be a crucial achievement, as it is responsible for more than 30% of CO_2 emissions in Europe [2]. Battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs) are considered the two main alternatives for clean mobility, both offering zero tailpipe emissions. Although BEVs are experiencing an earlier commercialization, benefitting from the exploitation of an existing infrastructure for the delivery of the energy vector, over the last few years the interest in FCEVs has steadily increased thanks to the higher milage and faster refuelling, together with the possibility to decarbonize heavy-duty transport, for which the employment of battery-based vehicles appears less realistic [3], as well as part of the fleets of buses for public transport and part of the current non-electrified diesel railways. Accordingly, hydrogen has been included in the policies of several countries, and more than 15,000 hydrogen refuelling stations are forecasted to be deployed in Europe by 2040 [4]. However, a major obstacle is represented by the chicken-and-egg dilemma, for which FCEVs cannot experience large-scale adoption as long as a dedicated infrastructure is missing, and, at the same time, the realization of a hydrogen delivery infrastructure is not economically

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sustainable as long as FCEVs and the consequent hydrogen demands are not sufficiently widespread. Within this framework, the present work develops a model able to optimize the design and operation of the overall hydrogen supply chain, from production sites to hydrogen refuelling stations (HRS), aiming at providing a tool to evaluate the techno-economic issues of hydrogen distribution and assist the deployment of a hydrogen infrastructure for clean mobility. Such task is particularly challenging, since each stage of the supply chain features multiple alternatives, each of which is characterised by different advantages and drawbacks, as well as costs and a diverse positioning in terms of industrial maturity.

The existing literature on this topic is quite heterogenous, as each work features distinctive assumptions and approaches, addressing the complexity of different aspects. In the remainder of this section, the main proposed approaches are outlined, highlighting the simplifications that are commonly introduced when modelling the hydrogen supply chain.

Most of the studies deal with optimization models, in which the objective is typically the minimization of the annual infrastructure cost, although in some cases environmental, safety, or financial concerns are included in multi-objective optimizations [5]–[15].

An important aspect is how the time dependency of quantities is handled. The most common approach is to consider a snapshot, i.e., a representative steady-state condition in which quantities and demand are time-invariant [5], [6], [11], [16]–[32]. The studied condition is usually identified as the “worst moment” throughout the year in terms of high demand and/or low production, and the network components are sized according to what should be the most stressful situation. However, this approach fails to track the optimal introduction and usage of storage units, and storage facilities are often sized according to exogenous parameters, for example, by setting the capacity equal to a certain multiple of the daily hydrogen production [25], [31], [32]. A more precise, yet computationally demanding, method is to consider a year-long analysis, tracking the variation of quantities according to a certain time resolution, which can be monthly [33], daily [34], or hourly [35].

Another challenge in modelling hydrogen transport is to include the multiplicity of delivery modes, which requires the introduction of a formulation that optimizes also the selection of the transport technology for each stage of the supply chain. In most works, such selection is imposed and each analysis assumes a single mode [16], [18], [20], [25]–[27], [29], [31], [32], [36]. Despite simplifying the formulation, this method may result in a sub-optimal design.

Finally, profound differences are observed regarding the spatial scale of the models. Many authors follow the simplified approach of considering extremely schematized networks, sometimes oversimplified and thus not representing actual territorial constraints. A more accurate method is to rely on a Geographic Information System (GIS) to define the candidate infrastructure network, starting from detailed spatial data [9], [24], [25], [27], [28], [32], [35], [37]–[39]; however, this may lead to models of high computational complexity.

The aim of this work is to propose an accurate model able to fill the research gaps that emerged from the analysis. This is done by developing a modelling tool that includes a multi-transport modality formulation, a detailed spatial description, and a time-dependent analysis of the infrastructure operation. The model features multiple hydrogen source points, as well as distinct pathways to connect them to hydrogen sinks, depending on the transport modality exploited. In particular, pipelines, compressed hydrogen trucks, and liquid hydrogen trucks delivery are included in the analysis, the first operating on a different network with respect to the last two. Hydrogen sources have different capacity limits and production profiles according to both the production technology and the location. In particular, steam methane reforming (SMR) equipped with carbon capture and storage (CCS) and solar PV-fed electrolysis systems are considered. For the former, a flexible operation within the assigned capacities that relate to those of existing plants in the country is assumed, while, for the latter, the production depends on the PV electricity generation, which varies according to solar radiation and location.

METHODS AND DATA

In this section, the methods developed to model the hydrogen supply chain are outlined, along with the main assumptions and data employed in the case study application. The modelling approach combines the use of detailed GIS spatial data to define the candidate networks' topologies with the resolution of a techno-economic optimization model to determine the cost-optimal infrastructure.

Options for the hydrogen supply chain included in the model

The modelled hydrogen supply chain includes the entire path: production, conditioning, storage, and transport up to refuelling stations. To ensure clean hydrogen production, SMR equipped with CCS and solar PV-fed electrolysis systems are the considered technologies. Other options (e.g., production from wind, biomass, biogas, waste-to-hydrogen or others) could be included in principle but are not considered for simplicity. As far as electrolysis is concerned, the integration of PV generation with grid electricity is allowed to ensure continuous operation, and revenues can be obtained from the sale of surplus electricity generation by the PV plants. A carbon tax is considered for the CO_2 emissions resulting from both the SMR production and the import of grid electricity, whose carbon intensity depends on the energy mix of the considered country. As far as the SMR plants are concerned, it is assumed to have a cap on the maximum capacity, related to the use of 20% of the current capacity of two centralized SMR plants that are already in operation in the region. The purpose of this choice is to investigate a long-term scenario where "blue hydrogen" has a baseline role while renewable-based hydrogen covers the majority of the demand, in line with the long-term EU perspectives [40].

Hydrogen can be delivered via pipelines, liquid hydrogen trucks (tanker trucks), or compressed hydrogen trucks (tube trailers). Conditioning is performed at production sites, obtaining either liquid or compressed gaseous hydrogen, depending on the subsequent transport technology. Similarly, hydrogen can be stored either as a liquid in cryogenic insulated tanks (-253 °C) or as a compressed gas in pressure vessels (160 bar) [41]. Storage facilities of both types can be installed at production sites, at intermediate storage hubs, and at refuelling stations. The different energy requirements of compression and liquefaction are accounted for considering the purchase of grid electricity, with the additional contribution due to the carbon tax.

In the case of road transport, both compressed and liquid hydrogen trucks are assumed to reach a single refuelling station or storage hub during each trip, where they completely empty their payload and then return back to the starting site (either a production site or a storage facility). Each refuelling station is supplied exclusively by one of the three transport modalities. The cost expenditures related to the hydrogen storage systems are considered, whereas the station structure is not detailed, since its presence is an input data and the installation cost does not vary significantly between the different types [25]. The hydrogen demand at each station is assigned as a daily amount, thus corresponding to the supply need and not to the exact car or bus or heavy vehicle fuelling, supporting the daily modelling approach. The values depend on both location and time.

The main techno-economic assumptions are reported in Table 1. In this work, a future 2050 scenario will be analysed, and, accordingly, the selection criterion is to exploit available projections or to adopt optimistic values among short-term estimates, relying on the fact that technology development and the increase of manufacturing volumes will lead to an improvement of efficiencies and to a decrease of costs. In order to have an uniform set of values, all costs are reported in $€_{2019}$ by means of historical inflation rates for both EU [42] and USA [43].

Table 1. Main techno-economic data.

Parameter	Value	Unit	Reference
Electrolysis CAPEX*	580	€/kW$_e$	[44]
Electrolysis consumption	49	kWh$_e$/kg$_{H2}$	[44]
Electrolysis-PV capacity ratio	0.5	-	[45]
LCOE PV	51	€/MWh$_e$	[46]
LCOE PV – CAPEX share	75%	-	[47]
Grid electricity purchase cost	150	€/MWh$_e$	Assumed
Electricity selling price	30	€/MWh$_e$	Assumed
SMR + CCS production cost	1.9	€/kg$_{H2}$	[48]
Liquid H_2 truck CAPEX	207	€/kg$_{H2}$	[31]
Liquid H_2 truck capacity	4.3	t$_{H2}$/vehicle	[31]
Compressed H_2 truck CAPEX	355	€/kg$_{H2}$	[49]
Compressed H_2 truck capacity	1	t$_{H2}$/vehicle	[49]
Gaseous H_2 pipeline CAPEX	$4 \cdot 10^3\ A + 336$ €/km, with A in m²		[26]
Carbon tax	90	€/t$_{CO2}$	[50]

*Includes stack replacement after 10 years

Network topology

According to the supply chain components included in the analysis, the nodes that constitute the candidate infrastructure network are of four types: transit, production, demand, and storage. The nodes modelling approach is represented in Figure 1, which shows the schematization of each type.

Transit nodes are those that result from the conversion of GIS data. They shape the transport pathways, but do not contribute to production, consumption, or storage of hydrogen.

Production nodes represent the sources of hydrogen in the network. Their capacity depends on the technology exploited and, in case of electrolysis powered by PV, also on the location. Conditioning is assumed to take place in the same facilities, and storage can be included, with a capacity that depends on both the plant size and the physical state of hydrogen [26].

Demand nodes are representative of refuelling stations and they are the hydrogen sinks in the network. They include some storage capacity, which is limited to the maximum expected daily demand in order not to model unrealistic stations, since their space availability is typically constrained. For each station, the demand profile depends on its location, i.e., on the number of FCEVs (either passenger cars or trucks and other vehicles with equivalent total hydrogen demand) and on the traffic intensity of the province.

Intermediate storage nodes play the role of decoupling hydrogen production and consumption. With respect to demand and production nodes, which also include storage, intermediate hubs have larger capacity limits and may benefit from more favourable positions, where hydrogen can be collected from different production sites to be redistributed later to refuelling stations.

As Figure 1 shows, except for transit nodes, each node type features a virtual sub-node, which connects the node with the others in the network by means of the network edges, and a storage section. According to such schematization, two mass balances can be written for each node, one for the virtual part and one for the storage section. In a general form, for each node n, edge e, transport mode m, and time step t, the two equations are:

$$\begin{cases} Y^{n,m} \cdot q_{edge}^{e,m}(t) = q_{stor,out}^{n,m}(t) - q_{stor,in}^{n,m}(t) + \xi_{prod}^{m} q_{prod}^{m}(t) \\ Q_{stor}^{n,m}(t+1) = Q_{stor}^{n,m}(t) + \left[q_{stor,in}^{n,m}(t) - q_{stor,out}^{n,m}(t) - \xi_{dem}^{m} q_{dem}^{n}(t)\right] \cdot \Delta t \cdot N_{td} \end{cases} \tag{1}$$

where q_{dem} is the hydrogen demand, q_{edge} is the quantity transported along edges, Q_{stor} is the storage level, $q_{stor,in}$ and $q_{stor,out}$ are the inlet and outlet storage flows, ξ_{prod} and ξ_{dem} are equal to 1 for production and demand nodes, respectively, and are zero otherwise, Y is the incidence matrix of the graph describing the transport network, Δt is the time interval that results from the time resolution of the model (expressed in days or fraction of days), and N_{td} is the number of typical days for which flows are repeated equally. The last two terms are detailed in the section "Hydrogen supply chain modelling", where the model timescale is discussed. As it can be inferred from Figure 1, each node may be connected to multiple edges, and the term $Y^{n,m} \cdot q_{edge}^{e,m}(t)$ is representative of the overall net hydrogen flow exiting from the node.

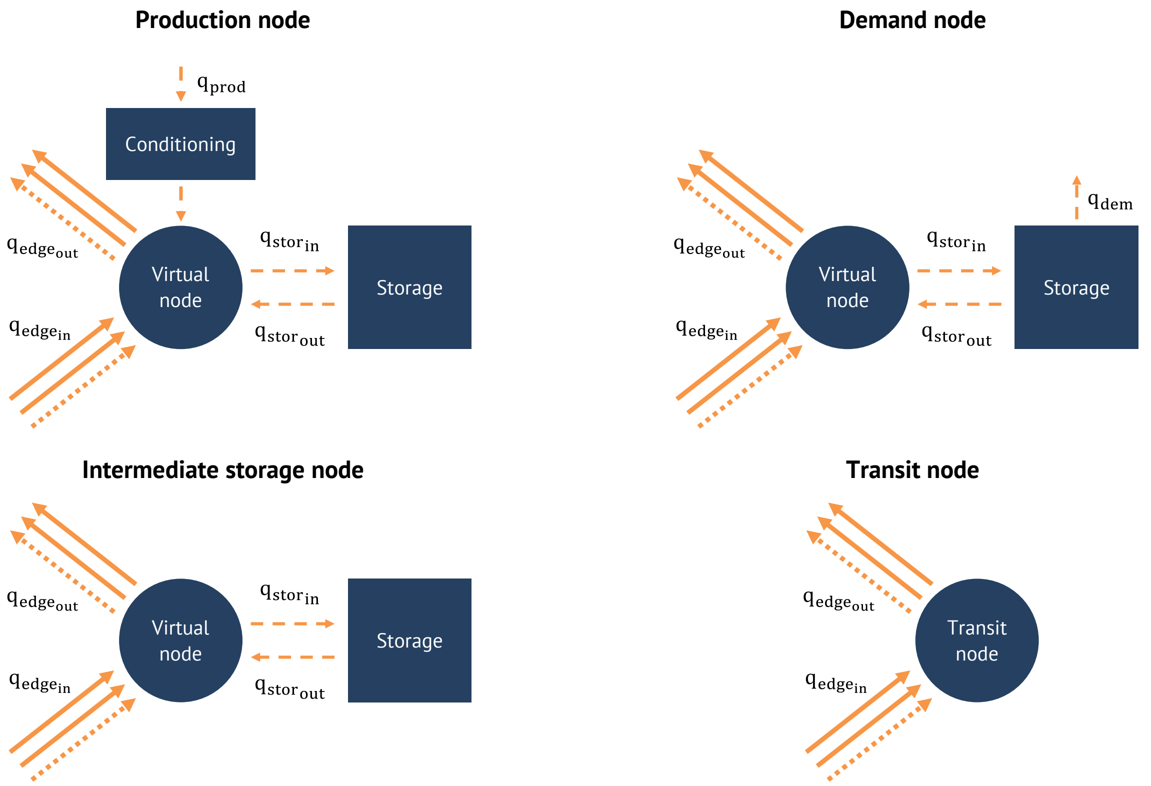

Figure 1. Network nodes modelling.

Georeferenced modelling

Local territorial constraints affect all stages of the supply chain. Hydrogen transport is extremely dependent on the features of the territory, both in the case of the deployment of new structures, such as a hydrogen pipeline network, which must comply with the space constraints of the region, and in the case of transport based on an existing infrastructure, which sets the available pathways, as in the case of road delivery via trucks. Moreover, the position and the distribution of sources and sinks strongly affect the choice of the transport modality: for example, pipeline delivery is favoured for long distances and large quantities, whereas compressed hydrogen trucks are more suitable for short distances and a more distributed demand [26]. Accordingly, the optimal design of the infrastructure is significantly influenced by the geographical features, and its modelling cannot be separated from that of the spatial constraints [9].

A detailed spatial description of the supply chain is ensured by building the candidate networks for pipeline and road transport from GIS spatial data, available in the *shapefile* format [51].

Although the validity of the approach is general, it has been here applied to the specific region of Lombardy in Italy, which is the case study on which the optimization model is finally applied and tested.
Assuming that the existing road network is not saturated, hydrogen trucks routes are assumed to run along the existing main roads and highways. For hydrogen pipelines, the hypothesis is that they could be installed following the existing railroad network, which represents an existing infrastructure where a right-of-way already exists [37]. Although this might not be the final choice in case a hydrogen pipeline network will be implemented, it is suitable for this study since it properly highlights a fundamental difference from the road network, i.e., having a lower extension and a different pathway. On the other hand, the actual position of natural gas pipelines, which would be the other and most likely candidate pathways for a hydrogen network, is not publicly available due to security concerns. Both the road and railroad network shapefiles are available on the geo-portal of the region [52].
As far as production facilities are concerned, the existing refineries of ENI Sannazzaro and Mol Mantova [53] are selected for SMR production equipped with CCS, whereas one large electrolysis system fed by solar PV is assumed to be installed in each province, located at the centroid.
For refuelling stations, the position of existing gasoline stations is adopted as candidate location, assuming that 10% of them (i.e., 366 stations for the case of Lombardy) will host hydrogen refuelling, selected according to a homogeneous spatial distribution.
The road and railroad network shapefiles are handled by means of a set of dedicated *Matlab* functions that allow to convert them into *directed graphs* and to connect production and demand nodes. The networks are simplified by keeping only the transit nodes where multiple edges intersect, thus preserving all the possible routes while reducing the dimension of the graphs. In addition, their complexity is further reduced by applying the *minimum spanning tree* algorithm, which allows to identify the subset of edges that yield the minimum extension of the network.
The directed graphs representing the candidate networks for pipeline and road transport are reported in Figure 2. Even after the simplification, their size is pretty large, as the former is made of 1243 nodes and 1242 arcs and the latter of 5158 nodes and 5157 arcs.
A total of 15 candidate intermediate storage nodes is identified for each graph through a random extraction among transit nodes, ensuring that the distance from each other is higher than 20 km.

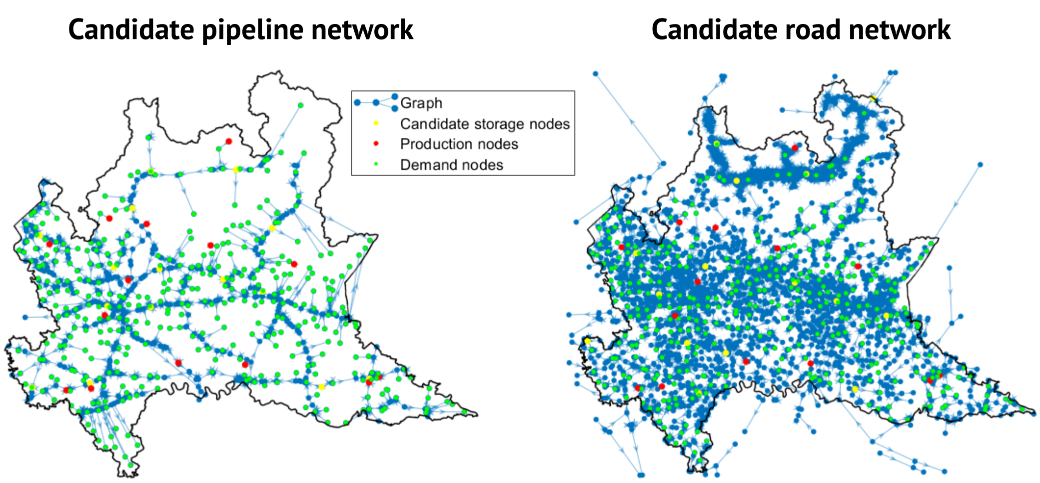

Figure 2. Candidate pipeline and road transport networks.

Hydrogen supply chain modelling

The optimization model adopts a mixed integer linear programming (MILP) formulation, and it is aimed at minimising the average cost of hydrogen delivered to refuelling stations, considering CAPEX and OPEX of all the elements of the infrastructure. Accordingly, the objective function is:

$$f_{ob} = \min \left\{ \frac{\sum_i CAPEX_i \cdot CRF_i + \sum_i OPEX_i}{\sum_n \sum_t Q_{dem}^n(t)} \right\} \quad (2)$$

where CRF is the capital recovery factor, and i, n, and t are indices referring to the supply chain components, nodes, and time steps, respectively.

The considered timeframe is one year and the adopted time resolution is daily. A "typical days" approach is implemented, identifying 52 different days, each repeated seven times to constitute the 52 weeks that form a year. In this way, a year-long analysis with daily resolution can be performed considering only 52 time steps instead of 365, with substantial advantages in terms of computational time while preserving a sufficient level of detail. Accordingly, in Eq. (1) the hydrogen flows are in metric tonnes per day (t/d), the time interval Δt is equal to 1 day, and the number of typical days N_{td} is equal to 7 days.

To summarise the structure of the model, the required input data are:

- the candidate networks topologies;
- the annual demand and the demand profiles;
- the production capacity limits (in t/d for refineries and in terms of PV peak power – MW_{nom} – for PV-fed electrolysis systems);
- the PV generation profiles;
- the storage capacity limits.

The resulting optimal configuration of the hydrogen infrastructure includes, for each edge and for each node:

- the employed transport modality;
- the installed production capacity;
- the installed storage capacity;
- the routes followed in transport and the delivered quantities.

Figure 3 shows a schematic representation of the possible hydrogen pathways envisaged in the model. As discussed in the section "Georeferenced modelling", the adopted approach leads to two different graphs representative of the candidate networks for road and pipeline delivery. While transport occurs on two parallel networks, production and demand nodes are unique and they are shared between the two graphs. Considering a generic production node, the produced quantity is "injected" in the respective graph through conditioning, from which variables, which are unique for production, are divided onto the two networks. As Figure 3 shows, intermediate storage is not envisaged for compressed hydrogen trucks, as their use involves a drop off at delivery points. Accordingly, it would be inefficient to deliver the hydrogen trailers to intermediate hubs and then to move them again, implying that is preferable to store the trailers at production sites and transport them to refuelling stations when required.

For production nodes, the optimization variables are the installed production capacity at PV-EL sites, the conditioning capacities, the hydrogen flow rates, the electricity imported from the grid, and the installed storage capacity. Along edges, variables include the installed pipeline capacity and the flow rates for the pipeline network, and the number of compressed and liquid hydrogen trucks running along the road network. The variables defined at candidate storage nodes are the storage capacity, the stored amount at each time step, and the incoming and outgoing flow rates, plus the compression capacity in the case of gaseous storage. Similarly, demand nodes feature variables for the storage capacity and level, for the incoming hydrogen flows, and for compression capacity and flow rates in the case of pipeline delivery. Binary variables are employed to ensure that each station receives hydrogen via one transport modality only.

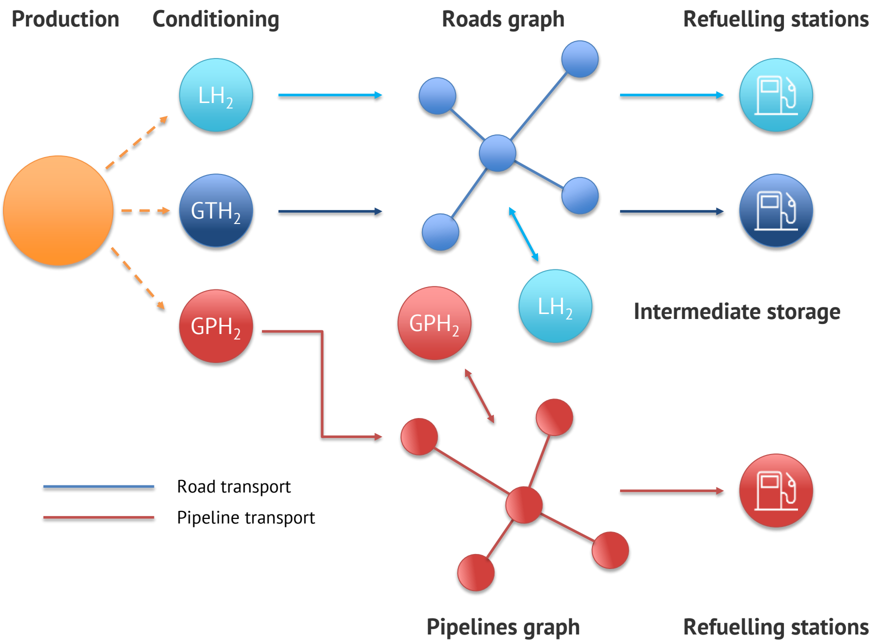

Figure 3. Schematic structure of the hydrogen pathways in the model.

Both compressed and liquid hydrogen trucks are described by means of integer variables. Together with the large size of the candidate transport networks, this makes the model extremely demanding in terms of computational time. Accordingly, some adjustments have been explored in order to be able to obtain a solution of the model on the regional scale in a reasonable time with the available computational resources (Intel Xeon W-2123 3.6 GHz processor, 32 GB RAM). Specifically, significant improvements are obtained by relaxing the integer variables representative of the number of delivery trucks to continuous values. This assumption might also be considered as an alternative description of the physics of the problem, as it is equivalent to envisage that trucks will be available with different capacities. For example, in the case of gaseous distribution, today's standard are 400 kg metallic tube trailers at 200 bar, whereas composite-based options at higher pressure, featuring a payload as large as 1,000 kg are entering the stage [41].

The simplification has been tested on simple topologies and compared to the complete formulation of the model with preliminary simulations. It emerged that extremely similar solutions can be obtained by imposing the storage capacity at demand nodes equal to the maximum daily demand prior to the simulation in the simplified formulation. With this adjustment, the error introduced in the value of the objective function with respect to the solution of the complete formulation of the model is lower than 1%; therefore, this effect is outweighed by the significant improvement of computational performances that is achieved, as the computational time is reduced by more than 90%. However, it must be stressed that the simplification is required only to deal with the regional case with the use of a common workstation; otherwise, provided the access to suitable computational resources, the complete formulation (which has also been validated, though on simple topologies) could be applied on a regional scale too.

Scenario assumptions

The developed model is applied to the investigation of the regional case study of Lombardy in Italy. The delivered hydrogen amount corresponds to an average vehicle stock share of 25% FCEVs among passenger cars in the country in 2050, with slight deviations between regions, according to population, vehicle ownership, and income per capita [54]. The hydrogen demand is computed for each province in the considered region and then distributed uniformly among the assumed 366 refuelling stations equipped with hydrogen sale. The resulting annual demand is 145 kt/y in the region, ranging between 0.2-1.1 kt/y per station.

For production via SMR with CCS, the available export capacity is assumed equal to 20% of today's refinery hydrogen production. The maximum PV installed capacity devoted to hydrogen production is assumed for each province to be five times the capacity installed in 2018, thus ensuring that the proportion among provinces is preserved.

RESULTS AND DISCUSSION

The solution of the model is obtained in 43 computational hours, and the resulting average cost of hydrogen delivered to refuelling stations is 5.83 €/kg. The obtained optimal infrastructure relies on all the three transport modalities, with a predominance of pipeline and liquid hydrogen truck delivery, which supply 173 and 171 refuelling stations, respectively, while compressed hydrogen truck delivery is adopted for 22 demand sites.

Figure 4 shows the distribution of production sites and their installed nominal capacities. As expected, thanks to the lower production cost, refineries operate at base-load capacity throughout the year, providing an annual production of 9 kt/y. Due to proximity, SMR production is mainly devoted to satisfy the demand of southern provinces in the region. On the other hand, PV-fed electrolysis systems are installed in ten of the twelve candidate sites, the largest being in the provinces of Milano, Varese, Bergamo, and Brescia, in correspondence of the highest demand values. Overall, 6 GW_e of PV and 3 GW_e of electrolysers are installed, providing a yearly hydrogen production of 136 kt/y. Electrolysers mainly rely on the electricity generated from PV, while the import from the electric grid is minimal due to the high purchase cost related to both the grid price and the introduction of a carbon tax.

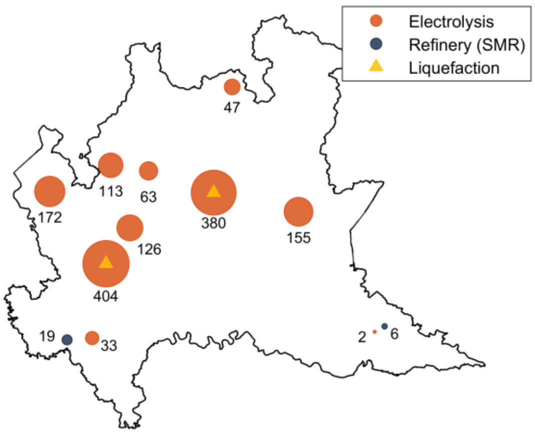

Figure 4. Location and capacity (in metric tonne per day) of production sites; location of liquefaction sites.

The optimal transport networks and the size of the installed pipelines are shown in Figure 5. With respect to the candidate networks (see Figure 2), the exploited edges are highlighted in red. For each technology, only the production, storage, and demand nodes in which such technology is adopted are represented. The installed pipeline network spans the entire region and is connected to all the production nodes (depicted in purple). The average pipelines diameter is 10 cm, whereas the maximum is 30 cm, and it is employed for the routes exiting the largest production facilities, prior to the ramification. Such values represent the optimal diameters for the assigned hydrogen demand, but actual installations may prefer larger pipelines in view of allowing a demand increase due to higher vehicle shares or to the addition of other uses (e.g., sector coupling with industrial plants or power generation). The road network exploited by compressed hydrogen trucks is less extensive, and the two refineries and the electrolysis facility of the Brescia province are not connected to it. The conclusion that this transport modality is more appropriately exploited to supply a small number of stations is consistent with its general suitability for small delivery requirements. The road network travelled by liquid hydrogen trucks, instead, is quite widespread, with most of the supplied hydrogen refuelling stations in the southern part of the region. Since the demand of such provinces is lower with respect to those in which pipeline delivery is the main option (located in the central-western part of the region), the consumption of liquid hydrogen represents only 25% of the total, even though the number of stations supplied is almost equal to those receiving hydrogen via pipeline, which, instead, account for 64% of the total consumption. Since liquefiers are assumed to have a minimum capacity of 50 t/d [26], the production of liquid hydrogen is concentrated in two sites only (highlighted in Figure 4), which, therefore, are the only production nodes connected to the LH_2 network. Moreover, four intermediate liquid storage hubs are present, with capacities that range from 183 t to 1,000 t. Analysing the time evolution of the storage level throughout the year, it emerges that all four facilities are able to absorb the summer overproduction of hydrogen from PV-fed electrolysers and deliver it later during winter.

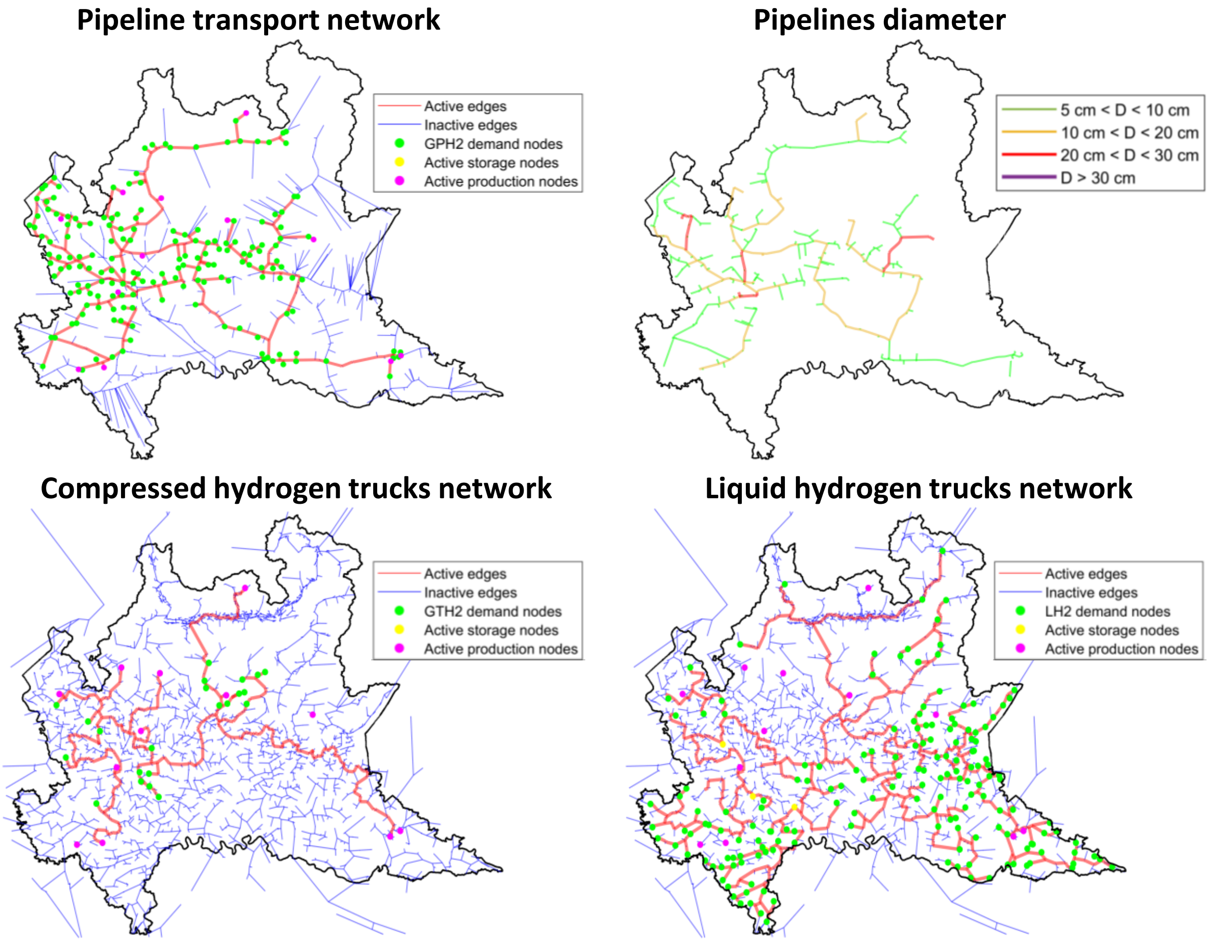

Figure 5. Resulting transport networks and pipeline size for the Italian region of Lombardy.

Figure 6 shows the breakdown of the average cost of hydrogen, for each technology and overall. Exceeding 7 €/kg, the highest average cost is reached by the stations that receive liquid hydrogen, due to the higher expenditures of liquefaction with respect to compression (conditioning is included in the production contribution in the figure). The lowest value is reached by stations supplied via pipeline, with an average cost of 5.20 €/kg. Gaseous truck delivery has an average cost closer to the pipeline technology, with a value of 5.62 €/kg, but with a more significant role of the station term, due to the storage that requires the drop off of tube trailers. The weighted average returns the overall average cost of 5.83 €/kg. Comparing the overall cost breakdown with those by technology, it emerges that the transport contribution is mainly due to the pipelines installation, whereas the intermediate storage cost is only related to liquid hydrogen, since this is the only modality for which it is present.

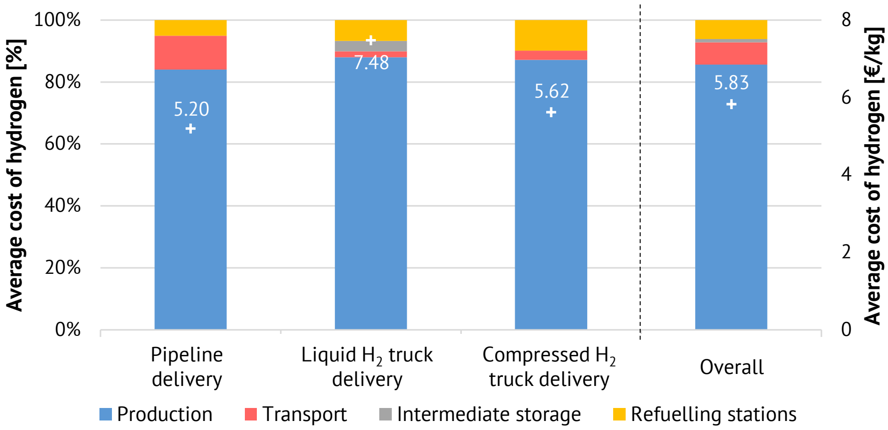

Figure 6. Average cost of hydrogen breakdown.

The greatest contribution is that of production, which accounts for more than 80% of the cost. The detailed breakdown of the production expenditure is reported in Figure 7. The shares related to capital costs of PV and electrolysis plants are the main items, representing together more than 60% of the overall production expenses to provide 94% of the delivered hydrogen (the remaining being left to SMR plants). It is also interesting to notice the contribution of the PV generation surplus revenues, which lower the cost by about 30 M€/y. The annual surplus is approximately 1 TWh_e, which correspond to about 1.5% of the region's annual consumption of electric energy, thus highlighting the interaction that the hydrogen infrastructure can have with the power sector. Finally, conditioning accounts for 12% of the overall production expenditure.

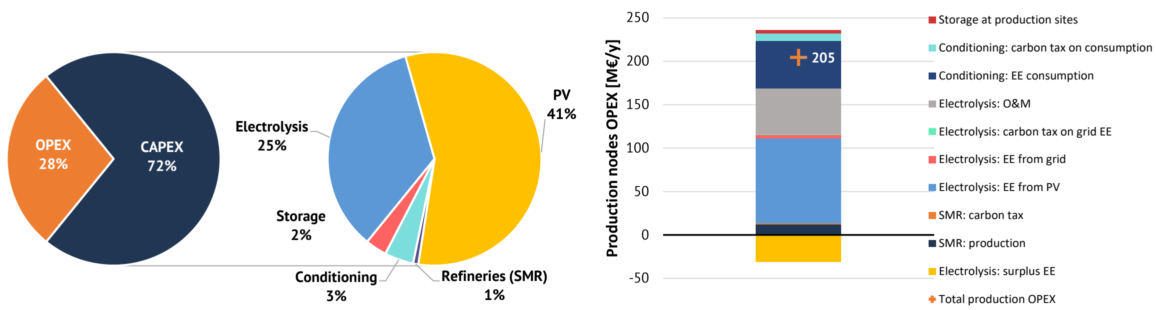

Figure 7. Production expenditure breakdown: CAPEX (left) and OPEX (right).

The total investment cost of the hydrogen infrastructure is estimated at 6.1 G€. Considering the assumed number of FCEVs (25% of the passenger car stock), this leads to a cost per vehicle of about 3,400 €, which is consistent with the values reported by the Fuel Cells and Hydrogen

Joint Undertaking [55]. As a term of comparison, cost expenditures related to infrastructural interventions are typically in the range of € billion: for example, a plan for 8.9 G€ has been defined by *Terna SpA*, the Italian electric grid TSO, for the infrastructure upgrade to be realized between 2021 and 2025 [56], and similar investments are also foreseen in the same period for the evolution national gas grid [57]. Moreover, to assess the magnitude of the investment, the obtained value can be weighted on the gross domestic product (GDP) of the region: considering that between 2016 and 2018 the GDP of Lombardy was approximately 375−390 G€ [58], the infrastructure cost would represent about 1.6% of the GDP. Assuming that the investment will be spread over 20 years and that the GDP will not vary significantly, the annual impact would be in the order of 0.08%. Accordingly, the investment does not appear unbearable, and a more precise assessment should consider the positive impact on the GDP itself in terms of value added and jobs created [59].

CONCLUSIONS

The study presented in this work addressed the problem of the optimal design and operation of a hydrogen distribution infrastructure for clean mobility uses, by developing a georeferenced MILP optimization model of the supply chain. The developed tool aimed at filling the research gap of having a model that combines a detailed spatial description of the infrastructure with a sufficiently refined time resolution and a multi-transport modality formulation. The presented georeferenced modelling methodology provides a general approach that allows to convert GIS data into directed graphs, thus introducing detailed spatial features in the optimization problem, which are required to properly represent the specific characteristics of the different transport modalities and to ensure the feasibility of the resulting infrastructure.

The Italian region of Lombardy was investigated as a test case, looking at a 2050 scenario in which FCEVs account for 25% of the passenger vehicles' stock and clean hydrogen production is provided for a baseline share via centralized SMR plants equipped with CCS (for which it is assumed a cap in terms of maximum capacity) and for the largest part by electrolysis systems fed by solar PV.

The application to the case study provides valuable insights on the optimal design strategies of a future hydrogen infrastructure. The resulting average cost of hydrogen delivered to refuelling stations is 5.83 €/kg, and the main contribution is related to the capital expenditure of PV-based electrolysis plants, which account for 94% of total production, whereas the assumed SMR plants capacity is saturated. The results proved the relevance of the multi-transport modality formulation in modelling the hydrogen supply chain, as the cost-optimal infrastructure employs all the three transport technology, exploiting the advantages that each one offers. As far as the economic sustainability of the hydrogen supply chain is concerned, further infrastructural integration over wider areas, improved production options (including also a different share of SMR+CCS plants as well as biomass, wind or other renewable sources), or the integration with other sectors (power generation, steel industry, production of chemicals) appear essential to further reduce the cost impact and to approach a more competitive long-term target hydrogen cost of 4 €/kg.

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NOMENCLATURE

Symbols		
Symbol	**Definition**	**Unit**
CO_2	Carbon dioxide	
GPH_2	Gaseous hydrogen transported via pipeline	
GTH_2	Compressed hydrogen transported via truck	
H_2	Hydrogen	
LH_2	Liquid hydrogen transported via truck	
q_{dem}	Hydrogen demand	t/d
q_{edge}	Hydrogen flow from/to edges	t/d
q_{prod}	Hydrogen production flow	t/d
Q_{stor}	Hydrogen storage level	t
$q_{stor,in/out}$	Hydrogen inlet/outlet storage flow	t/d
t	Time step	
Y	Directed graph incidence matrix	
$\xi_{dem,n}$	1 if n is a demand node, otherwise 0	
$\xi_{prod,n}$	1 if n is a production node, otherwise 0	

Subscripts and superscripts	
Symbol	**Definition**
e	Graph edge
i	Supply chain component
m	Transport modality
n	Graph node

Acronyms	
Symbol	**Definition**
BEV	Battery Electric Vehicle
CAPEX	Capital expenditure
CCS	Carbon Capture and Storage
CRF	Capital Recovery Factor
EU	European Union
FCEV	Fuel Cell Electric Vehicle
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
GDP	Gross Domestic Product
GIS	Geographic Information System
LCOE	Levelized Cost Of Electricity
MILP	Mixed Integer Linear Programming
OPEX	Operational expenditure
PV	Photovoltaic
RAM	Random Access Memory
SMR	Steam Methane Reforming
USA	United States of America

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